2012 ABERCB **008**

Shell Canada Limited

Application for the Quest Carbon Capture and Storage Project

Radway Field

July 10, 2012

Energy Resources Conservation Board

ENERGY RESOURCES CONSERVATION BOARD
Decision 2012 ABERCB 008: Shell Canada Limited, Application for the Quest Carbon Capture and Storage Project, Radway Field

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

SHELL CANADA LIMITED
APPLICATION FOR THE QUEST
CARBON CAPTURE AND STORAGE PROJECT **2012 ABERCB 008**
RADWAY FIELD **Applications No. 1689376, 1670112, and 1671615**

DECISION

[1] Having carefully considered all the evidence, the Energy Resources Conservation Board (ERCB/Board) hereby approves Applications No. 1689376, 1670112, and 1671615, subject to the conditions discussed in the decision and summarized in Appendix 2, and the Board's final approval, which will be issued after receiving the Minister's decision and, where required, incorporating any of the Minister's conditions in the approval.

Applications

[2] Shell Canada Limited (Shell) applied, in accordance with Part 4 of the *Pipeline Act*, for a pipeline to transport dense-phase carbon dioxide (CO_2). The pipeline would run from the Shell Scotford Upgrader located at Legal Subdivision (LSD) 12, Section 32, Township 055, Range 21, West of the 4th Meridian, to a proposed injection well located at LSD 15-29-060-21W4M.

[3] Shell applied, pursuant to Section 39(1)(b) and (d) of the *Oil and Gas Conservation Act* and Unit 4.2 of *Directive 065*: *Resources Applications for Oil and Gas Reservoirs* (*Directive 065*), for an approval to dispose of CO_2, a Class III fluid, into the Basal Cambrian Sands (BCS) in and around the Radway Field. Shell also applied to convert its test well, unique well identifier (UWI) 100/08-19-059-20W4/0 (8-19 well), into a Class III injection well in order to inject CO_2 into the BCS. Shell intends to drill as many as seven more injection wells into the BCS.

[4] Shell applied, pursuant to Section 13 of the *Oil Sands Conservation Act*, to amend Approval No. 8522 to construct and operate facilities for the capture of CO_2 at its Scotford Upgrader.

Background

[5] Shell submitted Application No. 1671567, which has been replaced with Application No. 1689376 registered on June 2, 2011, for a category B120 miscellaneous liquids pipeline. Application No. 1670112 was registered on December 2, 2010, for an approval to dispose of CO_2 within a sequestration area of interest (AOI), located in central Alberta northeast of the City of Edmonton. The AOI extends from Townships 56 to 63 and Ranges 18 to 24 West of the 4th Meridian (see Figure 1). Application No. 1671615 was registered on December 13, 2010, for an amendment to the existing Shell Scotford Upgrader. Alberta Environment[1] (AENV) has received *Environmental Protection and Enhancement Act* (*EPEA*) Applications No. 013-49587 and 001-284507 for approval of the proposed Quest Carbon Capture and Storage Project (the Project).

[1] Alberta Environment became Alberta Environment and Water and is now Environment and Sustainable Resource Development (ESRD).

[6] The Project would consist of CO_2 capture facilities, a pipeline to transport the CO_2 to a sequestration site, and a sequestration site for the injection of the CO_2 into the BCS.

[7] The facilities for the capture of CO_2 would be located at the existing Shell Scotford Upgrader, which is in Strathcona County at LSD 12-32-55-21W4M about 5 kilometres (km) northeast of Fort Saskatchewan, Alberta. The facilities would be designed to capture up to 1.2 megatonnes of CO_2 per year and would consist of three amine absorption towers, an amine regeneration unit, a multistage CO_2 compressor with coolers and separators, and a triethylene glycol dehydration unit.

[8] A pipeline would be used to transport dense-phase CO_2 from the Scotford Upgrader to the sequestration site located north of the County of Thorhild. The pipeline would be about 80 km long with an outside diameter of 323.9 millimetres (mm). The proposed route would extend east-northeast towards Lamont County, traverse north-northwest across the North Saskatchewan River, and terminate about 8 km north of the Town of Thorhild in LSD 15-29-60-21W4M.

[9] The CO_2 injection wells would be connected to the main pipeline by laterals, each of which would be less than 15 km long. The CO_2 would be injected through three to eight wells into the BCS, a deep saline geological formation, for permanent sequestration at a depth of about 2 km below ground level. Shell has applied for one of its current appraisal wells, the 8-19 well, to be turned into an injector and commence injection.

[10] The AOI, which is illustrated in Figure 1, shows the extent of carbon sequestration leases obtained from Alberta Energy on May 27, 2011, in support of the Project.

[11] Construction of facilities for the capture of CO_2 would begin in the third quarter of 2012 and pipeline construction would begin in the fourth quarter of 2013. The additional injection wells would be drilled as soon possible after approval of the project and could continue through 2015 or even later. The lifespan of the Project would be for the life of the Scotford Upgrader, which is more than 25 years.

[12] Shell will be required to seek regulatory approvals for the project from other provincial and federal regulatory bodies in addition to the applications considered by the Board during the hearing. Shell outlined these approvals in detail in the Environmental Assessment (EA) report filed with its applications to the ERCB. After the initial application, Shell also filed a project update and supplemental information that was requested from regulatory agencies during the review process.

[13] A single EA report was prepared to satisfy requirements under the *Canadian Environmental Assessment Act* (*CEAA*). The *CEAA* and *EPEA* are consistent with the *Canada–Alberta Agreement for Environmental Assessment Cooperation* (the Agreement), which designated AENV as the lead party. Natural Resources Canada, as the responsible authority under federal legislation, determined that a screening-level EA was required under the *CEAA*. The assessment identified mitigation measures to minimize adverse effects.

[14] This EA focused on key aspects of the biophysical, social, economic, and cultural environments, and on mitigation measures to minimize potential adverse effects. As discussed in [*262*], the EA and its conclusions were considered by the Board in its deliberations.

[15] In addition to mitigations committed to in the EA, Shell submitted an environmental protection plan (EPP) that includes mitigation for the environmental effects of pipeline construction on biophysical and cultural resources. The EPP identified measures to be implemented during construction and reclamation.

[16] To meet Alberta Culture requirements, a Historical Resources impact assessment was submitted to that agency by Shell. Historical and palaeontological resources were also considered as part of the EA and conservation and reclamation (C&R) plan. Shell has applied for clearance from Alberta Culture for components of the project likely to cause surface disturbance. Shell indicated that it would follow all mitigation requirements of that agency.

[17] Carbon capture infrastructure proposed for Shell's Scotford Upgrader would be regulated by AENV through an amendment to the existing *EPEA* approval. AENV would regulate pipeline construction by means of an *EPEA* approval under the *Conservation and Reclamation Regulation*. Shell submitted C&R plans for the pipeline and five proposed injection well pads. The pipeline C&R plan summarized the biophysical and cultural resource conditions identified through field assessments along the route. The C&R plan for the well pads described baseline terrestrial and historical resources conditions.

[18] *Water Act* licensing for the integrated project will be determined by ESRD. However, carbon capture infrastructure at the existing Scotford Upgrader will not require a new *Water Act* approval. Shell received approvals from Alberta Sustainable Resource Development for pipeline agreements (e. g., dispositions for Crown lands) at planned watercourse crossings. Alberta Energy issued six sequestration leases to Shell for rights to subsurface storage of CO_2 under the *Carbon Sequestration Regulations* enacted under the *Mines and Minerals Act* (*MMA*). Additional regulatory requirements could apply to carbon capture and storage (CCS) projects, including Shell Quest, in the future under this legislation and its regulations.

[19] Shell will not require any other authorizations for the CO_2 capture infrastructure from the Department of Fisheries and Oceans Canada (DFO) provided that a horizontal direction drill of the North Saskatchewan River is achieved. Shell has indicated that should it need to employ its proposed alternative crossing method of a two-stage coffer dam at the North Saskatchewan River, DFO and Transport Canada approvals would be applied for. Should it be necessary, Shell committed to providing to DFO and Transport Canada a contingency plan for the crossing that will include the assessment of effects, and mitigation measures.

[20] Approval for a horizontal directionally drilled pipeline crossing of the North Saskatchewan River was issued by Transport Canada under the *Navigable Waters Protection Act*. Shell applied to Transport Canada for approvals at four other crossing locations; however, no approvals were required. Authorizations for railway crossing agreements of Shell's surface infrastructure will be determined by the Canadian Transportation Agency.

Interventions

[21] Corey Clifton and Bernadette Clifton (Cliftons), owners of the northeast quarter of Section 18-56-20W4M, submitted an objection to the Project. The pipeline would be located adjacent to the Cliftons' property. The main concerns expressed by the Cliftons were the proximity of the pipeline right-of-way (ROW)—the controlled area along each side of the pipeline—safety, and pipeline routing.

[22] Tony Ouelette is the owner of a portion of the northeast quarter of Section 19-59-20W4M. His land is within the AOI and is about 800 metres (m) from the 8-19 well. Mr. Ouelette raised concerns about the health and safety of his family, the potential for water well contamination in the house and garden wells, the effect of the Shell Quest project on his future plans for his property, and further concerns related to his understanding that the Project is an experiment for CO_2 sequestration.

[23] Marian Kovac and Ann Kovac (Kovacs) own the south half of the northwest quarter of Section 25-59-21W4M. Their land is within the AOI. The Kovacs stated concerns about current and future land use, property value, compensation, and safety and CO_2 containment.

[24] Louis Douziech owns the southeast quarter of Section 11-60-21W4M, the northwest quarter of Section 1-60-21-W4M, and the northeast quarter of Section 2-60-21W4M. Mr. Douziech submitted an objection to the Project; however, he did not participate at the hearing.

[25] Ray and Jean Vaudan are the owners of the northeast quarter of Section 2-59-21W4M. Mr. and Mrs. Vaudan submitted an objection to the Project; however, they did not participate at the hearing.

Hearing

[26] The ERCB held a public hearing, which commenced on March 6, 2012, and concluded on March 9, 2012, in Redwater, Alberta, before Board Members George Eynon, P.Geo. (Presiding Member), and Robert C. McManus, M.E.Des., and Acting Board Member Robert J. Willard, P.Eng. All the people who participated in the hearing are listed in Appendix 1.

ISSUES

[27] The Board considers the issues associated with the applications to be

- the corporate structure of the applicant and other legal issues;
- the need for the project;
- amendment to the Scotford Upgrader;
- pipeline transmission of CO_2 to the injection sites;
- sequestration of CO_2—containment in the subsurface;
- public safety and emergency response;
- environment and socio-economics;
- monitoring, measurement, and verification;
- public consultation, communications, and access to information;
- the public interest; and
- ongoing approval processes.

[28] In reaching the determinations contained in this decision, the Board has considered all relevant materials constituting the record of this proceeding, including the evidence and

argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Board's reasoning relating to a particular matter and should not be taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

CORPORATE STRUCTURE OF APPLICANT AND OTHER LEGAL ISSUES

[29] During the hearing a number of issues were raised by the interveners with respect to Shell's corporate structure and the accountability and liability for the project. Questions were also raised as to whether the Board should defer consideration of the applications.

Evidence

[30] Mr. Ouelette raised the issue of Shell's corporate structure in regards to who would hold the approvals for the project and where the ultimate responsibility would lie for any accidents that might occur, including once the project ceased to operate. The Kovacs also raised concerns about accountability and liability of the project.

[31] Mr. Ouelette explained that Shell, in its opening statement, had stated that Shell Canada Energy will operate the proposed project on behalf of the Athabasca Oil Sands Project (AOSP), which is a joint venture between Shell Canada Energy, Chevron Canada Limited, and Marathon Oil Canada Corporation. Mr. Ouelette raised concerns that Shell Canada Energy was owned 100 percent by Royal Dutch Shell and that it was only a "shell" company. He wondered why Shell Canada Energy was not the primary applicant on the *Directive 056: Energy Development Applications and Schedules* (*Directive 056*) and *Directive 065* applications instead of Shell, which is not a partner in the AOSP.

[32] Mr. Ouelette also raised concerns that Shell was in noncompliance with the *MMA*, specifically Sections 115 and 116. These sections give the Minister of Energy authority to enter into an agreement with a person granting that person the rights to drill evaluation wells and to inject captured CO_2 for sequestration. Mr. Ouelette stated that the agreements were granted to Shell Canada Limited, not Shell Canada Energy. He also explained that the lessee in the six carbon sequestration lease agreements with Alberta for pore space rights was Shell Canada Limited. He argued that Shell was in noncompliance with the leases given that Shell Canada Energy, not Shell Canada Limited, will be the operator of the project and will be doing the injection of CO_2.

[33] Mr. Ouelette argued that the long-term liability for CCS projects remains in a state of flux as there are currently no regulations in place to specify the closure period referred to in the *MMA*. Mr. Ouelette also suggested that the Board should defer its consideration of the applications until the regulations outlined in Section 120 of the *MMA* have been passed and a complete regulatory framework for CCS is in place. He was of the view that in the absence of clear rules, it is not clear who will be regulating CCS (the ERCB or the Minister of Energy) and it may be best to wait until the regulations are enacted.

[34] Following its opening statement, Shell corrected its initial evidence and explained that Shell Canada Limited is the managing partner of Shell Canada Energy. Shell Canada Energy holds substantially all of the Shell group's assets and liabilities associated with its upstream

business in Canada. Shell Canada Energy is the operator of a number of projects in Alberta, including the Muskeg River Mine, the Jackpine Mine, and the Scotford Upgrader, and will operate the Quest CCS facilities. Shell Canada Limited is wholly owned by Royal Dutch Shell PLC.

[35] Shell testified that as the operator, Shell Canada Energy would respond on behalf of the AOSP if an accident occurred. Shell Canada Limited holds, for and on behalf of Shell Canada Energy, instruments and agreements that, under applicable law, must be held by a corporation, including legal title to land and regulatory approvals. The project will be self-insured by Shell. The liability management rating (LMR) for Shell Canada Limited as provided on March 3, 2012, was 10.33. Shell explained that the LMR is the ratio of a licensee's legible deemed assets to its deemed liabilities.

[36] Shell argued that the ERCB's rules are very clear that the applicant for a licence must be a corporation, hence Shell Canada Limited is the proposed licensee should the applications be approved. This is also the reason why Shell Canada Limited is the lessee of the pore-space rights under the *MMA*. Shell noted that the ERCB regularly receives applications in which the proponent is a partnership, and the licensees in those circumstances have to be a corporation.

[37] Shell submitted that it remains accountable for its operations through the life of the project. If a complaint about operations of the project is received, Shell will engage its public concerns process and work with the complainant to resolve the situation. Shell also notes that there are a variety of existing regulatory and legal mechanisms to ensure protection of landowners and the environment. These mechanisms include the ERCB's ongoing jurisdiction over the project, as well as ongoing environmental legislation administered by ESRD.

[38] Shell submitted that *Bill 24, Carbon Capture and Storage Statutes Amendment Act* addresses long-term liability for CCS projects. *Bill 24* addresses the transfer of liability for CCS projects from project proponents to the Government of Alberta (GOA) after project closure requirements have been satisfied and after the implementation of a post-closure stewardship fund that requires proponents (in this case Shell) to financially underpin future post-closure requirements.

[39] Shell understands that responsibility and liability for the sequestration project would be transferred to the GOA after the operating phase of the project has ceased and after the closure phase is completed to the satisfaction of the GOA. Shell must demonstrate that the sequestration of the CO_2 is securely contained within the storage complex. The GOA would then issue a closure certificate. It would be unlikely that the project would be transferred to the GOA before 35 years after project start-up, which was planned for 2015. Ministerial approval would be needed if Shell were ever to apply to transfer its pore-space lease.

[40] Shell argued that an existing comprehensive legislated regulatory regime is in place that gives the Board the authority to approve the construction and operation of the Shell Quest Project. Shell also referred to ERCB *Bulletin 2010-22: ERCB Processes Related to Carbon Capture and Storage (CCS) Projects*. Shell plans to comply with all further requirements that may be implemented by the GOA. Shell maintained that there is no reason for the Board not to approve the applications.

Analysis and Findings

[41] The Board notes that under the *Oil and Gas Conservation Act* (*OGCA*) a "person" can be a licensee or approval holder. The term "person", as defined in the *Interpretation Act*, includes a corporation. Section 20 of the *OGCA* explains the eligibility for a corporation to be a licensee. Among other things, a corporation is eligible to become an ERCB licensee if it is registered with an active status under the *Business Corporations Act*. *Directive 067: Applying for Approval to Hold ERCB Licences* also notes that an individual may hold a licence but a partnership may not.

[42] The Board notes that Shell Canada Limited is the person that has entered into the sequestration leases for pore-space rights with the Minister of Energy pursuant to the *MMA* and is the named holder of the rights. Shell Canada Limited is also the person named as applicant in the three applications before the Board. The Board also notes that under Section 39(1.1) of the *OGCA* the lessee of an agreement with the Minister of Energy, pursuant to Part 9 of the *MMA*, is also the party required to apply to the Board for a scheme for the injection of captured CO_2.

[43] Shell Canada Limited is the managing partner of the entity, Shell Canada Energy, that will operate the proposed CCS project. The Board notes that in the *Oil and Gas Conservation Regulations*, the term "operator of the scheme," when used in connection with a scheme approved under Section 39 of the OGCA, "includes a person who applied, or on whose behalf an application was made, for the approval of the scheme."

[44] As noted by the Board in a decision involving TrueNorth Energy Corporation,[2]

> In the Board's view, proponents of energy projects may use legitimate and legally recognized forms of business organization in order to advance their commercial interests. Corporate configurations such as limited partnerships, limited companies, and joint ventures are common examples of business organization and, in the absence of compelling reasons to reject such arrangements, are generally acceptable to the Board.

[45] Given the considerations in the above paragraphs, the Board finds that Shell Canada Limited is eligible, and the appropriate person, to apply to the Board for the subject applications. The Board also finds it acceptable that Shell Canada Energy plans to be the operator of the project while Shell Canada Limited is named as licensee.

[46] Mr. Ouelette has submitted that the Board should defer consideration of Shell's application until the complete regulatory framework for CCS is in place and the regulations contemplated under Section 120 of the *MMA* have been passed. Mr. Ouelette has not suggested at any time that the Board does not have the jurisdiction to consider the applications in light of the provisions of the *MMA*.

[47] The Board is of the view that it has the requisite jurisdiction under Section 39 of the *OGCA* to consider the applied for applications seeking approval of a scheme for the injection and sequestration of captured CO_2 to an underground formation. The Board is also of the view that it has, as an expert tribunal, the requisite experience in acid gas injection to consider the merits of the current applications. The ERCB considers that the injection of CO_2 is similar to acid gas

[2] *Decision 2002-089: TrueNorth Energy Corporation Application to Construct and Operate an Oil Sands Mine and Cogeneration Plant in the Fort McMurray Area*, Addendum to *Decision 2002-089* at Page 1.

injection. As noted in the ERCB *Bulletin 2010-22*, and as Shell submitted, the ERCB has over 20 years of experience in acid gas injection and enhanced oil recovery (EOR) schemes.

[48] The Board has considered requests to defer consideration of applications pending enactment of rules that are under legislation not administered by the ERCB.[3] The ERCB has proceeded on the basis that where it has jurisdictional obligations to receive and process applications it would do so within the current legislation and regulations. As noted above, the Board is of the view that it has the requisite authority to proceed in the absence of further regulations under the *MMA*.

[49] The Province of Alberta has passed regulations on CCS that provide for the issuance of pore space tenure. In the Board's view, the GOA's decision to enact tenure regulations and provide pore-space tenure to Shell is an indication that the Board should process Shell's *Directive 065* application in the absence of other *MMA* regulations.

[50] The Board notes that Shell has indicated it recognizes that more regulatory requirements may be forthcoming and is prepared to comply with such new regulations when they are in place. The Board anticipates that its existing jurisdiction and any additional requirements under the *MMA* would be complementary and not contradictory.

[51] In the Board's view, applicants will be required to comply with the Board's terms and conditions should approvals be issued, and with requirements that may be in future regulations under the *MMA*. As there is a regulatory regime in place for the ERCB to exercise its jurisdiction, the Board declines to defer consideration of the subject applications.

[52] With respect to concerns about who is responsible for the proposed project, the Board notes Shell's submission that Shell is accountable and responsible for the project during its operation. Shell is required to meet all the ERCB's regulatory requirements. In general, licensees are responsible for the care and custody of their wells, pipelines, and facilities. The Board further notes that an ERCB licensee must have reasonable insurance coverage (and maintain that insurance coverage) that is appropriate for the size of the company and the type of operation that the company carries out.

