SHELL CANADA LIMITED

Quest Carbon Capture and Storage Project

DIRECTIVE 65: APPLICATION FOR A CO_2 ACID GAS STORAGE SCHEME

Prepared by:
Shell Canada Limited
Calgary, Alberta

November 2010

Executive Summary

Shell Canada Limited (Shell), on behalf of the Athabasca Oil Sands Project, which is a joint venture between Shell Canada Energy, Chevron Canada Limited, and Marathon Oil Canada Corporation, is applying to construct, operate and reclaim the Quest Carbon Capture and Storage (CCS) Project (the Quest CCS Project). The goal of the Quest CCS Project is to separate, capture and permanently store carbon dioxide (CO_2), thereby reducing greenhouse gas emissions from the existing Scotford Upgrader. The Scotford Upgrader is located about 5 km northeast of Fort Saskatchewan, Alberta, within Alberta's Industrial Heartland, which is zoned for heavy industrial development.

The three components of the Quest CCS Project are:

- CO_2 capture infrastructure, which involves a process modification to the existing Scotford Upgrader. The method of capture is based on a licensed Shell amine system called ADIP-X.
- a CO_2 pipeline, about 84 km in length, which will transport the CO_2 from the Scotford Upgrader to the injection wells. The CO_2 injection well locations are in the CO_2 storage area of interest.
- a storage scheme consisting of 3 to 10 injection wells, which will inject the 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 scope of this application is limited to the CO_2 acid gas storage scheme (the Project).

Shell is applying to the Energy Resources Conservation Board for approval to inject up to 1.2 million tonnes per year (Mt/a) of CO_2 into the BCS through a maximum of 10 injection wells. One of the proposed CO_2 injection wells, located at 100/08-19-059-20W400, was developed as an appraisal well in 2010. Locations for an additional four wells were identified in 2010. The one licensed well and four identified locations are included in this application.

The BCS contains no hydrocarbons and is, on average about 40 m thick. The CO_2 will be contained within the BCS by a combination of three regionally extensive geological seals. The total thickness of the seals is over 120 m, and available seismic data indicate that no faults transect the seals. Between the seals and the base of ground water protection are more than 1,500 m of overlying strata.

The design capacity of the storage scheme is based on the CO_2 capture infrastructure, which will have:

- a stream day (or nameplate) capacity of up to 1.2 Mt/a of CO_2 (higher than 95% purity)
- a calendar day capacity of 1.08 Mt/a of CO_2 (based on an onstream factor of 90%)

The Quest CCS Project has been selected to receive funding from the Government of Canada Clean Energy Fund and the Government of Alberta Carbon Capture and Storage Fund. Shell expects the Quest CCS Project to reach full capacity by the end of 2015. Shell's Project Execution Plan has been developed to meet this expectation, subject to receiving timely regulatory approvals. The Quest CCS Project was endorsed by the Carbon Sequestration Leadership Forum at its Warsaw meeting in October 2010.

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Acronyms and Abbreviations

2D	two-dimensional
3D	three-dimensional
AENV	Alberta Environment
AOI	area of interest
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
CEAA	*Canadian Environmental Assessment Act*
CSLF	Carbon Sequestration Leadership Forum
DNV	Det Norske Veritas
EA	environmental assessment
EIA	environmental impact assessment
EPEA	*Environmental Protection and Enhancement Act*
ERCB	Energy Resources Conservation Board
ERP	Emergency Response Plan
FBDP	fracture break down pressure
FCP	fracture closure pressure
FEP	fracture extension pressure
FMI	Formation MicroImager
GHG	greenhouse gas
GOA	Government of Alberta
HARP	Heartland Area Redwater Project
HMU	hydrogen manufacturing unit
IEA	International Energy Agency
IPAC-CO2	International Performance Assessment Centre for Geologic Storage of CO_2
IPCC	Intergovernmental Panel on Climate Change
KB	kelly bushing
LMS	Lower Marine Sands
MASL	metres above sea level
MBSL	metres below sea level
MCS	Middle Cambrian Shale
MD	measured depth
MDSS	measured depth subsea
MDT	Modular Formation Dynamics Tester
MMV	measurement, monitoring and verification
NMR	nuclear magnetic resonance
NRTEE	National Round Table on the Environment and the Economy
Shell	Shell Canada Limited
TDS	total dissolved solids
the Project	injection and storage of CO_2 in the BCS saline aquifer
TVDSS	true vertical depth subsea
UMS	Upper Marine Siltstone
UWI	unique well identifier

WCSB.. Western Canada Sedimentary Basin
XRD .... x-ray diffraction

1 Introduction

Shell Canada Limited (Shell), on behalf of the Athabasca Oil Sands Project (AOSP), is applying for approval for the Quest Carbon Capture and Storage (CCS) Project (the Quest CCS Project). The Quest CCS Project is a proposed fully integrated CCS project located northeast of the City of Edmonton.

AOSP is a joint venture between Shell Canada Energy (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%).

Shell Canada Limited will hold all the necessary regulatory approvals with respect to the Project. Shell Canada Energy will operate the Project. Shell Canada Limited is the managing partner of Shell Canada Energy.

The Quest CCS Project will result in the capture and storage of up to 1.2 million tonnes per year (Mt/a) of carbon dioxide (CO_2) from the Scotford Upgrader.

The three main components of the Quest CCS Project (see Figure 1-1) are:

- CO_2 capture infrastructure, which involves a process modification to the existing Scotford Upgrader
- a CO_2 pipeline to transport CO_2 to storage infrastructure located north of Shell Scotford
- injection well storage infrastructure for permanent storage of CO_2 in a deep saline geological formation

The scope of this application is limited to the Class III CO_2 storage scheme (the Project). The application includes five unique well identifiers (UWIs). The Project application also outlines the proposed storage scheme, including well count, CO_2 storage area of interest (AOI), the Basal Cambrian Sands (BCS) storage complex, storage fluid class, injection volumes, and period of commercial operation.

1.1 Quest Carbon Capture and Storage Project

1.1.1 Quest CCS Project – Description

The Quest CCS Project is a fully integrated CCS Project with three components: CO_2 capture infrastructure, CO_2 pipeline and CO_2 storage.

CO_2 Capture Infrastructure

Up to 1.2 Mt/a of CO_2 will be captured from three hydrogen manufacturing units (HMUs) at the Scotford Upgrader. These HMUs manufacture hydrogen to upgrade oil sands bitumen. The method of CO_2 capture will be based on a commercially proven activated amine technology called Shell ADIP-X. The CO_2 capture and compression infrastructure also includes multistage compression of the captured CO_2 into a dense phase ready for transportation. The dense-phase composition will contain CO_2 in quantities higher than 95% by volume.

CO_2 Pipeline

Transportation of the captured CO_2 will be via a CO_2 pipeline, from the Scotford Upgrader to a storage area north of the Scotford Upgrader (see Figure 1-1). The CO_2 pipeline is about 84 km in length, of which about 28 km will be parallel to existing pipeline rights-of-way.

The pipeline will be sized to handle a CO_2 flow rate of 8,200 t/d, and has a design capacity of 3,300 t/sd.

CO_2 Storage

Wells will be designed for injection of CO_2 into the BCS, at a depth of approximately 2 km below the surface. A measurement, monitoring and verification (MMV) plan will be implemented.

The transport and storage volumes are based on the design of the CO_2 capture infrastructure, which will have:

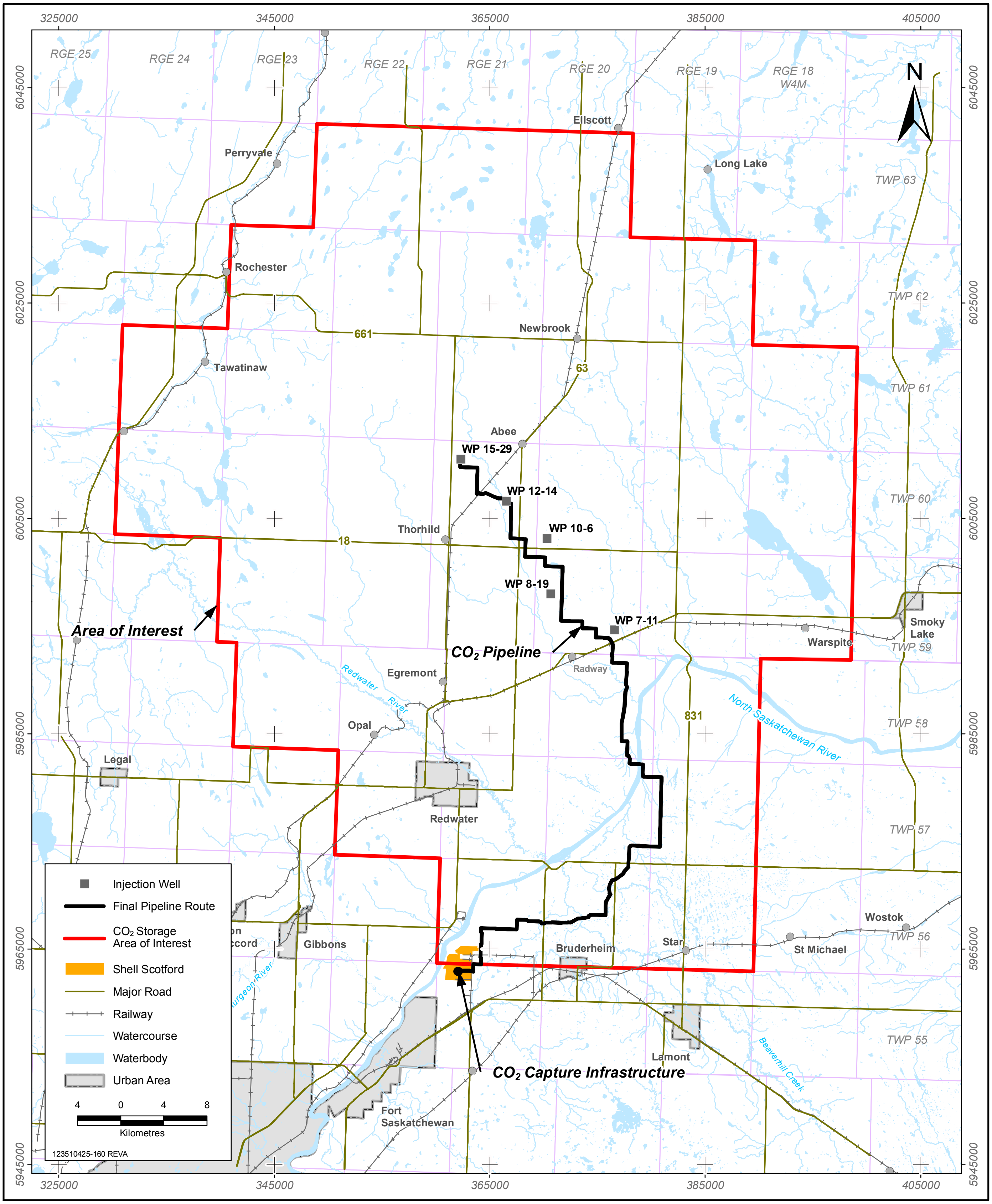
- a stream day (or nameplate) capacity of up to 1.2 Mt/a of CO_2
- a calendar day capacity of 1.08 Mt/a of CO_2 (assuming an onstream factor of 90%)

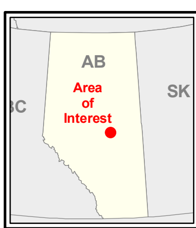
The cumulative stored volume is expected to be greater than 27 Mt of CO_2 over the expected life of the Scotford Upgrader (greater than 25 years)

1.1.2 Quest CCS Project – Location

The CO_2 capture infrastructure will be incorporated as a process modification to the existing Scotford Upgrader, on lands within the developed area of the Scotford Upgrader. The CO_2 pipeline will extend from the Scotford Upgrader, north across the North Saskatchewan River and will terminate north of the village of Thorhild. The 3 to 10 injection wells will be situated in the CO_2 storage AOI, occupying 40 townships in area, ranging from Townships 56 to 63 and Ranges 18 to 24, all west of the Fourth Meridian.

For the location of the proposed CO_2 capture infrastructure, the CO_2 pipeline and the proposed location of the first five injection wells, see Figure 1-1. For the location of the proposed CO_2 capture infrastructure in relation to Shell Scotford and nearby industrial facilities, see Figure 1-2.





QUEST CARBON CAPTURE AND STORAGE PROJECT

Quest CCS Project Components and Area of Interest

Acknowledgements: Original Drawing by Stantec
Pipeline: Sunstone Engineering October 15, 2010, Wells: Shell August 26, 2010, Basedata: National Road Network, Canvec, Altalis

PREPARED BY Stantec

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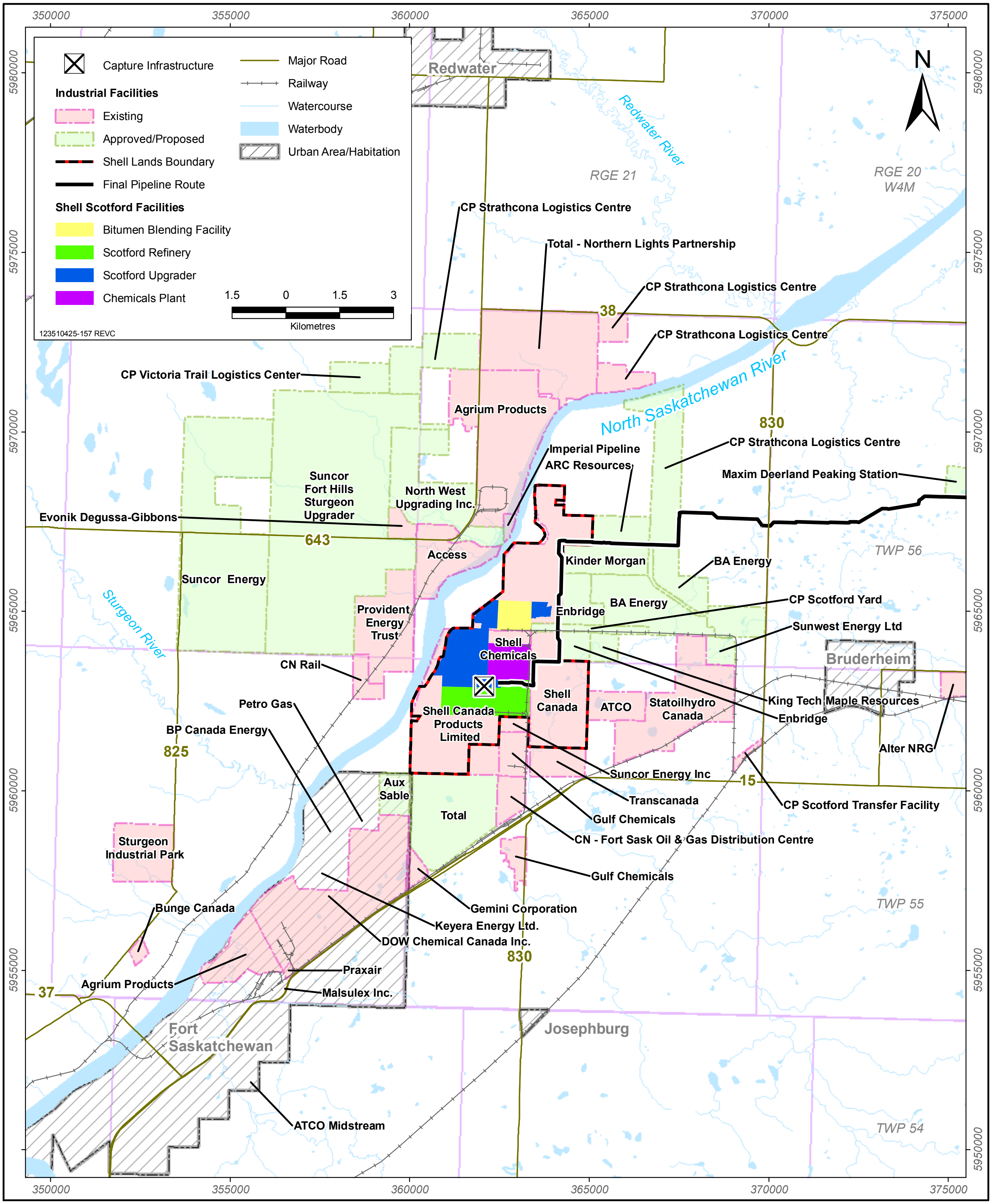
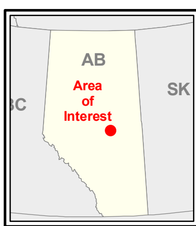
FIGURE NO. 1-1

Last Modified: Nov 18, 2010 By: jpetho





QUEST CARBON CAPTURE AND STORAGE PROJECT

Land Ownership and Urban Areas in the Vicinity of Shell Scotford

Acknowledgements: Original Drawing by Stantec
Pipeline: Sunstone Engineering October 15, 2010, Wells: Shell August 26, 2010, Basedata: National Road Network, Canvec, Altalis, Land Ownership: Alberta's Industrial Heartland Association February 9, 2009

PREPARED BY Stantec

PREPARED FOR

FIGURE NO. 1-2

Last Modified: Nov. 16, 2010 By: jpetho

1.1.3 Quest CCS Project – Schedule

The timing for the construction start-up and operation of the Quest CCS Project is expected to be as follows:

- Construction of the CO_2 capture infrastructure will begin in the third quarter of 2012 and continue until the end of 2014.
- Construction of the CO_2 pipeline will begin in the fourth quarter of 2013 and end in the second quarter of 2014.
- Construction of the lateral pipelines and drilling of the injection wells will take place between the third quarter of 2013 and the end of the third quarter of 2014.

Final investment decision on the Quest CCS Project is anticipated in Q1 of 2012.

The integrated Quest CCS Project will become operational in conjunction with the commissioning and start-up of the CO_2 capture infrastructure. Commissioning and start of operations ramp-up of the full Quest Project is anticipated to begin in the first quarter of 2015. Full sustained operation will be achieved by the fourth quarter of 2015. The Quest CCS Project is expected to operate for greater than 25 years.

These timelines are subject to change, pending regulatory approval, market conditions and internal and joint venture Project approvals.

For the integrated Quest CCS Project schedule, see Figure 1-3.

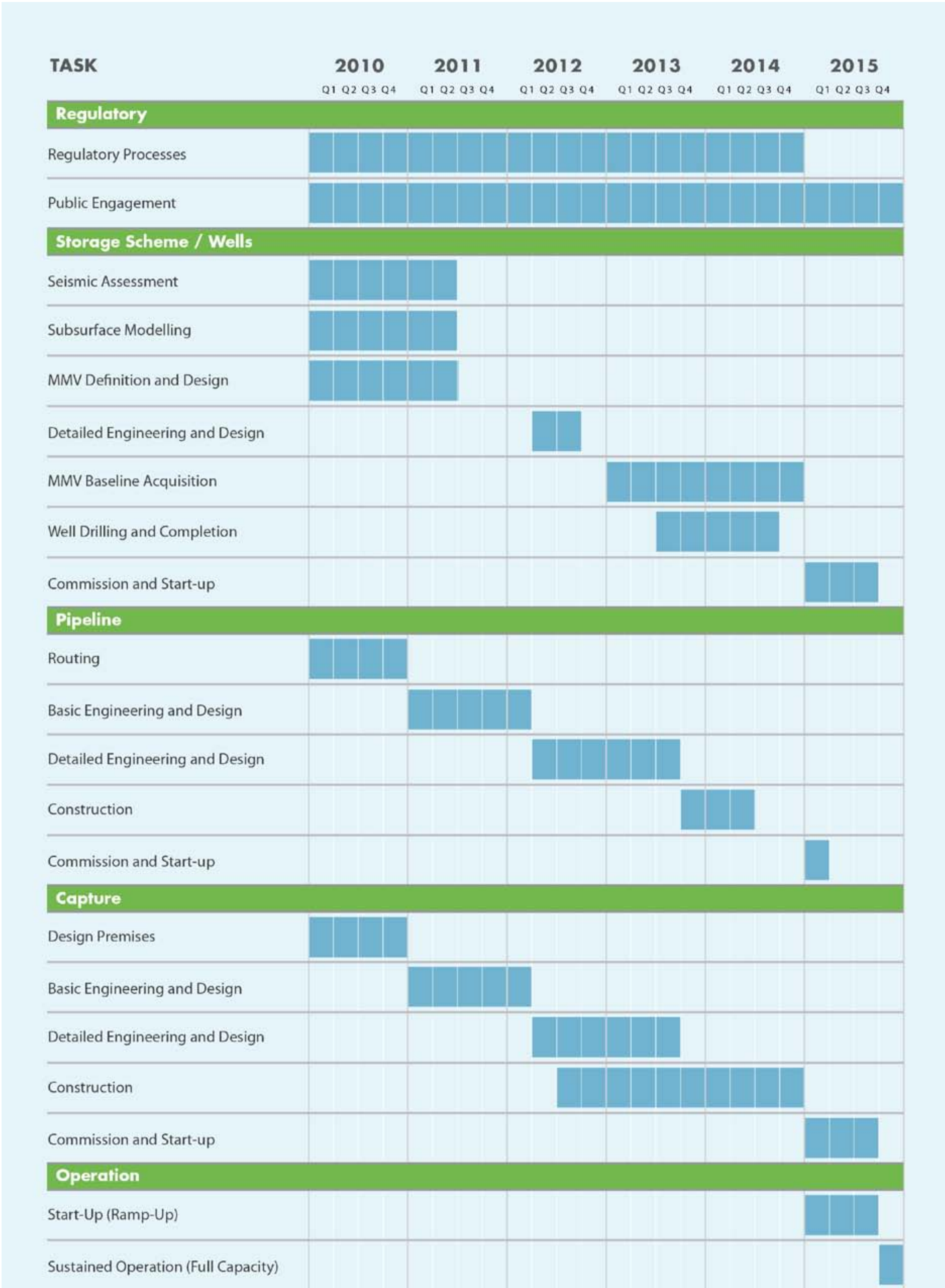


Figure 1-3 Quest CCS Project Schedule

1.1.4 Quest CCS Project – Need for the Project

The goal of the Quest CCS Project is to reduce greenhouse gas (GHG) emissions from the Scotford Upgrader through an integrated CCS project. There are no other large-scale commercial alternatives to direct GHG reduction as that offered by the Quest CCS Project. Shell's GHG mitigation strategy has several approaches (see the Environmental Assessment [EA], Volume 1, Section 7.4), of which the Quest CCS Project is just one. In the absence of the Quest CCS Project as an offset, Shell would continue to advance compliance options under the Alberta *Specified Gas Emitters Regulation*, including:

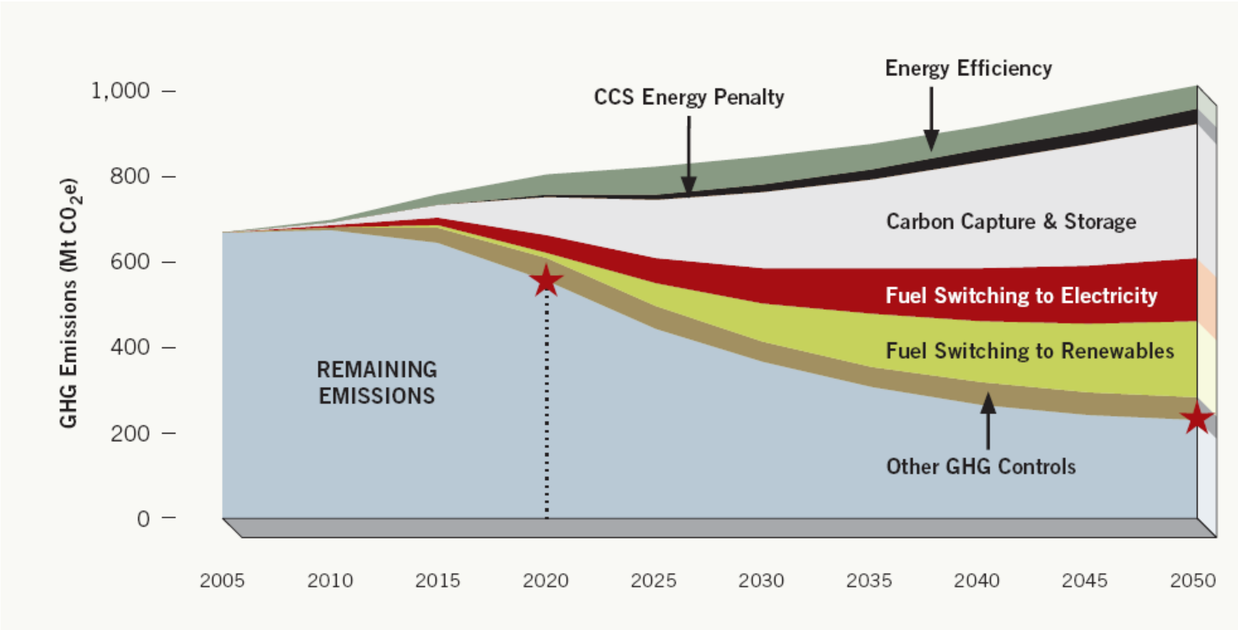
- additional improvements to energy efficiency
- using lower GHG-emitting energy supplies
- purchasing Alberta-sourced offsets
- contributing to the Climate Change and Emissions Management Fund

Canada and Alberta Climate Change Objectives

At the United Nations Climate Change Conference in Copenhagen in 2009, Canada announced its goal to cut CO_2 emissions by 20% below 2006 levels by 2020, and 60% below 2006 levels by 2050 (National Round Table on the Environment and the Economy [NRTEE] 2009). Subsequently, this target was updated to a 17% reduction in GHG emissions from 2005 levels by 2020, to align with the US target (Government of Canada 2010a, Internet site). According to the International Energy Agency (IEA), CCS is the only technology available to mitigate CO_2 emissions from large-scale fossil fuel use. The Intergovernmental Panel on Climate Change (IPCC) indicates that CCS technology has the potential to address climate-changing CO_2 emissions quickly.

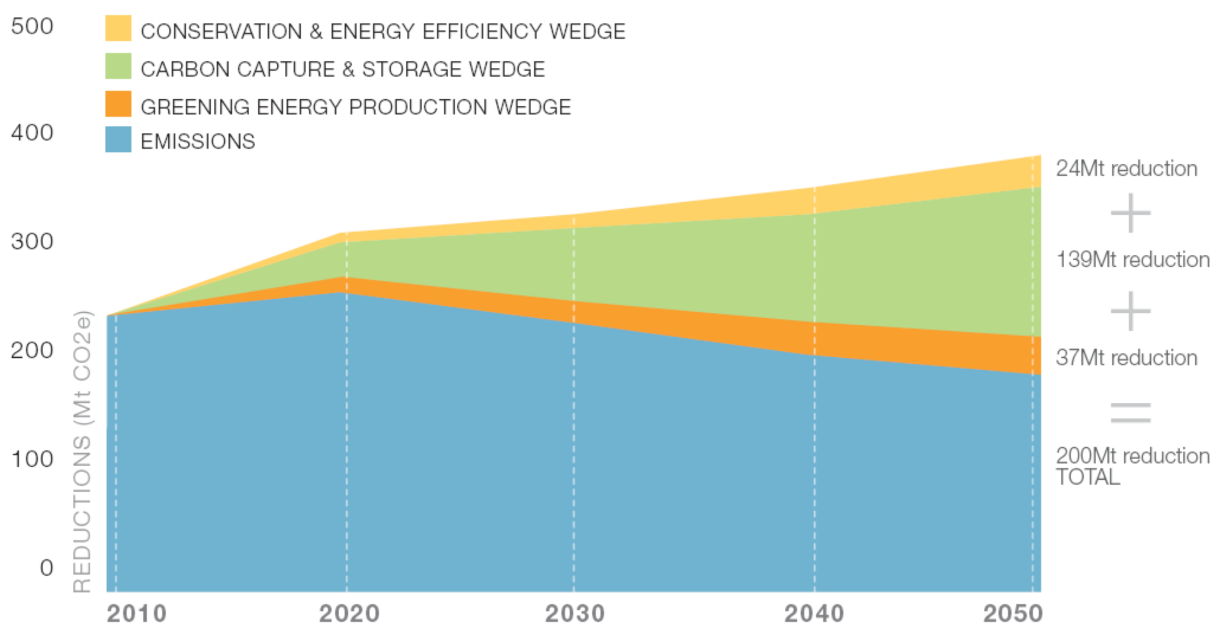
Through the Clean Energy Fund, the Government of Canada intends "to support and promote clean energy by providing funding for research into clean energy technologies such as CCS" (Government of Canada 2010b, Internet site), and to date has provided up to $466 million in support of three CCS projects in Alberta, including the Quest CCS Project. The Government of Canada policy would see CCS technology used to reduce CO_2 emissions by 325 Mt by 2050 (see Figure 1-4; NRTEE 2009).

CCS technology is an important component of the Government of Alberta's Climate Change Strategy (GOA 2008). An action item identified as part of this strategy was to support research and demonstration projects on CCS. Through the use of CCS technology, the Government of Alberta intends to reduce CO_2 emissions by 139 Mt by 2050. This, combined with increased energy conservation and efficiency, and other green energy technologies, would contribute to an overall reduction in CO_2 emissions of 200 Mt by 2050 (see Figure 1-5).



SOURCE: NRTEE (2009)

Figure 1-4 CCS Technology in the Reduction of CO_2 Emissions in Canada



SOURCE: GOA (2008)

Figure 1-5 CCS Technology in the Reduction of CO_2 Emissions in Alberta

Shell's CO_2 Emission Abatement Strategy

As a large industrial emitter of greenhouse gases in Alberta, Shell is required under the *Specified Gas Emitters Regulation* to reduce emission intensity. The Quest CCS Project is needed as a key component of Shell's greenhouse gas abatement strategy. Shell contributed $5 million toward founding the International Performance Assessment Centre for Geologic Storage of CO_2 (IPAC-CO2) at the University of Regina. The IPAC-CO2 will focus on key elements of the geological storage of CO_2, including:

- networking internationally to share and build on the findings of the other research organizations
- interacting with key stakeholders to identify emerging issues and ensure effective and acceptable risk assessment techniques are developed, applied and communicated
- creating communications to educate the public and build broad acceptance of CCS technology
- developing a pool of qualified personnel in the areas of performance and risk assessment

The Quest CCS Project will support Alberta and Canada's drive to address climate change as part of a global effort. The Quest CCS Project received global recognition and validation in October 2010, when it was endorsed by the Carbon Sequestration Leadership Forum (CSLF) as one of five new CO_2 capture projects to be added to its existing research and development portfolio. The CSLF is a global voluntary climate initiative of developed and developing nations that account for 75% of all anthropogenic CO_2 emissions. The members engage in cooperative technology development aimed at enabling the early reduction and steady elimination of CO_2 emissions (CSLF 2010a, Internet site; CSLF 2010b, Internet site).

The Quest CCS Project will provide several ancillary benefits for both Alberta and Canada. These ancillary benefits and synergies include:

- reductions of up to 1.2 Mt/a of CO_2 from 2015 onward—a material contribution to sustaining a key driver of the economic prosperity in Alberta
- demonstrating CO_2 storage capacity in a deep saline formation, which is essential for Alberta to meet its climate change strategy goals of 50 Mt/a of CO_2 storage by 2020 and 139 Mt/a storage by 2050
- promoting innovation for Alberta through the development and deployment of CO_2 capture and geological storage expertise. This can be applied across a variety of new and existing industrial sectors, including upgrading, refining and petrochemicals.
- creating value for Alberta by opening a new sector and developing technology, expertise, services and resources that could be marketed in North America and worldwide
- facilitating CCS projects in Alberta's Industrial Heartland—an industrial area with the potential for up to 4 Mt/a CO_2 capture between 2015 and 2020

1.1.5 Quest CCS Project – Regulatory Applications

To enable the construction and operation of the Quest CCS Project, Shell is requesting new licences and approvals, as well as amendment to existing approvals from provincial authorities. Shell is also submitting an EA for the provincial and federal authorities.

Shell is also applying to the ERCB for the flexibility to receive third-party CO_2, or to produce and export CO_2 to third parties from the capture infrastructure.

The major regulatory approvals requested by Shell for the Quest CCS Project are summarized below.

CO_2 Capture Infrastructure

The CO_2 capture infrastructure approvals include:

- amendment to the Scotford Upgrader Energy Resources Conservation Board (ERCB) Approval No. 8522 (as amended) pursuant to Section 13 of the *Oil Sands Conservation Act* for approval to construct and operate the CO_2 capture infrastructure
- amendment to the Scotford Upgrader Alberta Environment (AENV) Approval No. 49587-01-00 (as amended) pursuant to Division 2, Part 2 of the *Alberta Environmental Protection and Enhancement Act* (*EPEA*) for approval to construct, operate and reclaim the CO_2 capture infrastructure

CO_2 Pipeline

The CO_2 pipeline approvals include:

- applications for the construction and operation of the main CO_2 pipeline pursuant to Part 4 of the *Pipeline Act*
- Conservation and Reclamation (C&R) Plan for a Class I pipeline (see Volume 1, Appendix E), as specified under the Alberta *EPEA Activities Designation Regulation*

CO_2 Storage

The CO_2 storage approvals include:

- application to the ERCB for a Class III disposal scheme pursuant to Part 6, Sections 11, 12 and 39 of the *Oil and Gas Conservation Act*, and Part 15 of the *Oil and Gas Conservation Regulations*
- an environmental impact assessment (EIA) as directed by the Government of Alberta and under the Alberta *EPEA*. This will focus on the storage component of the Quest CCS Project, and will be submitted to the Government of Alberta concurrently with Shell's applications to the ERCB.

Environmental Assessment

Government of Canada funding of the Quest CCS Project triggers the need for an EA under the *Canadian Environmental Assessment Act* (*CEAA*) (Section 5(1)(b) of *CEAA*). This will address all three components of the Quest CCS Project. *The Canada–Alberta Agreement on Environmental Assessment Cooperation* (the Agreement) guides federal-provincial cooperation for the environmental assessment of projects subject to both the *CEAA* and the Alberta *EPEA*. A cooperative EA that is consistent with the Agreement, meaning a single EA, will be prepared by Shell to meet the requirements of both the *CEAA* and the *EPEA*.

1.2 CO_2 Storage Scheme – Project Description

The CO_2 storage scheme, referred to herein as the Project, is a storage scheme comprising 3 to 10 injection wells. The storage scheme is supported by an associated MMV plan. The BCS storage complex consists of all horizons from the top of the Upper Lotsberg Salt to the Precambrian basement (see Section 2.4). The CO_2 will be permanently contained within the BSC storage complex. The CO_2 injection zone for all injection wells is the BCS saline aquifer, located at the base of the BCS storage complex, directly overlying the Precambrian basement. The BCS is situated at a depth of approximately 1,800 to 2,100 m below ground level.

The fluid to be injected and stored is Class III, according to ERCB *Directive 051: Injection and Disposal Wells – Well Classifications, Logging and Testing Requirements* (March 1994) (Directive 51), Section 2, Injection/Disposal Well Classifications. The UWIs for the first five injection wells are: 08-19-059-20W4, 07-11-059-20W4, 10-06-060-20W4, 12-14-060-21W4 and 15-29-060-21W4. Well 08-19-059-20W4 (Well 8-19) has already been drilled. If additional wells are determined to be required, the storage scheme approval will be amended to include additional wells.

1.2.1 CO_2 Storage Scheme – Project Location

The proposed Project is located in central Alberta, northeast of the City of Edmonton. The CO_2 storage AOI is 40 townships in size, ranging from Townships 56 to 63 and Ranges 18 to 24, all west of the Fourth Meridian. For the location of the proposed storage scheme and the locations of the five UWIs included in this application, see Figure 1-1.

1.2.2 CO_2 Storage Scheme – Project Schedule

The current anticipated schedule for key Project work and milestones is as follows (see Figure 1-3):

- 2010 and 2011 – continuation of seismic assessment, subsurface modelling, and definition of the specifics of the MMV plan
- Q1 2012 – final investment decision for the Project
- Q2 2012 to Q3 2012 – detailed engineering and design
- Q1 2013 to Q4 2014 – acquisition of baseline MMV information
- Q3 2013 to Q3 2014 – drilling and completion of the injection wells

- Q1 2015 to Q3 2015 – commissioning and start-up of the Project
- Q4 2015 – full-capacity sustained operation

These timelines are subject to change, pending regulatory approval, market conditions and internal and joint venture Project approvals.

1.2.3 CO_2 Storage Scheme – Purpose of the Project

As an integral component of the integrated Quest CCS Project, the main objective of the CO_2 storage scheme is to inject and store the volumes of CO_2 that will be captured at Shell Scotford and transported to the CO_2 storage AOI via the proposed CO_2 pipeline.

1.2.4 CO_2 Storage Scheme – Need for the Project

Shell requires approval of this Project to establish a viable scheme for storage of the annual CO_2 volumes proposed to be captured and transported as part of the Quest CCS Project.

1.2.5 CO_2 Storage Scheme – Project Proponent

Shell Canada Limited, which will hold all necessary regulatory approvals in respect of the Project, is the managing partner of Shell Canada Energy. Shell Canada Energy will operate the Project, on behalf of the AOSP, which is a joint venture between Shell Canada Energy (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%).

1.2.6 CO_2 Storage Scheme – Proponent Contact Information

All communication regarding the enclosed application should be directed to:

Kathy Penney, Regulatory and Environmental Manager – Quest CCS Project
Shell Canada Energy
Shell Centre, 400 4th Avenue SW
Calgary, AB T2P 2H5
Phone: (403) 691-3111
Fax: (403) 691-3321
Email: Kathy.Penney@shell.com

and to counsel:

Bradley S. Gilmour
Bennett Jones LLP
4500 Bankers Hall East
855 2nd Street SW
Calgary AB T2P 4K7
Phone: (403) 298-3382
Fax: (403) 265-7219
Email: gilmourb@bennettjones.com

1.2.7 CO_2 Storage Scheme – Requested Approvals

Shell Canada Limited is hereby requesting approval for a CO_2 acid gas storage scheme, pursuant to Part 6, Sections 11, 12 and 39 of the *Oil and Gas Conservation Act*, and Part 15 of the *Oil and Gas Conservation Regulations*, and in accordance with ERCB *Directive 065: Resources Applications for Oil and Gas Reservoirs* (Directive 65), Unit 4, Section 4.2.

Shell is requesting a Directive 65 CO_2 acid gas storage scheme approval that will provide Shell the ability to store Class III fluids via the one well licence provided in this application (Licence 0421182; UWI 100/08-19-059-20W4/0), provided all requirements of Directive 51 are also met within specified periods. Further, Shell requests that the Directive 65 approval will also provide Shell with approval of the CO_2 storage scheme, with exclusive rights within the range of description provided in this application, including (see Section 2):

- well count
- area of interest
- storage complex
- annual CO_2 injection volumes
- period of commercial operation

2 Proposed Storage Scheme

2.1 Project Site Selection

Site selection criteria for CCS projects generally include the following:

- capacity
- injectivity
- containment
- MMV

The Quest CCS Project ranked favourably when screened against the emerging selection criteria for safety and security of CO_2 storage (see Table 2-1). In October 2010, Shell sought a third-party review of this aspect of the Project. The independent project review was managed and facilitated by Det Norske Veritas (DNV), and performed by an expert panel contracted by DNV. For the executive summary of the report, see Appendix A.

Table 2-1 Assessment of the BCS for Safety and Security of CO_2 Storage

Criterion Level	No	Criterion	Unfavourable	Preferred or Favourable	BCS Storage Complex
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)	Three major seals (Middle Cambrian Shale [MCS], Lower Lotsberg and Upper Lotsberg Salts) continuous over entire CO_2 storage AOI. Salt aquicludes thicken up dip to NE.
	2	Pressure regime	Overpressured pressure gradients >14 kPa/m	Pressure gradients less than 12 kPa/m	Normally pressured <12 kPa/m
	3	Monitoring potential	Absent	Present	Present
	4	Affecting protected groundwater quality	Yes	No	No
Essential	5	Seismicity	High	<=Moderate	Low
	6	Faulting and fracturing intensity	Extensive	Limited to moderate	Limited. No faults penetrating major seal observed on 2D or 3D seismic.
	7	Hydrogeology	Short flow systems, or compaction flow, Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow	Intermediate and regional-scale flow-saline aquifer not in communication with groundwater

Table 2-1 Assessment of the BCS for Safety and Security of CO_2 Storage (cont'd)

Criterion Level	No	Criterion	Unfavourable	Preferred or Favourable	Quest BCS
Desirable	8	Depth	<750-800 m	>800 m	>2000 m
	9	Located within fold belts	Yes	No	No
	10	Adverse diagenesis	Significant	Low	Low
	11	Geothermal regime	Gradients ≥35°C/km and low surface temperature	Gradients <35°C/km and low surface temperature	Gradients <35°C/km and low surface temperature
	12	Temperature	<35°C	≥35°C	60°C
	13	Pressure	<7.5 MPa	≥7.5 MPa	20.45 MPa
	14	Thickness	<20 m	≥20 m	>35 m
	15	Porosity	<10%	≥10%	16%
	16	Permeability	<20 mD	≥20 mD	Average over AOI 20-500 mD
	17	Caprock thickness	<10 m	≥10 m	Three caprocks MCS 20-55 m L. Lotsberg Salt 10-35 m U. Lotsberg Salt 55-90 m
	18	Well density	High	Low to moderate	Low

SOURCE: CCS Site Selection and Characterization Criteria – Review and Synthesis: Alberta Research Council, Draft submission to IEA GHG R&D Program June 2009.

2.2 Extent of Area of Interest

Shell has requested the exclusive right to drill through and store CO_2 within the BCS storage complex, below the top of the Upper Lotsberg Salt to the Precambrian basement, over the full extent of the 40 townships that define the CO_2 storage AOI (see Table 2-2, Figure 2-1) for the full life of the Scotford Upgrader (greater than 25 years).

Table 2-2 Townships Included Within the CO_2 Storage AOI

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	21, 20, 19

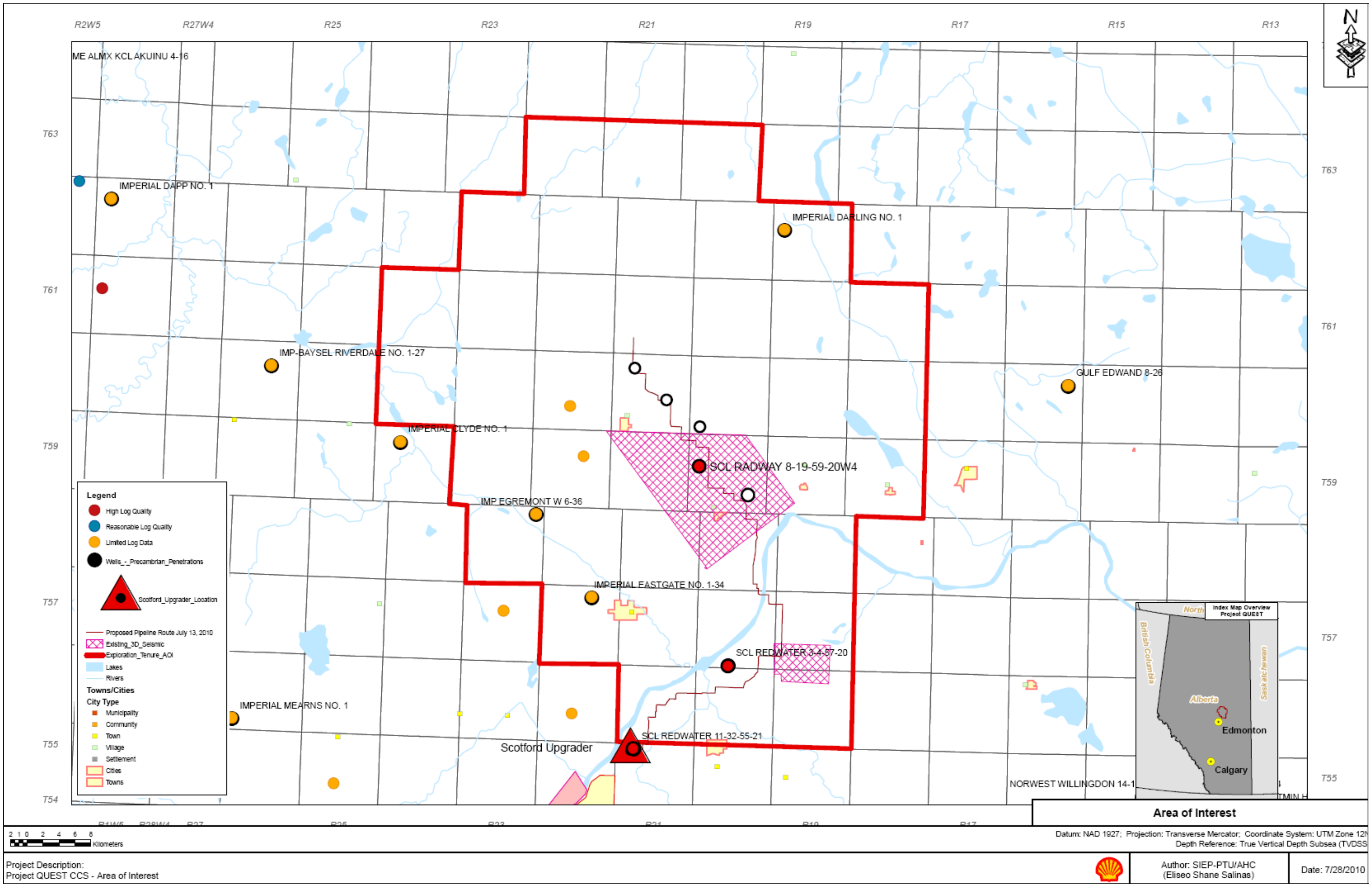


Figure 2-1 AOI and Injection Wells

2.2.1 Area of Interest – Methodology

The CO_2 storage AOI extent represents the current understanding of the CO_2 plume and area of elevated pore pressure taking into account the range of subsurface uncertainties. The philosophy is to create a series of subsurface models that adequately cover these uncertainties, to generate a wide range of CO_2 plume and pressure front size scenarios

With the signing of the Letter of Intent between Shell, the Government of Alberta and the Government of Canada, several key Project constraints were accepted between the signatories, including:

- developing a storage scheme that is capable of a sustained average injection rate of 1.08 Mt/a for a minimum of 10 years
- the Quest CCS Project reaching a sustained injection rate by the end of 2015

To meet the Government of Alberta's 2015 milestone, the Quest CCS Project team has to verify that:

- the Project is designed against the low case subsurface scenario model (low capacity/injectivity) so that the required volume and rate of CO_2 can be accommodated within the requested CO_2 storage AOI
- the CO_2 storage AOI covers the region of elevated pressures and prevents pressure interference between potential future CCS projects within the BCS, which may affect injection rates and volumes
- containment within the BCS storage complex is safeguarded over the entire life cycle of the Project by maintaining adequate offset distances between the injection wells and any third-party wells that penetrate the BCS storage complex

2.2.2 Area of Interest – Technical Reasoning

The extent of the CO_2 storage AOI is guided by the amount of pore space required to inject 1.08Mt/a of CO_2 for 25 years so that it is contained within the BCS storage complex for the entire lifecycle of the Project. The extent was determined using the full range of uncertainty on both the reservoir properties and the number of injection wells required (i.e., 3 to 10 wells). Volumetric calculations were carried out to validate dynamic models of CO_2 plume migration under various reservoir and development scenarios to assess the maximum CO_2 plume size that can be expected. The same process was undertaken for the area of elevated pressure in the highly saline brines ahead of the CO_2 plume. In each case, a conservative approach was taken to reflect that CO_2–brine displacement in the reservoir will not be homogeneous.

Modelling the CO_2 plume as well as the area of elevated pressure, to determine the extent of the AOI, is important for the following two fundamental reasons:

1. There must be sufficient injectivity and capacity to meet the Project objectives, assuming one or more potential CCS schemes in the BCS storage complex. Competing CCS projects have the potential to affect one another, in terms of injectivity, monitoring and liability, through overlapping areas of elevated pressure. Overlapping pressure fronts may result in each offsetting project reaching the ERCB imposed limit for bottomhole pressure (90% of the fracture pressure) prematurely. This would result in additional wells being required to redistribute pressure, or in the scheme being closed prematurely.

2. Containment must be maintained through early warning of potential CO_2–brine migration outside the BCS storage complex, with particular emphasis on safeguarding aquifers above the base of ground water protection (BGWP). Considerations for this include the following:

    - Adequate offset must exist between CO_2 injection wells and legacy wells and wells of future schemes that penetrate the BCS. Therefore, the proposed scheme maximizes the offset to existing legacy wells. The closest BCS penetration by a legacy well (Imp. Egremont 6-36-58-23W4) occurs 21 km west-southwest of Well 8-19. The closest up-dip legacy well (Imp. Darling No.1 16-19-62-19W4) is 31 km north-northeast of Well 8-19.
    - The CO_2 plume size is small compared with the CO_2 storage AOI, reaching a maximum plume size of 3 km away from the wellbore, and will not reach the legacy wells.
    - The legacy wells will encounter pressurized saline brine. Given the BCS reservoir pressure (see Section 6.5) and in situ fluid gradient (see Section 6.1), a minimum incremental pressure of 3.3 to 4.5 MPa in the BCS would be required to lift 11.7 kPa/m BCS brine into the BGWP zone through an open hole at hydrostatic conditions (see Table 2-3).
    - Current dynamic models indicate that the pressure increases at distances equivalent to the distance to the legacy wells would be about half that required to lift BCS brine into the BGWP or to the surface.

Table 2-3 Pressure Increase Required to Lift BCS Brine BGWP

Well Name	Surface elevation (MBSL)	BGP depth (MBSL)	Delta P (kPa)
Imperial Eastgate No. 1-34	-641.3	-401	3,452
Imperial Egremont W 6-36	-627.9	-408	3,334
Imperial Clyde No. 1	-629.4	-397	3,327
Imperial Darling No. 1	-704.4	-469	4,201
NOTE: MBSL – metres below sea level			

2.3 Well Count and Subject Well Identifiers

A Field Development Plan, that identifies the proposed final locations of the injection wells, will be completed in 2011. Final determination of the total number of injection wells depends on the results of an ongoing appraisal program. The ongoing appraisal program includes:

- Analysis of the recently drilled 8-19-59-20W4 well (Well 8-19) and core data
- water injectivity test at Well 8-19
- potential CO_2 injectivity test at Well 8-19
- acquisition of a new 3D seismic survey to be completed in the winter of 2010.

The first proposed CO_2 injection well, Well 8-19, was developed as an appraisal well in 2010. Locations for an additional four wells were identified in 2010, and the well licences for these wells received in November 2010. For the locations of the first licensed well and the four additional locations identified, see Table 2-4.

Although one licensed well has been included in the present application, the proposed storage scheme carries a range of 3 to 10 injection wells – all located within the AOI and within the BCS saline aquifer injection zone.

The final well number and locations of wells, and the routing of lateral pipelines to connect the wells to the main pipeline, will be determined in 2011. Shell intends to apply for disposal well licences for the additional wells listed (see Table 2-4), once the necessary pore-space tenure for these wells is received. Any changes to the approved scheme will be submitted to the ERCB as an amendment to the requested D65 approval. If required, as per the final configuration of the scheme, some of the UWIs included in the present application may be removed or replaced with updated locations. In addition, new CO_2 injection well UWIs, up to a total maximum of 10, may be added to the scheme.

Table 2-4 Well Locations Included in the CO_2 Storage Scheme Application

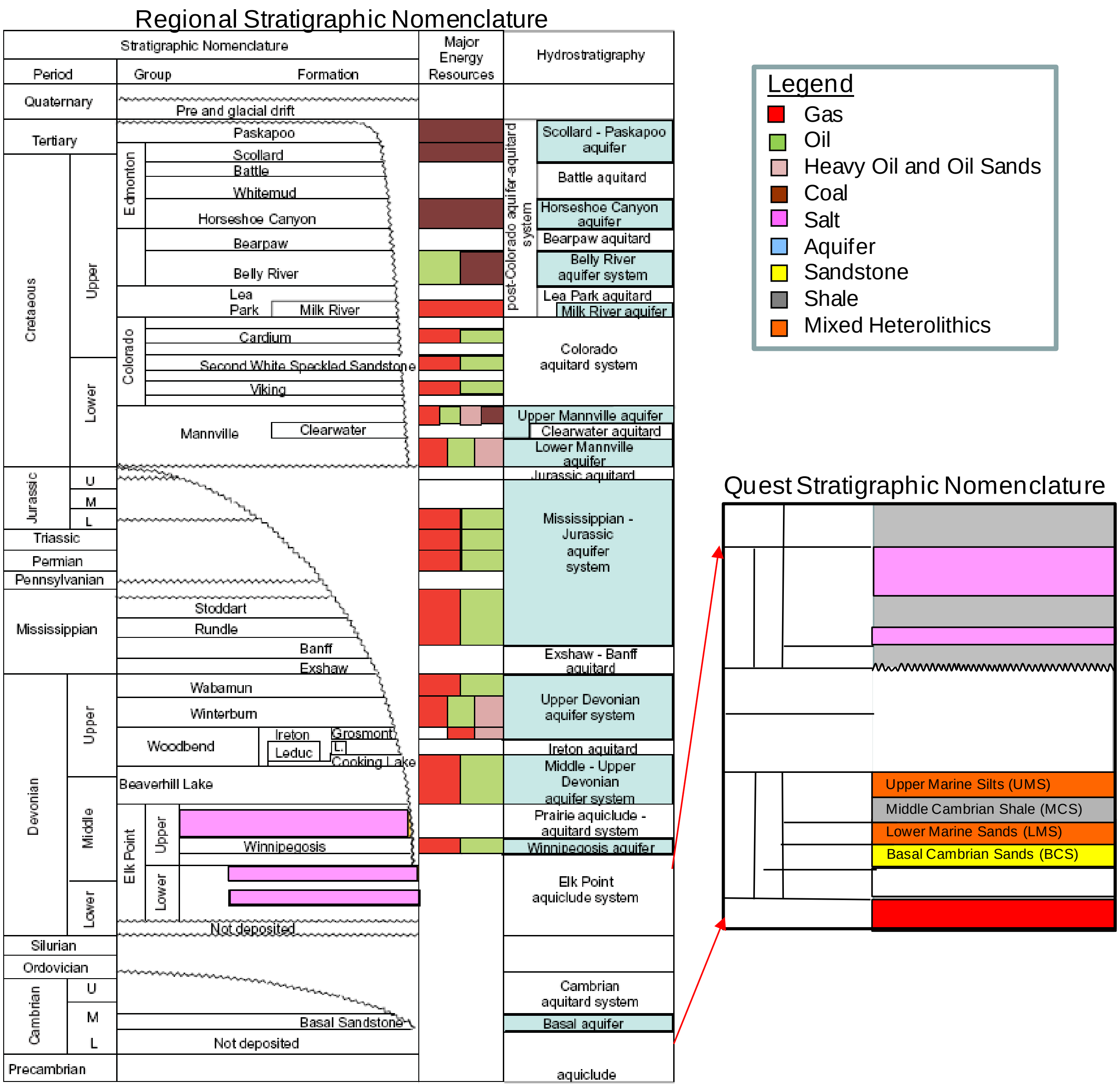
Well UWI	Potential Injection well	NAD 27 UTM Zone 12 North	NAD 27 UTM Zone 12 East
08-19-059-20W4	1	5997747.399	370705.482
07-11-059-20W4	2	5994416.66	376674.14
10-06-060-20W4	3	6002873.82	370401.14
12-14-060-21W4	4	6006367.36	366539.42
15-29-060-21W4	5	6010249	362408.94

2.4 CO_2 Storage Complex

The BCS storage complex includes the series of formations from below the top of the Upper Lotsberg Salt to the Precambrian basement (see Figure 2-2). CO_2 will be permanently contained within the BCS storage complex.

The BCS saline aquifer is situated at the base of the BCS storage complex and is the only CO_2 injection zone for all injection wells. The BCS unconformably overlies the Precambrian basement at a depth of approximately 1,800 to 2,100 m below ground level (see Figures 2-2 and 2-3). For the depth of the top and base of the BCS in the five subject wells, see Table 2-5.

For further geological details about the BCS, see Section 4.



Modified after Bachu et al. 2000.

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

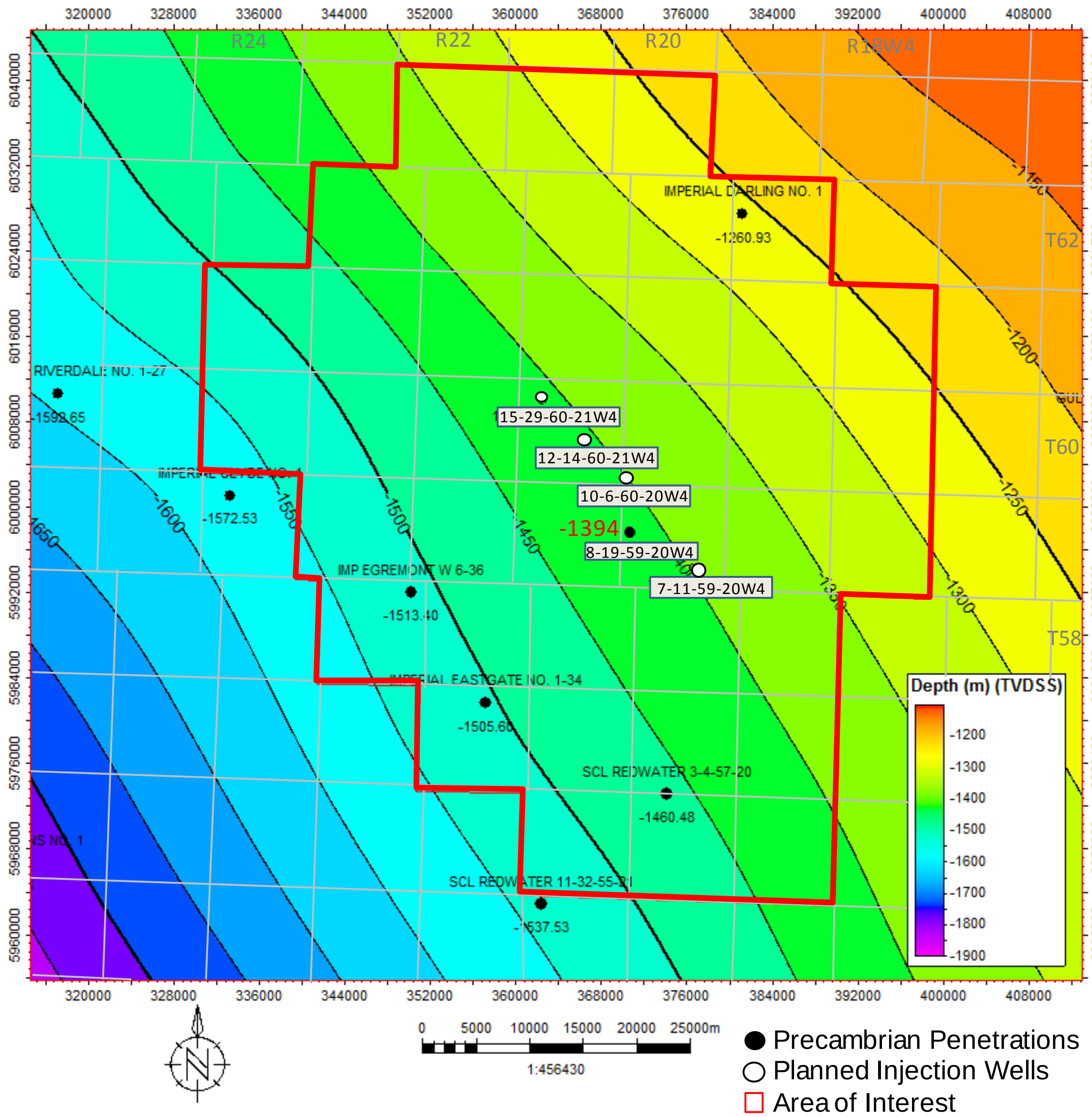


Figure 2-3 Top Structure of the Basal Cambrian Sands

Table 2-5 Top and Base of the BCS in the First Five Injection Wells

Well Name	Injection Well	Top BCS (MDSS)	Base BCS (MDSS)
08-19-059-20W4	1	2,041.3 m (-1,394 m)	2,087 m (-1,440 m)
07-11-059-20W4	2	Information to be submitted after drilling each well	
10-06-060-20W4	3		
12-14-060-21W4	4		
15-29-060-21W4	5		
NOTE: MDSS – measured depth subsea			

2.5 Injection Volumes

The Quest CCS Project will be designed to capture and inject an average of 1.08 Mt/a of CO_2. This rate corresponds to a daily average rate of 1.58 Mm^3/d of CO_2 at standard conditions (15°C, 101.325 kPa). The gas that is captured and compressed at the Scotford Upgrader and is to be injected, is expected to contain no less than 95% by volume CO_2. To achieve the annual average storage target of 1.08 Mt/a of CO_2, a daily average field injection rate of 1.59 Mm^3/d (56.2 MMscf/d) is required at standard conditions (15°C, 101.325 kPa).

The expected daily storage volume at any well is 0.32 Mm^3/d, assuming even distribution of the total volume across five injection wells.

The expected daily storage volumes for future injection wells will be updated after drilling. If reservoir properties and injectivity vary between wells, the total volume will be distributed in a way that limits flowing bottomhole pressure, in line with ERCB requirements, across all active injection wells.

2.6 Storage Fluid Class

The storage fluid class for the injection wells is Class III according to ERCB Directive 51, Section 2, Injection/Disposal Well Classifications.

2.7 Period of Operation

The Quest CCS Project is expected to begin commissioning and start-up in 2015, and achieve full sustained operation by the fourth quarter of 2015. The Project is expected to operate for the life of the Scotford Upgrader (greater than 25 years).

2.8 Measurement, Monitoring and Verification

The geology of the selected storage site offers multiple layers of protection to prevent any CO_2 or brine from causing any effects on the protected groundwater zone, the ecosystem, or the atmosphere. CO_2 will be permanently contained within the BCS storage complex. Within the BCS storage complex the three major geological seals (MCS, Lower Lotsberg Salt and Upper Lotsberg Salt) are considered sufficient for long-term containment of injected CO_2 and displaced brine (see Section 5). However, no matter how detailed and extensive the evaluation program to characterize the BCS storage complex, some small risk remains.

