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Quest Carbon Capture and Storage Project

ANNUAL SUMMARY REPORT - ALBERTA DEPARTMENT OF ENERGY: 2015

March 2016

Executive Summary

This Summary Report is being submitted in accordance with the terms of the Carbon Capture and Storage (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, comprising of Shell Canada Energy (60%), Chevron Canada Corporation (20%) and Marathon Oil Sands LP (20%), as amended.

The purpose of the Project is to deploy technology to capture CO_2 produced at the Scotford Upgrader and to compress, transport, 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% of the CO_2 produced from the Scotford Upgrader.

All capture equipment was mechanically complete by the end of Q12015, occurring concurrently with Operations Readiness activities, Measurement, Monitoring, and Verification (MMV) activities focused on gathering additional baseline data and preparing for the start of injection, and all wells and outstanding approvals were in place by the end of Q12015 to allow the project to progress into the Commissioning and Start Up (CSU) phase. First injection of CO2 into injection wells 7-11 and 8-19 occurred on August 23, 2015 and commercial operation was achieved on September 28, 2015 after the successful completion of the three performance tests outlined in Schedule F of the CCS Funding Agreement.

Initial injectivity assessments indicate the project will be capable of sustaining adequate injectivity for the duration of the project life; therefore, no further well development should be required. Post injection in August, MMV activities have shifted to operational monitoring. In the future, the MMV Plan will be integrated with the GHG reporting system in place at the Scotford Upgrader.

There were no noted spills/releases to air, soil or water within the Quest capture unit during the 2015 operating period and MMV data indicates that no CO_2 has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir during this reporting period.

Shell continued to conduct open houses for the local communities including two in the last part of October at Thorhild and Radway. Engagement with local governments continued in 2015 in order to update officials on progress and joining in celebration on achievement of commercial operations. Engagement with numerous industry and non-government associations for knowledge sharing also continued in 2015 and will continue in 2016.

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

- Successful completion of CSU activities
- Successful achievement of commercial operation
- Safe and leak-free first fill, startup, and operation of the pipeline and wells facilities, successfully managing CO_2 phase behavior and low temperature concerns.
- Low levels of chemical loss from the ADIP-x process
- Significantly lower carryover of triethylene glycol (TEG) into CO_2 vs. design with estimated losses on track to be roughly 6,000 kg annually vs. the design makeup rate of 46,000 kg annually

- Implementation of Flue Gas Recirculation (FGR) technology, in combination with the installation of low-NOx burners has allowed all three HMUs to meet their NOx level commitments without contravention in 2015 with the capability to operate close to baseline NOx levels pre-Quest.
- Reduction in compressor minimum flowrate, resulting in operation that is more efficient during turndown.
- Injection into the 5-35 well was deemed not to be necessary in 2015 due to strong injectivity performance, resulting in significant MMV cost savings. .
- Strong evidence that the project will be capable of sustaining adequate injectivity for the duration of the project life; therefore, no further well development should be required for injectivity requirements.
- Overall maintenance issues have been minimal for a new construction startup. Sharing of best practices by networking with external operating facilities continues to help improve maintenance practices and procedures.
- Strong integrated project reliability performance since initial injection in August, achieving an uptime of 98.3%. Mechanical availability for the reporting period was 98.7%, beating the project premise of 95.4%.
- Maintaining local support through the extensive stakeholder engagement activities
- Continued engagement of the Community Advisory Panel (CAP).
- International engagements with the Global CCS Institute to support public engagement, knowledge sharing activities at the CCUS in Pittsburgh, MIT in Boston, and numerous tours to the Scotford facility.
- A signed agreement with a US Department of Energy-funded entity to develop and deploy MMV technologies for use on Quest in the area of real-time ground water monitoring. Partnerships such as this arranged through the US DOE will assist in raising the profile of Quest and emphasize the Leadership demonstrated by Alberta and Canada in support of sustainable development of resources through innovation.

Project challenges for this reporting period included:

- Start up scheduling challenges, resulting in a re-work of the startup plan to commence with HMU 2 as opposed to HMU 3 as originally stated. The change in startup was deemed necessary in order to mitigate impact of loss of hydrogen during an already constrained turnaround period. A revised startup plan was successful developed and implemented.
- Upon testing the emergency shutdown of the compressor, reverse rotation of the motor was noted, with potential to cause damage to the machine. Modifications to compressor design were made and maximum operating pressure was de-rated. The compressor shutdown was successfully re-tested after additional blow-off capacity was added in the latter half of August.
- Attaining stable operation of HMU 3 while capturing CO_2 due to a drop in pressure in the off gases from the Pressure Swing Adsorbers (PSAs) while capturing at full rates resulted

in a low fuel pressure shutdown to the unit. Control modifications to timing were successfully implemented.

- Attaining stable operation of the HMU's reforming furnace temperature control scheme was challenging due to instability induced by the absorption process. This was managed by implementing amine ratio flow control with absorber inlet gas flows and reformer control modifications.

- Foaming of the ADIP-X solution in the HMU absorbers, leading to tray flooding and short duration reductions in CO_2 capture from the HMUs along with an impact to stability in the hydrogen plants themselves. Several actions were taken to mitigate the foaming issue, DCS control schemes were implemented to detect events and take automated action, anti-foam injection was utilized, and system cleanliness has improved with better amine filter change-out procedures, minimizing carbon levels in the system.

- A higher frequency of filter change-outs in the lean amine circuit than expected due to carryover of carbon fines from the carbon filter into the lean amine circuit. A procedural change involving back-flushing procedure to prepare the carbon filter for service will be employed to ensure that it is left with minimal amounts of carbon fines present.

- At low operating pressures on the compressor, there was insufficient pressure to move knock out water into the stripper reflux drum; as such, the second stage compressor knockout water from the reflux drum was re-routed to the amine drain drum. This was required due to hydraulic limitations in the system.

- Poor reliability of the power supply to the Line Break Valve (LBV) stations on the pipeline route was noted post start up due to shading of the solar panel by other equipment. The issue was pronounced at one particular LBV station with several near miss loss of power trips, and one actual event that caused a shutdown of the entire CO_2 pipeline. Interim mitigation measures are in place until a future fix is implemented to address this reliability issue.

- Several landowners were not satisfied with the level of clean-up on their sections of right of way and have requested additional work be done. Shell's Land Agent was engaged to expedite the process for following up on concerns and addressing with either additional work or compensation as needed.

- The above challenges were overcome and Quest has seen strong reliability performance through the fourth quarter of 2015 to safely inject 0.371 Mt of CO_2 by the end of 2015.

Revenue streams generated by Quest will remain twofold: (i) the generation of offset credits for the net CO_2 sequestered and an additional offset credit generated for the CO2 captured, both under the *Specified Gas Emitters Regulation*; and (ii) $298 million in aggregate funding from the Government of Alberta during the first 10 years of Operation for capturing up to 10.8 million tonnes. In 2016, the value of the offset credit will increase to $20/tonne and in 2017, the value will increase to $30/tonne.