[53] The ERCB requires that abandonment and reclamation of oil and gas facilities be carried out by licensees and working-interest participants. The ERCB has programs, such as the Licensee Liability Rating (LLR) program and the Liability Management Rating assessment, in place to ensure that funding is in place to cover abandonment and reclamation of the facilities, wells, and pipelines licensed to the licensee.

[54] *Directive 006: Licensee Liability Rating (LLR) Program and Licence Transfer Process* defines LMR as the ratio of a licensee's eligible deemed assets to its deemed liabilities in the Large Facility Liability Management Program (LFP) and the LLR and Oilfield Waste Liability (OWL) programs. Any security deposit provided to the ERCB as a result of the operation of these programs is considered in determining a licensee's "security-adjusted" LMR. If a licensee's deemed liabilities in the three programs exceed its deemed assets in these programs

[3] *Decision 2008-029: Petro-Canada Prehearing Meeting Applications for Wells and Associated Pipeline and Facility Licences, Sullivan Field.*

plus any provided security deposits, the licensee has a security-adjusted LMR below 1.0 and is required to provide the ERCB with a security deposit for the difference.

[55] The Board notes that Shell submitted its current LMR ratio as 10.33. The Board finds Shell's LMR ratio to clearly exceed the LMR required ratio of 1.0. The Board believes that these numbers indicate that Shell currently meets the LLR program requirements.

[56] The Board understands that Shell is required to meet any regulatory requirements that may be imposed under the *MMA* before a closure certificate is issued. The Board further understands that once this certificate is issued by the minister (35 years after injection began), the Crown in Right of Alberta becomes the owner of the injected CO_2 and assumes all the obligation of the pore space lessee. The Board therefore finds that during all phases of the project there will be a responsible party to address liability concerns.

[57] With respect to Mr. Ouelette and the Kovacs' concerns about Shell's liability for damage to their property, the Alberta courts, not the Board, have the authority to address such claims.

NEED FOR THE PROJECT

Evidence

[58] The goal of the project is to reduce greenhouse gas (GHG) emissions generated from the AOSP to the Scotford Upgrader. Shell submitted that its CCS project will play a vital role in reducing such emissions because currently there are no other large-scale commercial alternatives to direct GHG reduction in Alberta. Shell has established a corporate GHG management plan for its operations that includes numerous approaches to improving efficiencies and reducing emissions. The Project is a key component of the GHG abatement strategy for Shell.

[59] Shell was of the opinion that CCS will enable Canada and Alberta to help develop important oil sands resources with a smaller carbon footprint. Its CCS project will help demonstrate CCS technology in an oil sands application and enable future development of this resource with fewer CO_2 emissions. The CCS project will also provide knowledge and understanding that will help accelerate implementation of other CCS projects around the world. Development of oil sands makes an important contribution to the security of energy supply for North America; and CCS plays an important role in CO_2 reduction strategies, government climate change strategies, and reducing the overall carbon footprint. Shell further submitted that introducing CCS in Alberta would create jobs, stimulate economic activity, establish initial infrastructure, and support Canada's and Alberta's drive to address climate change as part of a global effort.

[60] Shell explained that the governments of both Canada and Alberta have identified CCS as an important part of their CO_2 reduction strategies. The Government of Canada supports the reduction of GHG emissions through its Clean Energy Fund and is aiming to reduce CO_2 emissions by 325 megatonnes per annum (Mt/a) by 2050 through a number of approaches, including CCS. The Government of Canadian has committed to supporting this research into clean energy technologies.

[61] Shell noted that Alberta released a Climate Change Strategy in 2008 that committed to reducing GHG emissions by 200 megatonnes by 2050. In this strategy, CCS is projected to provide 70 per cent of Alberta's GHG emissions savings. To facilitate the development of CCS projects in Alberta, several pieces of legislation and regulation have been brought into law, including the *Carbon Capture and Storage Funding Act* and associated regulations. This legislation set up a fund to enable large-scale CCS projects in Alberta and established the legislated framework for long-term liability and pore-space access for long-term geological sequestration of CO_2.

[62] Shell stated that its funding agreements with the governments of Canada and Alberta define several key project constraints that must be met in order to receive the full amount of funding. These constraints include that the project reach a sustained injection rate of 1.08 Mt/a by December 2015 and maintains that injection rate for at least ten years.

[63] The Cliftons and Mr. Ouelette did not dispute the need for the CCS project. Mr. Ouelette asked whether CO_2 would be "wasted" by injecting it into a non-hydrocarbon-producing reservoir with no chance of it being recovered for use in an EOR scheme.

[64] The Kovacs did not dispute the need for the CCS project, but did ask about carbon capture credits.

Analysis and Findings

[65] The Board notes that one of the purposes of the OGCA is to ensure safe and efficient practices in operations involving the storage or disposal of substances.

[66] The Board recognizes that the CO_2 infrastructure is designed to capture about 80 per cent of the CO_2 emissions currently being generated by the Scotford Upgrader, so as much as 1.2 Mt/a of CO_2 will be captured and sequestered by the Project. This represents a significant reduction in the amount of GHG emissions that would otherwise be released from the upgrader.

[67] The Board accepts Shell's contention that the Quest CO_2 sequestration scheme is needed in order for Shell to meet its corporate GHG reduction targets and to meet commitments made to the governments of Alberta and Canada in support of their respective strategies to meet GHG reduction targets.

[68] The Board acknowledges that Shell has obtained the rights to store CO_2 in the BCS through leases acquired under the *MMA*. The Board finds that the CO_2 capture facilities and associated pipelines and injection wells identified as part of the Quest scheme are needed so that Shell can sequester CO_2 in the BCS complex through the leases it has acquired.

[69] Accordingly, the Board finds that the need for Shell's CCS project is satisfied.

[70] The Board must determine whether the project is in the public interest and be satisfied that the injection and sequestration of the captured CO_2 will not interfere with the recovery or conservation of oil and gas or interfere with an existing use of the underground formation for the storage of oil and gas.

AMENDMENT TO THE SCOTFORD UPGRADER

Evidence

[71] Shell stated that up to 1.2 Mt/a of CO_2 would be captured from its hydrogen manufacturing units at the Scotford Upgrader. Modifications to the upgrader would include the addition of three amine absorption towers, an amine regeneration unit, a multistage CO_2 compressor with coolers and separators, and a triethylene glycol dehydration unit. The modifications would be located on the Scotford Upgrader site.

[72] Shell stated that its dehydration unit would maximize the amount of water removed from the CO_2 before transport to avoid internal corrosion risks in the pipeline. Shell would use a vent stack to safely vent the wet CO_2 stream from the amine regeneration unit in the event of a compressor trip or temporary outage. Shell did dispersion modelling to estimate the diameter and height of the vent stack required to keep potential ground-level concentrations of CO_2 within safe limits for nearby personnel.

[73] Shell applied to amend its AENV Approval No. 49587-00-00 (as amended) pursuant to Division 2, Part 2 of the *EPEA*.

[74] Shell stated that the Scotford Upgrader modifications were not designed to either import or export additional volumes of CO_2, either from Shell or from a third party. Therefore, Shell has requested the addition of a T-piece on its export pipeline to allow for flexibility to import or export CO_2, subject to a future application. The T-piece would be located downstream of the CO_2 compressor at the Scotford Upgrader, essentially at the upgrader fenceline.

[75] Shell noted that a third party would need to apply for regulatory approval to install any infrastructure needed to receive or export third-party CO_2, and that these applications might require additional EAs.

[76] Shell received no objections to the Scotford Upgrader modifications or to the addition of a T-piece on the CO_2 export pipeline.

Analysis and Findings

[77] The Board acknowledges that Shell applied to AENV to amend the Scotford Upgrader *EPEA* approval to construct, operate, and reclaim the CO_2 capture facilities. ESRD (the current successor to AENV) is required under its legislation to consider any decision of the Board. The Board understands that ESRD will therefore await the Board's decision before making a determination on Shell’s application.

[78] The Board notes that while the Scotford Upgrader modifications are designed to meet Shell’s CO_2 capture needs, Shell has also proposed to add a T-piece to its CO_2 export pipeline to address the possible future import or export of additional volumes of CO_2. The Board notes that the ERCB received no objections to the Scotford Upgrader modifications or to the addition of a T-piece to Shell’s CO_2 export pipeline.

[79] The Board finds it appropriate for Shell to add a T-piece to its CO_2 export pipeline.

[80] The Board approves the modifications to the Scotford Upgrader to allow Shell to capture, compress, and deliver by pipeline as much as 1.2 Mt/a of CO_2 from Shell's hydrogen manufacturing units, and approves the addition of a T-piece to Shell's CO_2 export pipeline.

[81] The Board also notes that if modifications to Shell's CO_2 export pipeline become necessary to accommodate either a higher production of CO_2 from the Scotford Upgrader or third-party import or export of CO_2, Shell must apply to the ERCB to amend its pipeline approval.

PIPELINE TRANSMISSION OF CO_2 TO THE INJECTION SITES

Evidence

Route Selection

[82] Shell stated that it used several criteria, including health and safety, environment, regulatory, landowner input, access, and cost, to determine the proposed pipeline route.

[83] Shell submitted that the proposed route (see Figure 1) limits the number of infrastructure crossings, minimizes the potential for line strikes, and maximizes the use of existing pipeline corridors to reduce the effects of land fragmentation and other linear disturbances where possible. Shell noted that the proposed routing also limits the number of watercourse and wetland crossings, and avoids the Bruderheim Natural Area. Shell also noted that the proposed route crosses the North Saskatchewan River at a site that is suitable for horizontal drilling (to reduce impacts on the environment) and that meets DFO and Transport Canada requirements.

[84] Shell completed more than 30 changes to the pipeline route to reduce impacts on individual landowners and in response to input from government agencies. Shell obtained confirmation of non-objection from 109 of the 111 landowners and occupants along the proposed pipeline ROW.

[85] The Cliftons, who own agriculture land in the NE 18-56-20 W4M, opposed the proposed pipeline routing immediately south and adjacent to their land along the northern portion of the SE quarter of section 18. The Cliftons expressed concerns about potential restrictions on their agricultural and recreational use of the land associated with a ROW along the southern boundary of their land.

[86] Specifically, they expressed concerns about fenceline maintenance and the "controlled area" defined in an ERCB document entitled *Safe Excavation Near Pipelines Requirements for Landowners and Industry*. The Cliftons noted that the controlled area extends 30 m on both sides of a pipeline and obligates a landowner to call Alberta One-Call before any excavation occurs on their land within the controlled area. The Cliftons expressed concerns that this would create delays or extra costs as they might need to access both sides of the property line to repair the fence or maintain their property line.

[87] Shell explained it took the full 25 m of land between the Inter Pipeline Fund (IPF) pipeline ROW and the northern boundary of the southeast quarter of section 18 as its proposed CO_2 pipeline ROW at the request of the landowner. No part of the CO_2 pipeline ROW would extend onto Clifton land. Shell stated that the existing 42-inch IPF pipeline is 30 m from the Clifton land

and Shell will need to be 5-7 m away from the IPF line and therefore closer to, but not on, the Clifton land to safely construct their line.

[88] Shell proposed to locate the proposed pipeline in the southern portion of its ROW approximately 17.5 m from the Clifton's property. Shell noted that this would reduce concern about equipment working along both sides of the Clifton's fenceline. Shell stated that, given the depth of the pipeline, the overburden would bear the weight of a D7 Cat. Shell's understanding was that fenceline maintenance would normally be done with smaller equipment such as a D-4 Cat. Shell further submitted that the distance of pipeline from the Clifton's land and the depth of the pipeline (1.5 m) would impose no restrictions for these types of maintenance or farming activities along the edge of their land.

[89] Shell stated that the proposed route does not directly affect the Clifton land. Shell noted that the 30 m controlled area has a requirement to contact Alberta One-Call to locate pipelines before working. Shell's only requirement is notification from the Cliftons when they want to work within the 30 m area. Shell said it would respond quickly to mark the pipeline to avoid a line strike and to ensure safe excavations to replace fence posts.

[90] The Cliftons proposed an alternative pipeline route that would remove the 30 m controlled area from their land. Shell did not support the Cliftons' proposal to shift the pipeline south of the existing IPF ROW as this would result in the pipeline being located close to an existing Westfire wellhead in LSD 07-18. The Clifton proposal would also increase the effect on the landowner of the SE of section 18, resulting in more extensive surface disturbance and disturbance of a treed area, as well as affect the landowner in the SW of section 17.

[91] The Cliftons expressed concern that development of their land would be restricted by having a pipeline ROW nearby. Shell responded that the Clifton land would not be subject to future development restrictions since their land is outside the ROW.

Construction and Operation

[92] Shell proposed to design, install, and operate the CO_2 pipeline as a high vapour pressure (HVP) pipeline in compliance with the *Pipeline Act*, its *Pipeline Regulations*, and the Canadian Standards Association (CSA) codes. It would use low-temperature carbon steel material with specific toughness requirements.

[93] Shell plans to use three layers of fusion-bonded epoxy coating and cathodic protection to protect the pipeline from external corrosion. Shell proposes to dehydrate the CO_2 before putting it into the pipeline and would monitor the internal condition of the pipeline using corrosion coupons and in-line inspection technology. In its Pipeline Integrity Management plan, Shell noted that it would remove any water trapped in the pipeline following hydrostatic testing and in-line inspection. Shell would continuously monitor pipeline corrosion, dew point, product stream quality, and operating temperature and pressure.

[94] Shell's proposed compressor would have a rated discharge pressure matching the maximum operating pressure of the pipeline and below the fracture pressure of the formation. The wellhead emergency shutdown (ESD) valves would shut the pipeline system down if the wellhead pressure limit is exceeded.

[95] Shell proposed to install seven ESD line block valves (referred to in this decision as ESD valves) on the pipeline at a maximum spacing of 15 km and at all major water crossings. The ESD valves are hydraulic, self-activated, and constructed of materials that are resistant to the low temperatures and high velocities associated with the decompression of dense phase CO_2.

[96] In the event of a line break, the ESD valves would be closed automatically by the supervisory control and data acquisition (SCADA) system at the Scotford Upgrader. Shell noted that a rupture size of 5 per cent or more of the pipe surface area (equal to a 67 mm diameter hole) would cause the pressure to decrease to the low pressure set point of 9000 kPa and trigger the ESD valves to close. Shell noted that smaller holes would cause leaks that would be detected by the continuous mass balance system, trigger an alarm at the Scotford Upgrader control centre, and initiate operator shutdown of the valves. Shell said it would be able to detect leaks as small as 2 mm with the continuous mass balance system.

[97] Shell said that operators would check the ESD valves and well sites daily to ensure that there are no leaks from the piping or the flanges. The location of a leak would be pinpointed by sight and sound, and operators could confirm a release with their CO_2 detectors. Shell would also conduct bi-weekly aerial surveys along the pipeline ROW to help identify small leaks.

[98] As noted previously, Shell said that the current project design at the Scotford Upgrader would neither receive additional CO_2 nor export any of Shell's CO_2. Shell requested the addition of a T-piece on its export pipeline to provide the option to import or export CO_2 in the future.

Analysis and findings

Route Selection

[99] The Board finds that Shell's process for evaluating and selecting the proposed pipeline route was thorough; it took into account input from the public, private landowners, and government agencies. The Board notes that, after more than 30 re-routes of this pipeline as a result of the consultation process, only one landowner, the Cliftons, presented outstanding routing concerns at the hearing.

[100] The Board confirms that its requirements for safe ground disturbance excavations near pipelines are driven by the need to ensure public and worker safety. The Board recognizes that the Cliftons expressed concerns about fenceline construction within the 30 m control area adjacent to a pipeline. The Board does not accept that the need to call either the pipeline operator or Alberta One-Call is an onerous or adverse impact on a landowner. Shell acknowledged its obligation to respond quickly to a landowner request to locate a pipeline. The Board believes that such a minor delay could readily be factored into any landowner excavation plans, particularly since it is for the landowners' personal safety.

[101] The Board notes that Shell's commitment to locate the pipeline in the southern half of the ROW would place the pipeline about 17.5 m from the Clifton's fenceline. The Board finds that this increases the distance and safety margin for the Cliftons when working along their fenceline adjacent to the proposed pipeline. The Board also finds that the Shell pipeline as proposed will not impose farming and agricultural or construction equipment operations restrictions on the Cliftons' land.

[102] While the pipeline route proposed by the Cliftons may have less perceived effect on the Cliftons, the Board agrees with Shell that it would have substantially larger impact on the owners of the land to the south as a result of more extensive surface disturbance. The Board accepts Shell's arguments for not relocating the pipeline farther south, acknowledging that the potential for impacting other parties greatly exceeds the inconvenience to the Cliftons.

[103] For these reasons the Board approves the pipeline route for which Shell applied, including the proposed adjustments made to accommodate some of the Clifton's concerns along the northern edge of Section 18.

Construction and Operation

[104] The Board notes that Shell's design as it pertains to CO_2 transportation meets or exceeds CSA requirements. While CO_2 is not an HVP gas as defined in ERCB's directives, some design requirements are similar to HVP requirements. The Board considers Shell's use of the pipeline material to be appropriate because it would help avoid ductile running fractures. The Board also accepts the proposed burial depth and notes that it exceeds the CSA requirement.

[105] The Board notes that Shell's mitigation plan will address the risk of internal and external corrosion of the pipeline. The Board further notes that dehydrating the CO_2 before pipelining would limit internal corrosion, and removing water trapped in the pipeline after hydrostatic testing and in-line inspections would help prevent corrosion during system start-up.

[106] The Board is not concerned that the proposed pipeline would be subject to any overpressure because it would be designed to match the compressor pressure rating and would be protected by the wellhead ESD valves. Accordingly, the Board finds that additional measures in this area are not required.

[107] The Board considers the proposed ESD valve spacing to be appropriate because it meets the CSA requirement for CO_2 pipelines. The Board notes that ESD valves at major water crossings, although not required by the CSA, serve as additional protection to limit product release in the event of a line break.

[108] The Board finds Shell's proposed leak detection and shutdown systems using continuous mass balance and ESD valves to be appropriate, noting that the design and operation plans exceed requirements. The Board notes that although a leak detection system is not mandatory under the *Pipeline Regulation* and CSA code, it serves as additional protection to ensure pipeline operational safety.

[109] The Board notes that ruptures greater than about the equivalent of a 67 mm diameter hole would be detected by the automatic shut-down system. The Board also notes that the mass balance system would be able to detect pinholes as small as 2 mm in diameter and acknowledges that these leaks would take longer to detect. This matter is discussed in greater detail in the Public Safety and Emergency Response section; however, the Board considers Shell's proposal for daily field checks and bi-weekly aerial surveys to be proactive measures to help identify such small leaks. The Board notes that Shell's proposed frequency of these activities exceed ERCB requirements as set out in *Pipeline Regulation* sections 43 and 44.

[110] The Board notes that no concerns were expressed about pipeline construction standards, pipeline segment isolation, or the leak detection system. The Board finds that Shell meets or exceeds pipeline design and construction requirements and standards.

SEQUESTRATION OF CO_2—CONTAINMENT IN THE SUBSURFACE

Evidence

Basal Cambrian Sandstone Reservoir

[111] Shell stated that it will inject and dispose of CO_2 into the BCS reservoir only. This formation is part of what it called the BCS storage complex, defined by Shell as the formations and strata from the top of the Precambrian Basement to the top of the Upper Lotsberg Salt. Shell included a sequence (the Winnipegosis complex) overlying the BCS storage complex as the second part of what it termed its zone of interest (ZOI) (see Figure 2).

[112] The underlying rocks are Precambrian in age—about 1.5 billion years old. Shell noted that during this elapsed time the Precambrian was eroded to a relatively smooth surface tilted gently to the southwest. The overall BCS storage complex maintains a relatively similar thickness across the AOI and beyond; however, the Cambrian rocks pinch out toward the northeast while the younger Devonian salt seals compensate by thickening in the same direction.

[113] Shell stated that several areas of non-deposition of the BCS, identified from seismic, occur in the north area of the AOI. Shell noted that those areas were avoided in selecting the project area.

[114] The Kovacs questioned Shell on its ability to determine the thicknesses of the various layers from the seismic data; Shell responded that it used seismic data to confirm the regional continuity and data from wells to confirm the thicknesses.