MMV activities aim to verify the absence of any significant environmental impacts due to CO_2 storage.

A risk-based workflow was applied to the MMV plan. The workflow relies on a systematic assessment of the whole suite of containment risks, followed by a review of the effectiveness of safeguards provided by geology and engineering. The proposed conceptual MMV plan is then designed to provide early warning of any breach of containment out of the BCS storage complex. Once indentified, appropriate responses are taken to reduce any effect and confirm that the remaining risk is not significant.

Transfer of long-term liability will depend on the actual storage performance verified through MMV activities. The MMV plan will be designed to demonstrate that actual storage performance conforms to model-based forecasts and that these forecasts are consistent with permanent secure storage. For a detailed description of the conceptual MMV plan for the Project, see Appendix B.

2.9 Storage Perforations

The completion strategy is to perforate the full height of the BCS. The perforated interval will be limited so that there are no perforations in the overlying Lower Marine Sand (LMS), and will maintain a minimum 1 to 2 m offset from the underlying Precambrian basement (see Section 7.1 for further completions details). The perforation interval for Well 8-19 followed the completion strategy and was perforated from 2,048.5 to 2,049.5 m measured depth (MD) and 2,055 to 2,085 m MD (top Precambrian = 2,087 m MD).

Shell will provide actual perforation intervals for injection wells 2 through 10 to the ERCB after drilling and logging.

2.10 Production Packer Depth

All completion designs adhere to Directive 51, Directive 65 (4.1.4) and *Oil and Gas Conservation Regulations*, Section 6.120. In Well 8-19, the packer depth is 2,033 m MD, which is within 15 m of the perforated interval, located at a depth of 2,048.5 to 2,049.5 m MD.

Injection wells 2 to 10 will set the production packer within 15 m of the perforated interval, or as closely above the injection interval as is practicable. If the completion and Project MMV requirements force a deviation from any of the above guidelines, Shell will request an exception from the ERCB.

2.11 Usable Groundwater Base

The BGWP was defined for all wells using the Alberta Environment Groundwater database [ERCB *Bulletin 2007-10: Alberta's Base of Groundwater Protection (BGWP) Information* (April 2007) and ERCB *General Bulletin 2000-8: Process Changes to Disposal Well Applications* (March 2000)]. Within the CO_2 storage AOI, the base of the Belly River Formation or Wapiti Group is considered the BGWP. The marine shales of the Lea Park Formation define the approximate lower boundary of the BGWP.

For the depth to BGWP for the first five injection wells, see Table 2-6. Depth to BGWP for injection wells 6 through 10 will be submitted when final well locations are chosen.

Surface casing is set below the BGWP zone and cemented to surface for effective isolation. For details on the well design and casing setting depths, see Section 7.

Table 2-6 Depth to Base of Groundwater Protection

Injection Well	Well UWI	Depth BGWP (MASL)	KB[1] (m)	Depth of BGWP (TVD) (m)
1	08-19-059-20W4	435.2	646.76	211.56
2	07-11-059-20W4	434.79	640.67	205.88
3	10-06-060-20W4	459.67	652.21	192.54
4	12-14-060-21W4	453.59	648.35	194.76
5	15-29-060-21W4	447.54	657.25	209.71

NOTES:
[1] Kelly bushing (KB) elevation for injection wells 2 to 5 is assumed to be 5 m above surveyed ground level.
MASL – metres above sea level
TVD – true vertical depth

SOURCE: ERCB *Bulletin 2007–10: Alberta's Base of Groundwater Protection (BGWP) Information* (April 2007)

2.12 Abandonment

The wells will be abandoned after the post-injection monitoring is complete.

For abandoning wells, ERCB *Directive 020: Well Abandonment* (July 2010) (Directive 20) guidelines will be adhered to, as a minimum. The wells will be considered as Level A, cased and completed wells, and well abandonment will include the following:

- The wells will be initially displaced with noncorrosive, inhibited fluid, before multiple cement plugs are placed.
- Multiple cement plugs along with bridge plugs will be placed inside the wells.
- Cement will cover all non-saline groundwater zones.
- The cement will be appropriate for long-term exposure to CO_2. However, it is unlikely that the cement plug will come in contact with CO_2 as it is inside the wellbore.

Gas migration and surface casing vent flow tests will be done before downhole abandonment begins, to avoid having to re-enter the well to correct a wellbore problem.

Surface abandonment will be completed only after the subsurface has been abandoned. Shell will adhere to the ERCB guidelines for surface abandonment, including cutting off the casing string(s) a minimum of 1 m below the final contour elevation, with the following exceptions:

- If the well is in an area with special farming practices, such as deep tillage, drainage works, or peat lands, or is within 15 km of an urban development, the casing string(s) must be cut off a minimum of 2 m below final contour elevation.
- Surface, intermediate and production casing strings will be capped at surface with a steel plate that is fastened and installed in a way to prevent any potential for pressure to build up within the casings while restricting access to the casing strings at surface.

3 Injection Well Suitability

All the wells for the Project will be drilled and completed using specifications suitable for CO_2 injection. Best industrial practices will be implemented in accordance with all applicable regulatory requirements. See Table 3-1 for confirmation that the Project location and the injection well design are suitable for CO_2 storage and in accordance with all existing regulatory requirements.

The suitability of injection wells 2 to 10 for CO_2 storage will depend on meeting Directive 51 requirements, which will be submitted to the ERCB for approval, on an individual well basis, before injection starts.

Table 3-1 Criteria for Storage Suitability

Criterion	Comment
Effect on existing or future hydrocarbon production	• No hydrocarbons occur in the BCS within the CO_2 storage AOI. • The closest hydrocarbon pool is located >1,000 m shallower in the stratigraphic section in the Leduc Fm. reef. The edge of the Leduc reef is located >10 km to the southwest of any of the potential injection wells. • Offset well licensees within 4.8 km of Well 8-19 have been notified. Similar notification will be repeated for each new additional well. Any correspondence received from the offset licensees will be forwarded to the ERCB.
Injectivity and Capacity	• Water was successfully injected into the offset BCS Well 11-32 (492 m^3/d). • Log properties in Well 8-19 are within the expected range from static and dynamic field model predictions indicating suitable capacity exists for storing a minimum of 14 Mt of CO_2 in the BCS storage complex. Models indicate that all injection wells will be in a similar range.
Containment	*General Containment* • The abundance, thickness and extent of the three major regional seals, the MCS, Lower Lotsberg Salt and the Upper Lotsberg Salt, are adequate across the CO_2 storage AOI. • No faults cross-cutting the sealing formations have been identified on 2D or 3D seismic data. • The number of well penetrations through the seals is low and the CO_2 storage AOI has been deliberately offset from these wells. The closest down-dip legacy well is 21 km southwest and the closest up-dip well is 31 km northeast from the injection wells. • A detailed MMV plan for the full life-cycle of the Quest CCS Project will be implemented. *Well Containment (Well 8-19 and 4 additional injection wells)* • Surface casing deepened beyond the BGWP for competent cement to surface, and resultant effective isolation from the BGWP zone. • Corrosion-resistant casing is used over the injection interval and the overlying MCS seal. • Substantially deeper intermediate casing covers all three major seals. Intermediate casing is cemented to surface and protects the surface casing. • The main-hole (production) casing is run from the surface to the injection zone. This third casing string is cemented from total depth to the surface. • Casing is pressure tested to verify mechanical integrity. Cement bond logs are run to confirm effective hydraulic isolation over the injection zone.

4 Geological Setting

The BCS storage complex is at the base of the central portion of the Western Canada Sedimentary Basin (WCSB) directly on top of the Precambrian basement. The BCS storage complex is defined herein as the series of intervals and associated formations from the top of the Precambrian basement to the top of the Upper Lotsberg Salt (see Figure 2-2 and Figure 4-1). The storage complex includes, in ascending stratigraphic order:

- Precambrian granite basement unconformably underlying the Basal Cambrian Sands
- Basal Cambrian Sands of the Basal Sandstone Formation – the CO_2 injection zone
- Lower Marine Sand of the Earlie Formation – a transitional heterogeneous clastic interval between the BCS and overlying Middle Cambrian Shale
- Middle Cambrian Shale of the Deadwood Formation – thick shale representing the first major regional seal above the BCS
- Upper Marine Siltstone (UMS) likely Upper Deadwood Formation – progradational package of siliciclastic material made up of predominantly green shale with minor silts and sands
- Devonian Red Beds – fine-grained siliciclastics predominantly composed of shale
- Lotsberg Salts – Lower and Upper Lotsberg Salts represent the second and third (ultimate) seals, respectively, and aquiclude to the BCS storage complex. These salt packages are predominantly composed of 100% halite with minor shale laminae. They are separated from each other by 50 m of undifferentiated Devonian mudstone.

The rocks that compose the BCS storage complex in the CO_2 storage AOI were deposited during the Middle Cambrian to Early Devonian directly atop the Precambrian basement. The erosional unconformity between the Cambrian sequence and the Precambrian represents approximately 1.5 billion years of Earth history. Erosion of the Precambrian surface during this interval likely resulted in a relatively smooth and gently southwest-dipping (<1 degree) top Precambrian surface. Regionally, the Cambrian clastic packages pinch out towards the northeast, and the Devonian salt seals thicken towards the northeast. For a cross-section of the WCSB showing the regionally connected BCS storage complex in relation to regional baffles and sealing overburden, see Figure 4-1.

The CO_2 storage AOI is within a tectonically quiet area; no faults crosscutting the regional seals were identified in 2D or 3D seismic data.

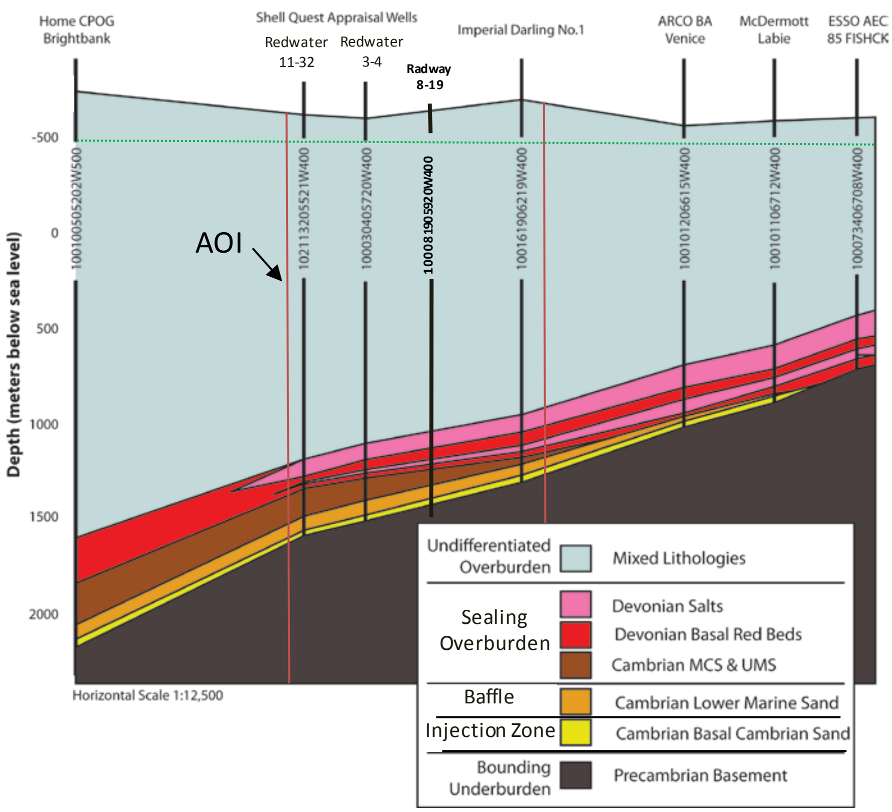


Figure 4-1 Cross-section of the WCSB Showing BCS Injection Zone

4.1 Geology of the CO_2 Injection Zone

Basal Cambrian Sands (BCS) – Basal Sandstone Formation

The BCS is the only CO_2 injection zone and is composed mainly of fine to coarse-grained sandstone with minor shaley intercalations, lying unconformably on a variably rugged topography of Precambrian age crystalline basement. This unit is widespread throughout much of the Alberta Plains, and is absent only locally where isolated Precambrian highs precluded deposition.

Core data suggest that BCS sediments were deposited in a tide-dominated bay margin that was created as the cratonic margin was flooded during the initial phases of a sea-level transgression, ultimately yielding a time-transgressive formation top. This interpretation indicates that the sea-level rise generated marginal-marine embayments and lagoons within antecedent topographic lows in which sand, originally deposited by rivers, was reworked into tidal dunes many times over. Within the CO_2 storage AOI, this process ultimately yielded a very clean, high net/gross (0.75–0.97), 35–46 m thick sheet sandstone that presently acts as a basin-scale saline aquifer with no known hydrocarbon accumulations (see Figure 4-2). This regional scale, high net to gross ratio BCS sandsheet is consistent with Cambrian deposits worldwide (Runkel et al., 2007; Spjeldnaes, 1981).

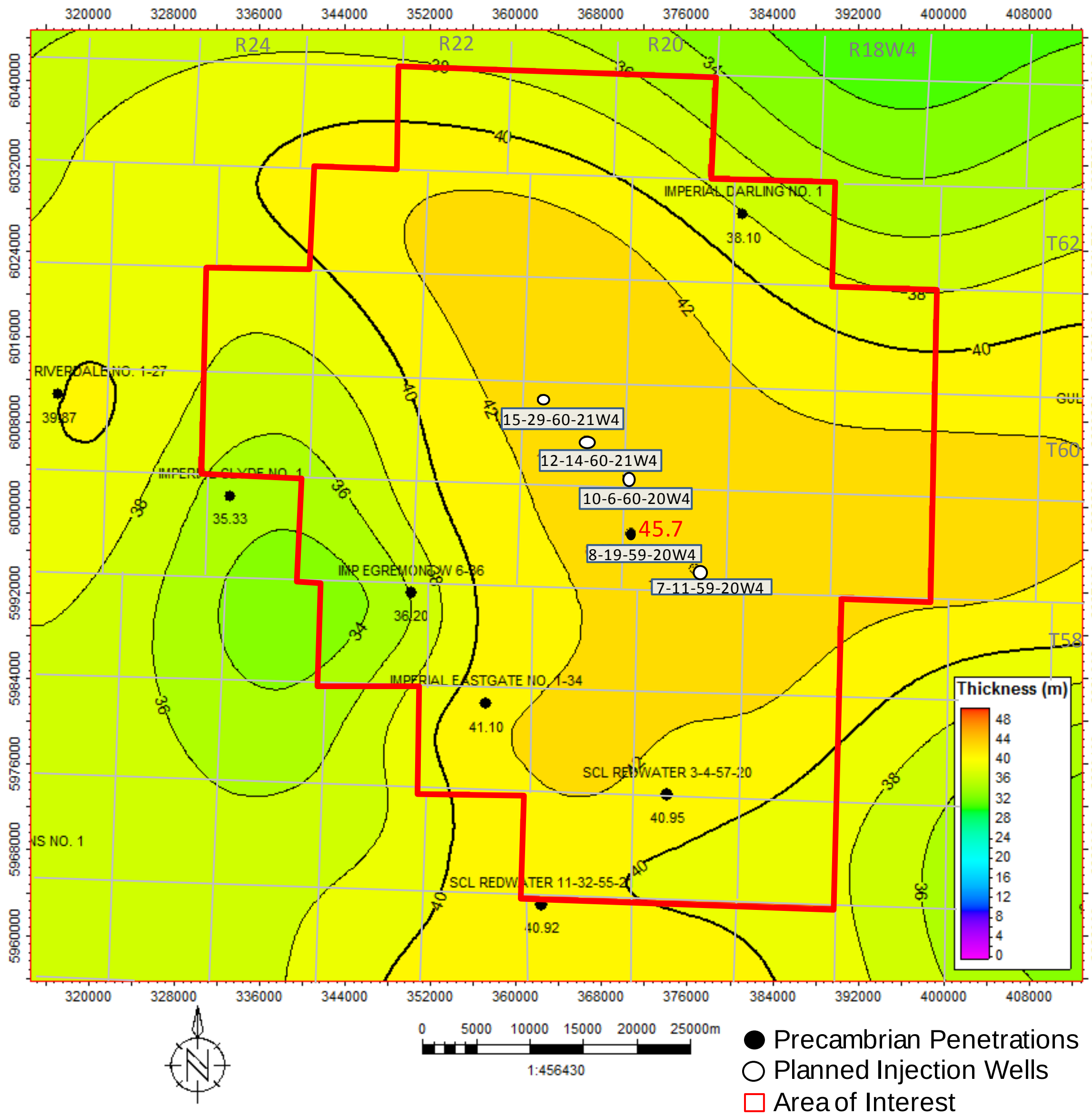


Figure 4-2 Basal Cambrian Sands – Gross Sand Thickness

4.2 CO_2 Injection Zone Porosity and Permeability

Characterization of the petrophysical properties in the AOI was primarily based on the results of the Quest CCS Project appraisal wells, Shell Redwater 11-32-55-21W4 (Well 11-32) and Shell Redwater 3-4-57-20W4 (Well 3-4) with additional input from offset legacy wells (see Figure 4-3 and Appendix C, Project Well List). The most appropriate evaluation technique was determined and applied to each well to maximize the use of all data available in the region. Wells were classified based on data availability, quality and age into the following three different groups:

- Group 1: wells with the most modern and best quality data, including Wells 11-32, 3-4 and 8-19 (see Figure 4-3, red wells). All wells have at least the following logs: gamma-ray, density, neutron, sonic and resistivity. Porosities were calculated using bulk density logs and core calibrated parameters. The final porosity results were consistent with core porosity measurements as well as nuclear magnetic resonance (NMR) total porosity logs. A low error in the porosity calculation resulted from the high quality of input data (i.e., porosity standard deviation: 0.014 v/v).
- Group 2: wells drilled and logged between 1958 and 1991 with only sonic logs and some neutron logs available to calculate porosities (see Figure 4-3, blue wells). Log quality is lower than Group 1 but sufficient to assess rock properties within a reasonable range of uncertainty. Sonic porosity calculation parameters and results were also calibrated to core data (see Appendix D). The final porosity error was estimated to be higher for these wells compared to the first group, with a resulting porosity standard deviation of 0.028 v/v.
- Group 3: wells (various ages) with very limited log data (see Figure 4-3, orange wells). Most of the wells in the CO_2 storage AOI are in this category. Porosities were estimated from neutron logs using gamma-ray correlation to convert API neutron counts into porosity. Where possible, the resulting porosities were cross-checked with core data (i.e., petrography). A high uncertainty range was estimated for the porosity results in this group of wells. The same error range as for Group 2 was estimated for Group 3 (i.e., 1 porosity standard deviation: 0.028 v/v).

The validation of property estimates from logs was performed using a variety of core data. Ambient porosity and permeability were measured on core plugs in Wells 11-32 and 3-4 (see Table 4-1). Stressed brine porosity and permeability measurements were performed on a subset of these plugs to determine the correction to in situ values. The corrected values were used to generate a porosity–permeability relationship that was applied to the porosity log to generate a best estimate of permeability across the BCS. Final permeability estimates were compared to the actual core measurements and to the permeability estimated from Modular Formation Dynamics Tester (MDT) (see Section 6.4), showing good agreement within the uncertainty range (see Table 4-1).

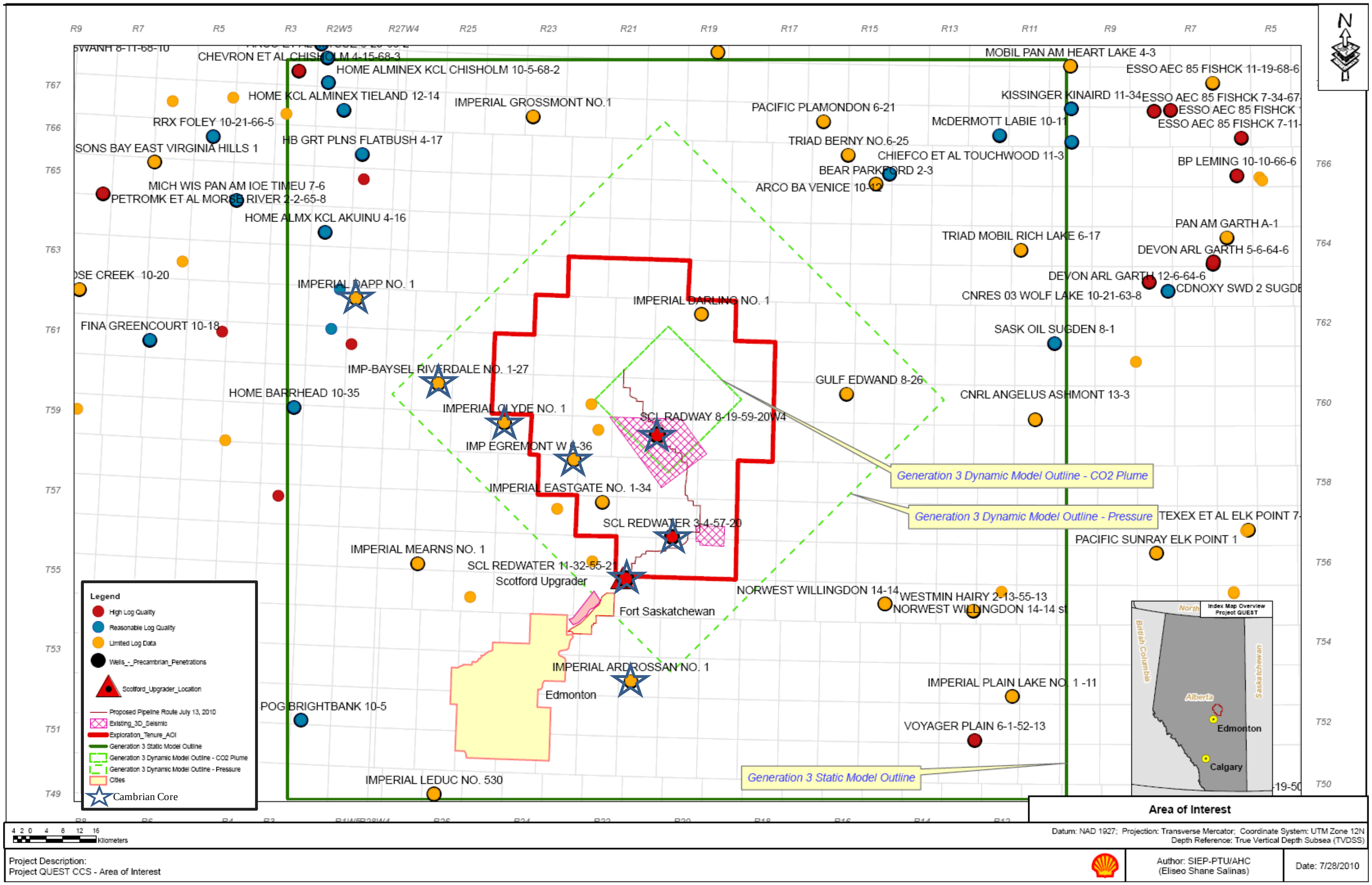


Figure 4-3 Area of Interest

Table 4-1 Average BCS Porosity and Permeability in and Near the CO_2 Storage AOI

Well Group	Well	Zone	Gross (m)	Porosity Average (fraction)	Core Perm. (K) mD	Calc. Perm. (K) mD
1	Shell Redwater 11-32-55-21 W4	BCS	40.93	0.14	256.3	229.0
1	Shell Redwater 3-4-57-20W4	BCS	40.95	0.16	303.3	368.6
3	Imperial Egremont W 6-36 (6-36-58-23W4)	BCS	36.20	0.10		54.0
3	Imperial Clyde No. 1 (9-29-59-24W4)	BCS	35.33	0.10		n/a
3	Imperial -Baysel Riverdale No. 1-27 (1-27-60-26W4)	BCS	29.70	0.11	74.9	40.0
3	Imperial Eastgate No. 1 (1-34-57-22W4)	BCS	41.10	0.12		85.8
3	Imperial Darling No. 1 (16-19-62-19W4)	BCS	38.10	0.14		n/a
3	Edwand No. 1 (8-26-60-16W4)	BCS	29.38	0.20		271.0

NOTES:
Calc. perm. – permeability calculated from the porosity-permeability relationship.
Data were extracted from the petrophysical input to the Generation 3 geological model.
For a full list of wells that had petrophysical analysis and were used in modelling, see Appendix C.

The following methodology was applied to Well 8-19 (consistent with Wells 11-32 and 3-4):

- Porosity was calculated using the bulk density curve and, compared with the total porosity curve (magnetic resonance porosity) from the NMR tool, both calculation methods gave the same average value of 0.16 (see Table 4-2).
- The preliminary arithmetic average permeability of Well 8-19 was calculated using the interpreted permeability from the NMR tool.

The final permeability values of Well 8-19 will be further calibrated with subsequent core analysis. For the actual log porosity and permeability values of the BCS in Well 8-19, and the expected range of values for injection wells 2 to 10, see Table 4-2.

Table 4-2 BCS Calculated Porosity and Permeability Values for CO_2 Injection Wells

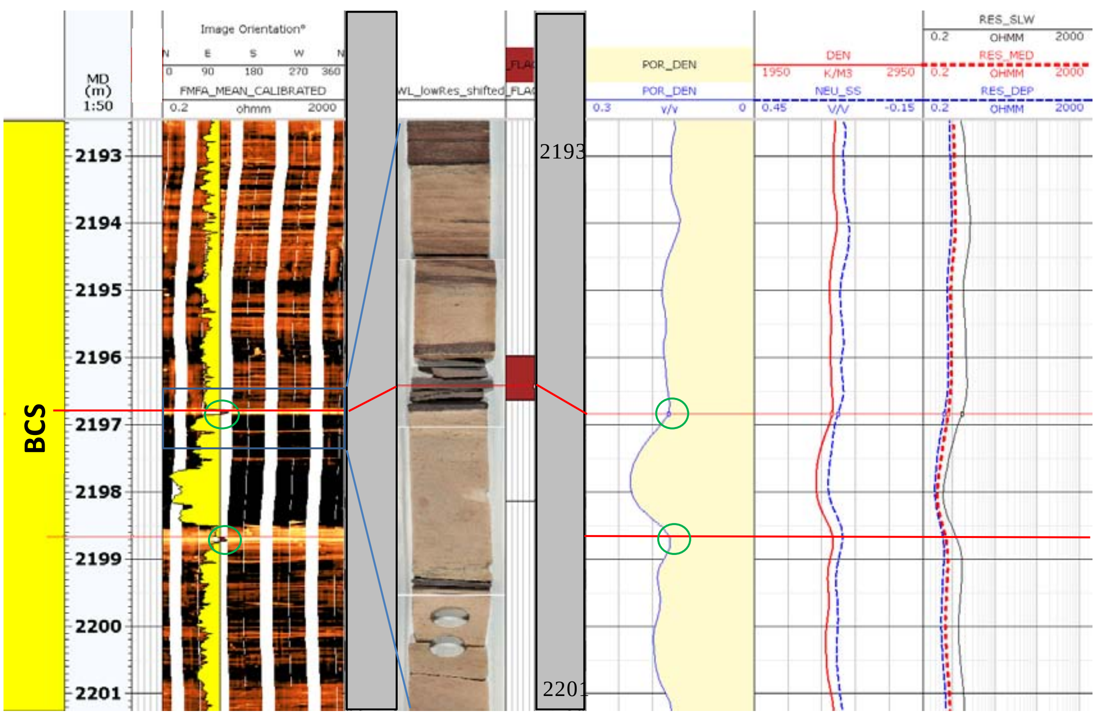
Parameter	Well 8-19	Injection Wells 2 to 10	
	Actual (calculated)	Minimum	Maximum
Average porosity BCS (v/v)	0.16	0.11	0.19
Average permeability BCS (mD)	150	20	500

4.3 Net Reservoir Calculations

In the Quest CCS Project, net reservoir is equivalent to net sand. Net sand is defined as lithologically clean sedimentary rocks, with limited dispersed clay content and variable properties such as grain size, porosity and permeability. No additional property cut-offs such as porosity or permeability have been used in the net definition.

Two petrophysical techniques were applied to estimate the net to gross ratio in the transgressive BCS sequence, so that the full range of uncertainty was captured:

- Widely used logs, such as gamma-ray, density, neutron and resistivity, were used to estimate the laminated shale volumes qualitatively by applying the Thomas Stieber technique.
- Due to the highly conductive formation water, the Formation MicroImager (FMI) images consistently distinguished the porous sandstones (high conductivity) from the tight shales in the BCS. A high resolution resistivity was extracted and processed from the FMI for this purpose. The results were integrated with the elemental capture spectroscopy tool to evaluate the sand count in the BCS in both Wells 11-32 and 3-4 (see Figure 4-4).



NOTE: The first track shows the mean FMI curve superimposed on the FMI image, and the application of the cutoff (i.e., yellow versus brown; highlighted by green circles). Two thin shale layers are at 2,196.8 and 2,198.7 m. The core image is magnified, to show the shale layer at 2,196.8 m. The fifth and sixth tracks show the density, neutron and resistivity logs on the same scale as the FMI.

Figure 4-4 Well 11-32 FMI Image – Calibration of a 6-cm Thick BCS Shale

Each technique was limited by assumptions, measurements and data resolution, but both methods were considered of equal validity within varying margins of error. Sensitivities were applied (i.e., on the FMI resistivity cutoff) and the associated uncertainty of the net to gross ratio was estimated (i.e., Thomas Stieber) to compare the final ranges. All results were consistent within a few units. A comparison of results is shown in Table 4-3.

Table 4-3 Wells 11-32 and 3-4 Net to Gross Results Comparison: Thomas Stieber Technique versus FMI Resistivity

Well	Formation	Gross Thickness (m)	Thomas Stieber Net to Gross Ratio			FMI Resistivity Extraction Net to Gross Ratio
			Low	Mid	High	Mid
Redwater 3-4-57-20W4	BCS	41	0.87	0.92	0.97	0.94
Redwater 11-32-55-21W4	BCS	41	0.75	0.8	0.85	0.92
Radway 8-19-59-20W4	BCS	46	Not complete at time of submission			0.90

See Figure 4-5 for a porosity height map (porosity x thickness), which illustrates the consistency between the final property estimates and the geological model created in Petrel modelling software.

4.4 Distance to Hydrocarbon Pool or Accumulation

There are no known hydrocarbons or hydrocarbon pools in the BCS within the CO_2 storage AOI. No hydrocarbon-bearing zones were encountered in Well 8-19. No hydrocarbons below the Upper Lotsberg are expected in any of the proposed future injection wells.

The vertical distance to the Leduc Formation, which holds the deepest known hydrocarbons in the CO_2 storage AOI, is more than 1,000 m. However, there is an additional lateral offset to hydrocarbons, as the edge of the Leduc reef is located more than 10 km down dip to the southwest of any of the potential injection wells (see Figure 4-6).

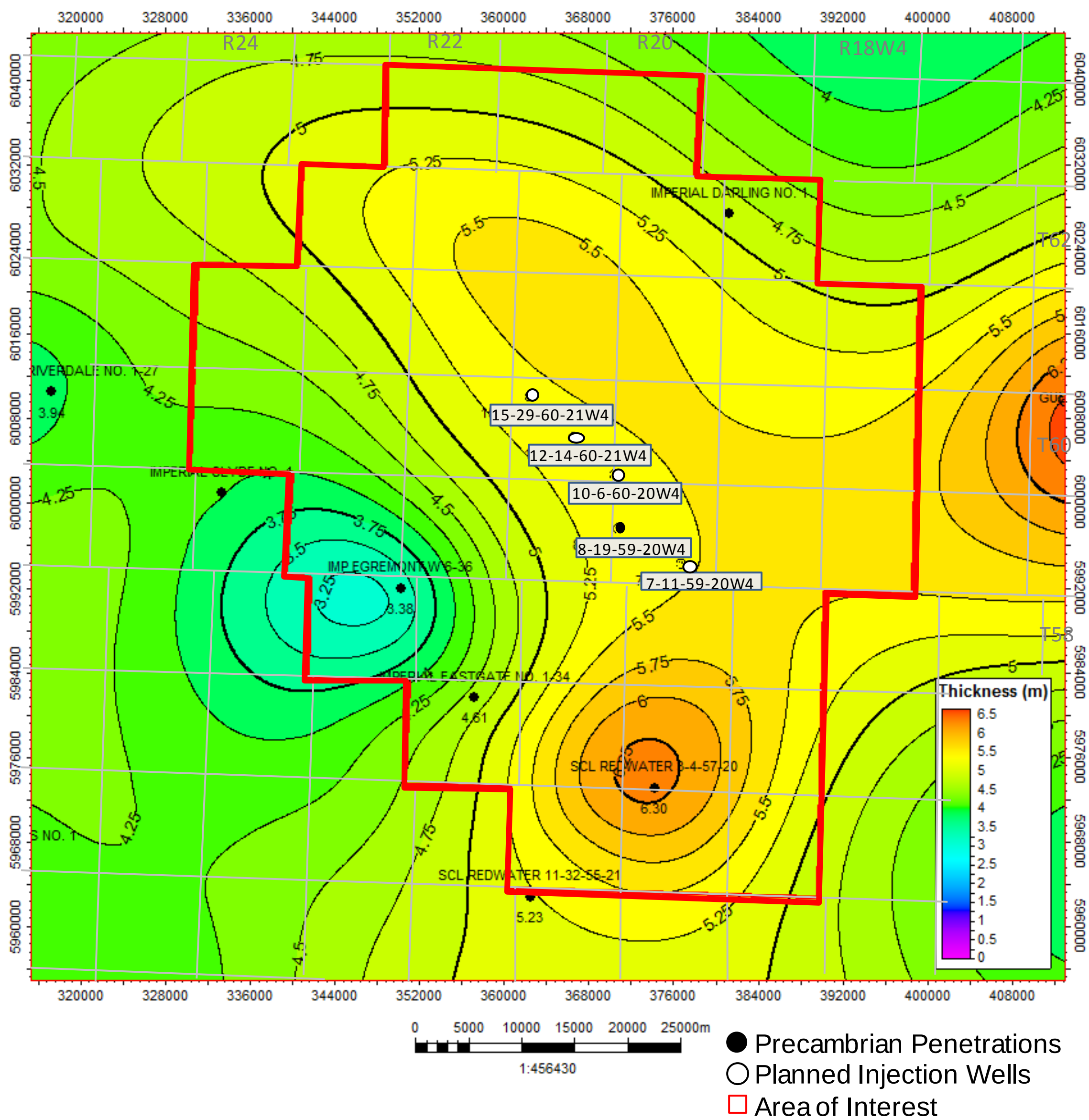


Figure 4-5 BCS Storage Capacity (Porosity x Thickness)

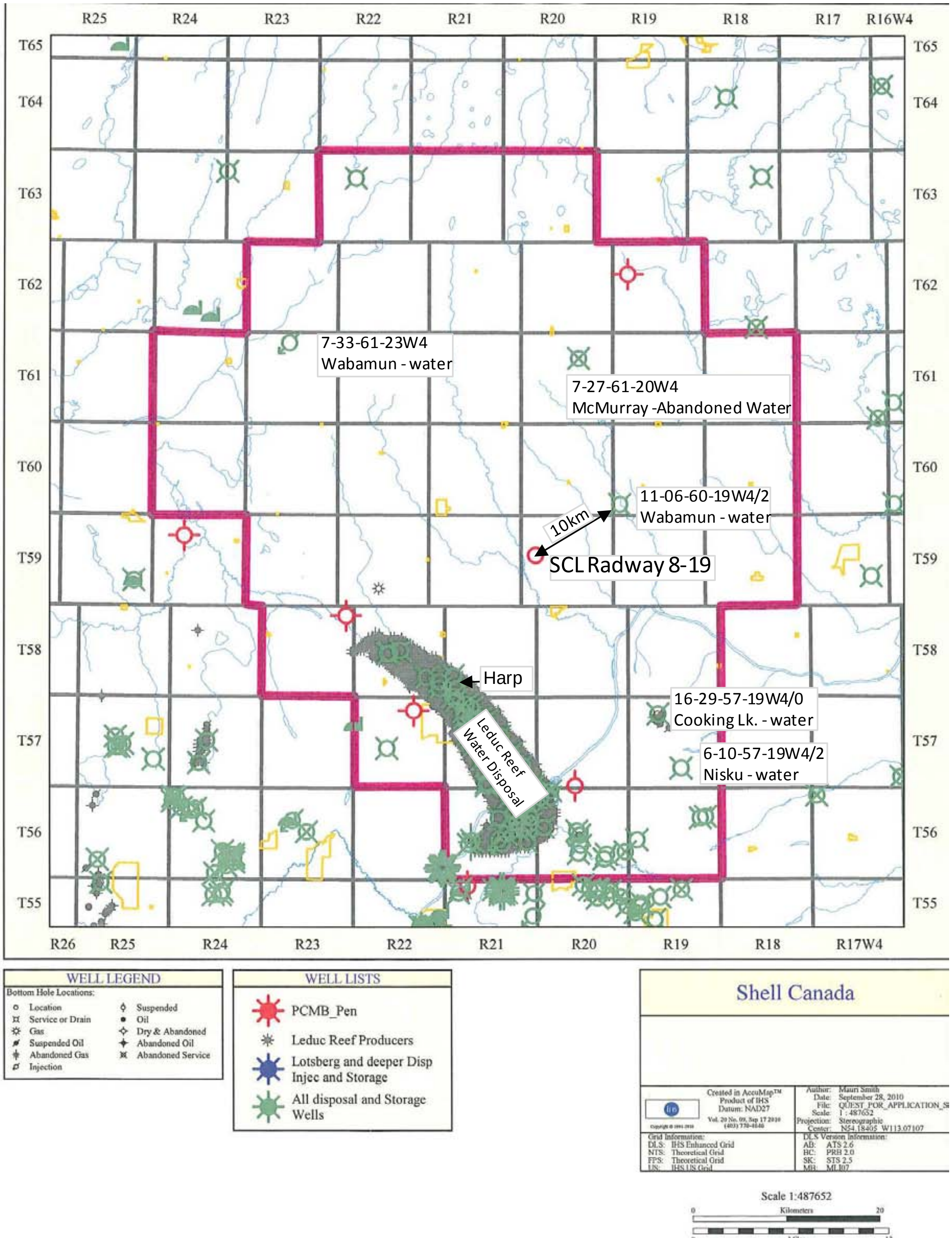


Figure 4-6 Offset Wells Used for Storage in all Formations

4.5 Distance to Closest Injection Site

There are currently no active, commercial CO_2 injection projects in the BCS storage complex within the CO_2 storage AOI.

The nearest proposed CO_2 injection project is the Heartland Area Redwater Project (HARP) by Alberta Research Council and ARC Energy Trust of Calgary. Their primary injection target is the Redwater Leduc Reef complex, located in part within the CO_2 storage AOI, but more than 10 km southwest of any of the potential Quest CCS Project injection wells (see Figure 4-6). Current information indicates that the HARP project does not plan to penetrate the Upper Lotsberg Salt.

The closest injection well considering the entire stratigraphic section (above Upper Lotsberg Salt) is 11-06-60-19W4/2, located 10 km northeast of Well 8-19. This well injects water into the Wabamun Formation (see Figure 4-6). None of the wells in Figure 4-6 penetrate through the base of the Upper Lotsberg Salt.

The closest injection well to penetrate the BCS is a water injection well, Canadian Natural Resources Limited 03/10-21-063-08W4/0. With this well, water is injected into the undefined Cambrian sandstone at a depth of approximately 1,400 m TVD and approximately 90 km northeast of the CO_2 storage AOI.

5 Containment

5.1 Annotated Cross-Section and Representative Well Logs

See Appendix D for an annotated regional cross-section used to display the regional stratigraphy of the BCS storage complex including the continuity, thickness and properties of the BCS injection zone, the baffles and the three major seals.

The cross-section contains representative well logs with the following information:

- identified and annotated zones of interest
- entire interval is water saturated
- location of completions and treatments to wellbore
- cumulative production
- finished drilling date and KB elevation
- log scales and cutoff used in the well log display

5.2 Bounding Formation Geology

This section describes the nature of the stratigraphy of interest considered to prevent migration of fluids out of the BCS storage complex. The basal bounding formation to the BCS is the Precambrian basement. Above the BCS are the three major seals considered the most important for containment. Deposited between the three major seals are additional intervals that act as secondary baffles impeding the vertical migration of CO_2 up through the stratigraphic column. In ascending stratigraphic order, the three major seals and three baffles in relation to the BCS injection zone are:

- Precambrian basement – basal bounding formation
- BCS – CO_2 injection zone
- LMS – baffle
- MCS – the first major seal
- Upper Marine Sand – baffle
- Devonian Red Beds – baffle
- Lower Lotsberg Salt – the second major seal
- Upper Lotsberg Salt – the third major (ultimate) seal

5.2.1 Basal Seal: Precambrian Basement

The CO_2 injection zone (BCS), in the Cambrian sequence lies directly above the Precambrian basement. Seismic surveys and appraisal well FMI logs indicate the existence of fractures on the Precambrian basement surface that likely were driven by accretion of Archean Province and Palaeo-Proterozoic terranes over 1.5 billion years before Cambrian deposition. Erosion of the Precambrian surface during this interval likely resulted in a relatively smooth and gently dipping (<1 degree) top Precambrian surface with small localized dip variations. However, the limited Precambrian topography that did exist allowed for known but rare areas of non-deposition during the Cambrian that appear to be both localized and concentrated along Precambrian basement block terrain boundaries. The CO_2 storage AOI has been located to avoid these areas of non-deposition. Despite the presence of fractures in the basement, no substantial porosity or permeability is expected in the Precambrian interval.

5.2.2 Baffle: Lower Marine Sands of the Earlie Formation

The LMS records a gradual deepening in the environment of deposition relative to the BCS as the transgression of the Middle Cambrian sea continued landward (east to northeast). Core descriptions of the LMS illustrate a fining upwards grain size distribution. Sedimentological description indicates a position in the subtidal environment, basinward of the marginal marine environment in which BCS deposition occurred. The upper LMS consists predominantly of sediments deposited in a distal environment, above storm wave base, with intermittent sand deposition likely delivered via episodic storm-driven flows. Within Shell Wells 11-32, 3-4 and 8-19, the LMS net to gross ratio ranges from approximately 0.35 to 0.57. Across the CO_2 storage AOI, the LMS varies in thickness from approximately 50 to 75 m. The average total porosity calculated for the recent Shell Wells 11-32, 3-4 and 8-19 is 10 to 12%, and the effective porosity is 6%. The average permeability is 4 mD.

CO_2 will not be injected into the LMS. Although the LMS shows some porosity and minor permeability, the vertical permeability is negligible, making the LMS a baffle to vertical CO_2 migration.

5.2.3 First Seal: Middle Cambrian Shales of the Deadwood Formation

The Middle to Upper Cambrian MCS records the first major seal above the BCS. Descriptions of core suggest that the MCS was likely deposited on the distal portion of the interior cratonic platform between the up-dip siliciclastic deposits characteristic of the BCS and the down-dip outer margin carbonate platform deposits that manifest in Middle to Upper Cambrian Rocky Mountain outcrops to the west and southwest (e.g., the Pika, Waterfowl and Lynx Formations). Core descriptions show a transition from principally massive thick-bedded shales at the base to progressively more thin-bedded shales with interbedded but rare limestones and coarse-grained siltstones and fine-grained sandstones up-section.

Within the CO_2 storage AOI, the MCS is the oldest formation affected by the Devonian unconformity. This yields a section that decreases from approximately 55 m in thickness in the southwest, where it is conformably overlain by the UMS and not subject to the unconformity-associated erosion, to approximately 20 m in the northeast, where it is in direct contact with Devonian strata (see Figure 5-1). The MCS is believed to be a competent seal even at the minimum thickness interpreted within the CO_2 storage AOI. The MCS clays consist predominantly of varying amounts of illite and kaolinite, with minor amounts (<15%) of smectite and chlorite, confirmed through x-ray diffraction (XRD) from core analysis and natural gamma-ray spectroscopy from logs and geochemistry. The MCS records the lowest estimated net to gross ratio within the Cambrian succession and acts as the first major stratigraphic seal. Horizontal permeability levels within occasional sands in the MCS are in the nano to microdarcy range, as interpreted from the shale and clay content described in these sands. However, the vertical permeability is interpreted to be in the nanodarcy range due to the presence of laminated bedding. No core measurements were achieved in these sand streaks.

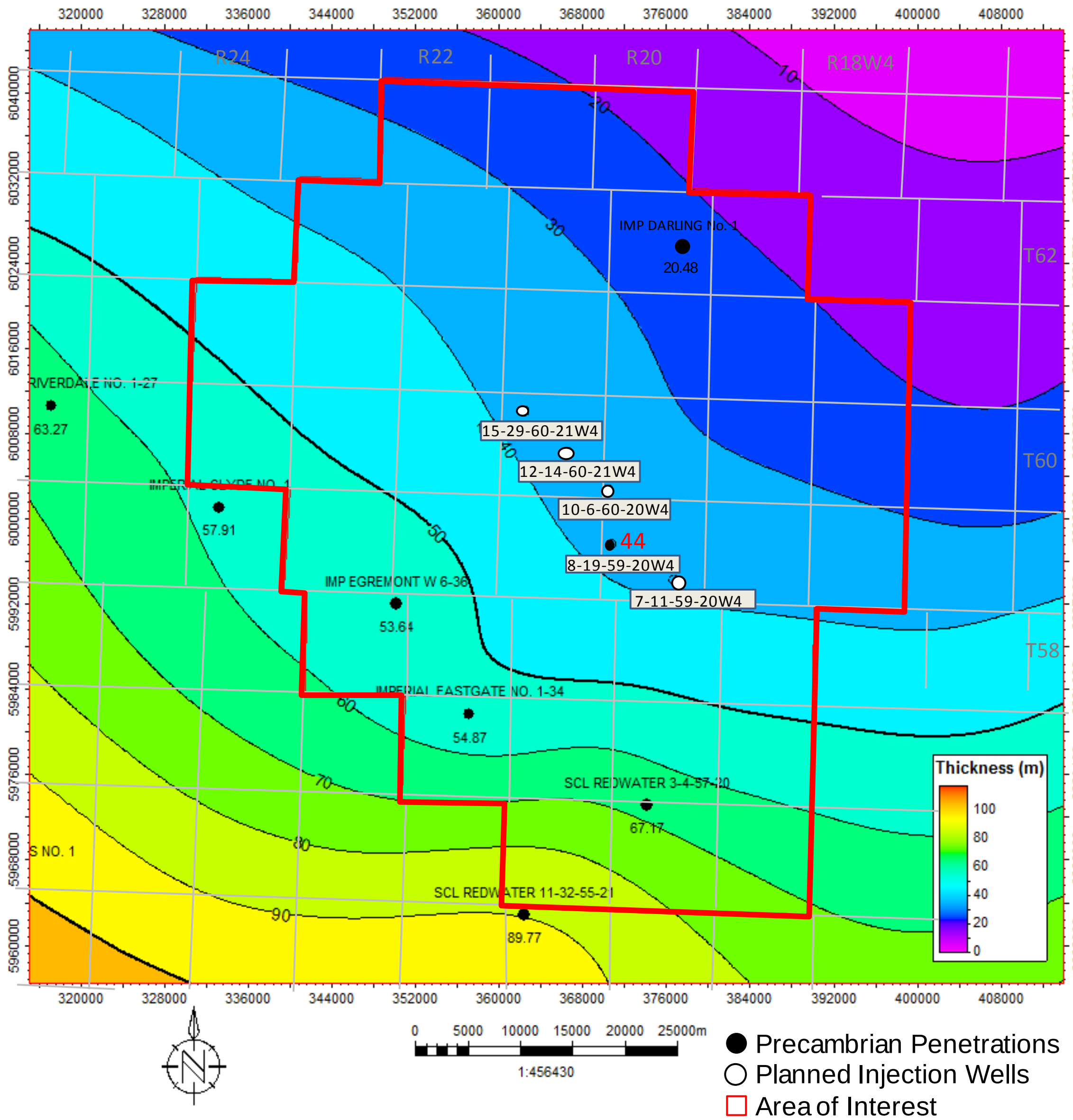


Figure 5-1 Thickness and Extent of Middle Cambrian Shale Over the AOI

5.2.4 Baffle: Upper Marine Sands likely of the Upper Deadwood Fm

The UMS lies above the MCS, which is the first major seal to the BCS storage complex. The Upper Cambrian UMS is only evident in the southwest portion of the CO_2 storage AOI primarily due to erosion associated with the Devonian unconformity. In the UMS, sediments similar to the transitional LMS have been recorded and likely represent a progradational package of siliciclastic material that was deposited in response to either an increase in sediment supply or to a relative fall in sea level. The UMS thins from a maximum thickness of approximately 60 m in the southwest to a northwest–southeast oriented erosional truncation in the northeast corner of the AOI. The UMS consists of predominantly greenish shales with minor silty and sandy interludes. Total porosities in the UMS can be up to 12%, with less than 1 to 2% effective porosity, as observed from Well 11-32 intermediate hole section NMR log. Permeability levels of less than 1 mD were consistently estimated in this section from NMR logs, and virtually no vertical connectivity was interpreted, consistent with the poor horizontal properties seen in logs.

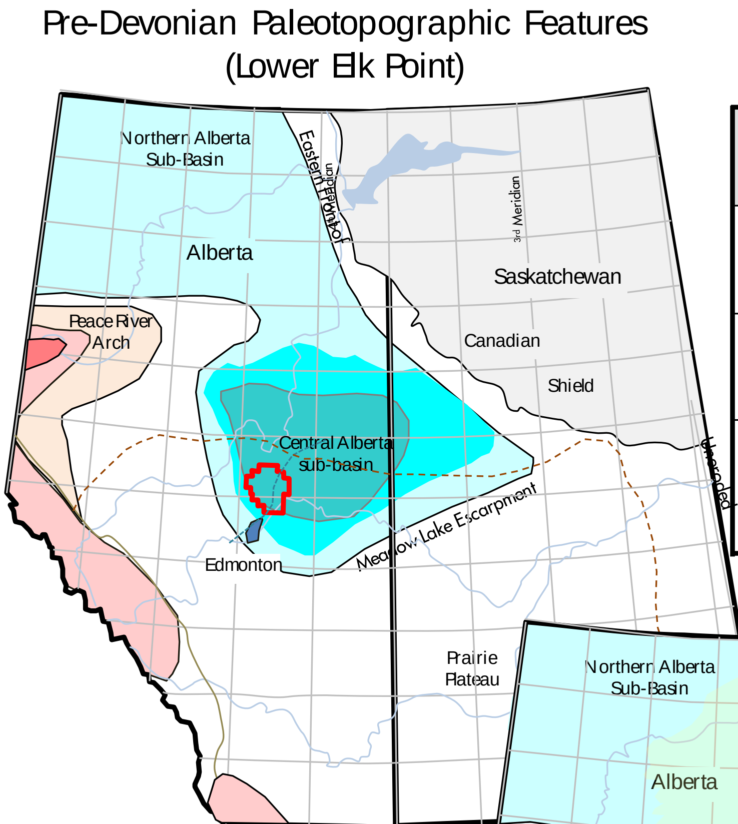
5.2.5 Baffle: Devonian Red Beds

Directly overlying the Cambrian UMS are Devonian Elk Point Group fine-grained siliciclastics and evaporites. The Devonian unconformity, which separates the Cambrian and Devonian sequences, represents approximately 100 million years. The Cambrian sedimentary sequence was typified by a passive continental margin transgression, whereas the Devonian Elk Point Group succession was controlled by a more complex palaeotopographic environment. The Basal Devonian Red Beds represent the first deposition on the Cambrian strata. The red beds consist of fine-grained siliciclastic sediments eroded from adjacent highlands (e.g., the Peace River Arch to the northwest, the Western Alberta Ridge to the west, and the cratonic high to the northeast).

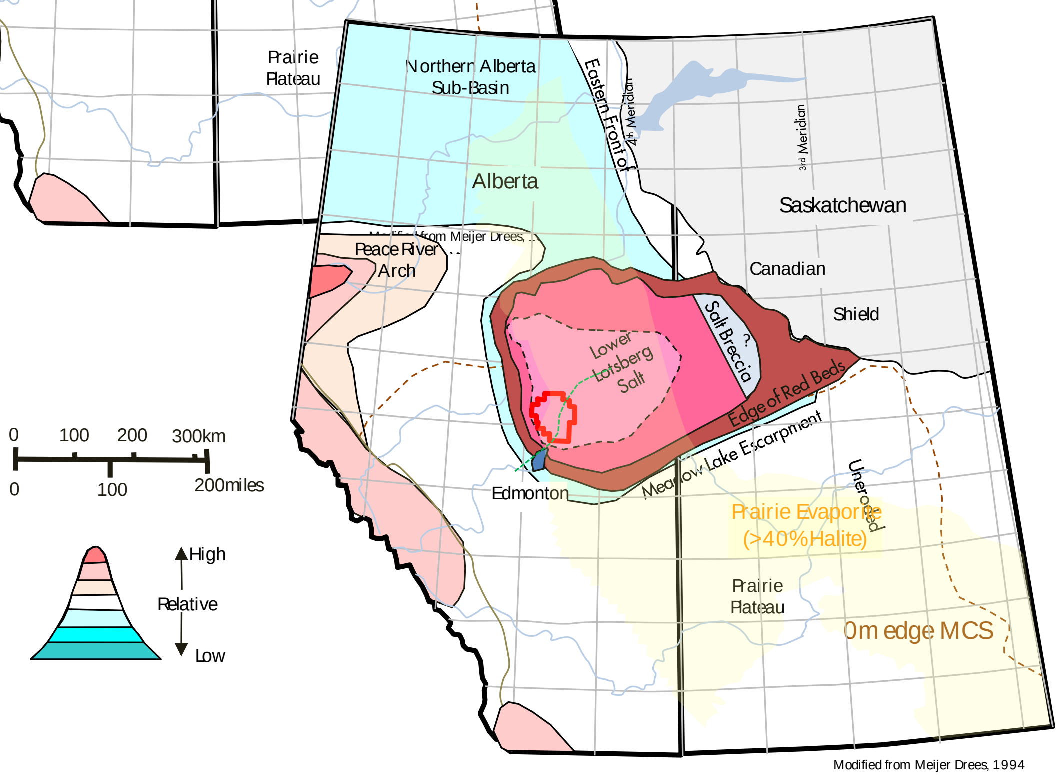
The Basal Red Beds are composed of green and red shales with silty stringers. These have been described as lagoon or bay deposits consisting of thick-bedded, mottled gray to red, silty mudstone with common halite-filled vugs and concretions. In the core from Well 3-4, most of the sequence consisted of shales grading to dolomitic siltstone with traces of salt and anhydrite. In Wells 3-4 and 11-32, total porosity values as high as 10% were recorded but typical porosity values were below 5%, with permeability values ranging from 0.001 to 1 mD, as confirmed from NMR readings in Well 11-32.

5.2.6 Second Seal and Third (Ultimate) Seal: Lotsberg Formation

Overlying the Devonian Basal Red Beds is the Devonian Lotsberg Formation, consisting of the Lower and Upper Lotsberg salts, separated by a layer of fine-grained siliciclastics, deposited during periods of relative basin isolation and subsequent evaporite formation. The salts are mainly 100% halite with minor shale laminae, and represent the second and ultimate seals for the BCS storage complex, respectively. The Lotsberg salts are true aquicludes, with their large lateral extent, thickness, impermeability and ability to anneal via plastic deformation. The Upper Lotsberg is the ultimate seal because it is the thickest, most regionally extensive seal and represents the top of the BCS storage complex. Both the Lower and Upper salt units thicken towards the Central Alberta sub-basin northeast of the CO_2 storage AOI to a maximum thickness of 60 m and 150 m, respectively (see Figure 5-2) (Grobe 2000). The Lower Lotsberg is thin (~10 m) in the Western portion of the AOI but thickens to 35 m in the northeast (see Figure 5-3). The Upper Lotsberg is a true aquiclude present over the entire AOI and varies in thickness from approximately 55 m in the west to 90 m in the northeast of the AOI (see Figure 5-4).



Formation Thickness (m)	Seal Thickness Across AOI (m)		
	Average (Logs)	Minimum	Maximum
Upper Lotsberg (Ultimate Seal)	84m	53m	91m
Lower Lotsberg (Secondary Seal)	34m	2m	36m
Middle Cambrian Shale (MCS) (Primary Seal)	44m	22m	90m



SOURCE: Modified from N.C. Meijer-Drees, 1994. Geological Atlas of the Western Canada Sedimentary Basin.

Figure 5-2 **Regional Extent of Middle Cambrian Shale and the Lower and Upper Lotsberg Seals**

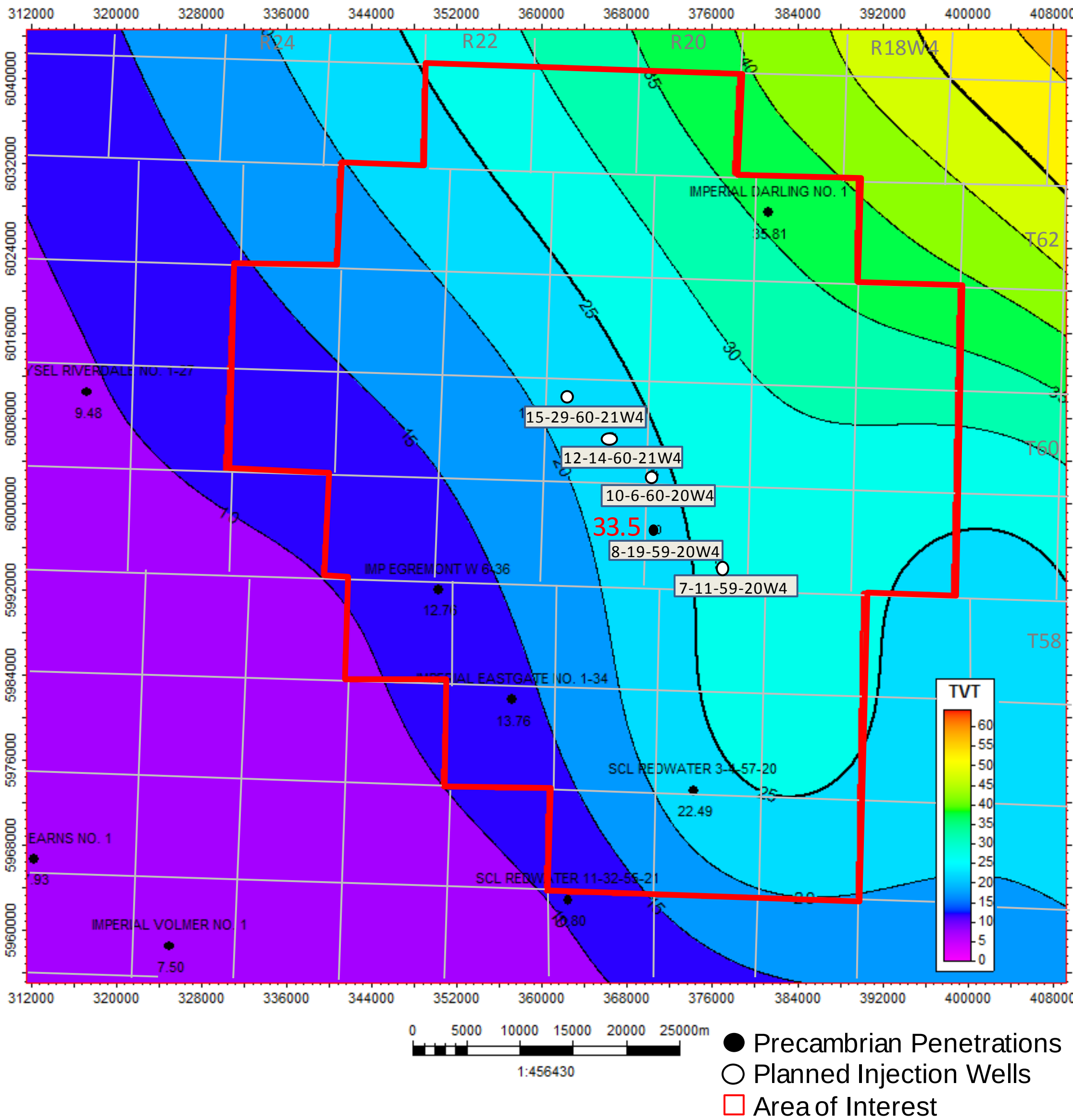


Figure 5-3 Extent and Thickness of the Lower Lotsberg Salt in the AOI

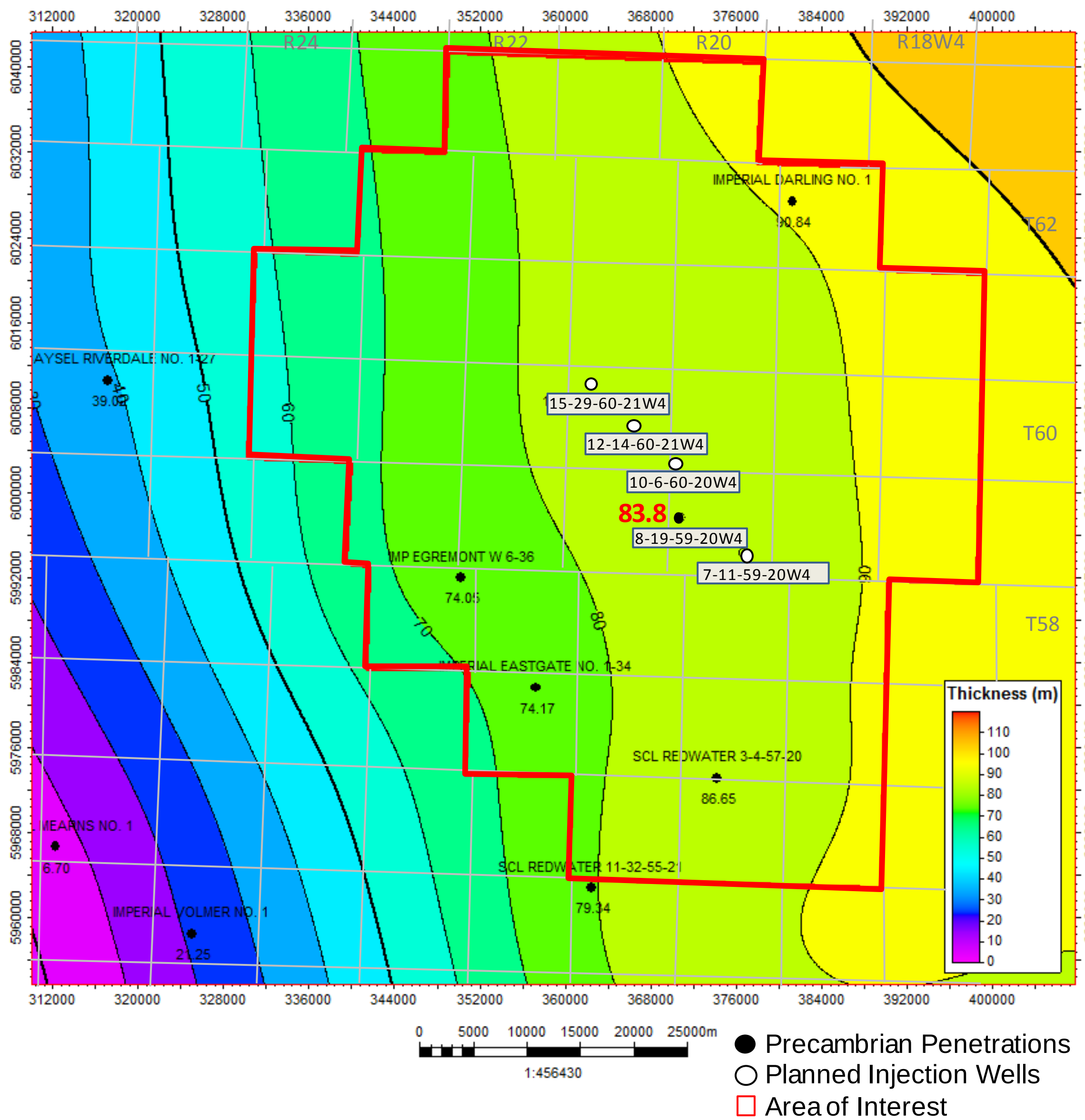


Figure 5-4 Extent and Thickness of the Upper Lotsberg Salt in the AOI

6 Reservoir

6.1 Native Reservoir Fluids

Two wells in the CO_2 storage AOI were sampled over the BCS formation. Fluid analysis from six pressurized samples taken at a depth of 2,084.9 m MD in the Well 8-19 is not yet complete at the time of issuing this application. The current reservoir fluid description is based on sample analysis from Well 11-32.