Quest will also see some operating efficiencies with the compressor given the more favourable subsurface pore space. Compressor will now operate utilizing 13-15 MW versus 18 MW as full design.

Quest will provide employment for eight permanent full time equivalent positions (FTEs) and an additional approximately 13 FTE incorporated into existing positions. Quest is expected to generate expenditures of up to $44 million per year in staffing, MMV, maintenance, and variable costs to the economy

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Abbreviations

2D	2-Dimensional
3D	3-Dimensional
4D	4-Dimensional
AER	Alberta Energy Regulator
AEW	Alberta Environment and Water
AFN	Alexander First Nation
AGS	Alberta Geological Survey
AOI	Area of Interest
AOSP	Athabasca Oil Sands Project
ARC	Alberta Research Council
ASLB	approved sequestration lease boundary
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*
CSU	Commissioning & Start Up
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
FGR	Flue Gas Recirculation
FID	Final Investment Decision
GHG	greenhouse gases
HBMP	Hydrosphere & Biosphere Monitoring Plan
HMUs	hydrogen manufacturing units
HPLT	High Pressure Low Temperature
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
MSM	Microseismic Monitoring Array
ORM	Opportunity Realization Manual
OSCA	*Oil Sands Conservation Act*
PSA	pressure swing adsorber
RCM	Reliability Centered Maintenance
RFA	Regulatory Framework Assessment
ROW	right-of way
SAP	Systems, Applications, Processes (Equipment Database Software)

SLCN .... Saddle Lake Cree Nation
STCC.......... Shell Technology Centre Calgary
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

1.1 Design Concept

The Athabasca Oil Sands Project (AOSP) is a joint venture operated by Shell and owned by Shell (60%), Chevron Canada Corporation (20%) and Marathon Oil Sands LP (20%) 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 a 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 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. Deliverables for each phase are reviewed to ensure proper quality before proceeding to the next phase.

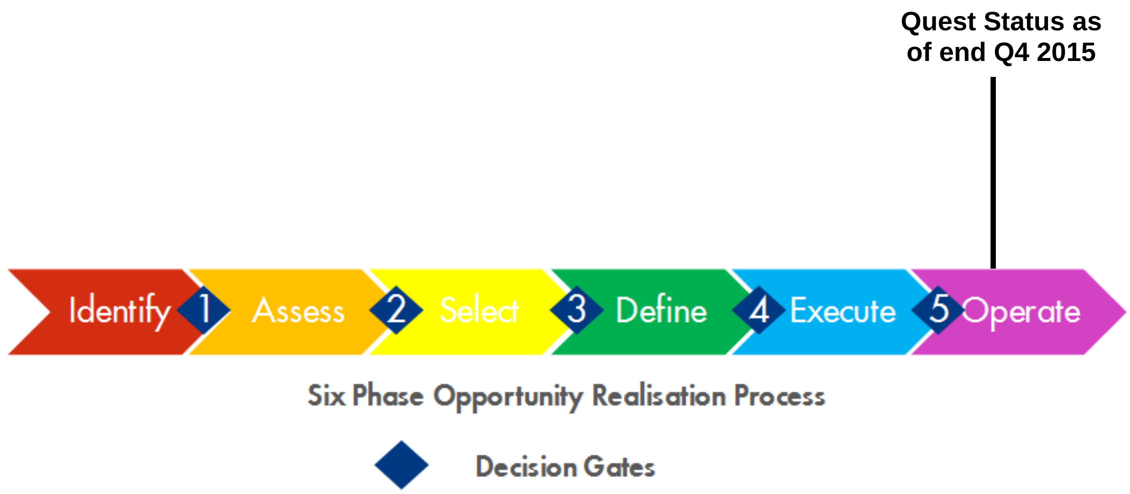


Figure 1-1: ORM Phases with current Project Maturity

Quest technical Project activities in the Define phase in 2011 included the engineering work required to deliver key project documents of this phase, including the Basic Design Engineering Package (BDEP), the Project Execution Plan (PEP) and the Storage Development Plan (SDP).

In September 2011, Shell completed the Define phase, which culminated with the required value assurance review (VAR). The VAR examined the status of the Project, including the Define phase deliverables and concluded that the Project was ready to proceed to the next decision gate.

Under normal circumstances, the Final Investment Decision (FID) follows the successful conclusion of the Define phase prior to moving to the next phase. However, Quest at that point did not have the required project provincial and federal regulatory approvals that the Shell Executive Committee (EC) set as a condition for approving FID. Energy Resources Conservation Board (ERCB) regulatory hearing dates expected in November in 2011 were scheduled for March 2012 delaying the possible approval date. 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. After receipt of the ERCB Decision Report, the Shell Executive Committee, followed by the Joint Venture partners, approved the FID of the Project in the summer of 2012. After formal receipt of the various regulatory approvals, the formal announcement of FID was made in early September.

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 was conducted in 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 recommendations to Quest for continued success; the Project team completed all recommendations. PER3 was conducted in 2014 and focused on the status of the Project as it proceeded towards the commissioning and startup phase; again recommendations were made and the Project team completed all recommendations.

The Project technical activities in 2012 correspond with the Execute Phase. This included the detailed engineering work required to deliver 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.

The Project technical activities in 2013 also correspond with the Execute Phase. This included 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.

The Project technical activities in 2014 also correspond with the Execute Phase, specifically the construction of the pipeline and wellsites, the fabrication of modules, the installation of modules at Scotford, and stick-built construction at Scotford.

The Execute Phase concluded in 2015 after the mechanical completion of the facilities in February of 2015, followed by a successful commissioning and startup, completion of the commercial sustainable operating tests, and subsequently handed over to Shell Scotford for sustained operations on October 1, 2015.

The Operate Phase of the project officially commenced in Q3 of 2015, and the Shell Scotford operations group successfully captured and injected 0.371 Mt of CO_2 in the 7-11 and 8-19 injection wells.

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: Capture Unit Location Schematic* for a schematic view of the capture unit location.