[115] Shell's examination of core samples taken from the BCS indicated that the BCS was primarily a clean, fine- to coarse-grained sandstone with minor shale intercalations. Shell submitted that the BCS consisted of sheet sands 35-46 m thick across the AOI. Shell stated that the BCS is a saline aquifer occurring about 1800-2100 m below ground level. The average reservoir properties for the BCS observed in the 8-19 well were 16 per cent porosity and 150 millidarcies (mD) permeability. Shell believes that the BCS in future injector wells would have values in the expected range of 11-19 per cent for porosity, and 20-500 mD for permeability.

[116] Shell stated that it has used its considerable expertise in subsurface geological mapping of deep reservoirs to assess the effectiveness of the seals (low-permeability barriers) to keep the CO_2 contained within the storage complex. Shell also noted that the injection wells are far away from the four legacy wells that penetrate the BCS storage complex. Shell stated that the project area meets all the requirements for safe and permanent CO_2 sequestration.

Geographic Extent of Pore Space Leases and the BCS

[117] Shell submitted that the AOI was 39 1/3 contiguous townships extending from Township 56 to Township 63 and from Range 18 to Range 24 West of the Fourth Meridian. Shell submitted

that it acquired the pore space rights from the Department of Energy (ADOE) to store CO_2 within the BCS storage complex in the AOI. The leases from the ADOE define a ZOI for the project that includes the geological strata from the top of the Elk Point Group to the Precambrian basement.

[118] Shell added that the entire area of the AOI was tectonically quiet and that no faults interrupting the regional seals could be identified from two-dimensional or three-dimensional (3D) seismic data.

[119] Shell noted it used about 140-150 wells, from the entire region that includes the project, to map and build its model and description of the BCS storage complex within the AOI. Shell identified, within the AOI, four of these existing wells (legacy wells) that penetrated the BCS. It noted that they were all more than 18 km from the nearest proposed CCS injection site.

Other Petroleum and Natural Gas Rights Holders in the AOI

[120] Shell confirmed that its pore space tenure does not preclude companies that hold or acquire existing petroleum and natural gas rights within the AOI from drilling wells into Shell's ZOI. Shell notes that such wells would represent a breach of the geologic seals and pose the greatest risk to containment.

[121] Shell noted that the BCS storage complex and Precambrian formations below the BCS are known to have no hydrocarbon potential in the AOI; therefore the likelihood that any wells would be drilled into the ZOI or below is remote.

[122] In its discussion with the ADOE, Shell requested that petroleum and natural gas (P&NG) rights that extend down to the ZOI within the AOI not be re-posted or reissued when they expire and revert back to the Crown, given the potential risk to sequestration of the CO_2. Further, Shell understands that there is notification in the ADOE system such that P&NG rights in the ZOI within the AOI are no longer available.

[123] Shell also confirmed that there are freehold mineral rights holders within the AOI and that potential for drilling activity on these lands exists indefinitely.

[124] Shell was asked how it would ensure early communication between the parties if any existing rights holders were to apply to drill within the AOI and into the BCS storage complex. Shell responded that the existing process and protocols under *Directive 056* should be sufficient to ensure communication between parties.

Legacy Wells

[125] Shell noted that, in addition to the three project wells it recently drilled, there are four legacy wells within the AOI that penetrate all three major seals and the BCS and create potential pathways for BCS CO_2 brine to migrate to surface. The legacy wells are owned and licensed to Imperial Oil Limited, Mantol Petroleum Limited, and Devon Canada Corporation. Shell noted that wells that breach these geologic seals generally pose the most significant risk to storage containment. Legacy wells are likely the most vulnerable given uncertainty about their current and future well abandonment integrity. Shell visually inspected the legacy well locations and notes that all have been cut and plated, and there is no obvious surface remnant of any of them.

[126] Shell noted that three of the legacy wells within the AOI were abandoned between 1949 and 1955, and the other in 1978. Shell noted that in one of these wells (LSD 16-19-62-19W4M) the first cement plug was set 1178 m above the BCS storage complex, representing potential for open communication between the BCS and any porous formation in this interval, including the Winnipegosis and Cooking Lake formations. The other three were open-hole abandonments with multiple, large (50 m or more) cement abandonment plugs over the porous zones in the well bores.

[127] Shell stated that if the plugs leak in any of the legacy wells, the BCS CO_2 brine would likely cross-flow into the under-pressured Cooking Lake Formation as noted above. Shell further noted that given the elapsed time and the nature of the salt seals (Lower and Upper Lotsberg formations), any potential conduits in the legacy wells are expected to have been closed by salt flow into the well bores.

[128] Shell submitted that a review of malfunctions of underground gas storage sites worldwide in depleted oil and gas fields, aquifers, and salt caverns (HSE 2008) indicated that 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. Shell submitted that, using past performance as a guide, the likelihood that lack of well integrity would permit a chronic leak is less than 1 in 120,000 for an average well in any one year.

[129] Shell indicated that, based on its modelling, the pore fluid pressure increase at distances of 20 to 30 km from the injection wells after 25 years of injection would need to be 3.3-4.5 megapascals (MPa) to lift BCS brine to the base of the groundwater protection (BGWP) zone. Shell noted that the modelling indicated a pressure increase of less than half that range and also noted that it would decline with time after that.

[130] Shell stated that the CO_2 injection area would be at least 18 km away from any legacy well. Shell concluded that legacy wells therefore present a very low risk of vertical communication between the BCS reservoir and the BGWP or surface.

Potential for Commercial Hydrocarbon Recovery and Storage Schemes in the BCS

[131] Shell stated that, for a number of reasons, no hydrocarbons occur in the BCS within the AOI. Shell cited the absence beneath the BCS of organic material to form source rocks, preventing the formation of oil and gas over a geological time scale. Shell further stated that the BCS exhibits no structural or stratigraphic closure as a trapping mechanism for oil or gas, and for that reason was not suitable for natural gas storage either, even though the BCS storage complex has excellent sealing capacity.

[132] Shell also noted that the nearest hydrocarbon pool is a Leduc Formation reef located more than 1000 m above the BCS and more than 10 km to the southwest of the proposed injection wells.

[133] Shell confirmed there are no salt caverns in the BCS storage complex within the AOI that would potentially affect seal integrity. Shell noted that the salt storage caverns associated with the 07-17-056-21W4 well are outside the south boundary of the AOI.

Experience with Acid Gas Injection and Containment in Alberta

[134] Shell noted that more than 50 acid gas (a combination of carbon dioxide and hydrogen sulphide) injection schemes are authorized and operating in Alberta. These schemes typically inject into saline formations. Currently, Shell is developing an acid gas injection operation in the Peace River area, the second phase of which will inject into the saline Leduc Formation.

[135] Mr. Ouelette argued that the Shell Quest project is nothing like the acid gas disposal schemes that have been approved by the ERCB in the past in that it is on a much larger scale. He noted that Shell will be injecting 1.08-1.2 Mt/a of CO_2 into the BCS at 30 MPa, in contrast to acid gas operations in the province, of which only four inject more than 50 tonnes per day.

Formations Acting as Seals and Baffles

[136] Shell identified various sealing formations throughout the geological column, emphasizing several within the BCS storage complex. Shell submitted that the Precambrian Granite Basement is an unconformity surface and that it forms the lower seal to the BCS complex.

[137] Shell indicated the first seal overlying the BCS is the Middle Cambrian shale, which is 90 m thick in the southwest of the AOI and thins gradually to 22 m on the northeast side. In the middle of the AOI the initial injection well (8-19) found the Middle Cambrian shale to be 45 m thick. Shell stated that as the shale thins the salts above thicken, resulting in what it termed compensational stacking.

[138] The upper sealing units in the BCS complex are the Lower and Upper Lotsberg Salts, 35 m and 85 m thick respectively, and there is an additional seal above the BCS complex, the Prairie Evaporite Formation.

[139] Shell stated that water chemistry differs significantly within each of the major formations in the sedimentary succession covering the AOI. Shell contended that the differences between the BCS and the overlying Winnipegosis aquifer, located at a depth of about 1600 m, indicate that the Winnipegosis is isolated from the BCS injection strata and that the Prairie Evaporite Formation also isolates the Winnipegosis from the Upper Devonian aquifer systems. Shell also identified aquitards that provide additional barriers above the ZOI, including the Ireton and Colorado shales. Shell further stated that all the barriers described can be identified and differentiated on the basis of water chemistry within the intervening aquifers.

[140] Shell identified a number of porous zones that would act as baffles (Cambrian Lower Marine Sand [LMS] and Upper Marine Siltstone and Devonian Basal Red Beds). Shell stated that these formations would restrict vertical fluid flow and CO_2 migration by permitting fluids to enter these porous zones.

[141] Shell emphasized the Cooking Lake baffle and noted that the results of a wellbore-based model it developed showed that CO_2 leakage up a wellbore would result in migration into the under-pressured Cooking Lake Formation. Shell conducted a pressure test in the 8-19 well, and it determined the pressure in the Cooking Lake Formation is currently 660 kilopascal (kPa) below the extrapolated BCS pressure gradient in the centre of the AOI. This is evidence that the Cooking Lake Formation could sustain flow from the BCS in the unlikely event that a leakage pathway exists. Shell stated that the fact that these formations are at different pressures confirms

hydraulic isolation of the Cooking Lake aquifer from the underlying BCS; separation of the two zones by many competent seals does not allow pressure equilibration between them.

Fault Penetration of the Seals

[142] Regarding its ability to identify small faults, Shell cited its seismic data and interpretation. Shell stated that it identified small faults within the Precambrian surface, but observed no evidence of faulting in the BCS or above. Shell stated that analysis of potential faulting was conducted by several geophysicists within Shell, and that the work was reviewed by Shell's Chief Geophysicist, its project partner Chevron, and a third-party, Det Norske Veritas (DNV).

[143] Shell asked DNV to conduct an independent review of the Quest CCS project because it believed there should be transparency regarding the technical work, noting that DNV is an internationally recognized authority. Shell submitted the most recent DNV review into evidence. It includes a *certificate of fitness for purpose* as well as various recommendations from the review panel.

[144] Shell's seismic surveys and Fullbore Formation MicroImager well logs confirm the presence of fractures in the Precambrian basement below the BCS. Shell stated that these are likely the result of terrane collisions during the 1.5 billion years before deposition of Cambrian sediments. Shell noted that, despite the presence of fractures in the Precambrian basement, no substantial porosity or permeability is expected in the Precambrian interval.

[145] Shell re-stated its conclusion about the pressure differences between the BCS and the Cooking Lake Formation (discussed above) as additional evidence that the faults in the Precambrian do not penetrate the BCS storage complex.

Construction of Wells

[146] Under ERCB *Directive 051*, Shell has applied for a Class III injection well status for the 8-19 well, which is currently classified as a test well. Shell set surface casing below the BGWP at 445 metres measured depth (mMD). Intermediate casing was set at 1984.5 mMD and cemented to surface. Production casing was set at 2131 mMD with a cement top of 250 mMD and a fibre-optic string outside the casing set at 1953 mMD. The tubing/casing annulus was pressure tested to 7000 kPa. Shell confirmed that all future injection wells will meet the requirements of *Directive 051*.

[147] Shell said that all injection wells have been designed to withstand pressure and temperature conditions in the wellbore in every expected operating scenario, and be an effective barrier to CO_2 leakage after abandonment. Shell stated that all injection wells would be constructed to the same standards.

[148] Shell engaged a third-party company, Oxand, to assess the long-term integrity of injection wells after 200 years. Oxand identified factors known to affect the long-term integrity of wellbores: CO_2 bottom-hole pressure, thermo-mechanical stress leading to creation of micro-annulus, initial poor cement job, poor cement bond due to washouts, chemical degradation of casing and cement, casing centralization, and presence of fibre-optic string.

[149] Oxand modelled several different combinations of selected factors. The results show that, for all scenarios considered, CO_2 would not migrate across the secondary seal (Lower Lotsberg Salt). Results also show that after 200 years and in the worst case scenario, the cumulative CO_2 migrating from the reservoir into an injector well would be 560 kg. Shell stated that this scenario has a low-risk score, and that all other scenarios have low- to very low-risk scores.

[150] Oxand's analysis of the effect of temperature changes on annular cement shows that casing contraction can create a 65 microns (μm) wide micro-annulus below the injection packer. However, results show that, despite this micro-annulus, CO_2 remains confined below the secondary seal (Lower Lotsberg Salt). Results also show that cement degradation creates a relatively small increase in cement permeability and, as a consequence, the increase in CO_2 migration from the reservoir into the annulus is negligible. Shell noted that its cement recipe has been modified correspondingly to increase durability with respect to development of a micro-annulus and reduce the effects on cement permeability.

[151] Shell noted that simulations indicate complete casing corrosion could occur in the worst-case conditions of high degradation kinetics and CO_2 migration along the production casing cement annulus. However, Shell stated that the tubing cement plugs inside the production casing would prevent CO_2 migration from occurring uphole inside the casing.

Water Chemistry in the Sedimentary Succession

[152] Shell indicated that if formation water from below the BGWP were to migrate upwards, changes in parameters such as total dissolved solids (TDS) would be affected and could be tracked using electrical conductivity measurements in monitoring wells. Shell noted that chloride to bromide (Cl/Br) ratios of formation water in major aquifers throughout the sedimentary succession in the AOI indicate that the BCS brine is distinctive, and that its Cl/Br ratio provides a fingerprint that could be used to identify it in the event of a leak from the BCS storage complex. Shell stated that the levels of oxygen, nitrogen, and noble gas concentrations would distinguish between injected and naturally occurring CO_2 in the subsurface.

[153] In addition, Shell stated it was attempting to develop an artificial tracer that could be added to the injected CO_2 to provide an additional way of distinguishing injected CO_2 from naturally occurring CO_2. Shell reported that its feasibility study would be completed prior to the commencement of baseline sampling. Further discussion of this issue occurs in the monitoring, measurement and verification (MMV) plan section.

CO_2 Trapping Mechanisms

[154] Shell submitted that the depth and temperature of the storage formation will keep the injected CO_2 fluid in a dense phase and, once injected, that the CO_2 will be permanently trapped within the pore spaces of the sandstone. Over time the CO_2 will become even more securely trapped as it dissolves into the brine in the storage formation.

[155] Shell stated that it modelled the relative amount of CO_2 that would be stored by the various physico-chemical trapping mechanisms based on well-established CO_2-fluid interactions. Shell noted that after 50 years (i.e., 25 years after the end of injection), 60 per cent of the CO_2 would still be mobile, 25 per cent would be residual, and 15 per cent dissolved (i.e., in solution). Shell

also noted that in the case of clean sandstone like the BCS, mineral trapping mechanisms are negligible.

Appropriate Injection Pressure

[156] Shell has requested a maximum bottomhole injection pressure (MBHIP) for the BCS at the 8-19 well of 32 MPa, with an equivalent maximum wellhead injection pressure (MWHIP) of 14 MPa. Shell argued that the fracture extension pressure (FEP) should be the parameter that is considered relevant to the integrity of the seal, and stated there would be no threat to the seal if the injection pressures remain below that value since no extension of any existing fractures would occur.

[157] Shell derived FEP values from interpretation of the step-rate injection pressure test using the intersection of two straight lines drawn through the data points. Shell stated that the first line defines pre-fracture in-flow conditions and the second reflects the post-fracture period of the test. Shell stated that the second, post-fracture straight line should be drawn through the later step-rate values, not the initial deviation values. Shell considered the initial deviation values to represent what it termed a “ballooning” effect that occurs prior to actual fracture extension.

[158] However, Shell agreed that if the second straight line were to be drawn through the first few points of the initial deviation the lines would have a different intersection, which might indicate a lower FEP. Shell stated that it did not consider this to be the standard technique for interpreting step-rate injection pressure test data.

[159] Shell ran minifrac step-rate tests in the BCS proposed injection zone at the 8-19 and in the 11-32 wells, and microfrac tests on LMS baffle zone immediately overlying the BCS in the 11-32 well. The test of the BCS in the 8-19 well was over a 1 m low permeability interval towards the top of the zone.

[160] Shell started with an FEP for the LMS in the 11-32 well of 37.0 MPa, the lowest FEP value measured in either the 11-32 or the 8-19 well. Shell applied the LMS gradient of 17.4 kPa/m to derive an FEP at the 8-19 location of 35.5 MPa. Shell stated that, to be conservative, it used this value for the BCS.

[161] Shell requested an MBHIP of 32 MPa, which it suggested represented a 26 per cent safety margin with respect to the 42.4 MPa derived from the minifrac step rate test value for the FEP in the BCS at the 8-19 well.

[162] With regard to the requested MWHIP of 14 MPa, Shell stated the maximum compressor discharge pressure and estimated pressure losses to the three to eight injection wells translate to a wellhead pressure of between 12 and 14 MPa, with a maximum bottomhole pressure of 31-32 MPa, depending on the density of CO_2.

[163] Shell also provided the minimum horizontal stress (fracture closure pressure, or FCP) based on a BCS minifrac in the 8-19 well calculated at 34.6 MPa. Shell further adjusted the FCP to take into account the effects of pressure and temperature differences associated with CO_2 injection. This was conducted in response to recommendations by DNV and a supplemental information request from the ERCB. Shell noted that for the cooling conditions expected during CO_2 injection, the fracture conditions within the BCS might result in predicted stress reductions that

exceed 4 MPa. Shell calculated the adjustments for dynamic effects of pressure and temperature associated with CO_2 injection and noted an increase in the minimum horizontal stress of 1.15 MPa. As a result, Shell recalculated the FCP in the BCS at the 8-19 well to be 35.75 MPa.

Ground Heave

[164] Shell noted that localization of surface heave might indicate fluids escaping the seal, and that the breadth of heave correlates with the depth of the pressure source. Shell also noted that step-like anomalies in the distribution of surface heave might indicate fault reactivation. Shell stated that surface heave will be monitored using satellite-based Interferometric synthetic aperture radar (InSAR), and that a two-year baseline data set will be acquired and analyzed (discussed below in the MMV program section).

[165] Shell stated that it used a homogeneous, linear, elastic half-space model to simulate the ground heave caused by CO_2 injection. Increased pore fluid pressure due to CO_2 injection in the BCS causes volume changes that can lead to heaving of the ground surface. Shell estimated a range of maximum heave between 0.6 centimetre (cm) and 6 cm, spread out over the entire AOI throughout the 25-year lifespan of the injection. Shell submitted that the heave would be gentle across an extremely wide area and would be extremely small compared with seasonal frost heave.

[166] Mr. Ouelette stated his concern that the ground surface at his property could be subject to as much as 6 cm of vertical heave and that this could affect the performance of his water wells and negatively affect structures on his property. In response, Shell stated that the Quest project does not have the potential to affect aquifer yield because the surface heave is a maximum of 6 cm over a 25-year period in a region with a natural variability of 50 cm to 1 m groundwater variation.

Extent of Pressure Front and CO_2 Plume

[167] Shell submitted CO_2 plume size estimates, assuming homogeneous radial displacement of brine by the injected CO_2. Shell noted that the plume distances varied from 440 to 2860 m depending on the number of wells needed to dispose of the 27 Mt of CO_2.

[168] Shell noted that the CO_2 plume associated with each individual well would not actually be circular because it would be influenced by a northeast-southwest trend of permeability modelled in the BCS. Shell stated that it therefore expects the plume dimensions in the northeast-southwest direction to be about double the calculated base-case size.

[169] Shell stated that during the injection phase CO_2 would replace reservoir brine in a more-or-less uniform radial front, but after injection ceases, the CO_2 would migrate vertically, due to buoyancy, to form an inverted cone shape and would tend to extend the plume radius at the top of the reservoir.

[170] Shell noted that the pressure front associated with CO_2 injection would extend about 8-12 times further into the reservoir than the CO_2 plume. Shell stated that the actual distance would depend on the total injected volume, the maximum allowable bottomhole injection pressure, and the formation compressibility. Based on a simple material balance, Shell estimated a CO_2 plume

radius of 500-3000 m, with a corresponding connected volume radius (i.e., the pressure front) of 4-30 km.

[171] The pressure distribution within the AOI after 25 years of injection is shown in the attached Figure 2. Shell noted that the elevated reservoir pressure would be lower away from the injectors, varying from about 6500 kPa near the injectors to less than 200 kPa at the perimeter of the AOI. Shell's modelling, using the heterogeneous, low-quality reservoir case, demonstrates that after 25 years a plume pressure increase sufficient to raise BCS brine to BGWP could be within 6 km of a legacy well.

Analysis and findings

Basal Cambrian Sandstone Reservoir

[172] While the Board acknowledges that the pore space rights include the entire ZOI, it understands that the CO_2 is to be injected only into the BCS.

