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# Quest Carbon Capture and Storage Project

# ANNUAL SUMMARY REPORT - ALBERTA DEPARTMENT OF ENERGY: 2013

**March 2014**

# Executive Summary

This Summary Report is being submitted in accordance with the terms of the CCS Funding Agreement – Quest Project dated June 24, 2011 between Her Majesty the Queen in Right of Alberta and Shell Canada Energy, as operator of the Project and as agent for and on behalf of the AOSP Joint Venture and its participants, comprised of Shell Canada Energy, Chevron Canada Limited, and Marathon Oil Canada Corporation, as amended.

The purpose of the Project is to deploy technology to capture $CO_2$ produced at the Scotford Upgrader and to transport, compress and inject the $CO_2$ for permanent storage in a saline formation near Thorhild, Alberta. Up to 1.2 Mt/a of $CO_2$ will be captured, representing greater than 35% capture of the $CO_2$ produced from the Scotford Upgrader. The Project is a part of the Athabasca Oil Sands Project (AOSP), an oil sands joint venture operated by Shell and owned by Shell Canada, Chevron Canada and Marathon Oil.

According to Shell's Opportunity Realization Manual (ORM) process, the Project has completed the Define phase whereby the Project scope is finalized and the Front End Engineering and Design (FEED) is completed. The project is now in the Execute Phase and will be until early 2015.

With the completion of FEED, the process design is finalized. The $CO_2$ will be captured from three existing steam methane reformers used to generate hydrogen at the Scotford Upgrader. A commercially proven activated amine process will be used in which the $CO_2$ is absorbed (captured) into the amine solution and then regenerated to produce at least 95% $CO_2$ purity. The $CO_2$ will then be compressed by an electrical drive compressor to a maximum dense-phase pressure of approximately 14 MPa. At this pressure, the $CO_2$ will be transported through a 12-inch diameter pipeline to a location 64 kilometers north of the Scotford Upgrader. No further compression or pumping is required to transport the $CO_2$ into the storage area by means of three injection wells.

By means of three injection wells, $CO_2$ will be injected approximately 2 km underground into the Basal Cambrian Sands (BCS) geological formation. The BCS formation is situated below layers of impermeable, continuous, and thick seals, which will keep $CO_2$ isolated within the formation and will prevent any upward migration. The $CO_2$ will be permanently trapped over time within the pore spaces of the rock formation by processes such as capillary forces, dissolution and mineralization.

Storage properties of the BCS complex have been validated through analysis of the data obtained from drilling five wells into the BCS formation (two appraisal and three injection wells). Risks of $CO_2$ containment loss are comprehensively detailed along with mitigation activities in the Measurement Monitoring and Verification (MMV) plan.

A detailed MMV plan has been developed and will be implemented by Shell to monitor the storage of $CO_2$ and to protect public health and safety. The MMV Plan will be integrated with the GHG reporting system in place at the Scotford Upgrader.

Final regulatory approvals for the Project were received August 2012, following a public hearing held in March of that year. Subsequent to that, a public announcement was held on September 5, 2012, whereby the joint venture owners and representatives of the Governments of Canada and Alberta announced that Shell had been given final approval to proceed with the Project.

All three Injector Wells, three Deep Monitoring, and nine Groundwater wells were complete in the first half of 2013. MMV activities have continued, including the baseline groundwater and biosphere sampling programs.

Engineering is now 99% complete and construction is progressing well on three work fronts by the end of Q4 2013 with the Module Yard, Pipeline construction, and Capture construction at Scotford. All major long lead items are now at Scotford including the amine vessels, $CO_2$ compressor, Amine Stripper tower, and three Absorber towers.

The Operations Readiness activities continue with preparation of both Operations and Maintenance procedures and ramping up the hiring and onboarding of new staff.

Shell continues to conduct open houses for the local communities including three in the last part of October at Thorhild, Radway, and Bruderheim.

Additionally, local community events were attended in the summer of 2013 to continue to provide opportunities to residents to receive information about the Project.

The current estimate of capital costs is about $875 million, which will be spent from 2012 to 2015. The current estimate of operating costs is about $41 million per year. Project revenues will be zero during construction and will be $30 million per year during operations from the sale of carbon credits at 2013 carbon prices.

The Project has experienced a number of successes in the past reporting period, including:

- Holding capital costs and schedule in line with Final Investment Decision.
- Near 100% completion on the major engineering work
- Module fabrication and delivery initiated.
- Pipeline construction began with successful drill under the North Saskatchewan River.
- Completed drilling of injection, monitoring, and groundwater wells.
- Executed the groundwater and biosphere sampling programs aligned with the MMV program for 2013 baseline data gathering
- Maintaining local support through the extensive stakeholder engagement activities
- Meeting the Government of Alberta funding milestones
- Initiation of the Community Advisory Panel for the Thorhild County Stakeholders.
- International engagements with the Global CCS Institute to support Public Engagement knowledge sharing, the Ministerial CSLF, the Technical CSLF, the presentation at the EU in Brussels identifying the positive developments in CCS, and a variety of other industry engagements.

Project challenges included:

- Maintaining good stakeholder relationships with the neighbours, with the significant construction in the area posed by Shell and other Operating companies for their pipeline construction.
- Managing the Project overall schedule within the bounds of the delay in receiving regulatory approvals
- Cost pressures from Pipeline construction due to welding productivity.

These challenges have been managed successfully with the result that the Quest team remains on track for a 2015 startup.

Within the next reporting period, construction at the site, the module yard and pipeline will be substantially complete. Operations readiness will be substantially complete and commission and start up will be underway as well as finalizing the remaining regulatory permits. Stakeholder engagement activities will continue to enable local residents to maintain their awareness of Project progress. Quarterly reporting will continue to the Governments of Alberta and Canada to keep them apprised of the Project's progress.

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# Abbreviations

2D ........ 2-Dimensional
3D ........ 3-Dimensional
4D ........ 4-Dimensional
AEW ........ Alberta Environment and Water
AFN ........ Alexander First Nation
AOI ........ Area of Interest
AOSP ........ Athabasca Oil Sands Project
ARC ........ Alberta Research Council
ASRD ........ Alberta Sustainable Resources Development
BCS ........ Basal Cambrian Sands
BHP ........ bottom-hole pressure
BLCN ........ Beaver Lake Cree Nation
CCS ........ carbon capture and storage
CEAA ........ *Canadian Environmental Assessment Act*
CRC ........ Calgary Research Center
D51 ........ Directive 51 application
D56 ........ Directive 56 application
D65 ........ Directive 65 application
ERCB ........ Energy Resources Conservation Board
FEED ........ Front End Engineering and Design
FEP ........ fracture extension pressure
FID ........ Final Investment Decision
GHG ........ greenhouse gases
HMUs ........ hydrogen manufacturing units
HVP ........ high vapor pressure
InSAR ........ Interferometric synthetic aperture radar
LBV ........ line break valve
LMS ........ Lower Marine Sand
LRDF ........ long running ductile fracture
MCS ........ Middle Cambrian Shale
MMV ........ measurement, monitoring and verification
ORM ........ Opportunity Realization Manual
*OSCA* ........ *Oil Sands Conservation Act*
PSA ........ pressure swing adsorber
RFA ........ Regulatory Framework Assurance
ROW ........ right-of way
ASLB ........ approved sequestration lease boundary
SLCN ........ Saddle Lake Cree Nation
TEG ........ triethylene glycol
UMS ........ Upper Marine Siltstone
VSP ........ vertical seismic profile
WCSB ........ Western Canada Sedimentary Basin
WIIP ........ water initially in place

# 1 Overall Facility Design

Facility design by the end of 2013 is 100% complete detailed design. Early works construction is 100% complete and capture construction has begun with delivery of all major equipment and several piping modules.

## 1.1 Design Concept

The Athabasca Oil Sands Project (AOSP) is an oil sands joint venture that operates the Scotford Upgrader located at Shell Scotford, located in the Alberta Industrial Heartland, northeast of Edmonton. The design concept for the Project is to remove $CO_2$ from the process gas streams of the three hydrogen-manufacturing units (HMUs), which are a part of the Scotford Upgrader infrastructure, by using amine technology, and to dehydrate and compress the captured $CO_2$ to a dense-phase state for efficient pipeline transportation to the subsurface storage area.

The three HMU's comprise two identical existing HMU trains in the base plant Scotford Upgrader and third one constructed as part of the Scotford Upgrader Expansion 1 Project, which has been operational since May 2011.

## 1.2 Design Scope

The design scope for the facilities includes:

- Modifications on the three existing HMUs
- Modifications on the three existing pressure swing adsorbers (PSAs)
- Three amine absorption units located at each of the HMUs
- A single common $CO_2$ amine regeneration unit (amine stripper)
- A $CO_2$ vent stack
- A $CO_2$ compression unit
- A triethylene glycol (TEG) dehydration unit
- Shell Scotford utilities and offsite integration
- $CO_2$ pipeline, laterals, and surface equipment
- Three to eight injection wells

## 1.3 ORM Design Framework and Project Maturity

The design framework followed by the Project is the standard Shell approach in project design, called the Opportunity Realization Manual (ORM). The ORM process manages a project as it matures through its lifecycle from initial concept to remediation following closure. ORM divides this lifecycle into stages as shown in Figure 1-1. Each phase has required deliverables that are reviewed to ensure proper quality of these deliverables before proceeding to the next phase.

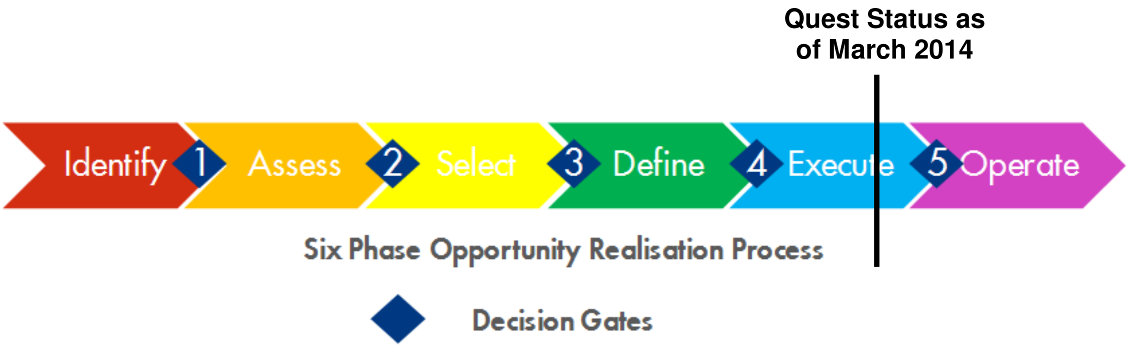



**Figure 1-1: ORM Phases with current Project Maturity**

The Project technical activities in the past year correspond with the Execute Phase. This includes completing the detailed engineering work required to deliver the approved-for-construction drawings, delivering the approved for construction drawings, technical specification for the procurement of all equipment and materials and the management of any changes to the Define Phase deliverables.

In December 2011, Shell made a risk-based decision to proceed into the Execute Phase before final regulatory approval in order to hold to the Project schedule. The Shell Executive Committee, followed by the Joint Venture partners, approved the FID of the Project in the summer of 2012 after the ERCB Decision Report on the hearing was received. This approval was announced in early September after formal receipt of the various regulatory approvals.

In June of 2012, Shell conducted the first Project Execution Review (PER) as required of the Project at that time. A second PER was completed in June 2013 and a third is planned for June 2014. PER1 examined the status of the Project, including the Execute Phase deliverables completed at that time as well as reviewing the output of the early works construction readiness review and concluded that the Project was proceeding according to plan and ready to start early works construction upon execution of the contracts and receipt of the regulatory approvals. PER2 examined the status of the Project including the Execute phase deliverables and provided 26 recommendations to Quest to continue success; the Project team has completed all recommendations. PER3 will focus on the status of the Project as it proceeds towards the commissioning and start up phase.

The Execute Phase concludes with the completion of the facilities construction and subsequent handover to Shell Scotford operations for startup and operation. This is planned to occur in mid-2015.

## 1.4 Facility Locations and Plot Plans

The Project facility locations are shown in *Figure 1-2: Project Facility* **Locations**.

The capture facility is situated within the Scotford Upgrader. The pipeline routing is shown as the dotted line in *Figure 1-2* and the final well count and locations are labeled appropriately.

The capture unit is located adjacent to two of the Scotford Upgrader HMU's. See *Figure 1-3* for a schematic view of the capture unit location.

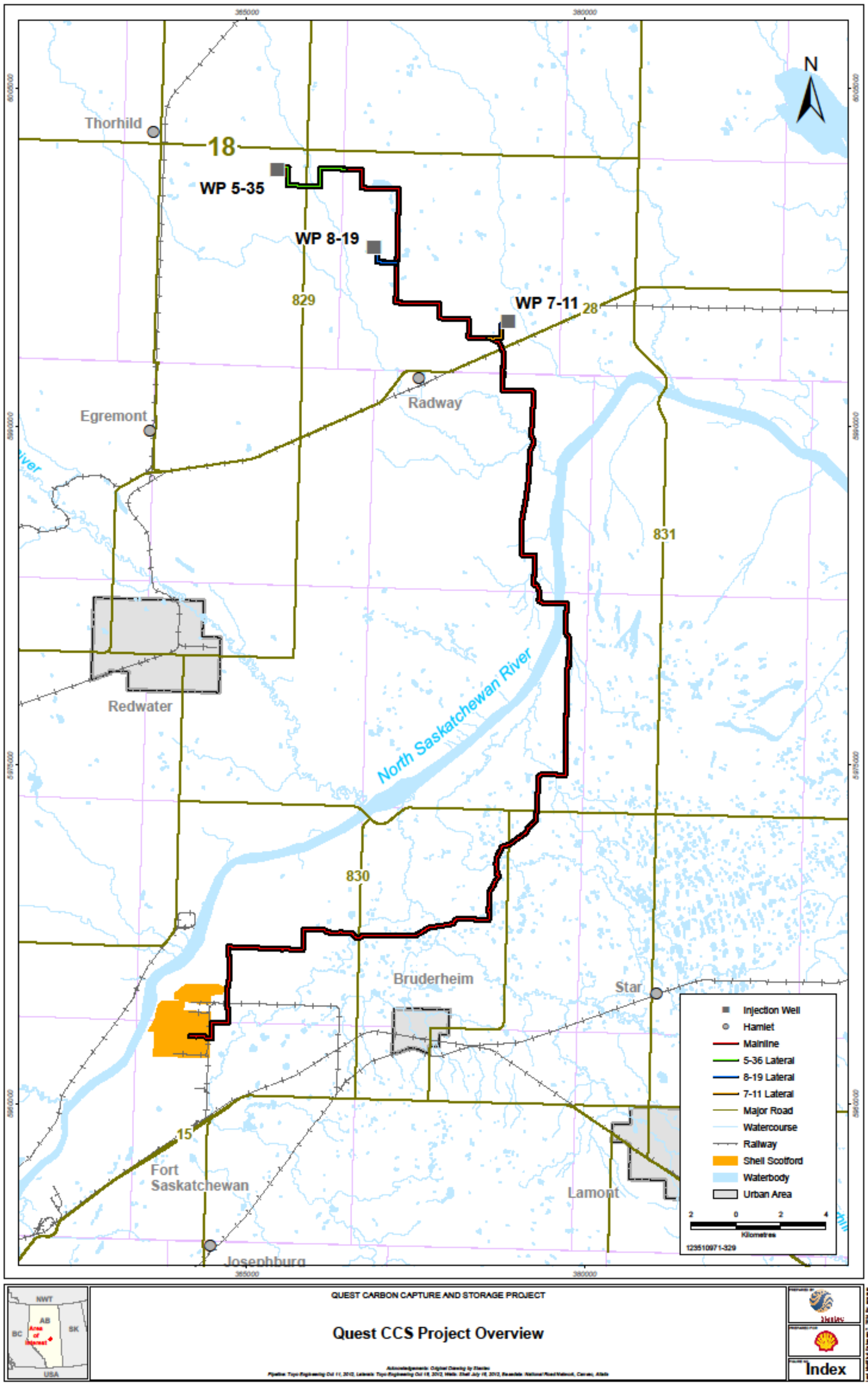



**Figure 1-2: Project Facility Locations**

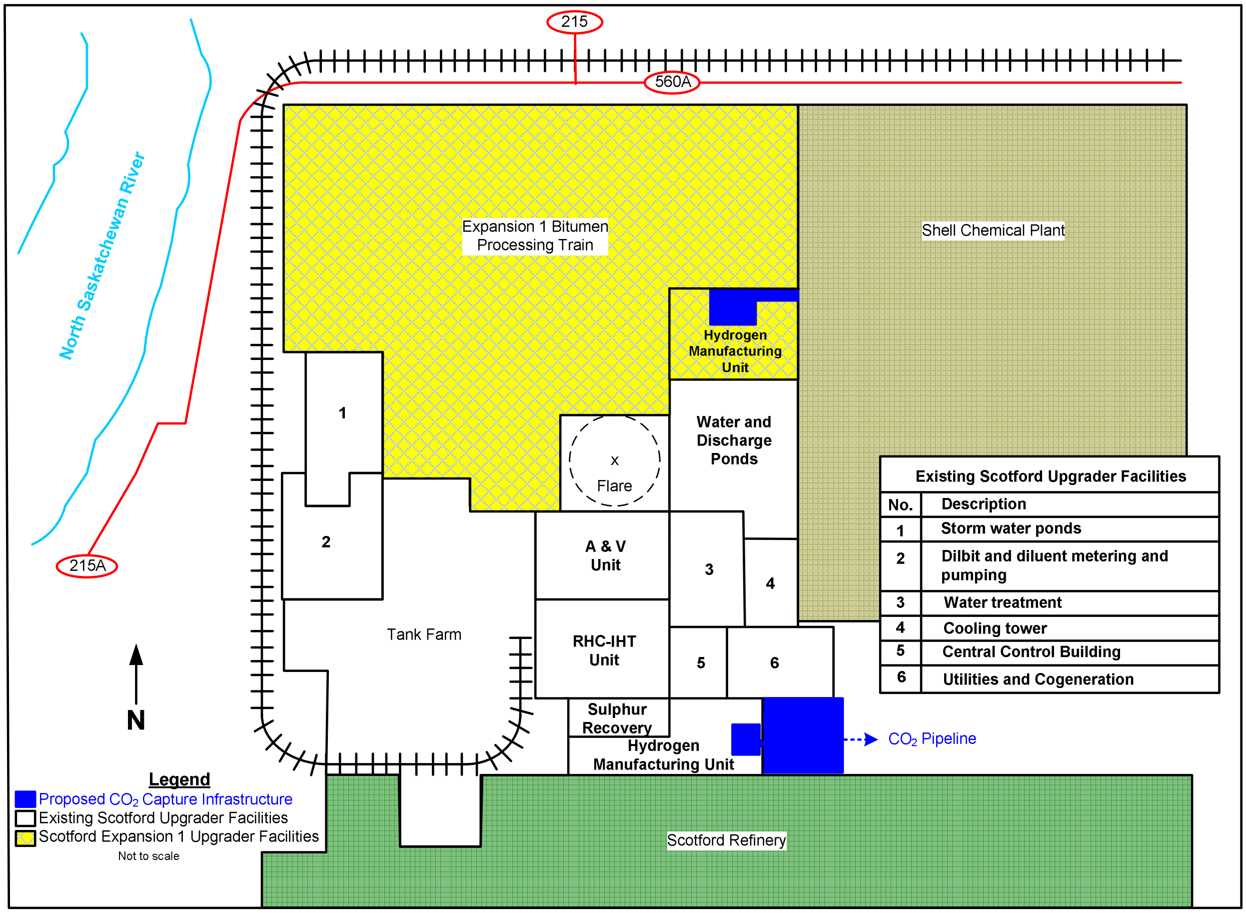



**Figure 1-3: Capture Unit Location Schematic**

Extensive work was done during the Define Phase to validate the BCS formation $CO_2$ storage properties and to establish the optimum storage location. *Figure 1-4* shows the BCS storage complex.