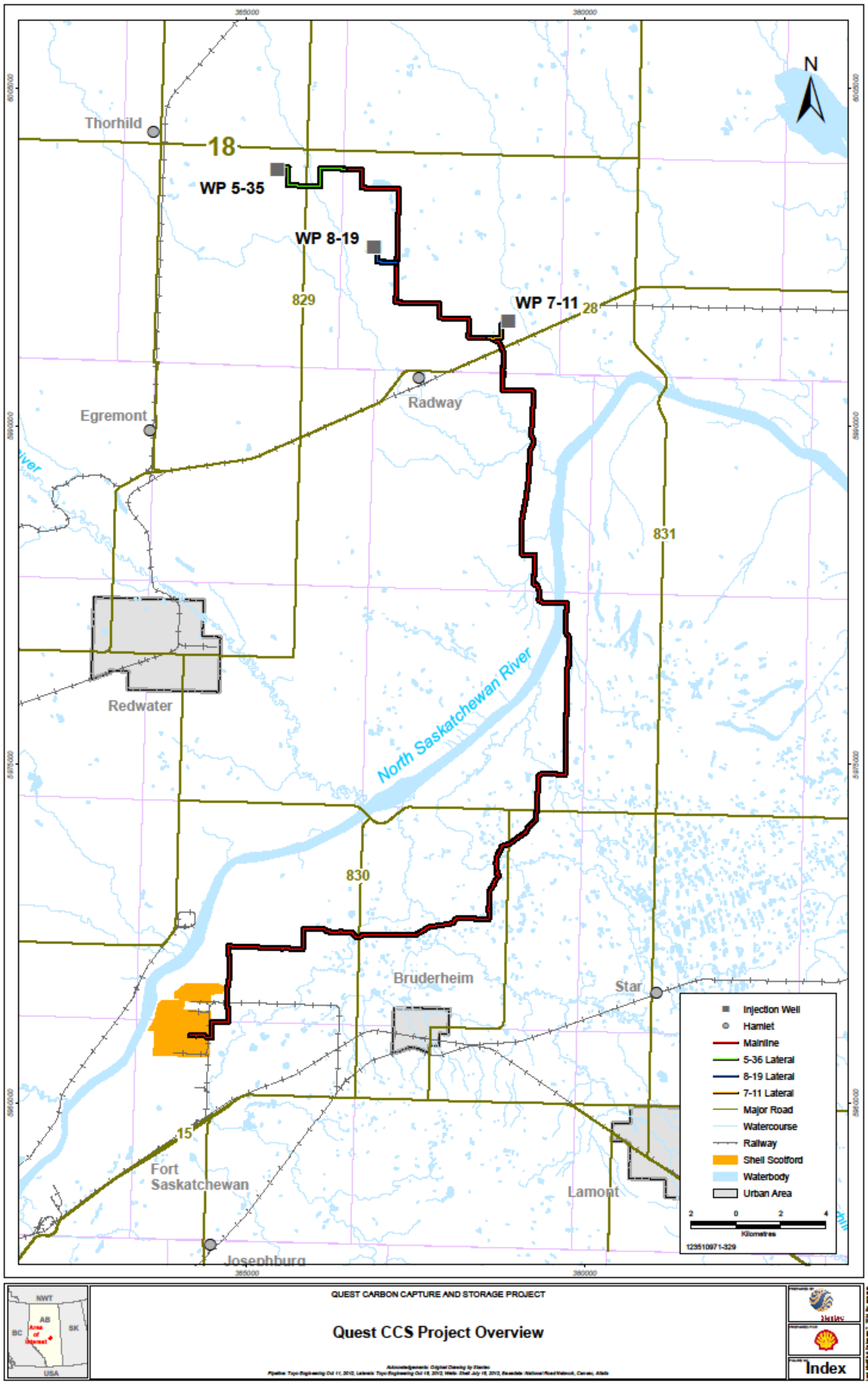


Figure 1-2: Project Facility Locations

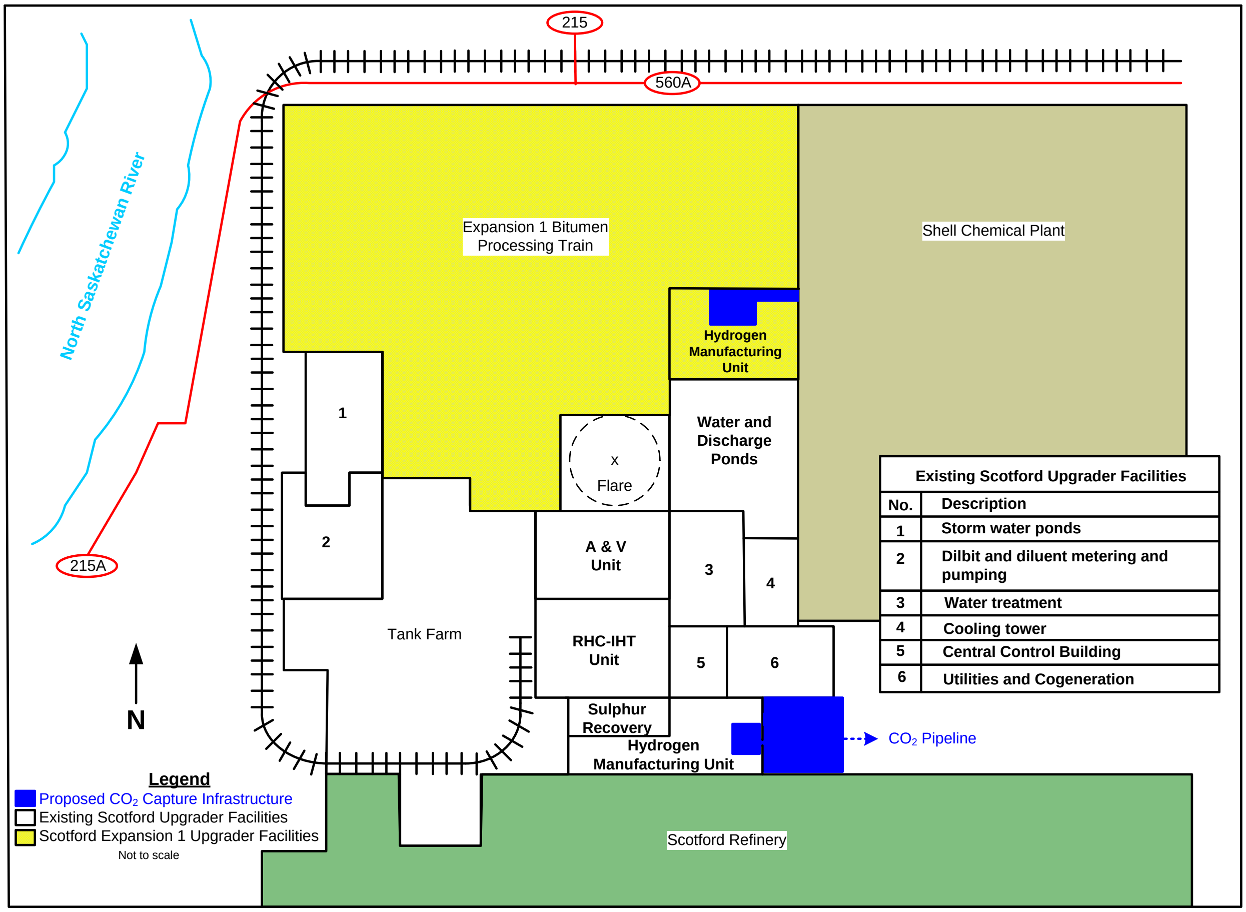


Figure 1-3: Capture Unit Location Schematic

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.