[173] As the regulator, the ERCB must be satisfied that the injected CO_2 can be sequestered safely and that containment in the reservoir will be maintained. The Board notes that to that end much of the time at the hearing was spent on the technical details of CO_2 containment.

[174] The Board notes Shell's selection and evaluation of the BCS as the most appropriate reservoir for sequestration of CO_2 based on the geological parameters of capacity, injectivity, containment, and monitoring. The Board further notes that Shell acquired the pore space rights that compose the AOI based on these parameters, its assessment of the geographic extent of the BCS indicated by existing well control, and its conclusion that it considered the BCS storage complex to be adequate for sequestering the volumes of CO_2 over the expected life of the project.

[175] The Board notes that the BCS is described as a widespread and relatively homogeneous sandstone immediately overlying and derived from Precambrian basement rocks of the Canadian Shield, a stable continental Precambrian craton. The Board also notes that the BCS is highly saline (about 311 000 milligrams/litre TDS) in the 8-19 well aquifer with porosity of 11-19 per cent and horizontal permeability of 20-500 mD. The Board further notes that the BCS occurs at depths of about 2000 m, below multiple layers of thick, low-permeability, and extensive sealing formations that separate it from the surface and non-saline groundwater sources.

[176] The Board acknowledges and understands that the BCS covers a large area, occurs in an area of relative tectonic stability over a long period of geologic time at considerable depth in the subsurface, and is isolated both from other rocks with oil and gas potential and from groundwater sources by several significant sealing formations. The Board also notes that the BCS appears to have sufficient porosity and permeability to be capable of accepting the volumes expected to be injected.

Geographic Extent of Pore Space Leases and the BCS

[177] The Board notes that Shell's pore space leases acquired from the provincial government come with the exclusive rights to drill through and store within the geological strata from the top of the Elk Point formation to the Precambrian basement (Shell refers to this stratigraphic interval

as its ZOI.) The Board also notes that this stratigraphic interval includes shales and salts overlying the BCS that will act as the necessary seals to prevent upward migration of the stored CO_2. The Board further notes that the geological horizons of the ZOI extend throughout the AOI and beyond. As well, the Board notes that the CO_2 plume would be limited to an area around each of the injection wells.

[178]The Board therefore finds the selection of an injection area in the geographic centre of the pore space leases to be appropriate given the geographic extent of both the reservoir formation (the BCS) and the various seals and baffles throughout the sedimentary succession, and the restricted area in which the injected CO_2 would occur in the subsurface.

Other Petroleum and Natural Gas Rights Holders in the AOI

[179]The Board notes that there are P&NG leases within the AOI that are held by third-parties and that include all rights down to the basement including Shell's entire ZOI.

[180]The Board notes that issuing rights for the entire section, regardless of low prospectivity for hydrocarbons, is the normal practice of the Crown. However, the Board further notes that the portion of the stratigraphic section that constitutes the BCS storage complex is devoid of hydrocarbons. The Board finds it extremely unlikely, given the current state of knowledge of the hydrocarbon potential, any third party would apply to drill a well into this section. The Board notes that the ADOE system identifies that P&NG rights within the ZOI in the AOI are no longer available. Further the Board notes Shell's evidence that there is notification within the ADOE system such that P&NG rights within the ZOI in the AOI are no longer available.

Legacy and Offset Wells

[181]The Board acknowledges that four third-party *legacy* wells—wells drilled many years ago and since abandoned—penetrated parts of the BCS storage complex in the AOI. It accepts that these legacy wells pose a risk to formation brine flow from the BCS storage complex. The Board notes, however, that selection of the AOI pore space leases and the location of the CO_2 injector wells to maximize the distance from these legacy wells effectively reduces the potential for CO_2 migration into those well bores.

[182]The Board further notes that the nearest legacy well (Egremont 6-36) is at least 18 km from the closest proposed injectors, and that after 25 years of injection, the expected rise in pore fluid pressure around these wells would be insufficient to raise BCS brine in the well bores to the protected groundwater aquifers.

[183]The Board acknowledges that for one of the legacy wells (16-19-62-19W4M), the abandonment left about 900 m of open hole below the first cement plug. However, the Board agrees that the three salt formations in that open-hole section are likely to have flowed into the wellbore and created three separate seals. The Board also notes that pressures would tend to decline once injection ceases and that the risk of fluids migrating via the legacy wells is further diminished.

[184]The Board therefore finds it unlikely that the four legacy wells present a significant risk to the containment of CO_2 in the BCS.

[185] The Board notes the results of modelling projections (assuming five injector wells and 25 years of CO_2 injection) indicating an overall pressure increase in the BCS that would be relatively uniform and extend over a large area (about 20-30 km away from the injector wells). The modelling also indicates that CO_2 saturations within the BCS brine would extend at most a few kilometres from each injector well over the same period.

[186] The Board also notes that Shell cited historic rates of well integrity failures associated with underground gas storage sites worldwide of less than 1 in 120 000 per well year (HSE 2008). The Board further notes that operations in Alberta in acid gas disposal in the subsurface over several decades has a similar safety record with respect to well integrity. The Board finds that the likelihood of a well integrity failure is therefore remote.

Potential for Commercial Hydrocarbon Recovery and Storage Schemes in the BCS

[187] The Board notes that there are neither source rocks that might have produced hydrocarbons to be trapped in the BCS, nor mechanisms to trap them even if they had been produced. Similarly, the Board understands that there are no existing uses of the BCS for the storage of oil and gas within the AOI. The Board also notes its mandate for both resource conservation and orderly development of resources, but finds that there is neither potential for competing oil or gas development nor any likelihood of mineral exploration of the Precambrian at these depths within the AOI.

[188] Similarly, the Board finds that given the lack of trapping mechanisms for oil and gas in the BCS, there is no potential for competing development of commercial storage schemes. Therefore, the Board finds that the injection of the captured CO_2 from the Scotford Upgrader will not interfere with the recovery or conservation of oil or gas, and as there is no existing use of the BCS for the storage of oil and gas, this project would not interfere with such use.

Experience with Acid Gas Injection and Containment in Alberta

[189] While the Board acknowledges Mr. Oulette's concern that the existing acid gas injection operations in Alberta are at a smaller scale than those of the subject CO_2 sequestration application, it notes that the nature of the activities are essentially equivalent.

[190] The Board notes *Bulletin 2010-22,* which states that the ERCB

> has been regulating the disposal, storage, and injection of fluids to underground geologic formations in Alberta for many years and with respect to carbon dioxide (CO_2) for more than 20 years. The ERCB has processes in place to provide for the effective regulation of these activities, including the more than 50 schemes involving CO_2 currently operating in Alberta.

[191] The Board further notes that in the case of the Shell Quest CCS project a fluid is to be injected at a pressure that is appropriate for the porosity and permeability of the reservoir, and must be trapped within the reservoir by a set of geologic sealing conditions. The Board notes that this is no different from the acid gas injection activities and therefore finds that the experience ERCB has with acid gas injection schemes to date is applicable in this case.

Formations Acting as Seals and Baffles

[192] The Board recognizes and understands the sequence of rocks in the ZOI, including various stratigraphic units that will act as seals against the migration of fluids from the reservoir. The Board acknowledges that above the BCS are three major seal formations that would confine the CO_2: a primary seal, the Middle Cambrian Shale, some 45 m thick, immediately above the BCS; and two horizons, the Lower Lotsberg and the Upper Lotsberg, 35 m and 85 m thick respectively, which are composed mainly of salts, with thin shales, dolomites, and anhydrites. The Board notes that this sequence of seal formations is over 260 m thick.

[193] The Board also notes the occurrence of Lower and Upper Marine Sands and Devonian Basal Red Beds, which are identified as *baffles* within the storage complex. The Board acknowledges that CO_2 brine would flow into and accumulate in these formations first in the unlikely event of a loss of containment. The Board agrees with Shell's assessment and finds that these virtually impenetrable seals and baffles naturally provide effective barriers to migration of the CO_2 from the storage complex throughout the AOI.

[194] The Board notes that there are also several other baffles, shallower in the geologic column, that would similarly retard migration of CO_2 fluids should a loss of containment occur. The Board notes that the Winnipegosis Formation, the first saline aquifer above the BCS storage complex occurring at 1600 m below the surface, is itself capped by another sealing formation in the form of the Prairie Evaporite Formation.

[195] Similarly, the Board notes several producing horizons and oil and gas fields that might be affected by such a loss of containment. These include proven oil resources in the Leduc, Nisku, and Wabamun formations and proven gas resources in the Nisku, Mannville Group, and Colorado Group. The Board notes that existing fields such as these, by definition, include a reservoir and some form of seal as a trapping mechanism, both of which provide supplemental barriers to migration of CO_2 brine upwards. The Board acknowledges that producing fields might see a slight increase in salinity or acidity of produced fluids, but finds that their lateral and vertical distances from the injection area—the nearest field is 1000 m vertically and 10 km laterally from the injection area—render this outcome unlikely.

Fault Penetration of the Seals

[196] The Board notes several additional factors mitigating the potential for injected CO_2 to escape the storage formation. The seismic data and interpretation provided by Shell indicate that there are no faults breaching the BCS storage complex—reservoir or seals—that might provide a pathway to shallower formations. The Board finds this conclusion is validated by the fact that the Upper Devonian Cooking Lake Formation is under-pressured for its depth, a situation that would not be possible if there were any pathway of communication between it and the normally pressured BCS.

Construction of Wells

[197] The Board finds that the proposed injection well design will ensure that the injected CO_2 safely reaches the deep storage formation and that shallow non-saline groundwater is protected. The Board notes that the surface casing in the 8-19 well covers the BGWP and that Shell has met all ERCB requirements, including those of *Directive 008: Surface Casing Depth Requirements*

and *Directive 009: Casing Cementing Minimum Requirements.* The Board also notes that Shell must meet all ERCB requirements for deep monitoring wells.

[198] The Board notes that the injection wells are designed to limit corrosion and to safely inject pressurized CO_2, and that up to three layers of casing, each cemented in place to surface, ensure that the injected CO_2 safely reaches the deep storage formation. The Board further notes that this construction serves to protect the shallow potable groundwater, especially since the initial casing string would be set at a depth of more than 400 m, which is well below the BGWP designated for this area.

[199] The Board also notes that this injector well casing program design mitigates the possibility of communication between the injection wells except through the reservoir.

Non-Saline Groundwater Protection

[200] The Board again notes that well construction requirements of the ERCB, as found specifically in *Directive 008* and *Directive 009* provide protection of non-saline groundwater aquifers.

[201] The Board acknowledges and understands that there are numerous ways to mitigate the risk of non-saline groundwater contamination from oil and gas sector activities (including those associated with waste, acid gas, and CO_2 disposal), and notes that Shell intends to use many of them in this project.

[202] The Board notes the presence of many geological seals and aquifers that would trap CO_2 above the main CO_2 target in the subsurface of the AOI, the distinct chemical signature of BCS brines, the intent of Shell's well construction plans, and the components of Shell's MMV program designed to detect any containment problems early and at depth.

[203] Given the combination of these active and passive mitigation measures, the Board finds that geological isolation of non-saline aquifers from the BCS Storage Complex would be achieved. However, the Board stresses the importance of the MMV program in verifying containment of the CO_2. The Board further notes that Shell has committed to a complete water well baseline study for two years before beginning CO_2 injection, and to making the data collected publicly available.

Water Chemistry in the Sedimentary Succession

[204] The Board notes that the chemistry of the different brines in the various formations can be identified on the basis of the Cl/Br ratio, but this might not be sufficient to clearly identify the injected CO_2. In that context, the Board notes that Shell is attempting to develop an artificial tracer—a unique fingerprint—to specifically identify its injected CO_2 and differentiate it from any other source of CO_2 in the unlikely event of a loss of containment in the storage formation. The Board notes that this has yet to be accomplished. This issue is discussed further in the MMV section of this decision.

CO_2 Trapping Mechanisms

[205] The Board notes and agrees that storage security within the BCS depends in part on physico-chemical trapping mechanisms. Shell stated that the depth and temperature of the storage formation will keep the injected CO_2 fluid in a dense phase and that the injected CO_2 would be permanently trapped by capillary forces at irreducible saturation within the pore spaces of the sandstone. Shell further stated that over time it would become even more securely trapped as it dissolves into the brine in the storage formation. The Board agrees with this physico-chemical process of increasing storage security over time.

Appropriate Injection Pressure

[206] The Board understands the importance of injecting the CO_2 at a pressure sufficient to move the fluid into the reservoir rock, but not so high as to exceed the fracture pressure of the sealing formations of the BCS storage complex. The Board's current practice is to use its discretion, provided in *Directive 051*, to apply a safety factor based on the available data and specific circumstances when approving an MBHIP for acid gas injection in a well.

[207] The Board notes that Shell conducted minifrac step-rate tests in both the 8-19 and 11-32 wells to identify the FEP of the BCS, which it calculated to be about 42.4 MPa at the 8-19 location. The Board notes Shell's statement that it had increased the safety margin by using an FEP (35.5 kPa) based on the LMS, the formation immediately above the BCS, at the 11-32 well. The Board notes that Shell used 90 per cent of that value (i.e., 32 MPa) as its proposed MBHIP for the commercial injection phase for the 8-19 well, which it characterized as having a 26 per cent safety margin.

[208] The Board also acknowledges that the step-rate injectivity plot of the 8-19 well data used by Shell to derive the 42.4 MPa FEP can be interpreted differently using the slope of the first points of deviation (see [126]-[127] above), resulting in an FEP of about 37.5 MPa. The Board further acknowledges that Shell did not accept this as normal analytical practice, citing a "ballooning effect" that Shell did not, however, substantiate.

[209] The Board believes that the more conservative approach is to relate the first deviation from the pre-fracture state to fracturing of the BCS, and therefore finds an FEP of 37.5 MPa at the 8-19 well to be the appropriate starting point. Given that finding, the proposed 32 MPa MBHIP provides a safety margin of 15 per cent, not the 26 per cent cited by Shell.

[210] Since the 8-19 well will be the first injector in a new CO_2 sequestration project, where the fracture pressure data are limited to that well and the 11-32 well, the Board is continuing its conservative approach of applying a safety margin to reduce the MBHIP to below the formation FEP. In this case, the Board is applying a 20 per cent safety margin to the 37.5 MPa value identified above, which is an additional 5 per cent over Shell's requested 32 MPa. The Board therefore approves a MBHIP of 30 MPa for the BCS in the 8-19 injection well. The MWHIP therefore should be about 12 MPa to ensure the MBHIP does not exceed 30 MPa.

Ground Heave

[211] The Board notes that the potential surface heave as a result of CO_2 injection is calculated to range from as little as 0.6 cm up to as much as 6 cm after 25 years of injection. The Board notes

that this is less than the seasonal frost heaves experienced locally, and it would not likely be of sufficient magnitude to adversely affect groundwater. The Board further notes that the surface heave after 25 years would gradually and progressively subside following cessation of injection (i.e., during the closure period) as the pressure dissipates over the area of the BCS brine aquifer.

[212] The Board notes that Shell's proposed MMV program includes the use of InSAR—a satellite-based synthetic aperture radar system—to image surface heave that might occur. The Board notes that the ERCB has considerable experience with InSAR monitoring of surface heave. InSAR has been used for many years to monitor *in situ* bitumen recovery schemes where steam injection at high pressure is occurring at depths much shallower than 2000 m.

[213] The Board acknowledges and understands the general public concern, and the specific concerns of local residents, about possible impacts on domestic water wells. However, the Board considers the risk of such limited and gradual ground heave to be minimal, especially compared to the recurrent surface heave of greater magnitude in the annual freeze-thaw cycle.

[214] The Board notes that Shell intends to use InSAR in conjunction with other techniques, including measuring and monitoring anomalous heave patterns at the surface, to detect containment leaks.

[215] It is the view of the Board that the expected maximum heave of 6 cm originating from a depth of about 2 km is not a significant concern. The Board notes that the heave is an absolute uplift, and that the magnitude tapers off gradually towards zero beyond the edge of the affected area. The Board also notes that the ground heave will largely dissipate with time as pressures equilibrate after injection stops.

[216] The Board notes that, given the area of the uplift, deformation of the overlying units would be minimal and the slopes extremely small. The Board therefore finds that there is little risk of fracturing or increasing the permeability of overlying strata.

CO_2 Plume and Pressure Front

[217] The Board finds the analytical results of CO_2 plume size submitted to be reasonable, although Shell acknowledges that the plume size could be somewhat larger. The Board also finds Shell's pressure front estimates to be based on limited preliminary data. The Board notes that Shell's MMV program will provide additional data over time and that Shell will likely need to conduct additional modelling of both the CO_2 plume and pressure front size estimates (see discussion in MMV section).

Conclusions

[218] The Board acknowledges and understands the additional mitigating factors and measures that would provide supplemental security and further reduce the risk of loss of containment. In this regard, the Board notes, among other factors, the evidence of lack of faulting through the BCS storage complex; the casing and cementing program for the injection wells; the intended MBHIP relative to the FEPs of the reservoir and the seal immediately above; and the increasing security of storage through physico-chemical reactions over time.

[219] For all the reasons stated in our analysis of the containment issues and evidence, the Board finds that the BCS is a suitable reservoir for sequestration of CO_2. The Board further finds that the combination of geological conditions, engineering design, and operational practices mitigates the potential harms of the project to the point where the risk level for breach of containment is extremely low. The Board notes also that the MMV program (see later section) is designed to provide detection of containment and conformance of the measured results with the predicted results.

PUBLIC SAFETY AND EMERGENCY RESPONSE

Evidence

Quantitative Risk Assessment

[220] To assess the risk to the public from the project, Shell conducted a quantitative risk assessment (QRA), which described the pipelines and injection wells, identified hazards, characterized the source, modelled the consequences, estimated frequencies and probabilities, and assessed the public safety risks.

[221] Shell based its consequence modelling end points on a literature review by toxicologists. Shell selected an emergency planning zone (EPZ) end point of 40 000 parts per million (ppm) (4 per cent) of CO_2 for a 30-minute exposure. The health effects resulting from exposure at this concentration and duration are headaches, dizziness, increased blood pressure, and breathing difficulty. This is an exposure concentration from which people could remove themselves within 30 minutes without any symptoms that would impair their ability to evacuate, and without any irreversible health effects. Shell used an end point of 100 000 ppm (10 per cent) for one minute to define a lethal exposure for the risk assessment.

[222] Shell modelled potential releases from the mainline, the distribution lines, and the injection well tubing. The ESDs and sub-surface safety valves in the well were assumed to work. Shell also conducted sensitivity modelling to predict changes to hazard extents with location, weather, segment length, diameter, ESD low-pressure set point, and fluid property assumptions. Based on this modelling, Shell determined that an EPZ radius of 450 m was appropriate for all the proposed facilities. Shell derived this distance by rounding up the highest value predicted for the largest diameter pipeline (12 inch mainline) and, erring on the conservative side, applying this value to all other facilities.

[223] Shell said that, based on its modelling and to illustrate the conservative EPZ, it determined that the predicted hazard extent from a worst-case injection well blowout, assuming the sub-surface safety valves did not close, was less than half the adopted EPZ radius of 450 m.

[224] Regional weather conditions, including the poorest dispersion case identified as F1.5, were used as inputs for the QRA. Shell's evidence indicates that F1.5 represents very stable atmospheric conditions, with a low wind speed of 1.5 metres per second, that typically occur at night. Shell acknowledged that the CO_2 plume would reach the edge of the EPZ within five minutes.

[225] Shell's QRA predicted the risk of lethality in terms of chances in a million per year for a person outdoors at a location near the pipelines or wells. Shell used historical release frequencies for other pipelines and for sour-gas producing wells in Alberta because there is little or no data for CO_2 pipelines and wells. These values were compared with historical results from CO_2 pipelines and injection wells in the United States and found to be conservative. The modelling calculated the maximum predicted risk of fatality within the pipeline ROW to be two chances in a million per year.

[226] Shell compared the predicted risks with the Major Industrial Accident Council of Canada (MIACC) guidelines for land use planning near hazardous facilities. According to MIACC guidelines, acceptable adjacent land use for the maximum predicted risk of two chances in a million per year would be low-density residential developments. Shell stated that, based on MIACC risk guidelines, the boundary of the ROW would be an adequate setback from the pipeline for residential development and that a setback of less than 100 m would be appropriate for the injection wells.