The figure shows the approved Sequestration Lease Area (SLA), formerly called the area of interest [AOI], which had a different boundary) for the storage area. Criteria for this selection included the BCS rock properties within the location, minimizing the number of legacy wells into the BCS storage complex (to reduce risk of potential leak paths), and avoiding proximity to densely populated areas (to minimize the number of landowner consents for the pipeline and injection wells). Section 3 contains additional details on the selection and properties of the BCS formation.

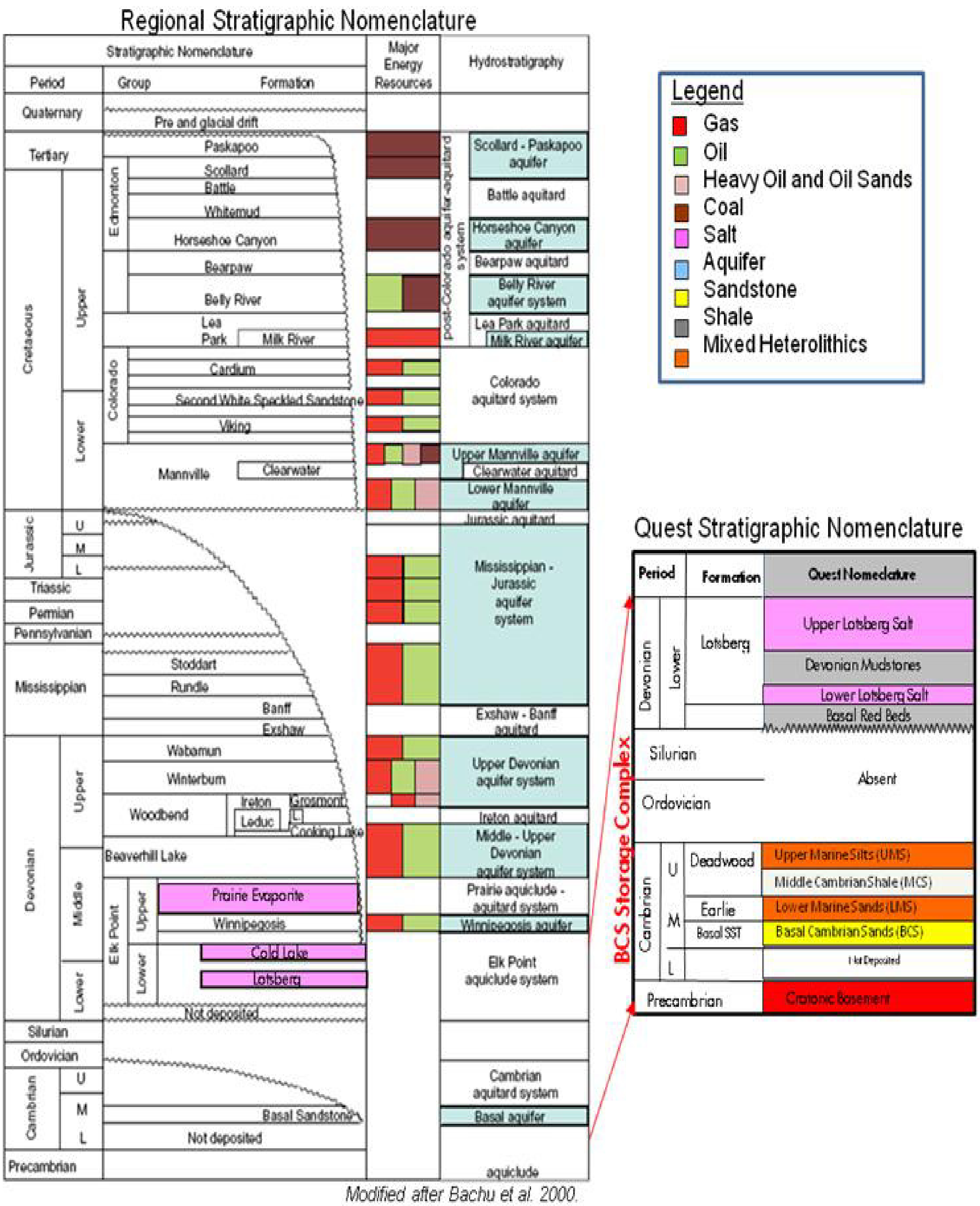



**Figure 1-4: BCS Storage Complex within the Regional Stratigraph**

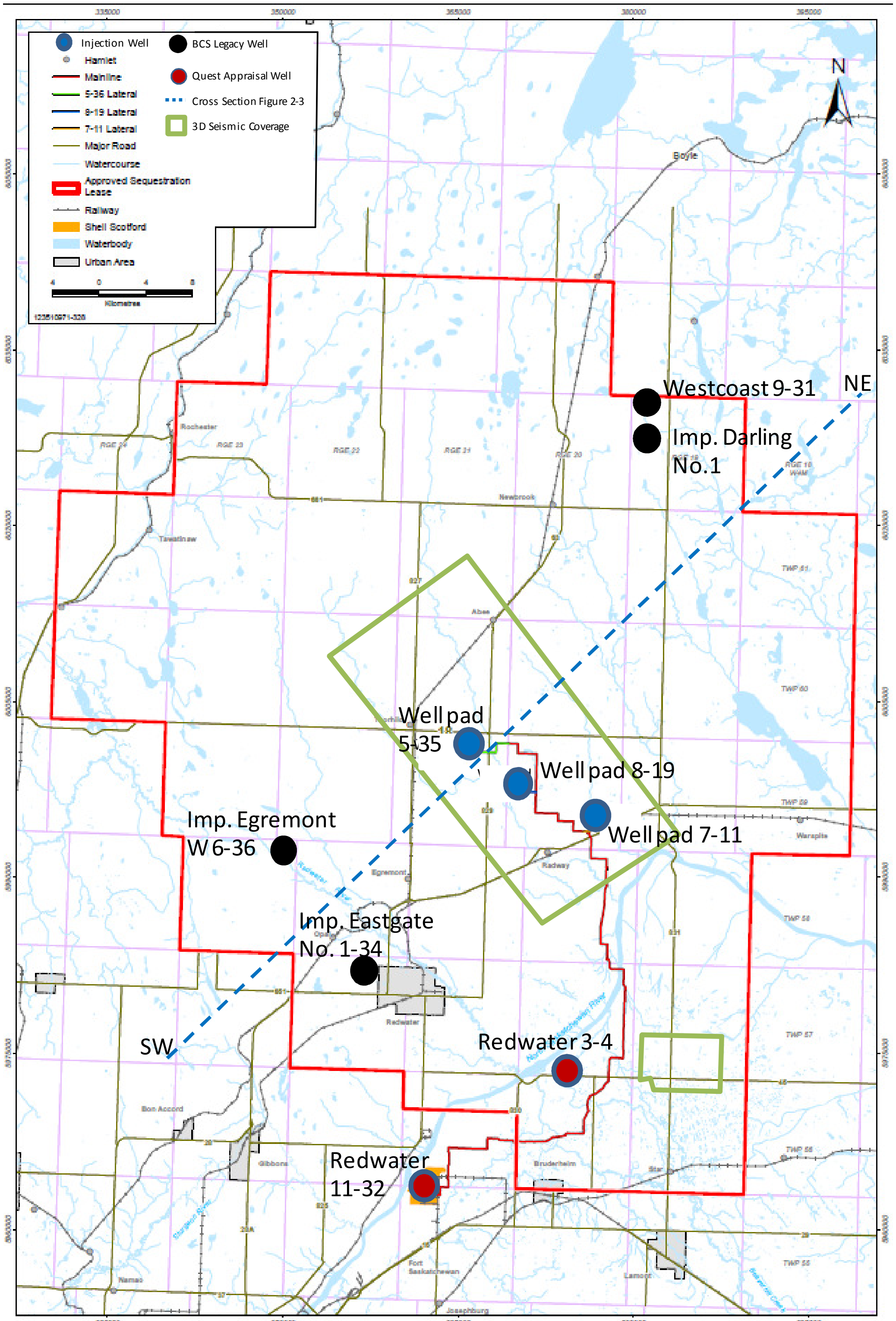



**Figure 1-5: Project Components and Sequestration Lease Area**

A critical requirement of the Project was that the storage area not be impeded by other future CCS projects. To that end, pore space tenure was applied for by Shell to the Province of Alberta immediately after CCS pore space regulations were passed. This tenure granted in May 2011 for the exclusive use by Shell of the BCS formation for the Project within the SLA depicted in *Figure 1-5*. This exclusive use allows Shell to store the design volumes of $CO_2$ into the formation without the risk of another CCS operator storing $CO_2$ in proximity to the Project, which would raise the required injection pressures and threaten the Project objectives.

## 1.5 Process Design

The process flow scheme for the Project is shown in *Figure 1-6.*

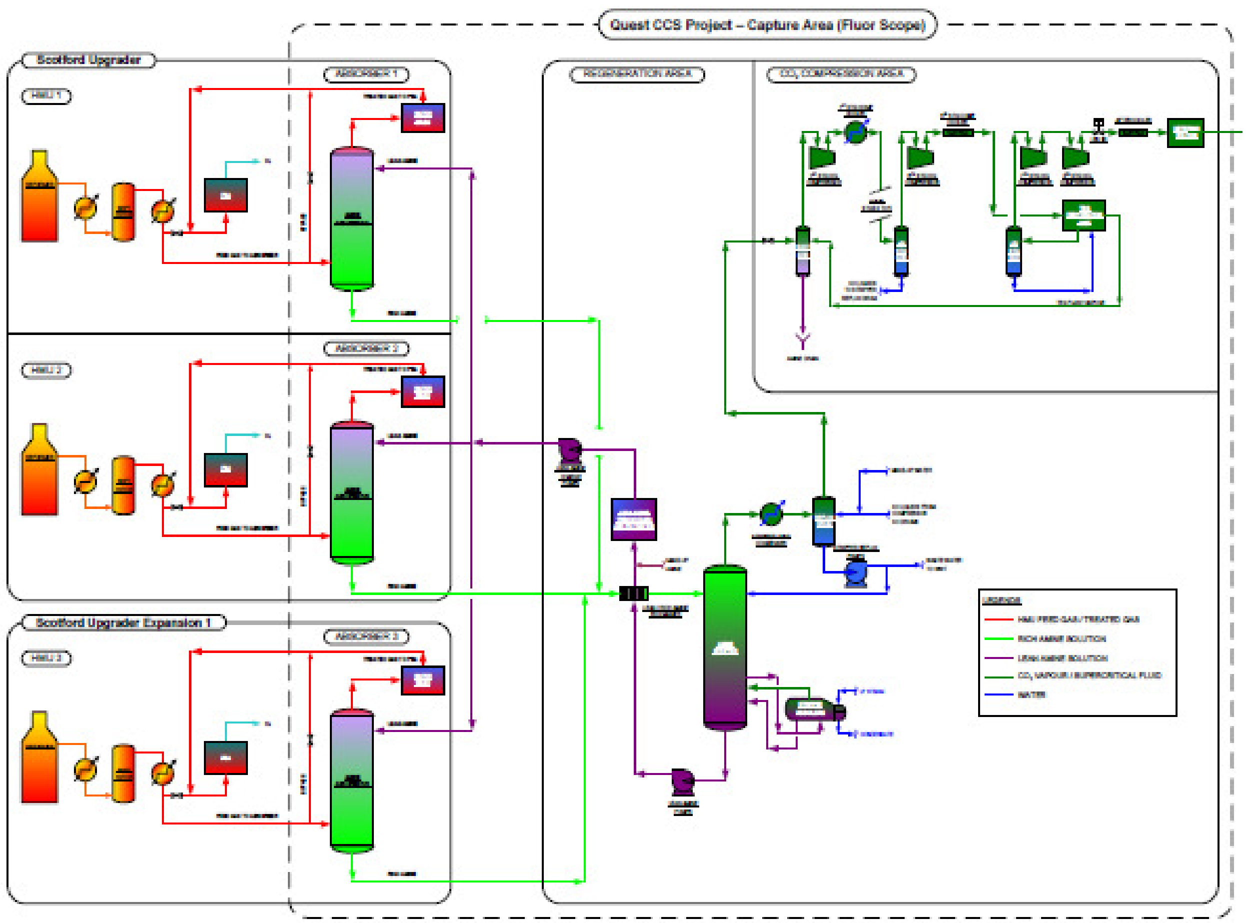



**Figure 1-6: Capture and Compression Process Design**

### *Process Description*

*$CO_2$ Absorption Section*

Amine absorbers located within HMU 1 (Unit 241), HMU 2 (Unit 242) and HMU 3 (Unit 441) treat hydrogen raw gas at high pressure and low temperature to remove $CO_2$ through close contact with a lean amine (ADIP-X) solution.

The hydrogen raw gas enters the 25-tray absorbers below tray 1 of the column at a pressure of approximately 3,000 kPa(g). Lean amine solution enters at the top of the column on flow control.

The $CO_2$ absorption reaction is exothermic. The bulk of the heat generated within the absorber is removed through the bottom of the column by the rich amine. Rich amine from the three absorbers is collected into a common header and sent to the amine regeneration section.

Warm treated gas exits the top of the absorbers and enters the 9-tray water wash vessels below Tray 1, where a circulating water system is used to cool the treated gas. Pumps draw warm water from the bottom of the vessel and cool it in shell and tube exchangers using cooling water as the cooling medium. The cooled circulating water is returned to the water wash vessel above Tray 6 to achieve the treated gas temperature specification. A continuous supply of wash water is supplied to the top of the water wash vessel in the polishing section. The purpose of the water wash is to remove entrained amine to less than 1ppmw; thereby, the downstream PSA unit adsorbent is protected from contamination.

A continuous purge of circulating water, approximately equal to the wash water flow, is sent from HMU 1 and HMU 2 to the reflux drum in the amine regeneration section for use as makeup water to the amine system. The purge of circulating water from HMU 3 is sent to the existing process steam condensate separator, V-44111.

*Amine Regeneration Section*

Rich amine from the three absorbers is heated in the lean/rich exchangers by cross-exchange with hot, lean amine from the bottom of the amine stripper. The lean/rich exchangers are Compabloc design to reduce plot requirements. The hot, lean amine is maintained at high pressure through the lean/rich exchangers by a backpressure controller, which reduces two-phase flow in the line. The pressure is let down across the 2 x 50% backpressure control valves and fed to the amine stripper.

The two-phase feed to the amine stripper enters the column through two Schoepentoeter inlet devices, which facilitate the initial separation of vapour from liquid. As the lean/rich amine flows down the trays of the stripper, it comes into contact with hot, stripping steam, which causes desorption of the $CO_2$ from the amine.

The amine stripper is equipped with 2 x 50% kettle reboilers that supply the heat required for desorption of $CO_2$ and produce the stripping steam required to reduce the $CO_2$ partial pressure. The low-pressure steam supplied to the reboilers is controlled by a feed-forward flow signal from the rich amine stream entering the stripper and is trim-controlled by a temperature signal from the overhead vapour leaving the stripper.