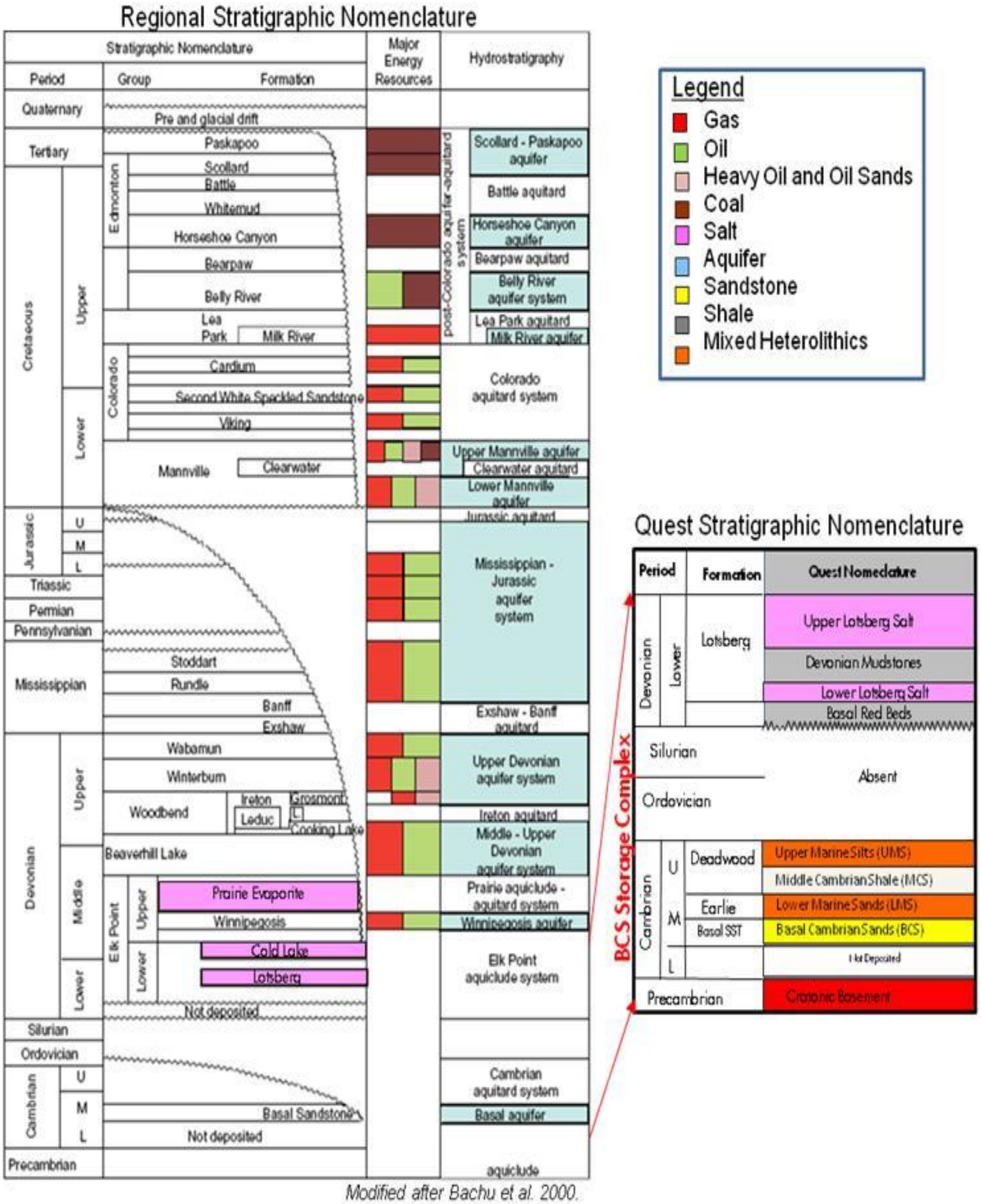


Figure 1-4: BCS Storage Complex within the Regional Stratigraph

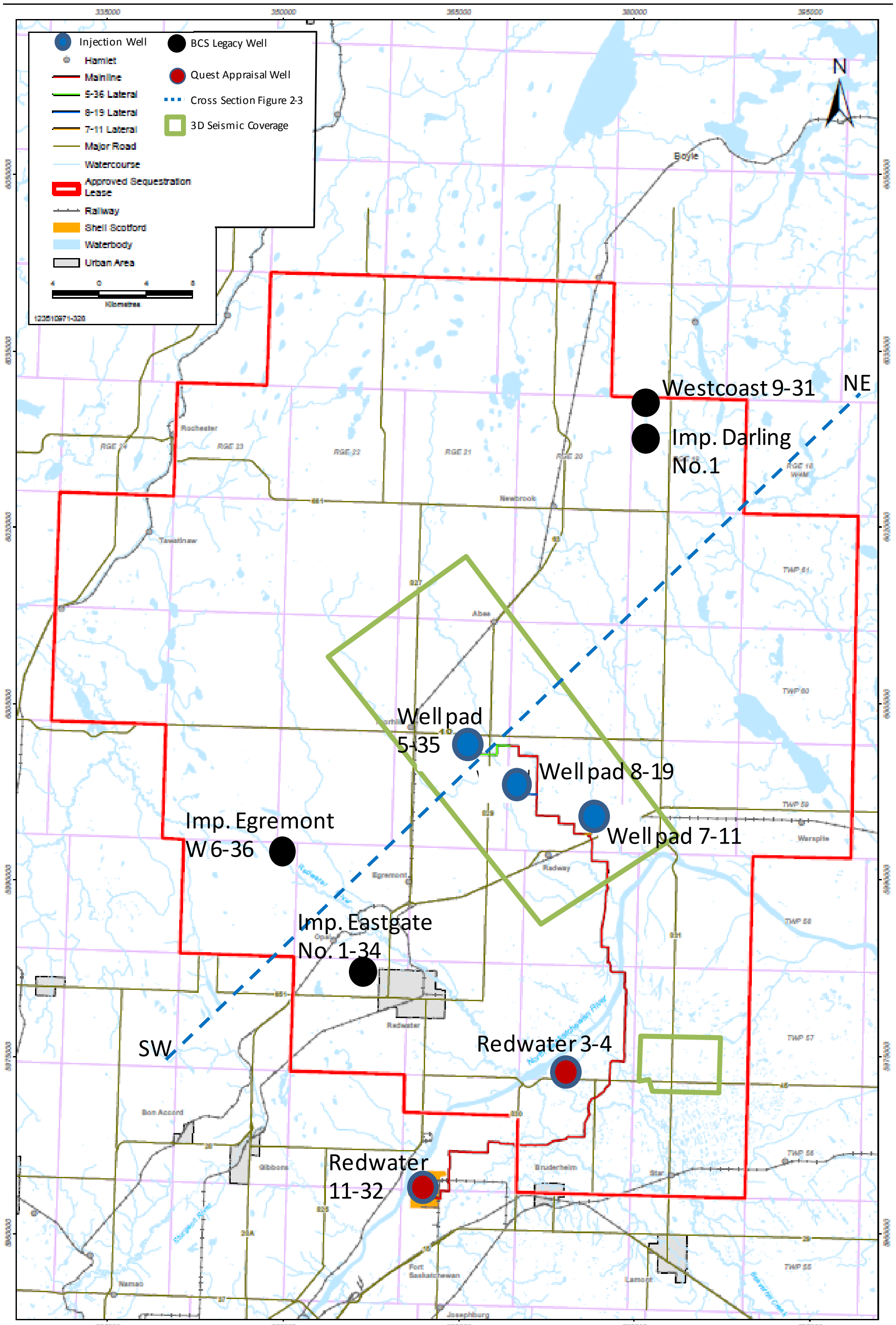


Figure 1-5: Project Components and Sequestration Lease Area

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 is 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.*

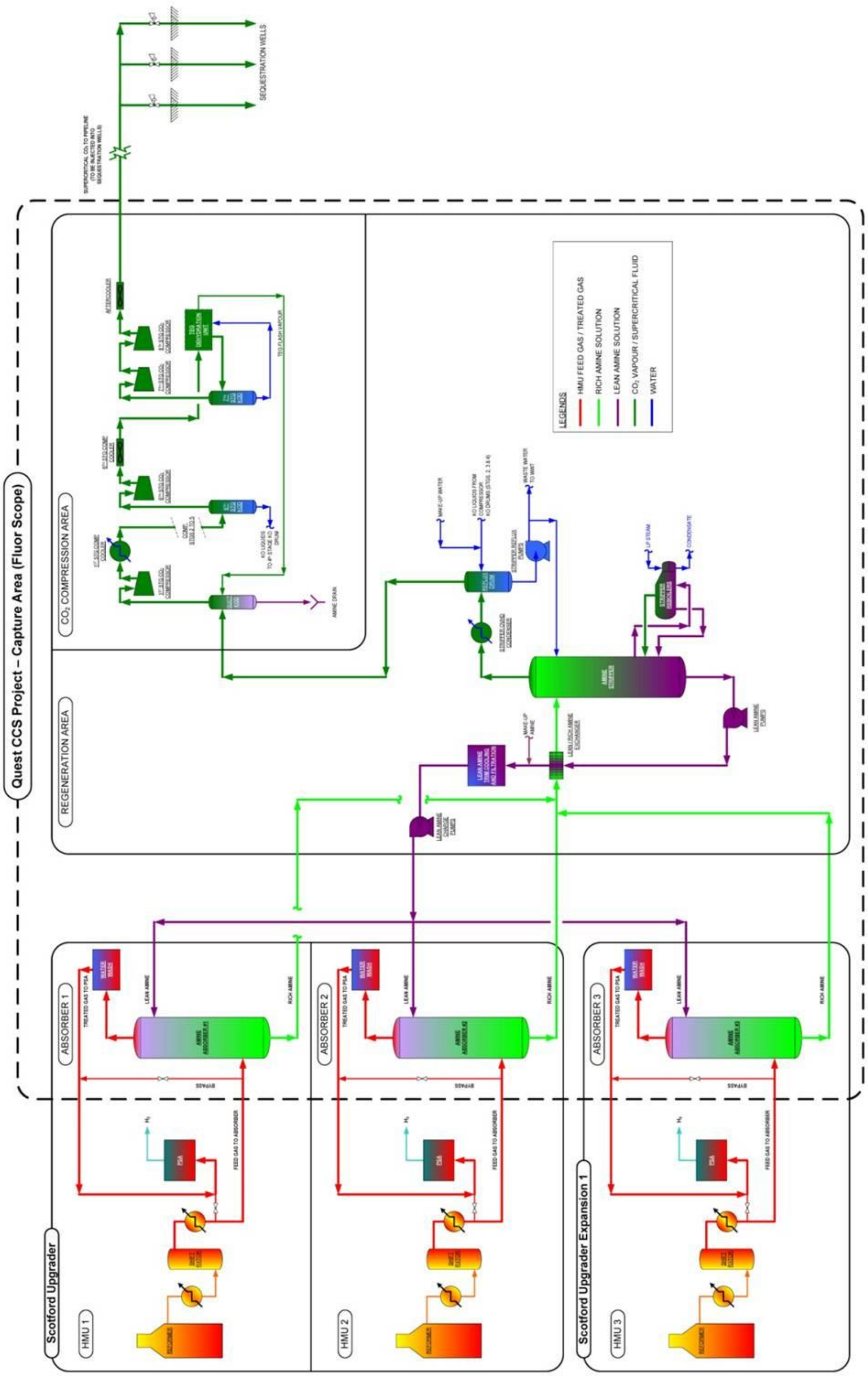


Figure 1-6: Capture and Compression Process Design

Process Description

CO_2 Absorption Section

Quest captures carbon dioxide from the hydrogen-manufacturing units (HMU). In the HMUs, light gas (e.g. natural gas) and steam are reacted in a steam methane reformer (SMR) to form pure hydrogen and carbon dioxide. The impurities are removed in pressure swing adsorbers (PSA) and the pure hydrogen is sent on to the residue hydro conversion unit. The capture process removes the carbon dioxide between the SMR and the PSA.

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 absorber 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, with the bulk of the heat generated within the absorber 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. Warm water is pumped from the bottom of the vessel and cooled 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 protecting the downstream PSA unit adsorbent 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 feed-forward flow from the rich amine stream entering the stripper and is trim-controlled by a from the overhead vapour temperature 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 flow is varied to control level in the reflux drum, and the purge of excess water to wastewater treatment is managed via flow control.

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 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 in shell and tube lean amine exchangers. The lean amine is cooled to its 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 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 a polyglycol –based anti-foam to the amine absorbers and amine stripper. 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.

Amine Storage

The total circulating volume of amine is 315 m^3. 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 is blended off-site and provided by an amine supplier. The amine storage tanks are also 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 total amine inventory. 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 is also be used to charge the system during start-up.

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

Compression

The CO_2 from amine regeneration is routed to the compressor suction by way of the compressor suction knock out (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(gauge).

Cooling and separation facilities are provided on the discharge of the first six 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 9,000 kPa(g) to 11,000 kPa(g), resulting in a dense-phase fluid. The CO_2 compressor is currently able to provide a discharge pressure as high as 11,500 kPag, reduced from 14,000 kPag initially due to issues identified during commissioning and startup with reverse rotation of the compressor on shutdown.. The dense-phase CO_2 is cooled in the compressor discharge cooler to roughly 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, 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 was estimated that 27 ppmw of TEG will escape with CO_2. Operation to date indicates that the number is actually < 5 ppmw. The dehydrated CO_2 is analyzed for moisture and composition at the outlet of the TEG unit.