[227] Shell stated that modelling releases from the BCS formation was difficult because of the convoluted pathway to the surface, secondary containment in under-pressured zones in the pathway, and dissolution of CO_2 into some of the aquifers. The results of the modelling indicated the CO_2 was so diffused that it would not actually reach the surface. Shell expected that release rates from a breach of containment in the subsurface, if they occurred, would be many orders of magnitude less than from a pipeline release, and therefore noted that the 450 m EPZ would also protect the public from possible releases from the reservoir formation.

[228] Shell estimated that the public safety risk for releases from the BCS formation reservoir would be at least one or more orders of magnitude (i.e., 10 to 100 times) less than for releases from the pipelines or wells.

Emergency Response Plan

[229] Shell updated its Corporate Emergency Response Plan (ERP) in 2011 to include CO_2 as a hazard. The amendment included general information on CO_2, spill and leak response, health effects, first aid, defensive responses, and public safety actions.

[230] Shell stated that, although not required by the Board, it will prepare a site-specific ERP for the Project that is compliant with the requirements of the ERCB's *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*. Shell's ERP will focus on preparedness and response to CO_2 emergencies and will include the pipelines and injection wells.

[231] Shell stated that releases from the pipeline or a well would be both visible and audible to operators and the public, comparing it with releases from a CO_2 fire extinguisher. Shell stated that, depending on the air temperature and humidity, a plume might still be visible at the EPZ end point concentration of 40 000 ppm.

[232] Shell calculated CO_2 concentrations that, in the unlikely event of a release, would occur inside residences adjacent to the pipeline. From its modelling, Shell determined that for releases with relatively short durations, shelter-in-place is viable and safe within all houses along the pipeline route. Shell said that shelter-in-place is the preferred strategy and is safer than evacuation.

[233] Shell indicated that its first priority during a response is people within the EPZ. After that, it would respond beyond the EPZ in areas identified using CO_2 detection devices and in consultation with local authorities. Shell said that, in addition to continuously monitoring the pipeline, it will have operators monitor the ESD valves and wellheads daily with CO_2 detectors as a preventative measure.

[234] Shell said that it contacted 29 governmental, regional, and local authorities about emergency response capabilities. Shell said that it has entered into understandings with the County of Thorhild, Sturgeon County, Bruderheim, and Lamont, and has requested their assistance in the event of an emergency response involving the public. Shell committed to providing training for responders since most would be unfamiliar with the hazards of CO_2.

[235] Shell was asked about the merits of adding an odorant to the CO_2 to make releases from the pipeline or a well noticeable to people. Shell said that the addition of mercaptans to CO_2 is unnecessary because leaks can be detected effectively without it. Shell noted that the addition of mercaptans could result in public confusion, as the smell is generally associated with natural gas and could be identified over an area much greater than the CO_2 plume. Shell also maintained that there could be operational difficulties with the process for adding mercaptans to the CO_2 stream at the Scotford Upgrader.

Analysis and Findings

[236] The Board acknowledges that Shell conducted a quantitative risk assessment of the pipelines and wells for the project, and that this risk assessment helped the Board evaluate the risks associated with transporting and injecting CO_2.

[237] The Board accepts the results of Shell's modelling, through which they established a 450 m EPZ for the purposes of preparing an ERP for the Quest project. The Board agrees that the risk associated with a CO_2 surface release from the BCS formation is considerably less than a release from either the pipeline or the wells. The Board also accepts the results of the QRA and the use of MIACC land use planning guidelines to establish risk-based land use setbacks for this project.

[238] With regard to the QRA with its conservative input assumptions and to the MIACC guidelines, the Board finds that the setback for the CO_2 pipeline being the right-of-way and the setback for the injection wells being 100 m are appropriate for the project.

[239] The Board accepts that Shell's proposed leak detection and shutdown systems will identify ruptures or leaks in a timely manner, as previously discussed in the pipeline section. The Board notes Shell's commitment to do daily field checks and bi-weekly aerial surveillance. The Board also accepts that a CO_2 release from a pipeline or well would, in most instances, be noticeable by sight and sound, which helps alert the public.

[240] The Board notes, however, that some residents might not be aware if such a release occurred at night or in an area with an obstructed line of sight or transmission of sound. The Board notes Shell's arguments against adding mercaptans because of potential operational issues or public confusion in the event of a release. However, the Board believes that confusion over the source is of minor consequence compared with the importance that the public be alerted to a potential CO_2 release, that they inform authorities, and that they shelter in place.

[241] For these reasons, the Board requires Shell to submit, before building the pipeline, additional detailed information on the technical, operational, cost, and public safety considerations of adding mercaptans. The Board could at that time determine that Shell be required to add mercaptans to the CO_2.

[242] The Board acknowledges that Shell has updated its corporate ERP to include CO_2 as a hazard. The Board further acknowledges that, since the ERCB does not currently have specific ERP requirements in *Directive 071* for CO_2, Shell would be exceeding ERCB requirements by voluntarily creating a site-specific ERP for the project. The Board therefore finds it reasonable for Shell to prepare and submit a site-specific ERP for ERCB review before beginning injection operations.

[243] The Board understands that the plume could take less than five minutes to travel the 450 m of the EPZ radius and acknowledges that evacuating people who might be affected within this time would not be feasible. The Board also understands that CO_2 concentrations are lower inside a residence. For these reasons, the Board finds that shelter-in-place is much safer than evacuation and is the preferred initial public protection measure for these operations.

ENVIRONMENT AND SOCIO-ECONOMICS

Evidence

[244] In support of the Quest project, Shell presented an EA that concluded that the project would not have a significant impact on the environmental, social, or economic environment of the study area.

[245] The EA was prepared to satisfy requirements under Canada's *CEAA* and Alberta's *EPEA*. Shell filed the EA along with its regulatory applications to the ERCB. After the initial application, Shell also filed a project update and supplemental information that was requested from regulatory agencies during the review process.

[246] The scope of the EA included the following activities and project elements as set out by the *EPEA*, the *CEAA*, and responsible authorities:

- construction of the capture infrastructure, CO_2 pipeline, and storage facilities;
- operation of the Project, including normal operation as well as accidents or malfunctions that might occur during the course of operation;
- decommissioning and abandonment of the Project at the end of its useful life, to the extent that is currently known;
- a pipeline route selection analysis that considers environmental, social, and engineering constraints;
- a conservation and reclamation plan for the pipeline;
- cumulative environmental effects; and
- an MMV plan for CO_2 sequestration.

[247] The EA focused on key components of the biophysical, socio-economic, and cultural environments, including

- atmospheric environment,
- air quality,
- sound quality,
- groundwater resources,
- aquatic environment,
- terrestrial environment,
- soils and terrain,
- vegetation and wetlands,
- wildlife and wildlife habitat,
- archaeological and heritage resources,
- land use, including traditional use by First Nations,
- public health and safety, and
- socio-economics.

[248] The EA identified and outlined measures to mitigate adverse effects. Where residual adverse effects of the project could not be mitigated, they were evaluated for their significance. The EA concluded that the Quest project would not have significant project-level or cumulative adverse effects on any environmental or socio-economic resources evaluated in the EA provided the mitigation measures outlined in the assessment are implemented.

[249] Shell proposed follow-up monitoring for each environmental component. Some components, such as air quality monitoring, would be incorporated into existing monitoring for the Scotford Upgrader.

[250] The Kovacs expressed concerns about potential environmental effects of loss of CO_2 containment on vegetation, crops, wildlife, livestock, insects, soil, surface water, and groundwater. Shell indicated that the main surface effects will be from the pipeline and surface well-site pads for injection wells. The closest Project infrastructure to the Kovacs’ lands is the 5-35-59-21W4M proposed injection well about 3 km away.

[251] Mr. Clifton expressed concerns about the potential for the proposed route to affect agricultural operations by introducing weeds and soil-borne diseases during construction and ongoing operations. Shell’s application outlines a Clubroot Management Plan, reclamation monitoring, and weed control.

[252] Mr. Ouelette expressed concern about an injection well on the land immediately to the south, about 800 m from his domestic water well.

[253] The Kovacs expressed general concerns about the ability to generate carbon credits through the way the land is managed, and about the impact of the project on carbon credit trading values. The Kovacs indicated that the potential to generate agricultural carbon offsets from their land will be affected.

[254] Shell said that the project does not directly affect the Kovacs' lands and will have no effect on any of the Kovacs' cultivation practices on their lands.

[255] Shell indicated that emission offsets, or carbon credits, are regulated under the *Climate Change and Emissions Management Act* and its regulations. Shell pointed out that the ERCB is not responsible for the administration of this act or for the associated regulatory regime that sets out the qualifications for offsets.

[256] The Kovacs and Mr. Ouelette expressed concern about the negative effect that the project would have on the property value of their lands. The Kovacs said that the long-term risks of CO_2 breaches are not known or guaranteed and that this will affect surface and property owners' land values. The Kovacs indicated that the public perception of the AOI as a CO_2 disposal area could adversely affect the value of their land. They expressed a view that compensation to landowners within the AOI would therefore be appropriate.

[257] The Kovacs presented the results of an informal survey of 20 people that purported to capture perceptions of property values within the AOI. The Kovacs acknowledged that its survey was not statistically valid nor were they experts in appraising property values.

[258] Shell said that no project surface facilities are proposed for the Kovacs' or Mr. Ouelette's lands, and it does not predict any significant adverse environmental effects. Shell also indicated that no setbacks or other land-use restrictions resulting from the project would affect land owned by the Kovacs. Shell noted that CO_2 injection at the 5-35-59-21W4 well will be contained within the BCS saline aquifer. Shell said that the MMV plan has been put in place to assure surface landowners and regulatory authorities of CO_2 conformance and containment.

[259] Shell does not believe that property values in the area, including for the Kovacs' and Mr. Ouelette's lands, will be negatively affected by the project. Shell also pointed out that the interveners did not provide formal, substantive, and site-specific evidence to support their concerns about land values, and it said that compensation issues are not issues to be considered by the Board.

[260] Shell is a member of the Northeast Capital Industrial Association (NCIA) and has committed to complying with the Regional Noise Management Plan (RNMP). It will manage noise as part of the Health Safety Security and Environment - Management System (HSSE-MS) and is preparing a site noise management plan (SNMP). Shell submitted that the SNMP will include monitoring and measurement programs to assess site noise. Shell will be providing this information to the NCIA for development of an annual noise report. Shell will ensure that the NCIA annual noise report and supporting data is submitted to the ERCB.

[261] Shell committed to

- ensuring drilling rig noise levels will not exceed 40 decibel average weighted (dBA) at any receptor location during drilling,
- measuring initial noise levels at the rig site upon startup, and
- informing potentially affected residents of the expected duration and character of noise in a timely fashion before the drilling activities.

Analysis and Findings

[262] The Board notes that Shell completed an EA for the project following the terms of reference developed by the *ESRD* and the *CEAA*. The Board acknowledges that the EA was broadly scoped in order to assess the significance of potential social, economic, and environmental impacts that could be triggered by the development of the Quest project. The EA also considered the potential for accidents, malfunction, and unplanned events.

[263] The Board accepts that Shell identified and considered potential environmental and socio-economic effects of the project and appropriate mitigations and monitoring programs. The Board accepts the conclusion in the EA that the Quest project would not have significant project-level or cumulative adverse effects on any environmental or socio-economic resources assessed in the EA.

[264] Landowner concerns are related to the potential for loss of containment to have adverse effects on domestic water wells, various environmental resources, and agricultural production. As discussed previously, the Board finds that the BCS is a suitable reservoir for sequestration of CO_2. The Board has also found that the risk of a breach of containment is extremely low. However, the Board accepts the need for the ongoing MMV program, as described later in the decision, to ensure that a loss of containment from the BCS formation would be identified early and effectively addressed.

[265] The Board notes that Shell included a pipeline C&R plan that addresses the potential for weeds and soil-borne diseases to affect agricultural production. The Board notes that the jurisdiction for weeds and management lies with the ESRD and the relevant municipal authority.

[266] The Board notes that impacts on the environment during construction and operations will be short-term and can be limited through adherence to regulatory requirements, mitigation measures identified in the project C&R plan, and other mitigations outlined in the EA.

[267] The Board understands that there is a regulatory regime for emission offsets and protocols administered by ESRD that establishes the rules for quantifying emission offsets for different activities and land eligibility. The Kovacs presented no evidence to support their concerns about the potential impact of the proposed project on their eligibility for carbon credits or on the value of such credits. As previously noted by the Board, given the suitability of the BCS as a CO_2 sequestration reservoir and its depth of two kilometres, the proposed project is not expected to affect the use of the Kovacs land or preclude opportunities for emission offsets or carbon credits.

[268] The Board understands the concern of the Kovacs and Mr. Ouelette about the impact of the project on property values. After considering all the evidence, the Board finds that the interveners did not provide sufficient evidence to determine an impact of the Project on property values. The Board also believes that Shell's commitment to ongoing community engagement and reporting of MMV performance results would address negative perceptions of any surface effects of underground sequestration of CO_2 that might be based on misunderstanding or lack of information.

[269] The Board recognizes that the Kovacs' land is near the centre of the Quest CCS Project approved sequestration lease. However, as the Board has previously noted in various decisions

and in the notice of a hearing for this proceeding (December 22, 2011) regarding submissions, compensation for land usage is not dealt with by the ERCB.

[270] The Board notes Shell is preparing a site noise management plan that will include monitoring and measurement programs to assess site noise performance, and that it will be reporting to the NCIA. The Board also notes that Shell committed to submitting a report and supporting data to the ERCB.

[271] The Board accepts Shell's commitment to ensuring that drilling rig noise emission levels will not exceed 40 dBA at any receptor location during drilling and to completing an initial measurement of sound levels at the rig site upon start-up. The Board accepts Shell's commitment to inform potentially affected residents of the expected duration and character of noise in a timely fashion before the drilling activities.

[272] For the reasons noted above, the Board finds no significant environmental and socio-economic effects of the project on landowners in the AOI.

MONITORING, MEASUREMENT, AND VERIFICATION

Evidence

[273] Shell submitted an MMV plan for the project, the principal purposes of which are to verify that actual storage performance conforms to model-based forecasts, and to trigger additional control measures to prevent or correct any loss of containment before significant impacts occur. Shell noted an MMV plan is required by ADOE as part of its pore space tenure agreement. ADOE also requires a report and update of Shell's MMV plan every three years. Shell also explained that MMV findings would be used to support its ongoing commitment to community engagement (see public engagement section).

[274] Shell stated that, while the MMV plan was comprehensive in nature, it is intended to be adaptive, responsive, and flexible enough to be appropriate throughout the life of the project. Shell noted that the MMV plan is designed to meet varying needs during four distinct phases of the project: pre-injection baseline data collection, injection, closure, and the post-closure period. Shell expects the MMV to change over the life of this project as the results of additional technical studies, baseline information, and performance monitoring data become available. Its plan includes measurement and monitoring targets, processes, and technologies that would be applied during all four phases of the project identified.

[275] Shell identified those measurement and monitoring processes and technologies that were sufficiently mature to be included now in the pre-baseline MMV plan, as well as those technologies still under evaluation.

[276] Shell stated in its closure plan that consistency between predicted and observed storage performance is required. Shell modelled various areas of the project to determine predicted performance on which to base conformance. Shell indicated that these models could be rerun and adjustments made to the predictions depending on baseline information and performance evidence.

[277] Shell said it intends to submit annual performance reports to the ERCB that would assess the current MMV plan and address any necessary adjustments or changes to both measurement methods and performance models. Shell committed to formally updating its MMV plan before beginning CO_2 injection, and would include in that report several more studies, as well as the results of the baseline data collection over the next two years.

[278] Shell submitted its MMV plan to a thorough third-party review by DNV, which issued a *certificate of fitness for purpose* for the Shell Quest project (noted in [142]). Shell received a number of recommendations from DNV and adopted several of them. Shell also referenced other international CO_2 projects as examples of project design and monitoring.

[279] Shell included in its MMV plan the following areas, which are addressed in this decision:

- baseline data prior to injection,
- project monitoring wells,
- wellbore integrity,
- containment,
- CO_2 plume,
- pressure front and ground heave,
- non-saline and saline aquifers,
- surface leak monitoring,
- noise,
- maximum injection pressure,
- geomechanical modelling/monitoring,
- geophysical modelling/monitoring,
- InSAR,
- geochemical modelling/monitoring,
- surface monitoring, and
- conformance with predictions.

Baseline Data Prior to Injection

[280] Shell emphasized the value of collecting baseline data in order to identify natural variations and thus be able to establish trigger thresholds. Shell discussed several baseline measurements that would be taken.

[281] First, water sampling and laboratory analysis of water chemistry (including natural tracers). Shell said that this would also include identifying natural fluctuation in electrical conductivity, pH, CO_2, and methane. Shell noted that identification and use of artificial tracers is still being studied and, since an artificial tracer requires no baseline, it will be introduced (if viable) at the time injection starts.

[282] Second, baseline measurements for analysis of future ground heave, in situ CO_2 plume, and pressure front, will be obtained using InSAR and time-lapse seismic data. Shell said it requires a minimum of two years of InSAR baseline data before starting injection of $CO_{2.}$ This data set is

required to identify the density and distribution of natural reflectors and to determine the potential need for installation of corner reflectors. Shell noted that part of the time-lapse seismic data baseline has already been acquired in the form of a 3D survey previously conducted. It further noted that additional baseline data in the form of 3D vertical seismic profiles (VSPs) will be acquired prior to CO_2 injection when the next two injector wells are drilled.

[283] Third, baseline ecosystem studies, spectral image analysis, and soil ph and salinity analyses will be conducted two years prior to injection of CO_2. Furthermore, line-of-site CO_2 flux is currently being tested as a viable means of measuring leaks of CO_2 into the atmosphere.

[284] Fourth, Shell noted that the results of reservoir modelling will provide the baseline against which conformance will be history-matched and for which updates would be made over the operating life of the project. This modelling, incorporating the latest well data, is ongoing to better define the expected growth of the CO_2 plume and pressure front. An expected range of outcomes will be developed for both the CO_2 plume and the pressure front, reflecting, in order of priority, the number of wells, sweep efficiency, maximum CO_2 saturation, porosity, BCS reservoir thickness and heterogeneity, CO_2 relative permeability, and other reservoir parameters.

Project Monitoring Wells

[285] Shell proposed a suite of measurement and monitoring devices to be placed in non-saline and saline aquifer monitoring wells. Shell proposed to drill three non-saline groundwater monitoring wells at each injector and one non-saline ground water monitoring well adjacent to each of the four BCS legacy wells inside the AOI.

[286] Shell also proposed to drill at least three deep monitoring wells to the Winnipegosis Formation located in the centre of the scheme where the reservoir pressure due to injection is expected to be highest and, therefore, positioned where there was the greatest (although still insignificant) potential for leakage. Shell stated that pressure monitoring in the Winnipegosis aquifer would permit detection of upward moving brine and CO_2 outside the BCS storage complex. Shell also indicated that it may use additional wells to monitor the BCS initially, such as the two injection wells (07-11-059-20W4 and 05-35-059-21W4) that will be drilled before commencing injection.

[287] Shell said that all monitoring well information, assessment, and corrective actions would be addressed in performance reports and that any evidence of containment loss would be immediately reported to the ERCB.

Wellbore Integrity

[288] Shell said that any loss of external or internal well integrity in the injection wells could potentially allow migration of the CO_2 and BCS brine out of the storage complex. However, Shell submitted that all injection wells will have three full casing strings, cemented to surface to isolate cross-flow and migratory paths within the well bores.

[289] Shell stated that the injection well tubing will be continuously monitored for pressure and temperature during injection and at time of closure. It noted that ultrasonic casing imaging, electromagnetic casing imaging, and casing caliper logs would be run every five years during injection and every ten years during the closure phase. These logs will determine the casing

integrity over the life of the injection well. Shell further indicated that cement bond logs would be run every five years, and that each injection well would have a permanent fibre-optic string distributed temperature and acoustic noise sensing system that will also provide continuous monitoring to detect any fluids migrating upwards outside the casing.

[290] Shell identified four legacy wells and three Shell Quest appraisal wells, all but one of which penetrated the seals of the BCS storage complex. Shell said that the three Shell Quest appraisal wells pose less risk than the legacy wells because they have been constructed to current standards and are still accessible for monitoring and remediation. Shell noted that the future injection wells would be constructed to the same standards.

[291] As previously noted, Shell said that its injection wells would be at least 18 km from the nearest legacy well, in part to limit the risk of any leakage of CO_2 or brine into non-saline aquifers through the legacy wellbores. Shell's subsurface modelling simulations indicate that the CO_2 plume will not reach these wells during the life of the project and that the increased reservoir pressure at these wells would not be enough to lift brine through the legacy well bores into non-saline aquifers.