In December 2008, six MDT samples from two depths within the BCS reservoir were obtained in Well 11-32. Four sample chambers captured formation fluids from 2,198.0 m MD, and two more samples were collected from a depth of 2,191.6 m MD. The high quality samples showed minimal contamination. The samples were analyzed for water density.

The level of total dissolved solids (TDS) of formation water from Well 11-32 was approximately 269,000 mg/L, which corresponds to a water density at ambient conditions of 1,176 kg/m^3. These values are consistent with regional fluid data (see Table 6-1). An average pH of 5.9 was measured from six pressurized samples immediately after they were flashed in the laboratory. The gas water ratio measured from the gas volume flashed from these samples averaged 0.25 m^3/m^3 with a composition of 25.2 mol% of CO_2, 72.2 mol% of N_2 and 2.4 mol% of C_1. The formation water viscosity was 1.18 cP at reservoir conditions.

Stimulation of methane formation in the subsurface by CO_2 injection is highly unlikely as microbial methane formation in the subsurface is not limited by CO_2 but rather by the H_2 required to reduce the CO_2 to form methane ($CO_2 + {}_4H_2 \rightarrow CH_4 + {}_2H_2O$) microbiologically. Methane formation in the BCS is even more unlikely as the salinity of the formation water is extremely high (269,000 mg/L). Microbial methane formation from H_2 and CO_2 is unlikely to occur above salinities of ~150,000 mg/L (= highest reported).

6.1.1 Composition of Injection Fluid

The design basis is for a minimum of 95% by volume CO_2. The expected performance, however, will be greater than 98% by volume CO_2. The remaining constituents, in descending order, are H_2, Cl, CO, H_2O and N_2. H_2S levels will be less than commercial-grade natural gas.

The captured gas will be dried to contain less than 6 lbs of water per MMscf of CO_2. The process control should also prevent any entrapped water getting into the CO_2 pipeline.

Table 6-1 Regional Fluid Data

Well Name	Top (m)	Base (m)	Date Reported	Recovery Description	TDS Calc. (mg/L)	Density (gr/cm³) (at 16°C)	Res. (Ohm)	Res. Temp (degC)	Rw Calc (Ohm)
IMPERIAL EASTGATE NO. 1-34-57-22	2,139.7	2,167.1	1-Nov-55	423.7M SW	308,982	1.210			0.020
IMPERIAL EASTGATE NO. 1-34-57-22	2,082.1	2,098.9	1-Nov-55	67.1M SW-CUT MUD	279,989	1.179			0.024
IMP EGREMONT W 6-36-58-23	2,152.2	2,160.7	13-Jan-53	1481.3M SW	231,277	1.190			0.021
CDNOXY SWD 2 SUGDEN 6-13-63-8	1,350.0	1,384.0	7-Jan-87	240.0M MUD-CUT SW:780.0M SW	243,801	1.176	0.042	25	0.030
ARCO B.A. VENICE 10-12-66-15	1,531.6	1,562.1	20-Mar-67	213.4M MUD:1089.7M SW	303,749	1.195	0.055	20	0.034
CHIEFCO ET AL TOUCHWOOD 11-3-67-10	1,449.3	1,480.7	30-Jan-69	652.3M MUD-CUT SW	280,382	1.162	0.044	23	0.030
MCD CHIEFCO LABIE 10-11-67-12	1,446.0	1,482.2	9-Apr-69	54.9M MUD:1073.5M SW	305,222	1.203	0.031	25	0.022
MCD CHIEFCO LABIE 10-11-67-12	1,446.0	1,482.2	13-Feb-68	54.9M MUD:1073.5M SW	310,521	1.196	0.041	24	0.028
PACIFIC PLAMONDON 6-21-67-16	1,623.7	1,627.3	13-Mar-58	810.8M SW	353,191	1.211	0.095	25	0.064
IMPERIAL GROSMONT NO. 1 WELL	1,927.9	1,933.0	10-Feb-50	57.9M SW	306,874	1.025			-

NOTES:

Most fluid samples collected through DST's and tested in the period between 1950-1970. All TDS measurements were consistent, ranging from 230,000-350,000 mg/L NaCl equivalent confirming the presence non-potable water.

SOURCE: IHS Geofluids database.

6.1.2 Viscosity, Density, Formation Volume Factor and Compressibility

The properties of pure CO_2 are publicly available. At expected average BCS reservoir conditions of 20,450 kPa and 60°C, pure CO_2 has a density of 731 kg/m^3, a viscosity of 0.061 cP, a formation volume factor of 0.0026 and an isothermal compressibility of 2.05 E-8 1/kPa.

At the maximum expected bottomhole pressure of 32 MPa (see Section 6.5.3) and expected typical flowing bottomhole temperatures of 25°C, these properties change to a density of 974 kg/m^3, a viscosity of 0.113 cP, a formation volume factor of 0.0019 and isothermal compressibility of 4.14 E-9 1/kPa.

At expected average well head conditions of 14 MPa and 5°C (see also Section 6.5.3) these properties change to a density of 972 kg/m^3, a viscosity of 0.113 cP, a formation volume factor of 0.0019 and an isothermal compressibility of 5.54 E-9 1/kPa. The properties at other conditions can be obtained (Megawatsoft 2010, Internet site).

6.1.3 Phase Behaviour

The critical point of the phase envelope for 100% pure CO_2 is defined by the critical temperature at 31°C and the critical pressure at 7,377 kPa. At this point, CO_2 will have a density of 467.6 kg/m^3. Above this temperature and pressure, CO_2 will be in a super-critical state, meaning it has a density similar to that of a liquid, although its flow behaviour will remain more like a gas.

The gas stream downstream of the compressor will remain in the dense state throughout the CO_2 pipeline route to the injection well, where the CO_2 will be stored in the BCS reservoir.

See Figure 6-1 for the various notional operating windows at the compressor outlet, the injection well head and the bottomhole perforations against the CO_2 phase envelope. The arrows indicate how the CO_2 moves between the compressor to the well head through the pipeline and onwards through the wellbore down to the perforations. The phase envelope indicates that the CO_2 will remain in the supercritical or liquid phase at all times during this process.

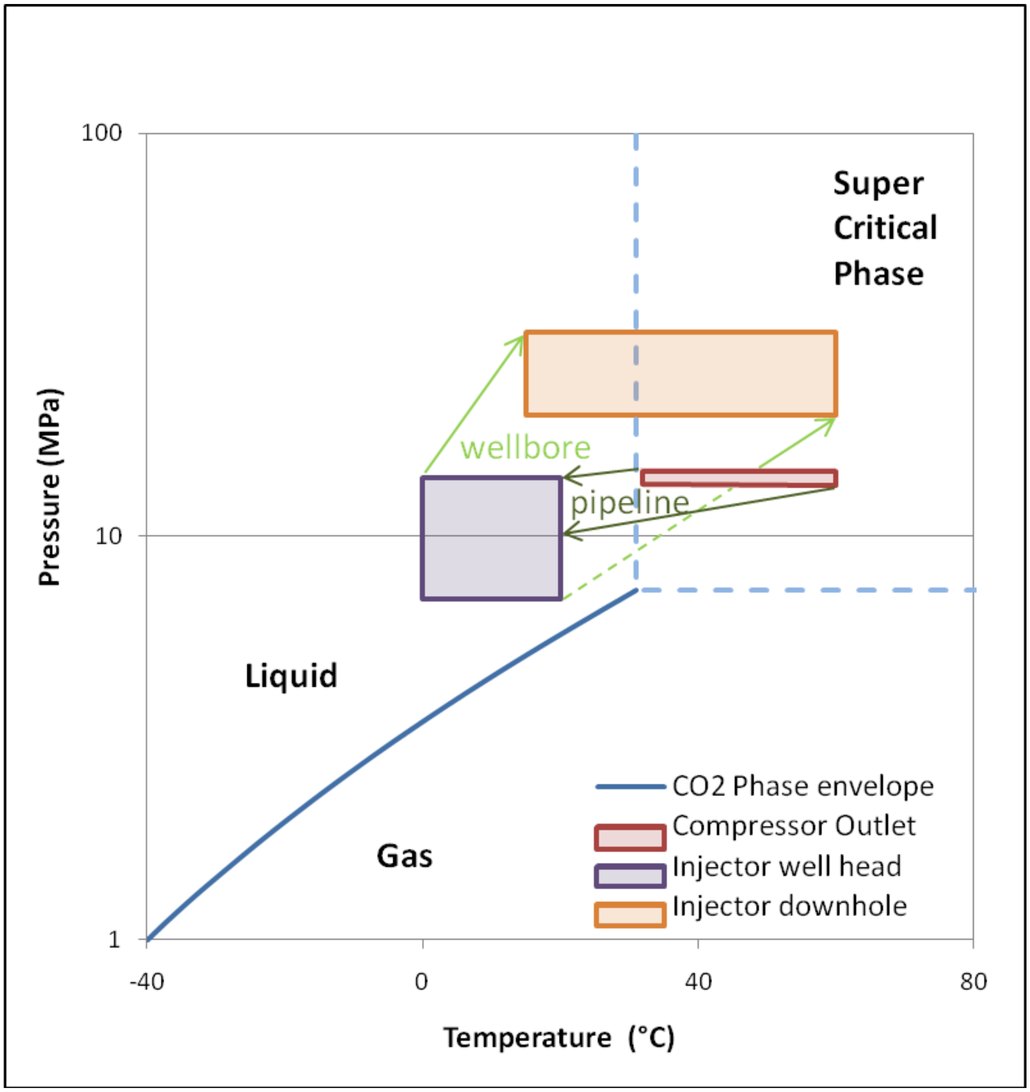


Figure 6-1 The CO_2 Phase Envelope and Quest CCS Project Operating Windows

6.2 Laboratory Testing – Fluid Interactions

6.2.1 Effect of CO_2 on BCS Brine

When dry super-dense CO_2 initially contacts formation water, some of the CO_2 will dissolve in the brine, and some water will evaporate into the super-dense CO_2. The wet CO_2 will then displace brine near the wellbore, leaving residual brine behind the displacement front. The trailing, dry CO_2 will continue to cause water in the residual brine to evaporate, resulting in salt concentrating in the brine and eventually precipitating from it. At the same time, CO_2 dissolved in the brine will acidify the brine because of carbonic acid being generated and separating to produce bicarbonate ions and protons. Acidification drives all of the geochemical processes during CO_2 injection, migration, storage and trapping in the reservoir by dissolving/precipitating minerals and gases and adsorbing/desorbing/exchanging ions.

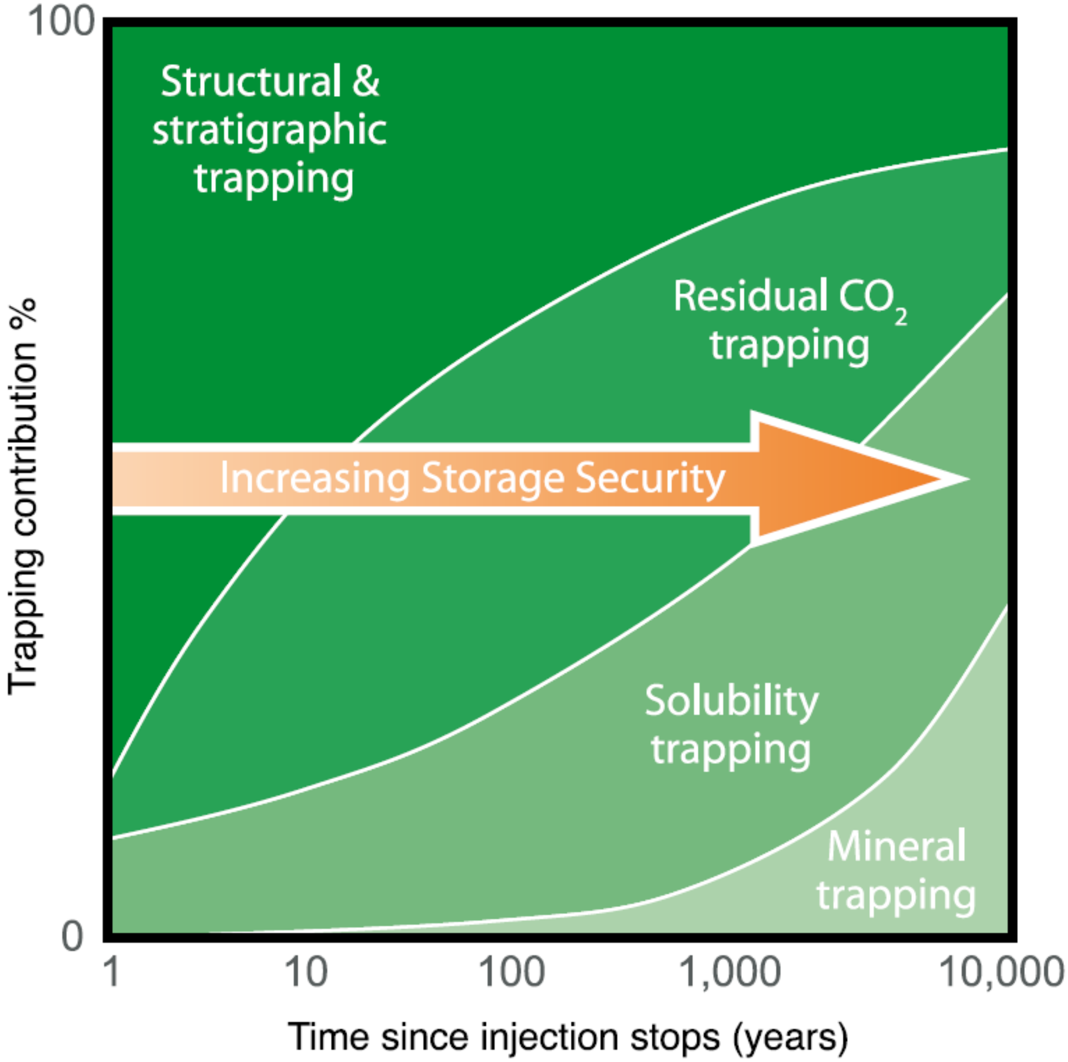
6.2.2 Mechanisms for Trapping CO_2

For a summary of CO_2 storage mechanisms, see Figure 6-2. Storage security depends on a combination of physical and geochemical trapping. Injected CO_2 partially displaces brine in the reservoir and partially dissolves in the brine. A portion of injected CO_2 is permanently trapped in place due to residual trapping, solubility trapping and mineral trapping mechanisms.

The free-phase CO_2 is the remaining CO_2 trapped by structural and stratigraphic traps in the BCS storage complex. Over time, the physical process of residual CO_2 trapping and geochemical processes of solubility trapping and mineral trapping increase. This results in more CO_2 becoming permanently trapped, and less free-phase CO_2 existing.

The average mineralogy of the BCS, defined through petrology, was used as input to geochemical modelling of rock and fluid interaction of injected CO_2 and formation brine. Primary minerals included in the reactive transport modelling in TOUGHREACT are quartz (75 vol%), K-feldspar (5 vol%), dolomite/ankerite (1 vol%), anhydrite (1 vol%), illite (1 vol%) and kaolinite (1 vol%). Halite and calcite are classified as secondary minerals that form during CO_2 injection. The key conclusions of the laboratory-calibrated, reactive transport modelling study are that at the end of injection:

- the main geochemical mechanism for trapping CO_2 is associated with dissolution in formation brine. At the end of injection, approximately 4% of the total injected CO_2 volume is dissolved in the brine. The remaining CO_2 is physically trapped via capillary forces at irreducible saturation with some portion of the CO_2 remaining in a mobile phase at the end of the injection period. After 50 years, (i.e., 25 years after the end of injection), these percentages go to 60% mobile, 25% residual and 15% dissolved CO_2.
- dolomite and K-feldspar continue to dissolve in the low pH flushed zone of the BCS. Hence, the net amount of geochemical CO_2 trapping in the matrix is negative, meaning additional CO_2 is released in the low pH zone while dissolving the carbonate impurities of the BCS.



SOURCE: IPCC (2005)

Figure 6-2 Summary of CO_2 Storage Mechanisms

6.2.3 Halite Precipitation

Injecting dry CO_2 over a prolonged time into the BCS will create a dry-out zone around each of the injection wells due to brine evaporation, resulting also in halite precipitation.

Geochemical modelling, using TOUGHREACT, estimated that at the end of 25 years of injection such dry-out zones may extend several tens of meters away from the wellbore into the formation. Core flooding experiments to study the effect of halite precipitation on CO_2 injection in the BCS have been conducted in Shell's Research Laboratory in Rijswijk and at MetaRock, Houston.

The first set of experiments showed a slight reduction in effective permeability during dry-out, potentially associated with end-cap effects. The second set of laboratory tests showed a slight increase in effective permeability, believed to be the result of increasing effective porosity due to the drying out of irreducible water.

In the unlikely event that permeability reduction due to halite precipitation occurs in the field, mitigation to restore well injectivity will involve flushing the region near the wellbore with fresh brine, and dissolving the halite.

6.2.4 Interaction Between CO_2 Injection Zone and First Seal

Any possible geochemical alteration of the first reservoir seal, the MCS, was studied during reactive transport modelling based on the available XRD data. The mineralogy package of the MCS predominantly consists of quartz (20 vol%), illite/smectite/mica (30 vol%), kaolinite (30 vol%), K-feldspar (7 vol%), dolomite/ankerite (1 vol%) and chlorite (4 vol%). Model results determined that:

- in the shale, CO_2 exposure reduces the pH from 5.5 to 4.0, leading to dissolution of dolomite and feldspar in the reactive zone within the shale
- the formation of clay minerals due to the dissolution of the feldspar appears to reduce the shale permeability further, hence potentially enhancing the sealing properties of the MCS

6.3 Migration Calculations

To meet the life expectancy of the Scotford Upgrader, all calculations of CO_2 migration were completed over a minimum injection period of 25 years. The full range of development possibilities were considered, including the following scenarios:

- base case – 5 injection wells
- high injectivity case – 3 injection wells
- low injectivity case – 10 injection wells

6.3.1 Radius of Influence

An analytical CO_2 plume size can be calculated by assuming homogeneous displacement of brine by the injected CO_2 in a cylindrical shape around the Well 8-19 wellbore. This is a highly simplified method used to indicate the minimum radius of influence. The presence of reservoir heterogeneities around the wellbore will cause non-uniform displacement (see Section 6.3.2), including:

- in high permeability layers, or towards the top of the reservoir, the CO_2 will migrate outside this notional cylinder
- in lower permeability layers or deeper intervals, the CO_2 front may not quite reach this notional cylindrical CO_2 plume radius

The reservoir parameters used to make this analytical calculation for cylindrical migration are from the Well 8-19 results, with regional property range (see Table 6-2). The results suggest that the radius of the CO_2 plume size after 25 years of injection could extend to between 0.5 to 3 km away from the wellbores, depending on, in order of priority, the number of wells, the sweep efficiency, maximum CO_2 saturation, porosity, BCS reservoir thickness and other reservoir parameters of minor effect.

The analytical results above were used to QC dynamic simulation results for various subsurface realizations. See Figure 6-3 for simulation results from a subsurface realization that incorporates reservoir heterogeneity and low case reservoir property values. The CO_2 saturation is displayed for a layer at the top of the BCS after 25 years of injection. The CO_2 plume of each individual well is not circular as it is influenced by the modelled northeast–southwest directionality of the expected reservoir permeability distribution. Heterogeneity and low reservoir properties result in a plume radius larger than in the analytical base case calculations, with the plume dimensions along their largest cross-sections approximately double the analytically calculated base case plume size (see Table 6-2). The simulated CO_2 plume sizes vary slightly with location depending on the permeability distribution and local thickness and topography variations (see Table 6-2).

The pressure front associated with the CO_2 injection will extend far beyond the area of the CO_2 plume. The radius of influence for pressure will depend mainly on the total injected volume, the maximum allowable bottomhole pressure and the formation compressibility. The minimum connected volume requirement would extend about 8 to 12 times further into the reservoir than the CO_2 plume according to simplified material balance calculation. Therefore, for a CO_2 plume size of between 500 m and 3 km, the minimum connected volume radius would need to be between 4 km and 30 km.

Table 6-2 Notional CO_2 Plume Radius Based on Reservoir Parameters for Well 8-19

Parameter	Base Case	Promoting Maximum Plume	Promoting Minimum Plume
BCS reservoir height (m)	46	28	43
BCS net-to-gross ratio	0.9	0.8	1
BCS porosity	0.16	0.11	0.19
BCS net pore height (m)	6.62	2.46	8.17
Maximum CO_2 saturation	0.6	0.4	0.75
CO_2/brine sweep efficiency	0.8	0.5	0.95
Effective CO_2 saturation	0.48	0.2	0.71
Formation Temperature	60	64	55
Formation Pressure	20.45	20.2	20.7
CO_2 density at Pi, Ti	731	711	761
Injected CO_2 after 25 years (Mt)	27	27	27
Number of wells	5	3	10
Notional CO_2 plume radius (m)	**860**	**2,860**	**440**

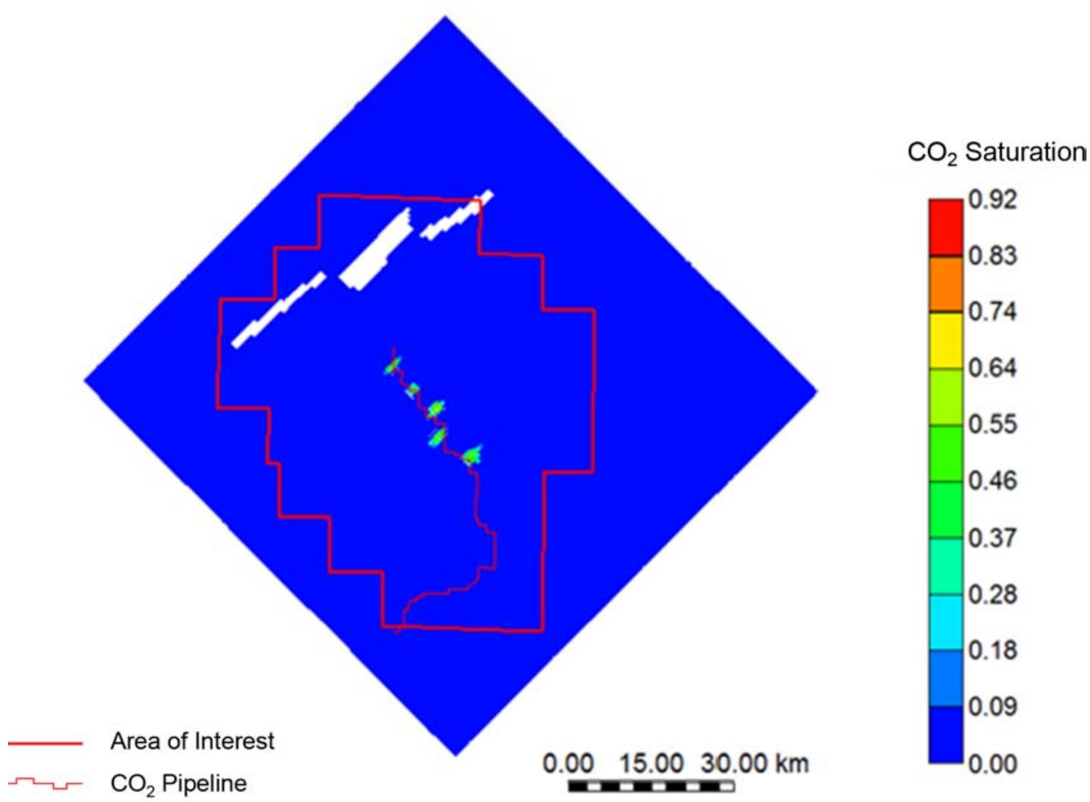


Figure 6-3 CO_2 Saturation after 25 years of Injection for a Heterogeneous, Low Reservoir Property Realization

See Figure 6-4 for the pressure increase after 25 years of injection, from dynamic modelling of the same heterogeneous, low reservoir property subsurface realization as shown previously (see Figure 6-3). The pressure response in the BCS is seen to extend some 20 to 40 km away from the injection wells. In other subsurface realizations where reservoir properties, specifically reservoir porosity and permeability, are higher, the extent of the pressure increase is somewhat smaller. Analytical aquifer boundary conditions are applied to the dynamic model built in the Computer Modeling Group's Generalized Equation-of-State Model (CMG-GEM) compositional reservoir simulator that assume some of the pressure increase will be dissipated by reservoir outside the model area.

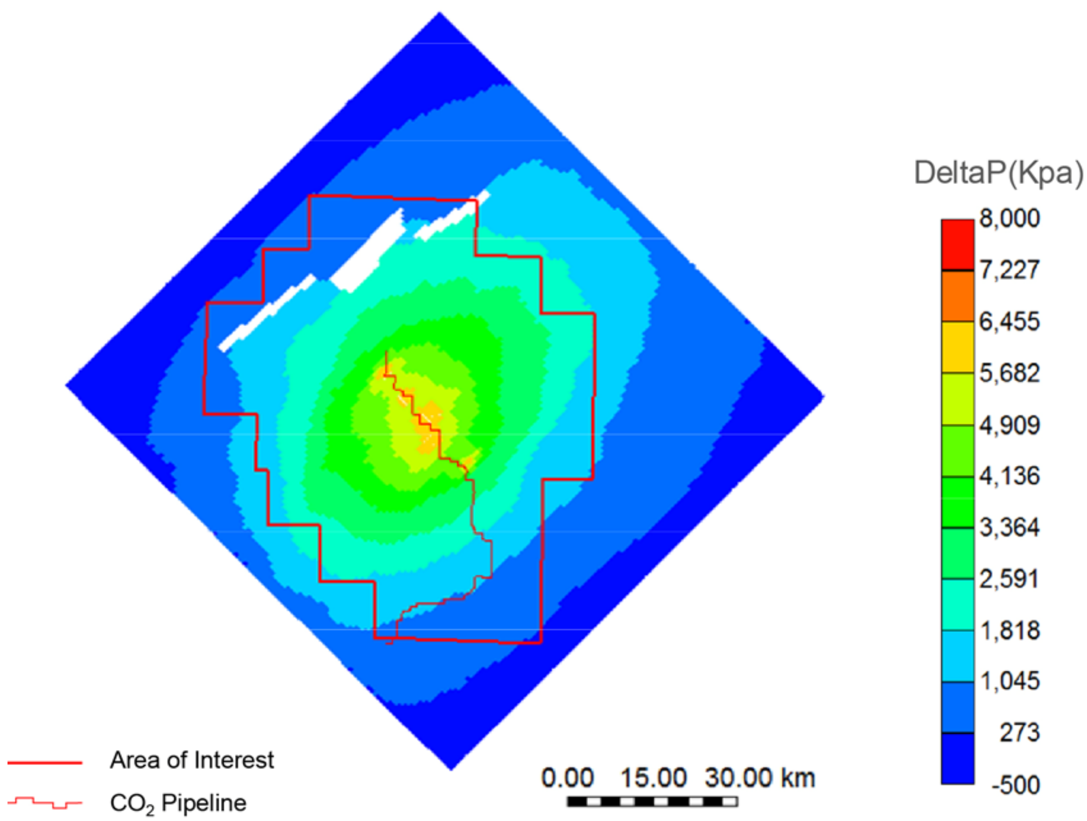


Figure 6-4 Pressure Increase after 25 years of Injection for a Heterogeneous, Low Reservoir Property Realization

6.3.2 Sensitivity to Displacement, Gravity and Fingering

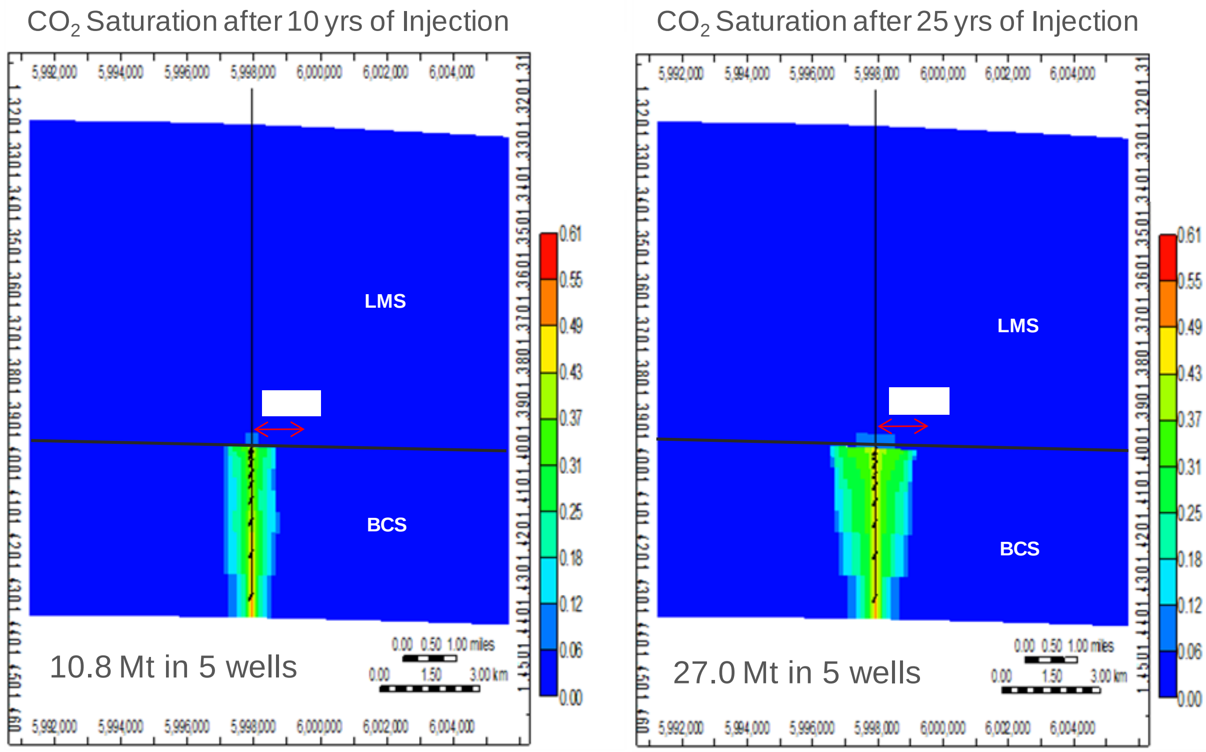
To determine the ranges of uncertainty in the migration of the CO_2 plume, sensitivity analyses of key reservoir parameters were run on various dynamic models. The sensitivity study results indicate that horizontal and vertical permeability and CO_2-brine relative permeability have the greatest effect on the amount of residual trapped, dissolved, and free-phase CO_2 (see Section 6.2.2) among all dynamic modelling parameters.

This is important because the CO_2 migration process directly affects the CO_2 trapping mechanisms and vice versa. For example, increased contact of CO_2 with fresh brine increases the amount of dissolved CO_2, resulting in less free CO_2 available to migrate.

There are two distinct CO_2 migration phases: one during injection, and one after injection. The characteristics of each are that:

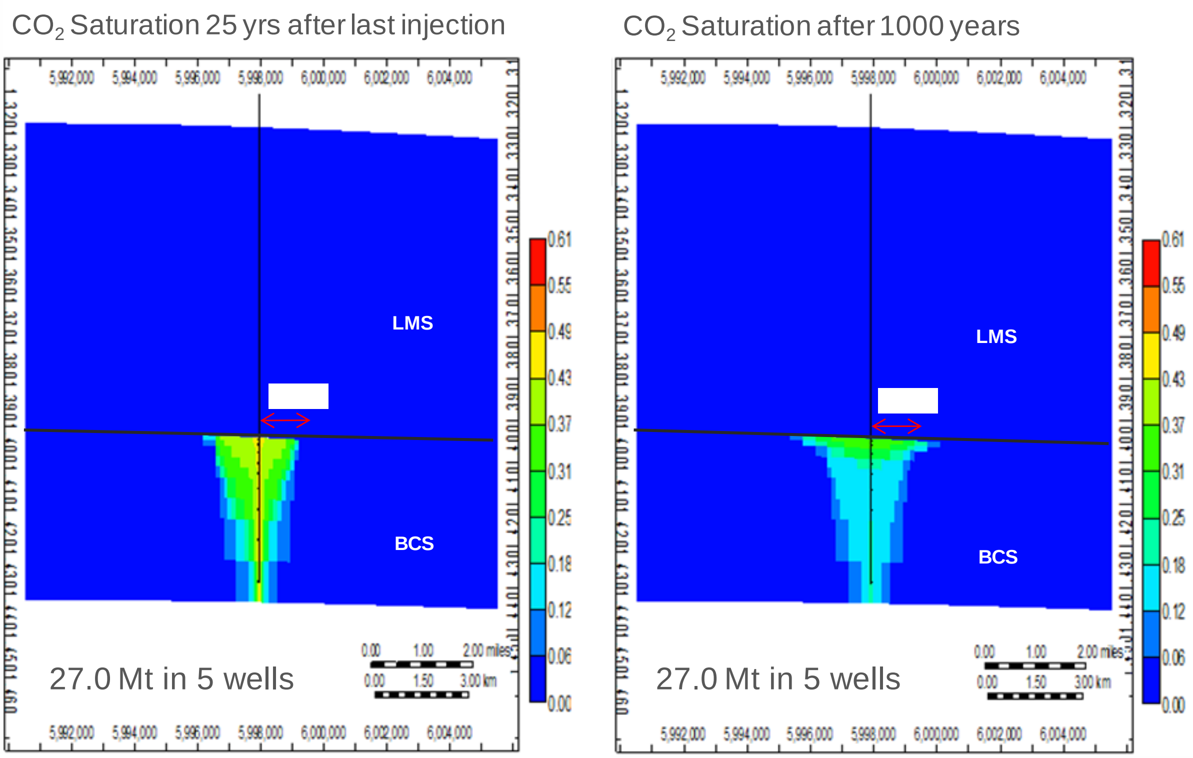
- during the injection phase, viscous force dominates, and CO_2 displaces reservoir brine in a more uniform front, roughly cylindrical in shape
- during the post-injection phase, gravity takes over to become the dominant force in the displacement process, as the viscous force (due to injection) stops. As the density of CO_2 is less than that of reservoir brine, CO_2 is buoyant and migrates upward resulting in an inverted cone-shaped CO_2 plume.

See Figure 6-5 and Figure 6-6 for cross-sections illustrating the plume development during and after injection, taken from an earlier generation subsurface model where reservoir properties are more uniform. In a more heterogeneous model where permeability variation are more pronounced, the plume will be less uniform and CO_2 migrates further in higher permeability zones. Nevertheless, the two CO_2 migration phases hold true.



NOTE: The non-uniform features at the edges are largely due to reservoir permeability heterogeneity. No significant viscous fingering is observed in the dynamic modelling studies. The 25-year scenario shows the effect of gravity, as the upper portion of the plume expands faster relative to the bottom portion. The radius of the CO_2 plume is less than 1.5 km. During this phase, as CO_2 contacts fresh brine, dissolution trapping is also in progress.

Figure 6-5 Cross-section of the Dynamic Model Results of CO_2 Plume Migration for the Base Case



NOTE: At Year 1000, CO_2 saturation has become very low and in most areas, the CO_2 is at residual saturation. A minute amount of free-phase CO_2 is stratigraphically trapped at the top of the reservoir. As CO_2 migrates vertically and horizontally, dissolution trapping and residual trapping are in progress, resulting in decreased free-phase CO_2.

Figure 6-6 Cross-section of the Dynamic Model Results of CO_2 Plume Migration for the Base Case after 25 years of Injection

6.4 Reservoir Pressure History

The reservoir pressure in the BCS is expected to be at initial conditions as no record of production or injection within the BCS exists in the CO_2 storage AOI. Four wells in the CO_2 storage AOI have pressure data available complemented by one well (Well 11-32) with good data just to the south of the CO_2 storage AOI.

Two of the data points in the CO_2 storage AOI are from build-up tests on the following old wells drilled in the early fifties:

- Egremont 06-36-058-23W4, which was tested in 1953 and built up to a pressure of 20,684 kPa at a recorded depth of -1,522.7 m ss.
- Eastgate 01-34-057-22W4, which was tested two years later with a maximum build-up pressure of 20,886 kPa at a recorded depth of -1,506.9 m ss.

The three modern wells drilled by Shell all have a comprehensive set of MDT pressure data that provide an accurate assessment of reservoir pressure as well as in situ fluid gradients:

- Well 11-32, drilled in 2008, had a total of 17 good quality pressure tests (see Table 6-3). All pressures showed vertical communication within the BCS along a constant gradient of 11.53 kPa/m consistent with the water analysis of 1,176 kg/m^3 (see Section 6.1). The test on Well 11-32, which was conducted several months after drilling the well, confirmed the MDT pressures, although the gauges were set deep (below the BCS). Both gauges measured an initial pressure of 22,445 kPa at the gauge depth of 2,231 m MD.
- Well 3-4 data confirmed the formation pressure and fluid gradients through the 15 quality pressure points that were obtained (see Table 6-4). A successful pressure test at the top of the LMS confirmed the continuation of the BCS fluid gradient into the LMS, suggesting that these formations were in communication over geological time. This data also confirms the extensive lateral pressure equilibrium over the BCS as the two wells are 15.6 km apart, and were found to have overlapping fluid gradients.
- Well 8-19 was recently drilled with a full suite of logs acquired over the BCS in September 2010. The MDT tool acquired good pressure points at 18 depths, (15 in BCS; 3 in LMS) of which 13 points (all in the BCS) had a mobility above 5 mD/cP (see Table 6-5). The actual pressure at 1,431 mss (2,077.76 TVD) was 20,463 kPa (within 13 kPa [2 psi] of the prognosis). The pressures show perfect continuation of the pressure trend observed in Wells 11-32 and 3-4. The gradient over the 13 high-quality points in the BCS suggest an in situ gradient of 10.71 kPa/m (1,194 kg/m^3), only slightly more dense than observed in Wells 11-32 and 3-4, and in line with a lower reservoir temperature expected in the Well 8-19 up dip from Wells 11-32 and 3-4.

For an overview of the pressure data acquired in the three Shell wells, see Tables 6-3, 6-4 and 6-5 and Figure 6-7.

For this Directive 65 application, the reservoir pressure in the CO_2 storage AOI has been assumed to be 20,036 kPa at top of the BCS in Well 8-19 at a depth of 1,394.5 m true vertical depth subsea (TVDSS).

Table 6-3 MDT Results for Well 11-32

Test	Depth (m MD)	Formation	Depth (m TVSS)	Formation Pressure (kPa[a])	Drawdown Mobility	Test Type	Mud Pressure before test (kPa[a])	Mud Pressure after test (kPa[a])
1	2173.0	BCS	1545.0	21,814.8	2.08	Normal Pretest	26,951.0	26,815.7
2	2179.0	BCS	1551.0	21,879.4	10.6	Normal Pretest	27,143.0	26,889.5
3	2183.9	BCS	1555.9	21,929.3	10.1	Normal Pretest	27,098.0	26,999.9
4	2189.1	BCS	1561.1	21,986.9	4.1	Normal Pretest	27,228.7	26,989.6
5	2190.6	BCS	1562.6	22,006.0	18.4	Normal Pretest	27,214.5	27,061.8
6	2191.5	BCS	1563.5	22,016.4	43.2	Normal Pretest	27,215.2	27,072.5
7	2191.6	BCS	1563.6	22,012.9	74.2	Post sampling	27,162.9	27,020.8
8	2195.0	BCS	1567.0	22,057.6	4.4	Normal Pretest	27,270.7	27,119.6
9	2195.6	BCS	1567.6	22,065.6	2.3	Normal Pretest	27,133.9	27,153.5
10	2197.5	BCS	1569.6	22,085.3	72.7	Normal Pretest	27,310.9	27,181.2
11	2198.0	BCS	1570.0	22,091.9	53.2	Normal Pretest	27,333.8	27,149.7
12	2198.0	BCS	1570.1	22,090.5	88.7	Normal Pretest	27,350.6	27,174.6
13	2198.0	BCS	1570.1	22,088.2	611.1	Post sampling	27,161.5	27,197.0
14	2200.0	BCS	1572.0	22,116.3	7.9	Normal Pretest	27,314.9	27,183.0
15	2202.1	BCS	1574.1	22,140.4	6.1	Normal Pretest	27,351.8	27,171.3
16	2204.0	BCS	1576.0	22,167.3	15.3	Normal Pretest	27,418.9	27,234.1
17	2205.8	BCS	1577.8	22,183.2	24.0	Normal Pretest	27,440.9	27,263.0

Table 6-4 MDT Results for Well 3-4

Test	Depth (m MD)	Formation	Depth (m TVSS)	Formation Pressure (kPa[a])	Drawdown Mobility	Test Type	Mud Pressure before test (kPa[a])	Mud Pressure after test (kPa[a])
1	2008.5	LMS	1394.9	20,089.7	2.26	Normal Pretest	25,065.1	25,159.8
2	2076.0	BCS	1462.4	20,826.4	14.5	Normal Pretest	26,099.8	25,990.8
3	2082.0	BCS	1468.4	20,897.0	4.70	Normal Pretest	26,422.8	26,078.5
4	2083.8	BCS	1470.2	20,915.1	71.5	Normal Pretest	26,378.9	26,179.3
5	2089.0	BCS	1475.4	20,974.3	143.2	Normal Pretest	26,456.2	26,202.0
6	2091.5	BCS	1477.9	21,006.0	3.87	Normal Pretest	26,607.1	26,282.7
7	2094.0	BCS	1480.4	21,036.4	11.0	Normal Pretest	26,601.1	26,214.0
8	2098.0	BCS	1484.4	21,079.2	466.7	Normal Pretest	26,654.1	26,247.6
9	2101.9	BCS	1488.4	21,125.5	278.3	Normal Pretest	26,380.8	25,611.4
10	2102.0	BCS	1488.4	21,124.7	324.0	Normal Pretest	26,278.9	26,200.6
11	2104.0	BCS	1490.4	21,150.2	824.4	Normal Pretest	26,810.6	26,406.9
12	2104.4	BCS	1490.8	21,154.3	245.7	Normal Pretest	26,266.7	26,215.5
13	2106.5	BCS	1493.0	21,177.9	207.1	Normal Pretest	26,848.1	26,392.1
14	2109.0	BCS	1495.4	21,208.7	440.1	Normal Pretest	26,904.8	26,526.3
15	2112.0	BCS	1498.4	21,243.0	290.6	Normal Pretest	26,909.2	26,609.3

Table 6-5 MDT Results for Well 8-19

Test	Depth (m MD)	Formation	Depth (m TVSS)	Formation Pressure (kPa[a])	Drawdown Mobility	Test Type	Mud Pressure before test (kPa[a])	Mud Pressure after test (kPa[a])
1	1992.4	LMS	1345.65	19,496.9	2.06	Normal Pretest	21193.96	21190.59
2	2000.5	LMS	1353.72	19,600.0	0.57	Normal Pretest	21291.69	21277.69
3	2004.0	LMS	1357.24	19,657.6	1.27	Normal Pretest	21330.81	21316.71
4	2041.7	BCS	1394.91	20,062.1	0.24	Normal Pretest	21717.25	21709.31
5	2045.8	BCS	1399.06	20,111.8	0.31	Normal Pretest	21758.93	21749.9
6	2049.2	BCS	1402.42	20,127.6	30.7	Normal Pretest	21792.31	21785.19
7	2056.1	BCS	1409.32	20,211.8	8.6	Normal Pretest	21867.14	21856.98
8	2061.1	BCS	1414.30	20,267.5	46.7	Normal Pretest	21916.09	21909.93
9	2063.5	BCS	1416.71	20,295.6	23.6	Normal Pretest	21938.7	21933.26
10	2066.4	BCS	1419.63	20,329.9	105.8	Normal Pretest	21965.54	21961.54
11	2069.6	BCS	1422.79	20,366.8	51.2	Normal Pretest	22009.17	21994.47
12	2071.8	BCS	1425.07	20,392.9	167.1	Normal Pretest	22030.12	22016.12
13	2074.3	BCS	1427.51	20,421.6	67.5	Normal Pretest	22052.89	22040.83
14	2076.8	BCS	1430.00	20,450.6	121.5	Normal Pretest	22083.28	22067
15	2080.5	BCS	1433.75	20,496.1	13.7	Normal Pretest	22112.11	22106.47
16	2083.1	BCS	1436.32	20,526.7	22.7	Normal Pretest	22144.61	22132.09
17	2084.9	BCS	1438.12	20,546.3	225.2	Normal Pretest	22156.56	22150.7
18	2086.2	BCS	1439.39	20,561.8	66.2	Normal Pretest	22170.14	22163.57

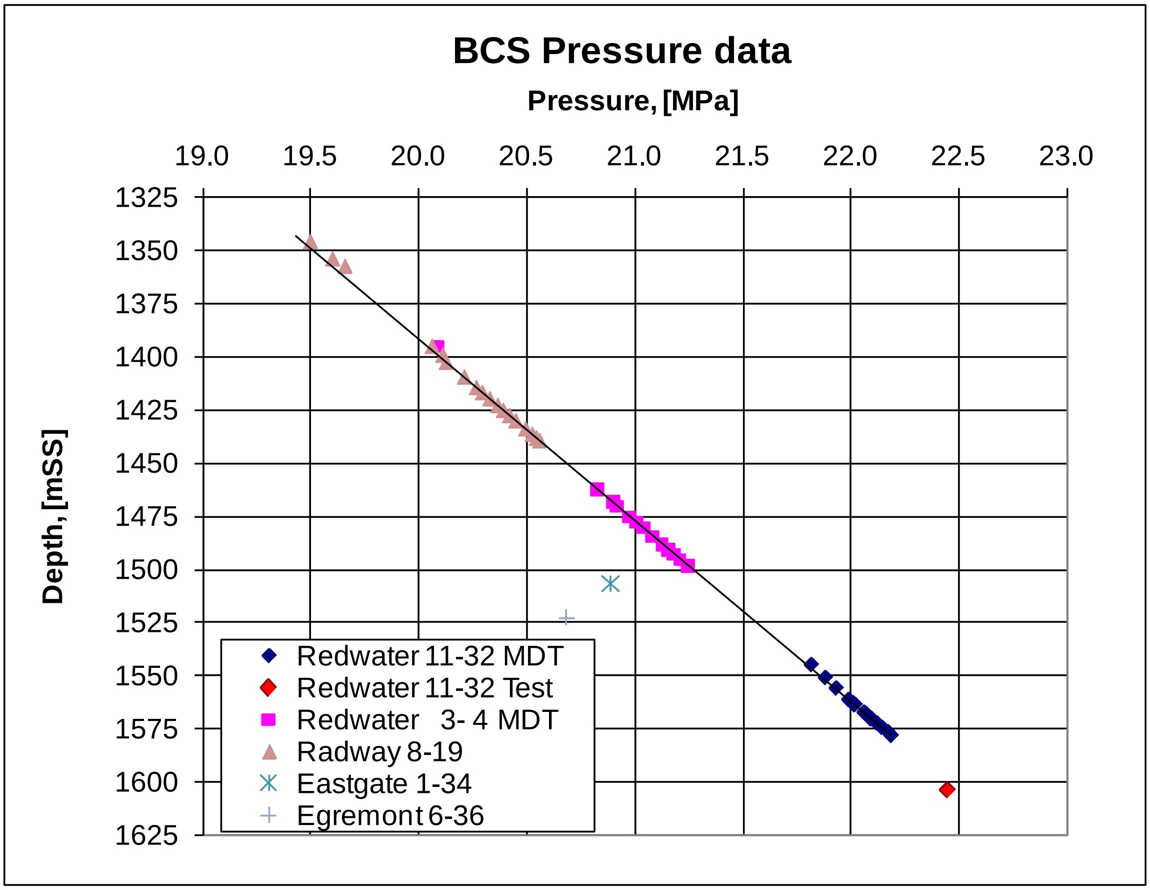


Figure 6-7 BCS Pressure Data

6.5 Operating Pressures

As per ERCB Directive 51, Section 8.0, Operating Parameters, the maximum bottomhole injection pressure for a Class III well will be the lesser of 90% of the formation fracture pressure or the pressure at which hydraulic isolation logging will be conducted (if the fracture data is not available).

This section describes how minifrac and log data from offset Well 11-32 was used to estimate formation fracture pressures in the BCS and overlying formations, and how these estimates were subsequently validated by data from Well 8-19.

Hydraulic isolation on Well 8-19 has been tested by a cement bond log and casing integrity test, which will be submitted in the Directive 51 submission for Well 8-19. Evidence of hydraulic isolation for future injection wells 2 to 10 will be submitted after drilling, as part of the Directive 51 approval process required prior to injection.

6.5.1 Fracture Data from Offset Well 11-32

A minifrac in the BCS and two microfrac tests over the LMS were successfully completed in Well 11-32 to collect fracture information. The program included the following components:

- A minifrac step rate test over a 5 m interval (2,188 to 2,193 m MD) in the BCS. The minifrac test was performed after perforating and acid washing the 5 m interval in the BCS.
- Microfrac tests in two layers in the LMS (2,121.8 to 2,123.8 and 2,150 to 2,152 m MD). The two microfrac tests were conducted in the LMS with the goal of providing fracture pressure data to understand the CO_2 injection and containment capabilities relative to the BCS.

The fracture pressures measured were consistent between the two LMS microfracs and the BCS minifrac. For a summary of the fracture break down pressures (FBDP), the fracture extension pressures (FEP) and the fracture closure pressures (FCP) over the BCS and LMS, see Table 6-6.

Table 6-6 Summary of Minifrac and Microfrac Fracture Pressures for Well 11-32

Test	Interval Depth (m)	Formation	FBDP (MPa)	FPP (MPa)	FCP (MPa)
Microfrac	2,122–2,123	LMS	50	37	33.4
Microfrac	2,150.5–2,151.5	LMS	51.5	37.9	35.2
Minifrac	2,188–2,193	BCS	47	45.4	31.7

As the offset Well 11-32 was located down dip from the planned CO_2 injection wells, a correction for depth needs to be applied to the fracture data from Table 6-6. This is best done by converting the fracture pressure to fracture gradients (see Table 6-7).

Table 6-7 Summary of Fracture Gradients from Minifrac Tests for Well 11-32

Test	Interval Depth (m)	Formation	FBDP (kPa/m)	FEP (kPa/m)	FCP (kPa/m)
Microfrac	2,122–2,123	LMS	23.6	17.4	15.7
Microfrac	2,150.5–2,151.5	LMS	23.9	17.6	16.4
Minifrac	2,188–2,193	BCS	21.5	20.7	14.5

These fracture gradients compare well with log-derived estimates for the minimum horizontal stress in these formations. The fracture closure pressure is generally considered to be equal to the minimum principal stress. Assuming an overburden gradient of 23.5 kPa/m and a formation fluid gradient of 11.7 kPa/m minimum horizontal stress estimates were calculated for the BCS, LMS and MCS (see Table 6-8).

Table 6-8 Summary of Log-Derived Minimum Horizontal Stress Estimates

Formation	Well 11-32 (kPa/m)	Well 3-4 (kPa/m)	Well 8-19 (kPa/m)
MCS	18.1	18.5	18.3
LMS	16.1	16.3	16.3
BCS	14.3	14.6	15.2

6.5.2 Fracture Data from Well 8-19

The minifrac on Well 8-19 was executed in October 2010. Interpreted results were not available in time to be included in this report. The minifrac results will be submitted as a supporting document with the D51 application.

6.5.3 Bottomhole Injection Pressure

Based on the available offset data from the appraisal wells, and validated by log derived minimum horizontal stress estimates for Well 8-19, the bottomhole injection pressures for the commercial well design will be limited to 90% of the lowest observed fracture extension pressure in the LMS at 17.4 kPa/m. For a top BCS reservoir depth in Well 8-19 at 2,041.3 m MD this would correspond to a bottomhole pressure constraint of 31,967 kPa (90% safety factor already applied). This value:

- is well below fracture initiation and extension pressures observed in the BCS of 20.7kPa/m in the 11-32 well
- is lower than the log-derived minimum horizontal stress interpreted for the first seal (the MCS) of 18.1kPa/m in the 11-32 well.

Pressure constraints will be implemented on a well-by-well basis, rather than for the entire development, as fracture pressures are depth dependant.

The bottomhole injection pressures are in alignment with surface design, assuming a 12-inch pipeline and 7 km well spacing. The current facility design is expected to deliver the injectant to the well heads at a pressure of between 12 and 14 MPa and a temperature of between 0 and 18°C. At these conditions, the maximum achievable bottomhole pressure would vary between 31 and 32 MPa, depending on the density of the CO_2. Surface monitoring and control will be implemented to avoid the bottomhole pressure exceeding the fracture pressure limit.

6.5.4 Fracture Extension and Cap Rock Threshold Pressures

Maintaining bottom-hole injection pressures below the fracture extension pressure within the BCS are expected to prevent pressure-induced fractures occurring that would potentially threaten the containment of the injected CO_2 and displaced brine within the BCS injection zone. If pressures in the reservoir and around the wellbore remain below this value, new fractures are not likely to be induced, and any existing open natural fractures are not likely to propagate.

Although fracturing of the BCS is undesirable for CO_2 plume development and might cause loss of conformance (e.g., CO_2 fingering), it does not threaten containment unless these fractures propagate upwards and remain open through all the seals within the BCS storage complex. Although fractures tend to propagate upwards within homogeneous formations, many different mechanisms exist for effectively arresting vertical fracture extension within the heterogeneous and layered formations in the BCS storage complex above the BCS. The following are some of the main barriers for arresting vertical fracture extension:

- The minimum horizontal stress contrast, calculated as the ratio of the Young's Modulus between two layers located at the reservoir–seal interface, is typically sufficient to arrest vertical fracture extension if it exceeds 1.1. Log analysis on Well 8-19 indicates a stress contrast between the MCS and the BCS of 1.5, which makes a very effective barrier to vertical fracture extension. Similar values for the stress ratio were calculated for Wells 11-32 and 3-4, while ratios at the LMS–BCS and MCS–LMS interface also exceed 1.1.
- Weak interfaces – slippage along weak interfaces induced by the approach of a propagating fracture will frequently arrest vertical fracture extension. The LMS contains a highly laminated sequence of many sand–shale interfaces. Many of these interfaces will likely be sufficiently weak to arrest vertical fracture growth. The presence of many such interfaces further increases the likelihood of fracture arrest.

In summary, the minimum horizontal stress contrast and the presence of many weak interfaces within the LMS are expected to constitute effective barriers to fractures propagating above the first seal (MCS). A further barrier is to avoid the extension of fractures within the injection zone (BCS), as intended by the bottomhole pressure constraint (see Section 6.5.3).

6.6 Injectivity Rates and Volumes

6.6.1 Proposed Daily Maximum Injection Rate

To achieve minimum capture and injection rates of 1.08 Mt/a of CO_2, a total system injection capacity of 1.20 Mt/a of CO_2 will be installed with an expected average operating time of approximately 90%.

A rate of 1.20 Mt/a of CO_2 corresponds to a daily rate of 1.76 Mm^3/d of CO_2 at standard conditions (15°C, 101.325 kPa). The gas that is captured and compressed at Scotford is expected to contain at most 5% contaminants. Therefore, to achieve a CO_2 injection rate of 1.20 Mt/a, a total gas injection volume of 1.85 Mm^3/d (65 MMscf/d) will be required.

It is currently envisaged that injection will occur through 3 to 10 injection wells. The total volume of CO_2 will be distributed among these wells so that flowing bottomhole pressures do not exceed 90% of the fracture extension pressure calculated at each well.

6.6.2 Expected Life of Scheme

For modelling purposes, Shell is evaluating subsurface scenarios for 10, 25, and 50 years of storage.

Screening volumes for the Project are all calculated on the current expected life of the Scotford Upgrader (greater than 25 years).

6.6.3 Cumulative Storage Volume

The aim of the Quest CCS Project is to capture and inject an annual average of 1.08 Mt of CO_2, which corresponds to an annual average volume of 581 Mm^3 at standard conditions. This volume includes a correction of 0.8% for contaminant gases in the CO_2 stream. For the Project's duration of 25 years, the cumulative stored mass and volume of injected gas at standard conditions would be:

- mass: 25 years x 1.08 Mt = 27 Mt
- volume: 25 years x 581 Mm^3 = 14,540 Mm^3

7 Well and Pad Conceptual Design

The well and pad conceptual design philosophy is based on the following objectives and success criteria:

- Work with stakeholders for each individual well to limit surface environmental effects associated with the well, well pads and access roads.
- Provide a wellbore suitable to meet data acquisition requirements over the life of the Project (greater than 25 years) including logging, coring and potential downhole MMV technologies.
- Facilitate long-term CO_2 injection at commercial rates for the life of the Project.
- Provide long-term wellbore integrity in a CO_2 environment based on injection rates and well life expectations.
- Abandon injection wells in accordance with Directive 20 or evolving regulations specific to CO_2 injection wells.
- Reclaim disturbed or developed areas as near to the baseline standards as possible. This includes soils, vegetation and drainage.

7.1 Pad Conceptual Design – Land Surface Disturbance

Surface disturbance for all injection and MMV wells are expected to include a well pad and a dedicated access road. Well 8-19 has an associated borrow pit. Each will be designed to limit land disturbance by using pre-existing access or clearings whenever possible.

Well pads for injection wells are expected to range in size from 130 m by 130 m to 140 m by 140 m depending on whether the wells are vertical or horizontal. However, dimensions for all injection wells are expected to closely resemble those of recently drilled Well 8-19 (see Table 7-1).

Shallow wells used for MMV will be preferentially drilled on the same pad as the CO_2 injection wells. If this is not possible, they too will be designed to limit land disturbance by using pre-existing access or clearings whenever possible.

Table 7-1 Dimensions and Composition of Well 8-19 Land Surface Areas

Feature	Size (m)	Area (ha)	Composition
Well Pad	125 x 125	1.56	0.77 ha of grass-dominated pasture and 0.79 ha of aspen
Access Road	130 x 20	0.28	Combination of pasture and aspen
Borrow Pit	Irregular	0.49	Aspen dominated

7.2 Well Conceptual Design

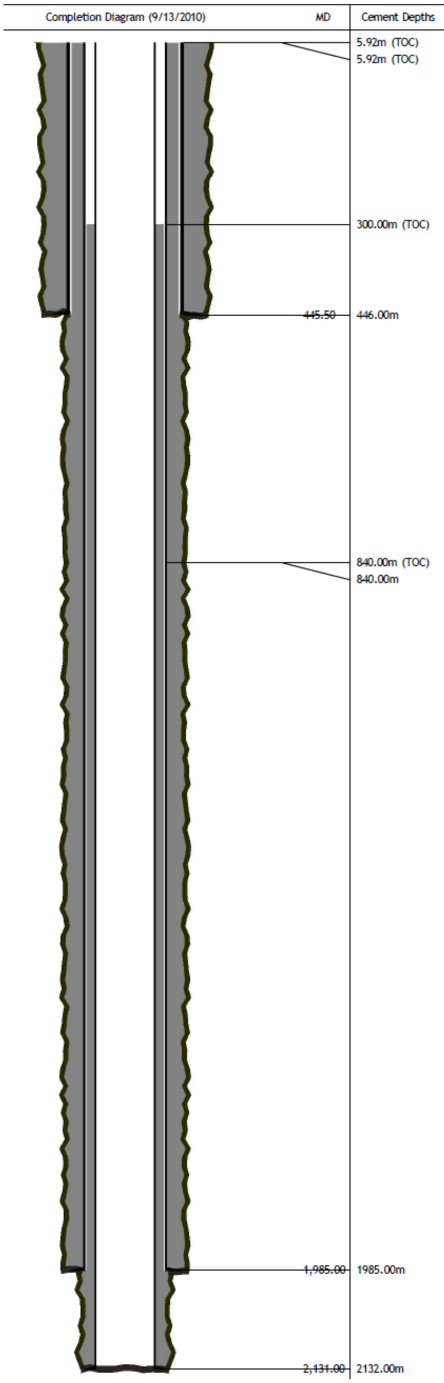
The conceptual well design will follow the design basis of the recently drilled Well 8-19 (see Figure 7-1). Key aspects include using:

- a shale inhibitive drilling fluid system suitable to maintain wellbore integrity, support data acquisition and minimize formation damage. Current design is an oil based mud system, although other compatible mud systems may still be used in future wells.
- three casing strings, each cemented to surface to maximize borehole stability. Surface hole casing will be set below BGWP zone. Intermediate casing setting depth will be located below the first seal (MCS) inside the LMS layer. This will provide effective isolation for the three main seals behind the intermediate casing before the main hole is drilled and cased. Main hole casing will be set below the top of the Precambrian basement.
- 22Cr chrome casing from TD to inside the MCS layer, for the production casing string to mitigate potential corrosion effects of the CO_2 brine. The packer will be set inside the 22Cr casing, for completion with mechanical integrity. Based on the predicted downhole conditions, injection schedule, estimated workover and well intervention requirements for the duration of well life time, TN-80S_S will be used above the 22Cr casing up to the surface.