The $CO_2$ stripped from the amine solution leaves the top of the amine stripper saturated with water vapour at a pressure of 54 kPa(g). This stream is then cooled by the overhead condenser. The two-phase stream leaving the condenser enters the reflux drum, where separation of $CO_2$ vapour from liquid occurs.

In addition to the vapour–liquid stream from the overhead condenser, the reflux drum also receives purge water from the HMU 1 and HMU 2 water wash vessels, as well as knockout water from the $CO_2$ compression area. The reflux pumps draw water from the drum and provide reflux to the stripper for cooling and wash of entrained amine from the vapour. Column reflux is on flow control, with drum level control managed by purging excess water to wastewater treatment.

$CO_2$ is stripped from the rich amine to produce lean amine by kettle-type reboilers and collected in the bottom of the amine stripper. The hot, lean amine from the bottom of the stripper is pumped by the lean amine pumps to the lean/rich exchanger, where it is cooled by cross-exchange with the incoming rich amine feed from the HMU absorbers. The lean amine is further cooled by the lean amine coolers, which are shell and tube exchangers. The lean amine is cooled to the final temperature by the lean amine trim coolers, which are plate and frame exchangers.

A slipstream of 25% of the cooled lean amine flow is filtered to remove particulates from the amine. A second slipstream of 5% of the filtered amine is then further filtered through a carbon bed to remove degradation products. A final particulate filter is used for polishing of the amine and removing carbon fines from the carbon-bed filter.

The filtered amine is then pumped by the lean amine charge pumps to the three-amine absorbers in HMU 1, HMU 2, and HMU 3.

*Anti-Foam Injection*

An anti-foam injection package is provided to supply anti-foam to the amine absorbers and amine stripper. Because there are minimal hydrocarbons present in the system and the service is considered clean, it is anticipated that foaming issues should be minimal. Should the need arise, anti-foam can be injected into the lean amine lines going to each of the absorbers, as well as the rich amine line supplying the amine stripper.

The anti-foam chemical currently identified for use in this system is polyglycol-based anti-foam. The actual anti-foam injection chemical required cannot be confirmed until the facility is operating.

*Amine Storage*

Two amine storage tanks, along with an amine make-up pump, supply pre-formulated concentrated amine as make-up to the system during normal operation. The concentrated amine will be blended off-site and provided by an amine supplier.

The amine storage tanks will also be used for storage of lean amine solution during maintenance outages. The size of the amine storage tanks provides sufficient volume for the amine stripper contents during an unplanned outage. Permanent amine solution storage is not provided for the entire amine inventory, which would require supplemental temporary storage. During major turnarounds, when the entire system needs to be de-inventoried, a temporary tank will be required for the duration of the turnaround. The amine system can be recharged with the lean amine solution using the amine inventory pump. This pump will also be used to charge the system during start-up.

The amine storage tanks are equipped with a steam coil to maintain the temperature of the tank contents. A nitrogen blanketing system maintains an inert atmosphere in the tank, which prevents degradation of the amine. The storage tanks will have ventilation to the atmosphere.

*Compression*

The $CO_2$ from amine regeneration is routed to the compressor suction by the compressor suction KO drum to remove free water. The $CO_2$ compressor is an eight-stage, integrally geared centrifugal machine. Increase in $H_2$ impurity from 0.67% to 5% in the $CO_2$ increases the minimum discharge pressure required (to keep $CO_2$ in a dense-phase state) to about 8,500 kPa(g). Though the compressor design is still under development, $H_2$ impurity greater than 5% may lead to potential surge situations. To avoid this situation, it is proposed to put the compressor in recycle mode when the $H_2$ content reaches 2.5%.

Cooling and separation facilities are provided on the discharge of the first five compressor stages. The condensed water streams from the interstage KO drums, are routed back to the stripper reflux drum to be degassed and recycled as make up water to the amine system. The condensed water from the compressor fifth and sixth stage KO drums and the TEG inlet scrubber are routed to the compressor fourth stage KO drum. This routing reduces the potential of a high-pressure vapour breakthrough on the stripper reflux drum and reduces the resulting pressure drops. The seventh stage KO drum liquids are routed to the TEG flash drum due to the likely presence of TEG in the stream.

The saturated water content of $CO_2$ at 36°C approaches a minimum at approximately 5,000 kPa(a). Consequently, an interstage pressure in the 5,000 kPa(a) range is specified for the compressor. This pressure is expected to be obtained at the compressor sixth stage discharge. At this pressure, the wet $CO_2$ is air cooled to 36°C and dehydrated by triethylene glycol (TEG) in a packed bed contactor.

The dehydrated $CO_2$ is compressed to a discharge pressure in the range of 8,000 kPa(g) to 11,000 kPa(g), resulting in a dense-phase fluid. The $CO_2$ compressor is able to provide a discharge pressure as high as 14,790 kPa at a reduced flow for start-up and other operating scenarios. The dense-phase $CO_2$ is cooled in the compressor, after the cooler to 43°C, and routed to the $CO_2$ pipeline. This dense-phase $CO_2$ is transported by pipeline from the Scotford Upgrader to the injection wells.

*Dehydration*

A lean triethylene glycol (TEG) stream at a concentration greater than 99% wt TEG contacts the wet $CO_2$ stream in an absorption column to absorb water from the $CO_2$ stream. The water-rich TEG from the contactor is heated and letdown to a flash drum that operates at approximately 270 kPa(g). This pressure allows the flashed portion of dissolved $CO_2$ from the rich TEG to be recycled to the compressor suction KO drum.

The flashed TEG is further preheated and the water is stripped in the TEG stripper. The column employs a combination of reboiling, by a stab-in reboiler using low temperature HP steam, and nitrogen stripping gas to purify the TEG stream. Nitrogen stripping gas is required to achieve the TEG purity required for the desired $CO_2$ dehydration because the maximum TEG temperature is limited to 204°C to prevent TEG decomposition. Stripped water, nitrogen and degassed $CO_2$ are vented to atmosphere at a safe location above the TEG stripper.

Though the system is designed to minimize TEG carryover, it is estimated that 27 ppmw of TEG will escape with $CO_2$. The dehydrated $CO_2$ is analyzed for moisture and composition at the outlet of TEG unit.

The lean TEG is cooled in a lean/rich TEG exchanger. The lean TEG is then pumped and further cooled to 39°C in the lean TEG cooler with cooling water and returned to the TEG absorber.

*Pipeline*

The pipeline design is a 12-inch $CO_2$ pipeline as per CSA Z662 transporting the dehydrated, compressed, and dense-phase $CO_2$ from the capture facility to the injection wells. Also included are pigging facilities, line break valves, and monitoring and control facilities. The line is buried to a depth of 1.5 m with the exception of the line break valve locations, which are located a maximum of 15 km apart.

In the Select Phase, with small changes in the Execute Phase, of the Project, a detailed route selection process was undertaken with the objective to:

- Limit the potential for line strikes and infrastructure crossings
- Align with the $CO_2$ storage area
- Use existing pipeline rights-of-way and other linear disturbances, where possible, to limit physical disturbance
- Limit the length of the pipeline to reduce the total area of disturbance
- Avoid protected areas and using appropriate timing windows
- Avoid wetlands and limit the number of watercourse crossings
- Accommodate landowner and government concerns to the extent possible and practical

The outcome of this process is the routing shown in *Figure 1-2*.

The pipeline route extends east from Shell Scotford along existing pipeline rights of way through Alberta's Industrial Heartland and then north of Bruderheim to the North Saskatchewan River. The route crosses the North Saskatchewan River and continues north along an existing pipeline corridor for approximately 10 km, where the route angles to the northwest to the endpoint well, approximately 8 km north of the County of Thorhild, Alberta. The total pipeline length is 64 km.

This pipeline crosses the Counties of Strathcona, Sturgeon, Lamont and Thorhild.

There are 336 crossings by the pipeline:

- 55 road crossings
- 4 railroad crossings
- 19 watercourse crossings
- 194 pipeline crossings
- 32 cable crossings
- 32 overhead crossing

*CO2 Storage*

The storage facilities design and construction activities consist of:

- The drilling and completion of three injection wells equipped with fibre optic monitoring systems
- A skid-mounted module on each injection well site to provide control, measurement and communication for both injection and MMV equipment
- The drilling and completion of three deep observation wells
- The conversion of Redwater Well 3-4 to a deep BCS / Cooking Lake pressure monitoring well
- The drilling of nine groundwater wells.

## 1.6 Modularization Approach

A key feature of the FEED work for the Project was the decision to use a modularization approach for the $CO_2$ capture infrastructure for the benefit to scheduling and cost.

The modularization approach for the Project is to use Fluor Third Generation Modular$^{SM}$ design practices. The Project is designed with a maximum module size of 7.3 m (wide) x 7.6 m (high) x 36 m (long) modules that are assembled in the Alberta area and transported by road to the Shell Scotford site by the Alberta Heavy Haul corridor.

Third Generation Modular$^{SM}$ execution is a modular design and construction execution method that is different from the traditional truckable modular construction execution methods because limitations exist to the number of components that are to be installed onto the truckable modules. The modules are transported and interconnected into a complete processing facility at a remote location including all mechanical, piping, electrical and control system equipment.

The module's boundaries were reflected in the three-dimensional model and matured through 30%, 60% and 90% model reviews of multi-disciplinary teams as well as safety, operability and maintainability reviews. The weight and dimensions of each model were accurately tracked through the process to ensure compliance with the maximum weight and size restrictions for the heavy load corridor. The structural steel manufacturing and fabrication for the modules was bid, awarded and manufacture of the steel commenced in 2012. In August of 2012, a request for proposal went out to five pre-qualified module yard contractors on the heavy load corridor. Proposals were received in October and evaluated thereafter. Award recommendations were made to Shell's contract board in mid-January 2013 followed by approval by the Joint Venture Executive Committee late in January 2013. The contract was signed in February. Fabrications of the structural steel for the modules started in early February and in mid-February, kick off meetings were held in the module yard to start the preparation work to start module pipe fabrication and module construction. Currently 13 of the modules have arrived at site with 12 set in their final location. Another 45 modules are in various stages of completion at the Fabricators yard in east Edmonton.

# 2 Facility Construction Schedule

As of February 2014, the underground work including the installation of the amine sump, underground cooling water, firewater, oily water and inside battery limits of the $CO_2$ pipelines, underground electrical and installation of all the piles and concrete foundations and paving are completion. Module fabrication, capture main construction and pipeline construction are all underway. Home office Engineering is complete, Procurement is ramping down with expediting of the final few remaining equipment, and materials to be delivered. The current work force on the project is approximately 850 people between the home office engineering, Scotford construction site, module yard and the pipeline. See Figure 2-1 for the overall construction schedule.

The 2013 plant turnaround is complete for the second train of the base plant and the tie-ins as well as the burner upgrades, installation of the flue gas recycle and the pressure swing absorber were completed. The flue gas recycle started up and partially tested to compare to theoretical results. Comparison was inside the expected range.

At the Capture site, the firewater loops, potentially oily water sewer system, underground portion of the cooling water line and inside battery limits $CO_2$ egress pipeline are complete. All the piling and foundation as well as containment paving is complete. Structural steel work has started on the compressor building along with placement of some of the piping spools. The compressor and motor are on site and will be lifted into the building in early April.

The pipe fabrication is approximately 72% complete and module assembly is approximately 36% complete with 13 modules at site and another 45 being assembly. The first of the modules arrived in early November 2013 with the last module scheduled to arrive at site in late June 2014. HMU #3 absorber dressing is complete and it has been lifted into place. Absorber towers for HMU #1 and #2 are on site and being dressed. They are scheduled to be lifted into place in late March. The Amine stripper is also on site and in the process of being dressed (fitted with ladders, platforms, and piping). It is scheduled to be set into place in late February/early March.

Pipeline construction began in 2013 with the horizontal drill of the North Saskatchewan River (NSR), which was completed in early October. From there, the pipeline kicked off to the north of the river. Currently, it is 34% complete with all welding on the main line complete from the NSR to kilometer 64 and ditching and lowering in around kilometer 52. There is 43 of the 336 crossing are complete. Current schedule has the welding complete on the line prior to the end of March 2014. The Line block valves and pigging facilities will be installed starting in late February and running through the spring as they are fabricated. The well site facilities will be added in July when their fabrication is complete. The line should be completed and handed over to our operations team by the end of the summer in 2014.

Mechanical completion is scheduled for early 2015 in HMU #3 and the main capture facility. This will allow commissioning and start up to begin in those areas. The spring 2015 turnaround of HMU #1 area and the base plant common facilities will be required to complete the final tie-ins and modification to that HMU. This work will then allow the commissioning and start up of the remaining HMUs.

All construction activities are phased to meet the planned startup in Q3 2015.

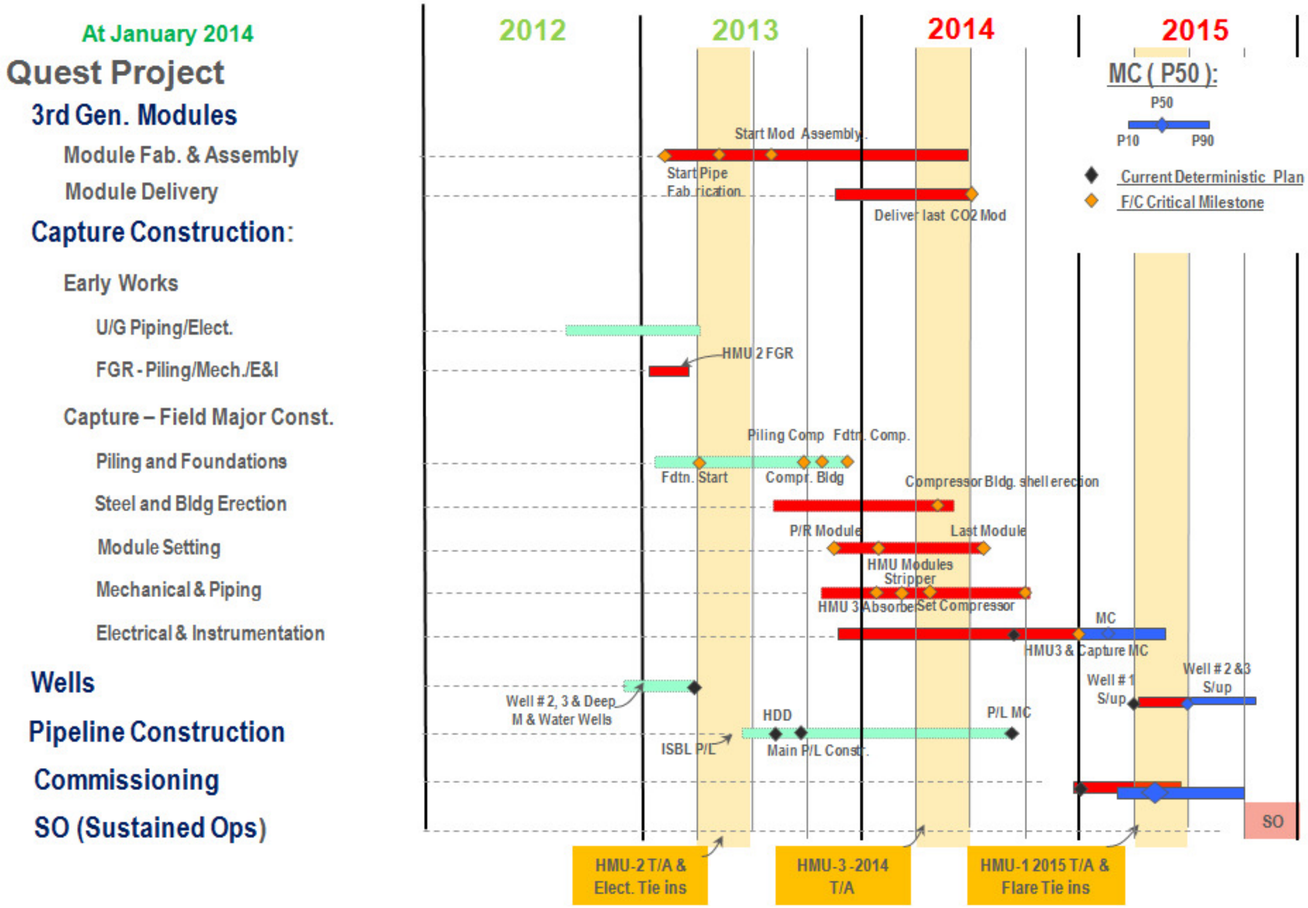



**Figure 2-1: Project Construction Schedule**

# 3 Geological Formation Selection

## 3.1 Storage Area Selection

A screening process resulted in a preferred storage area that was initially selected for further appraisal and studies in 2010 and 2011 by submitting an exploration tenure request with the regulator on December 16, 2009. The subsequent process of storage area characterization comprised a period of intensive data acquisition, resulting in storage area endorsement prior to submitting the regulatory applications on November 30, 2010 and culminating in the award of a Carbon Sequestration Leases by Alberta Energy on May 27, 2011.

Storage area selection was mainly based on data, analyses and modeling of the two $CO_2$ appraisal wells with supplemental data from legacy wells, seismic and study reports. Storage area selection criteria for CCS projects are still in the process of being developed by CCS authorities at international, national and provincial levels. One set of criteria has been developed by the Alberta Research Council (ARC) and the properties of the Basal Cambrian Sands (BCS) are compared with those criteria in Table 3-1.

The approved sequestration lease area (SLA), as defined by the approved Carbon Sequestration Leases and pursuant to Section 116 of the Mines and Minerals Act, was granted to Shell, on behalf of the ASOP Joint Venture, by the Alberta Department of Energy.