Containment

[292] As discussed in more detail in the Sequestration section [156], Shell requested a MBHIP of 32 MPa for the 8-19 well, with an equivalent MWHIP of 14 MPa. Shell proposed to control MWHIP with emergency shutdown devices that would be located in the supply lines to the injection wellhead and that would trigger at 10-12 MPa. Surface and downhole gauges would continuously monitor pressures.

[293] Shell also noted that the downhole microseismic array to be installed in one deep monitoring well would be capable of detecting induced fracturing in the injection zone and caprock of that well. Shell said that the microseismic array will be deployed in the deep monitoring well to be drilled on the 8-19 injection well pad. Shell said that microseismic would be key to measuring unexpected fracturing related to the pressure of injection, noting that microseismic monitoring is capable of measuring low-magnitude minus-3 event, such as an induced fracture, up to 600 m away. If microseismic events occur, the downhole array is capable of tracking the events if they are moving upward.

[294] Shell agreed that microseismic events are outside the expected responses and would trigger immediate notification to the ERCB.

[295] Shell said that understanding the geomechanical and stress properties of the rocks are important in two areas. Shell identified its importance, first for estimating the overall ground heave induced by elevated pressures in the reservoir, and second for calculating the fracture pressure of the BCS reservoir and the overlying Middle Cambrian Shale (MCS) seal. Shell identified that both of these affect the ability to sequester CO_2 safely in the BCS storage complex.

[296] As noted in the Containment section [165], Shell used a homogeneous, linear, elastic half-space model to simulate the ground heave caused by CO_2 injection. From the numerical model, Shell predicted a maximum heave of 6 cm after 25 years of injection. Shell said that it would use a geomechanical inversion of the InSAR surface-displacement data to monitor the distribution of

volume changes, reconciled with pressure measurements inside the BCS. Shell said that if the simple geomechanical model proved insufficient to explain the observed surface displacements, it would be revised. Shell expects that the induced surface displacement would decline after injection stops because of the decline of the injection pressure within the BCS.

[297] Shell is basing its current model on a wide range of estimated parameters. It believes the biggest outstanding uncertainty in determining geomechanical properties is scaling up from the core scale to the field scale. Once the injection period starts, Shell will obtain more InSAR data, and it will measure pressure increases within the BCS. Shell intends to use these data to estimate the field-scale compressibility and the Young's modulus of the BCS.

[298] While Shell said it has no plans for more geomechanical core studies on the BCS, it noted that it is currently doing geomechanical testing, as well as permeability and capillary pressure testing, on samples from the Middle Cambrian shale from the 8-19. Shell followed special procedures to properly preserve, transport, and test the shale core. The testing is incomplete because of difficulties drilling horizontal core plugs without disturbing the samples. Shell committed to providing the analyses to the ERCB upon completion. Shell indicates that it still has 17 m of core in "close to pristine" condition for further testing, if needed.

[299] From a geomechanical perspective, Shell believes there are other factors to ensure containment of the CO_2, within the BCS storage complex. These include the two regionally extensive salt seals. Shell noted that salt is a ductile medium that does not fracture under pressure and temperature.

CO_2 Plume

[300] Shell submitted simulations showing the volumes and areal extent of the CO_2 plume and elevated pressure front within the BCS based on available geological and reservoir information. Shell acknowledged that horizontal and vertical permeability of the reservoir and CO_2-brine relative permeability have the greatest effect on the determination of the extent of migration of the CO_2 plume. Shell presented analytical results that indicate CO_2 plumes of up to 3 km in diameter, but also noted that simulations using different reservoir properties indicate larger plume extents.

[301] Shell said that it would obtain an initial stabilized shut-in pressure measurement, but did not commit to ongoing pressure testing of its proposed injection wells.

[302] Shell indicated it would submit annually, for ERCB review, an updated plume and pressure area simulation and additional operational site-specific information. This information includes actual injection rates and volumes, pressure evidence from minifrac step-rate tests, and fall off tests, as well as information from seismic and InSAR on the extent of the CO_2 plume and pressure front. Shell also indicated it would include information from any new coring and permeability testing.

[303] In its MMV plan, Shell proposes a suite of geophysical monitoring systems. These include repeated surface 3D surveys over the injection area, repeated VSP in all injectors, and continuous microseismic monitoring in the deep monitoring well. Shell said that the first two techniques will monitor the extent of the CO_2 plume. The third would monitor potential leaks adjacent to the

well bore, as has been noted in the Containment section above. Shell committed to providing an update on its application of these techniques within three months of receiving project approval.

[304] Shell explained that time-lapse seismic, which includes 3D VSP, is sensitive to CO_2 saturations within porous formations. Besides being able to monitor the CO_2 plume within the BCS, Shell noted that time-lapse seismic can detect potential leaks of CO_2 above the primary seal, the Middle Cambrian Shale.

[305] Shell said that it has already acquired the baseline 3D program that covers all the potential injection well sites. Shell plans to acquire baseline 3D VSP data at each well site before beginning injection at each site. Follow-up 3D VSP data will be acquired at regular intervals beginning two years after injection starts, although Shell noted that as the CO_2 plume grows, the rate of expansion decreases and the interval between successive 3D VSP surveys might be lengthened.

[306] The 3D VSPs will be used to image the CO_2 plume until it reaches the limit of the VSP coverage, which is about 600 m from the injection well.

[307] Once the plume extends beyond 600 m, repeat surface 3D seismic programs would be used to monitor the plume. Shell expected that two repeat surface 3D surveys would be acquired during the injection period: one at the end of injection and one near the end of the closure period.

Pressure Front and Ground Heave

[308] Shell says that there are two purposes for its use of InSAR. The primary purpose is to assess conformance—that is, how well the surface displacement conforms to the predictions of the geomechanical model, and thus, whether the CO_2 is behaving as expected. The second purpose is monitoring for containment. Shell said that increased pore fluid pressure due to CO_2 injection at depth causes volume changes that can produce observable displacements of the ground surface. InSAR can measure these displacements with millimetre-precision when the displacements are greater than 2-3 mm.

[309] Shell said that it would use a geomechanical inversion of the InSAR surface-displacement data to monitor the distribution of volume changes, reconciled with pressure measurements inside the BCS. Shell's geomechanical models predict that there might be a few millimetres of uplift within the first 12 months localized at the injection site. InSAR measurements are expected to determine whether these model predictions are accurate.

[310] Shell notes that InSAR monitoring might also detect any anomalous surface displacement patterns that deviate from the predicted pattern, and that could indicate potential threats to containment. Shell provided several examples of such anomalies: a heave pattern that is more localized than predicted, possibly indicating escape of fluids above the ultimate seal; unexpected migration of uplift signal toward pathways such as legacy wells, indicating a threat to containment; and step-like anomalies within the distribution, possibly indicating fault reactivation.

[311] Shell plans to acquire InSAR data about once per month, based on the acquisition frequency of the satellite. Acquisition and processing will begin 2-3 years before injection, during injection, and during the closure period. Shell plans to process the InSAR data annually

and submit the results with its annual MMV report. Shell said that given the minimal amount of expected heave, yearly processing and reporting would be adequate.

[312] Shell agrees, if there is interest, to inform the local community about the InSAR technology and its findings through open houses.

[313] Shell said that the effective use of InSAR technology requires an array of reliable reflective targets on the ground, whose reflective characteristics are stable over time and not affected by wind, moisture, or vegetation growth. Examples include buildings, roads, and well pads. Shell said that these targets must be distributed over the entire AOI and be sufficiently dense (i.e., no gaps of more than 4 x 4 km) to capture the shape of the uplift pattern. Shell further noted that where gaps in natural reflectors occur, they can be filled by installing artificial targets called corner reflectors. Shell believes, based on preliminary radar acquisitions, that the natural targets in the AOI are of sufficient quality and density that corner reflectors would not be needed.

[314] Shell also noted that corner reflectors have different signal-to-noise characteristics than natural reflectors and would require only about 15 months before becoming as precise as the natural targets. Shell does not believe this is a concern for monitoring because, according to its models, surface heave will be increasing steadily with time.

[315] Shell said that additional surface deformation measurement techniques, such as tiltmeters, would not be required as backup for the InSAR monitoring. Shell said that, since little surface deformation is expected and because other areas of the MMV plan address containment issues, there is no need for backup ground deformation measurements. However, Shell also noted that if the InSAR data quality is so low as to be unusable for monitoring, there remains the possibility of using the Global Positioning System (GPS) to monitor ground deformation. Shell agrees that any problems with the quality of the InSAR data, as well as any anomalous deformation observations, would be addressed when its annual MMV report is submitted, and the MMV plan can be updated based on the Board's recommendations.

[316] Shell also acknowledged that in the unlikely event that InSAR or time-lapse seismic prove to be insufficient within the first five years of injection, it might drill observation wells into the BCS to directly measure pressure increases, and ultimately CO_2 build-up, at a few discrete locations.

Non-Saline and Saline Aquifers

[317] Shell proposed a non-saline groundwater monitoring program that consists of groundwater sampling and analysis, testing of landowner water wells, and use of monitoring wells at critical locations.

[318] Shell indicated that it would establish a monitoring network of existing landowner water wells to monitor groundwater quality. The network would include all existing landowner wells, subject to landowner consent, within 3.2 km of proposed injection wells, existing landowner wells near the BCS legacy wells, and a regional network of existing landowner wells distributed across the remaining area of the AOI at about one per township. Shell chose the 3.2 km radius in order to get a meaningful statistical sample set.

[319] Mr. Ouelette argued, citing the Hydrogeological Consultants Ltd. (HCL) report submitted in evidence, that groundwater monitoring should follow the entire baseline water well testing (BWWT) guidelines established by AENV for coalbed methane development. The HCL report stated that the information obtained would provide valuable chemical, microbiological, and physical hydrogeology information that could be used to assess potential impacts from development, as well as provide valuable information for subsequent hydrogeological investigations in the area.

[320] Shell did not agree with the HCL recommendation that it be required to follow every component of the BWWT guidelines, stating that microbiological sampling and pumping tests should not be required as part of its baseline program since its proposed project would not affect these parameters. Shell indicated that microbiological testing can be readily done if water well owners are concerned about public health issues. Shell also noted that rate tests of landowner wells risk well damage, and that the construction details of many landowner water wells make them unsuitable for pumping tests.

[321] The HCL report also recommended that water well owners be given the opportunity to join the MMV baseline study at any time over the lifetime of the project, even if they initially decide not to participate, arguing that when a new well is added to the MMV plan, the first sampling result for that well would be its baseline values. The Kovacs indicated that should a water well be built on their land, they would be interested in participating in Shell's MMV plan. Shell confirmed that, over the life of the project, the CO_2 plume might extend under the Kovacs' land.

[322] Shell said that well owners should not be given the option to join the MMV plan at a later date because, by not participating from the outset, the wells would not have been included in the baseline sampling period, and comparisons to baseline values would not be possible.

[323] Shell indicated that the BCS brine has a unique formation fluid chemistry that could be used to verify its presence or absence within protected groundwater resources.

[324] Shell indicated that it is conducting a study to determine whether an artificial tracer could be effectively attached to the injected CO_2 molecules so that its movement could be tracked. Currently, Shell is investigating the potential issue of miscibility of a tracer and CO_2. Shell said the technical challenge is developing a tracer that will travel with the CO_2 and not react with the components of the varying lithologies—carbonates, siliciclastics, evaporites, and coals—or with changing pressure and temperature conditions. Results to date suggest that some tracers have an affinity to coal, and consequently any CO_2 that has leaked outside from the storage complex and come into contact with coal could be stripped of the tracer, making it no longer useful as a method for distinguishing anthropogenic CO_2 from any naturally occurring biogenic CO_2. Shell indicated that it would submit the results of the study to the ERCB when it is complete.

Surface Leak Monitoring

[325] Shell proposed a suite of surface monitoring technologies involving remote sensing and onsite surveys, including line-of-sight gas flux monitoring for soil gases. Shell said that the details of the program, including frequency of measurement and reporting, are being finalized and will be addressed in a report to the ERCB before the start of baseline monitoring.

[326] The Kovacs expressed concern about the potential that a slow CO_2 or brine leak from the pipeline, wells, or the sub-surface would affect wildlife and the agriculture industry.

[327] Shell proposed using spectral optical imaging to determine baseline conditions in the biosphere. Shell also proposed using line-of-sight CO_2 gas flux monitoring to help collect baseline biogenic CO_2 flux data.

[328] Shell identified and evaluated potential methods for detecting releases of CO_2 to the atmosphere and for evaluating the effects of a release on ecological and agricultural resources by measuring vegetative stress over the entire area of injection and near legacy, monitoring, and injection wells. Shell proposed using satellite or airborne spectral image analysis to detect changes in vegetation health over the AOI.

[329] Shell noted that, given the size of the AOI, there would be temporal and spatial variations in the natural flux of CO_2 soil gas associated with varying soil moisture and vegetation changes. Given the inherent variability of climatic conditions that affect vegetation patterns and soil moisture, Shell proposed a tiered monitoring program that puts emphasis on indicators that are most sensitive to natural variability in CO_2 concentrations.

Analysis and Findings

[330] The Board agrees with the concept of the MMV plan and its components with respect to first developing a solid set of baseline information and data, and then conducting an ongoing monitoring program to verify project conformance with or identify deviation from Shell's modelled predictions of performance. The Board regards the MMV plan to be extremely important to all operational phases of the project, and equally important to the ongoing post-operational closure and post-closure phases.

[331] The Board agrees that accurate and complete baseline measurement is needed for determining natural variation in measured parameters. The Board acknowledges that it is only with such a baseline that Shell would be able to identify anomalous data and refine the need for various types and locations of measuring devices or systems. The Board finds that the MMV baseline monitoring program provided in the Application, though not finalized, is developed sufficiently to permit the Board to make an informed decision about early detection of loss of containment in the BCS and the ability to take early corrective action.

[332] The Board notes and accepts Shell's commitment to provide further reporting on the full set of baseline measurements to be taken during the pre-injection period. The Board expects Shell's report to outline what it is reporting, why it is being reported, where the measurements will be taken, when the measurements will be taken, and how the measurements will be taken. The Board requires that the report provide Shell's rationale and conclusions about the appropriate values or conditions it will use, given those baseline measurements, to trigger additional analysis or mitigation. Given that CO_2 injection is scheduled to begin in early 2015 and that the proposed baseline study is to be two years long, the Board requires that Shell submit a complete pre-baseline MMV plan by October 15, 2012.

[333] The Board believes that an effective MMV plan that supports timely reviews and corrective responses is critical for all phases of this project. The Board requires Shell to submit an annual report of operational performance, MMV results, associated analyses that describe how the

operational performance of the scheme conforms with the modelling and predictions, and discussion of the need for further MMV changes. The ERCB will review this report and based on that review, additional monitoring and/or modelling studies could be required. Other special reports, as discussed in this decision, are also required. This is in keeping with the adaptive process proposed by Shell. The Board also requires that evidence of loss of containment be reported immediately.

[334] The Board acknowledges that the MMV plan proposed by Shell is comprehensive, but that assessments of several elements would need to be completed for a complete pre-baseline MMV plan to be finalized. Shell must submit MMV plan updates as required by the ERCB; at a minimum Shell must submit updates at critical milestones such as commencement of injection, closure, and post closure.

[335] The Board recognizes the MMV plan must be adaptive and flexible to allow for enhancements, and that as more information is received the ERCB might provide further direction to Shell.

[336] The Board acknowledges the third-party review undertaken by DNV and recommends that Shell continue a similar third-party review process as the MMV evolves and matures. The Board strongly endorses Shell's plans to use MMV information to support its commitment for ongoing public engagement.

[337] Details on specific MMV reporting requirements are discussed below. Other reporting requirements are discussed in the respective sections of this decision. A summary of key reporting requirements, including MMV reports, is found in Table 1.

Project Monitoring Wells

[338] The Board acknowledges that the suite of measurement and monitoring devices Shell proposes to place in non-saline and saline aquifer monitoring wells should provide adequate data to identify changes in water quality. The Board also finds the number and location of the monitoring wells (see [284] and [285] above) to be appropriate.

[339] The Board agrees with pressure monitoring of the Winnipegosis aquifer in the centre of the scheme where injection would take place and where the potential for leakage is greatest. The Board agrees with using the additional injector wells that would be drilled before beginning injection, for monitoring if that would be operationally feasible. Given that three of the proposed additional injectors would be located as much as 10 km north of the initial injection area, the Board requires Shell to evaluate the need for adding a Winnipegosis formation deep monitoring well at either the 15-16 or 15-29 location. The Board requires Shell to include its analysis in the report to be provided by October 15, 2012. Based on the information provided the Board might require Shell to drill one or more such deep monitoring wells.

[340] The Board notes that, from Shell's modelling using the heterogeneous, low-quality reservoir case, after 25 years the plume pressure could be sufficient to raise BCS brine to the BGWP within 6 km of a legacy well. For this reason the Board requires Shell, in its annual reporting, to evaluate the need for additional deep monitoring wells adjacent to the four legacy wells in the AOI. Based on the information provided the Board may require Shell to drill one or more such deep monitoring wells.

Wellbore Integrity

[341] The Board has already noted that Shell is required to adhere to existing and future ERCB directives and regulations for drilling, construction, completions, testing and abandonment of wells.

[342] The Board notes the need to confirm hydraulic isolation in the injection wells and in deep monitoring wells. Shell indicated that a cement bond log and measurements obtained with the fibre-optic string will be adequate to confirm hydraulic isolation in the injection well. Not withstanding the simulations provided in the Oxand Report (see paragraphs [149]-[150]), the Board considers five years of thermal effects of CO_2 injection before verifying the integrity of the wellbore cement to be too long a period. The Board therefore requires that hydraulic isolation logging be conducted after two years of injection, and that the need for further hydraulic isolation logging over the life of the well will be determined through the annual reporting process.

Containment

[343] The Board agrees that the MMV plan must monitor the operating pressure and injection rate, as well as induced microseismic events. The Board is not only concerned about the operating pressure exceeding the MBHIP, but also about any signs of fracturing out-of-zone during injection below this pressure. Therefore, the Board requires Shell to immediately report any anomalies that indicate fracturing out-of-zone.

[344] The Board acknowledges the laboratory geomechanical analysis completed to date on the BCS storage complex, although it recognizes that scaling up the measurements derived from core analysis to the field scale will be difficult. The Board understands that Shell will attempt to use ground-heave measurements to determine field-scale parameters and will use these parameters to improve the calibration of its numerical model.

[345] The Board notes that the MCS is the first seal above the BCS reservoir and that the full characterization of this unit is essential. Regarding geomechanical testing of the MCS, the Board understands the difficulty sampling, preserving, and testing shale. The Board acknowledges that the core testing has not been completed, and that Shell is required to submit the final results to the ERCB.

[346] The Board finds that Shell's MMV plans for future geomechanical modelling are sufficient. However, if monitoring shows loss of containment or unexpected surface heave, Shell is required to conduct, and submit the results of, more comprehensive project modelling using site-specific parameters to re-evaluate the issue of deformations caused by pressure changes.

[347] The Board agrees with the need to install a microseismic array in the deep monitoring well to be located on the 8-19 well pad to identify potential formation fracturing. Recognizing the size of the injection area, the Board believes that microseismic arrays might be needed at other injection well pads. Therefore, the Board requires Shell to also address this issue in the October 15, 2012 report referred to above. Based on the report, the Board could require Shell to install more microseismic arrays.

CO_2 Plume

[348] The Board accepts Shell's plans to use time-lapse seismic as the primary method of tracking the CO_2 plume growth within the BCS. The Board agrees that 3D VSPs are appropriate until the plume exceeds the range of the VSP coverage (i.e., about 600 m), after which time further surface 3D seismic surveys would need to be conducted.

[349] The Board notes that Shell has addressed the frequency of time-lapse seismic surveys in its application; the plans must be confirmed in the annual reporting process. If the CO_2 plume expands faster than predicted, the Board may require additional surface 3D seismic to follow plume expansion.

[350] The Board understands and acknowledges that horizontal and vertical permeability and CO_2-brine relative permeability have the greatest effect on the extent of the CO_2 plume. The Board notes the analytical results presented by Shell that indicate CO_2 plumes of up to 3 km diameter, but also notes that simulations assuming different reservoir properties indicate larger plume extents. The Board further notes that relative permeability tests, initial pressure tests, and minifrac step-rate tests will be conducted in the BCS for all future injection wells. In that context the Board requires that after each injection well is drilled and the data collected Shell address the need to rerun CO_2 plume and pressure front models in its annual reporting.