Also currently under review are horizontal and highly deviated well designs and an option to decrease the number of casings strings to two.. If chosen for future injection wells, Shell will amend the D65 application and the wells will be required to attain D51 approval prior to injection.

RADWAY 100/08-19-059-20W4 (08-19-059-20W4)

Well Status Diagram



UWI: 100081905920W400
Water Depth: 640.10m
Longitude: -112.978
MAASP A:

Datum: DFE @ 646.02m (NABORS 78)(default)
TD:
Northing: 5,997,747.39m

RKB: 646.02m
Latitude: 54.114
Easting: 370,705.48m

Hole	Top MD (m)	Base MD (m)
445mm hole section	5.85	446.00
311mm hole section	446.00	1,985.00
222mm hole section	1,985.00	2,132.00

Surface Casing Size: 339.70 MD Top: 5.85m
MD Landed: 445.50m Min ID: 313.60mm

Item Description	#Jts	Length (m)
CASING JOINT(S)	35	425.81
CASING FLOAT COLLAR	1	0.48
CASING JOINT(S)	1	12.81
CASING FLOAT SHOE	1	0.55

Intermediate Casing Size: 244.50 MD Top: 5.92m
MD Landed: 1,985.00m Min ID: 225.00mm

Item Description	#Jts	Length (m)
Casing TN80SS, LT&C	57	787.11
ECP/Stage Tool	1	6.58
Casing TN80SS, LT&C	60	836.37
Casing TN80SS, LT&C	17	234.45
Casing TN80SS, LT&C	7	98.73
Casing Float Collar	1	0.62
Casing TN80SS, LT&C	1	14.68
~~Casing Float Shoe~~	~~1~~	~~0.54~~

~~Item Description # Jts Length (m) Top MD (m)~~

Production Casing Size: 177.80 MD Top: 5.92m
MD Landed: 2,131.00m Min ID: 156.23mm

Item Description	#Jts	Length (m)
Steel Casing	163	1,958.78
Chrome casing	14	153.95
Guide Shoe	1	0.52
Steel Shoe Track Joint	1	11.23
Float Shoe	1	0.60

Figure 7-1 As-drilled Well Diagram for Well 8-19

8 Hydraulic Isolation

8.1 Completion Data

As a minimum, all wells will adhere to ERCB Directive 51, Directive 65 and the *Oil and Gas Conservation Regulations*. The final number of wells will influence completion size and downhole instrumentation, as described below:

- Injection rate and volume dictate well and tubing size.
- The tubing and packer assembly will effectively isolate most of the casing from the injectant. Additionally an annulus filled with inhibited, non-corrosive fluid will further protect the casing.
- The MMV and well integrity requirements will influence the extent of surface and downhole instrumentation:
    - The downhole completion may include pressure gauges and a fibre-optic string to provide continuous downhole injection pressure and temperature readings.
    - Surface control and monitoring may include flow measurement and control devices to regulate the injection rate, to maintain the bottom-hole injection pressure below the fracture pressure and evenly distribute the injection over all the wells.
    - Injection rates, pressures and temperatures will be measured and transmitted real time.

An annual pressure test of the casing annulus will be done to confirm packer and well integrity as per established regulation and directives (Directive 51).

Subsurface safety valves are an option that is currently under technical review.

For the current completion schematic for Well 8-19, see Figure 8-1. Future injection wells 2 through 10 are expected to have a similar design. The Board will be notified of material modifications.

8.2 Offset Wells

There are no live wells injecting in the BCS formation within the CO_2 storage AOI.

Shell reviewed the well history and abandonment information for all legacy wells that penetrate into the BCS storage complex located within or in close proximity to the CO_2 storage AOI. The closest well to penetrate the BCS storage complex is a legacy well (Imp. Egremont 6-36-58-23W4), 21 km west-southwest of Well 8-19. The closest up-dip legacy well (Imp. Darling No.1 16-19-62-19W4) is 31 km north-northeast of Well 8-19.

For details on the abandonment reports and locations of offset wells reviewed for the Project, see Appendix E.

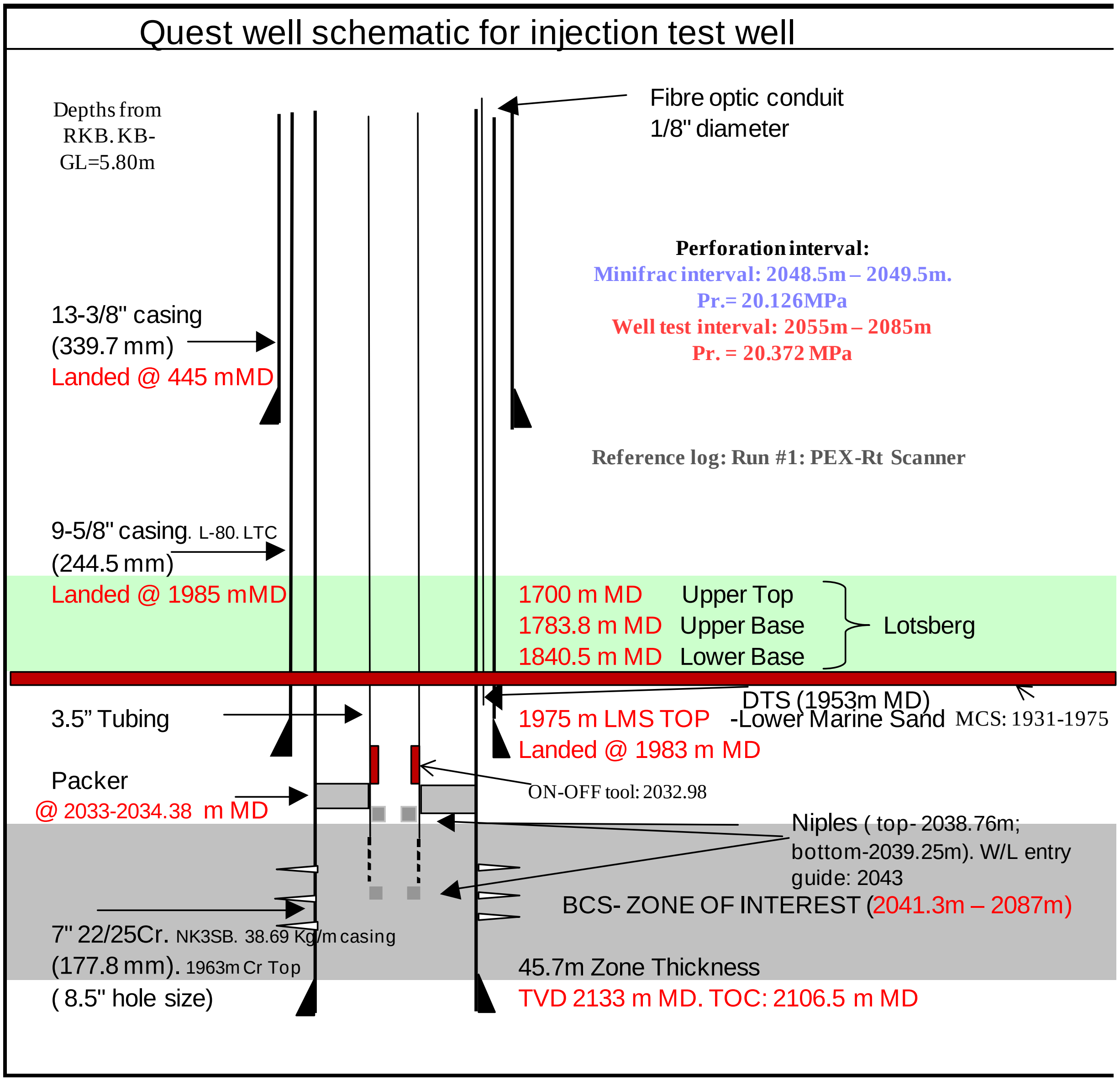


Figure 8-1 Current Completion Schematic for Well 8-19

9 Notification

9.1 Consents

Shell Canada Limited has obtained, from the Government of Alberta Department of Energy, the required consents (see Appendix F) to conduct drilling and testing on the following undisposed Crown lands:

- 08-19-059-20W4
- 07-11-059-20W4
- 10-06-060-20W4
- 12-14-060-21W4
- 15-29-060-21W4

9.2 Ownership BCS Storage Complex Rights

For details of the mineral ownership of Crown rights in the BCS storage complex in the Notification Program Area, see Appendix G.

9.3 Offset Operators, Approval Holders and Licensees

Shell has completed a comprehensive notification program in accordance with the Notification Guidelines defined in ERCB Directive 65. In addition to contacting parties as per the minimum notification requirements, Shell also reviewed the specifics of the Project to identify other potentially interested parties outside the minimum notification areas, and provided notification to these additional parties. These parties were:

- unit operators, approval holders of schemes, well licensees, mineral lessees, mineral lessors with rights that lie within both the BCS storage complex and the modelled maximum extent of the CO_2 plume
- unit operators with existing penetrations within both the BCS storage complex and the CO_2 storage CO_2 storage AOI

High-permeability and low well-count modelling scenarios indicate that the CO_2 plume could extend for distances up to 3 km from the injection well. However, the operational distance for identifying parties was taken as 4.8 km from the section containing the injection well.

A notification letter containing information on this application for a Class III storage scheme (see Appendix H) was sent to all parties identified above. For listings of all parties included in the notification program, see Appendix I.

10 Emergency Response

Shell will prepare a stand-alone site-specific Emergency Response Plan (ERP) for the CO_2 pipeline and the injection wells. The ERP will include all pipeline segments downstream from the emergency shutdown valve exiting Shell Scotford as well as CO_2 injection wells and the monitoring wells developed for the MMV plan. Shell will submit the CO_2 pipeline and injection wells ERP to the ERCB for review and approval before the start of operation. Shell Scotford personnel will be the primary Shell responders responsible for implementing the ERP, which will provide the structure, process, and action plans that will enable Shell to respond effectively to any emergency along the pipeline route, at the injection wells, or at the monitoring wells.

The primary goal of the ERP is to provide an effective and comprehensive response to prevent injury or damage to site personnel, the public, Shell operations and the environment in the event of an emergency.

The ERP will use existing interrelationships between Shell Scotford personnel (the primary Shell responders) and Shell personnel in Calgary. Through Shell's Oil Sands Crisis Management Team in Calgary and the Country Crisis Management Team, also in Calgary, Shell ERP personnel can call upon company-wide advice and support during an emergency. This is referred to as the Shell Emergency Response Management System.

In addition to this advice and support, Shell ERP personnel are also able to obtain additional personnel, equipment and resources to assist with emergency response activities. This is accomplished through interrelationships among the Shell Scotford Manufacturing Incident Command Team, the Shell Canada National Response Team and various mutual aid sources.

11 Concordance Table

Table 11-1 Concordance Table

Section	Directive 65 Requirements	Section
	CONTAINMENT	
1	Your geological interpretation of the acid gas disposal formation involved, including:	4
a)	Net pay isopach map of the pool	4.3; Figure 4-3
b)	Where pool delineation or fluid interfaces are based on structural interpretation, a structural contour map of the pool and offsetting area.	2.2 and 5
c)	An interpreted and annotated log cross-section or representative well log(s), showing: • Stratigraphic interpretation of the zone(s) of interest • Interpretation of the fluid interfaces present • Completions / treatments to the wellbore(s), with dates • Cumulative production • Finished drilling date and KB elevation • The scale of the log readings, and tabulation of your interpreted net pay, porosity, and water saturation for each well in the pool, along with the cutoffs, methodology, formulas, and constants used.	5.1; Appendix D
2 a) b) c) d) e)	For bounding formations, information including: Continuity and thickness of base and caprock Lithology Integrity of the base and caprock If fracturing is evident, explanation of how containment can be assured A comment on the stratigraphic, structural, or combination reservoir trap type and its containment features	5.2
	RESERVOIR	6
1	Analysis of the native reservoir fluid(s)	6.1
2	Acid gas properties, including:	6.1
a)	Composition	6.1.1
b)	Viscosity, density, gas injection formation volume factor, and compressibility factors	6.1.2
c)	Phase behavior through the range of pressures and temperatures to which the injected fluid will be subjected	6.1.3; Fig 6-1
3	An analysis of laboratory testing for determining injected fluid interaction with matrix, caprock matrix, and native fluid(s)	6.2

Table 11-1 Concordance Table (cont'd)

Section	Directive 65 Requirements	Section
	RESERVOIR (cont'd)	6
4	Migration calculation showing radius of influence, as well as a discussion if migration could occur due to displacement, gravity, fingering, etc. (not required for depleted reservoirs less than two sections in areal extent).	6.3
5	Complete pressure history of the pool, with material balance calculations if proposed disposal zone is a depleted hydrocarbon pool	6.4
6	Bottomhole injection pressure, maximum sandface pressure, caprock threshold pressure, fracture extension pressure, and formation fracture pressure	6.5
7	Injectivity of the reservoir, proposed daily maximum injection rate, cumulative disposal volume, and expected life of the scheme	6.6
	HYDRAULIC ISOLATION	8
1	For acid gas disposal wells injecting H2S, all completion data, well logs, testing requirements, and associated discussion, as described in *Directive 051.*	N/A
2	For non-H_2S gas disposal provide:	8
a)	The completion logs and associated discussion required by *Directive 051* for all proposed disposal wells, or Section 7 should include a reference to the isolation logs run and the interpretation of the results – only the well diagram is included. If a D-51 submission for 8-19 was made to the ERCB it should be attached as an Appendix and referenced.	8.1 Figure 8-1
b)	A discussion of the plans for complying with *Directive 051*, or	Throughout document (e.g., 8.1)
c)	a request for waiver of the *Directive 051* requirements, or	N/A
d)	A copy of an ERCB letter waiving the *Directive 051* requirements.	N/A
3	If requesting an extension to the three-month period for *Directive 051* submission date, provide	N/A
a)	The proposed submission date	N/A
b)	The reason(s) for needing the submission date extension.	N/A
4	When submitting *Directive 051* information after the approval has been issued, provide the field and pool name, the disposal scheme approval number, and the well location(s).	N/A

Table 11-1 Concordance Table (cont'd)

Section	Directive 65 Requirements	Section
	HYDRAULIC ISOLATION (cont'd)	8
5 a) b) c) d)	Provide the following information for either (1) all the wells in the pool if disposal is into a depleted hydrocarbon pool or (2) all the wells within the disposal well section and adjoining sections if disposal is into an aquifer system. Well location Status of well Completion intervals All casing information	4.4 and 4.5; Figure 4-3
	NOTIFICATION – EQUITY AND SAFETY	
1	Evidence of your right to dispose into the proposed zone	9.1
2	Provide:	
a)	A map showing the boundaries of the disposal pool or the area within the disposal section and the adjoining offset sections up to a 1.6 km radius with well licensees, mineral right lessees, and lessors recorded	Appendix I
b)	A statement confirming that all potentially adversely affected parties that may be impacted have been notified and giving any details of outstanding objections or concerns to the proposed scheme.	9
3	If the injected fluid contains any H_2S, a statement indicating that notification of the scheme for emergency response plan (ERP) purposes has been made to all potentially adversely affected parties. Include the details of any outstanding objections or concerns from the notified parties.	N/A

NOTE:
N/A – not applicable

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12.2 Internet Sites

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Carbon Sequestration Leadership Forum. 2010b. *About the CSLF*. Accessed October 2010. Available at: http://www.cslforum.org/aboutus/index.html?cid=nav_about

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Appendix A Independent Project Review of Quest Storage Component

NOTE: In support of the selection of the CO_2 storage area of interest for the Quest CCS Project, an independent project review was completed. The executive summary of this review is presented here as part of the Quest CCS Project environmental assessment.

DET NORSKE VERITAS

Independent Project Review (IPR) of Storage Component of the Shell QUEST Carbon Capture and Storage Project

Draft Report

Shell Canada Energy

2010-9343

Revision 1, 2010-11-04

Executive Summary

The current report represents the conclusions of an independent project review (IPR) of the storage component of the QUEST Carbon Capture and Storage (CCS) project. The IPR was managed and facilitated by DNV, and performed by a DNV contracted expert panel (Panel). The overall objective of the IPR was to prepare an independent assessment of the suitability of the targeted storage site for sequestration of 1.2 Megatons (Mt) CO_2 per annum for a minimum of 10 years, with possible extension of the injection period to a total of 25 years. The review was performed Sept.-Nov. 2010.

Extensive work has been performed by QUEST to identify, select and characterize a site suitable for geological storage of the required volumes of CO_2 for the CCS project. The Panel agrees that ample evidence has been provided to demonstrate that the selected site is naturally suited for geological storage of CO_2. The results of site characterization give confidence in the following statements:

There is sufficient pore space for the required 27 Mt of CO_2.

Injectivity can be sustained for the planned duration of CO_2 injection operations, i.e., 25 years.

Any migration of injected or displaced reservoir fluid out of the containment complex is extremely unlikely.

DNV and the Panel further agree that a risk and uncertainty management framework appropriate for the storage site is in place. In particular, the risk management framework should ensure that any signs of migration of injected or displaced reservoir fluid out of the containment complex are detected sufficiently early to allow corrective actions to be implemented before adverse impacts can occur.

The risk assessment activities have been carried out in a very comprehensive and systematic manner. In the opinion of DNV, particularly two elements represent pioneering work within risk management: The systematic way that identification and management of uncertainty is integrated with the risk assessment, and the development of a risk-based Monitoring, Measurement and Verification (MMV) plan that may set a precedent for design of MMV programs for CCS projects world-wide.

Appendix B Measurement, Monitoring and Verification

Quest Carbon Capture and Storage Project

MEASUREMENT, MONITORING AND VERIFICATION PLAN

Shell Canada Limited
Calgary, Alberta

November 2010

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Executive Summary

The Quest Carbon Capture and Storage Project (Quest CCS Project) promises to make a material early contribution to reducing CO_2 emissions generated by upgrading bitumen from the Alberta oil sands. The climate benefits and societal acceptability of this Project are both largely dependent on the quality of containment achieved within the Basal Cambrian Sands (BCS) storage complex.

Bachu et al. (2000) identified the most promising opportunities for CCS across Canada by matching the location of large localized CO_2 emissions with geological formations likely to support CO_2 storage. This systematic screening concluded the top ranking opportunities were located within the Alberta Basin due to the presence of deep permeable saline aquifers overlain by multiple extensive geological seals. The Quest project is located within the Alberta Basin and the geology of the selected storage site offers multiple layers of protection to prevent any CO_2 or brine from causing any impacts to the protected groundwater zone, the ecosystem, or the atmosphere. Each of these seals on its own is likely to be sufficient to ensure long-term containment of injected CO_2 and the displaced brine. However, no matter how detailed and extensive the appraisal program to characterize these geological barriers, some uncertainty and risk remain. Measurement, Monitoring and Verification (MMV) activities aim to verify the absence of any significant environmental impacts due to CO_2 storage. If necessary, MMV activities shall result in additional safeguards by triggering control measures that prevent or correct any loss of containment before significant impacts occur.

A risk-based workflow was applied. This approach relies on a systematic assessment of the whole suite of containment risks, followed by a review of the effectiveness of safeguards provided by geology, engineering and recognition of MMV performance targets. The proposed conceptual MMV plan is designed to provide early warning of any breach of containment triggering appropriate responses, thereby reducing risk and ensuring that the remaining risk is insignificant compared to everyday risks broadly accepted by society.

Transfer of long-term liability will depend on the actual storage performance verified through MMV activities. MMV will indicate that actual storage performance conforms to model-based forecasts and that these forecasts are consistent with permanent secure storage at an acceptable risk.

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Glossary

Barrier	Something that decreases the likelihood of a threat leading to the occurrence of a risk event.
Consequence	A possible adverse outcome due to the occurrence of a risk event.
Mitigation	Something that decreases the severity or likelihood of significant consequences given the occurrence of a risk event.
Risk	The product of likelihood and consequence of an unwanted event.
Risk Event	This event might occur, and if uncontrolled, will cause unwanted consequences.
Safeguard	Something that reduces risk such as a barrier or mitigation.
Shell Well Redwater 11-32	The unique well identifier is 1AA/11-32-055-21W4/00.
Shell Well Redwater 3-4	The unique well identifier is 100/03-04-057-20W4/00.
Shell Well Radway 8-19	The unique well identifier is 100/08-19-059-20W4/00.
Threat	Something that could cause the occurrence of a risk event.

Abbreviations

AEC	atmospheric eddy correlation
ALARP	as low as reasonably practicable
AOI	Exploration Tenure Area of Interest for the Project
AOR	area of review of MMV activities for the Project
APM	annulus pressure monitoring
ARC	Alberta Research Council
BCS	basal Cambrian Sands
BGWP	Base of Groundwater Protection
BGS	British Geological Survey
CBL	cement bond logs
CCS	carbon capture and storage
CDM	Clean Development Mechanism
CO_2	carbon dioxide
CSA	Canadian Standards Association
DAS	fibre-optic distributed acoustic sensing
DHMS	down-hole microseismic monitoring
DHPT	down-hole pressure-temperature gauge
DNV	Det Norske Veritas
DTS	fibre-optic distributed temperature sensing
EPA	Environmental Protection Agency
ERCB	Energy Resources Conservation Board
ESS	ecosystem studies
GHG	greenhouse gas
GPS	global positioning system
GPZ	groundwater protection zone
HIA	satellite or airborne hyperspectral image analysis
HSE	United Kingdom Health and Safety Executive
HSSE	Health Safety Security and Environment
IEA	International Energy Agency
INJ	injection wells
InSAR	Interferometric Synthetic Aperture Radar
IPAC	International Performance Assessment Centre
IPAC-CO_2	International Performance Assessment Centre for CO_2
IPCC	Intergovernmental Panel on Climate Change
IRM	injection rate metering at wellhead
LOSCO_2	line-of-sight gas flux monitoring
MCS	Middle Cambrian Shale
MMV	measurement, monitoring and verification
MNA	Monitored Natural Attenuation
MWIT	mechanical well integrity pressure testing
NETL	National Energy Technology Laboratory
OBW	observation wells in Winnipegosis (WPGS)
PTRC	Petroleum Technology Research Centre
Quest CCS project	Quest Carbon Capture and Storage Project
SEIS2D	time-lapse surface 2D seismic
SEIS3D	time-lapse surface 3D seismic
Shell	Shell Canada Limited

SPH ... soil pH surveys
SSAL ... soil salinity surveys
TNO ... Netherlands Organisation for Applied Scientific Research
UK ... United Kingdom Department of Energy and Climate Change
UNSED ... United Nations Conference on Environment and Development
USIT ... time-lapse ultrasonic casing imaging
VSP ... vertical seismic profiling
VSP3D ... time-lapse 3D vertical seismic profiling
WEC ... down-hole electrical conductivity monitoring
$WHCO_2$ ... wellhead CO_2 detectors
WHPT ... wellhead pressure-temperature gauge
WPGS ... Winnipegosis
WPH ... down-hole pH monitoring
WRI ... World Resources Institute
WRM ... well and reservoir management

1 Introduction

This document describes the Measurement, Monitoring and Verification (MMV) Plan for the proposed Quest Carbon Capture and Storage Project (Quest CCS Project) in Alberta, Canada.

The scope of this document is to establish the framework and procedures that will ultimately define the MMV plan once the ongoing appraisal process concludes. This means that the MMV plan described here is a conceptual outline, based on clearly defined parameters covering the following four basic principles:

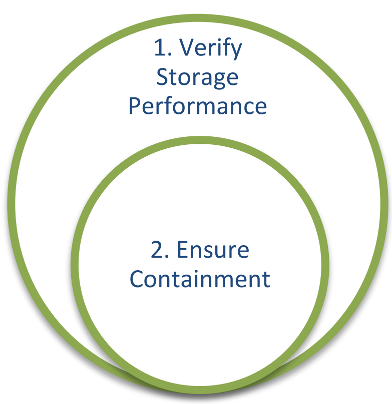
- the performance targets for MMV activities
- identifying and ranking explicit technology options
- how monitoring strategies are developed
- how to evaluate the expected effectiveness of these plans

The purpose of this document is to outline a conceptual MMV plan for the Quest CCS project based on a proactive verification plan that the storage complex is working as expected and the early detection of any leaks.

1.1 The Purposes of MMV

There are two interdependent primary purposes of MMV activities for the Quest CCS Project:

1. Verify storage performance (Conformance): implies normal operating conditions and assumes containment can be managed using well-established industry practices for well and reservoir management (WRM)
2. Ensure containment, which recognizes that:
   a. the management of containment is a critical requirement to safeguard health, safety and the environment
   b. the loss of containment could imply a consequence and impact outside of the BCS storage complex



To fulfil both purposes, there are several requirements. These are adapted from the IEA GHG proposed requirements for MMV (IEA 2006).

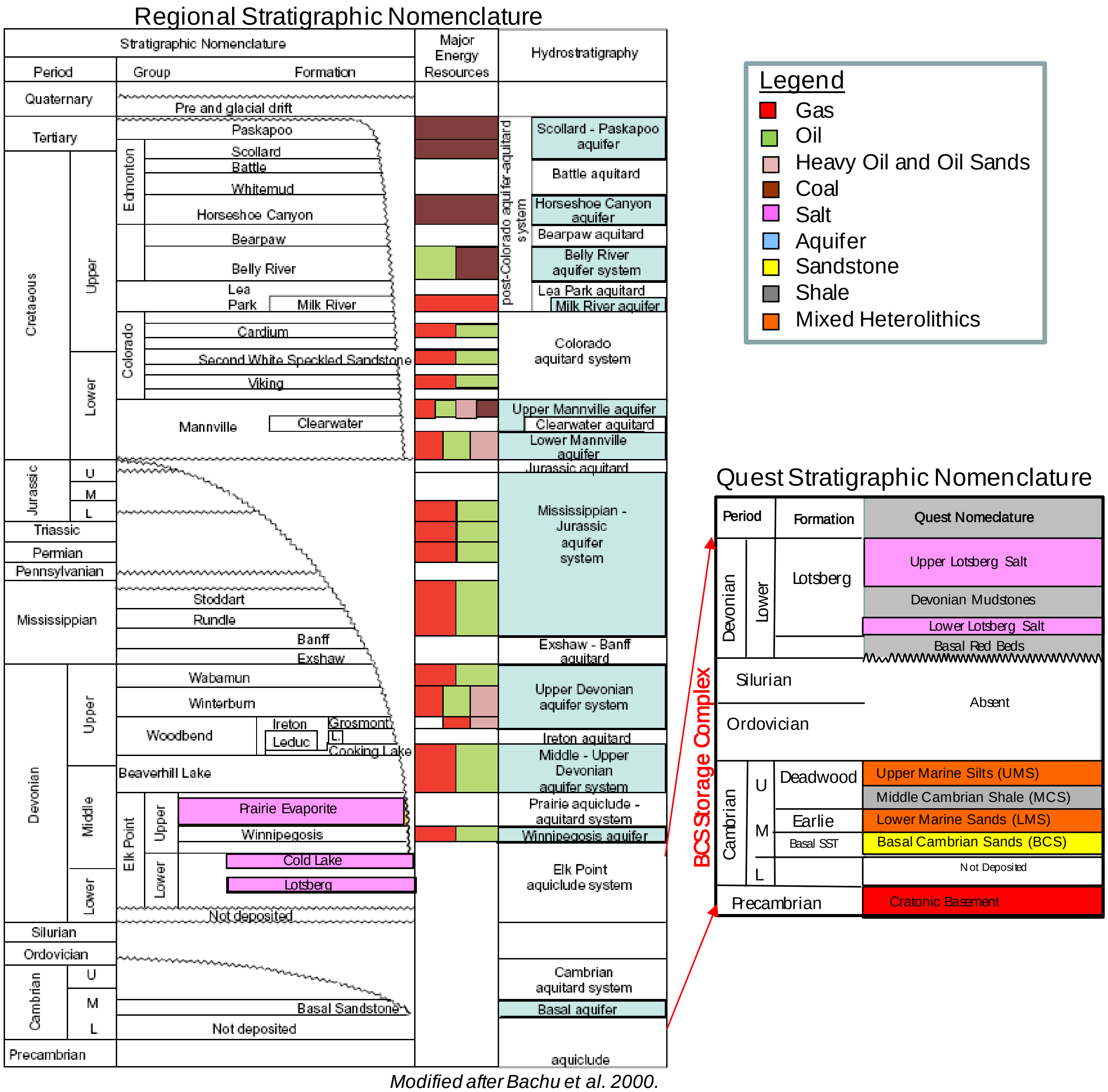
1. Verify storage performance of the BCS storage complex
   - Validate, calibrate and revise performance predictions according to observed actual performance.
   - Adapt injection and monitoring plans according to observed past performance to optimize future performance.
   - Provide the evidence base for setting the handover period by demonstrating the observed actual storage performance conforms to the predicted storage performance. Storage performance has two metrics:
     i. CO_2 plume migration within the storage formation
     ii. containment of CO2 and brine within the BCS complex
   - Enable transfer of long-term liability by demonstrating storage performance conforms to predictions that show a trend towards long-term stability at the time of site closure.
   - Provide the evidence base for reporting CO_2 storage inventories.
2. Ensure containment within the BCS storage complex.
   - Verify no loss of containment occurred that would affect the CO_2 inventory.
   - Detect early warning signs of any potential loss of containment to prompt control measures that prevent or reduce any impacts to the environment or human health.

1.2 Project Overview

Shell Canada Limited, which will hold all necessary regulatory approvals in respect of the Project, is the managing partner of Shell Canada Energy. Shell Canada Energy will operate the Project, on behalf of the Athabasca Oil Sands Project ("AOSP"), which is a joint venture between Shell Canada Energy (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%). . The goal of the Quest CCS Project is to separate, capture and permanently store CO2, thereby reducing greenhouse gas emissions from the existing Scotford Upgrader. The Scotford Upgrader is located about 5 km northeast of Fort Saskatchewan, Alberta, within Alberta's Industrial Heartland, which is zoned for heavy industrial development.

The three components of the Quest CCS Project are:

- CO_2 capture infrastructure, which will be connected to the Scotford Upgrader. The method of capture is based on a licensed Shell amine system called ADIP-X.
- a CO_2 pipeline, which will transport the CO_2 from the Scotford Upgrader to the injection wells, about 50 km north of the upgrader. The CO_2 injection well locations are in the CO_2 storage area of interest.
- a storage scheme consisting of 3 to 10 injection wells, which will inject the 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



SOURCE: Modified after Bachu et al. 2000. Stratigraphic nomenclature applied to the Quest Project is represented on the right side.

Figure 1-1 Stratigraphy and Hydrostratigraphy of Southern and Central Alberta Basin

2 MMV Design Framework

Standards for MMV are still developing for Carbon Capture and Storage (CCS) projects. This section describes the framework selected for developing an MMV program for the Quest CCS Project based on the following key elements:

1. the existing regulatory environment
2. a review of the existing global guidelines (Attachment A)
3. precedents set by existing projects

2.1 Existing Regulations & Precedents

Alberta's existing regulations for the permitting and oversight of Acid Gas Disposal projects have proved effective for more than 40 schemes involving CO_2 over the last 20 years. The ERCB intends to use the same processes for regulating any CCS projects in Alberta (Zeidouni et al 2009; ERCB 2010). Therefore, the Quest CCS Project MMV plan must conform to these existing standards as a minimum requirement.

There are many different directives applicable to Acid Gas Disposal in Alberta. The following directives are particularly relevant for MMV as they specify requirements for measurements and monitoring.

- **Directives 7 & 17**: Specify requirements for measuring and reporting the amounts of acid gas injected.
- **Directive 20**: Specifies minimum requirements for well abandonment, testing to detect leakage and mitigation measures in the event of detecting leakage.
- **Directive 51**: Classifies injection and disposal wells according to the injected or disposed fluid and specifies design, operating, and monitoring requirements for each class of wells.
- **Directive 65**: Addresses enhanced hydrocarbon recovery, natural gas storage and acid gas disposal. For acid gas disposal projects, this directive specifies requirements to ensure confinement of the disposed fluid and its isolation. This directive also requires the applicant to prove that disposal will not affect hydrocarbon recovery.

In addition, two existing CCS projects in Canada create important precedents for MMV: the Weyburn-Midale CO_2 enhanced oil recovery project in Saskatchewan (PTRC 2004) and Pembina Cardium CO_2 enhanced oil recovery (EOR) project in Alberta (ARC 2009).

Outside Canada, there are four notable examples of commercial-scale CCS projects with ongoing MMV activities:

- Sleipner and Snøhvit in Norway
- In Salah in Algeria (Mathieson et al. 2010)
- Rangely in the United States

See Attachment B for further details. Other commercial-scale projects under development with more mature MMV plans include Gorgon in Australia.

Although injected volumes are substantially smaller, numerous Acid Gas Disposal projects in Alberta also provide important experience (Bachu and Gunter 2005).

2.2 Timeframe of Review

MMV activities will meet varying requirements during four distinct phases over the lifecycle of the CCS project:

1. **Pre-Injection Phase**: Monitoring tasks are identified, monitoring solutions evaluated and selected, risks are characterized, and baseline monitoring data are acquired.
2. **Injection Phase**: Monitoring activities are undertaken to manage containment risk and storage performance, and are adapted through time to ensure their continuing effectiveness.
3. **Closure Phase**: Some monitoring activities continue to manage containment risk and to demonstrate storage performance is consistent with expectations for long-term storage.
4. **Post-Closure Phase**: A few monitoring activities continue to validate the storage site is stable and the containment risk has diminished to a level where no further monitoring is required.

2.3 Area of Review

MMV will operate within an Area of Review (AOR) with sufficient extent to include any potential material impacts due to CO_2 storage including the displacement of brine. This area spans four distinct environmental domains (see Figure 2-1).

- **Geosphere**: The subsurface domain below the base of the groundwater protection zone including the BCS storage complex. The geological storage complex comprises a primary storage formation (Basal Cambrian Sands, BCS), a primary seal (Middle Cambrian Shale, MCS), a secondary seal (Lower Lotsberg Salt), and an ultimate seal (Upper Lotsberg Salt). Above the storage complex, the geosphere also contains two addition deep saline aquifers, the Winnipegosis and the Cooking Lake, that provide important opportunities for MMV.
- **Hydrosphere:** The subsurface domain within the groundwater protection zone where water salinity measured as the concentration of total dissolved solids is less than 4,000 milligrams per litre. The Alberta Environment (AENV) *Water Act* defines saline groundwater as that containing greater than 4000 milligrams per litre (mg/L) total dissolved solids (TDS).
- **Biosphere**: The domain containing ecosystems where living organisms exist.
- **Atmosphere**: The local air mass where any changes to air quality matter and the global air mass where any changes influencing climate matter.

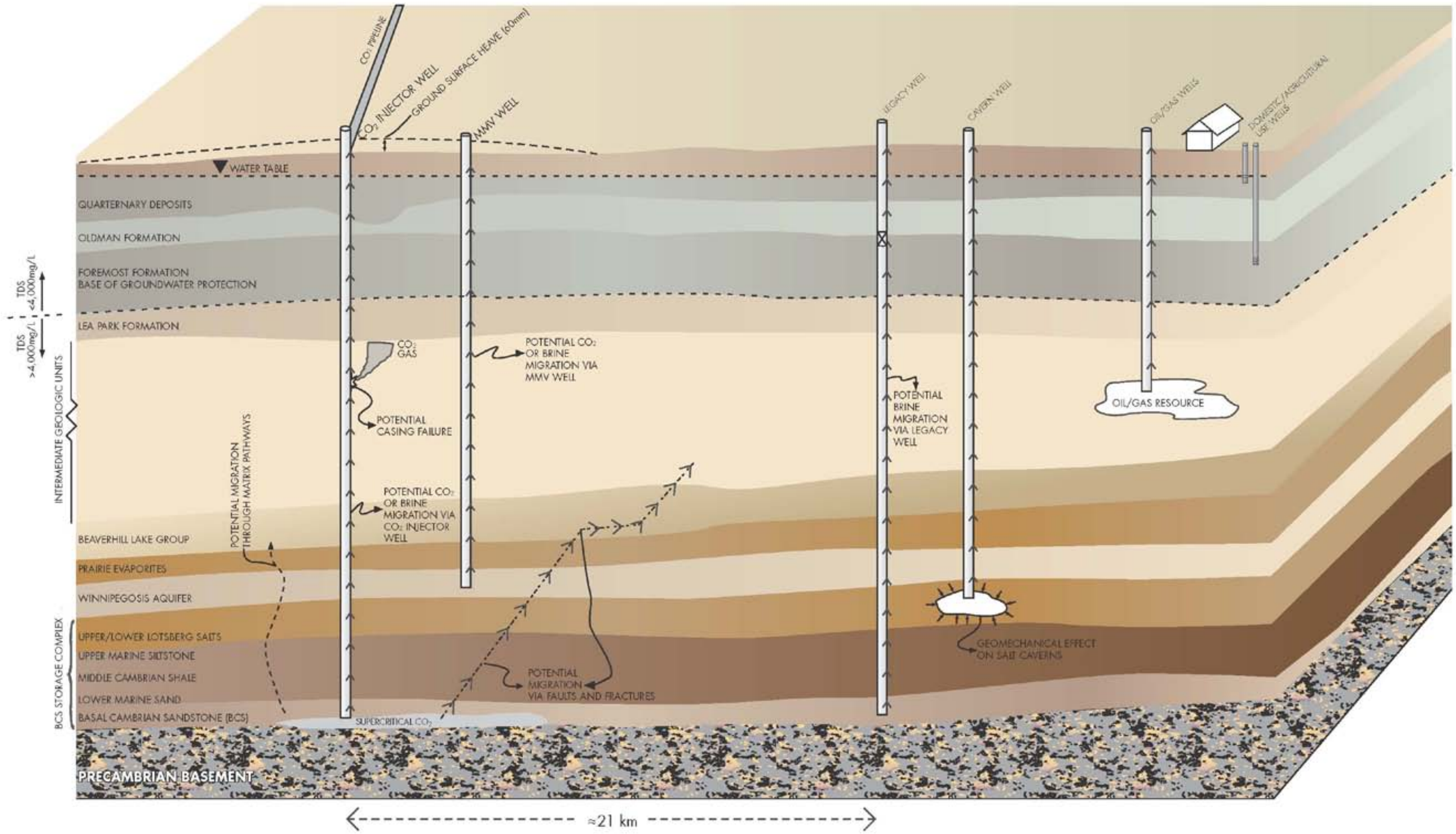


Figure 2-1 **Schematic of the Selected Storage Site and the Identified Risks to Containment**

2.4 Assumptions

The adopted framework for an adaptive MMV design results from choices based on several assumptions. The key assumptions influencing MMV design are as follows.

- The MMV plan will be designed based on risk mitigation. This builds on guidelines published by Det Norske Veritas (DNV2010).
- The Area of Review (AOR) for monitoring will have sufficient lateral extent to include the region of elevated fluid pressures within the BCS that could be sufficient to cause movement of fluids from the BCS to above the base of the groundwater protection zone. This is as per the emerging legislation within the European Union, United Kingdom and United States (Attachment A)
- The monitoring program comprises:
    - base-case activities that follow a planned schedule
    - contingent activities that only occur in the event of detecting potential loss of containment of BCS brine or injected CO_2 from the storage complex
- The monitoring program will be adapted according to performance of the storage site and the monitoring technologies, revised performance predictions, and the qualification of new technologies.
- The post-closure period before transfer of liability will be determined according to the strength of evidence obtained from the monitoring program that actual storage performance conforms against the predicted performance over the first decade of injection. There are two performance metrics:
    - absence of BCS brine or CO_2 leakage from the storage complex
    - migration of the CO_2 plume within the storage complex

2.5 Design Principles

Royal Dutch Shell is committed to the following guiding principles for CCS projects (Shell 2009).

1. Protect human health and safety.
2. Protect ecosystems.
3. Protect underground sources of drinking water and other natural resources.
4. Ensure market confidence in emission reductions through proper greenhouse gas accounting.
5. Facilitate cost-effective, timely deployment.

In addition, the MMV plan will apply the following principles:

- It will comply with regulatory requirements as they mature.
- It is risk and uncertainty based, with clear trigger points identified and associated with corresponding actions.
- Select monitoring components intended to ensure containment in accordance with the principle of reducing risk to as low as reasonably practicable (ALARP).
- Select monitoring components intended to manage non-HSE critical aspects of storage performance based on technical feasibility and the economic value of information gained.
- The MMV plan must be adaptable and able to respond to any opportunities to improve the cost-effective management of lifecycle storage risks.

3 Measurement, Monitoring and Verification Design Workflow

Under normal operating conditions, the role of MMV is to collect the necessary evidence to verify that the actual storage performance is consistent with expected storage performance. To this end, information gained through monitoring must demonstrate that:

- all the injected fluids entered the intended disposal formation
- no fluids migrated out of the storage complex
- the development through time of CO_2 plumes and fluid pressures inside the storage complex was consistent with model-based predictions

Although exceptionally unlikely to occur, there is the possibility of CO_2 or BCS brine migrating out of the storage complex. To protect against this remote possibility, MMV must also provide:

- multiple independent monitoring systems with the sensitivity, speed, and scale to generate reliable early warning of any potential loss of containment
- intervention options to prevent, attenuate, or reverse any potential consequences due to the potential loss of containment

The approach is to design the MMV plan according to risk. The quality of the selected storage complex and engineering solutions means that less-than-expected storage performance is extremely unlikely. Nonetheless, there remains the possibility, that some aspects of storage performance might not fulfil expectations. MMV activities will focus on detecting and characterising these unlikely events, and there are clear and material benefits in focusing MMV activities according to the relative likelihood and potential consequence (risk) of these exceptional events, such as the MMV activities will focus on where the risk is highest. Tailoring MMV activities according to the particular qualities of the individual storage site (in this case the BCS) will maximize the additional protection provided by MMV.

This MMV planning strategy requires a systematic approach to risk assessment as the range and balance of the MMV activities are designed for the site-specific qualities of the BCS storage complex. The currently available appraisal and site characterisation forms the foundation of this initial conceptual MMV plan. As more information becomes available during further appraisal and early operations the MMV plan will need to adapt to accommodate the ever increasing understanding of the storage complex.

The Bowtie Method (DNV 2010a) provides an appropriate framework for a systematic risk assessment of events with the potential to affect storage performance. Figure 3-1 illustrates a highly simplified bowtie risk analysis. The bowtie represents the relationship between the five key elements that describe how a risk might arise and how safeguards can provide effective protection against the risk and its associated consequences.

- **Top Event**: This is the unwanted event, placed in the centre of the bowtie.
- **Threats**: These possible mechanisms can lead to the top event.

- **Consequences**: These are the possible adverse outcomes due to the occurrence of the top event.
- **Preventative Measures**: These decrease the likelihood of a threat leading to the top event.
- **Corrective Measures**: These decrease the likelihood of significant consequences due to a top event.

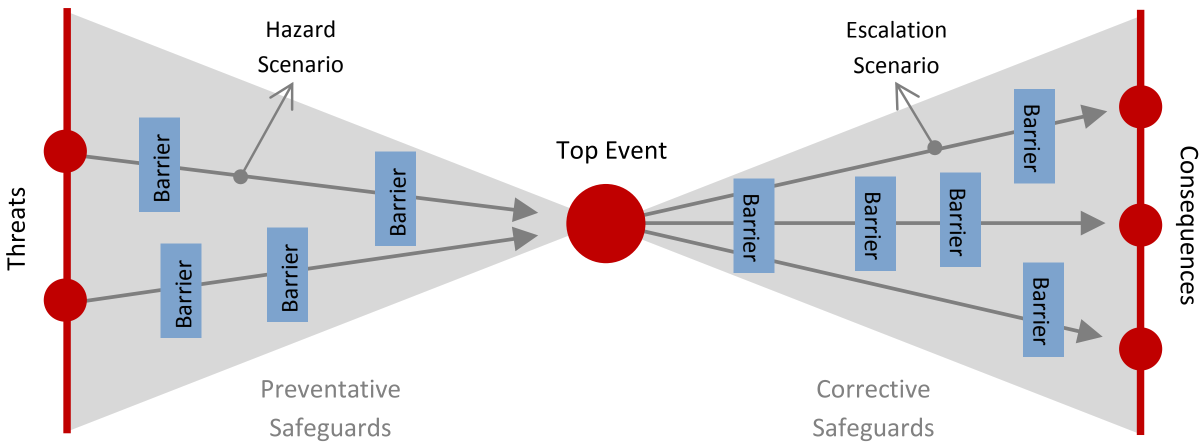


Figure 3-1 Schematic Diagram of the Bowtie Method

The Bowtie Method is a proven and effective method for analysing and communicating risks. The MMV plan must manage two distinct risks:

1. **Loss of conformance**: Conformance means that the behaviour inside the storage complex is consistent with model-based predictions. Therefore, lack of conformance is a project risk relating to the long-term liability and not a HSSE-critical risk. Therefore, a high-level risk analysis is sufficient for MMV planning.
2. **Loss of containment**: This is a HSSE-critical risk. Therefore a detailed and comprehensive approach to the bow-tie analysis is required

In both cases, two distinct types of preventative and corrective safeguards exist:

1. **Passive safeguards**: These safeguards are always present from the start of injection and do not need to be activated at the appropriate moment. These passive safeguards exist in two forms:
   - **Geological barriers** identified during site characterization
   - **Engineered barriers** identified during engineering concept selections
2. **Active safeguards**: These are engineered safeguards, brought in to service in response to some indication of a potential upset condition in order to make the site safe.

Each active safeguard requires three key components in order to operate effectively:

1. a sensor capable of detecting changes with sufficient sensitivity and reliability to provide an early indication that some form of intervention is required.
2. some decision logic to interpret the sensor data and select the most appropriate form of intervention
3. a control response capable of effective intervention to ensure continuing storage performance or to control the effects of any potential loss of storage performance

This combination of a sensor, decision and control response becomes the MMV plan.

Therefore, structure of this document has been set-up to reflect this systematic risk-based approach to building an MMV program to:

1. Address Conformance Risks
    a. identify and evaluate risks associated with any loss of conformance.
    b. discuss initial safeguards for conformance
    c. propose CO_2 storage performance targets for site closure and inventory reporting
2. Address Containment Risks
    a. identify and evaluate risks associated with a loss of containment
    b. provide a systematic evaluation of the wide range of geological and engineered safeguards already incorporated within the Project
    c. recognize opportunities for incorporating additional safeguards through MMV activities
    d. propose performance targets. MMV activities must verify actual performance statistics against these targets forming the basis of MMV technology screening.
3. Develop a Conceptual MMV Plan
    a. identify options for intervening in routine storage operations with active control measures such as changing the injection policy. These controls mitigate risk by:
        i. prevent any emerging threat, for instance by lowering the injection pressure to maintain the integrity of a geological seal within the storage complex
        ii. control any unexpected occurrence of a threat before any significant consequences arise, such as by stopping injection to repair a compromised cement bond before any CO_2 rising outside the casing reaches fresh groundwater resources
    b. evaluate a large variety and number of monitoring technologies capable of detecting changes within the storage complex, the groundwater, the biosphere and the atmosphere leading to a ranking of these technologies, according to their expected effectiveness and cost, for each particular monitoring task.
    c. show how the monitoring technologies combine in a program of activities that start before CO_2 injection, adapt to changing circumstances during injection, continue in a reduced form after CO_2 injection and end once long-term storage risks are demonstrated to be insignificant

d. confirm the future performance of these leading monitoring technologies within the Quest CCS site in an operational setting. The description of contingency monitoring plans shows the importance of an adaptive approach to MMV to mitigate any underperforming monitoring systems or to capture opportunities arising from technology developments likely to occur over the life of the Project.

4. Propose Annual Reporting Requirements

   a. propose a plan for routine reporting of MMV results to all stakeholders including regulatory authorities and the public

   b. include plans for responding to any indication of loss of containment from the MMV monitoring systems or any complaints from the public about impacts due to suspected loss of containment

4 Conformance Risks

Under normal operating conditions, containment is assured, and the focus of the MMV program is to prove conformance. Conformance means that the storage complex is behaving in a predictable manner, consistent with the subsurface modeling.

4.1 The Risk Event

The unwanted event considered in this analysis is one where:

> *Significant discrepancy exists between the model based predictions and observed migration on the CO_2 plume and region of significantly elevated fluid pressure inside the BCS storage complex.*

The definition of significance in the above remains to be discussed between the regulator and the project proponents. One possible measure of a significant discrepancy indicating a loss of conformance could be that the discrepancy must exceed a certain threshold representing the combined uncertainties associated within an agreed detectable range of modelling and monitoring results. Otherwise, unsuitably large modeling or monitoring uncertainty may lead to undetected fluid migration within the storage complex.

The following two sections characterize conformance risk in terms of the threats that might cause a loss of conformance and the potential consequences should this occur.

4.2 Potential Consequences

The potential consequences associated with loss of conformance are:

- the containment risk changes
- the post-injection closure period and terms for transfer of long-term liability changes
- the storage efficiency changes

4.2.1 Containment Risk Changes

Changes to the risk of containment may be positive or negative.

- Slower than expected pressure migration in a certain direction creates an opportunity to reduce MMV activities that were designed to mitigate the threat of fluid migration along pathways that will never experience elevated pressures.
- Faster than expected pressure migration in another direction creates a threat that additional MMV activities will be required as elevation pressures contact additional potential migration pathways that were not part of the base MMV plan.

4.2.2 Site Closure and Transfer of Long-Term Liability

Final agreement about the transfer of long-term liability is expected to be contingent on demonstrating conformance.

1. **Better than expected conformance:** Demonstration of better than expected conformance over the CO_2 injection period, for example a slower than expected plume expansion, and a forecast trend towards long-term stability of the CO_2 plume creates the opportunity to reduce the length of the expected closure period. Examples of this include a more localized than expected CO_2 plume or lower than expected increases in pore fluid pressure. The likely benefits of this are the avoidance of unnecessary monitoring activities and identification of scope for additional CO_2 storage within the site. Accordingly, the cost of post-closure stewardship will also be smaller.
2. **Worse than expected conformance**: Alternatively, if CO_2 migrates more rapidly or with a more complex morphology than predicted the expected closure period and related monitoring activities will likely increase to provide the additional information necessary to regain confidence in revised performance predictions. In this situation, the period and cost of post-closure stewardship will likely increase, and more stringent transfer conditions might be applied.

4.2.3 Storage Efficiency Changes

Storage efficiency has two key measures:

- the efficiency of pore-space utilisation for CO_2 storage
- the unit cost of CO_2 storage

The consequence of less injectivity than expected requires that additional injection wells be drilled to deliver the target storage rate. To avoid pressure interference that limits injectivity, the space between injectors must exceed some minimum distance (in the case of the Quest project the models indicate they must be greater than 5 km apart). Consequently, the footprint of the Quest CCS Project would increase.

Drilling more injectors in response to lower injectivity or capacity than expected also increases the cost of CO_2 storage per tonne. Costs escalate due to additional wells and pipeline laterals, and accompanying MMV activities. Similarly, remediation costs to prevent or correct any loss of containment might also substantially increase unit storage costs.

4.3 Potential Threats

There are two main threats towards demonstrating conformance:

- the original model is wrong
- the monitoring is wrong

4.3.1 Unexpected Modeling Errors

Model errors may arise from three sources.

1. Unexpected geological heterogeneities (model inputs) may strongly influence actual fluid transport in ways not represented by the models. Examples include a localized high permeability body, or a sealing fault.
2. The modeling process (model equations) may insufficiently represent the physical and chemical processes governing actual fluid transport. Examples include the relative permeability of CO_2 with respect to brine, and the reaction kinetics of CO_2 interacting with in-situ fluids and minerals.
3. Insufficient analysis of model uncertainties may lead to under-estimation of the predicted performance range. Examples include failing to identify the full range of model scenarios consistent with the observed storage performance history, and failing to fully account for uncertainties in the model equations.

Any of these represent a potential loss of conformance if the actual performance falls outside the predicted performance range.

4.3.2 Unexpected Monitoring Errors

Monitoring errors due to unexpected biases in the acquisition, processing or interpretation of monitoring data may result in a significant misrepresentation of the actual performance. This is a perceived loss of conformance, as the actual performance remains consistent with the predicted performance although the monitoring data indicate otherwise.

Distinguishing real from perceived loss of conformance is essential for implementing the right safeguards, as will be discussed in the next section.

4.4 Assessment of Safeguards

Safeguards provide opportunities to interrupt a developing threat before any significant consequences arise. Site selection, site characterization, and engineering concept selections provide the first round of safeguards incorporated into the Project. This section evaluates the effectiveness of these initial safeguards against identified conformance risks.

The conclusion is that with the initial safeguards in place the risks are already in the tolerable range. As several major development activities and project decisions have substantially reduced the risks and uncertainties about the expected performance of the BCS storage complex.

4.4.1 Basin-Scale Screening of CO_2 Storage Opportunities

Bachu et al. (2000) identified the most promising opportunities for CCS across Canada by matching the location of large localized CO_2 emissions with geological formations likely to support CO_2 storage. This systematic screening process concluded the top ranking opportunities are located within the central Alberta Basin due to the presence of deep permeable saline aquifers overlain by multiple extensive geological seals. On average, the geological formations within the Alberta Basin are conducive to storage of

CO_2. Nonetheless, many uncertainties remained about local geological properties on the scale of single storage sites.

4.4.2 Feasibility Study and Site Selection

Prior to site selection, a subsurface study evaluated the feasibility of storing CO_2 within the BCS saline aquifer. Existing exploration and appraisal wells, and 2D and limited 3D seismic as well as regional gravity and magnetic surveys provided an extensive and diverse data set. In addition, two new exploration wells drilled in the area supplied modern log and test data. Together these data supported an initial appraisal of the region surrounding the Scotford Upgrader near Edmonton. This study enabled a substantial reduction in subsurface uncertainties through better definition of aquifer thickness, porosity and permeability distributions as well as the number, thickness, composition and areal extent of the major geological seals. The conclusion was there is evidence of sufficient capacity, injectivity, and containment within the BCS storage complex to support the proposed storage project. The principle development decision supported by this study was selection of the site proposed for development as defined in the request for pore-space tenure submitted to Alberta Energy in December 2009.

Naturally, some uncertainties remain due to the potential for lateral property variations between the existing wells and seismic surveys. These uncertainties include the possibility of small-scale geological heterogeneities that might act as baffles limiting injectivity, or connected seals limiting capacity, or permeable pathways limiting containment. Oil and gas field developments routinely manage conformance risks such as these through the acquisition of appraisal data to guide the selection of development concepts such as the number, type and location of wells, plus the collection of early production and injection data to further constrain the subsurface understanding.

4.4.3 Site Characterization

Ongoing appraisal work to support Field Development Planning is delivering significant new subsurface information about the selected site. This includes the following:

- **High-resolution aeromagnetic survey**: Acquisition, processing and interpretation of these data indicate variations in the depth to the top of the Precambrian Basement and potentially the location of small faults (offsets less than 100 m) within the basement. Although the sensitivity and resolution of these data to basement structures is substantially less than seismic data, its areal coverage (8,500 km^2) is substantially greater than the combined coverage of all available seismic data across the storage site and spans the entire AOR.
- **2D seismic surveys**: Reprocessing and interpretation of legacy 2D seismic data provides coverage over the entire storage site. The seismic lines are orientated north-south or east-west with a typical spacing of 2 to 3 km. These data demonstrate the presence and continuity of the geological seals over the entire storage site as well as the absence of any large faults crossing these seals. Within the basement, many small faults (offsets less than 20 m) and occasional larger faults (offsets of about 100 m) exist. The larger faults within the basement are located close to the north-west boundary of the storage site, and coincide with major terrain boundaries in the basement identified from aeromagnetic data. At these locations the BCS is interpreted as being locally absent but the primary seal, although thinner, remains intact, while the secondary and ultimate seals (Lower and Upper Lotsberg Salts) are

unaffected. Where seismic lines pass close to existing wells, the data from these two independent sources are consistent.

- **3D seismic survey**: Acquisition, processing and interpretation of new 3D seismic data over the central area (176 km^2) of the storage site provide a detailed continuous image of the storage complex and overlying formations. Local variations in the structure of the BCS storage complex are resolved with a lateral resolution of 25 m and are consistent with 2D seismic data. The BCS is present throughout the 3D seismic image with an average dip direction consistent with the regional trend revealed by well data. Many small faults (offsets less than 20 m) exist within the basement, but no faults are detected crossing any of the seals within the BCS storage complex. These small faults control local variations in the depth to the basement, which in turn control the small variations (plus or minus 20 m) in the thickness of the BCS. Due to the small nature of these deep faults on the seismic image, there remains a small possibility that they extend just into the BCS, due perhaps to the process of differential compaction. If these faults do extent into the BCS, they are not likely to be sealing due to sand-on-sand contacts across the faults. If the faults are sealing, due perhaps to cataclysis, their mapped locations and orientations make it unlikely that they connect together sufficiently to limit injectivity. It is also unlikely that they compartmentalize the aquifer and limit storage capacity. Although these three conditions are each unlikely, there remains no guarantee that small faults cannot affect storage performance. Placement of the Radway 8-19 appraisal well, guided by this seismic image, close to a representative distribution of small faults affords an early opportunity to test the hydraulic properties of these faults.
- **Radway 8-19 appraisal well**: This is currently the only well penetrating the center of the BCS storage complex. Log and test data from this well confirm the expected depth, thickness and properties of all the geological formations within the storage complex.

4.5 Conformance Performance Targets

This section states the target level of risk or uncertainty reduction required through implementation of MMV safeguards. Performance targets should be specific, measurable, attainable, realistic, and time bound.

4.5.1 Performance Targets for Site Closure

Alberta Regulations governing site closure are still under development. To proceed now, we recognize two high-level qualification goals for site closure, adapted from internationally recognized guidelines (DNV 2010b).

1. An understanding of the total system relevant to CO_2 storage exists in sufficient detail to assess its future evolution adequately.
2. No significant negative impacts on human health or the environment occurred. Restrictions exist against any future activities that might compromise the integrity of the storage site.

To meet these high-level targets, MMV activities will be designed to deliver against the following targets during the site closure period.

- **Target**: Actual storage performance conforms to predicted storage performance within the range of uncertainty.
- **Target**: Knowledge of actual storage performance is sufficient to distinguish between two classes of possible future performance: those that result in permanent stable storage of the target mass of CO_2 inside the BCS and those that do not.
- **Target**: Measurements of any changes within the hydrosphere, biosphere, and atmosphere caused by CO_2 injected into the BCS storage complex are sufficient to demonstrate the absence of any significant impacts as defined by the Environmental Assessment

4.5.2 Performance Target for Storage Efficiency

The range of predicted pore-space utilization agreed with the regulator prior to CO_2 injection helps frame an appropriate performance target in the following form.

- **Target**: There is adequate evidence prior to site closure that actual pore-space utilization is consistent with the range of possible pore-space utilizations agreed prior to CO_2 injection, or any discrepancies between the two are tolerable.

4.5.3 Performance Target for CO_2 Inventory Reporting

Following the IPCC guidelines on CO_2 inventory reporting (IPCC 2006), the mass of CO_2 held within a geological storage complex is the difference between the mass of CO_2 injected into the complex and the mass of CO_2 emitted from the complex. Uncertainty about the CO_2 inventory therefore depends on uncertainties in the measured mass of injected and emitted CO_2.

The ERCB bulletin 2010-22 recommends the general provisions of Directive 007 and Directive 017 for CO_2 emissions monitoring.

Existing Acid Gas Disposal regulations require a maximum uncertainty in the monthly injected volume measurement of 5%. The sensitivity of emerging new technologies designed to measure CO_2 emission rates into the atmosphere depends on site-specific conditions. We propose the maximum uncertainty for these measurements be determined according to baseline monitoring data gathered at the storage site over at least 12 consecutive months prior to the start of CO_2 injection.

- **Target**: Measurement of monthly mass of CO_2 injected into the storage site has a maximum uncertainty of 5%.

5 Containment Risks

The project is designed for long-term secure containment of CO_2 and brine within the BCS storage complex. However, it is prudent to consider unlikely threats that may still occur with potential consequences. The following analysis of both the threats and potential consequences represents collective expert opinions and draws on existing risks descriptions provided by IPCC (2005), WRI (2008), EPA (2008a), and NETL (2009) as well as Acid Gas Disposal Projects in Alberta.

Containment focuses on the fact that the injected fluid should remain in the geological interval intended for long-term storage. Containment is a safety-critical risk, therefore a full containment Bowtie has been developed (see Figure 5-1).