**Table 3-1: Assessment of the BCS for Safety and Security of CO2 Storage**

| Criterion Level | No | Criterion | Unfavourable | Preferred or Favourable | BCS Storage Complex |
|---|---|---|---|---|---|
| Critical | 1 | Reservoir-seal pairs; extensive and competent barrier to vertical flow | Poor, discontinuous, faulted and/or breached | Intermediate and excellent; many pairs (multi-layered system) | Three major seals (Middle Cambrian Shale [MCS], Lower Lotsberg and Upper Lotsberg Salts) continuous over the entire SLA. Salt aquicludes thicken up dip to the northeast. |
| | 2 | Pressure regime | Overpressured pressure gradients >14 kPa/m | Pressure gradients less than 12 kPa/m | Normally pressured <12 kPa/m |
| | 3 | Monitoring potential | Absent | Present | Present |
| | 4 | Affecting protected groundwater quality | Yes | No | No |
| Essential | 5 | Seismicity | High | ≤ Moderate | Low |
| | 6 | Faulting and fracturing intensity | Extensive | Limited to moderate | Limited. No faults penetrating major seal observed on 2D or 3D seismic. |
| | 7 | Hydrogeology | Short flow systems, or compaction flow, Saline aquifers in communication with protected groundwater aquifers | Intermediate and regional-scale flow | Intermediate and regional-scale flow-saline aquifer not in communication with groundwater |
| Desirable | 8 | Depth | < 750-800 m | > 800 m | > 2,000 m |
| | 9 | Located within fold belts | Yes | No | No |
| | 10 | Adverse diagenesis | Significant | Low | Low |
| | 11 | Geothermal regime | Gradients ≥35°C/km and low surface temperature | Gradients <35°C/km and low surface temperature | Gradients <35°C/km and low surface temperature |
| | 12 | Temperature | <35°C | ≥35°C | 60°C |
| | 13 | Pressure | <7.5 MPa | ≥7.5 MPa | 20.45 MPa |
| | 14 | Thickness | <20 m | ≥20 m | >35 m |

| Criterion Level | No | Criterion | Unfavourable | Preferred or Favourable | BCS Storage Complex |
|---|---|---|---|---|---|
| | 15 | Porosity | <10% | ≥10% | 16% |
| Desirable (cont'd) | 16 | Permeability | <20 mD | ≥20 mD | Average over the SLA 20-500 mD |
| | 17 | Cap rock thickness | <10 m | ≥10 m | Three cap rocks<br>MCS 21 m to 75 m<br>L. Lotsberg Salt 9 m to 41 m<br>U. Lotsberg Salt 53 m to 94 m |
| SOURCE: CCS Site Selection and Characterization Criteria – Review and Synthesis: Alberta Research Council, Draft submission to IEA GHG R&D Program June 2009: http://sacccs.org.za/wp-content/uploads/2010/11/2009-10.pdf | | | | | |

## 3.2 Geological Framework

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

The BCS storage complex includes, in ascending stratigraphic order:

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

The rocks that comprise the BCS storage complex were deposited during the Middle Cambrian to Early Devonian directly atop the Precambrian basement. The erosional unconformity between the Cambrian sequence and the Precambrian represents approximately 1.5 billion years of Earth history. Erosion of the Precambrian surface during this interval likely resulted in a relatively smooth but occasionally rugose gently southwest dipping (<1 degree) top Precambrian surface. Within the SLA, the Cambrian clastic packages pinch out towards the northeast, while the Devonian salt seals thicken towards the northeast. For a cross-section of the WCSB showing the regionally connected BCS storage complex in relation to regional baffles and sealing overburden, see *Figure 3-2* (the AOI is the former name for the SLA). The SLA is within a tectonically quiet area; no faults crosscutting the regional seals were identified in 2D or 3D seismic data.

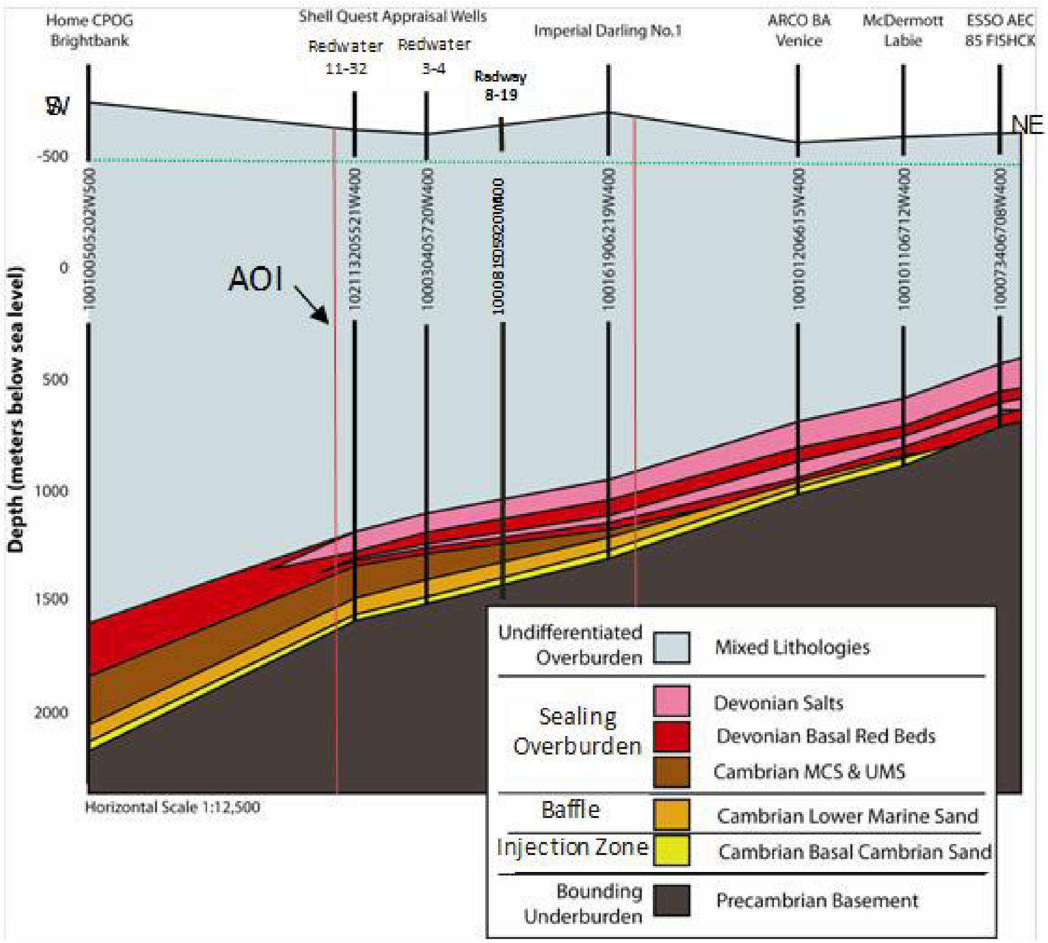



**Figure 3-2: Cross-Section of the WCSB Showing the BCS Storage Complex**

## 3.3 BCS Reservoir Properties

No new injection wells were drilled in this reporting period. However, it is confirmed based on 2012 drilling that the stratigraphic framework within the QUEST project area is as expected. *Figure 3-3* provides a summary of the formation thicknesses within the BCS storage complex and selected overlying formations up to the top of the Quest Sequestration Lease rights for IW 8-19, IW 5-35 and IW 7-11. The formation thicknesses observed within the 'new' injection wells IW 5-35 and IW 7-11 are very similar (almost identical) to those that were observed in IW 8-19. For instance, the BCS has a thickness of 47m in IW 8-19 versus 43 m in IW 5-35, and the MCS has a thickness of 52 m in IW 8-19 versus 51 m in IW 5-35. The differences between actual depth and prognosed (prog) formation thickness are also shown for the new IW 5-35 and 7-11 and are as expected.

**Injection Wells** thickness (m) & actual vs prog (m)

| | | | 8-19 | 5-35 | | 7-11 | |
|---|---|---|---|---|---|---|---|
| | Seal | Prairie Evap./ Lo Prairie Evap. | 126 | 122 | +5 | 127 | -4 |
| | | Winnipegosis/ Contact Rapids | 75 | 72 | -7 | 70 | -4 |
| | | | | | | | |
| BCS Storage Complex | Seal | Upper Lotsberg | 84 | 83 | 0 | 89 | +3 |
| | | | | | | | |
| | Seal | Lower Lotsberg | 35 | 36 | +2 | 36 | +1 |
| | | | | | | | |
| | Seal | MCS | 52 | 51 | +1 | 50 | -4 |
| | | LMS | | | | | |
| | Injection Target | BCS | 47 | 43 | -4 | 42 | -6 |
| | | PreCam | | | | | |

**Figure 3-3: Summary of zone thicknesses for Quest Sequestration rights interval**

With regards to the BCS reservoir properties, good agreement was observed between core analyses and log data (*Figure 3-4*).

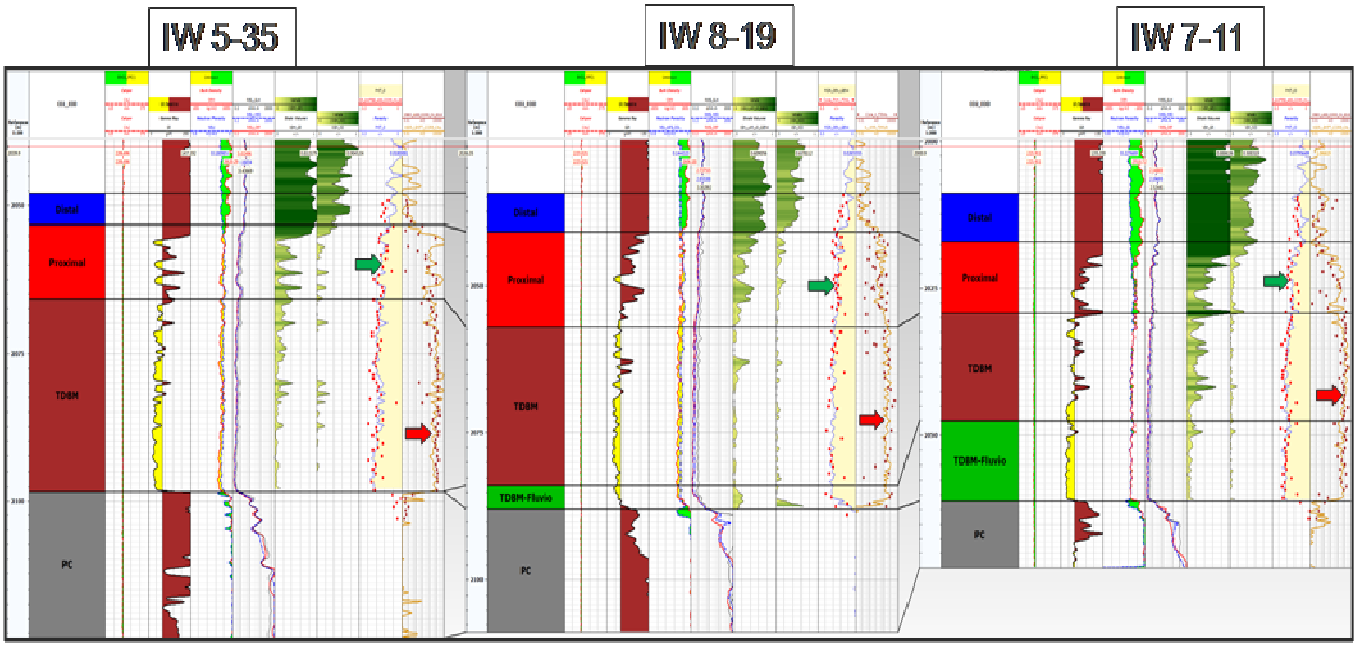



**Figure 3-4: BCS Reservoir Properties Comparison** of log response over the BCS formation and the corresponding core analysis results in all three injection wells. The green arrows are pointing to the porosity track, very good correspondence between the core porosity and log porosity. The red arrows are pointing at the permeability track, a good agreement between the log and core permeability in IW 5-35, whereas the correspondence is better in IW 7-11.

Based on the IW 5-35 and IW 7-11 BCS cores, the depositional environment was interpreted to be consistent with IW 8-19, as illustrated in *Table 3-2*

**Table 3-2: Depositional Environment in LMS-BCS for the injection wells from the core data.**

| Depositional Paleo-Environment | IW 8-19, thickness (m) | IW 5-35, thickness (m) | IW 7-11, thickness (m) |
|---|---|---|---|
| Distal Bay | 11* | 5* | 8* |
| Proximal Bay | 10 | 12 | 11 |
| Tide Dominated Bay Margin (TDBM) | 25 | 30 | 17 |
| TDBM (Fluvial Influenced) | 4.5 | 2.4 | 13 |
| * Based on core data only – log data indicates that that Distal Bay is significantly thicker. | | | |

Consistency was observed with regards to the geochemical composition of the BCS Formation brine from IW 5-35 and IW 7-11 compared to IW 8-19, as illustrated in *Figure 3-5.*

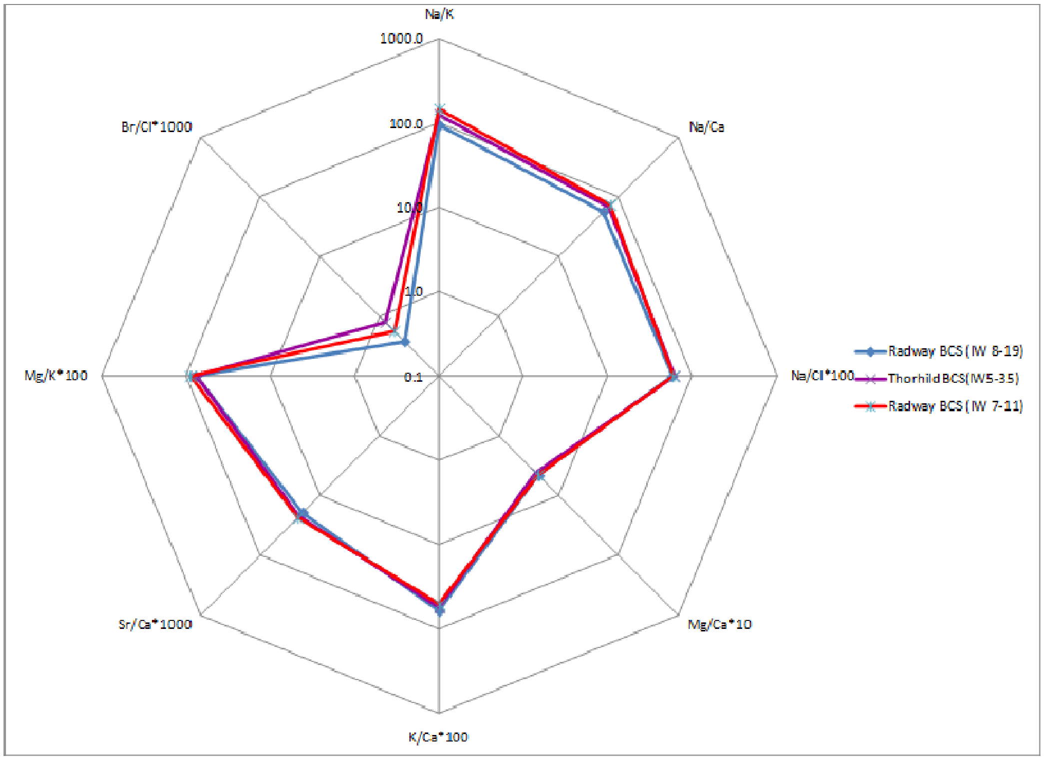



**Figure 3-5: Ion Ration plot of BCS Formation** brine waters from IW 8-19 (sampled in 2010), IW 5-35 (sampled in 2012) and IW 7-11 (sampled in 2013).

## 3.4 Estimate of Storage Potential

The uncertainty in the capacity of the storage area, the BCS storage complex, has been reduced considerably over time due to appraisal data gathering two appraisal wells, three injection wells, 2D seismic, 3D seismic and the ongoing reservoir modeling and feasibility studies). There is continued strong evidence for the BCS having the capacity to store the required volume for 25 years of injection. The residual uncertainty in pore volume is unlikely to decrease much further until several years of injection performance can be used to calibrate the existing reservoir models.

The Gen-4 dynamic model results, as presented in the 2013 status report to the AER, indicate that the pressure build up in the BCS is expected to be less than 2 MPa of DeltaP at the perforations of the injection wells while flowing at the end of the project life. Recent well results from IW 5-35 and IW 7-11 support this forecast and indicate an even lower DeltaP may occur. This pressure increase of 2 Mpa is less than 12% of the Delta Pressure required to exceed the BCS fracture extension pressure and less than 20% of the pressure required to exceed the AER operating constraint on bottom hole pressure (D65 approval condition ).

An updated pressure forecast will be included in the January 2015 AER annual report following the fifth generation of modeling.

## 3.5 Initial Injectivity Assessment

The project requires an initial water injectivity greater than 380 m3/d/MPa to confidently inject 1.08Mt/a of $CO_2$ to meet project objectives. *Table 3-3* summaries the project wells names and associated UWI's. Two prior appraisal wells were drilled in 2008 and 2009 and have been evaluated (respectively Red 11-32 and Red 03-04). IW 8-19, the first injection well, was drilled end 2010 and tested through January 2011. The regulatory approval for the acid gas disposal scheme (D65) was obtained in summer 2012, which enabled the execution of the drilling the rest of the Injection Wells and deep monitoring wells (IW and DMW respectively).