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.

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

CO_2 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. The module assembly was completed and all modules were transported to site by mid July 2014.

2 Facility Construction Schedule

Construction reached mechanical completion on February 10, 2015 with all A and B deficiencies, required for commissioning and startup respectively, completed on all systems. On February 20th, all the C deficiencies, required after startup,) were completed and Fluor, EPC contractor, demobilized by the end of February. In mid-April, the project, Site Commissioning and Start Up (CSU) team and Site Upgrader management signed off on the first phase of Project to Asset handover, signaling that the new facilities were ready for startup. The 2015 Upgrader turnaround started in April facilitating completion of the Quest scope by mid-May. Scope items included the HMU 1 and common process ties, HMU 1 burner change out and FGR tie ins, and HMU 1 PSA catalyst change out. Upon completion of the turnaround, the CSU team began executing their start up plan. The construction engineering team continued to support the CSU team throughout the startup and commercial operations tests. See Figure 2-1 for the actual construction schedule. Refer to Section 12 for further information on start up and commissioning.

Section 0: Construction reached mechanical completion on February 10, 2015 with all A and B deficiencies, required for commissioning and startup respectively, completed on all systems. On February 20th, all the C deficiencies, required after startup,) were complete

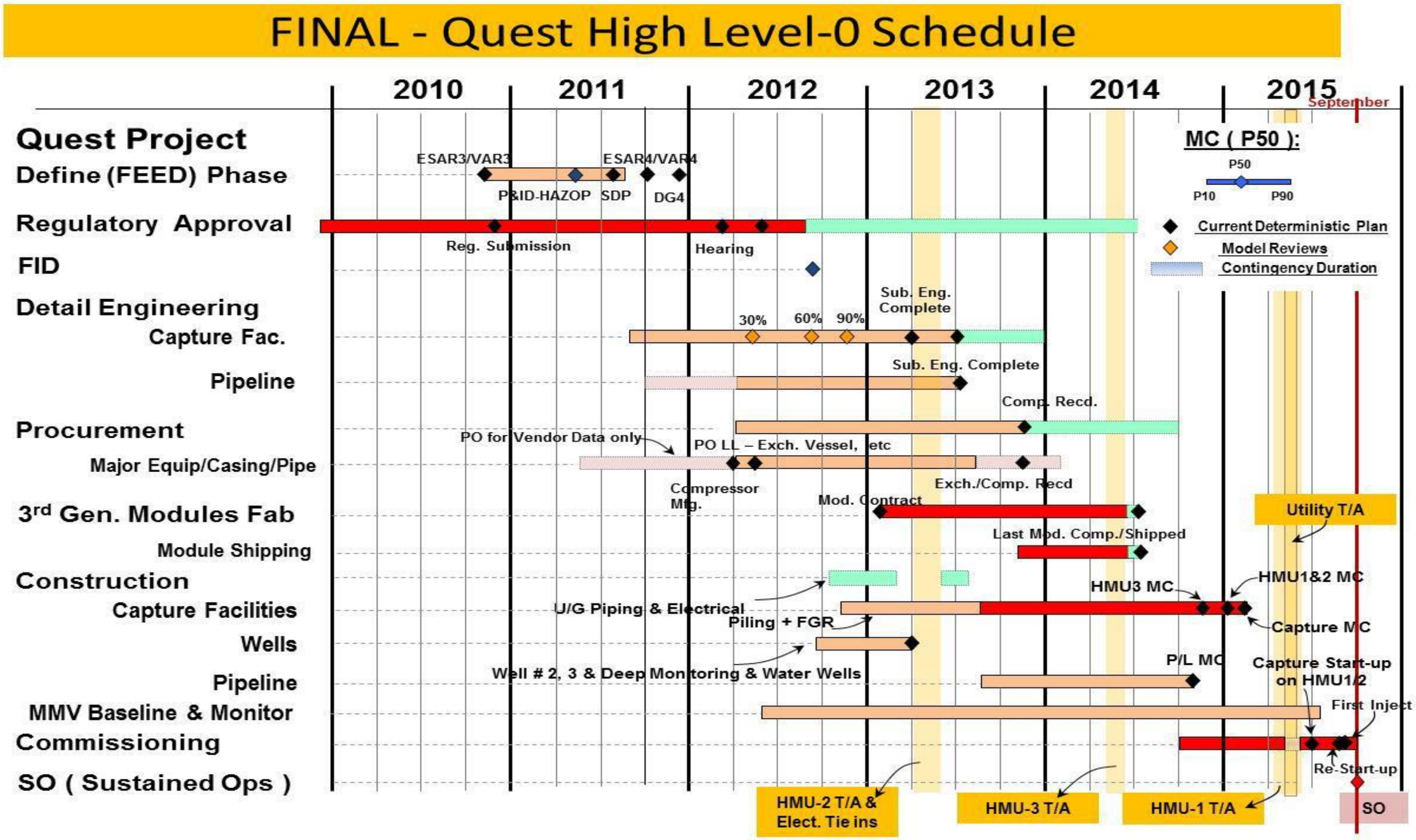


Figure 2-1: Project Construction Schedule

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. One set of and those criteria in Table 3-1 shows the properties of the Basal Cambrian Sands (BCS) are compared with storage area selection criteria for CCS projects was developed by the Alberta Research Council (ARC).

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, in May 2011, 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 CO_2 Storage

Criterion Level	No	Criterion	Unfavourable	Preferred or Favourable	BCS Storage Complex
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)	Three major seals (Middle Cambrian Shale [MCS], Lower Lotsberg and Upper Lotsberg Salts) continuous over 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
	15	Porosity	<10%	≥10%	16%

Criterion Level	No	Criterion	Unfavourable	Preferred or Favourable	BCS Storage Complex
Desirable (cont'd)	16	Permeability	<20 mD	≥20 mD	Average over the SLA 20-1000 mD
	17	Cap rock thickness	<10 m	≥10 m	Three cap rocks: MCS 21 m to 75 m L. Lotsberg Salt 9 m to 41 m 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 3-1* (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.