5.1 The Top Event

As per the bowtie analysis in Figure 5-1 the top event identified for this analysis is:

- Migration of CO_2 or BCS brine to above the Upper Lotsberg Salt, the ultimate seal of the BCS storage complex.

This is a natural choice as it represents the top of the storage complex. Prior to this event, the migrating fluids remain inside the intended geological formations. After this event, consequences due to loss of containment may arise as described in Section 6.2. The number and impact of these consequences increases if fluid migration continues upwards uncontrolled. Therefore, the MMV plan proposed in Section 7 focuses on early detection of a loss of containment.

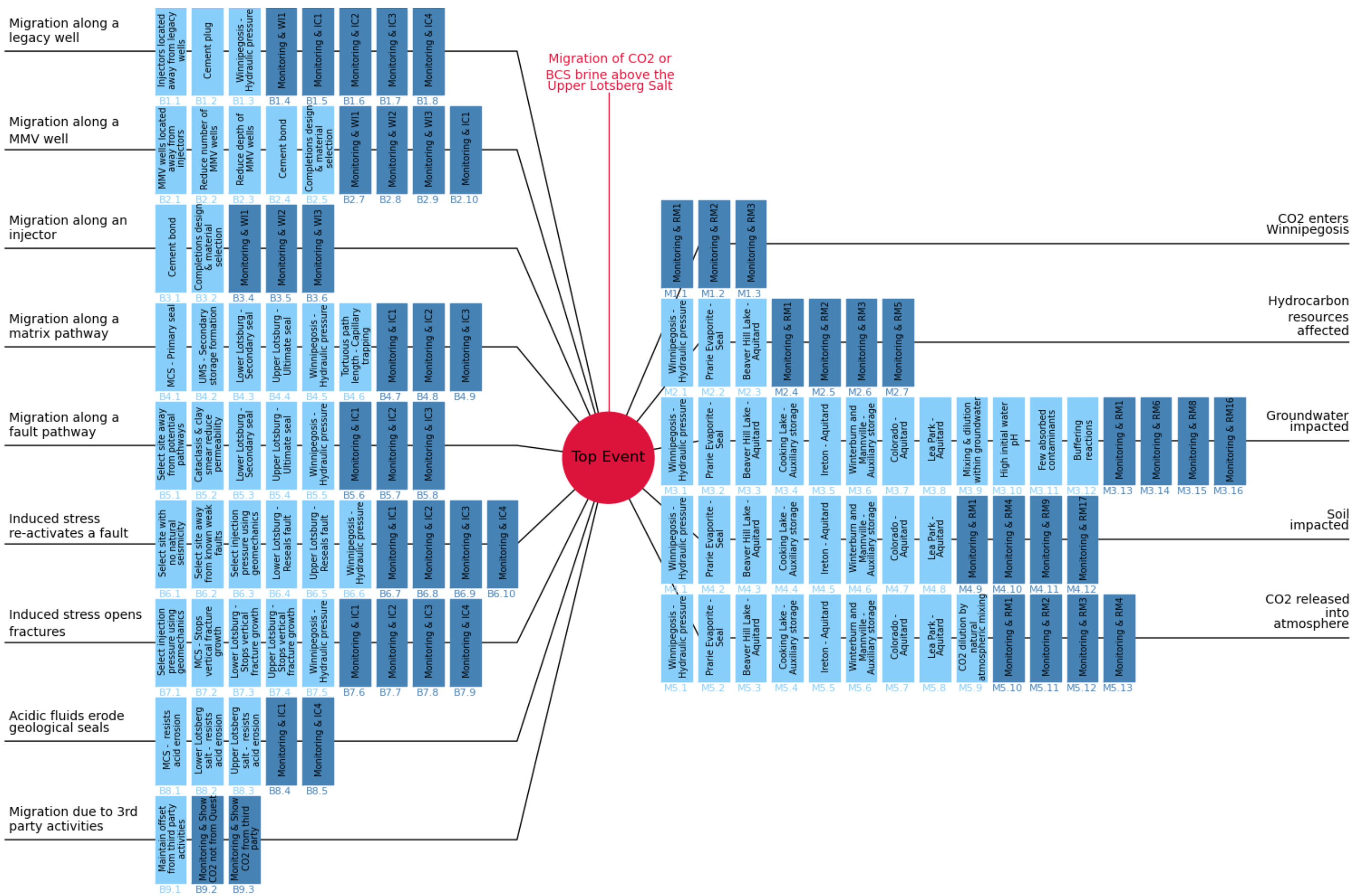
5.2 Potential Consequences

Five distinct environmental domains could be impacted as the result of a loss of containment. These domains are listed below in decreasing depth:

5.2.1 CO_2 Enters the Winnipegosis

The Winnipegosis is the first saline aquifer above the BCS storage complex at a depth of ~1600m MD. Therefore, a CO_2 or brine leakage into the Winnipegosis has no direct economic, health, safety or environmental impact and presents a potential early warning target MMV location. Any build-up of pressure and accumulation of CO_2 within the Winnipegosis would constitute a loss of the opportunity to potentially develop an independent CCS project within the Winnipegosis storage complex later.

The Winnipegosis is only recognized as an alternate CO_2 storage site because it is capped by another potential sealing formation in the form of the Prairie Evaporite.



NOTE: Identified with the potential to reduce the risk of loss of containment (top event) by reducing either its likelihood (left side) or its consequence (right side). Light blue denotes passive safeguards created by site and engineering concept selections. Dark blue denotes active safeguards where the unspecified monitoring activities pair with the control measures specified.

Figure 5-1 Initial Bowtie Representation of Safeguards

5.2.2 Hydrocarbon Resources Affected

Migration of CO_2 or brine out of the BCS storage complex might affect proven oil resources within the Leduc, Nisku and Wabamun formations and proven gas resources within the Nisku, Mannville Group and Colorado Group (see Table 5-1 for depths and offset distances of the different hydrocarbon accumulations). For producing fields this might result in a slight increase in salinity or acidity of the produced fluids, although the lateral and vertical offset of the producing fields makes this unlikely. Any pressure changes would likely be negligible.

It should be recognized that for a zone to be hydrocarbon bearing it must add both another reservoir and impermeable seal to the geosphere, both of which add further barriers to migration of CO_2 out of the geosphere.

5.2.3 Groundwater Impacts

The protected groundwater zone (GPZ) is the zone above the base of groundwater protection up to the ground surface and comprises surface and underground water with a salinity, measured as the concentration of total dissolved solids, less than 4,000 parts per million. The depth of the GPZ varies across the AOR from 100 to 400 m MD. This zone supports extensive domestic, agricultural and commercial use throughout the AOR. The potential consequences to the groundwater are discussed in the environmental assessment (Section 17, Volume 2A).

5.2.4 Soil Contamination

Migration of CO_2 into the soil may increase soil acidity and introduce contaminants mobilized and transported by the passage of CO_2 through the subsurface. Changes in soil quality may be sufficient to stress the flora and fauna.

5.2.5 CO_2 Release to the Atmosphere

Any release of CO_2 from the BCS storage complex back into the atmosphere will reduce the effectiveness of the Project's contribution to climate change mitigation.

5.3 Potential Threats

Threats that might lead to a loss of containment take the form of nine independent potential pathways for fluids to migrate above the ultimate seal. The following sections describe the defining characteristics of each pathway.

5.3.1 Migration along a Legacy Well

Several abandoned third party wells penetrate all the seals of the BCS storage complex and may constitute a threat to containment of CO_2 and displaced brine (Attachment C and Tables 5-2 and 5-3). Given the density of wells drilled to this depth around Edmonton, more than 20 such penetrations might exist within the AOR if the selected site had not sought to avoid them. By careful site selection, the AOR for the Project has reduced this number down to three. This number increases in magnitude rapidly above the Upper Lotsberg Salts (Figure 5-2). For this reason, the BCS as the deepest saline aquifer in the basin is the preferred target injection formation.

Table 5-1 Distance to closest offset producers

Formation	Hydrocarbon Producers in Quest AOI	Closest offset well	Average depth to top reservoir in AOI (m)	Distance from 8-19-059-20W4 (km)	Comments
Viking	yes	100/09-31-059-20W4/00	590	3.4	
Joli Fou	yes	100/08-36-059-20W4/00	615	8.7	
Mannville	yes	100/15-20-059-20W4/00	623	1.2	Includes Ellerslie, Glaucontic Sands
Wabamun	yes	100/14-29-059-20W4/00	750	8.2	
Nisku	Yes	100/09-06-058-21W4/00	850	15	Leduc Reef
Ireton	Yes	103/06-07-058-21W4/00	900	15	Leduc Reef
Leduc	Yes	100/03-08-058-21W4/0	1000	15	Leduc Reef
Winnipegosis	no	-	1600	-	Saline Aquifer
BCS	no	-	2000	-	Saline Aquifer

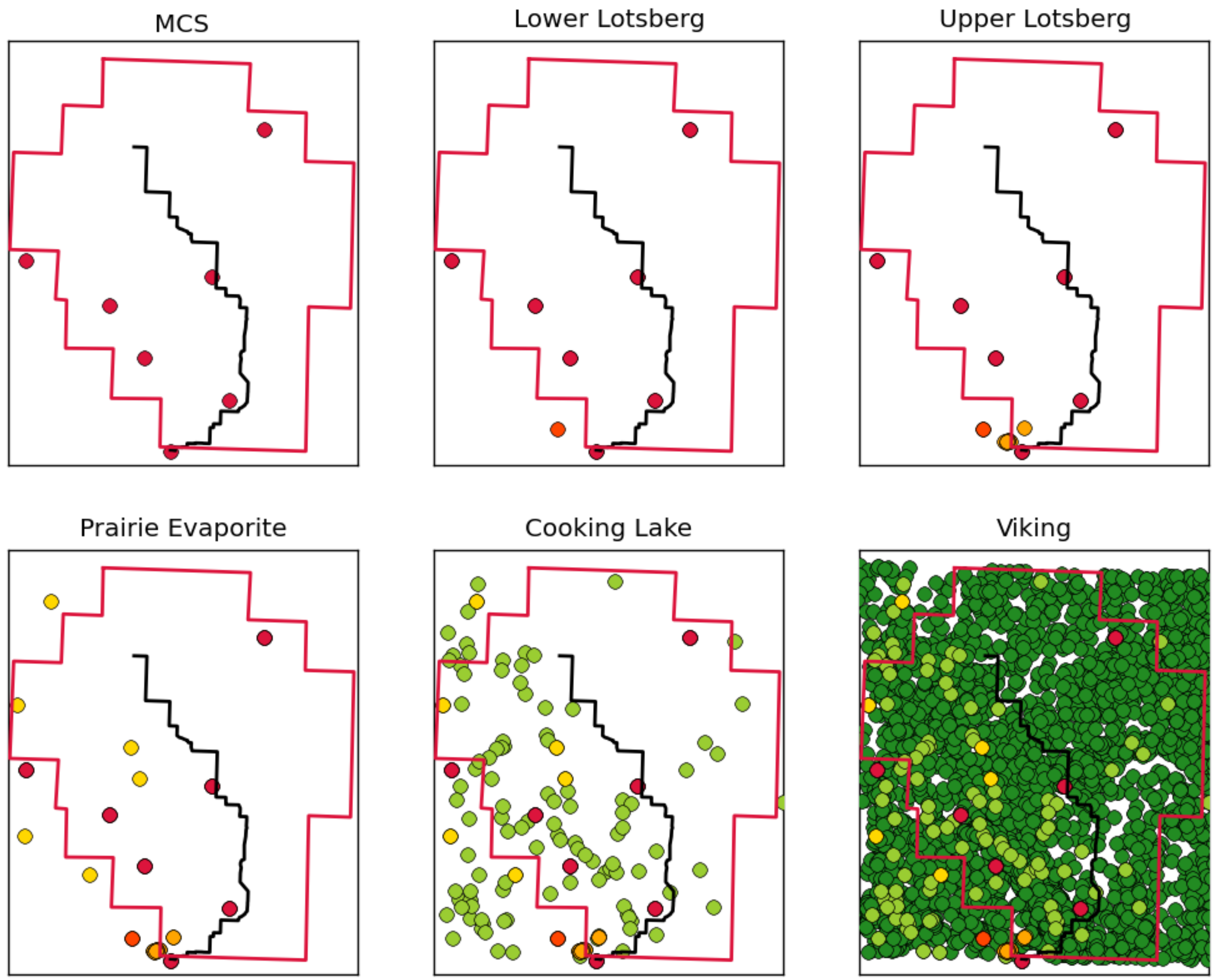
Table 5-2 Legacy Well Status

Well name and UWI	History	Seals Penetrated	Casings and holes	Cement plugs
Imperial Eastgate 100-01-34-057-22W400	Drilled and abandoned in 1955	- Upper Lotsberg - Lower Lostberg - MCS	- 9 5/8" casing to 277m - 9" openhole to 2205m (TD)	#1: 265 – 289 m #2: 644 – 710m #3: 887 – 981m #4: 1016 – 1048m #5: 1256 – 1292m #6: 2125 – 2205m
Imperial Egremont 100-06-36-058-23W400	Drilled and abandoned in 1952	- Upper Lotsberg - Lower Lostberg - MCS	- 13 3/8" casing to 186m - 9" openhole to 2235m (supposed TD)	#1: 172 – 195m #2: 624 – 670m #3: 844 – 875m #4: 969 – 1003m #5: 1178 – 1218m #6: 2140 – 2235m
Imperial Darling #1 100-16-19-062-19W400	Drilled and abandoned in 1949	- Upper Lotsberg - Lower Lostberg - MCS	- 13 3/8" casing to 183m - 9" (supposed) openhole to 2013m	#1: 168 – 198m #2: 525 – 587m #3: 708 – 740m #4: 762 – 792m
Imperial Baysel Riverdale 100-01-27-060-26W400	Drilled and abandoned in 1956	- Upper Lotsberg - Lower Lostberg - MCS	- 13 3/8" casing to 188m - 9" openhole to 2393m (TD)	#1: 175 – 200m #2: 710 – 765m #3: 971 – 1009m #4: 1136 – 1204m #5: 1531 – 1587m #6: 1750 – 1783m
Imperial Clyde #1 100-09-29-059-24W400	Drilled and abandoned in 1948	- Upper Lotsberg - Lower. Lostberg - MCS	- 13 3/8" casing to 135m - 9" openhole to 2295m (TD)	#1: 128 – 195m #2: 781 – 945m
Imperial Gibbons #1 100-02-16-056-22W400	Drilled and abandoned in 1949	- Upper Lotsberg - Lower Lostberg	- TD at 2024m Well report gathering in	Well report gathering in process
Imperial PLC Redwater LPGS 100-07-17-056-21W400	- Drilled in 1974 - Converted to LPG reproducer in 1975 - Abandoned in 2007	- Upper Lotsberg	- 13 3/8"casing to 188m - 9 5/8" casing to 1778m - 7" casing to 1770 - TD at 1861m	Well report gathering in process

NOTE: All legacy wells penetrating the BCS are abandoned.

Table 5-3 Appraisal Well Status

Well Name and UWI	TD	Status
SCL Redwater 102-11-32-55-21-W4M	2269m	Well cased and cemented to TD. BCS abandoned and well reconverted as a water disposal well
SCL-Redwater 03-04-57-20W4M	2190m	Well cased and cemented to TD. Well suspended with 19 joints of drill pipe and liner running tool cemented in hole. Top of cement at 1696.5m with top of fish at 1672m
SCL-Radway 8-19-59-20W4	2132m	Well cased and cemented to TD. Well suspended, will be part of the project injectors



NOTE: Shows the spatial distribution of existing wells recorded in the ERCB database and penetrating the base of each formation named above.

Figure 5-2 Spatial Distribution of Existing Wells in ERCB Database

Many of the legacy wells date from 1940 to 1960 so abandonment standards, execution, documentation and aging all contribute to uncertainty about the continuing integrity of legacy wells (Attachment C). Corrosion of casing, insufficient extent or quality of the initial cement bond outside the casing, an insufficient number, incorrect placement relative to the seals or quality of cement plugs inside the casing, or deterioration of any cement bonds through time will affect the integrity of these legacy wells. Therefore, the Quest CCS Project has been sited such that in all the current subsurface simulations the CO_2 plume does not reach these wells.

5.3.2 Migration along an Injector

Any well injecting CO_2 into the storage complex creates a threat to containment as it punctures the geological seals directly above the CO_2 plume. Any loss of external or internal well integrity will potentially allow migration of CO_2 and BCS brine out of the storage complex. This threat may arise for any of the following five reasons.

1. **Compromised cement**: Initial cement bond, or deterioration of the cement bond through time due to stress cycling, or chemical alteration may allow upward fluid migration outside the casing.
2. **Compromised casing**: Casing corrosion through time due to oxygen ingress, or contact with saline or acidic fluids may allow upward fluid migration inside or outside the casing.
3. **Compromised completion or wellhead:** Loss of integrity of the completion or wellhead due to undetected flaws in the initial design or execution or subsequent degradation due to corrosion, or deterioration of seals in the presence of CO_2 may allow fluids to escape through the wellbore.
4. **Well interventions**: During the cause of normal operations, routine well interventions may result in loss of well control.
5. **Compromised abandonment**: Injection and observation wells will be properly abandoned prior to site-closure. Undetected flaws in the design or execution of well abandonment or subsequent degradation of materials may allow upwards migration of fluids.

5.3.3 Migration along an Observation Well

One method of monitoring storage performance inside the BCS storage complex is direct measurement of pressure and saturation changes within observation wells. Any such observation wells constitute a threat for the same reasons as the injectors.

Legacy, injector and observation wells each represent a different type of threat: legacy wells are avoidable, injectors are essential; however, observation wells are optional.

5.3.4 Migration along a Matrix Pathway

Sedimentary processes often generate extensive thick impermeable geological seals that retain fluids under pressure for millions of years. The Alberta Basin contains many such seals, and careful site selection process for the Quest AOR has been used to optimize the use of these natural barriers.

Nonetheless, permeable pathways may exist up through the geological seals due to the occasional juxtaposition of different sedimentary formations. The areal extent of geological seals may not cover the entire AOR or variations in seal thickness due to changes in the depositional environment or subsequent erosion may mean it is locally absent. For instance, a seal may truncate against a local basement high or a channel filled with sand may erode down through a seal. Sedimentary process may sometimes result in complex heterogeneities that interconnect to allow fluids under pressure to migrate up and out of the storage complex.

5.3.5 Migration along a Fault

Faults exist as discontinuities over a range of length-scales in many rock formations. However, large faults that transect regional scale geological seals within the Alberta Basin are rare (more than 100 km separates the Snowbird Tectonic Zone from the Hay River Shear Zone to the north). Even when present, many faults are sealing and retain fluids under pressure over geological time-scales. Mechanisms associated with fault slip, such as clay smear and cataclysis, reduce permeability within the fault zone. Other mechanisms, such as dilation and fracturing may enhance fault permeability. Although unlikely, it remains a credible possibility that permeable fault pathways exist somewhere within the AOR.

No faults are identified in the AOR that cut across the BCS storage container.

5.3.6 Induced Stress Reactivates a Fault

Any pre-existing sealing faults may re-activate due to stress changes induced by CO_2 injection. Effective normal stresses will decrease and may de-stabilize any pre-existing weak fault. In addition, shear stress loading these faults will increase or decrease depending on the fault orientation and the sense of residual shear stress held on the fault due to friction. Any decrease in shear stress will stabilize the fault making re-activation less likely and vice versa.

Renewed fault slip might increase local permeability by dilation or fracturing within the fault damage zone and perhaps allow the fault to propagate upwards. Equally likely is a reduction of permeability due to clay smear or cataclysis along the fault surface.

No faults are identified in the AOR that cut across any of the seals in the BCS container.

5.3.7 Induced Stress Opens Fractures

CO_2 injection may induce open fractures due to pore fluid pressure increase and temperature decrease inside the aquifer close to the well. Occurrence of any such fracturing does not constitute a threat to containment unless these fractures propagate upwards sufficiently to transect the geological seals and remains at least partially open to provide an enduring permeable pathway.

Fracturing induced by water injection for hydrocarbon recovery is common, but rarely do these fractures propagate upwards sufficiently to compromise the integrity of the top seal.

5.3.8 Acidic Fluids Erode Geological Seals

Injected CO_2 will acidify formation fluids in contact with geological seals. Depending on the mineralogy of the seals there is potential for many different chemical reactions to occur. Many of these reactions yield products that occupy a greater volume and therefore most likely reduce permeability; the converse is also possible. For acidic fluids to erode geological seals, minerals must be present that react and these reactions must increase not decrease permeability.

5.3.9 Migration Due to Third Party Activities

Any nearby third-party CCS projects may induce migration of CO_2 or brine into the AOR causing environmental impacts. Existing activities, such as mining, agriculture, or landfill inside the AOR may also cause environmental impacts. Inability to identify the true source of these impacts might trigger a perceived loss of containment from the Quest BCS storage complex. The closest CCS project under evaluation is the HARP project located in the Redwater Reef approximately 10 km lateral separation and approximately 1000 m vertical separation from the 8-19 well location.

5.3.10 Threats Deemed Not Credible

This analysis excludes many other possible threats as not credible or not having the potential to cause a significant impact. The four examples described below illustrate some of the many reasons for excluding these threats.

5.3.10.1 Surface Uplift

During injection, the distribution of increased pore fluid pressure inside the storage complex will induce an increase in bulk volume due to poro-elastic effects. This in turn induces deformations of the surrounding rock mass and the overburden will experience uplift and some associated strains. Geomechanical calculations based on mechanical rock properties gained from appraisal data and dynamic simulations of the pressure distributions induced by CO_2 injection yield results showing insignificant surface uplift (*c.* 60 mm maximum) and subsurface strain (*c.* 10^{-5} maximum). Surface uplift already observed above the In Salah CCS project in Algeria show similar deformation rates induced by similar rates of CO_2 injection into a formation at a similar depth (Rutqvista et al. 2008).

5.3.10.2 Lateral Migration within the Storage Complex

Lateral migration of the injected CO_2 or displaced brine is a conformance risk but is not a containment risk. Unexpected lateral migration poses no direct threat to containment. To escape the BCS storage complex, fluids must eventually migrate upwards. Lateral migration only creates an indirect risk to containment because it may bring fluids towards potential pathways for upwards fluid migration. Any safeguards in place against these direct containment risks will also be effective against the indirect risks.

5.3.10.3 Molecular Diffusion through Geological Seals

CO_2 will diffuse across geological seals at the molecular level even in the absence of any connected pore networks. However, this physical process takes millions of years due to the thickness and extremely low rates of diffusion of geological seals within the BCS storage complex.

5.3.10.4 Capillary Migration through Geological Seals

Injection pressure must exceed the capillary entry pressure and sufficient time must pass for fluid front to permeate through an almost impermeable and thick seal. Salinity differences between the BCS and Winnipegosis brines indicate long-term isolation between these two aquifers. Injection pressure should never exceed the MCS capillary entry pressure. The MCS permeability and thickness mean that even if injection exceeds the capillary entry pressure, flow through the restricted pore network will take hundreds of years and then only result in an insignificant flux. Stratigraphic heterogeneities that may provide localized permeable pathways through geological seals pose a substantially greater threat.

5.4 Assessment of Safeguards

Safeguards provide opportunities to interrupt a developing threat before any significant consequences arise. Site selection, site characterization, and engineering concept selections provide the first round of safeguards incorporated into the Project. This section evaluates the effectiveness of these initial safeguards against containment risks. The conclusion is that with the initial safeguards in place the risks are already in the tolerable range.

5.4.1 Containment Safeguards

5.4.1.1 Preventative Measures

The system of preventative safeguards named in Table 5-4 represents a wide range of measures to reduce the likelihood of each threat triggering the top event. An effective safeguard will prevent the occurrence of the top event on most occasions (e.g., 90% success rate). Individual safeguards do not need to be perfect as multiple imperfect but independent safeguards will still be effective. For example, two barriers that fail independently at the rate of 1 in 3 deliver the same protection as a single barrier that only fails at the rate of 1 in 9.

5.4.1.2 Safeguards for Legacy Wells

Wells represent a deliberate breach of the geologic seals and as such pose the greatest risk to containment and legacy wells are likely the most vulnerable given uncertainty about their current and future integrity. The most effective form of safeguard is to eliminate this risk. The selected site allows for injection of CO_2 no closer than 21 km to any legacy well penetrating the BCS. Only seven such legacy wells exist within 31 km of anticipated injectors. After 25 years of injection, the expected rise in pore fluid pressure around these seven legacy wells will likely be insufficient to raise BCS brine into the groundwater protection zone (Attachment E). Thereafter, pressures will tend to decline and the risk of fluids migrating upwards along legacy wells diminishes.

Table 5-4 Active Control Options

	Preventative Controls
	Injection Controls
IC1	Re-distribute injection across existing wells
IC2	Drill new vertical or horizontal injectors
IC3	Extract reservoir fluids to reduce pressure
IC4	Stop injection
	Well Interventions
WI1	Repair leaking well by re-plugging with cement
WI2	Repair leaking injector by replacing completion
WI3	Plug and abandon leaking wells that cannot be repaired

	Corrective Controls
	Well Interventions
RM1	Repair leaking well by re-plugging with cement
RM2	Repair leaking injector by replacing completion
RM3	Plug and abandon leaking wells that cannot be repaired
	Exposure Controls
RM4	Inject fluids to increase pressure above leak
RM5	Inject chemical sealant to block leak
RM6	Contain contaminated groundwater with hydraulic barriers
RM7	Replacement of potable water supplies
	Remediation Measures
RM8	Pump and Treat
RM9	Air Sparging or Vapour Extraction
RM10	Multi-phase Extraction
RM11	Chemical Oxidation
RM12	Bioremediation
RM13	Electrokinetic Remediation
RM14	Phytoremediation
RM15	Monitored Natural Attenuation
RM16	Permeable Reactive Barriers
RM17	Treat acidified soils with alkaline supplements

NOTE: Identified with scope to prevent any loss of containment or to provide corrective controls that avoid or reduce consequences should loss of containment unexpectedly occur. Each of these options corresponds to a discrete operational activity initiated by a management decision based on monitoring information.

Given the average density of wells drilled to this depth around Edmonton, many other suitable storage sites of this size would likely contain more than 20 legacy wells within a radius of 30 km. Two-thirds of the legacy wells risk is eliminated by selecting a site with an unusually low number of legacy wells. The risk reduces further by allowing sufficient separation distances so that no significant interaction can occur between the storage complex and the remaining legacy wells.

No system of safeguards is perfect. In this case, uncertainty currently remains about the amount of pressure build-up and rate of pressure migration throughout the BCS. There is a small possibility that some known legacy wells will experience greater pressures sooner than expected

The previous abandonment of all seven legacy wells provides additional safeguards. Abandonment reports (Attachment C) document the number of cement plugs within each well. However, the results of any positive pressure tests are not available to verify the initial integrity of these abandoned wells and the current integrity may be still less due to degradation over the last 50 to 60 years.

5.4.1.3 Safeguards for Injectors

Injectors designed, drilled, completed and operated for the dedicated purpose of CO_2 injection allow for a wide range of engineered safeguards. Multiple casing strings, CO_2-tolerant casing, CO_2-tolerant cement, and cement placement along the entire well bore all provide independent layers of protection. Logging and pressure testing will verify initial well integrity. Although the continuing long-term integrity of such dedicated CO_2 injectors is highly likely, as demonstrated by many mature CO_2 EOR projects worldwide, some risk remains.

In-well monitoring must be a central part of MMV activities to verify well integrity over the entire project lifecycle and afford opportunities for early intervention to control any unexpected loss of well integrity promptly.

5.4.1.4 Safeguards for Observation Wells

Observation wells within the BCS pose a somewhat similar threat to containment as injectors as they will experience substantially elevated pore fluid pressures and CO_2. This risk is unique in that it is entirely voluntary given it can be perfectly eliminated by not drilling these wells at all or at least not drilling them into the storage complex. The potential benefits of accepting additional containment risk to allow direct measurements of conformance are uncertain. In-direct non-invasive conformance measurements should be feasible and may be sufficient. Currently there is no compelling reason to accept additional containment risk.

Therefore, this risk will be avoided to the extent possible by incorporating the safeguard that no observation wells will penetrate the Upper Lotsberg Salt.

5.4.1.5 Safeguards against any Matrix Pathways

The BCS storage complex contains three regional geological seals optimized by the site selection. Well control from just outside the AOR and 2D seismic lines every 2 to 3 km oriented north-south and east-west inside the AOR provide reliable information about the areal extent and thickness of these seals (see Figure 1-1).

- The primary seal, the Middle Cambrian Shale, is approximately 20 to 55 m thick over the entire AOI; the thinnest zones within the AOR occurs over occasional basement highs identified within 5 km of the north-west boundary of the AOR.
- The secondary seal, the Lower Lotsberg Salt, is typically approximately 10 to 35 km thick within the AOI and thins towards the west terminating just beyond the western boundary of the AOR.
- The ultimate seal, the Upper Lotsberg Salt, is approximately 55 to 90 m thick over the entire AOI and extends beyond the AOR boundary in all directions.

The depth of the BCS and the compensational stacking of the multiple seals inside and above the storage complex means any migration pathway must be long and highly tortuous. The length and tortuosity of any matrix pathway also provides a safeguard as such long migration routes increase the attenuation of any escaping fluids through capillary trapping and natural dispersion.

Each seal on its own is likely sufficient to ensure long-term containment of the injected CO_2 and displaced BCS brine. Nonetheless, a small risk remains that an unidentified localized permeable pathway allows significant fluid migration across any one of these seals. The presence of three independent seals within the storage complex substantially lowers the likelihood of fluids escaping – but does not eliminate this risk.

5.4.1.6 Safeguards against any Fault Pathways

No evidence exists of faults extending from the BCS through any of the three geological seals inside the storage complex. 2D seismic lines image all intersected faults with offsets exceeding 20 m. All of these faults appear within the basement with no evidence of faulting within the overlying sedimentary formations, although typical line spacing is approximately 2 to -3 km. Additionally, two 3D surveys covering a total area of 210 km^2 image the same fault system and detects fault offsets larger than 10 to 15 m. Once again, there is no evidence of any of these faults extending above the basement.

There is a very remote chance that small faults that transect but do not offset the primary seal may still generate a permeable pathway due to dilation or fracturing within the fault damage zone. Mechanisms such as ductile creep, clay smear, and cataclysis will however likely dominate and reduce permeability within the fault zone. Even if the shale seal happens to be brittle in parts, the two Lotsberg Salt seals will likely seal any fault zones due to salt creep. Core material recovered from the Basal Red Beds formation (Redwater 11-32) directly below the Lower Lotsberg Salt contains open fractures completely filled with salt.

In the extremely unlikely event of unexpected faults possessing unexpected permeability for fluids to escape the storage complex, the maximum flux will likely still be less than any unexpected migration of fluids along wells that provide a potential direct flow path from the storage complex to the surface (BGS 2010).

5.4.1.7 Safeguards against Fault Re-activation

Renewed slip on any pre-existing fault within the storage complex due to natural processes such as tectonics or induced by CO_2 injection may create permeable pathways for fluids to escape the BCS storage complex. The selected site has no recorded history of earthquakes and the monitoring network is sufficient to detect earthquakes of at least magnitude 2.

In-situ stress measurements indicate little initial deviatoric stress, which means that each principal stress is approximately equal to the mean stress. Faults remain stable due to their internal frictional resistance to further slip. Any decrease in the effective normal stress acting on the fault will diminish its frictional resistance to slip. This will happen within the BCS due to the expected increase in pore fluid pressure associated with CO_2 injection.

The absence of any significant shear stress acting on any small faults within the BCS means fault re-activation is unlikely despite any reduction to its frictional resistance.

Due to the large volume of injected CO_2, shear stresses will increase slightly during injection favouring re-activation of low-angle faults (dip of 30 degrees) inside the BCS or high angle faults (dip of 60 degrees) outside the BCS. These changes in shear stress will be small compared to the confining stress so fault re-activation remains unlikely. The frictional resistance of any pre-existing faults is largely uncertain so fault re-activation, although extremely unlikely, remains a possibility. If fault re-activation occurs, the region of renewed slip would likely remain confined to the pre-existing fault surfaces shown by existing seismic data do not extend across any of the seals. Even in the event of fault re-activation, it remains unlikely to threaten the integrity of the primary seal, let alone the secondary or ultimate seals. Moreover, clay smear and salt creep would most likely plug any permeable pathways should any fault re-activation occur within these seals.

5.4.1.8 Safeguards against Fractures Opening

Any injection-induced fracturing within the BCS cannot threaten containment unless these fractures propagate more than 330 m upward to pass through the ultimate seal.

Within a homogeneous medium, fractures tend to propagate most easily upwards due to the decrease in confining stress that opposes fracture opening. Geological formations are rarely homogeneous and typically contain horizontal layering that effectively arrest vertical fracture propagation due to any one of a number of different mechanisms.

1. **Minimum horizontal stress** may be higher within a particular layer, which arrests vertical fracture growth.
2. **Weak frictional interfaces** may slide in response to an approaching fracture, causing the fracture to arrest at the interface.
3. **Stiffness contrasts** between layers of more than a factor three suppress the stresses required to propagate the fracture from one layer to the other.
4. **Strength contrasts** between layers may arrest fractures at the interface with strong layers.

5. **Permeability contrasts** between layers may arrest fractures within permeable layers as the rate of fluid leak-off into the formation leaves insufficient pressure to propagate the fracture any further.
6. **Ductility contrasts** between layers may arrest fractures at the interface with layers that deform plastically instead of allowing brittle failure.

All six mechanisms are likely to operate throughout each of the geological seals inside the storage complex meaning even if fractures do open inside the BCS there is little chance they will ever threaten containment. The limestone shale (LMS) seal is a highly inter-bedded sand-shale system providing many weak interfaces as likely barriers to fracture growth. The measured compressive horizontal stress within the primary seal (middle Cambrian shale, or MCS) is 1.5 times greater than that in the BCS, which provides another effective barrier to vertical fracture propagation.

Existing regulations for acid gas disposal require the bottom-hole injection pressure never to exceed 90% of the measured fracture pressure within the disposal formation. This safeguard should ensure injection proceeds without opening fractures within the BCS. Some small uncertainty remains that fractures maybe initiated.

However, once injection ceases, reservoir pressures immediately start to decline gradually and so does the risk of open fractures.

5.4.1.9 Safeguards against Acidic Fluids

Mineralogy of the primary seal, the MCS, favours the reduction of permeability due to reactions with acidified brine. CO_2 dissolved in BCS brine lowers the pH from 5.5 to 4.0. The bulk of the minerals within the shale remain un-reactive in contact with this acidified brine.

Both Lotsberg Salt formations are made of pure halite that does not react with acidified brine. Salt creep would most likely fill any voids created by dissolution of currently unidentified reactive minerals before any permeable pathways transect the seals.

5.4.1.10 Safeguards against Third-Party Activities

Provision of exclusive porespace tenure is the prime safeguard against threats from any third-party CCS projects. The possibility of competing or indistinguishable environmental impacts from adjacent CCS projects is avoidable if the tenure region is sufficiently large to encompass the zone of elevated pore fluid pressures capable of lifting BCS brine above the base of the groundwater protection zone.

5.4.2 Corrective Measures

In the unlikely event of fluids escaping above the Upper Lotsberg Salt there remain a large number of additional geological formations to trap, delay, disperse, or attenuate these fluids and so reduce the likelihood of any environmental impacts (see Figure 1-1).

The first formation encountered is the Winnipegosis, a carbonate formation, with sufficient porosity to provide secondary storage. On top is the Prairie evaporite, a regional seal that extends outside the AOR in all directions and is 100 to 50 m thick inside the AOR with no indication of faulting seen on seismic.

Numerous seals that retain hydrocarbon accumulations exist within the next 1,200 m thick interval up to the base of the groundwater protection zone. These include the Beaverhill Lake, Ireton, Colorado, and Lea Park aquitards. Between these seals are numerous porous formations that provide secondary storage opportunities for any fluids escaping the BCS storage complex. These include the Cooking Lake, Winterburn, and Mannville aquifers.

Any migration pathways upwards through this stacked system of aquifers and aquitards will be highly tortuous given the lack of any large faults observed on seismic. Such long migration routes increase the attenuation of any escaping fluids through capillary trapping and natural dispersion.

A number of factors will mitigate the impact of CO_2 leakage on shallow groundwater quality. These include:

1. simple mixing and dilution of CO_2-impacted groundwater with ambient groundwater
2. pH buffering reactions such as calcite dissolution and/or silicate mineral weathering
3. limited trace metal availability in aquifer minerals
4. trace metal scavenging by secondary mineral precipitation

5.5 Containment Performance Targets

This section states the target level of risk or uncertainty reduction required through implementation of MMV safeguards. Performance targets should be specific, measurable, attainable, realistic, and time bound.

The proposed performance targets for MMV activities designed to ensure long-term containment are as follows.

- **Target**: Measurements of any changes within the hydrosphere, biosphere, and atmosphere caused by CO_2 injected into the BCS storage complex are sufficient to demonstrate the absence of any significant environmental impacts on an annual basis.

An annual performance review should evaluate actual storage and monitoring performance and if necessary revise the assessment of the four factors governing containment performance.

1. threat initiation rates
2. consequence impact ratings
3. safeguard failure rates
4. uncertainties about safeguard failure rates.

In response to any such changes, the MMV plan will be adapted so it meets the performance target, and it might be adapted to avoid exceeding the performance target in any manner that reduces the cost-effectiveness of MMV. Possible adaptations to the MMV program include the following options.

- replace an under-performing monitoring technology with an alternative
- replace an under-performing control measure with an alternative
- change the frequency of monitoring
- add or remove a safeguard

The preferred method for selecting from these many options is the same as the method described below for selecting the initial MMV design.

6 Measurement, Monitoring and Verification Concept Selection

6.1 Identification of Additional Risk Reduction Measures

Operations at the Quest CO_2 storage site will be designed to deliver long-term containment and maintain the confidence of stakeholders that the risk of a future loss of containment is acceptable given the beneficial contributions made towards mitigating climate change. The risks of actual storage performance failing to meet these requirements diminished substantially due careful site selection ensuring the presence of many different geological safeguards that either prevent any threats to containment from developing or mitigate the effects of any escaping fluids to avoid any significant impacts to human health and safety or the environment. Likewise, engineered safeguards incorporated into the project design provide similar layers of protection. Nonetheless, given the potential impact, it is prudent to have MMV plans in place to:

- verify storage performance
- give an early warning of the potential loss of containment
- deliver significant additional risk reductions

6.2 Additional Conformance Safeguards

Definition of the Field Development Plan marks the conclusion of appraisal activities. At this stage, subsurface models are as complete as possible prior to CO_2 injection and the range of predicted outcomes based on the Field Development Plan should indicate secure permanent storage of CO_2 inside the BCS complex regardless of any remaining uncertainties.

6.2.1 Additional Preventative Measures

Once CO_2 injection starts there is a range of measures available to reduce the likelihood of any loss of conformance occurring due to the threats identified previously.

6.2.1.1 Additional Safeguards against Unexpected Geological Heterogeneity

No matter how wide the range of geological models built, there will be other possible geological heterogeneities not properly represented. One additional safeguard is to gain early access to monitoring information with sufficient temporal and spatial resolution in order to characterize these geological heterogeneities before any loss of conformance arises, an example of such a technology would be time lapse seismic. Frequent updating of models to match observed performance should correct any discrepancies before they become significant. The frequency of such discrete monitoring activities will be time dependent:

- The rate of movement of the CO_2 front will generally decrease with time, the frequency of discrete monitoring activities such as time-lapse seismic should also decrease with time.

- More frequent initial monitoring will likely give early benefits in terms of uncertainty reduction and model updates.
- Reducing the frequency with the rate of movement of the CO_2 front will help avoid escalation of monitoring costs.

6.2.1.2 Additional Safeguards against Model Errors

Even if existing numerical codes used to predict storage performance are correct, future code developments, despite efforts to the contrary, might introduce new or reveal existing subtle model errors. This is not a reason to reject such code developments, as they will likely bring significant benefits through reduced computation time or increased spatial or temporal resolution. Instead, a continuing process of regular benchmarking will guard against this risk. Benchmarking checks for consistency between solutions obtained by independent numerical codes to the same storage simulation problems. Sometimes, model errors may arise due to the manner of application of a numerical code to a storage simulation task. The use of existing modelling standards, guidelines and assurance processes help to prevent these errors.

6.2.1.3 Additional Safeguards against Uncertainty in Predictions

Uncertainty estimates prior to injection should be large enough to include the actual storage performance observed during injection but small enough to allow regulatory approval before CO_2 injection commences. Uncertainty about the ultimate storage performance will be greatest prior to injection, but these should undergo progressive reduction during injection as updated models include more and more information from the observed storage performance. A final additional safeguard is to access new monitoring technology developments that increase the reliability or frequency of monitoring information without increasing costs.

6.2.1.4 Additional Safeguards against Monitoring Errors

Deploying only qualified monitoring technologies should reduce the likelihood of monitoring errors. Qualification is gained either because the technology is a widely accepted industry practise or through a validated field trial performance. Application of technical standards, guidelines and assurance processes for the acquisition, processing and interpretation of monitoring data provide a further safeguard.

6.2.2 Additional Corrective Measures

Revised storage performance models may forecast a state outside the predicted range of storage states. If this is not tolerable, then several control measures exist to correct this trend before any loss of conformance arises. For example, if injection rates are tending to decline and routine well interventions have no impact, then drilling an additional injector should correct this trend before the initial spare injection capacity is insufficient to maintain the target injection rate. These control measures include, but are not limited to:

- re-distributing injection across existing wells
- drilling new vertical or horizontal injectors
- drilling additional wells to extract reservoir fluids and re-inject elsewhere
- stopping injection

6.3 Additional Containment Safeguards

There are additional containment safeguards through MMV activities. Each of these active safeguards requires three key components to be effective:

1. **a sensor** capable of detecting changes with sufficient sensitivity and reliability to provide an early indication that some form of intervention is required.
2. **decision logic** to interpret the sensor data and select the most appropriate form of intervention.
3. **a control response** capable of effective intervention to ensure continuing containment or to control the effects of any potential loss of containment.

As before, a single barrier may be effective against multiple threats. However, for multiple active barriers to be effective against a single threat none can share the same detector, or decision logic, or control response. Otherwise, a single point failure would disable the entire group of barriers.

There is an important distinction between prevention and correction measures. From a precautionary standpoint, deep monitoring that prompts early intervention to avoid any loss of containment is preferred. However, these monitoring techniques might be less effective and more expensive than shallow monitoring alternatives. In this case, a proper balance between prevention and correction will achieve better outcomes from the same finite resource.

6.3.1 Additional Preventative Measures

Table 6-1 summarizes the control response options for preventing any loss of containment. There are two categories.

1. **Injection controls** to change the manner of CO_2 injection into the storage complex. These include re-distributing injections rates across existing wells, drilling additional injectors, drilling producers and re-injectors to manage reservoir pressures, and stopping injection.
2. **Well interventions** to restore well integrity. These include repairing the cement bond, replacing the completion, or abandoning a well that cannot be repaired.

Table 6-1 Remediation Measures

	Remediation Method	Type	Evidence For	Evidence Against
RM8	Pump and Treat	Active, Physical, Ex-Situ	1. Can remove contaminants from shallow to deep depths 2. Relatively insensitive to the nature of contaminants 3. Can be quick where hydraulic characteristics are good 4. Uses conventional wastewater treatment processes 5. Effluent quality can be easily monitored	1. Can be problematic if hydraulic characteristics are unfavourable 2. Requires ongoing source of power 3. Relatively high capital cost 4. Requires operational maintenance of equipment 5. Necessitates handling of produced water 6. Can be challenging in winter environments
RM9	Air Sparging or Vapour Extraction	Active, Physical, Ex-Situ	1. Remediation of gaseous and dissolved contaminants 2. Can be used as a means of exposure control	1. Can be problematic if hydraulic characteristics are unfavourable 2. Generally limited to volatile contaminants 3. Limited to contaminants near the vadose zone 4. Requires ongoing source of power 5. Relatively high capital cost 6. Requires operational maintenance of equipment 7. Necessitates scrubbing of effluent 8. Diminishing returns as contaminants become less concentrated 9. Can be challenging in winter environments
RM10	Multi-phase Extraction	Active, Physical, Ex-Situ	1. Removes gaseous, free liquid and dissolved contaminants 2. Relatively quick removal of concentrated contamination 3. Relatively insensitive to nature of contaminants	1. Can be problematic if hydraulic characteristics are unfavourable 2. Requires ongoing source of power 3. Relatively high capital cost. 4. Requires operational maintenance of equipment 5. Limited to contamination near the water table 6. Necessitates handling of produced fluids.
RM11	Chemical Oxidation	Active, Chemical, In-Situ	1. Removes contaminants from shallow & intermediate depths 2. Relatively low surface disturbance 3. Relatively quick degradation of organic contaminants 4. Able to treat high concentrations of contaminants 5. Does not require handling of produced groundwater	1. Can be problematic if hydraulic characteristics are unfavourable 2. Requires operational maintenance of equipment 3. Can be corrosive for other underground infrastructure 4. Potential for Health and Safety Issues
RM12	Bioremediation	Active or Passive, Biological, In-Situ	1. Relatively low surface disturbance 2. Does not require handling of produced groundwater 3. Relatively low capital cost	1. Generally limited to organic contaminants 2. May not be suitable for highly concentrated or toxic contaminants 3. Requires operational maintenance of equipment 4. Can be challenging in winter environments

Table 6-1 Remediation Measures (cont'd)

	Remediation Method	Type	Evidence For	Evidence Against
RM13	Electrokinetic Remediation	Active, Physical and Chemical, In-Situ	1. Treats inorganic contaminants not easily treated otherwise 2. Can be used in areas of low permeability	1. Requires source of power 2. Requires eventual groundwater extraction to remove contaminants that have not been immobilized 3. Relatively immature technology
RM14	Phytoremediation	Passive, Biological, In-Situ	1. Relatively passive method of remediation requiring little operational maintenance 2. Relatively low capital cost 3. Treats inorganic contaminants not easily treated otherwise	1. Limited to very shallow contamination 2. Requires periodic removal and disposal of plants 3. May not be suitable for contaminants with high toxicity or concentration 4. Requires a high level of ongoing monitoring 5. Generally long term remedial method 6. Can be challenging in winter environments
RM15	Monitored Natural Attenuation	Passive, Physical and Chemical and Biological, In-Situ	1. Requires little operational maintenance 2. Relatively low cost in the short to medium term. 3. Relatively low surface disturbance	1. Requires a high level of subsurface assessment 2. Requires a high level of ongoing monitoring 3. Generally a long term remedial method 4. May not be acceptable to all stakeholders
RM16	Permeable Reactive Barriers	Passive, Chemical, In-Situ	1. Requires little operational maintenance 2. Treats inorganic contaminants not easily treated otherwise	1. Limited to shallow to intermediate depths of contamination 2. Requires a high level of ongoing monitoring 3. Capital costs increase markedly with depth 4. Barriers may need replacing

6.3.1.1 Additional Safeguards for Legacy Wells

Intervention in any legacy well is not a straightforward option due to their nature of abandonment and ownership. However, controlling CO_2 injection does provide several options to respond to any indications of unexpected pressure build-up around a legacy well of suspect integrity. Examples are:

- Reducing injection rates of wells closest to the suspect legacy wells and increasing rates elsewhere to compensate should sufficiently delay further pressure build-up around the legacy well (IC1).
- If not, stopping injection at the closest wells may alleviate the situation (IC4) and then drilling any replacement injectors necessary (IC2).
- Finally, intervention in the legacy well to re-plug with cement (WI1) or drilling producers to prevent further pressure build-up (IC3) may be required.
- Drill a dedicated water production well to alleviate pressure (IC3)

6.3.1.2 Additional Safeguards for Observation Wells

Ready access to observation wells makes well intervention options attractive. Any observation well of suspected integrity might be remedied through:

- re-cementing (WI1), or replacing the completion (WI2)
- well abandonment (WI3)
- reducing or stopping CO_2 injection in the nearby injector.(IC1, IC4)

6.3.1.3 Additional Safeguards for Injectors

The additional safeguards described for observation wells (WI1, WI2, WI3, IC1, and IC4) are also effective for injectors for the same reasons. Different or more monitoring solutions may be required due to the greater containment threat posed by injectors, especially if observed wells never penetrate the ultimate seal.

6.3.1.4 Additional Safeguards against Matrix Pathways

Indications of upward fluid migration along a matrix pathway can trigger a re-distribution of injection rates across existing injectors (IC1) and may necessitate drilling additional injectors (IC2) or extracting fluids to create a hydraulic barrier (IC3).

6.3.1.5 Additional Safeguards against Fault Pathways

The additional safeguards against migration along matrix pathways (IC1, IC2, and IC3) are also effective against migration along fault pathways for the same reasons. Different monitoring solutions may be required to detect fluids migrating along fault rather than matrix pathways.

6.3.1.6 Additional Safeguards against Re-activating Faults

Indications of any fault re-activation will trigger interventions to reduce the likelihood of continued fault slip threatening containment. These interventions may include:

- reduction of injection rates close to the re-activated fault to delay and maybe prevent any further pressure build-up (IC1)

- stopping injection (IC4) whilst drilling one or more injectors to maintain injectivity (IC2)
- drilling one or more producers and extracting fluids (IC3) to avoid the threat

6.3.1.7 Additional Safeguards against Opening Fractures

Interventions that delay, avoid, or reverse pressure build-up around injectors can arrest any upwards propagating opening fractures before they transect the ultimate seal.

- reducing injection rates of the closest injector may be sufficient (IC1)
- drilling additional injectors (IC2) to allow further reductions of injection rate into the suspect well or even stopping injection into this well (IC4) should suffice
- drilling producers to extract fluids and reduce pressures inside the BCS (IC3), and potentially stopping all injection (IC4), provides an ultimate safeguard

6.3.1.8 Additional Safeguards against Acidic Fluids

The number and quality of natural geological safeguards against acidic fluids eroding seals leaves almost no requirement for additional active safeguards. Nonetheless, should monitoring indicate migration of fluids upwards towards the ultimate seal then interventions such as reducing (IC1) or stopping (IC4) injection near this location will prevent any loss of containment even if this particular cause is not identified.

6.3.1.9 Additional Safeguards against Third-Party Activities

Third-party activities may accidentally cause environmental impacts within the AOR that create a perceived loss of containment from the BCS storage complex. Without safeguards in place to correct this perception, it will likely trigger disruptive and ineffective interventions to CO_2 injection and may require costly remediation efforts that inappropriately raise the cost of CO_2 storage. Monitoring activities that demonstrate the source of such environmental impact is not this CO_2 storage project or is attributable to a third party help safeguard the Project.

6.3.2 Additional Corrective Measures

Tables 5-4 and 6-1 summarize the corrective control response options for avoiding, limiting, or recovering from any significant impacts in the unlikely event of CO_2 or displaced BCS brine migrating above the Upper Lotsberg Salt. There are three categories.

1. **Well interventions** to restore well integrity. These include repairing the cement bond, replacing the completion, or abandoning a well that cannot be repaired. These are different to the preventative well interventions. Preventative and corrective well interventions aim to restore well integrity below and above the ultimate seal respectively.
2. **Exposure controls** to prevent contaminants reaching sensitive environmental domains where significant impacts might occur such as the protected groundwater zone.
3. **Remediation measures** to recover from any significant impacts in the unlikely event of an uncorrected loss of containment.

6.3.2.1 Additional Safeguards to Protect the Winnipegosis

No additional safeguards appear necessary to protect the Winnipegosis, the second deepest saline aquifer. The only impact is the lost opportunity for a potential additional independent CCS development. In this situation, no CO_2 storage capacity is lost as it effectively joins the BCS storage complex.

Nonetheless, any loss of well integrity resulting in CO_2 or BCS brine entering the Winnipegosis requires correction by repairing any impaired cement bond (RM1), or replacing any impaired part of the well completion (RM2). Should these measures fail, it always remains possible to plug and abandon the well (RM3).

6.3.2.2 Additional Safeguards to Protect Hydrocarbon Resources

Well interventions (RM1, RM2 and RM3) would correct any loss of well integrity resulting in migration of CO_2 or BCS brine into hydrocarbon bearing formations. When necessary, drilling a dedicated well to inject water as a hydraulic barrier (RM), offers scope to block any migration pathways detected elsewhere.

6.3.2.3 Additional Safeguards to Protect Groundwater

The GPZ is potentially the most sensitive environmental domain and therefore likely requires the greatest number of additional safeguards. Any indication of changes to water quality, which if uncorrected might eventually lead to exceeding water quality guidelines, should trigger one or several additional control measures.

Well interventions (RM1, RM2 or RM3) allow options to immediately correct any suspected loss of well integrity within this zone. Exposure controls (RM4, RM6 and RM7) can avoid or delay any impacts in the unlikely event of an uncontrolled migration of CO_2 or BCS brine towards the Base of Groundwater Protection (BGGWP). Should all earlier safeguards prove insufficient to avoid contaminating some part of the protected groundwater, then prompt remediation measures will likely reverse these impacts before they can become significant. Contamination of the deepest parts of the BGWP requires a certain type of remediation (as per Table 6-1) The Bow-tie includes as representation of these safeguards RM1, RM6, RM8 etc as depending on individual circumstances not all options are likely to be effective. Each of these control options require either wellbore or groundwater monitoring of sufficient sensitivity and frequency to provide an early warning that allows intervention before any significant impacts occur, such as impacting the current potable water quality. Section 6.5 describes provisions for just such a hydrosphere monitoring system.

6.3.2.4 Additional Safeguards to Protect Soils

Any indication of early soil acidification or brine incursion would trigger control measures to remove the source of potential contamination (as per Table 6-1). The Bow-tie includes as representation of these safeguards RM1, RM2 or RM3, or limit exposure of the soil (RM4, RM6) and if necessary recovery from any significant impacts to soil quality (RM9 and RM17).

Section 6.5 describes provisions for a biosphere monitoring system of sufficient sensitivity and frequency to allow early interventions before any significant loss of soil quality occurs.

6.3.2.5 Additional Safeguards to Prevent CO_2 Entering the Atmosphere

CO_2 inventory reporting requires monitoring for any CO_2 emissions from the storage complex into the atmosphere. Any indication of CO_2 fluxes in excess of natural variations will trigger further investigation. Isotopic analysis of this CO_2 will likely distinguish between natural sources and emissions from the storage complex. If emissions do arise from the storage complex and occur close to an injector or observation well then well interventions (RM1, RM2 or RM3) may prevent any further emissions. Should these emissions arise elsewhere or well interventions fail, then exposure control measures (RM4, RM5) will be implemented.

6.3.3 Routine versus Contingency Monitoring Requirements

Decision logic informed by information gained through monitoring activities will trigger these interventions. Therefore:

- These monitoring activities will be part of the routine monitoring program.
- The detection systems designed to trigger corrective interventions cannot be part of contingency monitoring plans held in reserve and only deployed in the event of detecting the occurrence of the top event. If this were so, then any failure to detect the top event would render all active correction measures useless.
- To be effective, independent monitoring systems will trigger each active corrective safeguard.
- The role of contingency monitoring plans is to characterise any environmental impacts subsequent to their detection and to verify the effectiveness of any recovery measures.

6.4 Assessment of Monitoring Technologies

This section evaluates the many reasons and methods for monitoring storage performance to achieve two goals.

1. Judge the expected effectiveness of safeguards dependent of monitoring capabilities.
2. Generate a ranked list of monitoring technologies capable of performing each monitoring task.

This assessment provides the framework to select monitoring technologies for inclusion in the MMV plan but does *not* make a selection. Selection of initial monitoring activities still depends on the outcome of:

1. ongoing appraisal activities
2. the results of field trials
3. pre-injection baseline data acquisition
4. the first years of operational monitoring

Through time, the selected monitoring solutions must be adapted to respond to new threats or opportunities as they emerge.

Lack of certainty about the future performance of individual monitoring systems within the AOR dictates the need for an adaptive rather than a prescriptive monitoring plan, for the following reasons:

- Single monitoring solutions may fail or exceed expectations for unforeseen reasons.
- Adaptive monitoring means allowing sufficient flexibility and redundancy to respond to these changing circumstances.
- Prescriptive monitoring with no flexibility to adapt through time to local site conditions appears less complex and less expensive only if we ignore uncertainties about future monitoring performance.

6.4.1 Method of Assessment

The method adopted for assessing monitoring technologies is as follows.

1. Define the monitoring tasks required to support the identified active safeguards.
2. Identify candidate monitoring technologies with potential to fulfill at least one monitoring task.
3. Screen the candidate technologies against the tasks assuming the information gained is both free and perfect, and then regret any still judged incapable of the task.
4. Evaluate the effectiveness of technologies against the tasks using expert opinions. Document this process by recording and scoring evidence for and against including any uncertainty.
5. Estimate the lifecycle monitoring costs of each technology.
6. Estimate the lifecycle benefits generated by each technology in terms of risk reduction.
7. Rank technologies according to their overall benefits and costs to the Project.
8. Evaluate the effectiveness of the identified active safeguards triggered by high-ranking monitoring technologies.

6.4.2 Identification of Monitoring Tasks

Table 6-2 lists the monitoring tasks required to support each active safeguard identified to protect conformance (Section 7.2) and containment (Section 7.3) risks.

These tasks divide into four distinct groups:

1. **Containment monitoring tasks below the Upper Lotsberg Salt**: To trigger preventative controls to avoid or reduce the likelihood of fluids migrating above the BCS storage complex.
2. **Containment monitoring tasks above the Upper Lotsberg Salt**: In the unlikely event of any loss of containment, this monitoring will be designed to:
   a. Trigger corrective controls to avoid or reduce the likelihood of significant environmental impacts.
   b. Contingencies must also exist to allow for additional monitoring in the event of any detected loss of containment to characterize the impact and verify the efficacy of any correction measures applied.

3. **Conformance monitoring tasks within the BCS storage complex**: To verify that the build-up and migration of pore fluid pressures and CO_2 through time remains consistent with the range of published forecasts and provide the necessary information to revise and narrow the range of these forecasts whenever appropriate.
4. CO_2 inventory measurement tasks: To report the rate and volume of CO_2 injected into the storage complex and potentially emitted from the storage complex into the atmosphere.

Table 6-2 Monitoring Tasks Included Within the MMV Plan

Monitoring Tasks	
Containment Monitoring Tasks Below the Upper Lotsburg Salt	
T1	Detect migration of CO2 or brine along a legacy well
T2	Detect migration of CO2 or brine along a MMV well
T3	Detect migration of CO2 or brine along an injector
T4	Detect migration of CO2 or brine along matrix pathways
T5	Detect migration of CO2 or brine along a fault pathway
T6	Detect fault reactivation
T7	Detect induced fractures opening
T8	Detect fluid migration through pathways created by acidic fluids
T9	Third -party activities induce CO2 or brine migration
Containment Monitoring Tasks Above the Upper Lotsburg Salt	
C1	Detect CO2 or brine entering the Winnipegosis
C2	Detect and characterise any contamination of protected groundwater
C3	Detect and characterise any contamination of surface soils
C4	Detect and quantify any CO2 releases into the atmosphere
Conformance Monitoring Tasks within the BCS	
S1	Detect migration of CO2 within the BCS
S2	Detect migration of pressure within the BCS
CO2 Inventory Measurement Tasks	
I1	Monitor injection pressure per well
I2	Monitor injection rate per well
I3	Monitor injection volume per well
I4	Monitor total injection volume

6.4.3 Identification of Monitoring Technologies

The 56 identified monitoring technologies were drawn from a range of authoritative sources proposing technologies suitable for MMV (IPCC 2006; IEA 2006; EPA 2008; NETL 2009; Chadwick et al. 2008; BGS 2010) and supplemented by expert knowledge available within the Shell Group. There are various approaches to classifying these technologies to ease discussion, each with their own difficulties. The categories adopted here are as follows.

1. **In-Well Monitoring**: These are direct measurements of down-hole changes made either by permanent sensors incorporated into the well design, or by occasional petrophysical logging or well integrity testing activities that require well intervention. This group of technologies provides detailed information about changes within the well and the near-well environment (e.g. within 5 m), but provides no information about changes further afield.
2. **Geochemical Monitoring**: These are the methods of monitoring chemical changes throughout the subsurface using geochemical measurements within observation wells. These measurements are made either by permanent sensors incorporated into the well design, or through the occasional collection of fluid samples from the well for laboratory analysis. This group of technologies may provide detailed information about the transport and reaction of chemical species above the storage complex indicative of any loss of containment and its potential impacts.
3. **Geophysical Monitoring**: These are the methods of monitoring physical changes throughout the subsurface using remote-sensing techniques. This group of technologies may provide detailed images of the spatial distribution of CO_2 and increased pore fluid pressures within or above the storage complex.
4. **Near-Surface Monitoring**: These are the methods of monitoring near-surface changes within the biosphere or atmosphere.

Many technologies within the first three categories depend on sensors within wells – four different types of wells may support these kinds of monitoring:

a. **CO_2 injection wells in the BCS:** The measurements maybe taken either during the injection period and/or in the post-injection but pre-abandonment phase.

b. **Observation wells in the BCS**: To provide additional direct monitoring opportunities inside the storage complex.

c. **Observation wells in the Winnipegosis**: To provide direct monitoring opportunities within the first permeable formation above the ultimate seal.

d. **Observation wells in the Protected Groundwater Zone**: To provide direct monitoring opportunities to verify the absence of any adverse impacts to groundwater quality or provide early warning of the need for corrective measures to protect groundwater quality.

Only the first type of wells is a necessity. The other three types are options available for inclusion within the MMV program just like any of the monitoring technologies themselves. Appraisal activities for site characterisation are not yet complete, until then the target depths for observation wells remain subject to change. For example, permeability within the Winnipegosis may be insufficient or too uncertain to support the required monitoring tasks. In this case, other permeable formations above the storage complex and below the protected groundwater such as the Cooking Lake saline aquifer might offer better opportunities for monitoring.

Together, all the identified monitoring technologies possess a wide range of complimentary and overlapping capabilities (Table 6-3) with varying degrees of sensitivity, resolution, reliability and cost.