**Table 3-3: Summary of Project Well Names**

| Well Name | UWI |
|---|---|
| Red 11-32 | 1AA/11-32-055-21W4/00 |
| Red 3-4 | 100/03-04-057-20W4/00 |
| IW 8-19 | 100/08-19-059-20W400 |
| DMW 8-19 | 102/08-19-059-20W400 |
| IW 5-35 | 102/05-35-059-21W400 |
| DMW 5-35 | 100/05-35-059-21W400 |
| IW 7-11 | 103/07-11-059-20W400 |
| DMW 7-11 | 102/07-11-059-20W400 |

The results of the well test support initial injectivity of each individual injection well (IW 7-11, IW 5-35, IW 8-19) greater than the full project requirement. *Table 3-4* summarizes the injectivity assessments for all of the wells tested in the BCS.

**Table 3-4: Summary of Injectivity Estimates for the BCS Formation**

| Well Name | Rate | DeltaP | Injectivity |
|---|---|---|---|
| | m3/d | kPa | m3/d/MPa |
| IW 7-11 | 396 | 0.19 | 2085 |
| IW 5-35 | 342 | 0.33 | 1036 |
| IW 8-19 | 360 | 0.95 | 379 |
| Red 11-32 | 492 | 12.13 | 41 |

With similar petrophysical log responses in IW 5-35, IW 7-11 and IW 8-19, it can be inferred that the initial PI in IW 8-19 is understated. As it was an injection test, with known near well bore formation damage, it is likely that the injectivity for IW 8-19 is a minimum initial injectivity. The IW 8-19 fifth injection test more than likely still had significant formation damage. The project total initial injectivity can be calculated as 9 times the quoted requirement of 380 m3/d/MPa.

- Project initial injectivity = 379+1036+2085 = 3500 m3/d/MPa of water.
- Average Initial injectivity = 1167 m3/d/MPa of water

It is very probable that the project will be capable of sustaining injectivity greater than the 380 m3/d/MPa for the duration of the project life; therefore no further well development should be required for injectivity requirements.

## 3.6 Risk to Containment in a Geological Formation

There are nine potential threats to containment identified and explained in detail in Section 4.3.3 of the MMV Plan. The latest risk assessment summary is included in the MMV plan update supplied to Alberta Energy on 27th Feb 2014. Each are considered unlikely but are, in principle, capable of allowing $CO_2$ or BCS brine to migrate upwards out of the BCS storage complex. A further update of the risk assessment will be conducted in 2014 to incorporate the results of the next generation of subsurface modeling (Gen-5) and the integrity studies on the injection wells drilled in 2012/2103.

The potential risk events that could lead to loss of containment and their current risk assessment are summarized here as follows:

1) **Migration along a legacy well:** Due to an insufficient number, thickness and depth of cement plugs placed during abandonment or their subsequent degradation through time or a behind casing leak path that was not remediated before abandonment.

   The probability of legacy wells being intersected by the $CO_2$ plume or brine pressures high enough to lift brine into the groundwater is very low.

2) **Migration along an injection well:** due to a poor or subsequently degraded cement bond or corrosion of the casing and completion

   The risk of leakage from the Storage Complex along a leakage pathway in the injection wells is considered very low. However, in 2014 Shell is contracting an independent external review of the integrity of the injection wells and an associated update of the leakage risk assessment for the QUEST injection wells to ensure that Shell's risk assessment is still appropriate post drilling:

3) **Migration along a deep monitoring well:** Any such wells drilled into the BCS storage complex pose a threat similar to the injection wells.

   This is risk is currently considered very low due to the termination depths of Quest DMWs above the storage complex, large distance between proposed BCS monitoring well Redwater 3-4 and injection wells (21 km) and the use of injection wells for pressure monitoring.

4) **Migration along a rock matrix pathway:** due to unexpected changes in the depositional environment or erosional processes.

   The probability is considered very low even though permeable pathways could exist as sedimentary processes may sometimes result in complex heterogeneities that interconnect to allow fluids under pressure to migrate up and out of the storage complex.

5) **Migration along a fault** that extends out of the BCS storage complex and provides a permeable pathway

   The risk of migration along a fault is considered low, as there is no evidence of faults on 2D or 3D seismic that crosscut any of the regional seals covering the full SLA.

6) **Induced stress reactivates a fault** creating a new permeable pathway out of the BCS storage complex.

   In line with the low likelihood of the presence of faults intersecting either the BCS or any of the seals in the storage complex, there is a low likelihood of fault reactivation.

7) **Induced stress opens fractures:** Increased pressures and decreased temperatures may initiate fractures that propagate vertically to create a new permeable pathway out of the BCS storage complex.

   The risk of inducing fractures in the Quest project is low according to the Gen-4 modeling results, the expected injection pressure will be less than 22.5 MPa at the end of project life which is only 12% of the Delta Pressure required to exceed the BCS fracture extension pressure.

8) **Acidic fluids erode geological seals**: Injected $CO_2$ will acidify formation fluids which may react in contact with geological seals to locally enhance permeability within the seal

   Based on the regional geology, the choice of using three regional seals for the storage container and results of geochemical modeling and core analysis the risk of acidic fluids eroding geological seals is very low.

9) **Third Party Activities:** third party activities could generate a risk of leakage from the BCS storage complex.

   This risk is considered very low because Shell holds the Sequestration rights from top Elk Point Group to the Precambrian basement and there are no other 3rd party CCS projected proposed in the area.

As previously mentioned, this risk assessment is based on pre-baseline and pre- 2012/2013 drilling campaign. The next (pre-injection) version of the MMV Plan will include a re-assessment of risk profiles based the 2012/13 drilling results, Gen-5 modeling results and the independent injection well integrity study.

# 4 Facility Operations – Capture Facilities

## 4.1 Operations Activities

The facility did not operate in 2013. From the design basis, expected performance is as follows:

- Anticipated Energy demand - Steam ~103.7 MWh, Electricity ~ 65.9 GWh,
- Anticipated Heat or energy recovered - 13 MWh due to heat integration
- Anticipated $CO_2$ capture ratio - 80%
- Anticipated Total $CO_2$ captured - 1.08 million tonnes per year (T/a)
- Anticipated $CO_2$ emissions to atmosphere - 199,000 T/a
- Other emission to air, soil or water - No reportable incidences in 2013

Operations activities for the past reporting period focused on the following activities:

Design input to the engineering of the $CO_2$ capture facilities continued. Members of the Operations, Maintenance, and Engineering disciplines have been very active in reviewing design work to support the Project & Construction teams, and facilitate operability and maintainability in design.

Commissioning of the flue gas recycle facility on HMU 2 was completed. This facility is required to help manage the NOX emissions once $CO_2$ is removed from the fuel gas system.

The wells (7-11, 5-35 and 8-19) have been completed & turned over to Operations for care and custody until start-up. The well pads remain under the care and custody of the construction team until the pipeline connections to the Wellheads have occurred.

Interface management between Shell Scotford Operations organization and the Construction team continued. This included activities to provide clarity on responsibilities around HSE interface, site access, permitting, and execution of tie-ins.

Operations lead activities for the implementation of the Flawless project delivery program in the construction phase, intended to contribute to a smooth commissioning and start-up of the Project. From the identified lessons learned from other Shell projects, and generally accepted good trade practices, a list of activities was generated to bring awareness to the constructors (Trades) in order to reduce the likelihood of flaws from interfering with the commissioning, start-up, and future operation of the facility. Two major "flawless" activities the Operations organization has been involved in at the Module Yard and Fabrication shop is the cleanliness & tightness of the piping and equipment sub components.

Maintenance planning and execution activity preparation is ongoing. A key activity that has been completed is the identification of the preventative maintenance activities required for the capture facility.

Commissioning Work Execution Plans (schedules), are underway and all 65 system-cleaning procedures have been drafted.

The Projects operations team continued to develop during 2013, 15 people were brought on; 10 operations personnel, 3 maintenance personnel and 2 commissioning & start-up support staff. Later in 2014, we plan to bring on contract operators and contract maintenance personnel to support Quest until steady state operation is achieved. In addition, we are anticipating two permanent maintenance positions will be created.

## 4.2 Next Steps

Key operations activities for 2014 include the following:

- Turnaround Scope - Execution of the turnaround work required for a second Hydrogen Manufacturing Unit (HMU3) that includes burner modifications, pipe connections, and flue gas recycle work.
- Flue Gas Recycle - Preparation for and commissioning of the Hydrogen Manufacturing Unit 3 (HMU3) flue gas recycle system outside of the turnaround.
- Hiring and Onboarding - Hiring of Operations and Maintenance personnel to support commissioning and start-up (C/SU).
- Utilize external networks to strengthen skills and competencies with pipeline, subsurface, $CO_2$ operations, and maintenance.
- The Activity Based CSU plan is under development and will be ready before mechanical completion.
- The Project to Asset Transition Plan has been initiated, items for handover have been agreed upon with Site and close out of items has begun. It is expected that all items will be addressed by Q4 2015. This includes un-used commissioning materials, engineering and operations documents (procedures), drawings and assurance documentation.
- Shell Pre-Start-up Audit to affirm we are prepared for start-up.
- Shell Pre-Start-Up Safety Reviews on the installed facility.
- Take delivery of CSU spare parts

# 5 Facility Operations – Transportation

## 5.1 Pipeline Design

Some minor changes to the pipeline general design conditions as outlined in Table 5-1 have occurred over the development of this project. The current design specifications are as below, changes highlighted in bold text.

**Table 5-1: Pipeline Design and Operating Conditions**

| Characteristic | Specification | Units | Value |
|---|---|---|---|
| **General** | | | |
| Pressure | Normal | MPa | **10** |
| At inlet | Design minimum | MPa | 8 |
| | Design maximum | MPa | 14.8 |
| **Estimated Delta P to Well Site** | | | 0.4 (for three-well scenario) |
| Temperature | (@ Comp Discharge) | | |
| | Normal (Winter) | | 43°C |
| | Normal (Summer) | | 43°C |
| | Upset condition | | 60 °C (max – summer, cooling unit down) |
| Flow rates | Normal | Mt/a | 1.2 |
| | Design minimum | Mt/a | 0.36 |
| | | | |
| **Main Flow Line Data** | | | |
| | Length | Km | ~**64** |
| | Size | Inches, NPS | 12 |
| | Wall thickness | Mm | 12.7 (11.4 +1.3 CA) |
| **Laterals Data** | | | |
| | Length | Km | **3 laterals:~1, 1.6 and 3.8** |
| | Size | Inches, NPS | 6 |
| | Wall thickness | Mm | 7.9 (6.6+1.3 CA) |
| Reservoir pressure | | MPa | 22 – 33.3 |
| Reservoir temperature | | | 63°C |
| Well bore tubing diameters | | NPS/ID mm | 4.5/99.06 |
| Well depth | | M | 2,070 |

*Pipeline Fluid Composition*

The composition is described in Table 5-2.

**Table 5-2: Pipeline Fluid Composition**

| Component | Normal Composition | Upset Composition |
|---|---|---|
| $CO_2$ | 99.23 | 95.00 |
| $H_2$ | 0.65 | 4.27 |
| $CH_4$ | 0.09 | 0.57 |
| CO | 0.02 | 0.15 |
| $N_2$ | 0.00 | 0.01 |
| **Total** | **100.00** | **100.00** |

*Pipeline Pressure Data*

| | |
|---|---|
| Pipeline Design Pressure | 14.8 MPa @ 60°C |
| Maximum Operation Pressure | 14.0 MPa |
| Minimum Operation Pressure (10% higher than Critical Pressure) | 8.5 MPa |
| $CO_2$ Critical Pressure | 7.4 MPa |

*Pipeline Operating Temperature*

The temperature of the $CO_2$ leaving the Scotford Upgrader will be approximately 43°C. As the $CO_2$ travels in the pipeline, heat is transferred to the soil. At approximately 20 km from Shell Scotford, the $CO_2$ will be at ground temperature. For the basis of design, a ground temperature of 4°C was assumed during summer and 0°C during winter.

Due to the $CO_2$ being cooled throughout the pipeline length, it is deemed unnecessary to provide for thermal relief.

*Flow Rate Requirements*

Design capacity of the pipeline throughput is 1.2 Mt/a. The $CO_2$ pipeline is designed to receive and transport up to an additional 2.2 Mt/a of $CO_2$, should there be a commercial option to receive $CO_2$ from a third party or additional Shell volumes.

*Water Content and CO2 Phase Change Management*

Operating experience around the world with dense phase $CO_2$ in carbon steel pipelines, is that corrosion is not an issue for high purity $CO_2$ with low water content (below 100 ppmw). Under these conditions, zero corrosion rates have been observed. Quest exceeds these conditions: the >99% purity $CO_2$ will be dehydrated to a water content of 96 kg/MSm$^3$ (52 ppmw) during summer and 64 kg/MSm$^3$ (35 ppmw) during winter, within the capture facilities.

A moisture analyzer will be installed between the sixth and seventh stages of the compressor, with a system trip at 68 ppmw. There will be a sampling procedure to confirm the moisture analyzer measurement.

The system will normally be kept in the dense phase by operating at ~10 MPa. The system will trip at pressures below 8MPa. (The critical point pressure to maintain $CO_2$ in the dense phase is approximately 7.4 MPa).

When the pipeline is depressured for whatever reason, it will be brought back up to a pressure greater than 8MPa with dry nitrogen.

*Design Life*

Design life for the pipeline and associated surface facilities is for the remaining life of the Scotford Upgrader, approximately 25 years.

*Pipeline Steel Grade*

Items that have been identified as a possible concern for $CO_2$ pipelines include long running ductile fracture (LRDF) and explosive decompression of elastomers.

Shell Global Solutions, through Shell's Calgary Research Center (CRC), has performed material testing in order to determine the appropriate elastomers to minimize explosive decompression and the appropriate grade of steel with sufficient toughness to resist LRDF.

Results from the LRDF testing show that the toughness requirements for the line pipe are quite achievable in commercially available steel grades, as verified by history. Specifically, CSA Z245.1 Gr. 386 Cat II pipe would need a minimum wall thickness of 11.4 mm plus corrosion allowance (1.3 mm), and a minimum toughness of 60J at –45°C.

## 5.2 Pipeline Safeguarding Considerations

*Line Break Valves*

As per Class 2 requirements for CSA Z662, line break valves (LBVs) will be spaced at no greater than 15 km intervals. There are six LBV's in this system.

The line break valves have been placed in areas near secondary roads, which allows for ease of access by operations and maintenance personnel. Because the LBVs are located in populated areas, they will be fenced for security. The fencing is standard 8-foot chain link with three strands of barbed wire on top.

The LBV stations are expected to be enclosed in a cabinet style enclosure for weather protection. The cabinets will be designed to keep the valve elevations at a working height from the ground surface.

In the event of a line break valve closure, the line break valve computer will send a signal to all line break valves to close, thus minimizing loss of containment. The rate of closure should take 30 seconds from the open position to the fully closed position. This slow rate of closure will minimize the pressure surge (caused by the kinetic energy of the fluid) at an LBV.

After emergency shutdown due to a pipeline leak or rupture, after repairs, the depressurized section will be brought up to temperature and pressurized again, slowly, by the line break bypass valves, which also serve as temperature-controlled vents in the case of emergency.

*Flow Meters*

Leak detection is based upon the principles laid out in CSA Z662 Annex E as pertaining to HVP lines. Leak detection is based on material balance. The mass flow meter at the Shell Scotford boundary limit and at the wellhead will be of custody transfer accuracy, Coriolis-type flow meter.

Both automated and manual emergency shutdown systems will be installed. Automated shutdown will be initiated when pressure transmitters indicate operating parameters outside of acceptable limits. Both (not just a single Pressure Indicating Transmitter) pressure transmitters at each LBV, must indicate a low pressure trip in order to confirm a line break incident.

Emergency shutdowns can be initiated manually from each of the well sites or from Shell Scotford when pressure, temperature, and flow transmitters indicate upset conditions.

*Corrosion Protection*

Following regulatory requirements and the Pipeline Integrity Management Plan, cathodic protection will be installed for the pipeline; it is planned to be an impressed current system for the entire line.

*Inspection*

An in-line inspection tool (smart pig) run of the pipeline will be performed within the first year from startup to verify pipeline integrity. Frequency of repeat inspections will be based on results from this inspection, other surface inspections, and ongoing monitoring results.

Other inspection activities will include:

- Routine (daily) operator tours of the pipeline facilities above ground will commence during the CSU phase of project.
- Non-destructive examination (ultrasonic thickness test) on above ground piping to identify possible corrosion of the pipeline
- Internal visual examination of open piping and equipment evaluated for evidence of internal corrosion when pipeline is down for maintenance. This will be done during routine maintenance activities when parts of the surface facilities will be accessible
- Pipeline right-of way (ROW) surveillance including, for example, aerial flights to check ROW condition for ground or soil disturbances and third party activity in the area

# 6 Facility Operations - Storage and Monitoring

As of March 31, 2014, no storage volumes have been injected. Data collection for the purposes of gaining baseline information and related studies has been ongoing.