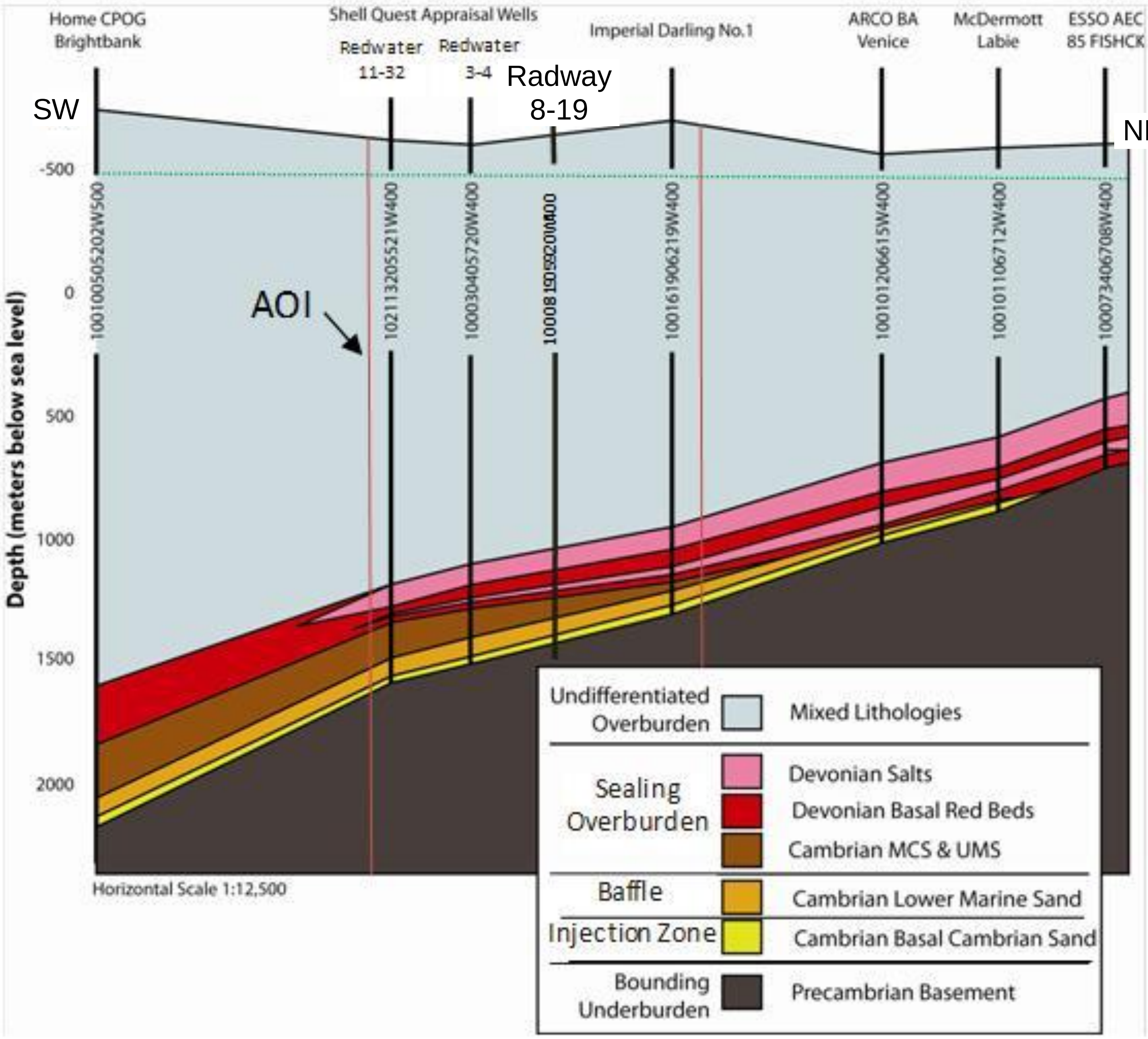


Figure 3-1: Cross-Section of the WCSB Showing the BCS Storage Complex

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 3-2 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.

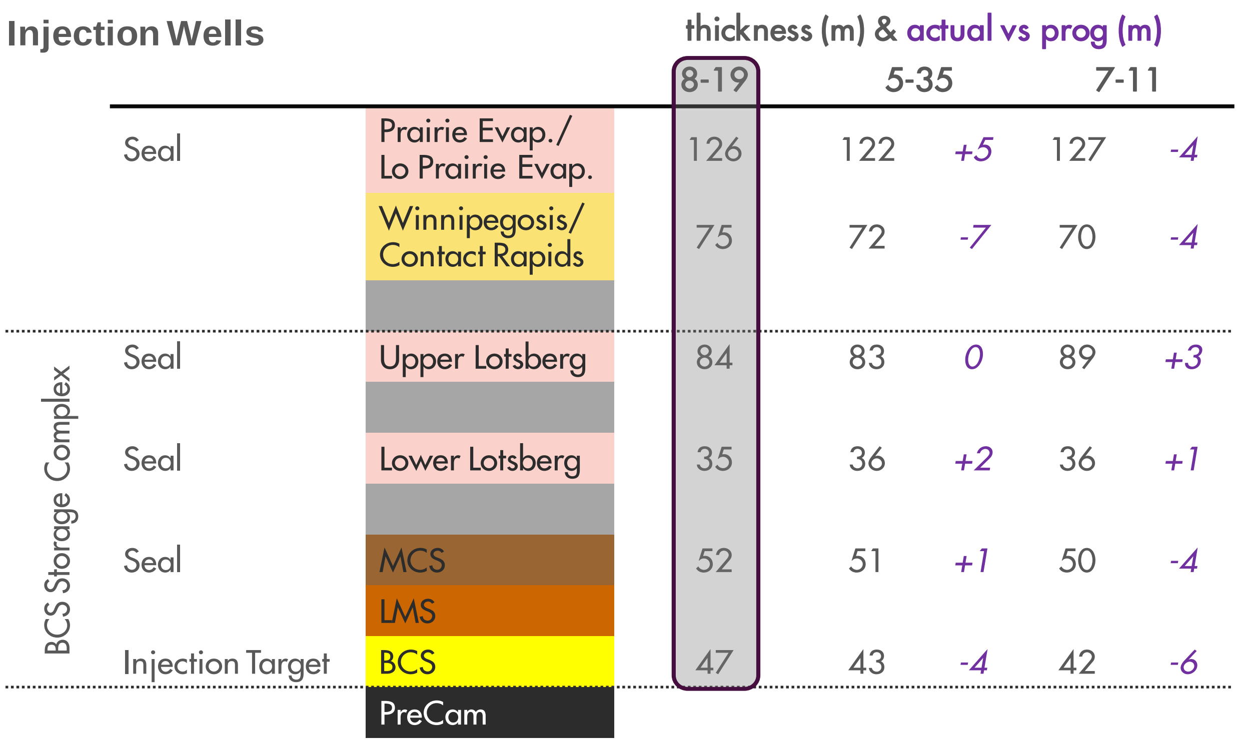


Figure 3-2: Summary of zone thicknesses for Quest Sequestration rights interval

With regards to the BCS reservoir properties, Good agreement was observed between core analyses and log data of BCS reservoir properties as seen in *Figure 3-3*.