6.4.4 Technology Screening and Evaluation

The next step is to simplify the evaluation of these technologies by screening their known capabilities against the monitoring requirements. This was completed in two steps:

1. **Technology screening**: Table 6-4 summarizes the effectiveness of the numerous identified technologies against their ability to perform the identified monitoring tasks.
2. **Technology Evaluation**: Each technology that survived the screening process its effectiveness to perform the identified monitoring tasks was assessed according to the following criterion: **Evaluation Criterion:** The monitoring technique is fast enough, precise enough, and big enough to trigger the control response correctly.

Figure 6-1 and Figure 6-2 summarizes these results for all containment and conformance monitoring tasks respectively. For each containment-monitoring task, there is a wide range of partially effective monitoring technologies. No monitoring technology is perfect – but the combination of multiple technologies with different imperfections provides a highly effective integrated monitoring system. Although the final evaluation of these technologies depends on the conclusion of the ongoing appraisal activities – there are clearly many highly effective technology combinations available to fulfill the monitoring requirements.

Table 6-3 Monitoring Technologies – Technical Capabilities

Monitoring System		Information Gained	Availability	Coverage
Well Monitoring				
Cement bond logs	CBL	Initial quality of cement bond	Once, during well completion	Entire well length
Time-lapse ultrasonic casing imaging	USIT	Casing corrosion detection	During well intervention	Injection and monitoring wells
Time-lapse EM casing imaging	EMIT	Casing corrosion detection	During well intervention	Injection and monitoring wells
Time-lapse multi-finger calliper	CAL	Tubing corrosion detection	On demand	Injection wells
Annulus pressure monitoring	APM	Pressure leak detection	Continuously	Injection and monitoring wells
Injection rate metering at wellhead	IRM	Rate and volume of CO2 injected	Continuously	Injection wells
Wellhead pressure-temperature gauge	WHPT	Injection pressure, temperature	Continuously	Injection wells
Operational Integrity Assurance System	OIA	Exception based well monitoring	Continuously	Injection wells
Down-hole pressure-temperature gauge	DHPT	Downhole pressure, temperature	Continuously	Injection and monitoring wells
Mechanical well integrity pressure testing	MWIT	Leak detection	On demand	Injection and monitoring wells
Well-head CO2 detectors	WHCO2	CO2 leak detection	Continuously	Injection and monitoring wells
Tracer injection & gamma logging	TRL	Leak detection & CO2 conformance	Continuosly / On demand	Injection and monitoring wells
Time-lapse saturation logging	SATL	Leak detection & injection profile	During well intervention	Injection and monitoring wells
Time-lapse temperature logging	TMPL	Leak detection outside casing	During well intervention	Injection and monitoring wells
Time-lapse annular flow noise logging	AFNL	Leak detection outside casing	During well intervention	Entire borehole
Time-lapse density logging	DENL	Leak detection outside casing	During well intervention	Entire borehole
Time-lapse sonic logging	SONIC	Leak detection outside casing	During well intervention	Entire borehole
Fibre-optic distributed temperature sensing	DTS	Leak detection outside casing	Continuously	Entire length of FO down-hole
Fibre-optic distributed pressure sensing	DPS	Leak detection outside casing	Continuously	Many discrete locations down-hole
Real time casing imager	RTCI	Leak detection outside casing	Continuously	Region of wrapped FO down-hole
Fibre-optic distributed acoustic sensing	DAS	Leak detection outside casing	Continuously	Entire length of FO down-hole
Pressure interference testing	PIT	Fraction of path containing CO2	On demand	Injection and monitoring wells
Pressure fall-off test	PFOT	Storage capacity	On demand	Injection wells

Table 6-3 Monitoring Technologies – Technical Capabilities (cont'd)

Monitoring System		Information Gained	Availability	Coverage
Geochemical Monitoring				
Water chemistry monitoring	WC	Leak detection, storage mechanisms	On demand	Monitoring wells
Down-hole electrical conductivity monitoring	WEC	Brine leak detection & impact assessment	Continuously	Monitoring wells
Downhole pH monitoring	WPH	CO2 leak detection & impact assessment	Continuously	Monitoring wells
Artificial tracer monitoring	ATM	Leak detection & impact assessment	On demand	Monitoring wells
Natural isotope tracer monitoring	NTM	Leak detection & impact assessment	on demand	Monitoring wells
U-tube fluid sampling	UTUBE	Leak detection, storage mechanisms	Continuous, or on-demand	Monitoring wells
Isotube fluid sampling	ITUBE	Leak detection, storage mechanisms	Continuous, or on-demand	Monitoring wells
Ground water gas analysis	GWG	Leak detection & impact assessment	On demand	Discrete locations across AOR
Soil CO2 gas flux surveys	SGF	CO2 leak detection & impact assessment	On demand	Discrete locations across AOR
Soil CO2 gas concentration surveys	SGC	CO2 leak detection & impact assessment	On demand	Discrete locations across AOR
Soil pH surveys	SPH	CO2 leak detection & impact assessment	On demand	Discrete locations across AOR
Soil salinity surveys	SSAL	Brine leak detection & impact assessment	On demand	Discrete locations across AOR

Table 6-3 Monitoring Technologies – Technical Capabilities (cont'd)

Monitoring System		Information Gained	Availability	Coverage
Geophysical Monitoring				
Time-lapse 3D vertical seismic profiling	VSP3D	3D distribution of CO2 plume	On demand, winter only	Within 1km of the wellbore
Time-lapse surface 3D seismic	SEIS3D	3D distribution of CO2 plume	On demand, winter only	Entire CO2 plume
Time-lapse surface 2D seismic	SEIS2D	2D distribution of CO2 plume	On demand, winter only	Entire CO2 plume
Surface microseismic monitoring	SMS	Microseismic catalogue	Continuously, or on demand	Underneath geophone array
Down-hole microseismic monitoring	DHMS	Microseismic catalogue	Continuously, or on demand	<600m of monitoring well geophones
Time-lapse surface microgravity	SGRAV	Areal distribution of CO2 plume	On demand	Entire CO2 plume
Time-lapse down-hole microgravity	DHGRAV	Detection of CO2 plume near borehole	On demand	Monitoring wells
Time-lapse surface controlled source EM	CSEM	Spatial distribution of CO2 plume	On demand, winter only	Entire CO2 plume
Time-lapse cross-well controlled source EM	CSEMX	Cross-well distribution of CO2 plume	On demand	Section between wells within c. 500m
Time-lapse cross-well seismic	SEISX	2D distribution of CO2 plume	On demand	Section between wells within c. 500m
Magnetotelluric - natural source EM	NSEM	Spatial distribution of CO2 plume	On demand, winter only	Entire CO2 plume
InSAR - Interferometric Synthetic Aperture Radar	INSAR	Pressure front & fault re-activation	Monthly	Entire region of elevated pressure
GPS - Global Positioning System	GPS	Pressure front & fault re-activation	Continuously or on demand	Entire region of elevated pressure
Surface tiltmeters	STLT	Pressure front & fault re-activation	Continuously	Entire region of elevated pressure
Down-hole tiltmeters	DHTLT	Vertical distribution of pressure changes	Continuously	Monitoring wells
Surface Monitoring				
DIAL - Differential absorption LIDAR	DIAL	CO2 leakage rate to atmosphere	On demand	Areal coverage over parts of AOR
Line-of-sight gas flux monitoring	LOSCO2	CO2 leakage rate to atmosphere	Continuously or on demand	Areal coverage over parts of AOR
Atmospheric eddy correlation	AEC	CO2 leakage rate to atmosphere	On demand	Discrete locations across AOR
Airborne infra-red laser gas analysis	AIRGA	CO2 leakage rate to atmosphere	On demand	Areal coverage of entire AOR
Hand-held infra-red gas analysers	HIRGA	Leak detection & impact assessment	On demand	Discrete locations across AOR
Satellite or airborne hyperspectral image analysis	HIA	Leak detection & impact assessment	Monthly	Entire AOR and beyond
Ecosystem studies	ESS	Leak detection & impact assessment	On demand	Discrete locations across AOR

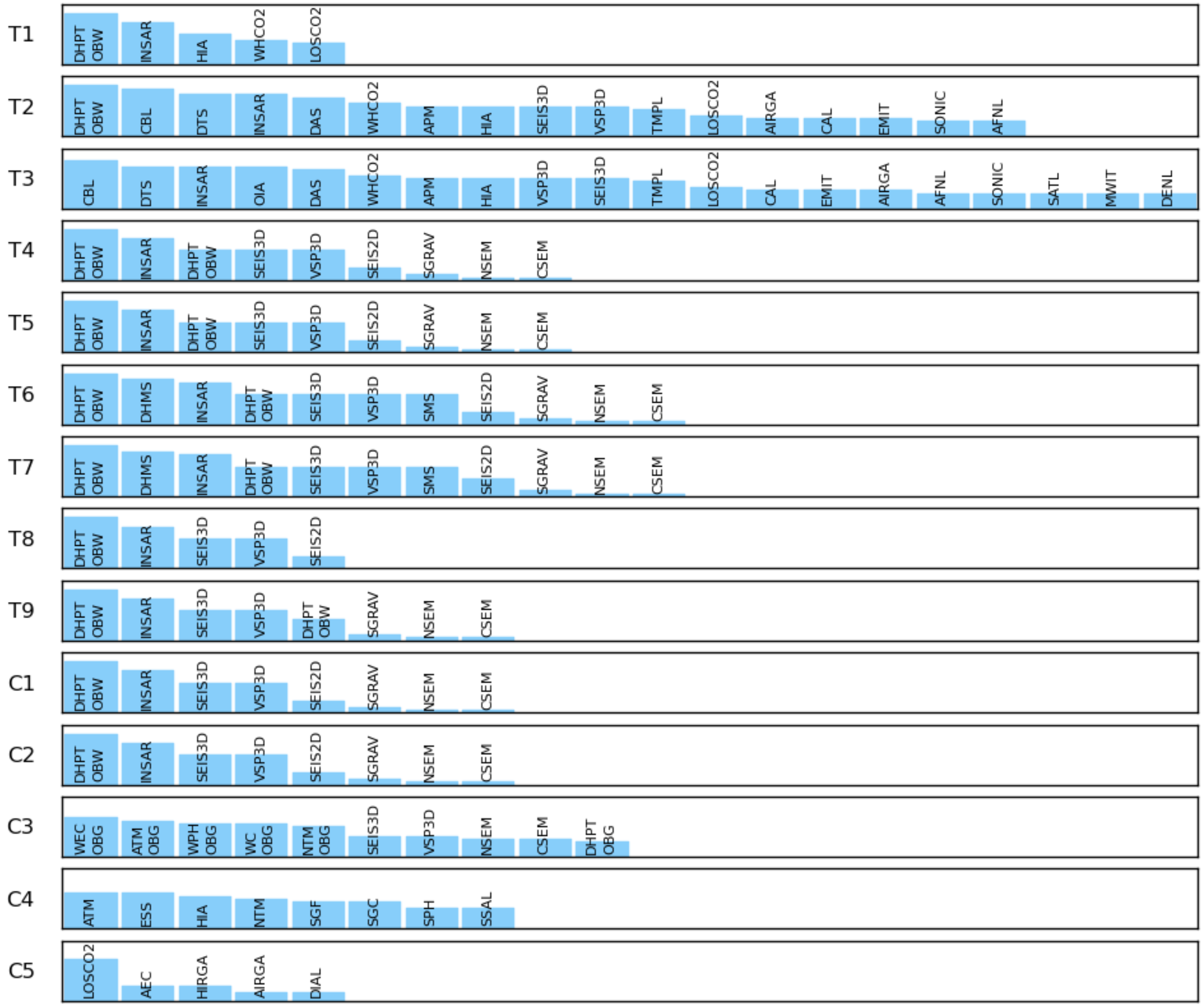
NOTE: The monitoring technologies considered for MMV have a diverse and overlapping range of technical capabilities.

Table 6-4 Candidate Monitoring Technologies

Candidate Monitoring Systems

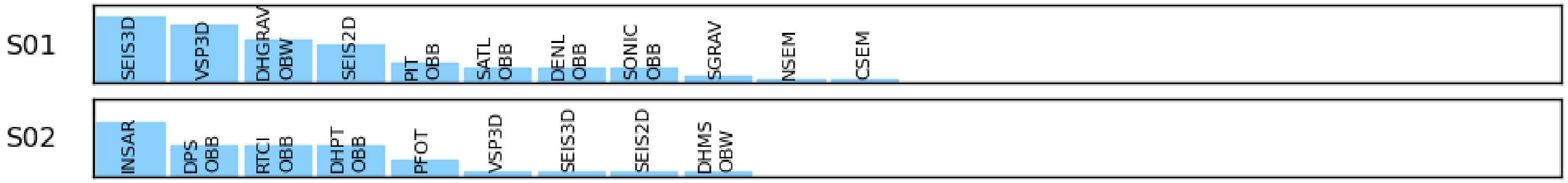
			Wells				In-Well Monitoring																							Geochemical												Geophysical															Surface							
		Monitoring Tasks	Injection wells	Observation wells in BCS	Observation wells in WPGS	Observation wells in GWPZ	Cement bond logs	Time-lapse ultrasonic casing imaging	Time-lapse EM casing imaging	Time-lapse multi-finger caliper	Annulus pressure monitoring	Injection rate metering at wellhead	Wellhead pressure-temperature gauge	Operational Integrity Assurance System	Down-hole pressure-temperature gauge	Mechanical well integrity pressure testing	Well-head CO2 detectors	Tracer injection & gamma logging	Time-lapse saturation logging	Time-lapse temperature logging	Time-lapse annular flow noise logging	Time-lapse density logging	Time-lapse sonic logging	Fibre-optic distributed temperature sensing	Fibre-optic distributed pressure sensing	Real time casing imager	Fibre-optic distributed acoustic sensing	Pressure interference testing	Pressure fall-off test	Water chemistry monitoring	Down-hole electrical conductivity monitoring	Downhole pH monitoring	Artificial tracer monitoring	Natural isotope tracer monitoring	U-tube fluid sampling	Isotube fluid sampling	Ground water gas analysis	Soil CO2 gas flux surveys	Soil CO2 gas concentration surveys	Soil pH surveys	Soil salinity surveys	Time-lapse 3D vertical seismic profiling	Time-lapse surface 3D seismic	Time-lapse surface 2D seismic	Surface microseismic monitoring	Down-hole microseismic monitoring	Time-lapse surface microgravity	Time-lapse down-hole microgravity	Time-lapse surface controlled source EM	Time-lapse cross-well controlled source EM	Time-lapse cross-well seismic	Magnetotelluric - natural source EM	InSAR - Interferometric Synthetic Aperture Radar	GPS - Global Positioning System	Surface tiltmeters	Down-hole tiltmeters	DIAL - Differential absorption LIDAR	Line-of-sight gas flux monitoring	Atmospheric eddy correlation	Airborne infra-red laser gas analysis	Hand-held infra-red gas analysers	Satellite or airborne hyperspectral image analysis	Ecosystem studies	
Containment	Below Salt	Detect migration of CO2 or brine along a legacy well	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	●	○	○	○	●	●	●	●	●	●	●	1
		Detect migration of CO2 or brine along a MMV well	○	●	○	○	●	●	●	●	●	○	○	○	●	●	●	○	○	●	●	●	●	●	●	●	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	○	○	●	●	●	○	○	●	●	○	○	○	●	●	●	●	●	●	●	2
		Detect migration of CO2 or brine along an injector	●	○	○	○	●	●	●	●	●	○	●	●	●	●	●	●	○	●	●	●	●	●	●	●	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	○	○	●	●	●	○	○	●	●	○	○	○	●	●	●	●	●	●	●	3
		Detect migration of CO2 or brine via matrix pathways	○	○	●	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	○	○	●	●	●	○	○	●	●	○	○	○	○	○	○	○	○	○	○	4
		Detect migration of CO2 or brine along fault pathways	○	○	●	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	○	○	●	●	●	○	○	●	●	○	○	○	○	○	○	○	○	○	○	5
		Detect fault reactivation	○	●	●	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	●	●	●	●	●	○	○	●	●	○	○	○	○	○	○	○	○	○	○	6
		Detect induced fractures opening	○	●	●	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	●	●	●	●	●	○	○	●	●	○	○	○	○	○	○	○	○	○	○	7
		Third-party activities induce CO2 or brine migration	○	○	●	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	○	○	●	●	●	○	○	●	●	○	○	○	○	○	○	○	○	○	○	8
	Above Salt	Detect CO2 or brine entering the Winnipegosis	○	○	●	○	○	○	○	○	○	○	○	○	●	○	○	●	●	●	●	●	●	○	○	○	○	○	○	●	●	●	●	●	●	●	○	○	○	○	○	●	●	●	○	○	●	●	●	○	○	●	○	○	○	○	○	○	○	○	○	○	○	9
		Detect CO2 entering HC resources	○	○	●	○	○	○	○	○	○	○	○	○	●	○	○	●	●	●	●	●	●	○	○	○	○	○	○	●	●	●	●	●	●	●	○	○	○	○	○	●	●	●	○	○	●	●	●	○	○	●	○	○	○	○	○	○	○	○	○	○	○	10
		Detect & characterise groundwater contamination	○	○	○	●	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	●	●	●	●	●	○	○	○	○	●	●	●	○	○	●	●	●	○	○	●	○	○	○	○	○	○	○	○	○	○	○	11
		Detect & characterise surface soils contamination	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	12
		Measure any CO2 releases into the atmosphere	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	●	●	○	○	13
Conformance	BCS	Detect migration of CO2 within the BCS	●	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	●	○	○	●	●	○	○	○	○	○	○	●	●	●	●	●	●	●	○	○	○	○	○	●	●	●	○	○	●	●	●	○	○	●	○	○	○	○	○	○	○	○	○	○	○	14
		Detect migration of pressure within the BCS	●	●	○	○	○	○	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	●	●	○	○	●	○	○	○	○	○	○	○	○	○	○	○	○	●	●	●	●	●	○	○	○	○	○	○	●	○	○	○	○	○	○	○	○	○	○	15
	Injection	Monitor injection pressure per well	●	○	○	○	○	○	○	○	○	○	●	●	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	16
		Monitor injection rate per well	●	○	○	○	○	○	○	○	○	●	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	17
		Monitor injection volume per well	●	○	○	○	○	○	○	○	○	●	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	18
		Monitor total injection volume	●	○	○	○	○	○	○	○	○	●	○	●	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	○	19
			INJ	OBB	OBW	OBG	CBL	USIT	EMIT	CAL	APM	IRM	WHPT	OIA	DHPT	MWIT	WHCO2	TRL	SATL	TMPL	AFNL	DENL	SONIC	DTS	DPS	RTCI	DAS	PIT	PFOT	WC	WEC	WPH	ATM	NTM	UTUBE	ITUBE	GWG	SGF	SGC	SPH	SSAL	VSP3D	SEIS3D	SEIS2D	SMS	DHMS	SGRAV	DHGRAV	CSEM	CSEMX	SEISX	NSEM	INSAR	GPS	STLT	DHTLT	DIAL	LOSCO2	AEC	AIRGA	HIRGA	HIA	ESS	
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	28	29	29	30	31	32	33	33	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	

NOTE: Candidate monitoring technologies screened according to their ability to perform the identified monitoring tasks. Open and filled circles denoted combinations screened out and screened in respectively.



NOTE: Monitoring technologies ranked according to their expected effectiveness for each containment monitoring task described in Table 6-3 demonstrate a wide range of viable options exists. The height of each blue bar denotes the expected success rate from 0 to 100%.

Figure 6-1 Ranked Monitoring Technologies for Containment



NOTE: As in Figure 6-1, except for the two key conformance monitoring tasks: measure the distribution of CO_2 inside the BCS (S01), and measure the distribution of pressure inside the BCS (S02).

Figure 6-2 Ranked Monitoring Technologies for Conformance

6.4.5 Technology Ranking

Monitoring for containment is a safety-critical task and takes precedence over conformance monitoring. Therefore, technology ranking considers only the benefits and costs of each technology in relation to the conformance monitoring tasks. Figure 6-3 shows the ranking of each monitoring option according to a combined evaluation of benefits and costs. This cost-benefit assessment is the basis for selecting technologies to perform the containment monitoring tasks. Many of these monitoring technologies will also support the conformance monitoring tasks at the same time for no additional cost. Should, however, some additional monitoring be required to satisfy all the conformance monitoring tasks then these must be justified by a value of information assessment on a case-by-case basis.

6.4.5.1 Ranking Benefits

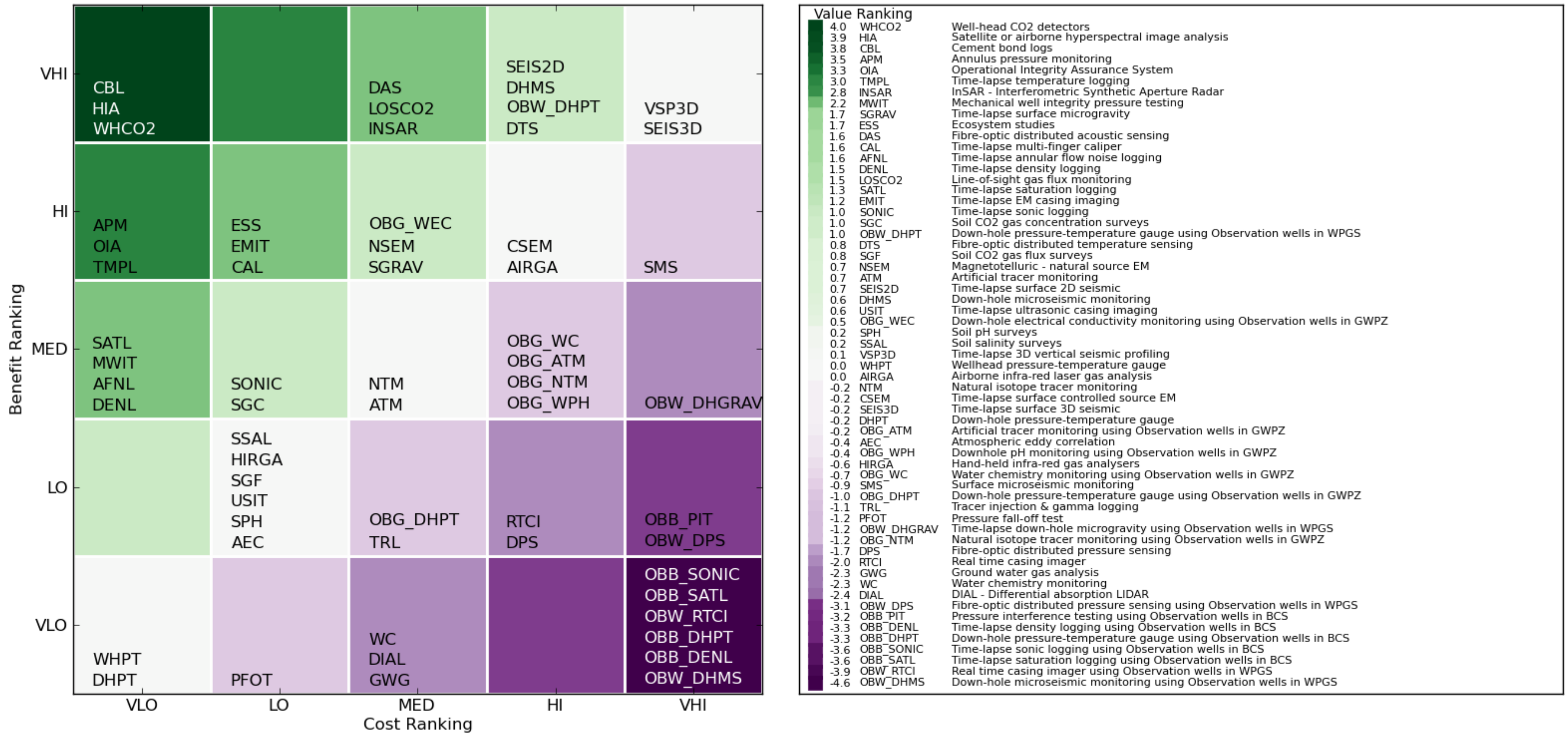
Individual monitoring systems may be applicable to multiple tasks. For instance, time-lapse seismic methods might be highly effective at monitoring the conformance of CO_2 inside the BCS and partially effective at a range of different containment monitoring tasks. The metric used for estimating the total benefit of each technology is simply the number of monitoring tasks weighted by their expected likelihood of success. This is a simple measure useful only for comparing the relative benefits of each technology assuming all monitoring tasks are equally important. This ranking is sufficient to support the matching of monitoring technologies with the active safeguards described in Section 7.3.2.

6.4.5.2 Ranking Costs

The estimated lifecycle costs for each monitoring technology depends on the notional acquisition schedule shown in Table 6-5. Estimates of any initial capital costs and the subsequent operating costs relied on current local market conditions. Figure 6-3 shows the resulting cost ranking. These estimates are not final and remain subject to change.

Figure 6-3 shows a good distribution of costs and benefits. Not all high-benefit technologies are also high cost and several high-cost technologies deliver little benefit. Some care is required when interpreting this 5-by-5 matrix as differences of less than 20% may disappear.

The criteria for selecting monitoring technologies cannot translate to a dividing line on this matrix with everything above the line *in* and everything else *out*. The prime reason for this is that not all technologies are independent, for instance if time-lapse VSP fails then so will 2D and 3D surface seismic. Moreover, if time-lapse 3D surface seismic succeeds then 2D surface seismic provides no new information. Allowance for these inter-dependencies is essential and once again relies on expert judgement.



NOTE: Ranking of monitoring technology options according to a combined evaluation of benefits and costs. Colours denote the difference between the benefit and cost rankings as an indicator of value.

Figure 6-3 Cost Benefit Ranking of MMV Technologies

Table 6-5 Preliminary Monitoring Schedule

Monitoring Systems		Quantity	Frequency 1	Frequency 2	Frequency 3	Frequency 4
Wells						
Injection wells	INJ	5	-	-	-	-
Observation wells in BCS	OBB	5	-	-	-	-
Observation wells in WPGS	OBW	5	-	-	-	-
Observation wells in GWPZ	OBG	15	-	-	-	-
In-Well Monitoring						
Cement bond logs	CBL	10	Once	-	-	-
Time-lapse ultrasonic casing imaging	USIT	10	Once	Every 5 years	Every 10 years	-
Time-lapse EM casing imaging	EMIT	10	Once	Every 5 years	Every 10 years	-
Time-lapse multi-finger caliper	CAL	10	Once	Every 5 years	Every 10 years	-
Annulus pressure monitoring	APM	10	Continuous	Continuous	Continuous	-
Injection rate metering	IRM	5	-	Continuous	-	-
Wellhead pressure-temperature gauge	WHPT	5	-	Continuous	Continuous	-
Operational Integrity Assurance system	OIA		-	Continuous	-	-
Down-hole pressure-temperature gauge	DHPT	10	-	Continuous	Continuous	-
Mechanical well integrity pressure testing	MWIT	5	Once	Every year	Every year	-
Well-head CO2 detectors	WHCO2	10	-	Continuous	Continuous	-
Tracer injection / wireline logging	TRL	1	-	Every 5 years	Every 10 years	-
Time-lapse saturation logging	SATL	10	-	Every 5 years	Every 10 years	-
Time-lapse temperature logging	TMPL	10	-	Every 5 years	Every 10 years	-
Time-lapse annular flow noise logging	AFNL	10	-	Every 5 years	Every 10 years	-
Time-lapse density logging	DENL	10	-	Every 5 years	Every 10 years	-
Time-lapse sonic logging	SONIC	10	-	Every 5 years	Every 10 years	-
Fibre-optic distributed temperature sensing	DTS	10	Continuous	Continuous	Continuous	-
Fibre-optic distributed pressure sensing	DPS	10	Continuous	Continuous	Continuous	-
Real time casing imager	RTCI	10	Continuous	Continuous	Continuous	-
Fibre-optic distributed acoustic sensing	DAS	10	Continuous	Continuous	Continuous	-
Pressure interference testing	PIT	5	-	Every year	Every year	-
Pressure fall-off test	PFOT	5	-	Every year	Every year	-

Table 6-5 Preliminary Monitoring Schedule (cont'd)

Monitoring Systems		Quantity	Frequency 1	Frequency 2	Frequency 3	Frequency 4
Geochemical Monitoring						
Water chemistry monitoring	WC	15	Every year	Every year	Every 2 years	-
Down-hole electrical conductivity monitoring	WEC	15	Continuous	Continuous	Continuous	-
Downhole pH monitoring	WPH	15	Continuous	Continuous	Continuous	-
Artificial tracer monitoring	ATM	1	Every year	Every year	Every 2 years	-
Natural isotope tracer monitoring	NTM	15	Every year	Every year	Every 2 years	-
U-tube fluid sampling	UTUBE	5	Every year	Every year	Every 2 years	-
Isotube fluid sampling	ITUBE	5	Every year	Every year	Every 2 years	-
Ground water gas monitoring	GWG	15	Every year	Every year	Every 2 years	-
Soil gas flux monitoring	SGF	1	Every year	Every year	Every 2 years	-
Soil gas concentration monitoring	SGC	1	Every year	Every year	Every 2 years	-
Soil pH surveys	SPH	1	Every year	Every year	Every 2 years	-
Soil salinity surveys	SSAL	1	Every year	Every year	Every 2 years	-

Table 6-5 Preliminary Monitoring Schedule (cont'd)

Monitoring Systems		Quantity	Frequency 1	Frequency 2	Frequency 3	Frequency 4
Geophysical Monitoring						
Time-lapse 3D vertical seismic profiling	VSP3D	5	Once	7 times	-	-
Time-lapse surface 3D seismic	SEIS3D	5	Once	Every 5 years	Once	-
Time-lapse surface 2D seismic	SEIS2D	5	Once	Every 5 years	Once	-
Time-lapse cross-well seismic	SEISX	5	Once	Every 5 years	Once	-
Surface microseismic monitoring	SMS	5	-	Continuously	-	-
Down-hole microseismic monitoring	DHMS	5	-	Continuously	-	-
Time-lapse surface microgravity	SGRAV	5	Once	Every 5 years	Once	-
Time-lapse down-hole microgravity	DHGRAV	5	Once	Every 5 years	Once	-
Time-lapse surface controlled source EM	CSEM	5	Once	Every 5 years	Once	-
Time-lapse cross-well controlled source EM	CSEMX	5	Once	Every 5 years	Once	-
Magnetotelluric - natural source EM	NSEM	5	Once	Every 5 years	Once	-
InSAR - Interferometric Synthetic Aperture Radar	INSAR	1	Monthly	Monthly	Monthly	-
GPS - Global Positioning System	GPS	1	Continuous	Continuous	Continuous	-
Surface tiltmeters	STLT	1	Continuous	Continuous	Continuous	-
Down-hole tiltmeters	DHTLT	5	Continuous	Continuous	Continuous	-
Surface Monitoring						
DIAL - Differential absorption LIDAR	DIAL	5	Continuous	Continuous	Continuous	-
Line-of-sight gas flux monitoring	LOSCO2	5	Continuous	Continuous	Continuous	-
Atmospheric eddy correlation	AEC	1	Continuous	Continuous	Continuous	-
Airborne infra-red laser gas analysis	AIRGA	1	Once	Every year	Every 2 years	-
Hand-held infra-red gas analysers	HIRGA	1	Every year	Every year	Every 2 years	-
Satellite or airborne hyperspectral image analysis	HIA	1	Every year	Every year	Every 2 years	-
Ecosystem studies	ESS	1	Every year	Every year	Every 2 years	-

NOTE: This preliminary schedule of monitoring for each candidate technology is the basis for estimating life-cycle monitoring costs. Monitoring frequencies were adapted to suit the different requirements of each MMV time period: 1. pre-injection phase, 2. injection phase, 3. closure phase, and 4. post-closure phase. This example is for the development scenario of 5 injection wells and assumes without commitment an equal number of Winnipegosis or BCS monitoring wells and three times this number of groundwater monitoring wells. The MMV program will be selected from these options and the monitoring schedule will be revised again at that time.

6.4.6 Description of Notable Technologies

The remainder of this section describes some of the more notable technologies in more detail.

- **Down-hole pressure gauges** (DHPT) within observation wells completed in the Winnipegosis (OBW) would provide continuous monitoring. Any sustained pressure rise above both the established level of natural variations and the known drift rate of the gauge may provide an early indication of loss of containment. The sensitivity of a pressure gauge is 0.2 parts per million (corresponding to 3 Pa in the Winnipegosis), with an expected drift rate of 0.7 Pa per annum. If the hydraulic properties of the Winnipegosis measured by appraisal wells are representative then fluids entering this formation through a point source can be detected if the rate exceeds 3-30 kg/day, corresponding to 1-10 parts per million of the daily injected volume. The duration of fluid escape prior to detection could be 25 to 150 days for a gauge located 2 to 3 km from the source. No other method is likely to exceed the speed and sensitivity of this detection capability. The Winnipegosis is a carbonate, so there is a possibility of low permeability zones between the source and the gauge allowing fluids to escape undetected. If ongoing appraisal of the Winnipegosis indicates this risk is unacceptable then the Cooking Lake aquifer offers an alternative. The observation well design will support the option to plug the Winnipegosis interval and re-complete within the Cooking Lake aquifer.
- **InSAR** delivers monthly monitoring of surface displacements with millimetre precision over the entire AOR. Surface displacements induced by subsurface volume increases accompanying increased pore fluid pressure are readily detectable by InSAR. Lateral resolution of a detected subsurface anomaly depends on signal-to-noise but is likely 0.5 to 1.0 of the depth of the anomaly. Any fluids escaping above the ultimate seal will generate a localized surface uplift anomaly inconsistent with any possible anomaly due to stored fluid volumes below the primary seal. Detecting the former and distinguishing it from the latter provides an early indication of any loss of containment throughout the AOR. The smallest detectable mass of escaped fluids is likely 100,000 to 200,000 tonnes corresponding to 0.4 to 0.8% of the CO_2 mass planned for injection over 25 years. Considerable uncertainty about the bulk compressibility means this result may change following ongoing appraisal activities.
- Surface displacement distributions consistent with volume changes inside the BCS provide a good indication of pressure migration within the storage complex and its conformance with model-based predictions. Indications of unexpected pressure migration towards any potential migration pathways such as legacy wells indicate an increased threat to containment. Any step-like anomalies within the distribution of surface displacements provide a good indication of fault re-activation, revealing the location, strike, dip, burial depth, and rate of slip. Other distinctive anomalies may indicate and characterize any widespread opening of fractures.
- **Time-lapse seismic** should image the CO_2 plume but be insensitive to the displaced brine. Inside the plume, CO_2 likely replaces about 40% of the initial pore fluids and due to its higher compressibility causes a reduction in the bulk p-wave velocity of about 8% relative to the initial brine saturated. The difference between two seismic surveys, one acquired before injection and the other sometime later, will show increased reflection amplitudes from the top of the basement in places where CO_2 resides in the overlying BCS. The expected repeatability of these measurements is about 20% (normalized root-mean-square). Calculations to simulate this time-lapse

seismic response based on appraisal data indicate 10,000 to 60,000 tonnes of CO_2 is detectable above the noise with a lateral and vertical resolution of about 25 m and 10 m respectively. If the available appraisal data are not representative and seismic repeatability is much worse than anticipated, then time-lapse seismic may fail to detect any change no matter how large the CO_2 plume.

- During the first period of injection, 3D vertical seismic profiles (VSP3D) provide a cost-effective means of acquiring time-lapse seismic around each injector. Depending on reservoir properties and the rate of injection, the CO_2 plume may exit the region imaged by VSP after 2 to 15 years. Thereafter, 3D surface seismic surveys will be required to track the CO_2 plumes at considerably greater expense and therefore a much-reduced frequency. According to the rate of expected CO_2 movements, 3D VSP surveys might be appropriate every 1 to 3 years followed by 3D surface seismic surveys every 5 to 10 years. The final 3D surface seismic survey would be planned a couple of years prior to closure so that conformance can be proven.
- **Distributed temperature and acoustic noise monitoring** using fibre-optics permanently installed in injectors would provide a continuous capability to detect any fluids migrating upwards outside the casing. The risk to well integrity is minimized by placing the control line housing the fibres in-between two casing strings to eliminate any obstacles to obtaining a good quality cement bond between the outside casing and the formation. Monitoring different optical properties along these fibres yields measurements of temperature and acoustic noise with a resolution of 1 to 10 m. The injected CO_2 will be 25 to 47°C cooler than in-situ temperatures providing a clear temperature signal in the event of any fluids migrating upwards outside the casing. Low mass flux rates are harder to detect. Dynamic models of heat transport for this process indicate flux rates of just 3 kg per day should be detectable. Acoustic noise generated by fluid flow outside the casing provides an independent detection opportunity – sensitivity in this case depends on the rate and turbulence of the flow.
- **Down-hole electrical conductivity and pH monitoring** within groundwater observation wells can provide continuous monitoring for any impacts to existing water quality due to CO_2 or brine ingress. Annual fluid sampling, or more frequently if the continuous data indicate a need, should provide highly sensitive measurements of any water chemistry changes.
- **Line-of-sight CO_2 gas flux monitoring** is able to continuously map the areal distribution of any CO_2 emissions from the storage complex into the atmosphere. This system measures CO_2 concentrations according to the differential absorption of a laser beam at frequencies tuned to those absorbed by CO_2 molecules. This system uses many different fixed paths between a central laser and a network of surrounding corner reflectors. Measurement of wind vectors and inversion of all these data using a model for CO_2 advection and dispersion yields the distribution of CO_2 flux rates. A recent pilot successfully demonstrated this new technology.
- Numerical simulations indicate this system should detect CO_2 emission rates of 3 kg/hour over a 2-by-2 km area. A larger version capable of monitoring a 6-by-6 km area should be able to detect 250 kg/hour. This is sufficient to cover much more than the surface projection of the CO_2 plume expected around a single injector after 25 years of injection. For a five well system that injected 25 million tonnes of CO_2 after 25 years, each of the five separate CO_2 plumes contains 5 million tonnes so the smaller and larger monitoring systems will detect any CO_2 emissions exceeding 5 or 440 ppm per annum, respectively.

6.5 Conceptual Base-Case Monitoring Plan

As new information about storage and monitoring performance becomes available through time, the MMV base-case plan shall be adapted using the process described in Section 6.5 and Section 7.6. The initial base-case monitoring will be finalized at the same time as the Field Development Plan once the ongoing appraisal process concludes. Consequently, the base-case plan described below is conceptual. This conceptual plan does not constitute a commitment and will be subject to change in response to the final appraisal information. These changes will affect the shape and the content of the MMV plan but not the outcomes, which must still meet the performance targets.

Figure 6-4 summarizes the conceptual MMV plan. The schedule of monitoring activities shown covers the four monitoring domains (atmosphere, biosphere, hydrosphere, and geosphere) and wells associated with the Project that cross cut all these domains. This figure also shows how the expected schedule changes for each activity between the four time phases for MMV (pre-injection, injection, closure, and post-closure). This schedule combines continuous monitoring using permanent sensors and discrete monitoring activities to gain additional information periodically. In this example, many in-well monitoring activities continue to the end of the closure period. This is contingent on abandonment of these wells only happening at the end of the closure period. There may be greater benefits to earlier abandonment to allow for post-abandonment monitoring but this likely requires the removal of bottom-hole sensors and the loss of direct monitoring inside the BCS. This decision will likely depend on actual storage performance during injection and early part of the closure period.

6.5.1 Injection Well Monitoring Plan

An initial cement bond log (CBL), annual mechanical well integrity tests (MWIT), repeat casing integrity logs (USIT) every 5 years, and continuous annulus pressure monitoring (APM) and well-head CO_2 monitoring ($WHCO_2$) provide ongoing direct verification of well integrity during the injection period. During the closure period, APM, $WHCO_2$ and MWIT continue as before, but USIT only occurs once just prior to well abandonment.

Injection rate metering (IRM) at the wellhead, and pressure and temperature monitoring at the wellhead (WHPT) and at the BCS injection interval (DHPT) provide continuous measurements throughout the injection period. Once injection stops, only WHPT and DHPT continue until well abandonment. Permanent fibre-optic sensors support continuous distributed temperature and acoustic sensing (DTS and DAS) to verify the absence of any fluids migrating upwards outside the casing. These measurements start just before CO_2 injection and end just before site closure. An operational integrity assurance system will combine all these continuous streams of data to provide an exception-based monitoring capability that automatically generates an early warning of potential loss of well integrity.

During the closure phase, the injection well infrastructure would also support the opportunity for low cost data acquisition through potential logging and sampling to verify the CO_2 storage mechanism in the BCS.

Finally, each injector may support the repeated injection of an artificial tracer.

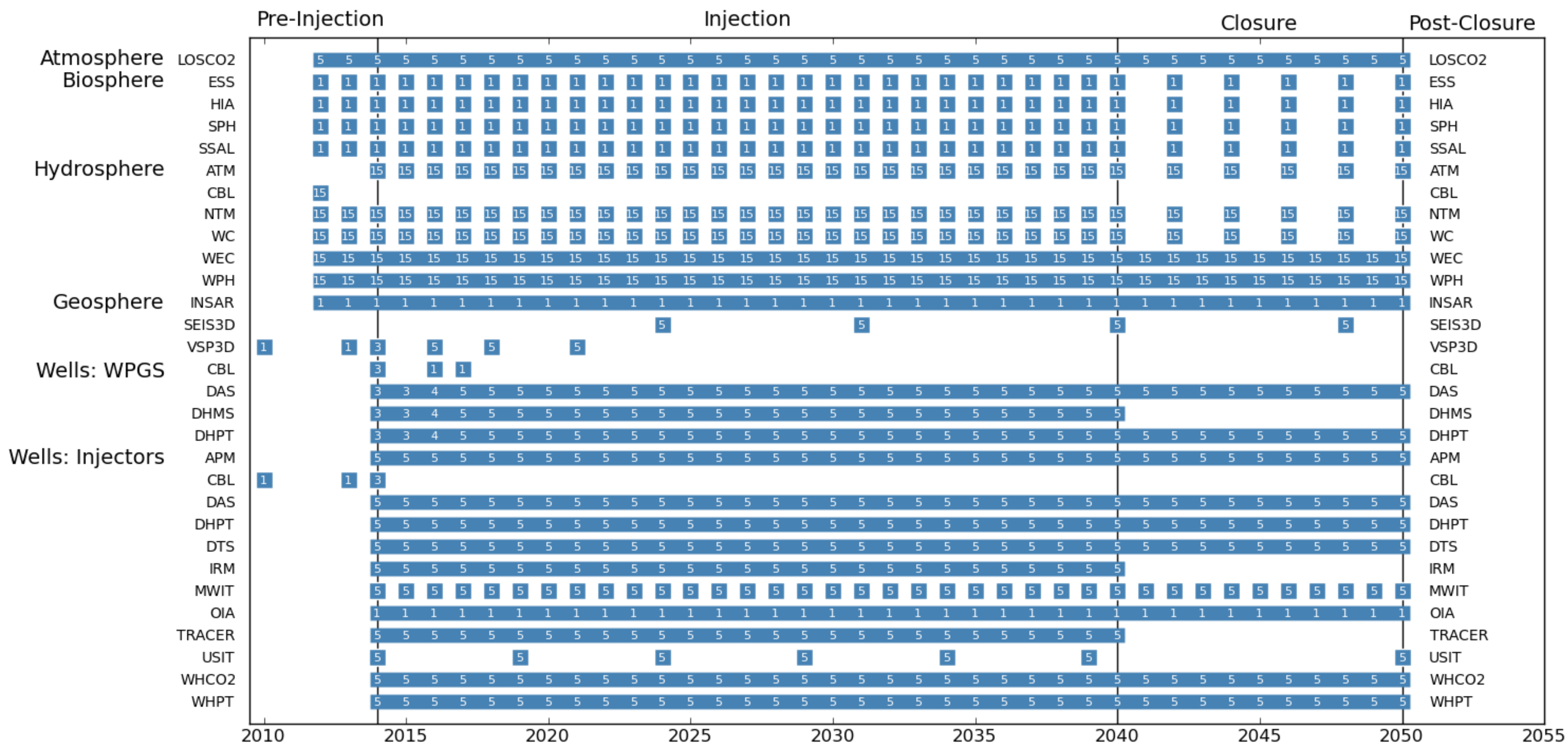


Figure 6-4 Schedule of Measurement, Monitoring and Verification Activities

6.5.2 Geosphere Monitoring Plan

The geosphere monitoring system comprises a balance between non-invasive remote sensing methods and in-well measurements directly above the ultimate seal within the Winnipegosis formation.

- InSAR provides essentially continuous monitoring of the footprint of pressure changes inside the BCS and time-lapse seismic (VSP3D, SEIS3D) tracks the CO_2 plume moving behind this pressure front. InSAR requires two years of monitoring prior to CO_2 injection to establish a baseline.
- Time-lapse seismic requires a single survey prior to CO_2 injection as a baseline. These baseline data for surface seismic do not appear in the MMV schedule as the design of the appraisal seismic surveys also supports time-lapse seismic. For the time-lapse VSP's the baseline will be acquired at the time of drilling. The interval between VSP surveys starts small and lengthens in line with the rate of expected advance of the CO_2 front. Once the CO_2 front extends beyond the VSP image area, time-lapse seismic monitoring continues at the surface with the last survey scheduled two years prior to site closure to ensure the interpreted results are available to support the site closure process.
- Sensors inside Winnipegosis observation wells provide continuous pressure monitoring to detect any early signs of fluids escaping above the ultimate seal.
- Down-hole microseismic monitoring (DHMS) should detect any early signs of fractures propagating towards the ultimate seal or fault re-activation.
- A CBL and DTS or DAS within these wells provide a means of verifying well integrity.

6.5.3 Hydrosphere Monitoring Plan

Groundwater monitoring wells completed at least two years prior to CO_2 injection support continuous electrical conductivity (WEC) and pH (WPH) monitoring of the ground water to establish a baseline and to verify the absence of significant impacts to groundwater quality throughout the injection and closure periods. Fluid sampling and laboratory analysis of water chemistry start with annual measurements two years prior to CO_2 injection and continue with measurements every two years throughout the closure period. Analysing these same fluids samples for natural and potentially artificial tracers follows the same schedule with the exception that artificial tracers do not require any baseline data.

6.5.4 Biosphere Monitoring Plan

Ecosystem studies (ESS), hyper-spectral image analysis (HIA), and soil pH (SPH) and salinity (SSAL) annual monitoring for two years prior to CO_2 injection will establish a sufficient baseline. Monitoring during injection generates the information necessary to verify the absence of any significant impacts to the biosphere or to trigger corrective controls measures if necessary. During the closure period, bi-annual monitoring is sufficient as average pressures inside the storage complex will decrease and the forces driving migration of the CO_2 plume and BCS brine become much smaller.

6.5.5 Atmosphere Monitoring Plan

Line-of-sight CO_2 flux monitoring (LOSCO_2) provides continuous monitoring of any material CO_2 flux from the storage complex into the atmosphere. Installation of these sensors systems two years prior to the start of CO_2 injection will generate baseline data sufficient to understand existing CO_2 fluxes including any seasonal variations. The background variations may be larger than expected due to the site location within Alberta's Industrial Heartland. In this case, baseline data shall provide the evidence to motivate revising the CO_2 inventory reporting performance target. The ability to relocate these monitoring systems from time-to-time allows opportunities for occasional temporary monitoring outside the expected surface footprint of the subsurface CO_2 plume.

6.6 Contingency Monitoring Plan

The initial MMV plan includes monitoring to support corrective safeguards as shown on the right-hand side of the bowtie. However, not all monitoring efforts will be part of the initial MMV plan – some efforts are only activated (contingent) on detecting signs of unexpected storage or monitoring performance.

Contingency monitoring arises through adaption of the MMV plan to changing circumstances as previously described. One aspect of this contingency monitoring is the need to characterize any impacts or to verify the effectiveness of any remediation measures in the unlikely event of any loss of containment. Time-lapse seismic methods are a natural choice.

- time-lapse seismic likely delivers the required coverage and sensitivity
- base-case activities will generate the necessary seismic baseline data
- seismic acquisition can often proceed with only a limited lead-time
- replicate seismic processing methods already proven by base-case activities

Another aspect of contingency monitoring is preparation of alternative monitoring systems as potential replacements for any under-performing monitoring technologies. Key example of this are:

- The preference to deliver conformance monitoring through non-invasive geophysical techniques, i.e. time-lapse seismic methods and InSAR. Should one or both of these methods prove insufficient within the first 5 years of injection then there remains the opportunity to drill observation wells into the BCS to acquire direct measurements of pressure and ultimately CO_2 build-up at a very limited number of discrete locations. In this situation, the additional risk to containment created by drilling further wells through all geological seals at the center of the storage complex is unavoidable without forfeiting some requirements for conformance monitoring. In selecting this option, the same active safeguards identified to ensure long-term integrity of injectors should also protect these BCS observation wells.

- If InSAR monitoring of natural scatterers proves insufficient there remains the opportunity to deploy corner reflectors to ensure sufficient reliable monitoring targets.

One final aspect of contingency monitoring is to optimize the deployment of high-cost monitoring technologies such as time-lapse seismic. Time-lapse VSP surveys should track the CO_2 plume for the first 4-16 years depending on injectivity performance. According to results obtained from these VSP data and updated model-based predictions for the short-term advance of the CO_2 plume, the switch to more expensive surface seismic methods will be delayed as long as possible without any loss of information.

6.7 Technology Qualification

Technology qualification is a process to reduce the risk of relying on unreliable monitoring technologies without creating additional monitoring costs. Technologies may become qualified through examination of a documented set of activities to prove the technology meets the specified requirements for its intended use. DNV (2010) describes a technology qualification process for the selection and qualification of geological storage sites for CO_2. This process is flexible enough to allow the use of emerging new technologies and structured enough to allow regulatory control if required. This same process is also appropriate to qualify monitoring technologies for MMV.

Qualification of an individual technology requires the following steps.

1. Define the performance criteria for qualification
2. Document the performance evidence
3. Evaluate the evidence against the criteria

This process shall be followed at the time of selecting the initial MMV plan and again before including alternative technologies in any revised MMV plan.

7 Revised Storage Performance Evaluation

This section describes the expected improvement in storage performance gained through MMV activities. The goal here is to demonstrate that residual containment risks after MMV are broadly acceptable or at least tolerable and as low as reasonably practicable.

7.1 Assessment of Additional Safeguards

7.1.1 Conformance Safeguards

The result of evaluating a wide range of different technologies against the identified tasks for conformance monitoring is that several effective options exist to meet the proposed performance targets.

- **Site Closure**: Time-lapse seismic methods and InSAR that respectively provide indicators of CO_2 and pressure development inside the BCS storage complex should satisfy the first performance target for site closure. These are both non-invasive techniques with zero threat to containment. If within the first five years of CO_2 injection the performance of these two monitoring methods proves insufficient there is still the opportunity to drill observation wells into the BCS to provide direct measurement of pressure and ultimately CO_2 development at a very limited number of locations to still satisfy the performance target. Deploying safeguards in these observation wells similar to those already identified for injectors will help ensure containment.

The second performance target shall be satisfied through extensive monitoring under the program of MMV activities to ensure containment.

- **Storage Efficiency**: The strategy described above for monitoring pressure and CO_2 development satisfies the performance target for storage efficiency as well. In combination with frequent bottom-hole pressure measurements in the wells themselves, which can be used to constrain and history match reservoir models.
- **CO_2 Inventory:** A fiscal meter located where the CO_2 pipeline leaves the Scotford site, wellhead injection meters and the combination of wellhead and bottom-hole pressure gauges will satisfy existing regulatory requirements for measuring the injected volume of CO_2 with a maximum monthly uncertainty of 5%. There are also opportunities to adopt emerging new technology for measuring any CO_2 emissions from the storage site into the atmosphere with at least the same maximum uncertainty. Together these monitoring systems will satisfy the proposed performance target for CO_2 inventory reporting.

7.1.2 Containment Safeguards

Assessment of containment safeguards follows the bowtie approach again to provide a more detailed analysis of these safety-critical risks. For increasing numbers of safeguards, we will estimate the reduced likelihood or impact of each consequence, and the sensitivity to uncertainty about the effectiveness of each safeguard:

- The top ranking uncertainties remain as before related to the geological formations overlying the BCS storage complex.
    - Ongoing appraisal activities will reduce these uncertainties.
    - Therefore, this MMV plan should be revisited once the appraisal program has concluded.
    - The next group of influential uncertainties concern many of the top ranking monitoring technologies.
    - Some of these uncertainties may reduce through ongoing technical feasibility studies.
    - Others may reduce through early field trials, potentially as part of the program of baseline monitoring prior to CO_2 injection.
    - Others still may only reduce during the first 5 years of CO_2 injections, e.g. time-lapse seismic methods.

8 Reporting

Quest will integrate within existing operations. As such, much of the environmental monitoring data and operational performance will be reported and communicated through existing mechanisms. Shell expects that Quest will also require additional reporting not currently completed at the Scotford Upgrader.

8.1 Scotford Upgrader Current Reporting Requirements

The following is a list of current reporting requirements for the Scotford Upgrader that will likely be expanded to include the performance and emissions of Quest:

- Monthly and Annual Air report, AENV
- Annual Operations Report and meeting, ERCB
- Annual GHG reporting, SGER, AENV
- Annual GHG reporting, CEPA, Environment Canada
- NPRI, Environment Canada
- Annual Groundwater Report, AENV
- Annual and monthly production reporting, ERCB

8.2 Anticipated Additional Reporting Requirements

It is expected that Quest will also require additional reporting including but not limited to the following:

1. An annual progress report similar to that in accordance with ERCB Directives 7 and 17 and a monthly report of volumes injected to the Petroleum Registry of Alberta. Uncertainty in the monthly volume of injected CO_2 reported will not exceed 5%.
    - This shall be shall be published within 6 months of the expiration of each calendar year. This report shall include but is not limited to, the following:
    - A table of the injected volume of gas on a monthly, annual and cumulative basis, since start-up
    - A table and plot of the net volume of gas stored on a monthly basis
    - A table and plot showing the monthly injection rates
    - A plot of both bottom hole reservoir pressures and wellhead injection pressures, along with a summary of any pressure test data obtained and the results and evaluations of all bottom-hole pressure surveys conducted, during the reporting period
    - A gas analysis representative of the composition of the gas injected during the reporting period
    - A discussion of the volume of gas injected into the storage site

- A summary of any change or modification in the operation of the Project, including well work-overs, recompletions and suspensions, or any surface facility operations during the reporting period
- Results and evaluation of all monitoring done during the reporting period

2. Annual performance reporting to NRCAN and Alberta Department of Energy. The format and content of this report will be determined as discussions with both of these agencies continue.
3. An annual report summarizing the results of the MMV program including detection of leaks (chronic and acute). There are many possible formats for communicating this information including using a third party auditor and, or external review panel, as an example. The final program, format to be presented publically, audience and frequency of publication will be developed as the project and associated consultation progresses.

8.3 Communication Venues

The Scotford Complex has a number of mechanism and forums in which Shell communicates with the public giving and receiving information pertaining to the performance. This includes:

- Community Newsletter- once per quarter
- Community Meeting- once per year
- Report to the community- once every 2 years

Information on the performance of Quest will be integrated into these reporting venues.

Scotford also has an Emergency Response Plan that is activated in the event of an emergency. The Project is developing a stand-alone ERP for wells and pipeline, and will append emergency response plans for the capture infrastructure to the existing Scotford site ERP, prior to operations. In the event there is a release of CO_2, the appropriate plans will be activated.

8.4 Multi-stakeholder Groups

Shell Canada Energy as operators of the Scotford Upgrader, participates in a number of regional groups including, but not limited to:

- The Fort Air Partnership which monitors ambient air quality,
- The NCIA which is conducting a regional groundwater study and has constructed a regional noise model and the
- Northeast Region Community Awareness and Emergency Response (NRCAER) Hotline for posting operational information of interest to community members

Shell will investigate the feasibility and appropriateness of expanding its involvement in these groups to include the Quest project.

9 Summary

The Quest Carbon Capture and Storage Project promises to make a material early contribution to reducing CO_2 emissions generated by upgrading bitumen from the Alberta oil sands. The climate benefits and societal acceptability of this Project are both largely dependent on the quality of containment achieved within the Basal Cambrian Sands storage complex.

The geology of the selected storage site offers multiple layers of protection to prevent any CO_2 or brine from causing any significant impacts to the protected groundwater zone, the ecosystem, or the atmosphere. No matter how detailed and extensive the appraisal program to characterize these geological barriers some small uncertainty and risk will remain. MMV activities will be designed to verify the absence of any significant environmental impacts due to CO_2 storage. If necessary, MMV activities will create additional safeguards by triggering control measures that will be designed to prevent or correct any loss of containment before significant impacts occur.

A systematic assessment of containment risks and the effectiveness of safeguards provided by geology, engineering and MMV demonstrated significant risk reductions so that the remaining risk is insignificant compared to everyday risks broadly accepted by society. Transfer of long-term liability will depend on the actual storage performance verified through MMV activities. MMV must demonstrate actual storage performance conforms to model-based forecasts and that these forecasts are consistent with permanent secure storage at an acceptable risk to gain climate change benefits.

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Attachment A Emerging MMV Guidelines

According to the Kyoto Protocol (1998) and the Copenhagen Accord (2010), project activities under the Clean Development Mechanism (CDM) must result in emission reductions that are "real, measurable and long-term". CCS offers one route towards achieving such emissions reductions (IEA 2007). The Intergovernmental Panel on Climate Change (IPCC 2005) found that existing technologies are sufficient to meet these requirements for monitoring and verification of underground geological storage of CO_2.

The Greenhouse Gas Inventory Guidelines (IPCC 2006) consider underground storage sites to be a source of CO_2 emissions. This means the difference between the amount of injected and emitted CO_2 is a measure of the inventory of stored CO_2. For potential CCS CDM projects to be an effective mitigation for climate change, annual CO_2 emissions rates should be less than 0.01% of the mass of CO_2 stored underground (Hepple and Benson 2004), or perhaps less than 0.001% (Shaffer 2010). The IPCC (2006) evaluated a wide range of feasible monitoring methods for detecting emissions from an underground storage site and concluded the performance of each individual method will be site specific.

The IEA Greenhouse Gas Research and Development Program supported the development of guidelines in three key areas related to monitoring for verification of geological storage of CO_2:

1. Risk assessment (Quintessa 2004),
2. Monitoring tool selection (IEA 2006)
3. Site selection, characterization and qualification (DNV 2010a), DNV 2010b)

The latter, developed by a joint industry project (JIP) including Shell and led by Det Norske Veritas (DNV), represent the most comprehensive guidelines and examples yet for safe and sustainable geological storage of CO_2. This JIP advocates a site-specific risk-based approach.

Independently, the World Resource Institute issued general guidelines (WRI 2008) for CCS operators and regulators, including recommendations for monitoring and verifications plans to follow a site-specific risk assessment that allows flexibility to select appropriate monitoring methods adapted through time to suit the different risk profiles at each stage of the project.

A.1 Future Regulatory Expectations

The volume and time-scale of CO_2 storage required for CCS to be an effective mitigation for climate change greatly exceeds the existing experience acquired through Acid Gas Disposal projects. This necessitates the development of new standards for CCS projects. The Canadian Standards Association (CSA) and the International Performance Assessment Centre for Geologic Storage of Carbon Dioxide (IPAC-CO_2) recently announced a joint agreement to develop Canada's first carbon capture and storage standard for the geologic storage of industrial emissions (CSA 2010). International and other national authorities, industry and environmental non-governmental organizations will most likely influence the development of these standards.

A.1.1 International Authorities

Several international authorities published guiding principles for CCS developments to aid the harmonization of standards between jurisdictions (IPCC 2005; IPCC 2006; OSPAR 2007; WRI 2008; DNV 2010a). These are likely to influence future regulations.

A.1.2 Government Authorities

Many governments are developing country-specific frameworks for CCS regulations: Australia, Brazil, Canada, China, European Union, Germany, Indonesia, Norway, Poland, Qatar, South Africa, The Netherlands, UK, and USA. Some of this initial work adds to the existing guidance from international authorities.

European Union: The European Council Directive on permanent underground CO_2 storage (European Council 2009) develops the OSPAR (2007) principles for monitoring to state the following six objectives for monitoring.

1. Demonstrate CO_2 behaves as expected.
2. Detect any migration or leakage.
3. Measure any environmental or health damage.
4. Determine effectiveness of CO_2 storage as GHG mitigation.
5. In case of leakage, assess effectiveness of corrective measures.
6. Update risk assessment and monitoring plan based on performance of the storage site.

Further monitoring requirements arise because the transfer of liability to the authorities after site closure is contingent on demonstrating the permanence of CO_2 storage according to three criteria.

1. Actual CO_2 behavior conforms to modeled behavior within range of uncertainty.
2. Absence of any detectable leaks.
3. Storage site is evolving towards long-term stability.

The European Council Monitoring and Reporting Guidelines (MRG), a draft amendment to the Emissions Trading Scheme (ETS), also stipulate additional monitoring requirements beyond the 2009 EC Directive in the instance of detecting actual emissions from the storage site to quantify the emissions and the efficacy any remediation activities.

United Kingdom: Government response to consultation on CCS (UK 2009a; UK 2009b) accepts four key clarifications of the monitoring requirements for CCS.

1. Monitoring should cover the volume affected by CO_2 storage rather than just the volume occupied by the CO_2 plume itself.
2. The post-closure period before transfer of liability will be determined individually for each project depending on the behavior of the storage site during operation based on evidence from the monitoring program.
3. The duration and type of post-transfer monitoring will be decided based on evidence from the monitoring program and will determine the 'transfer fee'.
4. Site closure includes removal of infrastructure and sealing of wells before handover to the authorities with the possible exception of some wells that may be maintained for monitoring purposes.

A subsequent study commissioned by the UK (BGS 2010) identified technologies and methodologies judged suitable for MMV in the UK.

USA: Environmental Protection Agency (EPA) consultation on Federal requirements for geological storage of CO_2 (EPA 2008) proposes a broadly similar monitoring requirements to elsewhere.