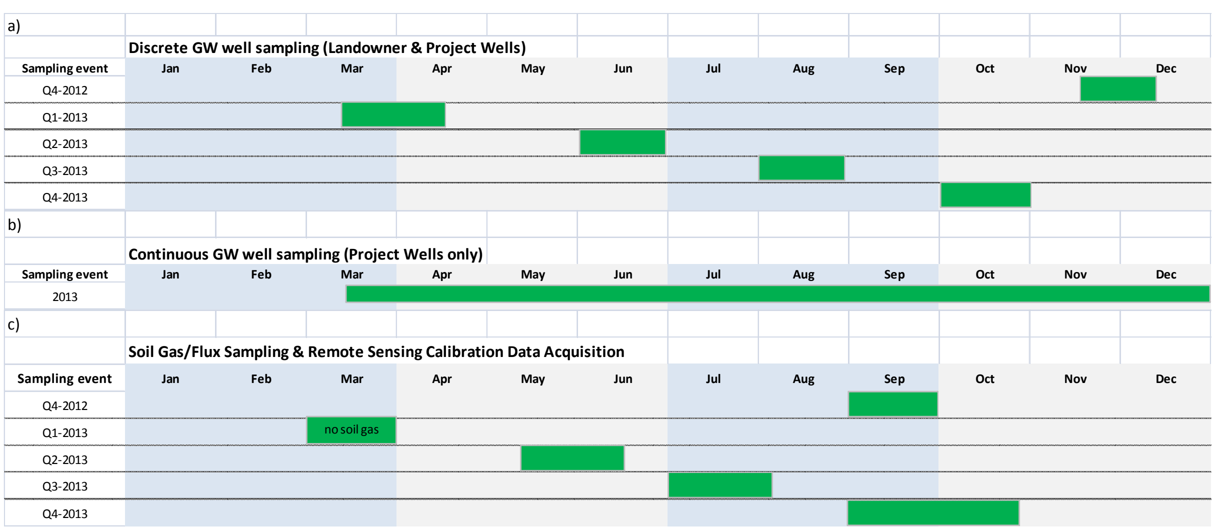
The list of recent activities associated with the MMV Plan includes:

- The 2013 Hydrosphere and Biosphere Field Program, was carried out by Golder Associates Ltd., in order to attain baseline data for hydrosphere monitoring, soil gas and vegetation and soils data for calibration of remote sensing.
- PFC tracer feasibility studies ongoing – interim results published in the AER 2nd annual report; January 2014, with Special Report #3 progressing for publication in June 2014.
- Analysis of log and core data from the 2012/2013 well campaign and commencement of the next generation of subsurface modeling (Gen-5).
- Continuation of the Light source feasibility study including a controlled release test at the 8-19 injection well pad
- Submission of an MMV plan update to AER on February 14, 2014 and submission of the MMV plan update and the Closure plan update February 27, 2014 to Alberta Energy.
- The submission of the AER 2nd annual report in January 2014.

## 6.1 Summary of MMV Operations and Maintenance Activities

Recent activities associated with the MMV Plan are described in the following sections. A summary overview of Hydrosphere Biosphere Monitoring Plan (HBMP) activities can be seen in Table 6-1.

**Table 6-1: Summary overview of HBMP activites completed to date**



In additional to baseline data acquisition, Shell doing a significant amount of work towards implementation of the supporting Infrastructure which will transmit all data types between well sites, Scotford Upgrader, Calgary office and relevant external parties.

### 6.1.1 Atmospheric Monitoring – Light Source

A Light Source field trial was successfully completed between September 8th and 13th, 2013. In addition, Boreal laser delivered a new enhanced performance single line-of-sight $CO_2$ sensor that was successfully tested in this field trial. Compilation of the field trial data is ongoing along with final hardware (laser) and software development work. The information from the field trial is being used as input to calibrate the monitoring system and to help set final detection thresholds that will be used for Light Source atmospheric $CO_2$ monitoring. These detection thresholds will be confirmed in the pre-injection MMV Plan Update 2015.

### 6.1.2 Biosphere Monitoring Activities

#### 6.1.2.1 Soil and Vegetation Sampling for Remote Sensing Calibration

Fourteen soil and vegetation plots were sampled over 3 different field events in the spring, summer and fall timeframes with an additional soil survey carried out later in the fall. A summary of the campaign completed to date, is provided in Appendix E of the AER annual report. A similar baseline campaign with be undertaken in 2014.

#### 6.1.2.2 Soil Gas and Soil Surface $CO_2$ Flux Sampling

A significant soil gas and soil surface $CO_2$ flux-sampling program has been carried out since Q3-2012 in order to support the baseline-monitoring program. The first soil gas and soil surface $CO_2$ flux sampling campaign took place in Q3-2012 and was followed by four sampling campaigns in 2013, distributed throughout the year.

A summary of the soil gas and soil surface $CO_2$ flux-sampling campaign completed to date is provided in Section 3.6 of Appendix E of the AER annual report. Another baseline soil gas and soil surface $CO_2$ flux sampling campaign will be undertaken in 2014, which will complete the soil gas and soil surface flux $CO_2$ data gathering program.

### 6.1.3 Hydrosphere Monitoring Activities

#### 6.1.3.1 Artificial and Natural Tracers

PFC tracer feasibility are studies ongoing – preliminary results are available in Appendix D of the AER annual report and final results will be submitted by June 2014. The aim of this study is to identify potential scavenging and losses of the PFC tracer due to the interaction of the parent fluid, i.e. $CO_2$, with different rock matrices and other subsurface fluids. The experimental study for this research was conducted in collaboration with The Commonwealth Scientific and Industrial Research Organization (CSIRO). The preliminary conclusion is that PFCs may remain in sufficient detectable amounts in its parent $CO_2$ phase at shallow depth in the Hydrostratigraphic column. The data confirmed that PFCs have very low solubility in water and are not retained at significant/critical amounts during migration by matrices prone to adsorb organic compounds such as clays. Hence, experimental data obtained so far suggest that PFCs are a suitable reliable passive/conservative tracer of injected $CO_2$. Experimental measurements are continuing to explore the behavior of organic substrate adsorption and $CO_2$/water/hydrocarbons partitioning.

In addition to the artificial PFC tracer study, the use of the natural abundance C isotopic composition of $CO_2$ is being investigated as a potential natural tracer. As part of the HBMP activities, the isotopic composition of $CO_2$ in soil gas and well gas are being determined. Samples from the Scotford Upgrader are also being collected for analysis. Furthermore, the University of Calgary was contracted to undertake laboratory and modeling studies to assess whether or not the isotopic composition of the injection gas may change along the stratigraphic column in case of a hypothetical leakage event. Draft reports for the laboratory and modeling studies have been received and are currently under review. A potential extension to these studies is also being investigated.

#### 6.1.3.2 Water Well Sampling

A significant groundwater sampling program has been carried out since Q4-2012 in order to support the baseline monitoring program. The first groundwater sampling campaign took place in Q4-2012 and was followed by four sampling campaigns in 2013, distributed throughout the year.

A summary of the water well sampling campaign completed to date is provided in Section 4.0 of Appendix E of the AER annual report. Another baseline water well sampling campaign will be undertaken in 2014.

In April 2013, Alberta Innovates – Technology Futures (AITF) started a study entitled ‘GROUND WATER STUDY FOR QUEST CCS PROJECT’ to support the HBMP. During 2013, the main focus has been on revising and updating the conceptual geological model from surface to the Lea Park Formation for the QUEST Sequestration Lease area. A key focus of this study is to assess the characteristics of potable groundwater aquifers across the Quest project area and to evaluate potential trigger conditions, which may suggest a deviation from established baseline conditions. Final observations from the AITF study are expected by the end of 2014.

### 6.1.4 Geosphere Monitoring Activities

#### 6.1.4.1 DAS/DTS

The optical fibers that have been previously cemented within the injection wells on each well pad will be used for these technologies. These fibers were successfully deployed and initial testing shows that they are functional. Shell will test the fibers again prior to implementing hardware associated with DAS or DTS data collection. Studies completed to date support DTS/DAS for the use in the following:

- DTS as a temperature log that can be used to for hydraulic isolation testing across the BCS storage complex when the well has been shut-in for a short period of time

The DAS system in Quest has been demonstrated to be similar quality to a conventional walkaway VSP and Shell plans to use DAS for the baseline 3D VSP's that will be acquired in Q4 2014.

The remaining feasibility work is focused on the ability to use DTS/DAS to detect potential leaks real time while injection is occurring.

#### 6.1.4.2 Microseismic

Shell received approval on November 29th 2013 for the Special Report #1 and MMV plan [Ref.]. This approval recognizes that no requirements are needed at this time for revisions or changes to the planned down hole microseismic monitoring (DHMS) and contingency monitoring in the deep observation wells. The microseismic array will be installed in DMW 8-19 as per the MMV plan, though the well used for DHMS may be adjusted based on observed injection performance. Shell has been working to finalize a vendor contract to construct and deploy the microseismic array, which will be complete by Q1 2014. Guidelines for an appropriate vendor include their ability to supply instruments that can handle high salinity environments and an array that can be installed using magnets. C&P activities are on going for this contract with a plan for installation to occur in June/July 2014. This planned timing for installation will allow Shell to record baseline seismicity prior to 2015 injection.

#### 6.1.4.3 3D VSP

Shell is in the process of designing the 3D VSPs scheduled for 2014 by modeling the response for different shot spacing and locations. The information gained from that modeling will be aimed at optimizing processing and reservoir imaging.

The baseline survey is planned to be acquired October/November 2014 after the farmers have harvested their crops. This will help to reduce stakeholder impact and complete a baseline survey prior to the 2015 injection. It is not advantageous to do this survey earlier in 2014 due to unnecessary noise attributed to heavy construction on the sites.

#### 6.1.4.4 InSAR

Shell acquired 15 RadarSat2 satellite images for InSAR baseline data in 2013 and will continue through 2014. The full set of images acquired as of Q3 2014 will be re-processed, in a similar process as used in 2012, prior to the start of injection to complete the baseline phase. In addition, in 2013 Shell received Approval from the AER on October 4, 2013 that corner reflectors are not required for InSAR monitoring subject to the following:

- When InSAR section is revisited in annual status reports, Shell must confirm a data-processing method has been used that captures sufficient natural coherent targets within the AOI(SLA) and,
- Confirm they are keeping track of how fast the area of deformation at the surface is expanding. If it appears it will extend beyond the AOI (SLA) in the lifetime of the project, Shell shall either demonstrate the existence of adequate natural stable targets outside the AOI, or revisit the question of whether artificial corner reflectors may be required.

### 6.1.5 In-Well Monitoring Activities

#### 6.1.5.1 DMW Pressure Monitoring

The log, core and pressure data acquired in the Cooking Lake in DMW 7-11 confirm the fluid mobility seen in previous DMWs drilled in 2012 and therefore support the proposed use of the Cooking Lake as a pressure-monitoring zone. Figure 6-1 summarizes the final conclusion on the potential use of the Winnipegosis, Contact Rapids/Lower Winnipegosis, Moberly, and Cooking Lake Formations as a deep pressure monitoring zone.

In 2013, the Cooking Lake was perforated in DMW 5-35 and DMW 7-11 and gauges installed. Continuous baseline pressure data acquisition will start in Q1 2014 to assist in determining the detection thresholds to be submitted as part of the pre-injection MMV plan update in January 31, 2015.

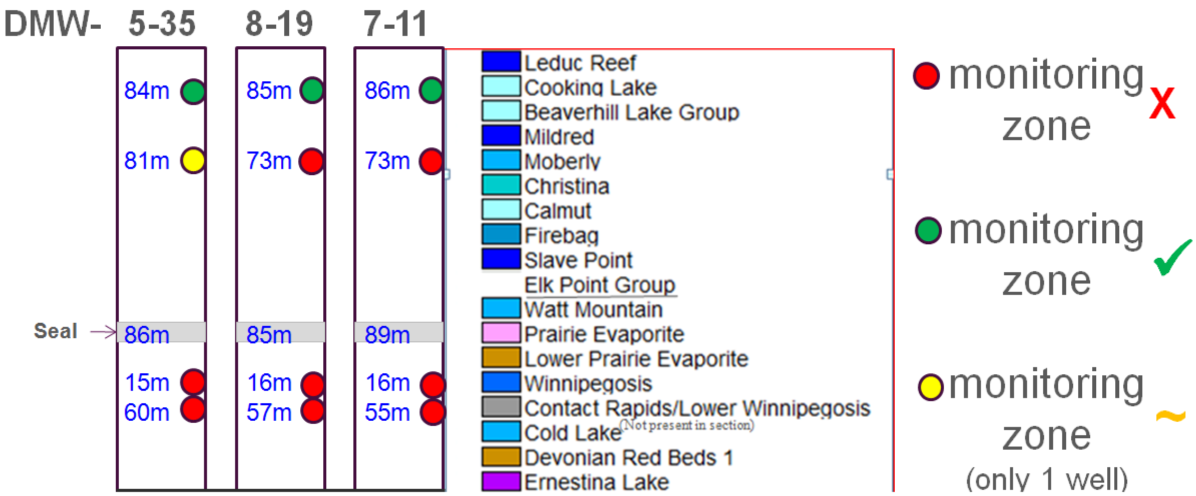



**Figure 6-1: Stratigraphic thickness** (blue font) for selectred formations within the DMW 5-35, 8-19, and 7-11. Also indicated is the potential of the Winnipegosis, Contact Rapids/Lower Winnipegosis, Moberly, and Cooking Lake Formations to be usesd as a deep.

# 7 Facility Operations - Maintenance and Repairs

With approximately one year remaining before start-up, work continues on developing the maintenance plans for the capture facility, pipeline, and wells. Work is complete on identifying the key preventative maintenance activities and final reviews and approvals are either complete or well under way. Training plans and the maintenance procedures for the maintenance personnel is well under way, and will include vendor training for key components (analysers, compressor).

Wherever possible, we are leveraging existing processes, systems and procedures to facilitate a smooth transition of the Quest project into Site routine maintenance and operations.

We are identifying spare parts requirements based on vendor supplied information. As well, we are going to complete the last of our RCM studies. SAP (electronic equipment database) structure will be created and populated with all required information.

Networking with external, operating facilities continues to help better identify maintenance practices and procedures.

# 8 Regulatory Approvals

## 8.1 Regulatory Overview

As stated in the previous annual report, a public hearing was conducted March 5 to 9, 2012, by the ERCB (now AER) to assess the applications that had been submitted for the Project. These applications included an amendment to the existing Scotford Upgrader license to include the $CO_2$ capture facility, a Directive 56 application (D56) for the pipeline, a Directive 65 application (D65) for the storage scheme and a Directive 51 application (D51) for the 8-19 injection well. These were submitted in November 2010 along with a harmonized federal/provincial Environmental Assessment.

The Decision Report outlining the ERCB response to the hearing and applications was released on July 10, 2012. This report provided approval of the Project subject to 23 conditions relating to various aspects of the Project that are required to be carried out. Shell subsequently accepted these conditions and Minister's approval of the application was granted on August 18, 2012.

Ongoing regulatory work, in this reporting period, included involvement in the Regulatory Framework Assessment (RFA), involvement in the GHG quantification protocol development and application for lateral and monitoring well approvals. In the RFA process, Shell participated in the technical subcommittees and the steering committee to develop a framework of regulations required for the ongoing CCS projects. This developmental work concluded in December 2012. The GHG quantification process followed a similar path of Shell participation in the discussions and development of the draft protocols for GHG quantification. This draft work continues by the Department of Alberta Environment and Water and is expected to be completed in May 2014.

## 8.2 Regulatory Hurdles

No direct hurdles were seen in this reporting period, but there have been some indirect Project hurdles due to the timing of the original approvals. The application approvals were later than planned for in the Project schedule. This resulted in Project work such as on-site construction having to be started late in the year, rather than in the summer. The consequence of this work has been some higher costs because work done in the winter to carry out the activities is more costly than doing it in the summer. There is some accompanying schedule pressure due to this delay, but the expectation, as of the end of this reporting period, is that this will not affect the overall Project deliverables.

## 8.3 Regulatory Filings Status

*Table 8-1* lists the regulatory approvals status relevant to the Project for the reporting period of March 2013 to March 2014.

### Table 8-1: Regulatory Approval Status

| Approval or Permit | Regulator | Status and Timing of Approval/Permit | Comments |
|---|---|---|---|
| **Project** | | | |
| CEAA Screening Decision pursuant to Section 20 of CEAA | NRCan | Received on June 20, 2012 | |
| **$CO_2$ Capture Infrastructure** | | | |
| Decision regarding Application No. 013-49587 pursuant to Division 2, Part 2 of *EPEA* | AEW | Received on August 3, 2012 | |
| Decision regarding Application No. 1671615 pursuant to Section 13 of the *Oil Sands Conservation Act,* and to amend Approval No. 8255 | ERCB | ERCB Decision Report received on July 10, 2012<br>Ministerial Order Approval received on August 18, 2012 | ERCB Public hearing held March 5 – 9, 2012 |
| **$CO_2$ Pipeline** | | | |
| Decision regarding Application No. 011-284507 pursuant to *EPEA* | AEW | Decision received on February 15, 2013 | |
| Decision regarding Application No. 1689376 pursuant to Part 4 of the *Pipeline Act* | ERCB | ERCB Decision Report received on July 10, 2012<br>Ministerial Order Approval received on August 18, 2012<br>AER (formerly ERCB) Main Pipeline Approval received August 24, 2012. Amendments to Main Pipeline approval to be done in Q1 2014. | ERCB Public hearing held March 5 – 9, 2012 |
| Pipeline lateral line approvals | AER (formerly ERCB) | Received April 22, 2013, August 22, 2013 and September 17, 2013 | |
| **$CO_2$ Injection and Storage** | | | |
| Decision regarding Application No. 1670112 pursuant to Section 39(1)(b) and (d) of the *Oil and Gas Conservation Act* and Unit 4.2 of Directive 065 | AER | ERCB Decision Report received on July 10, 2012<br>Ministerial Order Approval received on August 18, 2012 | ERCB Public hearing held March 5 – 9, 2012 |
| $CO_2$ Disposal Class II Scheme Approval No. 11837, Application No. 1670112 | AER | Received on August 24, 2012 | |
| Well License approvals to drill injection, deep monitoring and groundwater monitoring wells, Application No. 1739197, 1739195, 1739220, 1739215, 1739194, 1739201, 1739198 | AER | Received on June 16, 2012, November 16, 2010, September 17 and 19, 2012 | |
| Directive 051 applications for 5-35 and 7-11 injection wells | AER | Planned submission for Q2 2014 | Required for wells 7-11 and 5-35 |

## 8.4 Next Regulatory Steps

In the upcoming period, the Project regulatory activity will focus on obtaining the remaining permits required for the Project.