[351] The Board understands that accurate and timely reservoir pressures that meet ERCB *Directive 40: Pressure and Deliverability Testing Oil and Gas Wells* stabilized pressure requirements, and that are taken at the injectors and test wells, would greatly enhance understanding of plume movement. Following an initial baseline pressure analysis of the fall-off data from the 8-19 well, the Board requires an additional fall-off test with pressure-gradient analysis, after two years of injection in all injection wells, for comparison with the baseline data. These data will provide stabilized shut-in reservoir pressures and information on any indication of fracture flow. Based on the results of each fall-off test the Board may require Shell to conduct further fall-off tests in order to better understand plume movement.

Pressure Front and Ground Heave

[352] The Board notes the use of InSAR for identifying ground heave and the application of the technology for assessing containment monitoring and operational conformance with CO_2 sequestration targets. The Board notes that the quality of the baseline and ongoing monitoring InSAR data, and the frequency of processing and reporting, are important for effective monitoring.

[353] The Board understands that containment issues such as migration of fluids above the seal or movement toward legacy wells will manifest as anomalous surface patterns, and it notes that InSAR measurements must be of good enough quality to detect these types of localized anomalies. The Board concludes that a sufficiently dense array of reliable monitoring targets as well as accurate baseline topographic data are therefore essential. Since Shell maintains that the preliminary InSAR results show that the current distribution of natural targets is adequate, the Board requires Shell to include the preliminary InSAR results showing the distribution of likely natural targets in the October 15, 2012 reporting. If corner reflectors are deemed necessary by the ERCB after reviewing the updated MMV plan, they must be installed near each injection site at least 15 months before injection.

[354] The Board agrees with Shell that annual processing and reporting are adequate to monitor the small amount of heave (6 cm) over 25 years of injection. The Board requires that Shell provide a preliminary report two years before commencing injection, on the InSAR baseline data, that addresses the suitability of the data for the pressure front and geomechanical modelling and analysis recommended in its MMV plan. The Board also requires some early indication of the efficacy of the InSAR program and directs that Shell provide a report to the ERCB six months after injection begins.

[355] The Board agrees with Shell that installation of ground-based deformation monitoring instruments, such as tiltmeters, are not necessary. If, in the future, InSAR data is found to be of too low quality for effective monitoring, the Board may require that GPS instruments be installed.

Non-Saline and Saline Aquifers

[356] The Board supports Shell's plan to monitor both shallow non-saline groundwater and deeper saline groundwater to either detect a potential problem early or to confirm the presence or absence of contamination by brine from the BCS reservoir. The Board supports the plan to create a baseline data set by testing private water wells. The Board believes such a program would provide useful technical information and a high level of assurance to landowners that their water wells are not impacted.

[357] The Board notes Shell's position to not add landowner water wells to the MMV plan after the initial baseline sampling period begins, but believes the additional information would have some value to all parties. The Board therefore finds that additional water well owners should be given the opportunity to participate in the landowner water well portion of the MMV program at any time, and requires Shell to include such wells in the MMV plan and associated reports. The Board encourages landowners to participate in the pre-injection BWWT program.

[358] The Board notes that Shell's water well monitoring program is based on wells within a 3.2 km radius around each injection well. The Board requires clarification of the process through which Shell determined the statistical significance of the number of wells. This information must be included in the October 15, 2012 report.

[359] The Board notes the arguments that pump-rate testing and bacteriological testing of water wells discussed in the BWWT guidelines would provide valuable information on aquifer and well characteristics. The Board agrees with Shell's assessment that the type and nature of the proposed project is not expected to impact these parameters. Therefore, the Board finds that both pump-rate testing and bacteriological testing are not necessary for this project. The Board notes that these tests are readily available to landowners and are water well maintenance procedures that are the responsibility of the landowner.

[360] The Board believes that the baseline water well monitoring plan that Shell has put forward might not fully assess natural variability in all of the parameters that Shell proposes to study during the two-year baseline period. The Board also notes that parameters such as naturally occurring concentrations of methane, organic compounds, and inorganic analytes might require longer baseline timeframes. The Board therefore requires Shell to address a phased assessment of natural variability in its October 15, 2012, pre-baseline reporting of the MMV plan, including the

need for more frequent sampling during both the baseline data collection and early operational monitoring periods.

[361] The inclusion of deep saline aquifer monitoring wells in the MMV is viewed by the Board as an important component in understanding potential effects of CO_2 injection into the BCS storage complex. The Board notes that placement of these wells near the centre of the project will provide valuable insight into potential effects near the injectors. However, the Board believes there might be value in installing additional monitoring wells in the Winnipegosis and BCS toward the periphery of the pressure build-up zone in the BCS later in the project life. The Board therefore requires Shell to address this potential need for additional monitoring wells in its annual reports and presentations.

Surface Leak Monitoring

[362] The Board agrees that the use of satellite or air-borne spectral image analysis is an appropriate method of detecting changes in vegetation health over an area the size of the AOI. The Board notes that Shell is currently testing and evaluating other measurement and monitoring technologies and that some of those technologies would become part of the updated MMV plan to be submitted to the ERCB before the start of baseline monitoring.

[363] The Board notes the importance of Shell's tracer feasibility study and requires Shell to complete and submit the results of its study one year before injection starts. If a tracer is deemed not technically feasible, Shell is required to provide a discussion of the baseline data and the methods by which anthropogenic CO_2 will be distinguished from naturally occurring CO_2. For this purpose, the Board recognizes the need for baseline data and requires Shell to take and analyze measurements of biogenic flux of CO_2 in different soil types throughout the AOI, and to report on the results before injection begins.

PUBLIC CONSULTATION, COMMUNICATIONS, AND ACCESS TO INFORMATION

Evidence

[364] Shell said that one of the principles of its sustainable development policy is its commitment to engage with stakeholders in a meaningful way, to identify issues, and to search for mutually agreed-upon solutions.

[365] Shell said that it carried out an extensive and comprehensive stakeholder consultation program for this Project. Shell indicated that it communicated project information to landowners, occupants, and residents within 5 km of the Scotford Upgrader and within the CO_2 pipeline EPZ, as well as to First Nations and Métis organizations. Shell also notified leaseholders, P&NG rights holders, government agencies, regional and municipal governments, special interest groups, NGOs, industry participants, and industry associations about the project.

[366] Shell employed several different tools for communicating to stakeholders and the public, including project information packages, open houses, a Quest-specific newsletter, and a dedicated 1-800 number. Shell conducted several workshops (Quest Cafes) within area communities to discuss potential stakeholder concerns.

[367] Shell met face-to-face with landowners along the pipeline ROW and within the EPZ to provide project information, discuss questions and concerns, and get access to properties for seismic surveys, water well testing, and other environmental data collection. Shell said that these meetings resulted in about 30 pipeline reroutes and confirmation of non-objection from 109 of 111 landowners.

[368] Shell also established a website where stakeholders could find information, ask questions, and express concerns. Shell attended various community events to give local people the opportunity to ask questions and get information about the project.

[369] Shell engaged the Pembina Institute to provide an independent third-party evaluation of Shell's public consultation and communication programs. The Pembina Institute provided recommendations to Shell to enhance its public consultation program.

[370] Shell noted that it learned several things from its stakeholder consultation program. First, the importance of early consultation. Shell said that it initiated community consultations long before reaching a final decision on whether or not to proceed with the project and long before design details were established.

[371] Second, the importance of genuine consultation. Shell said its engagement showed a genuine concern for how people felt about the project, and it identified problems and potential solutions. Based on feedback from community people, project details were modified, as illustrated by the 30 reroutes of the pipeline.

[372] Third, Shell noted that it is not new to the Scotford area; it has been operating at the Scotford Upgrader since 1985.

[373] Fourth, the involvement of Pembina. Based on Pembina's critique, Shell modified its community programs. This included a decision to attend community events where area residents would have an opportunity to discuss the project with Quest representatives and get more information.

[374] Shell has considered, if the Quest project is approved, holding annual open houses, producing a dedicated newsletter, and working with a community advisory panel to help communicate complex technical data in a meaningful manner. Shell also committed to maintaining open lines of communication with municipal authorities and government agencies.

[375] Mr. Ouelette expressed interest in receiving regular updates on Shell's future activities. He specifically expressed a desire that follow-up on any future water well testing include direct contact with a person who could help him interpret the results and help him understand changes that may be occurring to his water.

[376] Shell indicated that future communication plans would include examining opportunities to review the results of the MMV plan, including water well monitoring (subject to privacy requirements) and any special operational and incident reports, with academia and the public.

[377] Shell noted that plans to share knowledge will help accelerate the deployment of CCS technology worldwide. Shell described its obligations under funding agreements with the Federal

Government of Canada and the GOA requiring transparency and cooperation with knowledge gleaned from the project.

[378] The Kovacs said that MMV information should be made available to the public. They indicated that public presentations and newspapers have been effective at communicating the MMV and project details. They suggested that the use of social media could be effective for younger generations.

Analysis and Findings

[379] The Board notes that Shell's public consultation initiatives appear to have been effective. The Board notes the number of project modifications made to address public concerns, and that Shell was able to get non-objections from 109 of 111 landowners. The limited number of parties appearing before the Board in opposition to the project supports the Board's assessment that participant involvement programs had been effective.

[380] The Board notes several features of Shell's public consultation and communications program that were effective in addressing landowner and public concerns. These included early engagement with stakeholders, the use of "Quest Cafes," a review by the Pembina Institute, and the more typical open houses, newsletters, and 1-800 number.

[381] The Board notes the apparent strong foundation of communication and engagement with area landowners and communities. The MMV could provide an ongoing opportunity for ensuring that area stakeholders continue to be informed about the project, including the water well monitoring program.

[382] The Board finds that the communication and public consultation program initiated by Shell exceeds the minimum Participant Involvement Program requirements of *Directive 056*. The Board commends Shell for its communication and consultation to date.

[383] The Board notes Shell's plan to consult with the regulatory, scientific, and public communities on how to best share its reports and data. The Board strongly supports Shell's plan to consider forming community advisory panels to help with the communication of complex monitoring data and developments.

THE PUBLIC INTEREST

Evidence

[384] Shell indicated that it had entered into agreements with the governments of both Canada and Alberta to provide funding to this project as a part of each government's objective to reduce GHG emissions.

[385] Shell said that the Quest project is intended to demonstrate the viability of CCS in order to enable Canada and Alberta to develop oil sands resources with a smaller carbon footprint. The project would demonstrate carbon capture from a bitumen upgrader for the first time. Shell stated that its project would provide knowledge and information to help reduce GHG emissions. Shell

intends to share its MMV results openly with government, academics, industry regulators, and community stakeholders.

[386] Shell submitted that it designed its project to minimize risk to the environment and the public, and it believes its MMV plan provides early detection of potential problems and verification of the effectiveness of corrective measures taken.

[387] Mr. Ouelette argued that the Board should require Shell to capture CO_2 from the Scotford Upgrader and use it for enhanced oil recovery rather than permanently sequestering it. Mr. Ouelette maintained that the definition of gas under the waste provisions in the *OGCA* includes CO_2 and argued that the Board has the jurisdiction to prevent the waste of CO_2 as a gas under Section 38.

[388] Shell responded to Mr. Ouelette's argument about the waste of CO_2 by pointing out that CO_2 is not derived from Shell's raw bitumen. The CO_2 at the Scotford Upgrader is produced from methane, which Shell buys from a natural gas utility. Consequently, CO_2 is not a gas within the meaning of that term, and Section 38 of the *OGCA* does not apply.

[389] During argument, Mr. Ouelette suggested that the Board would approve the Shell Quest project without considering the risks because the governments of Alberta and Canada were providing significant funding for the Project. Mr. Ouelette emphasized that despite government funding, the Board should rigorously review the details, especially the MMV.

Analysis and Findings

[390] The Board notes that in assessing the Shell Quest project, it must consider whether the applications are in the public interest generally and assess the social, economic, and environment impacts of the project.[4] The Board also has the power where necessary to apply conditions to mitigate site-specific or local impacts.

[391] For the project to be in the public interest, it must not only benefit the applicant and those directly connected to it, it must also benefit Albertans in general.

[392] The Board notes that establishing need, as discussed previously, does not imply that the Project is in the public interest or should ultimately be approved. In its assessment of the public interest, the Board must weigh the benefits against the risk factors that are present, given the nature of the development, the proposed location, and other factors associated with the specific situation.

[393] A finding by the Board that the approval of a project would be in the public interest does not imply that there are no site-specific impacts. The challenge for the Board is to ensure that any site-specific or local impacts are mitigated to an appropriate and acceptable level. Should the Board determine that the risks cannot be sufficiently mitigated and that the risk exceeds the potential benefit, the Project would not be in the public interest and therefore would not be approved.

[4] Section 3, *Energy Resources Conservation Act,* RSA 2000 c. E-10

[394] The Board notes there are potential risks associated with Shell's proposed project. Therefore, as set out in this decision, the Board's attention is necessarily focused on the level of risk and the ability and willingness of Shell to mitigate or eliminate such risks. The Board strives to balance the risks with meeting legislative objectives, which include in this case containment of CO_2 within the reservoir, protection of groundwater, and public safety.

[395] The Board recognizes that while the determination of the public interest is a subjective matter, constrained by the objectives of the legislation and the Board's power to carry out those purposes, the determination must arise from the evidence presented and from the careful and fair consideration of that evidence by the Board.

[396] The Board notes that, in this case, such evidence included relevant public policy on GHG emissions. The governments of Canada and Alberta have adopted strategies and targets for reducing GHG emissions as part of their respective climate change strategies. Developing effective CCS technologies is an important part of both the Canadian and Alberta government strategies.

[397] To this end, the Alberta government enacted legislation to provide for the funding of CCS projects, to establish a framework to address long-term liability for stored or sequestered $CO_{2,}$ and to address access and ownership of pore space for CO_2 storage.

[398] The Government of Canada also supports the reduction of GHG emissions through its Clean Energy Fund, and is aiming to reduce CO_2 emissions by 325 Mt/a by 2050 through a number of approaches, including CCS. The Canadian federal government has committed to supporting research into clean energy technologies and will also invest public funds into the Shell Quest project.

[399] The Board notes that the Shell Quest project is recognized by both the Alberta and Canadian governments as a project for support under their respective GHG reduction strategies and further notes that developing effective carbon capture and sequestration technologies is an important component of both the Canadian and Alberta government strategies.

[400] The Board finds that direct capture and storage of CO_2 emissions has the potential to be one of the leading available processes capable of significantly reducing the amount of GHG released to the atmosphere in Alberta and elsewhere. The Board notes that the Quest project is expected to demonstrate the viability of CCS in reducing the carbon footprint of oil sands resource development in Alberta. The Board also notes that Shell has committed to sharing its knowledge and experience from the Quest project to help reduce the carbon footprint of hydrocarbon resource development.

[401] The Board finds the BCS formation to be highly suitable for Shell's goal of CO_2 sequestration at this location. The Shell Quest project is at a suitable surface location to minimize impacts to existing land use activities in the area. The Board finds that the project design and MMV program mitigate potential impacts of construction and operation of the Shell Quest project. The Board therefore finds that impacts to individual residents or landowners in the area will be minimal.

[402] The Board notes that the CO_2 to be injected is not derived from raw bitumen but rather is a byproduct of a chemical reaction involving purchased methane at the Scotford Upgrader. As

such, the Board does not consider the subject CO_2 to be "gas" as defined in the *OGCA* and for the purposes of Section 38 of the *OGCA*.

[403] The Board acknowledges Mr. Ouelette's concerns about the permanent storage of the CO_2 as opposed to using it for EOR. However, the Board notes that Shell has asked for regulatory flexibility to install a T-piece that will allow CO_2 to be diverted from the Shell Quest pipeline for other uses. The Board understands that these alternatives could include opportunity for EOR.

[404] The Board notes that the overall purpose of this project is permanent storage (i.e., sequestration) as opposed to enhanced recovery, which cycles CO_2 through an existing producing oil field. The Board notes that permanent sequestration of the CO_2 is consistent with the GHG reduction policies of the governments of Canada and Alberta.

[405] The Board notes the concern of Mr. Ouelette regarding regulatory capture. Presumably Mr. Ouelette's argument is that the Board will be biased towards approving the project because the governments of Canada and Alberta have provided financial support and, as such, are promoters of the project.

[406] The Board notes that the ERCB is established by the Alberta Legislature under the *Energy Resources Conservation Act* as an arms-length quasi-judicial regulatory body. Board members are appointed for five-year fixed terms. Further, Board members are required by legislation to undertake their responsibilities by exercising the duty of care that includes the public interest and avoiding conflicts of interest. These legislative features ensure that Board members undertake their duties and their deliberations with regard to the public interest.

[407] Accordingly, the Board conducts detailed assessments of the evidence, the potential impacts, and the effectiveness of proposed mitigation. In the Board's view its duty and its overall approach to scrutinize potential impacts and proposed mitigation serve to address Mr. Ouelette's concerns regarding regulatory capture.

[408] The Board's analysis of the evidence in this decision addresses the public interest and the key issues of the Quest application. The Board has determined that the potential for a CO_2 breach of containment in the BCS was very low. Furthermore, the Board has determined that the overall public safety, environmental, and social risks and impacts associated with the capture of CO_2, and its subsequent transmission and injection into the BCS, are also very low. The Board has also determined that the project design and MMV program mitigate potential impacts of construction and operation of the Shell Quest project.

[409] The Board finds that the Shell Quest project is in the public interest based on the need for the project and the need to balance the social, economic, and environmental impacts of the project as discussed in this decision. The Board's conclusions are based on all the evidence placed before it during these proceedings.

ONGOING APPROVAL PROCESSES

[410] The Board notes that additional applications must be filed and approved before the Project can be fully implemented. Shell's project includes the drilling of as many as eight injection wells and three associated deep monitoring wells. Shell plans to initially drill three injection wells,

assess their performance, and determine if more injection wells are required. Previously, the Board received a complete *Directive 056* well licence application for only one of the initial injection wells (the 8-19 test well) that addressed landowner and resident proximity issues. The information requirements specified in *Directive 051* and associated *Directive 065* information have been submitted in this proceeding to re-license the 8-19 well as an injection well.

[411] The Board notes that Shell must submit and receive *Directive 056* well licence approvals for any additional injection wells and deep monitoring wells. Shell must also submit information required by *Directive 051* and *Directive 065* before the ERCB can approve starting injection into additional wells.

[412] The Board notes that *Directive 056* applications and approvals for the short lateral pipelines to connect the injection wells with the main CO_2 pipeline are also required, and that *Directive 056* notification and consultation requirements must also be met. If there are outstanding objections following notification and consultation, a non-routine application must be filed by Shell.

[413] The Board is mindful of Shell's project commencement date of early 2015, its obligation to demonstrate a sustained injection rate by year-end 2015, and the regulatory process associated with proximity issues related to wells and pipelines. The Board therefore strongly recommends that Shell proceed as quickly as possible to confirm additional injection well locations and lateral pipeline routes and to seek the necessary approvals.

[414] As discussed in the Background section, the Board notes that Shell might also be required to obtain approvals from other local, provincial, and federal regulatory bodies.

CONCLUSION

[415] The Board has considered the applications and evidence to make its decision in the public interest. As illustrated by this decision, the Board has rigorously reviewed and considered the evidence submitted in this proceeding with respect to the capture of CO_2 at the Scotford Upgrader, the transportation by pipeline to an area in and around the Radway Field, and the injection of CO_2 into the Basal Cambrian Sandstone for sequestration.

[416] The Board concludes that the capture, transportation, injection, and sequestration of the CO_2 will not interfere with the recovery or conservation of oil or gas. The Board also finds that this project will not interfere with the storage of oil or gas within the project's AOI.

[417] For the reasons contained in this decision, the Board hereby approves Applications No. 1689376, 1670112, and 1671615, subject to the conditions set out in Appendix 2 and the Board's final approval.

[418] As required by Section 39(2) of the *OGCA*, the Board has referred this application to the Minister of the ESRD for that minister's approval with respect to the application as it affects matters of the environment. Similarly, as per Section 39(3) of the *OGCA*, this decision is subject to any additional conditions imposed by the Minister of the ESRD. Therefore, the Board's final approval will be issued after receiving the minister's decision and may contain conditions additional to those contained in this decision.

Dated in Calgary, Alberta, on July 10, 2012.