1. The Area of Review (AOR) for monitoring is considered to include the pressure front defined as the region of elevated pressures sufficient to cause movement of formation fluids into the protected groundwater zone.
2. Determination of the AOR is initially based on predictive models and should be re-determined in the event of any significant discrepancy between predicted and actual performance or within 10 years of the last determination, whichever is the sooner.
3. Monitoring the CO_2 plume and pressure front may be achieved with a combination of direct and in-direct techniques selected according to site-specific requirements.
4. Continuous monitoring of injection with automatic alarms and shut-off equipment is recommended as an important safety consideration. The EPA proposes to require down-hole safety shut-off value.
5. Duration of the site closure period is not specified but anticipated to be determined according to demonstrated performance of the storage site.

EPA (2008) proposes a quantitative risk assessment methodology as a high-level approach towards determining the suitability of sites for geological storage of CO_2. The US Department of Energy's National Energy Technology Laboratory (NETL) provide guidance for MMV (NETL 2009), including a classification of monitoring technologies according to their readiness for monitoring CO_2 storage sites.

A.1.3 Industry Authorities

Advocacy by industries and companies with relevant expertise may influence future regulations.

- **CO_2QUALSTORE:** A joint industry project (JIP) led by Det Norske Veritas (DNV) includes partners from a number of sectors; oil and gas companies (BP, BG Group, Petrobras, Shell and Statoil); energy companies (DONG Energy, RWE Dea and Vattenfall); technical consultancy and service providers (Schlumberger and Arup); the IEA Greenhouse Gas Reseearch and Development Programme; and two Norwegian public enterprises (Gassnova/Climit and Gassco). This JIP draws together experience and good practises to generate guidelines and recommendations for geological storage of CO_2 including MMV (DNV 2010a, DNV 2010b).
- **Royal Dutch Shell** advocates that the IPCC GHG inventory guidelines (2006), the World Resource Institute guidelines (WRI 2008) and the DNV guidelines (DNV 2010a) form the basis for any MMV program.

Attachment B Analog Measurement, Monitoring and Verification Plans

Five fully-integrated, large scale CCS projects are in commercial operation today storing more than 0.5 million tonnes CO_2 per year. Four projects - Sleipner, In Salah, Snøhvit and Rangely – inject CO_2 from a natural gas production facility where it is separated from the natural gas sent to market. In the first three cases, the CO_2 is injected into saline aquifers, while in the fourth it is used for EOR. A fifth project captures CO_2 at the Great Plains Synfuels Plant and transports it for EOR to the Weyburn-Midale project. All five are contributing to the knowledge base needed for widespread CCS use. The following summary of these projects was adapted from IEA (2010).

Sleipner

The Sleipner project began in 1996 when Norway's Statoil began injecting more than 1 million tonnes a year of CO_2 under the North Sea. This CO_2 was extracted with natural gas from the offshore Sleipner gas field. In order to avoid a government-imposed carbon tax equivalent to about USD 55/tonne, Statoil built a special offshore platform to separate CO_2 from other gases. The CO_2 is re-injected about 1 000 metres below the sea floor into the Utsira saline formation located near the natural gas field. The formation is estimated to have a capacity of about 600 billion tonnes of CO_2, and is expected to continue receiving CO_2 long after natural gas extraction at Sleipner has ended.

In Salah

In August 2004, Sonatrach, the Algerian national oil and gas company, with partners BP and Statoil, began injecting about 1 million tonnes per year of CO_2 into the Krechba geologic formation near their natural gas extraction site in the Sahara Desert. The Krechba formation lies 1 800 metres below ground and is expected to receive 17 million tonnes of CO_2 over the life of the project.

Snøhvit

Europe's first liquefied natural gas (LNG) plant also captures CO_2 for injection and storage. Statoil extracts natural gas and CO_2 from the offshore Snøhvit gas field in the Barents Sea. It pipes the mixture 160 kilometres to shore for processing at its LNG plant near Hammerfest, Europe's northernmost town. Separating the CO_2 is necessary to produce LNG and the Snøhvit project captures about 700 000 tonnes a year of CO_2. Starting in 2008, the captured CO_2 is piped back to the offshore platform and injected in the Tubåsen sandstone formation 2,600 metres under the seabed and below the geologic formation from which natural gas is produced.

Rangely

The Rangely CO_2 Project has been using CO_2 for enhanced oil recovery since 1986. The Rangely Weber Sand Unit is the largest oilfield in the Rocky Mountain region and was discovered in 1933. Gas is separated and reinjected with CO_2 from the LaBarge field in Wyoming. Since 1986, approximately 23-25 million tonnes of CO_2 have been stored in the reservoir. Computer modeling suggests nearly all of it is dissolved in the formation water as aqueous CO_2 and bicarbonate. Though Rangely uses CO_2 for EOR, it is considered a CCS project insofar as it follows an MMV plan that satisfactorily assesses the viability of the long-term storage of the CO_2.

Weyburn-Midale

About 2.8 million tonnes per year of CO_2 are captured at the Great Plains Synfuels Plant in the US State of North Dakota, a coal gasification plant that produces synthetic natural gas and various chemicals. The CO_2 is transported by pipeline 320 kilometres (200 miles) across the international border into Saskatchewan, Canada and injected into depleting oil fields where it is used for EOR. Although it is a commercial project, researchers from around the world have been monitoring the injected CO_2. The IEA Greenhouse Gas R&D Programme's Weyburn-Midale CO_2 Monitoring and Storage Project was the first project to scientifically study and monitor the underground behavior of CO_2. Canada's Petroleum Technologies Research Centre manages the monitoring effort. This effort is now in the second and final phase (2007-2011), of building the necessary framework to encourage global implementation of CO_2 geological storage. The project will produce a best-practices manual for carbon injection and storage.

MMV Capability Transfer between CCS Projects

The CO_2QUALSTORE joint industry project (JIP) led by Det Norske Veritas (DNV) recently compiled a workbook of examples for underground storage of CO_2 including MMV plans (DNV 2010b). The JIP includes the following partners from a number of sectors; oil and gas companies (BP, BG Group, Petrobras, Shell and Statoil); energy companies (DONG Energy, RWE Dea and Vattenfall); technical consultancy and service providers (Schlumberger and Arup); the IEA Greenhouse Gas R&D Programme; and two Norwegian public enterprises (Gassnova/Climit and Gassco). This workbook provides guidance on how site-specific performance targets can be defined and includes practical examples of how to follow the guidance and its various steps. This workbook represents the most recent collection of shared experience and good practises applicable to MMV. This guidance and the good practises illustrated through the examples are central to the approach taken by Shell to all current CCS development projects including Quest.

Attachment C Legacy Wells

Location of Legacy Wells

Seven wells penetrate all geological seals down to the basement. None of these wells are closer than 21 km to any of the injection locations considered. The one well in the centre of the storage area is the Radway 8-19 appraisal well. The number of well penetrations through the base of the other named formations only increases significantly above the Prairie evaporite.

Abandonment Status of Legacy Wells

There are seven third-party abandoned wells penetrating the storage complex of the Quest project within the AOI. Most of the wells were completed open-hole for appraisal, notably across the BCS, and were then abandoned by installing multiple cement plugs in the open-hole section. The last well however was reconverted to become a gas storage well and then abandoned in 2007.

The available well reports do not confirm the integrity of the plugs and therefore their initial and current conditions are not known and cannot be ascertained without intervening in the wells, which is a risky and complex operation. A recent field visit confirmed there is no equipment left on site on any of these locations.

At least two wells have their deepest cement plug located above the storage complex. This creates the potential for open communication between the BCS and the Winnipegosis. However, all these wells are located more than 21 km from the planned injectors, significantly far from the expected extent of the CO_2 plume. Therefore potential CO_2 migration through these wells outside of the storage complex is very unlikely. Still, these wells are located within the AOI and although not expected, may experience a notable pressure increase (Attachment E).

There are also four third-party active gas injection wells penetrating part of the ultimate seal of the storage complex.

- Provident 16 (100-14-01-056-22W400)
- Provident 15 (100-12-01-056-22W400)
- Provident 14 (102-11-01-056-22W400)
- Provident 12 (100-11-01-056-22W401)

They have all been drilled and completed recently (2006-2009) and are still active, hence accessible for further investigation. Besides, they are all located on the edge of the AOI, therefore potential CO_2 migration through these wells outside of the storage complex is very unlikely.

Recently, three Shell wells were drilled in 2008, 2009 and 2010 penetrating the BCS as part of the appraisal phase of the Quest project. All wells are still accessible. Redwater 3-4 well will be re-entered either for abandonment or for converting it into an observation well.

Attachment D Historic Rate of Well Integrity Failures

The occurrence of sustained casing pressure is an indicator for a loss of well integrity. Of the approximately 20,000 oil and gas wells tested in Alberta, 10% experienced sustained casing pressure (Watson and S Bachu 2008). Of the 7,000 underground gas injection wells in the USA, 6% experienced sustained casing pressure, of which 90% had a leakage rate of less than 200 tonnes per year and 60% had a leakage rate of less than 35 tonnes per year (Marlow 1989).

A review of malfunctions of underground gas storage sites worldwide in depleted oil and gas fields, aquifers and salt caverns (HSE 2008) demonstrates the historical rate of well failures is less than 1 in 120,000 per well year. The modes of well failure recognized include releases through failed or leaky boreholes, casing failure and well valve failure resulting in release rates of 200 tonnes per year. This excludes sudden blowouts resulting in substantially greater release rates. Most of the operating experience comes from underground gas storage in depleted oil or gas fields with between 600,000 and 860,000 well years recorded and just five failure events identified.

Taking past performance as a guide, the likelihood of well integrity being insufficient to prevent a chronic leak is less than 1 in 120,000 for an average well in any one year.

Attachment E Changing Pressure inside the BCS

The extent of the storage AOI is guided by the expected extent of the pressure front after 25 years of injection at an average rate of 1.08 Mt/a. At that point, the pressure response in the BCS will likely extend some 20 to 30 km away from the injectors. The permeability distribution in the BCS governs the speed and directionality of the pressure front development. The injected volume and the capacity of the BCS storage complex govern the magnitude of the pressure change.

The legacy wells likely pose the greatest threat of allowing formation brine to flow out of the BCS storage complex. Therefore, site selection for the storage AOI focused on ensuring maximum offset to existing legacy wells. However, because appraisal data indicate the BCS reservoir is extensive and well connected on a regional scale, the pressure front will likely exert influence far from the injection wells. The closest BCS penetration by a legacy well (Egremont 6-36) is a distance of 21 km WSW from the Radway 8-19 location, whilst the closest up-dip legacy well (Darling No.1) is 31 km NNE of the Radway 8-19 well.

Site selection maximizes offset to existing legacy wells, but some residual risk around brine migration into intermediate aquifers overlying the BCS remains, particularly after a sustained period of injection. Given the BCS reservoir pressure (D65, Section 6.5) and in situ fluid gradient (D65, Section 6.1) a minimum incremental pressure of 3.5 MPa in the BCS is required to lift BCS brine with a density equivalent to 11.7 kPa/m into the Base of Ground Water Protection (BGWP) zone. Dynamic models for a range of subsurface scenarios indicate that the pressure increase at distances of 20 to 30 km away from the injection well locations after 25 years of injection will be less than half the pressure required to lift BCS brine up to the BGWP zone or to surface. The pressure increase from a hypothetical alternative injection scheme in the BCS would have an incremental effect on the BCS pressure so that an equivalent CCS project, equidistant from a legacy well as the Quest injectors, would double the pressure increase seen at this legacy well. In this case, legacy wells pose a greater threat to containment. A pore-space tenure AOI that essentially extends to include the closest legacy wells to the southwest and the northeast mitigates this risk. Monitoring these legacy wells may be required later in field life, particularly if additional CCS projects start operating nearby.

Attachment F Monitoring Technology Capabilities

Table 6-3 summarizes the capability of each monitoring technology considered for inclusion in the MMV plan. These technologies fall into four categories:

1. In-Well Monitoring
2. Geochemical Monitoring
3. Geophysical Monitoring
4. Surface Monitoring

Many technologies exist with independent capabilities for measuring different physical, chemical, or biological changes. Many other technologies exist with similar or overlapping capabilities. The frequency (availability) of monitoring information gained and the region of coverage are both critical factors affecting the value each technology offers for MMV. Rarely will a technology offer continuous monitoring over a broad region. More often, a choice exists between less frequent monitoring with broad coverage and more frequent monitoring with restricted coverage. These differing capabilities informed the screening and evaluation of all these technologies against the identified monitoring tasks for MMV.

Appendix C Project Well List

Wells Used in the Quest Project Petrophysical Evaluation and Subsurface Modeling

UWI	Operator Well Name	Short Well Name	Kb Elev (m)	GL Elev (m)	Drill TD (m)	Current Status	Current Status Date	TD IN…	Wells evaluated by Petrophysicist for Project Screening. Used for GEN 2 Static Model
100020206508W500	PETROMK ET AL MORSE RIVER 2-2-65-8	PETROMK 2-2	863.9		2712	DRY	5-Oct-78	PRECAMBRIAN	Group 1
100030405720W400	SCL REDWATER 3-4-57-20	REDWATER 3-4	613.59	608.8	2190	ABD WTR	9-Apr-09	PRECAMBRIAN	Group 1
102113205521W400	SCL REDWATER 11-32-55-21	SCOTFORD 11-32	627.93	623.2	2243	WTR DISP	1-Jan-09	PRECAMBRIAN	Group 1
100071006904W500	HOME MITSUE 7-10-69-4	HOME 7-10	717.8		2217.1	DRY	15-Sep-80	PRECAMBRIAN	Group 1
100071106706W400	ESSO AEC 85 FISHCK 7-11-67-6	ESSO 7-11	646.3	643.3	1342	DRY	18-Mar-91	PRECAMBRIAN	Group 1
100123106707W400	ESSO AEC 85 FISHCK 12-31-67-7	ESSO 12-31	608.4	607.7	1334	DRY	11-Feb-85	PRECAMBRIAN	Group 1
103102106308W400	CNRES 03 WOLF LAKE 10-21-63-8	CNRES 3/10-21	579.2	574.3	1452	WTR INJ	17-Jul-01	PRECAMBRIAN	Group 1
100041506803W500	CHEVRON ET AL CHISHOLM 4-15-68-3	CHEVRON 4-15	604.4		2100.1	DRY	3-Mar-76	PRECAMBRIAN	Group 1
100060105213W400	VOYAGER PLAIN 6-1-52-13	VOYAGER 6-1	690.7	687.3	2100.1	GAS	15-Nov-78	BCS	Group 1
100073406708W400	ESSO AEC 85 FISHCK 7-34-67-8	ESSO 7-34	648.8	644.3	1386	DRY	6-Mar-85	PRECAMBRIAN	Group 1
102072906501W500	ANDERSON ESSO BIG BEND 7-29-65-1	ANDERSON 2/7-29	644.7		2115	DRY	22-Mar-80	CAMBRIAN	Group 1
100012805703W500	CHEVRON MAJEAU 1-28-57-3	CHEVRON 1-28	703.8	699.2	2525	DRY	30-Nov-79	LMS	Group 1
100071906101W500	ANDERSON ESSO WESTLOCK 7-19-61-1	ANDERSON 7-19	640.2	635.7	2250	DRY	31-Dec-79	PIKA TOP MC	Group 1
100041706601W500	AMOCO BIG BEND 4-17-66-1	AMOCO 4-17	632.2	628.5	2133.9	ABD GAS	27-Feb-80	BCS	Group 2
100080106211W400	SASKOIL SUGDEN 8-1-62-11	SASKOIL 8-1	630	625.9	1635	DRY	19-Jul-91	BCS	Group 2
100100505202W500	HOME CPOG BRIGHTBANK 10-5-52-2	HOME 10-5	745.5	740.1	2920	DRY	14-Jan-68	PRECAMBRIAN	Group 2
100100506802W500	HOME ALMINEX KCL CHISHOLM 10-5-68-2	HOME 10-5	602.9		2079.3	DRY	17-Feb-65	PRECAMBRIAN	Group 2
100101106712W400	MCD CHIEFCO LABIE 10-11-67-12	MCD 10-11	597.7	593.8	1482.2	DRY	6-Feb-68	PRECAMBRIAN	Group 2
100103506202W500	HOME CDN-SUP GRIDGELK 10-35-62-2	HOME 10-35	641.9	637.6	2145.2	DRY	25-Mar-66	UPPER CAMBRIAN	Group 2
100103406102W500	LARIO ET AL GRIDGELK 10-34-61-2	LARIO 10-34	621.8	617.8	2164.7	ABD GAS	14-Oct-98	UPPER CAMBRIAN	Group 2
100041606402W500	HOME ALMX KCL AKUINU 4-16-64-2	HOME 4-16	630.3	626.1	2248.5	DRY	25-Mar-67	BCS	Group 2
100060606902W500	SUN ET AL MITSUE 6-6-69-2	SUN 06-06	623.6		2064.4	DRY	12-Feb-66	PRECAMBRIAN	Group 2
100062906802W500	ARCO ET AL MITSUE 6-29-68-2	ARCO 6-29	606.6		2044	DRY	28-Dec-67	PRECAMBRIAN	Group 2
100070606504W500	MICH WIS PAN AM IOE TIMEU 7-6-65-4	MICH 7-6	701	697.4	2411	DRY	27-Aug-68	PRECAMBRIAN	Group 2
100110306710W400	CHIEFCO ET AL TOUCHWOOD 11-3-67-10	CHIEFCO 11-3	655	651.4	1480.7	DRY	25-Jan-69	PRECAMBRIAN	Group 2
100103505903W500	HOME BARRHEAD 10-35-59-3	HOME 10-35	667.5	663.5	2514	DRY	9-Dec-64	BCS	Group 2
100121406702W500	CNRL TIELAND 12-14-67-2	CNRL 12-14	619.4	615.1	2078.7	GAS	1-Feb-08	PRECAMBRIAN	Group 2
100101206615W400	ARCO B.A. VENICE 10-12-66-15	ARCO 10-12	578.8	575.2	1591.1	DRY	4-Mar-67	PRECAMBRIAN	Group 2
100113406710W400	KISSINGER KINNAIRD 11-34-67-10	KISSINGER 11-34	707.1	703.8	1513.3	DRY	19-Mar-75	PRECAMBRIAN	Group 2
102061306308W400	CDNOXY SWD 2 SUGDEN 6-13-63-8	CDNOXY 2/6-13	578.2	573.8	1462	ABD WTR DISP	16-Sep-91	PRECAMBRIAN	Group 2
100012706026W400	IMP-BAYSEL RIVERDALE NO. 1-27-60-26	IMP-BAYSEL 1-27	650.1	645.6	2291.5	DRY	13-Feb-56	BCS	Group 3 - Priority
100013405722W400	IMPERIAL EASTGATE NO. 1-34-57-22	IMPERIAL 01-34	645.9	641.3	2205.8	DRY	6-Sep-55	PRECAMBRIAN	Group 3 - Priority

UWI	Operator Well Name	Short Well Name	Kb Elev (m)	GL Elev (m)	Drill TD (m)	Current Status	Current Status Date	TD IN…	Wells evaluated by Petrophysicist for Project Screening. Used for GEN 2 Static Model
100063605823W400	IMP EGREMONT W 6-36-58-23	IMP 06-36	632.2	627.9	2242.4	DRY	30-Jan-53	PRECAMBRIAN	Group 3 - Priority
100082606016W400	EDWAND NO. 1	EDWAND 8-26	681.8	677.9	1905.3	GAS	5-Mar-64	BCS	Group 3 - Priority
100092905924W400	IMPERIAL CLYDE NO. 1	IMPERIAL 9-29	629.4	629.4	2294.2	DRY	24-Jul-48	PRECAMBRIAN	Group 3 - Priority
100131706723W400	IMPERIAL GROSMONT NO. 1 WELL	IMPERIAL 13-17	629.7	626.4	1952.5	DRY	31-Jan-50	PRECAMBRIAN	Group 3 - Priority
100161906219W400	IMPERIAL DARLING NO. 1	IMPERIAL 16-19	708.1	704.4	2012.6	DRY	13-Jul-49	PRECAMBRIAN	Group 3 - Priority
100081705321W400	IMPERIAL ARDROSSAN NO. 1	IMPERIAL 8-17	725.1	722.1	2377.7	DRY	6-Nov-48	BCS	Group 3
100052906201W500	IMPERIAL DAPP NO. 1	IMPERIAL 5-29	635.8	632.5	2308.9	DRY	19-Dec-48	PRECAMBRIAN	Group 3
100010107013W400	TENN HB B1 PICHE LAKE 1-1-70-13	TENN 01-01	582.5	577.9	1417.9	DRY	16-Mar-67	BASAL RED BEDS	Group 3
100011105312W400	IMPERIAL PLAIN LAKE NO. 1 WELL	IMPERIAL 1-11	695.6	692.5	1962	DRY	10-Dec-49	BCS	Group 3
100020306615W400	BEAR PARKFORD # 1 WELL	BEAR 2-3	575.8	572.7	1613.9	DRY	23-Oct-95	PRECAMBRIAN	Group 3
100020605904W500	GRT PLNS THUNDER LK 2-6-59-4	GRT 2-6	653.2	649.5	2347	DRY	24-Jun-62	UPPER CAMBRIAN	Group 3
100020807003W500	PENN WEST MITSUE 2-8-70-3	PENN 2-8	617.8	613.9	2050.1	SUS OIL	1-Oct-94	PRECAMBRIAN	Group 2
100021305513W400	WESTMIN HAIRY 2-13-55-13	WESTMIN 2-13	619	615	1745	DRY	14-Oct-83	PRECAMBRIAN	Group 3
100021605525W400	IMPERIAL VOLMER NO. 1	IMPERIAL 2-16	701	698	2216.5	ABD OIL	6-Aug-48	BASE DEVONIAN	Group 3
100021605622W400	IMPERIAL GIBBONS NO 1	IMPERIAL 2-16	653.5	650.1	2023.9	DRY	13-May-49	BASE DEVONIAN	Group 3
100021707103W500	HOME ALMINEX MITSUE 2-17-71-3	HOME 2-17	718.7	715.1	2112.9	DRY	17-May-64	PRECAMBRIAN	Group 3
100031405706W400	ELK POINT NO. 2	ELK 3-14	566.3	563.9	1328.6	DRY	26-Sep-46	CAMBRIAN	Group 3
100032804825W400	IMPERIAL EYOT NO. 1	IMPERIAL 3-28	757.7	754.1	2392.4	DRY	2-Jul-48	BASE DEVONIAN	Group 3
100040306910W400	MOBIL PAN AM HEART LAKE 4-3-69-10	MOBIL 4-3	766.9	762.9	1534.1	DRY	8-Feb-58	PRECAMBRIAN	Group 3
100041507002W500	TGT FUTURITY W HONDO 4-15-70-2	TGT 4-15	606.2	602.3	1970.2	DRY	14-Oct-58	PRECAMBRIAN	Group 3
100041606904W500	PAN AM A-1 PARKER LAKE 4-16-69-4	PAN 4-16	758.6		2251.6	DRY	23-Feb-58	PRECAMBRIAN	Group 3
100043307003W500	MOBIL ET AL HONDO 4-33-70-3	MOBIL 4-33	679.1	675.1	2093.7	DRY	4-Jan-65	PRECAMBRIAN	Group 2
100050606406W400	DEVON ARL GARTH 5-6-64-6	DEVON 5-6	581.4	578.4	1404	SWD	1-Feb-05	PRECAMBRIAN	Group 1
100050806605W400	BP PCI WDW 4 LEMING 5-8-66-5	BP PCI 5-8	641.7	637.7	1358	SUS SWD	2-Feb-96	CAMBRIAN	Group 3
100050907016W400	PAN AM A-1 AVENIR 5-9-70-16	PAN 05-09	566.9	563	1501.1	DRY	25-Feb-58	DEVONIAN	Group 3
100052806406W400	PAN AM GARTH A-1	PAN 5-28	607.5	603.5	1406.3	DRY	20-Nov-59	PRECAMBRIAN	Group 3
100053106506W500	HUDSON'S BAY EAST VIRGINIA HILLS 1	HUDSON'S 5-31	797.1	793.1	2567	ABD GAS	22-Feb-60	PRECAMBRIAN	Group 3
100060305107W500	NORTHROCK LAKEWOOD PEMBINA 6-3-51-7	NORTHROCK 6-3	824.8	819.6	3065.4	DRY	19-Sep-00	UPPER CAMBRIAN	Group 1
100060707108W500	NORTHENG ET AL ADAM 6-7-71-8	NORTHENG 6-7	760.3	753.4	2320	DRY	17-Dec-87	PRECAMBRIAN	Group 1
100060907108W500	PCI ADAMS 6-9-71-8	PCI 6-9	808.6	803.5	2350	ABD OIL	17-Jan-97	PRECAMBRIAN	Group 1
100061106919W400	TRIAD CALLING LAKE 6-11-69-19	TRIAD 6-11	539.5	535.8	1610.9	DRY	5-Oct-57	BASE DEVONIAN	Group 3
100061204906W400	VERMILION CONSOLIDATED OILS #15	VERMILION 6-12	604.4	602.9	1411.8	ABD GAS	15-Sep-51	UPPER CAMBRIAN	Group 3
100061404609W400	N.U.L. KINSELLA #75	N.U.L.KINS 6-14	704.7	701.3	2058	GAS	26-Apr-02	PRECAMBRIAN	Group 3
100061706411W400	TRIAD MOBIL RICH LAKE 6-17	TRIAD 6-17	609.6	605.6	1571.2	DRY	12-May-57	PRECAMBRIAN	Group 3
100062007007W500	HOME IMP FINA GRIZZLY MTN 6-20-70-7	HOME 6-20	1086.9	1083.3	2624.3	DRY	26-Mar-58	PRECAMBRIAN	Group 2
100062106716W400	PACIFIC PLAMONDON 6-21-67-16	PACIFIC 06-21	608.1	604.4	1646.8	DRY	16-Mar-58	BCS	Group 3
100062506105W500	TBE NEERLND 6-25-61-5	TBE 6-25	695.3	690.1	2311	ABD GAS	18-Oct-98	DEVONIAN	Group 1
100062506616W400	TRIAD BERNY 6-25	TRIAD 6-25	584	580	1619.7	DRY	19-Mar-57	BCS	Group 3
100062904521W400	CNRL DUHAMEL 6-29MU-45-21	CNRL 6-29	750.4	747.7	2121.7	ABD OIL	27-Feb-75	BASAL RED BEDS	Group 3
100063504615W400	MERLAND ET AL BRUCE 6-35-46-15	MERLAND 6-35	710.5	703.7	2114	DRY	9-Jul-91	PRECAMBRIAN	Group 1

UWI	Operator Well Name	Short Well Name	Kb Elev (m)	GL Elev (m)	Drill TD (m)	Current Status	Current Status Date	TD IN…	Wells evaluated by Petrophysicist for Project Screening. Used for GEN 2 Static Model
100070307108W500	PC PCP ADAMS 7-3-71-8	PC PCP 7-3	885	879.4	2300	DRY	7-Jan-91	PRECAMBRIAN	Group 3
100071007108W500	PCENT ADAMS 7-10-71-8	PCENT 7-10	850.6	846	2388.4	DRY	8-Mar-83	PRECAMBRIAN	Group 1
100071207111W400	RAX ET AL MILLS 7-12-71-11	RAX 7-12	649.5	645.6	1372.8	SUS GAS	1-Jul-06	BASAL RED BEDS	Group 3
100071405706W400	TEXEX ET AL ELK POINT 7-14-57-6	TEXEX 7-14	604.7	601.1	1588.6	DRY	18-Mar-56	PRECAMBRIAN	Group 3
100071407012W400	TENN HB A1 PICHE LAKE 7-14-70-12	TENN 07-14	609.3	605.3	1397.5	DRY	14-Feb-67	BASE DEVONIAN	Group 3
100073105105W400	HUSKY DH VERMILION 7A-31-51-5	HUSKY 07-31	625.8	622.1	1356.4	DRY	31-Jul-71	UPPER CAMBRIAN	Group 3
100080204614W400	SUNCOR BRUCE 8-2-46-14	SUNCOR 8-2	684.8	680.7	1664.5	DRY	14-Dec-84	CAMBRIAN	Group 3
100081106810W500	STAR ET AL SWANH 8-11-68-10	STAR 8-11	970.2		2739.5	PUMP OIL	1-Jan-61	PRECAMBRIAN	Group 3
100081705026W400	IMPERIAL LEDUC NO. 399	IMPERIAL 8-17	722.1	719.3	1638.6	ABD OIL	18-Jun-97	CAMBRIAN	Group 3
100082607106W500	CREE ET AL FLORIDA LAKE 8-26-71-6	CREE 08-26	823.6	820.2	2255.5	DRY	27-Feb-59	PRECAMBRIAN	Group 3
100082906410W500	IMP FORESTRY 8-29-64-10	IMP 8-29	959.8	956.2	2804.2	DRY	23-May-59	UPPER CAMBRIAN	Group 3
100083304604W400	HOMESTEAD ADMIRAL HOPE 8-33	HOMESTEAD 8-33	655.6		1696.8	DRY	24-Jul-56	UPPER CAMBRIAN	Group 3
100091804909W500	AMOCO HB PEMBINA 9-18-49-9	AMOCO 9-18	926.9	920.1	3300	GAS	1-Oct-93	PRECAMBRIAN	Group 3
100100304906W400	HUSKY DH WILDMERE 10-3-49-6	HUSKY 10-03	655	651.7	1822.1	DRY	20-Dec-67	UPPER CAMBRIAN	Group 2
100100305107W400	HUSKY D.H. VERMILLION 10-3-51-7	HUSKY 10-03	621.5		1402.1	DRY	22-Sep-70	UPPER CAMBRIAN	Group 3
100100806703W500	HOME ALMINEX KCL AKUINU 10-8-67-3	HOME 10-8	626.4	622.4	2090	DRY	21-Feb-64	BASE DEVONIAN	Group 3
100100907406W400	AMOCO KIRBY 10-9-74-6	AMOCO 10-9	634.6	630.6	1094.2	SUS GAS	30-Aug-03	BASE DEVONIAN	Group 3
100101006606W400	BP LEMING 10-10-66-6	BP LEMING 10-10	633.3	628.6	1363	DRY	18-Dec-98	PRECAMBRIAN	Group 1
100101505106W400	HUSKY DH VERMILION 10-15-51-6	HUSKY 10-15	629.1	625.1	1809	DRY	25-Jul-68	PRECAMBRIAN	Group 3
100101606706W500	IMP HB ROCHE LAKE 10-16-67-6	IMP 10-16	826	821.4	2365.2	DRY	23-Feb-61	UPPER CAMBRIAN	Group 3
100101606907W500	HOME IMP FINA GRIZZLY MTN 10-16-69-7	HOME 10-16	929		2515.5	DRY	19-Feb-59	PRECAMBRIAN	Group 2
100101707106W400	AMOCO AEC IPIATIK GRIST 10-17-71-6	AMOCO 10-17	657.1	652.9	1225	DRY	19-Mar-80	PRECAMBRIAN	Group 3
100101806106W500	FINA GREEN COURT 10-18-61-6	FINA 10-18	681.5	677.9	2632.3	DRY	11-Mar-66	PRECAMBRIAN	Group 2
100102006208W500	MOBIL OIL GOOSE CREEK 10-20-62-8	MOBIL 10-20	776.6	773	2787.4	DRY	11-Jan-58	PRECAMBRIAN	Group 3
100102106605W500	RRX FOLEY 10-21-66-5	RRX 10-21	751.9		2423.2	DRY	16-Jan-70	PRECAMBRIAN	Group 2
100102406705W500	HB VIRGINIA HILLS EAST 10-24-67-5	HB VIRGIN 10-24	751.6	748	2106.8	DRY	19-Feb-58	CONTACT RAPIDS	Group 3
100102605909W500	IMP ET AL LOMBELL 10-26MU-59-9	IMP 10-26	751.6	747.4	2621.3	ABD GAS	18-Jul-97	UPPER CAMBRIAN	Group 3
100102607107W400	AEC PHILLIPS WIAU 10-26-71-7	AEC 10-26	666.9	663.1	1230	GAS	1-Apr-97	PRECAMBRIAN	Group 3
100102807006W500	HOME FINA ALMINEX GRIZZLY 10-28-70-6	HOME 10-28	946.1	944	2429	DRY	1-Apr-65	PRECAMBRIAN	Group 2
100102907105W500	CHEVRON MITSUE 10-29-71-5	CHEVRON 10-29	721.5	717.5	2051.3	DRY	24-Dec-65	LOTSBERG	Group 3
100103307208W400	AEC PHILLIPS WIAU 10-33-72-8	AEC 10-33	714.1	710.7	1292	DRY	20-Mar-08	BASE DEVONIAN	Group 3
100111905006W400	HUSKY DH VERMILION 11-19-50-6	HUSKY 11-19	624.5	620.6	1827.6	DRY	2-Jul-68	PRECAMBRIAN	Group 2
100111906710W500	HOME REGENT EDITH SWANH 11-19-67-10	HOME 11-19	1066.8	1062.5	2917.5	SOLV INJ	31-Dec-70	PRECAMBRIAN	Group 3
100111906806W400	ESSO AEC 85 FISHCK 11-19-68-6	ESSO 11-19	671.3	668.3	1340	DRY	27-Feb-85	BASAL RED BEDS	Group 3
100112105908W500	WESTERN GREENCOURT #21-11	WESTERN 11-21	855.3	851.6	2607	DRY	14-May-54	BASE DEVONIAN	Group 3
100112407310W400	B.A. CLYDE LAKE 11-24	B.A.CLYDE 11-24	670.3	666.3	1266.4	DRY	13-Mar-57	TOP L SALT	Group 3
100112606910W400	ARCO HEART LAKE 11-26-69-10	ARCO 11-26	686.4	682.4	1432	DRY	24-Mar-67	BASE DEVONIAN	Group 3
100113507025W400	WHITE ROSE ET AL HONDO 11-35-70-25	WHITE 11-35	661.4	657.5	1905	DRY	11-Oct-58	PRECAMBRIAN	Group 2
100120606406W400	DEVON ARL GARTH 12-6-64-6	DEVON 12-6	588.4	585.4	1413	SWD	20-Nov-85	PRECAMBRIAN	Group 1
100121306306W500	HESS CR EF DORIS 12-13-63-6	HESS 12-13	719	714.8	2339	DRY	23-Mar-65	UPPER CAMBRIAN	Group 3

UWI	Operator Well Name	Short Well Name	Kb Elev (m)	GL Elev (m)	Drill TD (m)	Current Status	Current Status Date	TD IN…	Wells evaluated by Petrophysicist for Project Screening. Used for GEN 2 Static Model
100121906108W400	ALBERT W. LOTSBURG NO. 1	ALBERT 12-19	583.1	580.3	1461.5	DRY	31-Jul-50	MIDDLE CAMBRIAN	Group 3
100122107003W500	STAR ET AL MITSUE 12-21-70-3	STAR 12-21	692	688	1776	DRY	27-Oct-82	GRANITE WASH	Group 3
100122807103W500	MOBIL GEOG SE MITSUE 12-28-71-3	MOBIL 12-28	649.5	645.6	2009.5	DRY	21-Jul-65	PRECAMBRIAN	Group 2
100123607004W500	PENN WEST MITSUE 12-36-70-4	PENN 12-36	732.1	727.9	2148.8	WTR INJ	15-Apr-92	PRECAMBRIAN	Group 2
100130306011W400	CNRL ASHMONT 13-3-60-11	CNRL 13-3	657.8	655	1741.6	ABD GAS	14-Jul-00	PRECAMBRIAN	Group 3
100132205723W400	DORSET FEDORAH 13-22-57-23	DORSET 13-22	660.2		1981.2	DRY	8-Jun-48	LOTSBERG	Group 3
100140506605W400	BP PCI WDW9 LEMING 14-5-66-5	BP PCI 14-5	641.6	641.5999756	2071	ABD WTR DISP	12-Dec-01	PRECAMBRIAN	Group 3
100141405515W400	NORWEST WILLINGDON 14-14-55-14	NORWEST 14-14	633.4	629.7	1991.6	SUS SWD	11-May-98	PRECAMBRIAN	Group 3
100141405515W402	NORWEST WILLINGDON 14-14-55-14	NORWEST 14-14/2	633.4	629.7	1991.6	DRY	17-Jun-81	PRECAMBRIAN	Group 3
100142805506W400	AMOCO B-26 LINDBERGH 14-28-55-6	AMOCO 14-28	669.6	666.3	662	ABD BITUMEN	17-Jan-93	CAMBRIAN	Group 3
100142904806W500	IMP CDN-SUP PEMBINA 14-29BR-48-6	IMP 14-29	856.5	851.9	3146.1	ABD OIL	28-Jul-94	UPPER CAMBRIAN	Group 3
100150605626W400	IMPERIAL MEARNS NO. 1	IMPERIAL 15-6	699.8	696.8	2534.7	DRY	20-Dec-48	PRECAMBRIAN	Group 3
100152104827W400	ESSO WIZARD LAKE CPR B-3	ESSO 15-21	774.8	774.8	2906.9	FLOW OIL	1-Jan-98	PRECAMBRIAN	Group 3
100160507108W500	SEARCH PCP ADAMS 16-5-71-8	SEARCH 16-5	799.7	794.8	2344	PUMP OIL	10-Mar-90	PRECAMBRIAN	Group 1
100160604804W500	CS ETAL KEYSTONE 16-6-48-4	CS ETAL 16-6	810.2	805.9	2874.3	DRY	24-Aug-59	BASE DEVONIAN	Group 3
100160906022W400	AMOCO THORHILD 16-9-60-22	AMOCO 16-9	669.5		1808	DRY	21-Jun-84	LOTSBERG	Group 3
100161004613W400	SUNCOR ET AL KILLAMN 16-10-46-13	SUNCOR 16-10	707.9	703.3	1666.5	DRY	16-Jun-84	CAMBRIAN	Group 3
100161704820W400	IMPERIAL DINANT NO. 1	IMPERIAL 16-17	755.6	751.6	2519.5	DRY	21-Feb-52	PRECAMBRIAN	Group 3
100162205922W400	MOSAIC THORH 16-22-59-22	MOSAIC 16-22	647.5	642.9	1845	DRY	18-Feb-85	LOTSBERG	Group 3
100162705512W400	CHEMCELL DUVERNAY NACL 16-27-55-12	CHEMCELL 16-27	556	552.6	1539.8	ABD SERVICE	16-Sep-80	BASAL RED BEDS	Group 3
100162805608W400	PACIFIC SUNRAY ELK POINT 1	PACIFIC 16-28	630	626.4	1708.1	DRY	25-Nov-56	PRECAMBRIAN	Group 3
100163607124W400	CHEVRON CALLING LAKE 16-36-71-24	CHEVRON 16-36	665.7	661.7	1826.1	DRY	26-Mar-55	PRECAMBRIAN	Group 3
102142805506W400	AMOCO INJ LINDBERGH 14-28-55-6	AMOCO 2/14-28	673	668	1398	WASTE DISP	1-Apr-99	LOTSBERG	Group 3
103081705026W400	IMPERIAL LEDUC NO. 530	IMPERIAL 3/8-17	723.3	719.6	2741.7	DRY	11-Dec-74	PRECAMBRIAN	Group 3

Schematic of Static and Dynamic Model Boundaries and Associated Wells

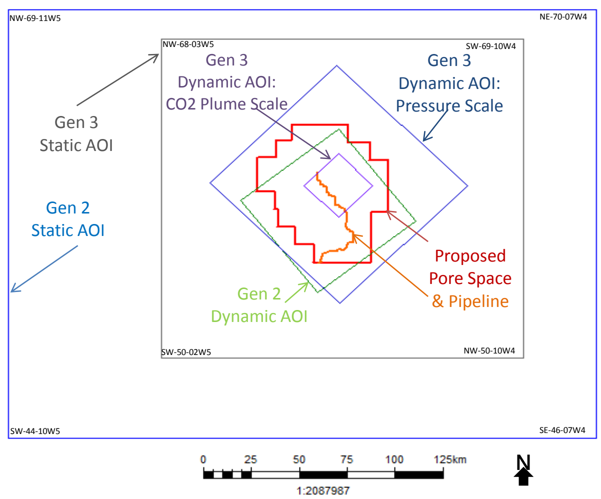


Figure 1: Schematic outline of the boundaries of the various generations of subsurface models. GEN 2 Model: Early regional scale tank model used for D65 application. GEN 3 Model: Focused Area of evaluation within the Pore Space Application area incorporating facies and associated property heterogeneities. GEN 3 Model currently in progress awaiting results of Radway 8-19-059-20W5.

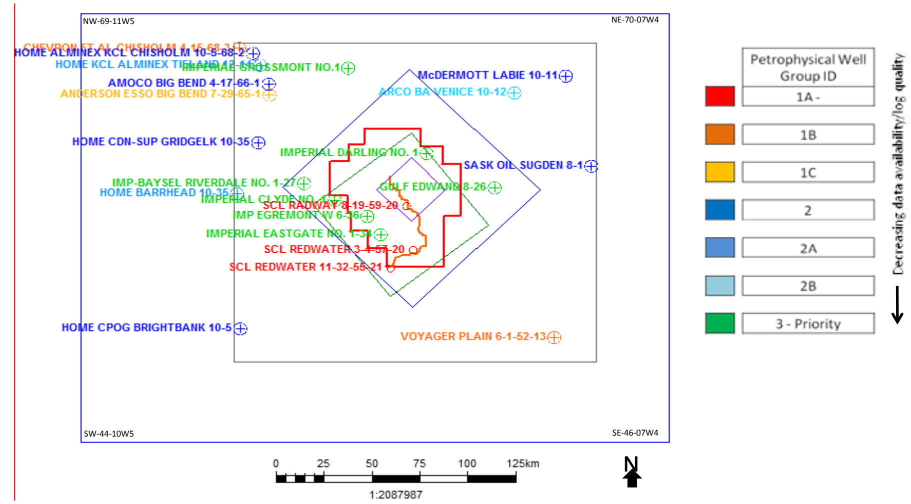
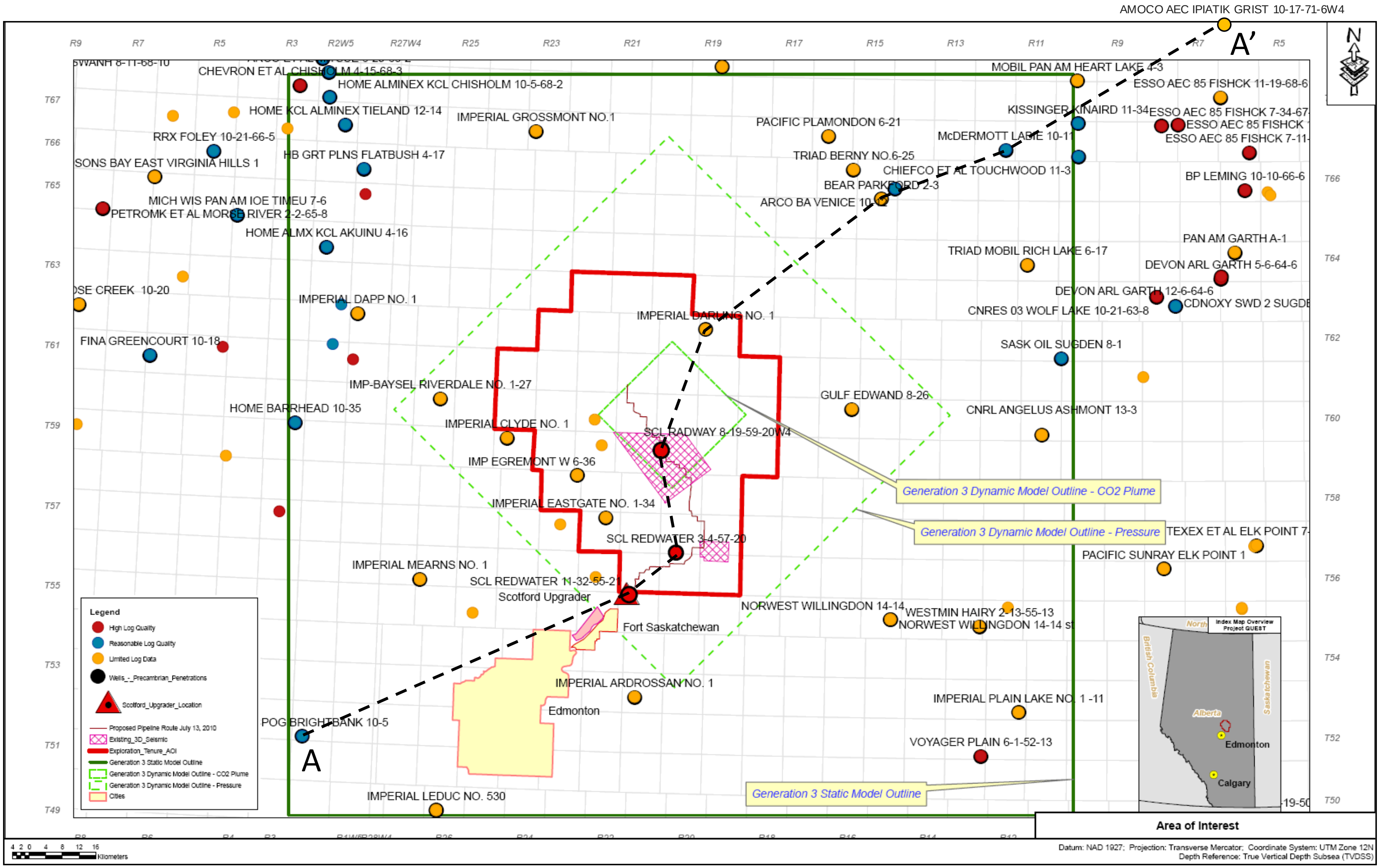


Figure 2: Wells used to populate Static and Dynamic Models. Group 1A-1C: Wells with at least GR, Density, Neutron, Sonic and Resistivity logs. Group 2-2B: Wells with only sonic logs and some neutron logs available to calculate porosities. Log quality lower than Group 1 but sufficient to assess rock properties within a reasonable uncertainty range. Group 3 – Priority: wells within the AOI with very limited data, porosities primarily estimated from neutron logs.

Appendix D Annotated Regional Cross-Section

D.1 Map of Wells Included in the Regional Cross-Section



AMOCO AEC IPIATIK GRIST 10-17-71-6W4
A'
A
MOBIL PAN AM HEART LAKE 4-3
ESSO AEC 85 FISHCK 11-19-68-6
CHEVRON ET AL CHISHOLM 4-15-68-3
HOME ALMINEX KCL CHISHOLM 10-5-68-2
HOME KCL ALMINEX TIELAND 12-14
IMPERIAL GROSSMONT NO.1
PACIFIC PLAMONDON 6-21
KISSINGER KINAIRD 11-34
McDERMOTT LABIE 10-11
RRX FOLEY 10-21-66-5
HB GRT PLNS FLATBUSH 4-17
TRIAD BERNY NO.6-25
CHIEFCO ET AL TOUCHWOOD 11-3
BEAR PARKFORD 2-3
ARCO BA VENICE 10
BP LEMING 10-10-66-6
MICH WIS PAN AM IOE TIMEU 7-6
PETROMK ET AL MORSE RIVER 2-2-65-8
HOME ALMX KCL AKUINU 4-16
PAN AM GARTH A-1
TRIAD MOBIL RICH LAKE 6-17
DEVON ARL GARTH 5-6-64-6
DEVON ARL GARTH 12-6-64-6
CNRES 03 WOLF LAKE 10-21-63-8
IMPERIAL DAPP NO. 1
IMPERIAL DARLING NO. 1
FINA GREENCOURT 10-18
SASK OIL SUGDEN 8-1
IMP-BAYSEL RIVERDALE NO. 1-27
GULF EDWAND 8-26
HOME BARRHEAD 10-35
CNRL ANGELUS ASHMONT 13-3
IMPERIAL CLYDE NO. 1
SCL RADWAY 8-19-59-20W4
IMP EGREMONT W 6-36
Generation 3 Dynamic Model Outline - CO2 Plume
IMPERIAL EASTGATE NO. 1-34
Generation 3 Dynamic Model Outline - Pressure
SCL REDWATER 3-4-57-20
PACIFIC SUNRAY ELK POINT 1
IMPERIAL MEARNS NO. 1
SCL REDWATER 11-32-55-21
Scotford Upgrader
NORWEST WILLINGDON 14-14
WESTMIN HAIRY 2-13-55-13
Fort Saskatchewan
IMPERIAL ARDROSSAN NO. 1
IMPERIAL PLAIN LAKE NO. 1 -11
Edmonton
POG BRIGHTBANK 10-5
VOYAGER PLAIN 6-1-52-13
Generation 3 Static Model Outline
IMPERIAL LEDUC NO. 530
Legend
High Log Quality
Reasonable Log Quality
Limited Log Data
Wells_-_Precambrian_Penetrations
Scotford_Upgrader_Location
Proposed Pipeline Route July 13, 2010
Existing_3D_Seismic
Exploration_Tenure_AOI
Generation 3 Static Model Outline
Generation 3 Dynamic Model Outline - CO2 Plume
Generation 3 Dynamic Model Outline - Pressure
Cities
Index Map Overview Project QUEST
British Columbia
Alberta
Saskatchewan
Edmonton
Calgary
Area of Interest
Kilometers
Datum: NAD 1927; Projection: Transverse Mercator; Coordinate System: UTM Zone 12N
Depth Reference: True Vertical Depth Subsea (TVDSS)

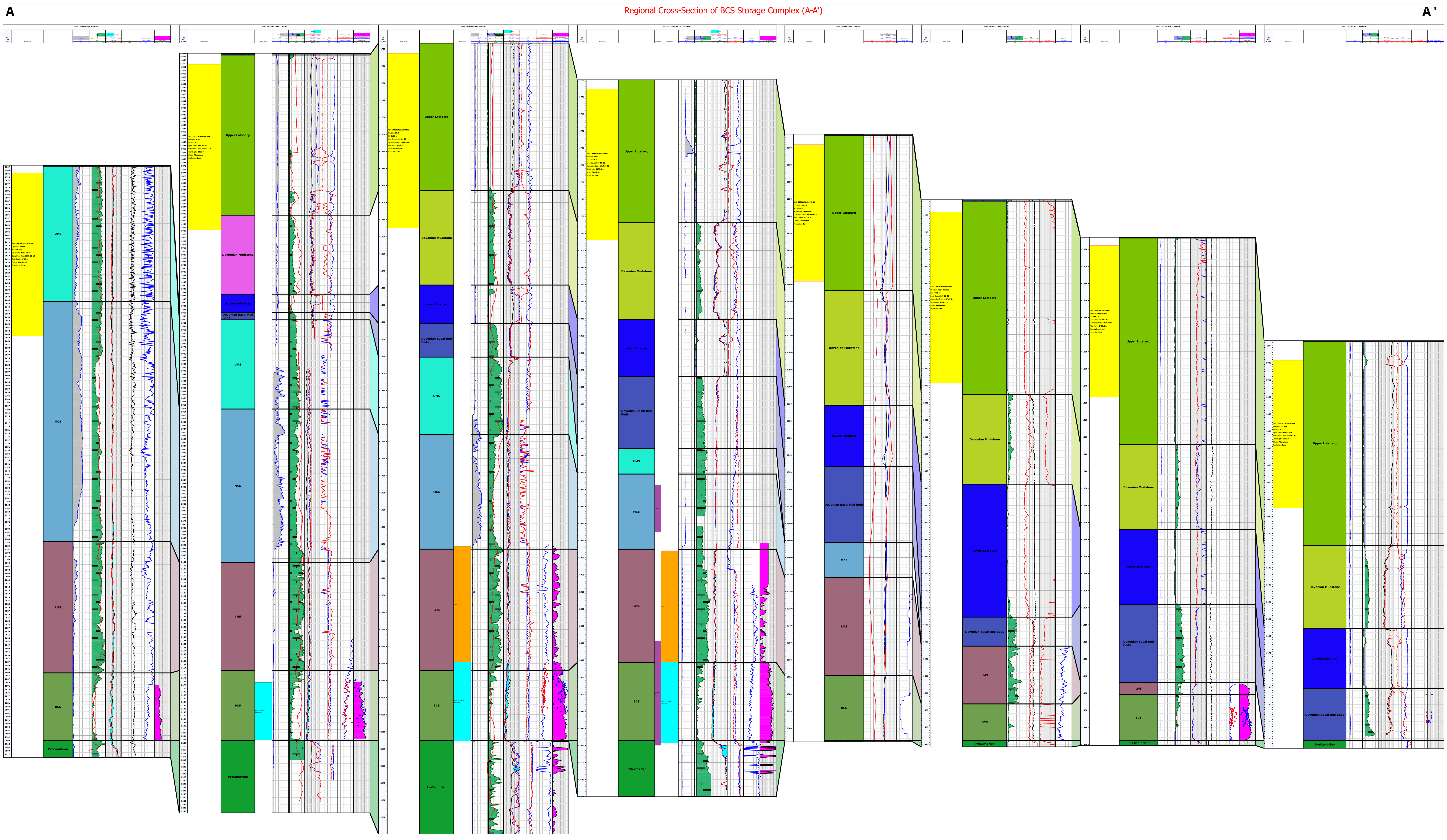
D.2 Location of Completions and Treatments to Wellbore – Cumulative Production and KB

Well UWI*	Well Name	Rig Release Date (d/m/y)	Status	Production	KB(m)	DST	MDT fluid samples	Mini/Micro Frac	Water Injection Test	Formation	Top (m TVD)	Base (m TVD)	Result
100/10-05--052-02W4/00	HOME CPOG BRIGHTBANK 1	8/1/1968	Abandoned	none	745.5	1				BFS, Viking	1224.7	1249.7	saline water
						2				Nisku	1740.4	1758.7	misrun - water
						3				Muskeg	2441.4	2465.8	misrun - water
1AA/11-32-55-21W4/00	SCL REDWATER 11-32-55-21	2/1/2008	Standing	none	627.9		1			BCS	2191.6	-	Highly Saline
							2			BCS	2198.0	-	Highly Saline
								2		LMS	2122	2123	microfrac
								1		LMS	2150.5	2151.5	microfrac
								1		BCS	2188	2193	minifrac
									1	BCS	2172.92	2173.38	H20 injectivity test
									2	BCS	2173.99	2174.6	H20 injectivity test
									3	BCS	2176.12	2176.73	H20 injectivity test
									4	BCS	2179.62	2181.45	H20 injectivity test
									5	BCS	2182.52	2187.09	H20 injectivity test
									6	BCS	2193.01	2196.24	H20 injectivity test
									7	BCS	2197.3	2202.64	H20 injectivity test
100/03-04-57-20W4/00	SCL REDWATER 3-4-57-20	18/3/2009											
100/08-19-059-20W4/00	SCL RADWAY 8-19-59-56	9/9/2010	Standing		646.76		1			BCS	2084.9	-	not yet analyzed
								1		BCS	2048.5	2049.5	minifrac
									1	BCS	2055	2085	H20 injectivity test
100/16-19-062-19W4/00	IMPERIAL DARLING NO. 1	9/7/1949	Abandoned	none	708.1	1				Viking	544.4	549.9	5490m3/d gas cut mud
						2				Viking	549.2	551.4	saline water
						3				McMurray	700.4	705.9	misrun
						4				McMurray	700.7	702.9	saline water
						5				Wabamun	720.2	726.9	mud
						6				Wabamun	727.9	733	saline water
						7				Nisku	765	767.5	mud
						8				Nisku	774.8	777.2	saline water
						9				Moberly	1228.6	1242.4	saline water
100/10-12-066-15W4/00	ARCO BA VENICE 10-12	25/2/1967	Abandoned	none	578.8	1				Viking	297.2	354.5	gas cut mud
						2				Clearwater Group	464.8	508.7	misrun
						3				Clearwater Group	463.3	508.7	gas cut saline water
						4				Winnipegosis	1143	1173.5	mud
						5				Moberly	792.5	832.1	saline water
						6				Basal Red Beds- LMS	1531.6	1562.1	Salty Water
100/10-11-067-12W4/00	McDERMOTT LABIE 10-11	3/2/1968	Abandoned	none	597.7	1				McMurray	473.1	479.2	mud
						2				Viking	283.5	290.5	misrun
						3				Basal Red Beds-BCS	1446	1482.2	Saline water
100/10-17-071-06W4/00	AMOCO AEC IPIATIK GRIST 1	5/3/1980	Abandoned	none	657.1	1				Beaverhill Lake	515	530	Oil Cut Mud
						2				Ernestina lake-Lotsberg	973	983	mud. No Gas.

* Wells are listed from top (A-SW) to bottom (A' - NE)

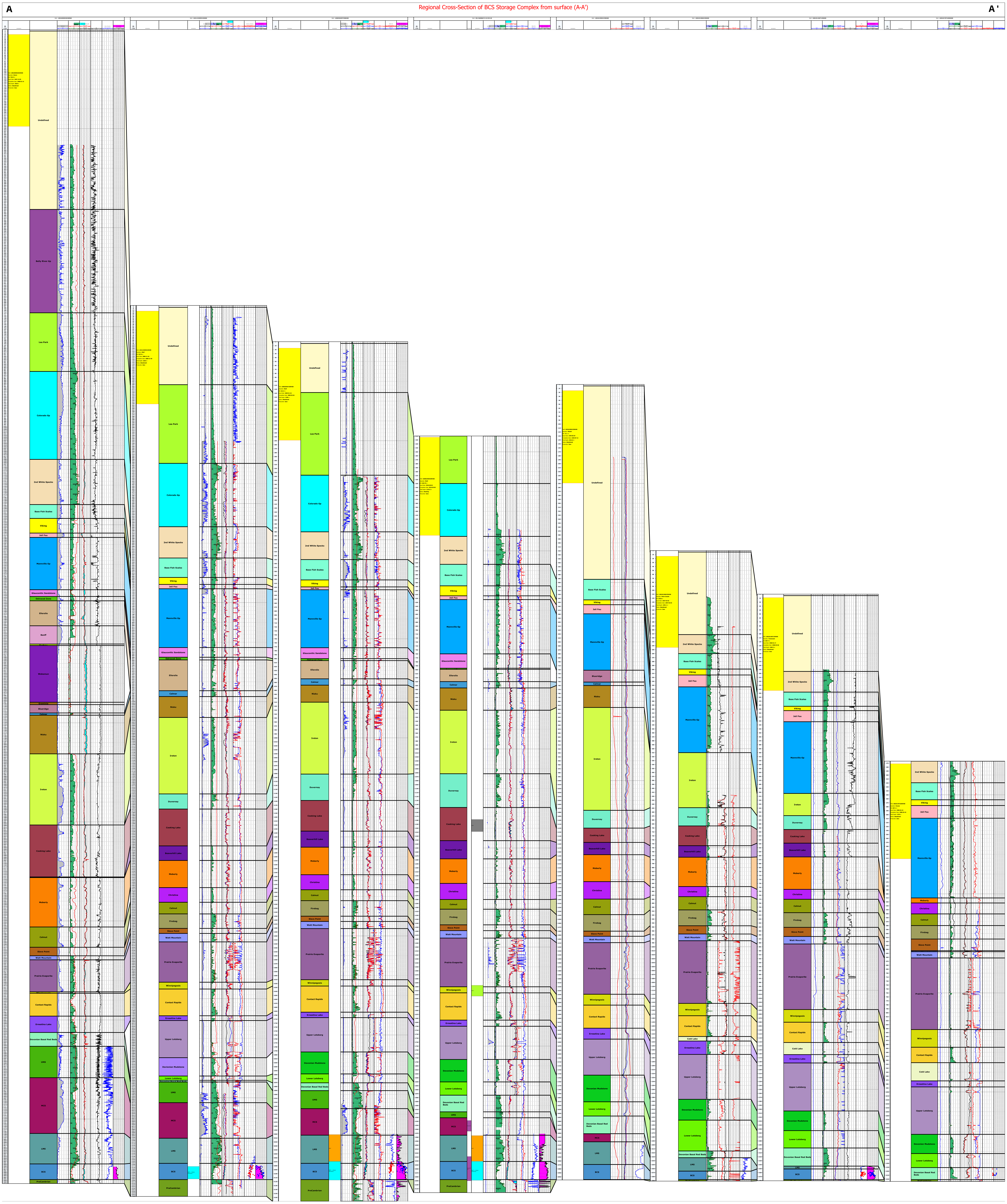
D.3 Regional Cross-Section BCS Storage Complex

In map pocket at back of binder


A
Regional Cross-Section of BCS Storage Complex (A-A')
A'
Upper Lotsberg
Devonian Mudstone
Lower Lotsberg
Devonian Basal Red Beds
UMS
MCS
LMS
BCS
PreCambrian

D.4 Regional Cross-Section Surface to Basement

In map pocket at back of binder


Regional Cross-Section of BCS Storage Complex from surface (A-A')
A
A'

Appendix E Abandonment Status of Legacy Wells

E.1 Abandonment Status of Legacy Wells

E.1.1 Abandoned Wells

Seven third-party abandoned wells penetrate the BCS storage complex in the pore-space tenure Area of Interest (AOI). Most of the wells were completed open hole for appraisal then were a bandoned by i nstalling m ultiple c ement pl ugs i n t he open-hole sect ion. However, Well 7-17 was reconverted to a gas storage well and abandoned in 2007. For a summary of the main information about the status of the legacy wells, see Table E-1.