During construction of the main pipeline, re-routes were found to be needed at five locations to address environmental and safety risks. Although minor in nature, three of these re-routes will require amendments to the current pipeline license to ensure accurate mapping records with the AER. These amendments will also change the pipeline length to that which is now contemplated. These amendments will be done in Q1 2014.

A minor amendment is needed to the well license for the 8-19 injection well to change the well type from “test hole” to “injection”. This amendment will be done prior to injection. Applications under D51 for injection in the 7-11 and 5-35 wells will be submitted to AER in Q2 2014. There are some remaining activities on these two wells prior to proceeding with the application. The associated amendment to the D65 scheme approval for sequestration will also be submitted to AER.

Ongoing support work is expected throughout 2014 for the continued work on the RFA process and the GHG quantification protocols being developed by Alberta. Public Engagement

# 9 Public Engagement

## 9.1 Background

Shell conducted a thorough public engagement and consultation program for the Project that has been ongoing since 2008, beginning with initial stakeholder engagement that included meetings with regulatory agencies and local authorities before the formal commencement of the public consultation process for the Project. Regulatory agencies and local authorities provided input on the planned participant involvement program. The Project was publicly disclosed in October 2008 by way of a booklet and news release, followed by a publicly advertised open house in Fort Saskatchewan on October 16, 2008.

## 9.2 Shell's Stakeholder Engagement Strategy

Shell's stakeholder engagement is guided by its Good Neighbour Policy, which states:

- Shell's objective is to develop a mutually prosperous, long-term relationship with our neighbours living in close proximity to our operations.
- We will earn trust and respect at an early stage through honest, open and proactive communication.
- We will, on an ongoing basis, involve our neighbours in decisions that impact them with the objective of finding solutions that both parties view as positive over the long term.
- We will construct and operate our oil sands operations in an environmentally responsible and economically robust manner.
- We will use and encourage local businesses – where they are competitive and can meet Shell's requirements.
- We will ensure that the jobs created by our oil sands operations are filled by its neighbours whenever possible – but always on a strictly merit basis. To help make this happen, we will as necessary work with our neighbours, contractors, educational institutions and other producers to develop the skills required.

An extensive and open consultation program was initiated in January 2010 before filing Project applications in November 2010. The consultation program included stakeholders such as:

- Directly affected landowners and occupants along the pipeline route and within 450m of either side of the right of way
- Landowners and occupants within the seismic activity area
- Landowners and occupants within a 5 km radius of Shell Scotford
- Municipal districts/local authorities
- Industry representatives

- Provincial and federal regulators
- Aboriginal communities

Face-to-face consultation with landowners and occupants along the route and within the seismic activity area was undertaken and all were provided with a Project information package. All stakeholders were provided with Project update mailers and invitations to open houses, which were also publicly advertised.

The comprehensive Project information package included:

- Letter introducing Shell and the Quest CCS Project
- Project Overview booklet
- Map outlining the proposed route
- Pipeline construction and operation booklet
- 3D seismic backgrounder
- Shell CCS DVD
- Welcome to Shell Scotford brochure
- Privacy information notice
- Letter from the Chairman of the ERCB
- ERCB brochure Understanding Oil and Gas Development in Alberta
- ERCB publication EnerFAQs No. 7: Proposed Oil and Gas Development: A Landowner's Guide
- ERCB publication EnerFAQs No. 9: The ERCB and You: Agreements, Commitments and Conditions

In the reporting period of March 2013 – March 2014, the following specific stakeholder engagement events occurred:

- Shell conducted three Open Houses in the communities of Thorhild, Radway and Bruderheim in October 2013 to update the local stakeholders on the pipeline construction and progress to date on the capture plant and local drilling activities.
- Shell attended a series of local community events in the summer of 2013 to provide more of a community presence and information about the Project, which allowed for a broader reach of community members. (Events included the Fort Sask Trade Show; Community Appreciation Day; Canada Day Festivities and Parade in Fort Saskatchewan and Bruderheim; Bruderheim Ag Days; and various Days of Caring activities.)
- County/Town Council specific Project updates were given to councils in Thorhild, Redwater, Lamont and Sturgeon County as well as the City of Fort Saskatchewan, the Town of Bruderheim and the County of Strathcona. The meetings were held in the spring and summer of 2013.
- In 2013, Shell issued two community newsletters to stakeholders in the Quest communities providing an update on the Quest project.

- In order to provide more stakeholder involvement in the storage area-monitoring program, a Community Advisory Panel (CAP) has been convened with participation from local citizens. The Panel will provide input into the development of the monitoring program and review the results of work. The CAP was initiated in November 2012 with 5 meetings throughout 2013. The CAP also toured the Quest capture site at Scotford as well as visited the crossing of the North Saskatchewan River in September 2013. The next meeting is tentative set for March 2014.

In addition, Shell provided the following mechanisms where the public could ask questions, voice concerns and provide input regarding the Project:

- A Project information phone line (1-800-250-4355, press 3)
- A Project email address (quest-info@shell.com)
- Project updates posted at www.shell.ca/Quest throughout the regulatory process
- Comment cards, evaluation forms and information brochures available at Shell-sponsored public events

## 9.3 First Nations and Métis Groups

While the Government of Alberta did not require consultation with Aboriginal stakeholders, the federal government continued to engage aboriginal parties. Shell continued to engage the Regulatory Authority for Aboriginal Consultation, regarding ongoing Aboriginal engagement for the Project.

To date, Shell has conducted a number of activities in keeping with business principles and best practices in respect of Aboriginal engagement:

- Shell has distributed invitations to open houses, information packages and application information to self-identified interested parties including Saddle Lake Cree Nation (SLCN), Alexander First Nation (AFN) and Métis Nation of Alberta Region 4.
- Shell has provided Project information to and sought direction from provincial and federal regulators with respect to First Nations consultation.
- Based on initial Project descriptions and subsequent provincial direction, which recommended notification of Beaver Lake Cree Nation (BLCN), Shell provided notification of open houses and information packages to the BLCN consultation office.
- As a result of Project design changes, provincial regulators advised that Aboriginal Consultation was not required for the Project; thus, Shell closed its consultation with BLCN at the request of ASRD.
- Shell has advised provincial and federal regulators that it will continue to provide Project information to interested Aboriginal stakeholders and consult with parties upon request.

Shell has continued to keep interested Aboriginal groups informed of its Project activities through direct mail project updates, Quest newsletter to community representatives and invitations to community representatives for open houses.

## 9.4 Issues Identified

Based on face-to-face discussions and feedback from stakeholders throughout consultation activities, the following issues were raised.

- Pipeline/well/storage failure
- Pipeline routing
- Containment/leakage
- Groundwater contamination
- Perception; relatively new technology; unknown in the area
- Land use conflicts/value
- Incident management/emergency preparedness and safety

## 9.5 Issue Management

Shell's Project Issue Resolution Team met regularly from the onset of landowner engagement by land and seismic agents. Any issues arising from stakeholder interactions were identified and mitigation/resolution actions determined and acted upon wherever possible. In response to landowner feedback, several reroutes were undertaken to avoid the Bruderheim Natural Area and re-route through the North Saskatchewan River in response to landowner feedback.

During other consultation activities (such as open houses, community meetings, county council presentations), issues brought forward were vetted through the consultation team and mitigation measures determined, where possible and appropriate.

# 10 Costs and Revenues

## 10.1 Capex Costs

Capex costs reflect the current estimate for the Project (Table 10-1). Estimates are subject to change as the Project progresses. The categories follow those used by Shell over the life of the Project to track project costs.

The cost estimate remains unchanged from the 2012 estimate of $874 million and is premised on a Base Case of three injection wells and a reduced pipeline length. Other changes include updated phasing based on actual project costs and incorporating changes due to construction delays. Actual spending and forecasting is on an incurred basis.

Development costs for the Project for the FEED stage (January 1, 2009 to December 31, 2011) have been added to the table below and reflect costs associated with front end engineering for the capture and pipeline units as well as sub-surface modeling and early drilling. Capitalization of the project began January 1, 2012 as per Shell Canada Limited capitalization policy.

## Table 10-1 Anticipated Project Capital Costs (February 2014 Estimate)

| | FEED 2009 - 2011 Jan 1 , 2009 - Dec 31, 2011 | FISCAL 2011 Jan 1 , 2012 - March 31, 2012 | FISCAL 2012 April 1 , 2012 - March 31, 2013 | FISCAL 2013 April 1 , 2013 - March 31, 2014 | FISCAL 2014 April 1 , 2014 - March 31, 2015 | FISCAL 2015 April 1 , 2015 - March 31, 2016 | Total |
|---|---|---|---|---|---|---|---|
| **Overall Venture Costs** | 10,547 | | | | | | |
| **Shell Labour, & Commissioning** | 10,547 | 5,414 | 32,639 | 39,304 | 55,616 | 25,372 | 158,345 |
| **Tie-in Work /Brownfield Work** | | | | | | | |
| Tie-In/Turnaround Work Capture | 0 | 0 | 7,331 | 12,944 | 6,539 | 14,058 | 40,873 |
| Tie-In Work Pipeline | | 0 | 196 | 706 | 313 | 0 | 1,215 |
| **Sub Total** | 0 | 0 | 7,527 | 13,650 | 6,852 | 14,058 | 42,087 |
| **Capture Facility*** | 52,671 | | | | | | |
| Engineering | | 6,662 | 40,889 | 17,540 | 5,298 | 0 | 70,388 |
| Construction Management | | 0 | 218 | 16,364 | 17,258 | 0 | 33,840 |
| Material | | 6,092 | 42,315 | 57,057 | 3,348 | 0 | 108,812 |
| Site Labor | | 0 | 0 | 5,479 | 24,302 | 0 | 29,781 |
| Subcontracts | | 0 | 0 | 3,649 | 9,277 | 0 | 12,927 |
| Mod Yard Labor Including Pipe Fab | | 0 | 14,250 | 61,035 | 19,218 | 0 | 94,503 |
| Indirects / Freight | | 0 | 15 | 37,041 | 20,978 | 0 | 58,035 |
| FGR Mods/HMU Revamps | | 0 | 0 | 0 | 0 | 0 | 0 |
| **Sub Total** | 52,671 | 12,753 | 97,688 | 198,166 | 99,679 | 0 | 408,286 |
| **SUBSURFACE - Wells*** | 63,175 | | | | | | |
| Injection Wells | | 1,090 | 17,970 | 4,368 | 1,103 | 150 | 24,681 |
| Monitor Wells | | 0 | 1,311 | 0 | 0 | 0 | 1,311 |
| Water Wells | | 0 | 1,620 | 0 | 0 | 0 | 1,620 |
| Other MMV | | 0 | 1,657 | 4,213 | 8,526 | 5,327 | 19,722 |
| **Sub Total** | 63,175 | 1,090 | 22,558 | 8,582 | 9,629 | 5,477 | 47,335 |
| **PIPELINES - TOE*** | 4,035 | | | | | | |
| Engineering | | 576 | 4,272 | 2,708 | 25 | 0 | 7,581 |
| Materials | | 0 | 1,878 | 24,613 | 3,000 | 0 | 29,491 |
| Services | | 0 | 0 | 53,536 | 15,900 | 0 | 69,436 |
| **Sub Total** | 4,035 | 576 | 6,150 | 80,857 | 18,925 | 0 | 106,508 |
| **Total Contingency, Inflation & Mrkt Escalation** | 0 | 0 | 0 | 0 | 18,000 | 93,129 | 111,129 |
| **Sub Total** | 0 | 0 | 0 | 0 | 18,000 | 93,129 | 111,129 |
| **Grand Total** | 130,429 | 19,832 | 166,563 | 340,560 | 208,700 | 138,036 | 873,690 |

* Shell labour costs during FEED are booked here.

## 10.2 Opex Costs

Opex reflects an average year spend (Table 10-2). All years are anticipated to be similar, based on the injection profile of up to 1.2 Mt/a of $CO_2$ injected.

There has been no change to the operating costs for the Project because no design change has been implemented from the original assessment. The premise natural gas price is $4.72/GJ and $99.00/MWhr for electricity.

**Table 10-2 Anticipated Project Operating Costs (2011 Estimate)**

| Item | Average Costs per Year (,000) |
|---|---:|
| Steam and Electricity | 25,893 |
| Chemicals | 239 |
| Labour & Maintenance | 4,277 |
| Insurance | 152 |
| Property Tax | 2,874 |
| Directs vs. indirect costs | 172 |
| MMV Costs | 4,544 |
| Tariffs | 0 |
| Sustaining Capital | 1,254 |
| Turnarounds | 1,872 |
| **Total** | **41,277** |

## 10.3 Revenues

Revenues reflect funding received and to be received (Table 10-3) until commercial operation. Ongoing revenues during operations will be estimated on the basis of credits received for the $CO_2$ volumes stored, along with the additional credits received as per the multi-credit agreement signed with the Province of Alberta. Using 2013 Alberta carbon prices of $15 per tonne, and on the basis of the draft *Quantification Protocol for the Capture of* $CO_2$ *from Steam Methane Reforming and Permanent Storage In Saline Geological Formations* (to be finalized in 2014), the approximate revenue is expected to be approximately $30 million per year.

### Table 10-3: Anticipated Project Revenue 2009 – 2015

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|---|
| | Apr 1, 2009 – Mar 31, 2010 | Apr 1, 2010 – Mar 31, 2011 | Apr 1, 2011 – Mar 31, 2012 | Apr 1, 2012 – Mar 31, 2013 | Apr 1, 2013 – Mar 31, 2014 | Apr 1, 2014 – Mar 31, 2015 | Apr 1, 2015 – Mar 31, 2016 |
| Revenues from $CO_2$ Sold | | | | | | | |
| Transport Tariff | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Pipeline Tolls | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenues from incremental oil production due to $CO_2$ injection | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue for providing storage services | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Other incomes – Alberta innovates Grant, NRCan Funding & GoA Funding | $3,547,059 | $1,817,101 | $1,302,507 | $238,000,000 | $115,000,000 | $53,000,000 | $161,000,000 |
| | $3,547,059 | $1,817,101 | $1,302,507 | $238,000,000 | $115,000,000 | $53,000,000 | $161,000,000 |

### Table 10-4: Government Funding Granted 2009 – 2015

Government funding granted or pending through construction of Quest project.

| Government Funding | 2009<br>April 1 , 2009 - March 31, 2010 | 2010<br>April 1 , 2010 - March 31, 2011 | 2011<br>April 1 , 2011 - March 31, 2012 | 2012<br>April 1 , 2012 - March 31, 2013 | 2013<br>April 1 , 2013 - March 31, 2014 | 2014<br>April 1 , 2014 - March 31, 2015 | 2015<br>April 1 , 2015 - March 31, 2016 | April 1 , 2016 - March 31, 2026 |
|---|---|---|---|---|---|---|---|---|
| Alberta Innovates Grant | $ 3,547,059 | $ 1,817,101 | $ 1,302,507 | | | | | |
| NRCan Funding | | | | $ 108,000,000 | | | $ 12,000,000 | |
| GoA Funding | | | | $ 130,000,000 | $ 115,000,000 | $ 53,000,000 | $ 149,000,000 | $ 298,000,000 |
| | $ 3,547,059 | $ 1,817,101 | $ 1,302,507 | $ 238,000,000 | $ 115,000,000 | $ 53,000,000 | $ 161,000,000 | $ 298,000,000 |
| | | | | | | | | |
| Gov't Funding as Percentage of Total Project Spend | 0.2% | 0.4% | 0.5% | 17.1% | 25.1% | 28.8% | 40.1% | 60.9% |

## 10.4 Funding Status

To date, the Project has received a total of $6.6 million from the Alberta Innovates program, which is now concluded. The Project has met the criteria of allowable expenses for the $120 million NRCan funding from the Government of Canada, and 90% of the funding was paid in August 2012 with the Project having met the CEAA compliance. Within the terms of the NRCan agreement, 10% of the $120 million will be held back pending full completion of the Project work and successful Commercial Operations to the end of the NRCan program in 2014. Funding from the Government of Alberta CCS Funding Agreement of $15 million was received in May 2012, $40 million in October 2012, $75 Million in April 2013 and a further $100 Million in October 2013.

Funding levels expected in the next reporting period will be $15 million from the Province of Alberta associated with the CCS Funding Agreement Milestone #5 (invoice March 2014) and a further $38 million associated with Milestone #5 to be invoiced in September 2014.

# 11 Project Timeline

The timeline for the Project is shown in Table 11-1. There were no significant changes in schedule in this reporting period.