ENERGY RESOURCES CONSERVATION BOARD

<*original signed by*>

George Eynon, P.Geo
Presiding Member

<*original signed by*>

Robert C. McManus, M.E.Des.
Board Member

<*original signed by*>

Robert J. Willard, P.Eng.
Acting Board Member

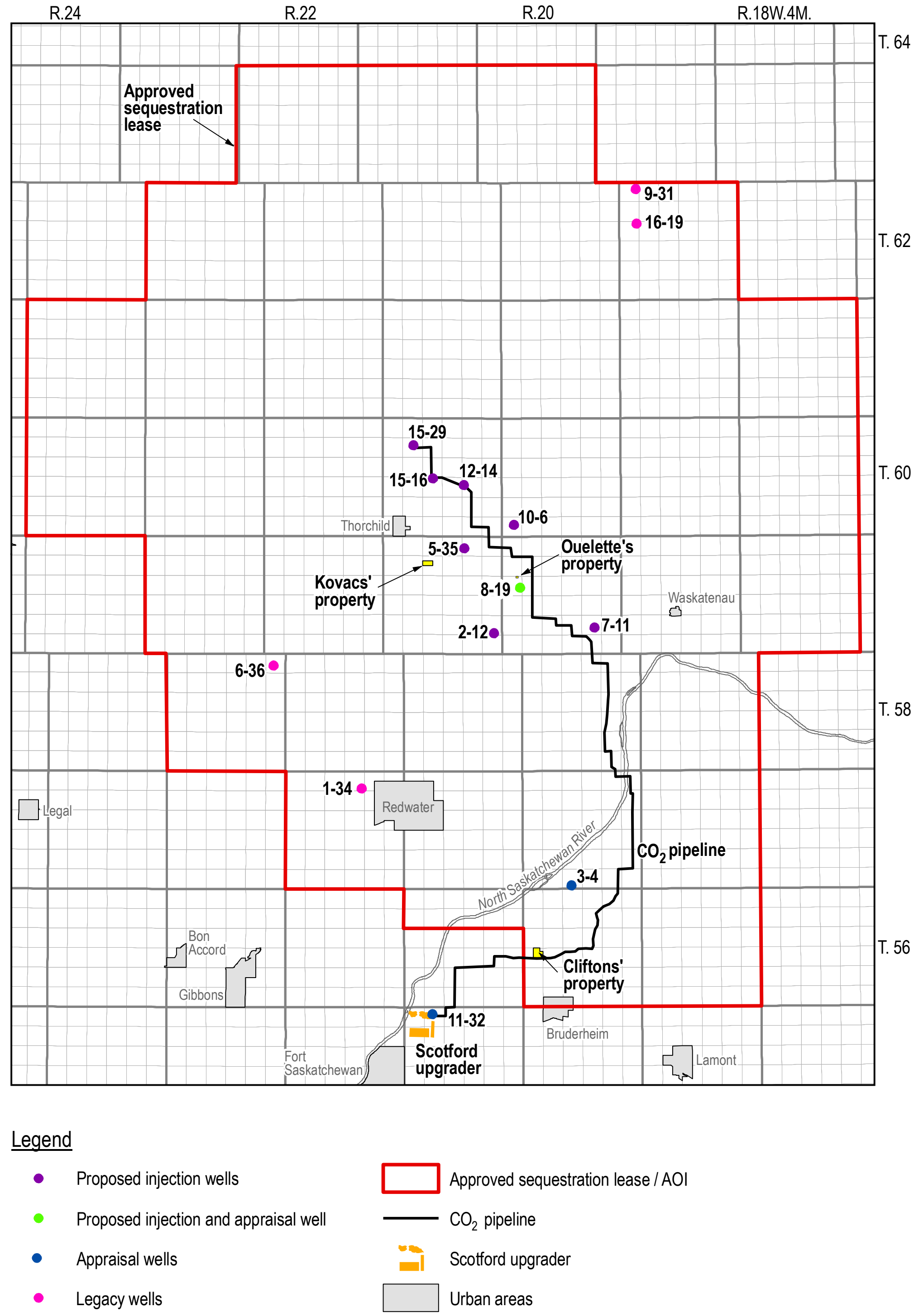

Figure 1. Shell Quest Project

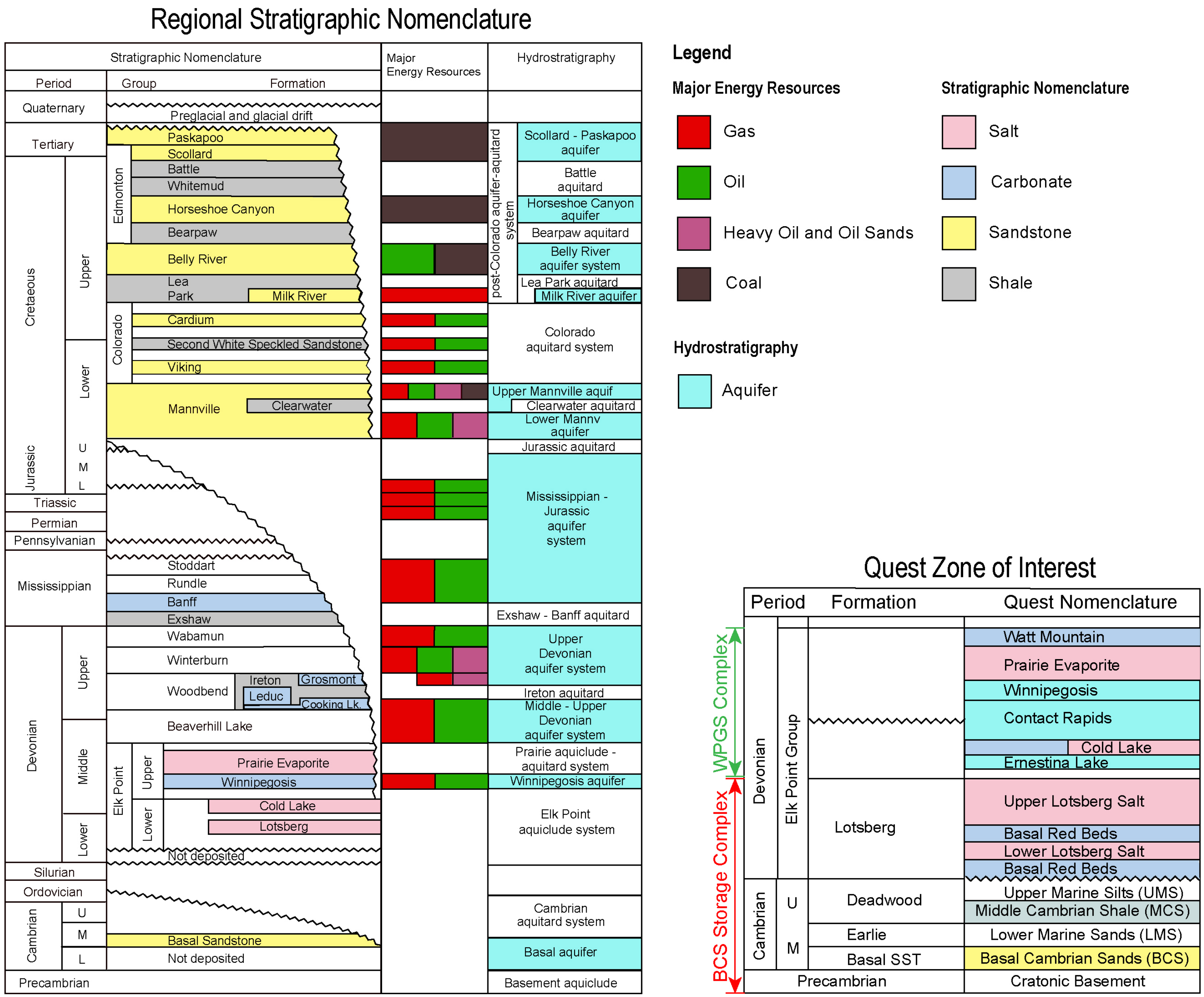

Figure 2. Project area stratigraphy

APPENDIX 1 HEARING PARTICIPANTS

Principals and Representatives	Witnesses
Shell Canada Limited (Shell) B. Gilmour, LLB. B. Williams, LLB. C. Wilton, LLB.	I. Silk, B.A., M.A., MBA S. Crouch, B.Sc., M.Sc. S. Bourne, B.A., PhD. K. Penny, M.Sc. A. Spence, B.Sc., B.Eng. T. Wiwchar, B.Sc., P.Eng. J. Doupe, M.Eng. D. Yoshisaka, M.Sc., P.Eng. M. Davies, B.Sc., M.Sc. M. Bentzen, M.E. Des., B.Sc. A. Springer, B.Sc., M.Sc., P.Eng. B. Koppe, P.Biol.
Corey and Bernadette Clifton Y. Cheng, LLB. Tony Ouelette R. Secord, LLB.	A. Clifton B. Clifton T. Ouelette R. Clissold, P.Geol. (Hydrogeological Consultants ltd.)
Marian and Ann Kovac D. Stanley	M. Kovac
Energy Resources Conservation Board staff B. Prenevost, Board Counsel, LLB B. Kapel Holden, Board Counsel, LL.B M. Gonie M. Schuster H. Longworth, P.Eng M. Zelensky, P.Eng K. Rose K. Jors D. Palombi F. Moreno, P.Eng J. Pearse K. Haug, P.Eng T. Lemay, P.Geol P. Zhang, P.Eng R. Keeler, P.Eng., P.Geol. C. Tobin B. Curran N. Rutherford, P.Geoph., P.Eng. (Rutherford Consulting Group Inc.)	

APPENDIX 2 SUMMARY OF CONDITIONS

Conditions generally are requirements in addition to or otherwise expanding upon existing regulations and guidelines. An applicant must comply with conditions or it is in breach of its approval and subject to enforcement action by the ERCB. Enforcement of an approval includes enforcement of the conditions attached to that licence. Sanctions imposed for the breach of such conditions may include the suspension of the approval, resulting in the shut-in of a facility. The project-specific conditions imposed on the licences are summarized below.

The Board notes that Shell has made certain undertakings, promises, and commitments (collectively referred to as commitments) with respect to its applications. These commitments do not constitute conditions to the ERCB's approval of the applications. The commitments have been given some weight by the Board in this decision. The Board expects Shell to comply with its commitments.

CONDITIONS

The Board requires that Shell do the following:

1. Use a MBHIP of 30 MPa for the BCS in the 8-19 injection well. [210]
2. Before construction of the pipeline, submit additional detailed information on the technical, operational, cost, and public safety considerations of adding mercaptans to the CO_2 stream. [241]
3. Submit a complete pre-baseline MMV plan by October 15, 2012. [332]
4. Submit an annual report of operational performance, MMV results, associated analyses that describe how the operational performance of the scheme conforms with the modelling and predictions, and discussion of the need for MMV changes. [333]
5. Submit MMV plan updates as required by the ERCB; as a minimum, Shell must submit updates at critical milestones such as commencement of injection, closure, and post-closure. [334]
6. Evaluate the need for adding another deep monitoring well completed in the Winnipegosis formation at either the 15-16 or 15-29 location, and provide its analysis by October 15, 2012. [339]
7. In its annual reporting, evaluate the need for additional deep monitoring wells adjacent to the four legacy wells in the AOI. [340]
8. Conduct hydraulic isolation logging after two years of injection. Any further hydraulic isolation logging over the life of the well will be determined by the ERCB through the annual reporting process. [342]
9. Immediately report any anomalies that indicate fracturing out-of-zone. [343]
10. Complete and submit the final results of its geomechanical testing of the MCS. [345]
11. Immediately report evidence of loss of containment. [346]

12. Submit a more comprehensive project model using site-specific parameters to re-evaluate the issue of deformations caused by pressure changes, if monitoring shows loss of containment or unexpected surface heave. [346]

13. Address the potential need for micro-seismic arrays at other injection well pads by October 15, 2012. [347]

14. Address the need to rerun CO_2 plume and pressure front models in the annual reporting process after the additional injection wells are drilled. [350]

15. Conduct additional fall-off tests with pressure transient analyses after two years of injection, in all injection wells, for comparison with the baseline pressure analysis of the 8-19 well. [351]

16. Submit the preliminary InSAR results showing the distribution of likely natural targets in its October 15, 2012, report. If the ERCB deems corner reflectors necessary, Shell must install the corner reflectors near each injection site at least 15 months before injection. [353]

17. Two years before commencing injection, provide a preliminary report on the InSAR baseline data that addresses the suitability of the data for the pressure front and geomechanical modelling and analysis recommended in its MMV plan. [354]

18. Provide a report to the ERCB six months after injection begins for early indication of the efficacy of the InSAR program. [354]

19. Allow additional water well owners to participate in the landowner water well portion of its MMV program at any time. Shell is required to include such wells in the MMV plan and associated reports. [357]

20. Clarify the process by which Shell determined the statistical significance of the number of domestic water wells for monitoring within the 3.2 km radius of the proposed injector well locations. This information must be included in the October 15, 2012, report to the ERCB. [358]

21. In its October 15, 2012, pre-baseline reporting of the MMV plan, address a phased assessment of natural variability of the geochemistry of the water in the domestic water wells included in its baseline study, including the need for more frequent sampling during both the baseline data collection and early operational monitoring periods. [360]

22. Address the potential need for installing additional monitoring wells in the Winnipegosis and BCS toward the periphery of the pressure build-up zone in the BCS later in the project life. This information must be included in each annual report and presentations. [361]

23. Complete its tracer feasibility study, and submit the results of the study one year before injection. If a tracer is deemed not technically feasible, then Shell must provide a discussion of the baseline data and the methods by which anthropogenic CO_2 will be distinguished from naturally occurring CO_2. Shell is also required to conduct and analyze measurements of biogenic flux of CO_2 in different soil types throughout the AOI, and to report on the results before injection. [363]

APPENDIX 3 SUMMARY OF EXPECTED TIMING OF REPORTING[5]

<table>
<tr><th></th><th>Timing</th><th>Key Areas of Submission</th></tr>
<tr><td>Pre-baseline report</td><td>Oct. 15, 2012</td><td>Complete pre-baseline MMV plan, including the full set of baseline measurements to be taken during the pre-injection period. [332]</td></tr>
<tr><td>Special report #1</td><td>Oct 15, 2012</td><td>Special report, including
evaluation and analysis of the need to add another deep monitoring well completed in the Winnipegosis formation at either the 15-16 or the 15-29 well location [339]
geomechanical testing of primary seal (MCS) [345]
potential need for downhole microseismic arrays in other deep monitoring wells [347]
up-to-date InSAR results, and the need for corner reflectors [353]
explanation of method for determining statistical significance of number of landowner water wells included in baseline data collection and analysis [358]
phased assessment of non-saline groundwater natural variability and frequency of water well sampling [360]
update on technologies to be used for monitoring changes in vegetation health due to surface leaks [362]</td></tr>
<tr><td>First annual status report</td><td>Jan 31, 2013</td><td>Provide a summary of construction and implementation activities. Include updates, conclusions, and review of
feasibility of using 7-11 and 5-35 injection wells as BCS monitoring wells before beginning injection [286]
stakeholder engagement [336]
detailed feasibility of technical, operational, cost, and public safety considerations of adding mercaptans [241]
update of CO_2 plume and pressure front models [350]
8-19 and any other drilled injection wells' initial baseline fall-off test analyses [350] [351]
any testing results</td></tr>
<tr><td>Special report #2</td><td>Jan. 31, 2013
(two years before injection start-up)</td><td>A preliminary report on the InSAR baseline data with respect to the suitability of the pressure front and geomechanical modelling and analysis. [354]</td></tr>
<tr><td>Second annual status report</td><td>Jan 31, 2014</td><td>Provide a summary of construction and implementation activities. Include updates, conclusions, and review of
geology update from new injection wells
initial injection well drilling and testing, and the need for more injection wells
stakeholder engagement
any testing results</td></tr>
<tr><td>Special report #3</td><td>Jan 31, 2014
(one year before injection)</td><td>Results of the feasibility of using an artificial tracer for CO_2 injection, including conclusions and action plan; or if tracer is deemed not technically feasible, provide a discussion of alternatives. [363]</td></tr>
</table>

[5] This table is a summary. References are to specific paragraphs in this decision.

	Timing	Key Areas of Submission
Third annual status report	Jan 31, 2015	Update, conclusions, and review of • site-specific ERP [227] • baseline data and analysis of biogenic flux of CO_2 in different soil types throughout the AOI [363] • geology update from new injection wells • CO_2 plume and pressure front models • initial injection well drilling and testing, and the need for more injection wells • stakeholder engagement • MMV plan
Special report #5	July 31, 2015 (Six months after injection start up)	The efficacy of the InSAR program [354]. Installation of GPS instruments may be required if the quality of InSAR data is too low for effective monitoring [355]
Ongoing annual operational reports	Each March 31, 2016-2040	Provide a report and presentation [336] of general performance of the previous calendar year, identification of operational problems, and discussion of the need for MMV changes. Include updates, conclusions, and review of • need for additional deep monitoring wells adjacent to the four legacy wells in the AOI [340] • results from well testing, including data from annual hydraulic isolation logging [342] • need for hydraulic isolation logging beyond the first five years of injection [342] • projected timing for additional 3D surface seismic surveys [348] • required frequency of time-lapse seismic surveys [349] • update of CO_2 plume and pressure front models, including the results of the prescribed reservoir pressure fall-off test two years after the start-up of each injection well [351] • need for ongoing fall-off shut-in reservoir pressure tests in all injection wells [351] • updated geology • potential need for additional monitoring wells in the Winnipegosis and BCS toward the periphery of the pressure build-up zone [361] • stakeholder engagement
Event triggered reporting	As required	Events that raise any immediate risks to public safety or environment must be immediately reported to the ERCB and other agencies as appropriate, including • any anomalies that indicate fracturing out-of-zone [343] • any indications of loss of containment [346] • unexpected surface heave [346] • appropriate mitigative measures
Closure report	2040	Summarize project total performance, updated surface and subsurface information, and detailed review of containment. MMV plan update, with specific attention to any performance problems evident in the 25 years of operations [334]
Post-closure report	TBD	MMV plan update

APPENDIX 4 ABBREVIATIONS LIST

AOI	area of interest
AOSP	Athabasca Oil Sands Project
BCS	Basal Cambrian Sandstone
BGWP	base of groundwater protection
Br	bromide
BWWT	baseline water-well testing
C&R	conservation and reclamation
CCS	carbon capture and storage
CEAA	Canadian Environmental Assessment Act
Cl	chloride
Cliftons	Corey and Bernadette Clifton
cm	centimetre
CO_2	carbon dioxide
CSA	Canadian Standards Association
dBa	decibel average weighted
DFO	Department of Fisheries and Ocean Canada
DNV	Det Norske Veritas
EA	environmental assessment
EPEA	Environmental Protection and Enhancement Act
EPP	environmental protection plan
EPZ	emergency planning zone
ERCB/Board	Energy Resources Conservation Board
ERP	emergency response plan
ESD	emergency shutdown
ESRD	Environmental and Sustainable Resource Development
FEP	fracture extension pressure
GHG	greenhouse gas
GOA	Government of Alberta
GPS	Global Positioning System
HCL	Hydrogeological Consultants Ltd.
HSSE-MS	Health Safety Security and Environment - Management System
HVP	high vapour pressure
InSAR	interferometric synthetic aperture radar
IPF	Inter Pipeline Fund
km	kilometres
Kovacs	Marian Kovac and Ann Kovac
kPa	kilopascal
LFP	Large Facility Liability Management Program
LLR	licensee liability rating
LMS	Cambrian Lower Marine Sands
LSD	Legal Subdivision
m	metres
MBHIP	maximum bottomhole injection pressure
MCS	Middle Cambrian Shale
mD	millidarcies
MIACC	Major Industrial Accident Council of Canada
mm	millimetre

μm	microns
MMA	Mines and Minerals Act
mMD	metres measured depth
MMV	monitoring, measurement, and verification
MPa	megapascals
Mt	megatonnes
Mt/a	megatonnes per annum
MWHIP	maximum wellhead injection pressure
NCIA	Northeast Capital Industrial Association
NRCan	Natural Resources Canada
OGCA	Oil and Gas Conservation Act
OWL	Oilfield Waste Liability Program
P&NG	petroleum and natural gas
ppm	parts per million
QRA	quantitative risk assessment
RNMP	regional noise management plan
ROW	right-of-way
SCADA	supervisory control and data acquisition
Shell	Shell Canada Limited
SNMP	site noise management plan
TDS	total dissolved solids
The agreement	Canada – Alberta Agreement for Environmental Assessment Cooperation
The Project	Quest Carbon Capture and Storage Project
VSP	vertical seismic profile
ZOI	zone of interest
3D	three-dimensional