Table E-1 Abandoned Third-Party Legacy Wells

Well Name and UWI	History	Seals Penetrated	Casings and Holes	Cement Plugs
Imperial Eastgate 100-01-34-057-22W400	• Drilled and abandoned in 1955	• Upper Lotsberg • Lower Lostberg • MCS	• 9 5/8" casing to 277 m • 9" openhole to 2,205 m (TD)	#1: 265 – 289 m #2: 644 – 710 m #3: 887 – 981 m #4: 1016 – 1,048 m #5: 1256 – 1,292 m #6: 2125 – 2,205 m
Imperial Egremont 100-06-36-058-23W400	• Drilled and abandoned in 1952	• Upper Lotsberg • Lower Lostberg • MCS	• 13 3/8" casing to 186 m • 9" openhole to 2,235 m (supposed TD)	#1: 172 – 195 m #2: 624 – 670 m #3: 844 – 875 m #4: 969 – 1,003 m #5: 1178 – 1218 m #6: 2140 – 2,235 m
Imperial Darling No. 1 100-16-19-062-19W400	• Drilled and abandoned in 1949	• Upper Lotsberg • Lower Lostberg • MCS	• 13 3/8" casing to 183 m • 9" (supposed) openhole to 2,013 m	#1: 168 – 198 m #2: 525 – 587 m #3: 708 – 740 m #4: 762 – 792 m
Imperial Baysel Riverdale 100-01-27-060-26W400	• Drilled and abandoned in 1956	• Upper Lotsberg • Lower Lostberg • MCS	• 13 3/8" casing to 188 m • 9" openhole to 2,393 m (TD)	#1: 175 – 200 m #2: 710 – 765 m #3: 971 – 1,009 m #4: 1136 – 1,204 m #5: 1531 – 1,587 m #6: 1750 – 1,783 m
Imperial Clyde No.1 100-09-29-059-24W400	• Drilled and abandoned in1948	• Upper Lotsberg • Lower Lostberg • MCS	• 13 3/8" casing to 135 m • 9" openhole to 2,295 m (TD)	#1: 128 – 195 m #2: 781 – 945 m
Imperial Gibbons No.1 100-02-16-056-22W400	• Drilled and abandoned in 1949	• Upper Lotsberg • Lower Lostberg	• TD at 2,024 m • Well report gathering in process	Well report gathering in process
Imperial PLC Redwater LPGS 100-07-17-056-21W400	• Drilled in 1974 • Converted to LPG reproducer in 1975 • Abandoned in 2007	• Upper Lotsberg	• 13 3/8"casing to 188 m • 9 5/8" casing to 1,778 m • 7" casing to 1770 • TD at 1861m	Well report gathering in process

The available well reports do not confirm the integrity of the plugs. Therefore, the initial and current conditions of the wells are not known and cannot be determined without intervening in the wells, which is considered risky and complex. A recent field visit confirmed that no equipment has been left on site on any of these well locations.

At least two wells have their first cement plug above the BCS storage complex and have the potential for open communication between the BCS and the Winnipegosis (first permeable formation above the BCS storage complex). However, all these wells are located at more than 21 km from the planned injection wells, far from the CO_2 plume extent that is expected to be not more than 2.5 km from each injection well. Therefore, potential CO_2 migration through these wells outside of the BCS storage complex is very unlikely.

E.1.2 Active Wells

Four third-party active gas storage wells penetrate a portion of the Upper Lotsberg, which is the first seal of the BCS storage complex.

- Provident 16 (100-14-01-056-22W400)
- Provident 15 (100-12-01-056-22W400)
- Provident 14 (102-11-01-056-22W400)
- Provident 12 (100-11-01-056-22W401)

As they have all been drilled and completed recently (2006-2009) and are still active, they are accessible for further investigation. They are all located downdip, on the edge of the AOI, therefore potential CO_2 migration through these wells outside the BCS storage complex is very unlikely.

E.1.3 Shell Appraisal Wells

Recently, three Shell wells were drilled in 2008, 2009 and 2010, penetrating the BCS as part of the appraisal phase of the Quest CCS Project. For details on their current status, see Table E-2.

Table E-2 Recently Drilled Shell Appraisal Wells

Well Name and UWI	TD	Status
SCL Redwater 102-11-32-55-21-W4M	2,269 m	Well cased and cemented to TD. BCS abandoned and well reconverted as a water disposal well
SCL-Redwater 03-04-57-20W4M	2,190 m	Well cased and cemented to TD. Well suspended with 19 joints of drillpipe and liner running tool cemented in hole. Top of cement at 1696.5 m with top of fish at 1672 m
SCL-Radway 8-19-59-20W4	2,132 m	Well cased and cemented to TD. Well suspended, will be part of the Project injection wells

All wells are still accessible. The Redwater 3-4 well will be re-entered, either for abandonment, or for converting into an observation well.

Appendix F Consents to Drill, Log and Test

F.1 Government of Alberta Consent and Authorization

Shell Canada Limited has obtained, from the Government of Alberta Department of Energy, the required consents to conduct drilling and testing on the following undisposed Crown lands:

- 08-19-059-20W4: Consent to Drill and Log, received March 5, 2010 (see Section F.1.1). Additional testing consent received July 7, 2010 (see Section F.1.2).
- 07-11-059-20W4: Consent to Drill, Log and Test, received October 15, (see Section F.1.3)
- 10-06-060-20W4: Consent to Drill, Log and Test received October 15, (see Section F.1.3)
- 12-14-060-21W4: Consent to Drill, Log and Test, received October 15, (see Section F.1.3)
- 15-29-060-21W4: Consent to Drill, Log and Test received October 15, (see Section F.1.3)

Shell Canada Limited has also obtained, from the Government of Alberta Department of Energy, the required authorization to proceed with completions and stimulation operations for the 00/08-19-059-20W4/0 well (see Section F.1.4).

F.1.1 Consent to Drill and Log in Undisposed Crown Rights, Received March 5, 2010

Government of Alberta
Energy

Resource Revenue and Operations
Tenure
2nd Floor, North Petroleum Plaza
9945-108 Street
Edmonton, Alberta T5K 2G6
Telephone: 780/427-8062
Fax: 780/422-1123
Email: Retha.Purkis@gov.ab.ca

March 5, 2010

SHELL CANADA LIMITED
400 4 AVE SW
PO BOX 100 STN M
CALGARY AB T2P 2H5

Attention: Frank Terner
Land Representative

Re: Consent to Drill and Log in Undisposed Crown
QUEST CCS Test Wells
00/08-19-059-20W4/0 (WLG 10030161)
00/09-09-062-22W4/0 (WLG 10030162) herein called "the Subject Wells"

Alberta Energy has reviewed your requests for CO_2 disposal/injection received on February 17, 2010. At this time, Alberta Energy authorizes the drilling, coring and logging in undisposed Crown rights in the Basal Cambrian zone in the Subject Wells for the purpose of establishing that the Basal Cambrian zone is non-hydrocarbon bearing.

Alberta Energy will need to review your drilling and logging data to confirm that the Basal Cambrian zone is non-hydrocarbon bearing before authorizing the injection and/or microfrac testing of any specific intervals in the upper Basal Cambrian or PreCambrian zone in the Subject Wells. Alberta Energy also requests that Shell provide a depth and a reason why a microfrac into the PreCambrian zone is required. Authorizations regarding carbon dioxide storage or disposal will not be considered until we have received all well logs, gas detection logs and strip logs illustrating the chip sample descriptions, and have reviewed those logs and satisfied ourselves as to the matters referred to above. Final approval for disposal will be subject to the new tenure process currently being developed.

This authorization is given upon the following conditions:

(1) The Subject Wells must be licensed within six (6) months from the date of this letter;

(2) If well licences are not issued by the ERCB in respect of the Subject Wells within the six-month period referred to in condition 1, this authorization is null and void and you must make a fresh application for another authorization;

(3) In addition to the requirements of paragraph 2 above, all information and data obtained from the Subject Wells must be submitted to the ERCB;

. . . / 2

(4) If hydrocarbons are encountered during the conduct of operations or activities in respect of the Subject Wells, those operations must cease and Alberta Energy must be informed immediately and all data on the hydrocarbons will be made available to the public via the ERCB;

(5) The activities and operations authorized by this letter must be performed in accordance with ERCB requirements;

(6) Shell Canada Limited hereby indemnifies and saves harmless Her Majesty from and against any and all actions, suits, proceedings, claims, demands, losses, liabilities, damages and costs which may be brought against or suffered by Her Majesty or which Her Majesty may sustain, pay or incur, by reason of or in connection with operations or activities conducted in respect of the Subject Wells by Shell Canada Limited, its servants, agents or contractors.

(7) Shell Canada Limited also assumes liability and responsibility for any injury, damage, loss, debts, costs, damages and expenses which it or its employees, agents or contractors may suffer, sustain, pay or incur by reason of any matter or thing arising out of, or in any way attributable to, operations or activities conducted in respect of the Subject Wells by Shell Canada Limited, its servants, agents or contractors.

(8) Because this letter confers a personal and non-assignable right on Shell Canada Limited, Shell Canada Limited shall not assign, transfer or otherwise part with the possession of any of the rights, interests or privileges conferred or granted by this authorization.

Yours truly,

Retha Purkis

Retha Purkis
Director
Unconventional Tenure

/sgw

cc: ERCB
Attention: Nancy Barnes

F.1.2 Additional Testing Consent Received July 7, 2010

Government of Alberta
Energy

Resource Revenue and Operations
Tenure
2nd Floor, North Petroleum Plaza
9945-108 Street
Edmonton, Alberta T5K 2G6
Telephone: 780/427-8062
Fax: 780/422-1123
Email: Retha.Purkis@gov.ab.ca

July 7, 2010

SHELL CANADA LIMITED
400 4 AVE SW
PO BOX 100 STN M
CALGARY AB T2P 2H5

Attention: Alyssa Rohrick
Land Representative

Re: 00/08-19-059-20W4/0 (WLG 10030161)
<u>00/09-09-062-22W4/0 (WLG 10030162)</u>

Alberta Energy has reviewed your letter dated May 31, 2010. Alberta Energy authorizes Shell to obtain fluid samples for chemical analysis, as well as pressure and temperature measurements from the Keg River/Winnipegosis, Ernestina, Slave Point and Cooking Lake formations in the 00/08-19-059-20W4/0 and 00/09-09-062-22W4/0 wells.

Please ensure that all data obtained from the above wells are immediately submitted to the ERCB and to Alberta Energy. Contact me or Sharon Wong in my absence at sharon.wong@gov.ab.ca when the information is transmitted so that we are prepared to receive it. Also, please provide me with a timeline for testing these wells as there may be technical personnel from Alberta Energy who have an interest in observing the testing process.

Yours truly,

Retha Purkis

Retha Purkis
Director
Unconventional Tenure

/sgw

cc: ERCB
Attention: Nancy Barnes

F.1.3 Consent to Drill, Log and Test in Undisposed Crown Lands

Government of Alberta
Energy

Resource Revenue and Operations
Tenure
2nd Floor, North Petroleum Plaza
9945-108 Street
Edmonton, Alberta T5K 2G6
Canada
Telephone: 780/427-8062
Fax: 780/422-1123
Email: retha.purkis@gov.ab.ca

October 15, 2010

SHELL CANADA LIMITED
400 4 AVE SW
PO BOX 100 STN M
CALGARY AB T2P 2H5

Attention: Kelly Irish
Land Representative

Re: Consent to Drill and Log in Undisposed Crown
QUEST CCS Test Wells
00/07-11-059-20W4M (WLG 10090307)
02/10-06-060-20W4M (WLG 10090308)
00/12-14-060-21W4M (WLG 10090309)
00/15-29-060-21W4M (WLG 10090310) herein called "the Subject Wells"

Alberta Energy has reviewed your request received on September 3, 2010. At this time, Alberta Energy authorizes the drilling, coring, logging and sampling of the 00/07-11-059-20W4M, 02/10-06-060-20W4M, 00/12-14-060-21W4M and 00/15-29-060-21W4M wells through the Cambrian and into the Precambrian for the purpose of determining the presence or absence of hydrocarbons.

Please ensure that all drilling, logging, coring, sampling and test data obtained from the above wells are immediately submitted to the ERCB and to Alberta Energy. Alberta Energy will need to review these data prior to Shell's completions and stimulation operations, including injection testing and fracturing. To ensure Shell's operations are not delayed, Alberta Energy will endeavour to review these data within 2 business days of receipt. The information may initially be submitted electronically to Retha.Purkis@gov.ab.ca with a cc to Sharon.Wong@gov.ab.ca, followed by hard copies. Alberta Energy also requests that Shell inform us of the date and approximate hour that bottom hole is expected so that we can be prepared to review the technical data from each of the wells within the specified period.

Authorizations regarding carbon dioxide storage or disposal will not be considered until we have received and reviewed all well logs, gas detection logs, strip logs illustrating the chip sample descriptions, core, and chemical test data. Final approval for disposal will be subject to review of all technical data and the new tenure process currently being developed.

This authorization is given upon the following conditions:

(1) The Subject Wells must be licensed within six (6) months from the date of this letter;

Alberta
Freedom To Create. Spirit To Achieve.

(2) If well licences are not issued by the ERCB in respect of the Subject Wells within the six-month period referred to in condition 1, this authorization is null and void and you must make a fresh application for another authorization;

(3) As specified in paragraph 2 above, all information and data obtained from the Subject Wells must be submitted to the ERCB;

(4) If hydrocarbons are encountered during the conduct of operations or activities in respect of the Subject Wells, those operations must cease and Alberta Energy must be informed immediately and all data on the hydrocarbons will be made available to the public via the ERCB;

(5) The activities and operations authorized by this letter must be performed in accordance with ERCB requirements;

(6) Shell Canada Limited hereby indemnifies and saves harmless Her Majesty from and against any and all actions, suits, proceedings, claims, demands, losses, liabilities, damages and costs which may be brought against or suffered by Her Majesty or which Her Majesty may sustain, pay or incur, by reason of or in connection with operations or activities conducted in respect of the Subject Wells by Shell Canada Limited, its servants, agents or contractors;

(7) Shell Canada Limited also assumes liability and responsibility for any injury, damage, loss, debts, costs, damages and expenses which it or its employees, agents or contractors may suffer, sustain, pay or incur by reason of any matter or thing arising out of, or in any way attributable to, operations or activities conducted in respect of the Subject Wells by Shell Canada Limited, its servants, agents or contractors;

(8) Because this letter confers a personal and non-assignable right on Shell Canada Limited, Shell Canada Limited shall not assign, transfer or otherwise part with the possession of any of the rights, interests or privileges conferred or granted by this authorization.

Yours truly,

Retha Purkis

Retha Purkis
Director
Unconventional Tenure

/sgw

cc: ERCB
Attention: Nancy Barnes

F.1.4 Authorization for Completions and Stimulation Operations

Government of Alberta
Energy

Resource Revenue and Operations
Tenure
2nd Floor, North Petroleum Plaza
9945-108 Street
Edmonton, Alberta T5K 2G6
Telephone: 780/427-8062
Fax: 780/422-1123
Email: Retha.Purkis@gov.ab.ca

September 17, 2010

SHELL CANADA LIMITED
400 4 AVE SW
PO BOX 100 STN M
CALGARY AB T2P 2H5

Attention: Alyssa Rohrick
Land Representative

Re: QUEST CCS Test Well
00/08-19-059-20W4/0 (WLG 10030161)

Thank you for providing the well logs for the 00/08-19-059-20W4/0 well. Alberta Energy has reviewed the data and authorizes Shell to proceed with planned completions and stimulation operations, including injection testing and fracturing for the 00/08-19-059-20W4/0 well.

Please ensure that all drilling, logging, coring, sampling and test data obtained from the well are submitted to the ERCB and Alberta Energy. Final approval for disposal will be subject to review of all technical data and the new tenure process currently being developed.

Yours truly,

Retha Purkis

Retha Purkis
Director
Unconventional Tenure

/sgw

cc: ERCB
Attention: Nancy Barnes

Alberta
Freedom To Create. Spirit To Achieve.

Appendix G Mineral Ownership of Crown Rights in BCS Storage Complex

Table G-1: BCS Storage Complex Mineral Lessees

BCS Storage Complex Mineral Lessees

Agreement Number	*Issue Date*	*Current Expiry Date*	*Area (ha)*	*Company*	*Interest (%)*	*Legal Description*	*Rights (Short Name)*
0406030212	2006-03-09	2011-03-09	256.00	SEVERO ENERGY CORP.	100.00	059-20W4: Sec 29	P&NG from base of MANN to BSMT
0406030210	2006-03-09	2011-03-09	256.00	MUTINY OIL & GAS LTD.	100.00	059-20W4: Sec 20	P&NG from base of MANN to BSMT
0405080092	2005-08-11	2010-08-11	256.00	ANTELOPE LAND SERVICES LTD.	100.00	059-20W4: Sec 6	P&NG from SURF to BSMT
0405090090	2005-09-08	2010-09-08	256.00	WINDFALL RESOURCES LTD.	100.00	059-21W4: Sec 25	P&NG from SURF to base of 2WS
0405090090	2005-09-08	2010-09-08	256.00			059-21W4: Sec 25	P&NG from base of WAB to BSMT
0405080093	2005-08-11	2010-08-11	256.00	ANTELOPE LAND SERVICES LTD.	100.00	059-21W4: Sec 1	P&NG from SURF to BSMT
0408030243	2008-03-06	2013-03-06	256.00	SEVERO ENERGY CORP.	100.00	059-21W4: Sec 26	P&NG from base of MANN to BSMT
0405080090	2005-08-11	2010-08-11	256.00	ANTELOPE LAND SERVICES LTD.	100.00	058-21W4: Sec 34	P&NG from SURF to BSMT
0405080094	2005-08-11	2010-08-11	256.00	ANTELOPE LAND SERVICES LTD.	100.00	059-21W4: Sec 2	P&NG from SURF to BSMT
0410020107	2010-02-11	2015-02-11	256.00	HAWK EXPLORATION LTD.	100.00	059-21W4: Sec 14	P&NG from SURF to BSMT
0409070123	2009-07-09	2014-07-09	256.00	MOSAIC ENERGY LTD.	50.00	059-21W4: Sec 23	P&NG from base of 2WS to BSMT
0409070123	2009-07-09	2014-07-09	256.00	SEVERO ENERGY CORP.	50.00		
0405120722	2005-12-15	2010-12-15	256.00	INSIGNIA ENERGY LTD.	100.00	058-21W4: Sec 33	P&NG from SURF to BSMT
0406010193	2006-01-12	2011-01-12	256.00	CANADIAN NATURAL RESOURCES LIMITED	100.00	059-21W4: Sec 3	P&NG from SURF to BSMT
0408070458	2008-07-24	2013-07-24	256.00	INTEGRITY LAND INC.	100.00	059-21W4: Sec 28	P&NG from base of MANN to BSMT
0406010186	2006-01-12	2011-01-12	256.00	CANADIAN NATURAL RESOURCES LIMITED	100.00	058-21W4: Sec 32	P&NG from SURF to BSMT
0405120733	2005-12-15	2010-12-15	256.00	CANADIAN LANDMASTERS RESOURCE SERVICES L	100.00	059-21W4: Sec 9	P&NG from SURF to BSMT
0406030214	2006-03-09	2011-03-09	256.00	SEVERO ENERGY CORP.	100.00	059-20W4: Sec 32	P&NG from base of MANN to BSMT
0408120355	2008-12-18	2013-12-18	2304.00	ANGELS EXPLORATION FUND INC.	100.00	059-19W4: Sec 15 059-19W4: Sec 21 059-19W4: Sec 22 059-19W4: Sec 28 059-19W4: Sec 29	P&NG from SURF to BSMT
0408120355	2008-12-18	2013-12-18	2304.00			059-19W4: Sec 2 059-19W4: Sec 3 059-19W4: Sec 10 059-19W4: Sec 11	P&NG from base of MANN to BSMT
0408120356	2008-12-18	2013-12-18	1280.00	NYTIS EXPLORATION COMPANY INC.	50.00	059-19W4: Sec 30 059-19W4: Sec 32	P&NG from SURF to BSMT
0408120356	2008-12-18	2013-12-18	1280.00	SEVERO ENERGY CORP.	50.00	060-19W4: Sec 6	P&NG from base of VIK to BSMT
0408120356	2008-12-18	2013-12-18	1280.00			059-19W4: Sec 31 059-20W4: Sec 25	P&NG from base of WAB to BSMT
0406030216	2006-03-09	2011-03-09	256.00	NYTIS EXPLORATION COMPANY INC.	50.00	059-20W4: Sec 35	P&NG from base of MANN to BSMT
0406030216	2006-03-09	2011-03-09	256.00	SEVERO ENERGY CORP.	50.00		
0407110090	2007-11-01	2012-11-01	256.00	MUTINY OIL & GAS LTD.	100.00	059-20W4: Sec 23	P&NG from base of MANN to BSMT
0406030215	2006-03-09	2011-03-09	256.00	SEVERO ENERGY CORP.	100.00	059-20W4: Sec 34	P&NG from base of MANN to BSMT
0406030211	2006-03-09	2011-03-09	256.00	SEVERO ENERGY CORP.	100.00	059-20W4: Sec 27	P&NG from base of MANN to BSMT
0407100546	2007-10-18	2012-10-18	256.00	EMBER RESOURCES INC.	100.00	059-20W4: Sec 22	P&NG from base of MANN to BSMT
0406030823	2006-03-23	2011-03-23	256.00	SIFTON ENERGY INC.	100.00	060-20W4: Sec 33	P&NG from base of MANN to BSMT
0409040271	2009-04-30	2014-04-30	512.00	SOUTH BAY RESOURCES CANADA, ULC	100.00	058-20W4: Sec 22 058-20W4: Sec 27	P&NG from SURF to BSMT
0410020102	2010-02-11	2015-02-11	256.00	HAWK EXPLORATION LTD.	100.00	058-20W4: Sec 33	P&NG from SURF to BSMT

Table G-1: BCS Storage Complex Mineral Lessees

BCS Storage Complex Mineral Lessees

Agreement Number	Issue Date	Current Expiry Date	Area (ha)	Company	Interest (%)	Legal Description	Rights (Short Name)
0410020106	2010-02-11	2015-02-11	256.00	SOUTH BAY RESOURCES CANADA, ULC	100.00	059-20W4: Sec 4	P&NG from SURF to BSMT
0405080089	2005-08-11	2010-08-11	256.00	ENCANA CORPORATION	100.00	058-20W4: Sec 32	P&NG from SURF to BSMT
0405080087	2005-08-11	2010-08-11	256.00	TOWNSHIP LAND CO. LTD.	100.00	058-20W4: Sec 29	P&NG from SURF to BSMT
0405080091	2005-08-11	2010-08-11	256.00	TOWNSHIP LAND CO. LTD.	100.00	059-20W4: Sec 5	P&NG from SURF to BSMT
0405080088	2005-08-11	2010-08-11	256.00	ANTELOPE LAND SERVICES LTD.	100.00	058-20W4: Sec 30	P&NG from SURF to BSMT
0409010099	2009-01-08	2014-01-08	256.00	NYTIS EXPLORATION COMPANY INC.	100.00	060-20W4: Sec 17	P&NG from base of MANN to BSMT
0406030213	2006-03-09	2011-03-09	256.00	SEVERO ENERGY CORP.	100.00	059-20W4: Sec 31	P&NG from base of MANN to BSMT
0410020109	2010-02-11	2015-02-11	256.00	HAWK EXPLORATION LTD.	100.00	060-20W4: Sec 19	P&NG from SURF to BSMT
0407050566	2007-05-31	2012-05-31	256.00	TWOCO PETROLEUMS LTD.	100.00	060-20W4: Sec 30	P&NG from SURF to BSMT
0410030640	2010-03-25	2015-03-25	256.00	HAWK EXPLORATION LTD.	100.00	060-21W4: Sec 13	P&NG from SURF to BSMT
0409020068	2009-02-05	2014-02-05	1536.00	LANDSOLUTIONS INC.	100.00	060-22W4: Sec 35 060-22W4: Sec 36	P&NG from SURF to BSMT
0409020068	2009-02-05	2014-02-05	1536.00			060-22W4: Sec 25	P&NG from base of 2WS to BSMT
0409020068	2009-02-05	2014-02-05	1536.00			060-22W4: Sec 34	P&NG from base of VIK to BSMT
0409020068	2009-02-05	2014-02-05	1536.00			060-22W4: Sec 26 060-22W4: Sec 27	P&NG from base of MANN to BSMT
0407090138	2007-09-06	2012-09-06	256.00	SCOTT LAND & LEASE LTD.	100.00	060-21W4: S Sec 35 060-21W4: NW Sec 35	P&NG from SURF to BSMT
0407090138	2007-09-06	2012-09-06	256.00			060-21W4: NE Sec 35	P&NG from base of MANN to BSMT
0408030245	2008-03-06	2013-03-06	256.00	EMBER RESOURCES INC.	100.00	060-21W4: Sec 34	P&NG from base of 2WS to BSMT
0408030244	2008-03-06	2013-03-06	256.00	EMBER RESOURCES INC.	100.00	060-21W4: Sec 33	P&NG from SURF to BSMT
0405120111	2005-12-01	2010-12-01	256.00	CANADIAN NATURAL RESOURCES LIMITED	100.00	060-21W4: Sec 16	P&NG from SURF to BSMT
0405100169	2005-10-06	2010-10-06	768.00	SEVERO ENERGY CORP.	100.00	061-21W4: Sec 3 061-21W4: Sec 4 061-21W4: Sec 5	P&NG from SURF to BSMT
0409010095	2009-01-08	2014-01-08	256.00	NYTIS EXPLORATION COMPANY INC.	100.00	059-21W4: Sec 33	P&NG from base of 2WS to BSMT
0405120113	2005-12-01	2010-12-01	256.00	CANADIAN NATURAL RESOURCES LIMITED	100.00	060-21W4: Sec 32	P&NG from base of 2WS to BSMT
0406010199	2006-01-12	2011-01-12	64.00	NYTIS EXPLORATION COMPANY INC.	100.00	060-21W4: SE Sec 6	P&NG from base of 2WS to BSMT
0405120112	2005-12-01	2010-12-01	256.00	CANADIAN NATURAL RESOURCES LIMITED	100.00	060-21W4: Sec 31	P&NG from base of 2WS to BSMT
0405100168	2005-10-06	2010-10-06	256.00	SEVERO ENERGY CORP.	100.00	060-21W4: Sec 30	P&NG from SURF to BSMT
0408040150	2008-04-03	2013-04-03	256.00	SEVERO ENERGY CORP.	100.00	061-22W4: Sec 2	P&NG from SURF to BSMT
0409030381	2009-03-19	2014-03-19	256.00	SEVERO ENERGY CORP.	100.00	060-22W4: Sec 14	P&NG from base of VIK to BSMT
0409020067	2009-02-05	2014-02-05	256.00	CHINOOK ENERGY INC.	100.00	060-22W4: Sec 3	P&NG from base of MANN to BSMT
0409030199	2009-03-05	2014-03-05	256.00	SEVERO ENERGY CORP.	100.00	060-22W4: Sec 15	P&NG from base of MANN to BSMT
0408090074	2008-09-04	2013-09-04	256.00	NYTIS EXPLORATION COMPANY INC.	50.00	060-22W4: Sec 10	P&NG from base of MANN to BSMT
0408090074	2008-09-04	2013-09-04	256.00	SEVERO ENERGY CORP.	50.00		

Appendix H Notification Letter

Shell Canada Energy
400 4th Avenue S.W.
P.O. Box 100 Station M
Calgary,Alberta
T2P 2H5
Tel +1 403-691-3111
Internet http://www.shell.ca

November 22, 2010

See Attached Distribution List

Dear Sir/Madam:

Re: Information on Application for Approval of a Class III Carbon Dioxide Disposal Scheme
Shell Quest Carbon Capture and Storage Project
TWP 059 RGE 20W4M: 11, 19
TWP 060 RGE 20W4M: 6
TWP 060 RGE 21W4M: 14, 29

Shell Canada Limited, on behalf of Shell Canada Energy ("Shell"), as operator, is applying to the Energy Resources Conservation Board (ERCB/Board) pursuant to Part 15 of the *Oil and Gas Conservation Regulations* and Unit 4 of *Directive 065* for approval of a Class III Carbon Dioxide Disposal scheme.

The objective of this application is to:
Allow Shell to operate a proposed Carbon Capture and Storage scheme for the injection, storage and monitoring of carbon dioxide into the Basal Cambrian Sands formation at an approximate depth of 2050m below ground level in the following sections:

TWP 059 RGE 20W4M: 11, 19
TWP 060 RGE 20W4M: 6
TWP 060 RGE 21W4M: 14, 29

You are being notified of this application as part of the ERCB notification requirements pursuant to Directive 065.

Please direct any concerns and/or questions regarding this application to the undersigned.

You may also send your concerns in writing to:

Shell Canada Limited
400 – 4th Avenue S.W.
P.O. Box 100, Station M
Calgary, Alberta T2P 2H5

Or, by fax at (403) 384-5040

It will be considered an indication of non-objection should we not receive a response on or before December 13, 2010. Shell will be filing the subject application with the ERCB on or before December 31, 2010.

Should you have any concerns and/or objections, Shell will discuss your concerns with you. Should your concerns remain unresolved your concerns will be filed with the ERCB.

The ERCB application process is a public process, and all documents filed with the ERCB will be placed on the public record unless otherwise authorized by the Board in accordance with Section 12 of the *Alberta Energy and Utilities Board Rules of Practice, Alberta Energy and Utilities Board Act.*

If you would like to receive a copy of this application, please contact the undersigned.

Any questions regarding ERCB process should be directed to the ERCB Customer Contact Centre at (403) 297-8311.

Yours truly,

for Kelly Irish
Mineral Land Representative
Shell Canada Limited
Telephone: (403) 691-3423

Appendix I Offset Operators, Approval Holders and Licensees

Table I-1: 100/07-11-059-20W4/00 Notified Owners

Crown Mineral Lessees	Crown Coal Lessees	Active Offsetting Well Licencees	Freehold Mineral Owners	Freehold Coal Owners	Freehold Lessees
Severo Energy Corp.	N/A	Nytis Exploration Company Inc.	Canpar Holdings Ltd. (62.61% Mines and Minerals)	Carbon Development Corporation (100% Coal)	Apache Canada Ltd.
Nytis Exploration Company Inc.		Rocky River Petroleum Ltd.	Severo Energy Corp. (37.39% Mines and Minerals)		
Apache Canada Ltd.		Apache Canada Ltd.			
Angels Exploration Fund Inc.					
Mutiny Oil & Gas Ltd.					
Rocky River Petroleum Ltd.					
Ember Resources Inc.					
South Bay Resources Canada ULC					
Township Land Co. Ltd.					
Antelope Land Services Ltd.					
EnCana Corporation					
Hawk Exploration Ltd.					

Table I-2: 100/08-19-059-20W4/00 Notified Owners

Crown Mineral Lessees	Crown Coal Lessees	Active Offsetting Well Licencees	Freehold Mineral Owners	Freehold Coal Owners	Freehold Lessees
Severo Energy Corp.	Carbon Development Corporation	Severo Energy Corp.	Canpar Holdings Ltd. (62.61% Mines and Minerals)	Carbon Development Corporation (100% Coal)	Apache Canada Ltd.
Nytis Exploration Company Inc.	North Point Coal Company Limited	Nytis Exploration Company Inc.	Severo Energy Corp. (37.39% Mines and Minerals)		
Windfall Resources Ltd.					
Ember Resources Inc.					
Mutiny Oil & Gas Ltd.					
Hawk Exploration Ltd.					
Mosaic Energy Ltd.					
South Bay Resources Canada ULC					
Antelope Land Services Ltd.					
Township Land Co. Ltd.					
Canadian Natural Resources Limited					

Table I-3: 102/10-06-060-20W4/00 Notified Owners

Crown Mineral Lessees	Crown Coal Lessees	Active Offsetting Well Licencees	Freehold Mineral Owners	Freehold Coal Owners	Freehold Lessees
Hawk Exploration Ltd.	Carbon Development Corporation	Severo Energy Corp.	Canpar Holdings Ltd. (62.61% Mines and Minerals)	Carbon Development Corporation (100% Coal)	Apache Canada Ltd.
Nytis Exploration Company Inc.	North Point Coal Company Limited	Mosaic Energy Ltd.	Severo Energy Corp. (37.39% Mines and Minerals)		
Severo Energy Corp.					
Windfall Resources Ltd.					
Ember Resources Inc.					
Mutiny Oil & Gas Ltd.					
Mosaic Energy Ltd.					

Table I-4: 100/12-14-060-21W4/00 Notified Owners

Crown Mineral Lessees	Crown Coal Lessees	Active Offsetting Well Licencees	Freehold Mineral Owners	Freehold Coal Owners	Freehold Lessees
Canadian Natural Resources Limited	Carbon Development Corporation	Mosaic Energy Ltd.	N/A	N/A	
Apache Canada Ltd.	North Point Coal Company Limited	Nytis Exploration Company Inc.			
Mosaic Energy Ltd.		Apache Canada Ltd.			
Ember Resources Inc.					
Scott Land & Lease Ltd.					
Twoco Petroleums Ltd.					
Hawk Exploration Ltd.					
Nytis Exploration Company Inc.					
Monarch Energy Limited					
Severo Energy Corp.					

Table I-5: 100/15-29-060-21W4/00 Notified Owners

Crown Mineral Lessees	Crown Coal Lessees	Active Offsetting Well Licencees	Freehold Mineral Owners	Freehold Coal Owners	Freehold Lessees
Severo Energy Corp.	N/A	Severo Energy Corp.	N/A	N/A	
Nytis Exploration Company Inc.		Nytis Exploration Company Inc.			
Monarch Energy Limited		Ember Resources Inc.			
Mosaic Energy Ltd.		Mosaic Energy Ltd.			
Harlech Exploration Ltd.					
Landsolutions Inc.					
Canadian Natural Resources Limited					
Ember Resources Inc.					
Scott Land & Lease Ltd.					

Table I-6: Offset Active Well Names, Licencees and Modes

UWI	Well Name	Current Licencee	Mode
100/07-01-059-20W4/0	RRP RADWAY 7-1-59-20	ROCKY RIVER PETROLEUM LTD.	Standing
100/07-01-059-20W4/2	RRP RADWAY 7-1-59-20	ROCKY RIVER PETROLEUM LTD.	Standing
100/10-11-059-20W4/0	NYTIS RADWAY 10-11-59-20	NYTIS EXPLORATION COMPANY INC.	Flowing
100/13-14-059-20W4/0	NYTIS RADWAY 13-14-59-20	NYTIS EXPLORATION COMPANY INC.	Flowing
100/02-15-059-20W4/0	ACL RADWAY 2-15-59-20	APACHE CANADA LTD.	Flowing
100/02-15-059-20W4/2	ACL RADWAY 2-15-59-20	APACHE CANADA LTD.	Standing
100/02-15-059-20W4/4	ACL RADWAY 2-15-59-20	APACHE CANADA LTD.	Flowing
100/08-19-059-20W4/0	SCL RADWAY 8-19-59-20	SHELL CANADA LIMITED	N/A
100/15-20-059-20W4/0	SEVERO RADWAY 15-20-59-20	SEVERO ENERGY CORP.	Flowing
100/15-20-059-20W4/2	SEVERO RADWAY 15-20-59-20	SEVERO ENERGY CORP.	Suspended
100/10-29-059-20W4/0	SEVERO RADWAY 10-29-59-20	SEVERO ENERGY CORP.	Standing
100/10-29-059-20W4/2	SEVERO RADWAY 10-29-59-20	SEVERO ENERGY CORP.	Standing
100/14-29-059-20W4/0	SEVERO RADWAY 14-29-59-20	SEVERO ENERGY CORP.	Suspended
100/14-29-059-20W4/2	SEVERO RADWAY 14-29-59-20	SEVERO ENERGY CORP.	Flowing
100/14-29-059-20W4/3	SEVERO RADWAY 14-29-59-20	SEVERO ENERGY CORP.	Flowing
100/06-30-059-20W4/2	SEVERO RADWAY 6-30-59-20	SEVERO ENERGY CORP.	Suspended
100/15-30-059-20W4/2	SEVERO RADWAY 15-30-59-20	SEVERO ENERGY CORP.	Flowing
100/06-31-059-20W4/0	SEVERO RADWAY 6-31-59-20	SEVERO ENERGY CORP.	Comingled
100/06-31-059-20W4/2	SEVERO RADWAY 6-31-59-20	SEVERO ENERGY CORP.	Comingled
100/06-31-059-20W4/3	SEVERO RADWAY 6-31-59-20	SEVERO ENERGY CORP.	Flowing
100/09-31-059-20W4/2	SEVERO RADWAY 9-31-59-20	SEVERO ENERGY CORP.	Suspended
100/09-31-059-20W4/3	SEVERO RADWAY 9-31-59-20	SEVERO ENERGY CORP.	Flowing
100/09-31-059-20W4/4	SEVERO RADWAY 9-31-59-20	SEVERO ENERGY CORP.	Flowing
102/07-32-059-20W4/0	SEVERO 102 RADWAY 7-32-59-20	SEVERO ENERGY CORP.	Standing
102/07-32-059-20W4/2	SEVERO 102 RADWAY 7-32-59-20	SEVERO ENERGY CORP.	Flowing
102/07-32-059-20W4/3	SEVERO 102 RADWAY 7-32-59-20	SEVERO ENERGY CORP.	Flowing
102/15-24-059-21W4/0	NYTIS THORH 15-24-59-21	NYTIS EXPLORATION COMPANY INC.	Flowing
102/15-24-059-21W4/3	NYTIS THORH 15-24-59-21	NYTIS EXPLORATION COMPANY INC.	Standing
100/04-25-059-21W4/0	SEVERO THORH 4-25-59-21	SEVERO ENERGY CORP.	Suspended
100/10-25-059-21W4/2	SEVERO THORH 10-25-59-21	SEVERO ENERGY CORP.	Flowing
100/10-25-059-21W4/3	SEVERO THORH 10-25-59-21	SEVERO ENERGY CORP.	Comingled
100/02-36-059-21W4/2	SEVERO THORH 2-36-59-21	SEVERO ENERGY CORP.	Standing
100/02-36-059-21W4/3	SEVERO THORH 2-36-59-21	SEVERO ENERGY CORP.	Standing

Table I-6: Offset Active Well Names, Licencees and Modes

UWI	Well Name	Current Licencee	Mode
100/07-36-059-21W4/0	SEVERO THORH 7-36-59-21	SEVERO ENERGY CORP.	Suspended
100/07-36-059-21W4/2	SEVERO THORH 7-36-59-21	SEVERO ENERGY CORP.	Flowing
100/10-06-060-20W4/0	MOSAIC RADWAY 10-6-60-20	MOSAIC ENERGY LTD.	Suspended
100/04-07-060-20W4/0	MOSAIC RADWAY 4-7-60-20	MOSAIC ENERGY LTD.	Suspended
100/04-07-060-20W4/2	MOSAIC RADWAY 4-7-60-20	MOSAIC ENERGY LTD.	Suspended
100/10-01-060-21W4/0	MOSAIC THORH 10-1-60-21	MOSAIC ENERGY LTD.	Standing
100/10-01-060-21W4/2	MOSAIC THORH 10-1-60-21	MOSAIC ENERGY LTD.	Suspended
100/06-14-060-21W4/2	MOSAIC THORH 6-14-60-21	MOSAIC ENERGY LTD.	Flowing
100/03-15-060-21W4/2	NYTIS THORH 3-15-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
100/08-15-060-21W4/0	NYTIS THORH 8-15-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
100/09-15-060-21W4/0	NYTIS THORH 9-15-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
100/09-15-060-21W4/2	NYTIS THORH 9-15-60-21	NYTIS EXPLORATION COMPANY INC.	Standing
100/07-19-060-21W4/3	NYTIS THORH 7-19-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
100/05-20-060-21W4/0	NYTIS THORH 5-20-60-21	NYTIS EXPLORATION COMPANY INC.	Suspended
100/05-20-060-21W4/2	NYTIS THORH 5-20-60-21	NYTIS EXPLORATION COMPANY INC.	Suspended
100/05-20-060-21W4/3	NYTIS THORH 5-20-60-21	NYTIS EXPLORATION COMPANY INC.	Suspended
100/05-20-060-21W4/4	NYTIS THORH 5-20-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
102/05-20-060-21W4/0	NYTIS THORH 5-20-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
102/05-20-060-21W4/2	NYTIS THORH 5-20-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
100/10-20-060-21W4/2	NYTIS THORH 10-20-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
100/10-20-060-21W4/3	NYTIS THORH 10-20-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
100/10-20-060-21W4/4	NYTIS THORH 10-20-60-21	NYTIS EXPLORATION COMPANY INC.	Comingled
100/02-23-060-21W4/0	ACL THORHILD 2-23-60-21	APACHE CANADA LTD.	Flowing
100/03-28-060-21W4/2	NYTIS THORH 3-28-60-21	NYTIS EXPLORATION COMPANY INC.	Flowing
100/13-29-060-21W4/0	SEBRING THORH 13-29-60-21	EMBER RESOURCES INC.	Flowing
102/16-30-060-21W4/0	SEVERO 102 ET AL THORH 16-30-60-21	SEVERO ENERGY CORP.	Flowing
102/16-30-060-21W4/2	SEVERO 102 ET AL THORH 16-30-60-21	SEVERO ENERGY CORP.	Comingled
100/07-31-060-21W4/0	MOSAIC THORH 7-31-60-21	MOSAIC ENERGY LTD.	Standing
100/06-32-060-21W4/0	MOSAIC THORH 6-32-60-21	MOSAIC ENERGY LTD.	Standing
100/15-33-060-21W4/0	CORDERO THORH 15-33-60-21	EMBER RESOURCES INC.	Standing

Table I-7

BCS Storage Complex Penetration Licencees

UWI	Well Name	Current Operator
100-08-18-058-24W400	Dorset FBA 8-18	Baytex Energy Ltd.
100-16-09-060-22W400	Amoco Thorhild 16-9	BP Canada Energy Company
100-16-22-059-22W400	Mosaic Thorh 16-22	Mosaic Energy Ltd.
100-08-18-058-24W400	Dorset FBA 8-18	Baytex Energy Ltd.
100-13-22-057-23W400	Dorset Fedorah 13-22	Baytex Energy Ltd.
100-07-17-056-21W400	Imp PLC Redwater LPGS 7-17	Imperial Oil Resources Limited
100-14-01-056-22W400	Provident 16 Redwater 14-1	Provident Energy Ltd.
100-12-01-056-22W400	Provident 15 Redwater 12-1	Provident Energy Ltd.
102-11-01-056-22W400	Provident 14 Redwater 11-1	Provident Energy Ltd.
100-11-01-056-22W400	Provident 12 Redwater 11-1	Provident Energy Ltd.
100-02-16-056-22W400	Imperial Gibbons No 1	Imperial Oil Limited
100-09-29-059-24W400	Imperial Clyde No. 1	Imperial Oil Limited
100-16-19-062-19W400	Imp. Darling No.1	Mantol Petroleum Limited
100-01-34-057-22W400	Imperial Eastgate No. 1-34-57-22	Imperial Oil Limited
100-06-36-058-23W400	Imp Egremont W 6-36-58-23	Imperial Oil Limited
100-01-27-060-26W400	Imp Baysel Riverdale No. 1-27-60-26	Imperial Oil Limited
1AA-11-32-055-21W400	SCL Redwater 11-32	Shell Canada Limited
100-03-04-057-20W400	SCL Redwater 3-4-57-20	Shell Canada Limited
102-14-01-056-22W400	PVEL TD 17 Redwater 14-1-56-22	Provident Energy Ltd.

Figure I-1: Offsetting Mineral Owners to 00/07-11-059-20W4/0

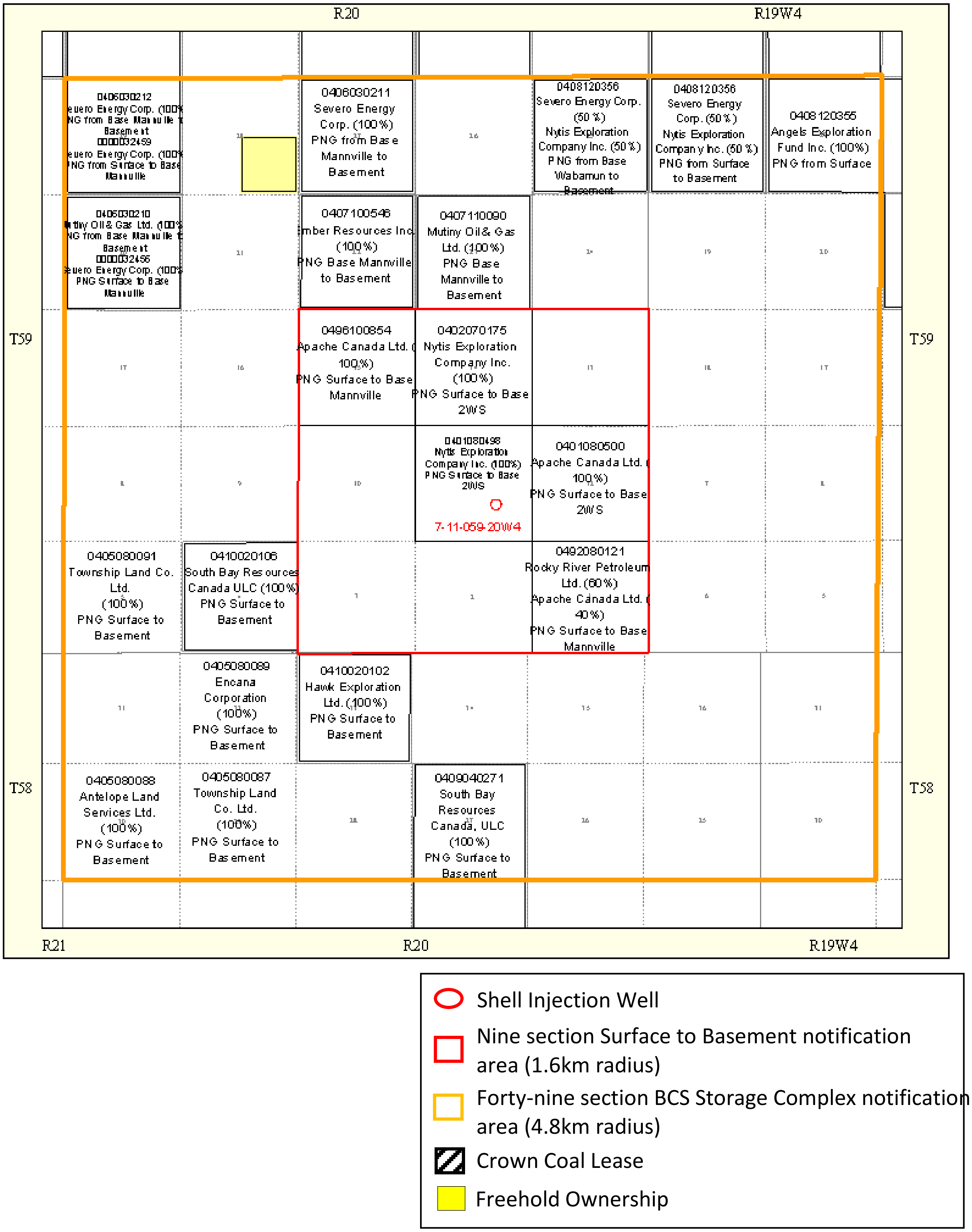


Figure I-2: Offsetting Mineral Owners to 00/08-19-059-20W4/0

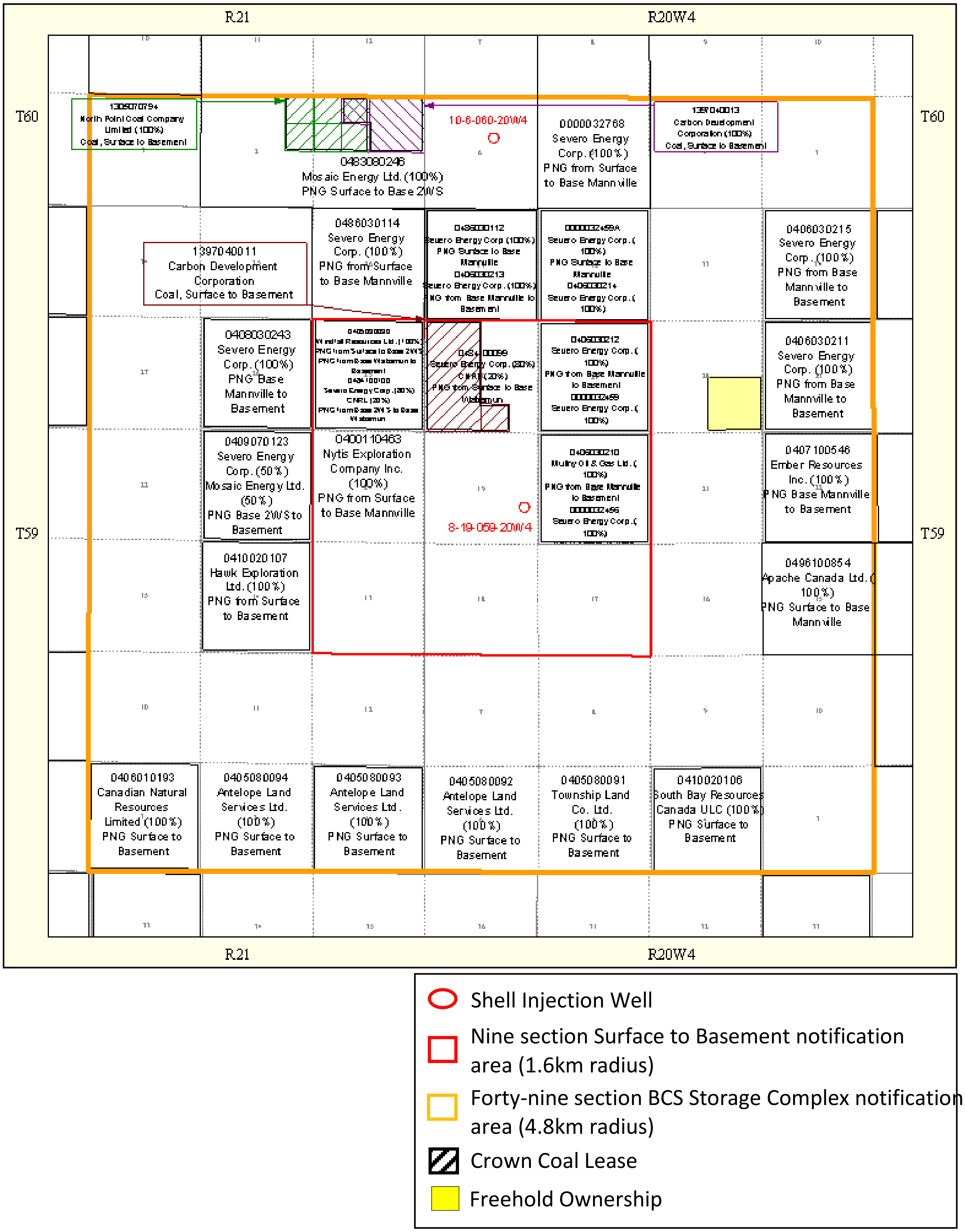


Figure I-3: Offsetting Mineral Owners to 00/10-06-060-20W4/0

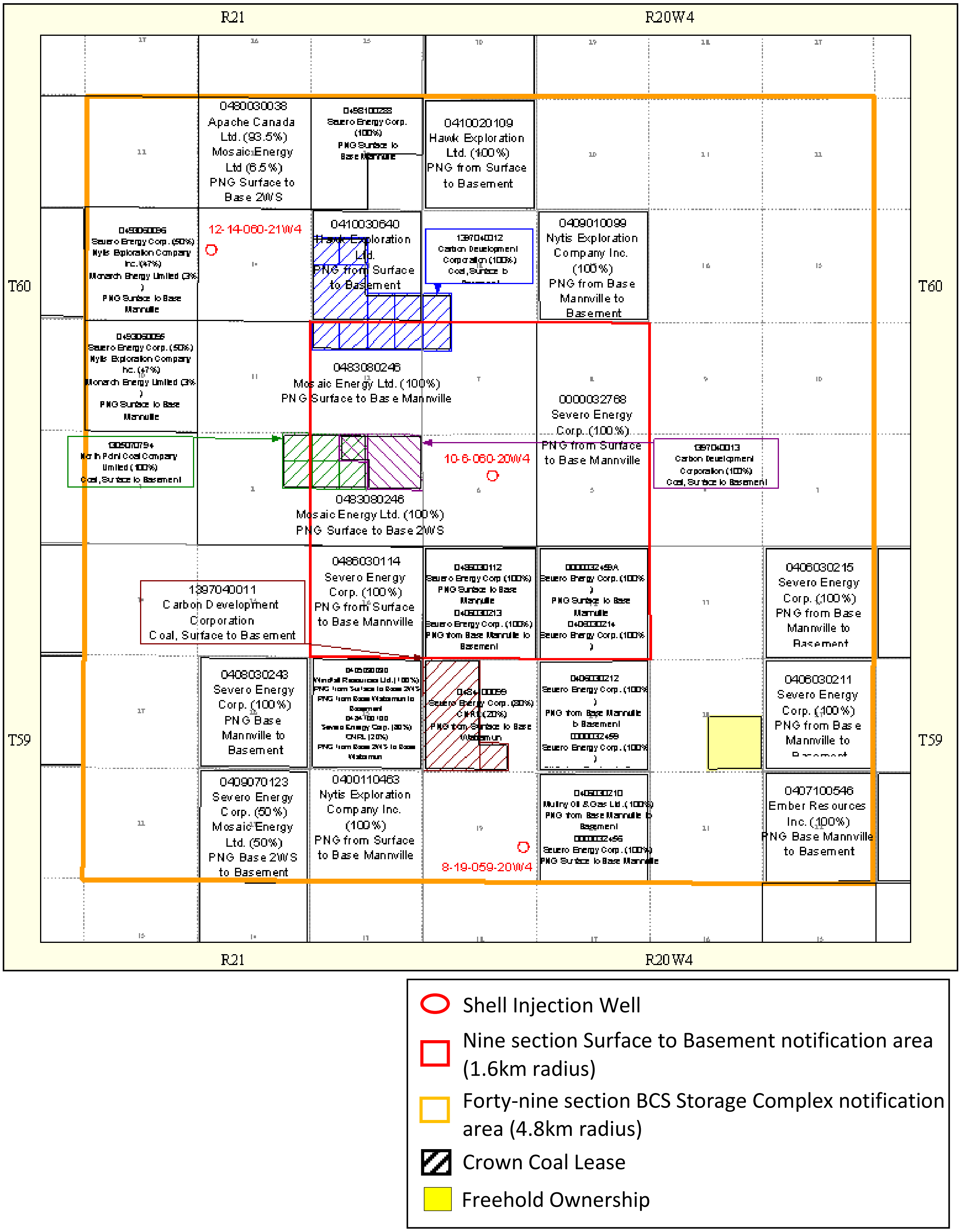
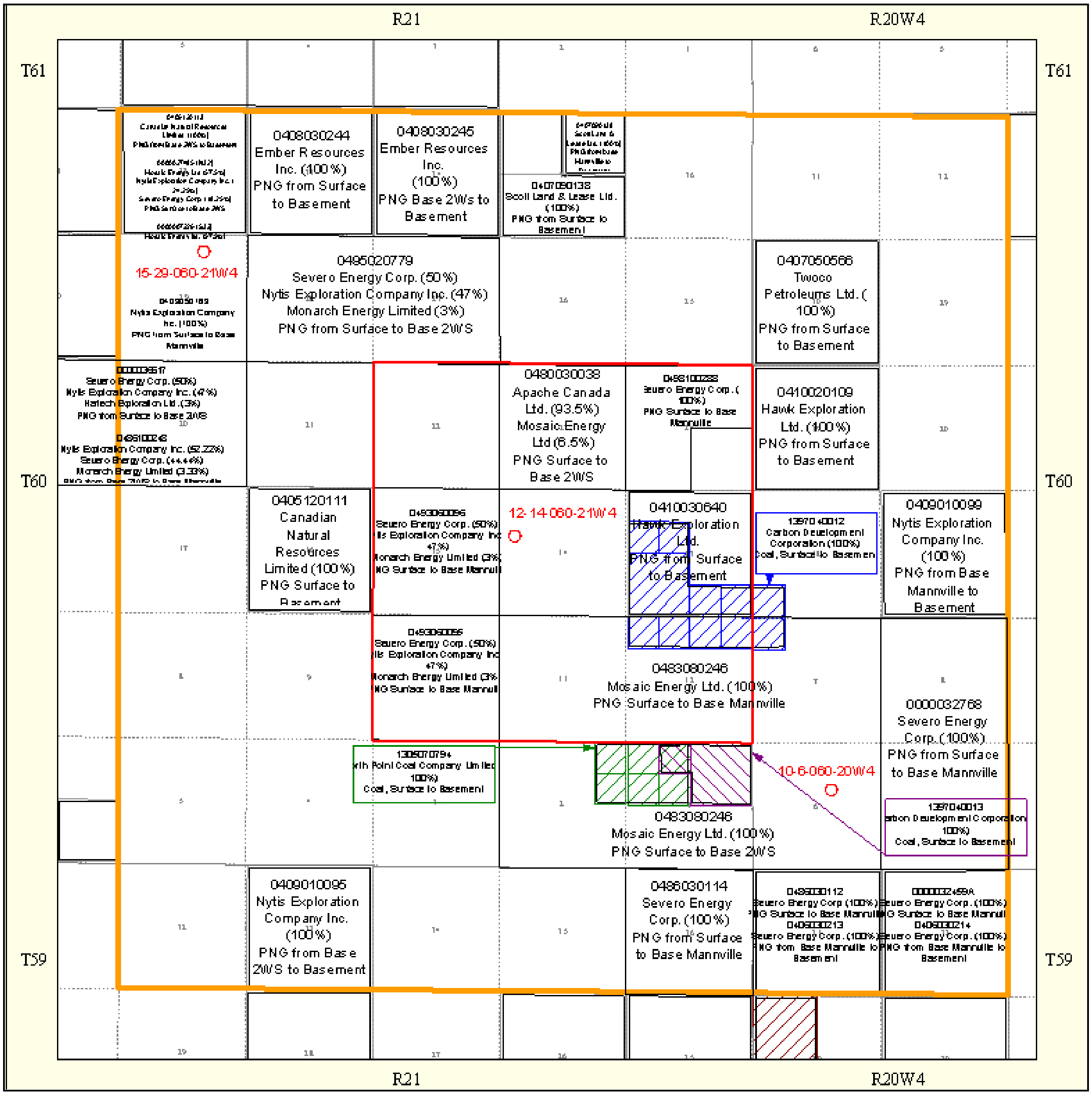


Figure I-4: Offsetting Mineral Owners to 00/12-14-060-21W4/0



Shell Injection Well

Nine section Surface to Basement notification area (1.6km radius)

Forty-nine section BCS Storage Complex notification area (4.8km radius)

Crown Coal Lease

Freehold Ownership

Figure I-5: Offset Operators and Approval Holders to 00/15-29-060-21W4/0

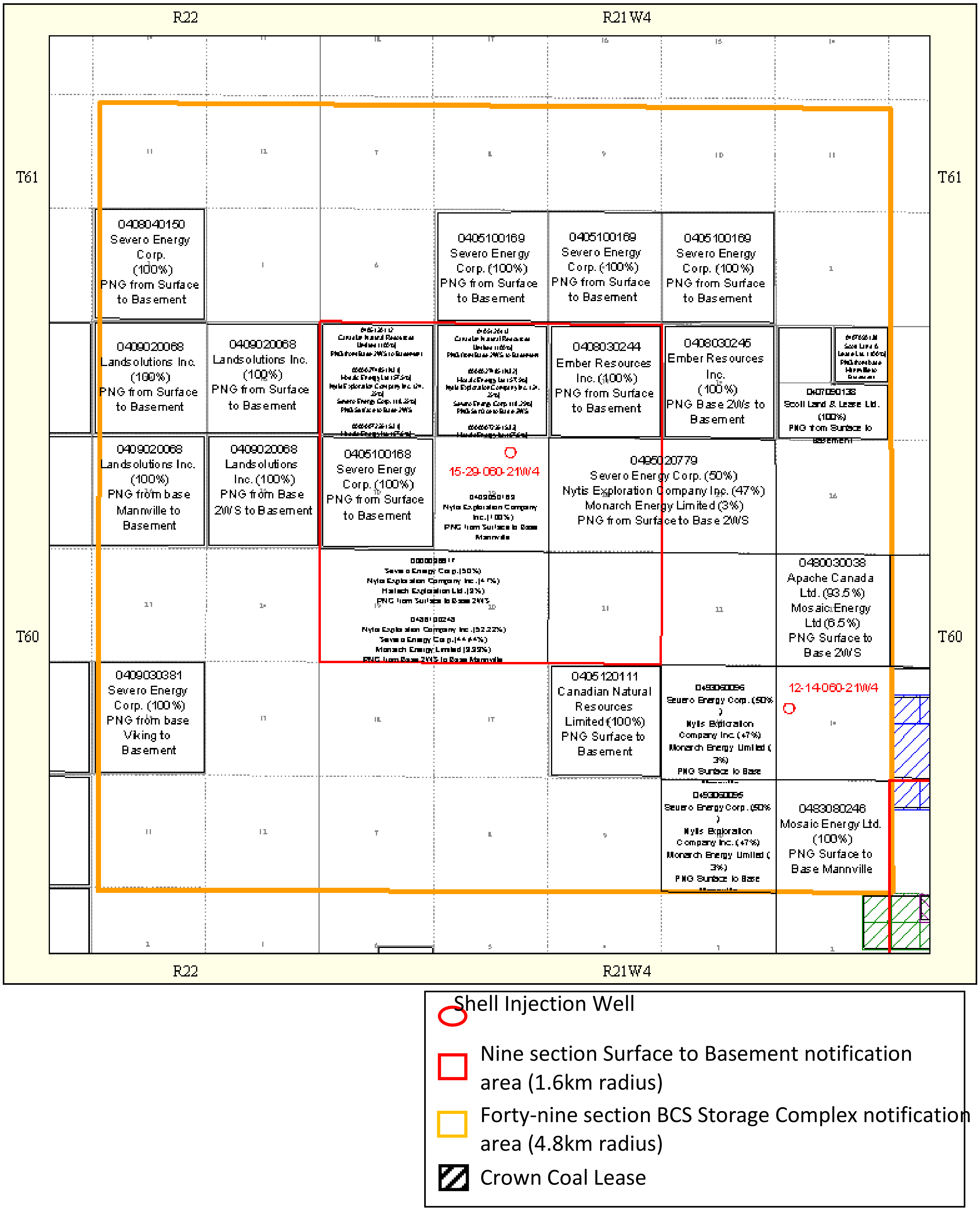


Figure I-6: Locations of Offset Active Wells