Minor changes in schedule, since last reporting period, are reflected in the following activities:

- Main venture activities are extended into 2015 to reflect commercial operations to Q4 2015
- Commissioning and start up for the pipeline continues into 2015
- Commission and start up of the wells are in 2015 to follow the start up of HMU3
- Regulatory activities extend into 2014 to include the D51 injection well application, amendments to the main line D56 approval and the amendment required for the D65 storage approval.

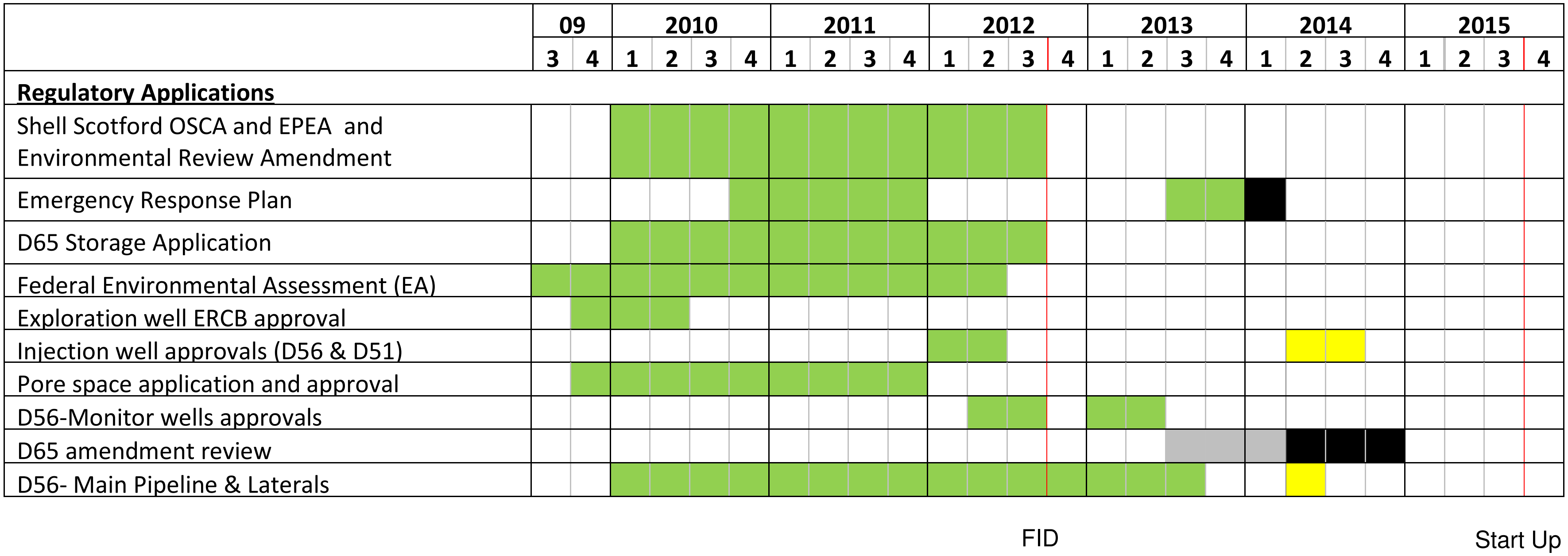
For further details on the construction activities, see Section 2, *Figure 2-1*.

## Table 11-1: Project Timeline

| | 09 | | 2010 | | | | 2011 | | | | 2012 | | | | 2013 | | | | 2014 | | | | 2015 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 |
| **Venture** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Venture Level Management | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Project Economics | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Venture Optimization | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Risk Management | | | | | | | | | | | | | | | | | | | | | | | | | | |
| JV Updates, Communication | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Stakeholder Management | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Project Assurance | | | | | | | | | | | | | | | | | | | | | | | | | | |
| CCS Learning and Knowledge Sharing | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Capture** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Complete Basic Design & Engineering | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Prepare Draft RFP for Long Lead Items | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Detailed Engineering | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Construction | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Commissioning and Start-up | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Commercial Operation Tests | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Pipeline** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Pipeline Routing Selection | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Pipeline Cost Estimate | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Pipeline Define Engineering | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Pipeline Support/Study Work | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Detailed Engineering | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Main Pipeline River Cross Construction | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Construction | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Commissioning and Start-up | | | | | | | | | | | | | | | | | | | | | | | | | | |

## Table 11-1: Project Timeline (cont'd)

| | 09 | | 2010 | | | | 2011 | | | | 2012 | | | | 2013 | | | | 2014 | | | | 2015 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 | 1 | 2 | 3 | 4 |
| **Storage** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Initial Site Appraisal | | | | | | | | | | | | | | | | | | | | | | | | | | |
| MMV Base Lining | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Aeromagnetic surveys | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Seismic Phase 1 | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Seismic Phase 1B- planning and scouting | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Seismic Phase 2 (optional) | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Drill appraisal Radway well 8-19 | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Water injection test Radway well 8-19 | | | | | | | | | | | | | | | | | | | | | | | | | | |
| CO2 injection test Radway Well 8-19 | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Storage Performance Assessment | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Produce Field Development Plan | | | | | | | | | | | | | | | | | | | | | | | | | | |
| MMV definition and planning | | | | | | | | | | | | | | | | | | | | | | | | | | |
| MMV baseline data acquisition | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Detailed well engineering | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Wells procurement - rigs, tubulars | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Drill water monitoring wells | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Pad Prep for injection wells/monitoring wells | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Injection wells drilled/completed | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Monitor wells drilled/completed | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Commissioning and start-up | | | | | | | | | | | | | | | | | | | | | | | | | | |


09
2010
2011
2012
2013
2014
2015
3 4 1 2 3 4 1 2 3 4 1 2 3 4 1 2 3 4 1 2 3 4 1 2 3 4
Regulatory Applications
Shell Scotford OSCA and EPEA and Environmental Review Amendment
Emergency Response Plan
D65 Storage Application
Federal Environmental Assessment (EA)
Exploration well ERCB approval
Injection well approvals (D56 & D51)
Pore space application and approval
D56-Monitor wells approvals
D65 amendment review
D56- Main Pipeline & Laterals
FID
Start Up

# 12 General Project Assessment

The Project schedule, as noted in Section 11, is largely maintained with the plan of achieving commercial operation by end of 2015. Project development costs are on budget and the projected capital and operating costs are within the expected ranges for a Project at this stage.

## 12.1 Project Successes – 2013

*Capital Cost Management*

As a greenhouse gas reduction project, the Project does not carry the revenue streams that traditional projects do and is economically challenged. Additionally, government funding for the Project is on a fixed basis and any cost overruns will be borne strictly by Shell and the joint venture owners. These concepts result in the capital management being a major focal point for the Project. The Project was able, through examination of the subsurface data, to lower the Base Case number of wells required for injection from five injection wells to three injection wells. This resulted in a reduction of capital required and the current capital forecast is reduced as shown in Section 10. As of this date, the updated capital costs forecast are being maintained at the expected level with no indications of an overrun. Although there are cost and schedule pressures, the team has been able to successfully mitigate and manage these risks, project to date.

*Detailed Engineering*

Detailed engineering reached 99% complete with the issue for construction of the electrical heat tracing drawings. A small team will remain to support and answer questions from construction as they arise.

*Module Work*

In November of 2013, the first pipe rack modules arrived at site and were successfully set in place. The HMU #3 equipment modules arrived in January and were set into place along with its absorber tower completing the module construction for that unit.

*Construction Work*

In 2013 the underground work entailing the firewater, potentially oily water sewer, underground section of the cooling water, inside battery limit $CO_2$ pipeline, piling, concrete foundations and paving was completed. The pipeline construction was kickoff with successful crossing of the North Saskatchewan River

*Deep Injection and Monitoring Well Drilling Campaign*

The Base Case for Project's subsurface program is a three-injection well concept with each one also having a deep monitoring well located next to it. In total, these six wells are the scope of the deep drilling for the Project. One of the wells was completed earlier when it was drilled as the final test well and the resulting favourable analysis of the storage area resulted in it being re-designated as an injection well. Over the period of end 2012 to early 2013, Shell drilled the five remaining wells at the predetermined sites. Drilling activities during the campaign were carried out and the initial studies of the local storage areas are positive. The second and third injection wells were flow tested with better than expected results, thereby confirming that the three injection wells complete the required deep drilling program for the Project.

*Baseline MMV Data Acquisition*

A key criteria of the monitoring, measurement and verification program is the establishment of baseline data prior to operations. In the spring of 2012, this program commenced with field data gathering of soil, air, groundwater and other tests. The program will continue through the upcoming period to ensure that a baseline set of data is gathered for two years prior to startup. Two of the deep monitoring wells were completed in the Cooking Lake formation in September 2013; the down-hole gauges have been recording pressure data since January of 2014. The third deep monitoring well will be completed in the summer of 2014 with both a pressure gauge and a micro-seismic array.

*Stakeholder Engagement*

Stakeholder management continues to be a priority for Shell. The high level of stakeholder involvement continued in 2014 with three open houses located near the Project's activities. Bi-annual engagements with the municipal and county councils in the areas also received positive feedback. Shell maintained a visible local presence by attending a number of community events in the region over the summer of 2013.

Quest continues to attract wide media coverage and interest from various industry organizations. Shell attended and provided Project information and updates to a large number of these organizations at conferences and meetings over the course of the year in addition to media interviews. Such events included Quest being presented at the EU hearings in Brussels in June 2013, involvement in the CSLF (Carbon Sequestration Leadership Forum) Technical and Ministerial events, and presentation to the Energy Ministry in Norway.

*Provincial Government Milestones*

Critical to the Project funding for the Government of Alberta is a series of milestones that have been agreed to within the funding agreement that measures the progress of the Project. Funding payments are based on the Project completing these milestones as they come up. The second two project milestones were completed in the past year with a fifth scheduled for March 2014. These two passed successfully with no major findings or issues. At this point in the project, the initial review of the March 2014 milestone indicates that this one will be passed in the same manner. These milestones are another indicator that the Project is proceeding as planned.

## 12.2 Project Challenges

There have been some challenges for the Project, but none that have been insurmountable to date. A description of these challenges and activities undertaken to address them follows.

*Land Acquisition*

Acquisition of Amendments to right-of-way and temporary workspace agreements for the pipeline and riser sites is a key Project activity to ensure that construction can safely complete the project and adhere to all environmental and regulatory requirements. Since the initial acquisition of the pipeline right-of-way, area land values have increased by six thousand dollars per acre in the Heartland Industrial district, which has increased costs for revisions and has created an issue for some area stakeholders who have been requesting top-up compensation to address the change in area rates. Negotiation with landowners and legal representatives has taken place to alleviate landowner concerns and all agreement revisions and additional area acquisitions had been acquired with strict time sensitivity to meet construction needs. Since initial acquisition there have been parcels of land that have changed ownership which has created new landowner concerns and demands for compensation. Another challenge has been construction of the pipeline right-of-way paralleling several other area operator projects that are currently under construction, thus limiting the area the Shell Quest team has for construction as landowners had since sold the areas for the Quest temporary workspace to other companies for right-of-way.

*Capture Site Construction*

There have been delays in the delivery of valves and some electrical and instrumentation bulk items that have affected the timely fabrication of pipe spools for the modules and site construction as well as assembly of the modules. Efforts are underway to expedite this material as well as source from other vendors to maintain the project schedule. Where we can advance the delivery to match to the required ship to site dates for the modules, work arounds have been engineered to allow those components to be installed at site without jeopardizing our off site hydro test strategy.

Concurrent construction of two other major pipelines in the same corridor between Scotford and the North Saskatchewan River has affected our pipeline construction progress. We adjusted our course of construction to focus on the north side of the river in the fall and early winter to allow the competing lines to complete work in joint areas. We will need to ramp up the peek manpower on the pipeline to complete the wetter areas by Scotford prior to spring break up to avoid the higher cost of installation in these areas if they are not frozen.

*Regulatory*

Two injection wells require D51 Approval prior to commencement of injection. Hydraulic isolation test /log is a D51 requirement but it requires injection, usually water, to perform it. Our experience with the IW 8-19 well test has been that water injection has a high risk of causing formation damage in the BCS. We are therefore evaluating the options for hydraulic isolation testing to meet the D51 requirements.

Furthermore, post drilling, Shell identified surface casing vent flows in all deep monitoring and injection wells as well as gas migrations in injection wells IW 7-11 and IW 5-35. Detailed discussions have been held with the AER concerning this issue and approval was granted to defer any repair until well abandonment with a number of monitoring commitments (see 2014 MMV plan). Shell has concluded that this issue does not impact the hydraulic isolation and containment risk of the BCS and has also commissioned an independent external study on injection well integrity

*Stakeholder Engagement*

Shell has developed and initiated an extensive stakeholder management plan to proactively engage the communities that we will be working in. With this, we have however observed some increased landowner concerns associated with the increased activity in the region. This activity has included the initiation of the groundwater-sampling program, vegetation analysis program, construction activities for our pipeline, and construction activities for two additional pipelines in the region not associated with Quest. As such, we are evaluating additional opportunities to improve our relationships including good neighbor deeds such as clearing driveways of snow, brochure handouts associated with the groundwater-sampling program to better explain the program, increasing Shell employee presence in the field, and providing Quest Coffee talks with the residences. We are also evaluating changes to our Open House content to better manage the real-time issues.

*Schedule Pressure*

In addition to the delayed Final Investment Decision in 2012, the valve delivery issues highlighted above have added additional pressure to the project schedule. Efforts are underway and will continue through 2014 and early 2015 to maintain the 2015 start up plan

## 12.3 Indirect Albertan and Canadian Economic Benefits

The primary benefit in this reporting period has been additional business generated with Canadian and Albertan third party contractors for the following activities:

- Engineering design in the Calgary offices
- Construction work at the Scotford Upgrader site
- Well drilling in the storage area
- Field work done to benchmark the hydrosphere and biosphere properties of the storage area surface and groundwater regions

Well drilling activities and engineering design were completed in 2013. The construction work and benchmarking activities will continue throughout 2014.

Additionally, there are benefits in terms of salaries paid to the Albertan and Canadian employees of Shell Canada who are working on the Project team.

There are additional benefits in the Edmonton area as the module yard that is constructing the modules for the capture facility will be in full production in Sherwood Park. Pipeline construction is using local labour and is to be complete in Q3 2014.

# 13 Next Steps

The Project is now in the Execute Phase through to 2015 and the focus in the upcoming reporting period will be to meet the major construction milestones and get ready to handover the facilities to the commissioning and start up team.

In 2014, all modules will be set in place upon completion of their fabrication and assembly. The compressor building erection will be completed followed closely by the installation of the compressor and motor into the building. Final bolt ups and welds will be completed on the modules as they arrive. The underground and module cabling will be connected to the electrical substation building when it arrives. There will be a unit outage in 2014 on a portion of the Expansion 1 Upgrader that will allow for the tie ins to be completed for this area as well as the change out of the burners in the steam methane reformer and installation of the flue gas recycle.

The main pipeline installation is scheduled for completion in the first half of 2014 followed by a hydro test of the system in the May/June time period. The well site skids and Line Block valves will be installed during the spring and early summer. Then the system will be cleaned, dried and preserved for start up in 2015.

Fieldwork will be ongoing throughout 2014 to continue to gather benchmarking data to quantify the storage area hydrosphere, biosphere and subsurface properties prior to $CO_2$ injection. This is required as part of the overall measurement, monitoring and verification plan.

Operational activities will include developing the specific operation and maintenance procedures for the operation of the facility during this year. There will also be hands-on learning as the team spends time at other facilities to gain operational experience from the Joint Venture partners and external Shell facilities. Maintenance will be loading the maintenance systems with all the new equipment complete with preventive maintenance requirements. Some of the systems will start to be turned over to operations as they are completed for cleaning and the start of commissioning activities.

Regulatory activities will focus on amending the D 56 application for the pipeline for the final alignment and preparing the D 51 applications to convert our wells to injection wells. Work will continue as needed on providing assistance as needed to the provincial regulators on the Regulatory Framework Assessment and GHG offset quantification protocols currently in progress.

Stakeholder engagement activities will continue to ensure continued public knowledge of the Project's progress. The Community Advisory Panel will continue into 2014 and continue to update the group on Quest activities as we move from construction to commissioning and start up. Similarly, ongoing reporting will continue to both the Governments of Canada and the Province of Alberta in accordance with the respective funding agreements to keep these bodies apprised of the Project activities.

On a milestone basis, *Figure 13-1* lists the major activities occurring during the next reporting year.

| **Key Milestone** (Bold indicates GoA milestone) | **Original Target** | **Actual/ Forecast** | **Status** | **Status Comment** |
|---|---|---|---|---|
| HMU 1 &2 Amine Absorber tower – Set/Install | Mar 31, 2014 | Mar 31, 2014 | | Vessels being dressed |
| **GOA milestone 5 – Set 3rd Gen Module** | Mar 31, 2014 | Mar 31, 2014 | | Module in place. Audit to occur in early March. |
| Last Module Set/Install | June 30, 2014 | June 30, 2014 | | Work ongoing to maintain schedule |
| Compressor final alignment | Aug 30, 2014 | Aug 30, 2014 | | On track |
| **GOA milestone 6 – Set all 3rd Gen Modules** | Sep 30, 2014 | Sep 30, 2014 | | On track |
| Pipeline Mechanical Completion | Oct 31, 2014 | Oct 31, 2014 | | On track |
| **GOA Milestone 7 Quest Mechanical Completion** | Mar 31, 2015 | Mar 31, 2015 | | On track |
| **Full capacity "sustained ops" achieved** | Dec 31, 2015 | Dec 31, 2015 | | On track |

**Figure 13-1 Project Milestones**