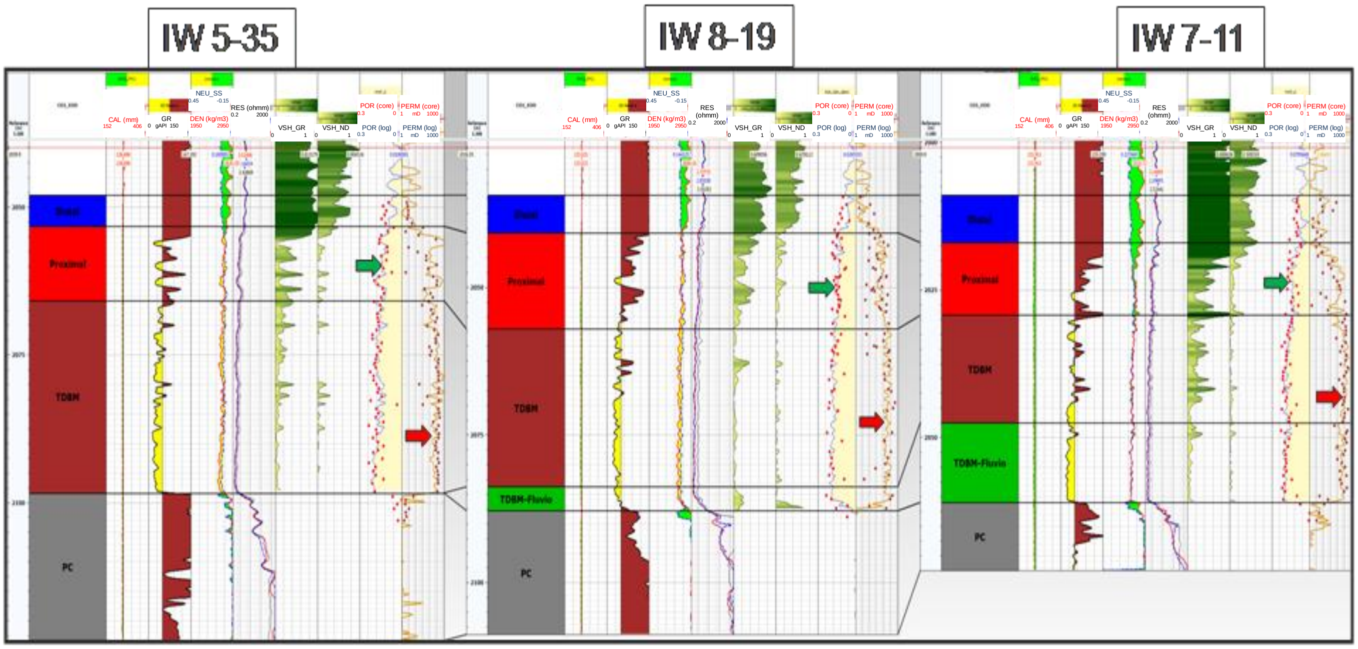


Figure 3-3: BCS Reservoir Properties Comparison of log response over the BCS formation and the corresponding core analysis results in all three injection wells. The green arrows are pointing to the porosity track, very good correspondence between the core porosity and log porosity. The red arrows are 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 also observed in 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 3-4.*

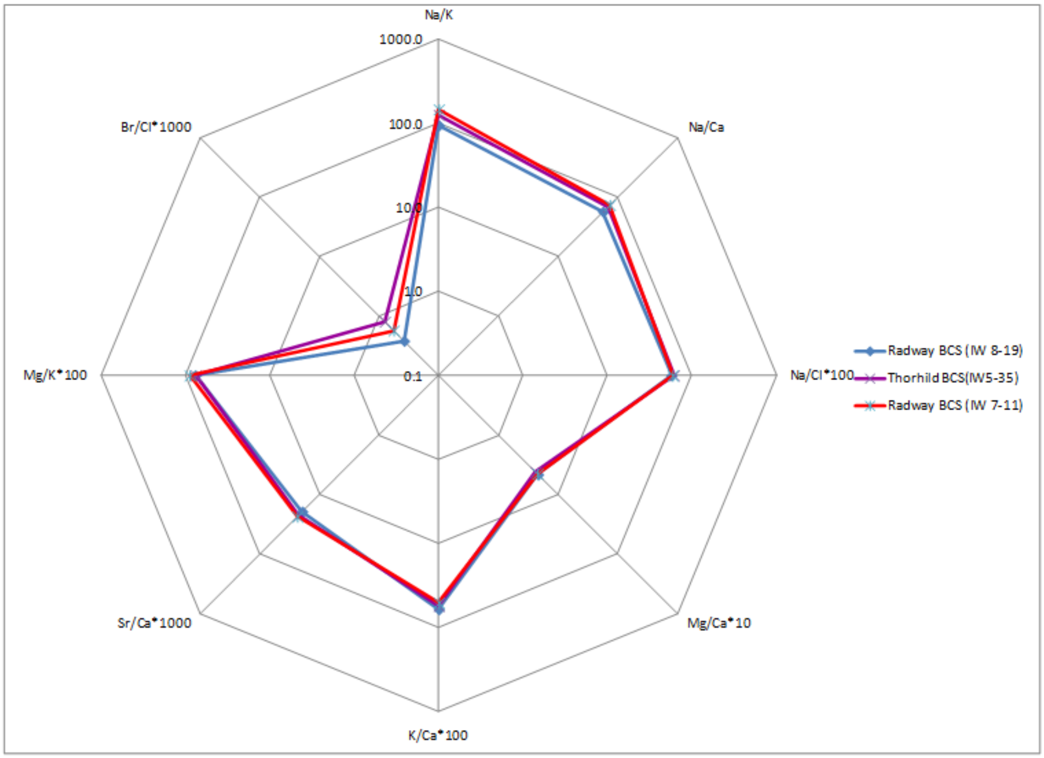


Figure 3-4: Ion Ration plot of BCS Formation brine waters from IW 8-19 (sampled in 2010), IW 5-35 (sampled in 2012) and IW 7-11 (sampled in 2013).

3.4 Estimate of Storage Potential and Dynamic Model Updates

The uncertainty in the capacity of the storage area, the BCS storage complex, has been further reduced post injection. There is continued strong evidence to support the assessment of BCS having more than sufficient capacity to store the required volume for 25 MT of CO_2 over the life of this project. The residual uncertainty in pore volume is unlikely to decrease much further until several years of injection performance data is attained that maybe used to calibrate the existing reservoir models.

Gen-5 static and dynamic reservoir models were presented in the Third Annual Status Report to the AER. The results indicate that the pressure build-up in the BCS is expected to be less than 2 MPa of differential pressure (DeltaP) at the injection wells by the end of the project life. This pressure increase of less than 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).

Figure 3.6 illustrates that actual pressure build up in the reservoir to date (solid lines) has been less than the predicted expectation case (dashed lines); note that no injection is taking place at IW 5-35 yet, but reservoir pressure is being monitored.. This provides convincing evidence that the actual reservoir properties are better than the previous expectation case. This in turn means that the associated injection pressures over the life of the project will be less than previously expected. **Therefore, the likelihood of fracturing or CO_2 leakage has been further reduced to very negligible levels.**

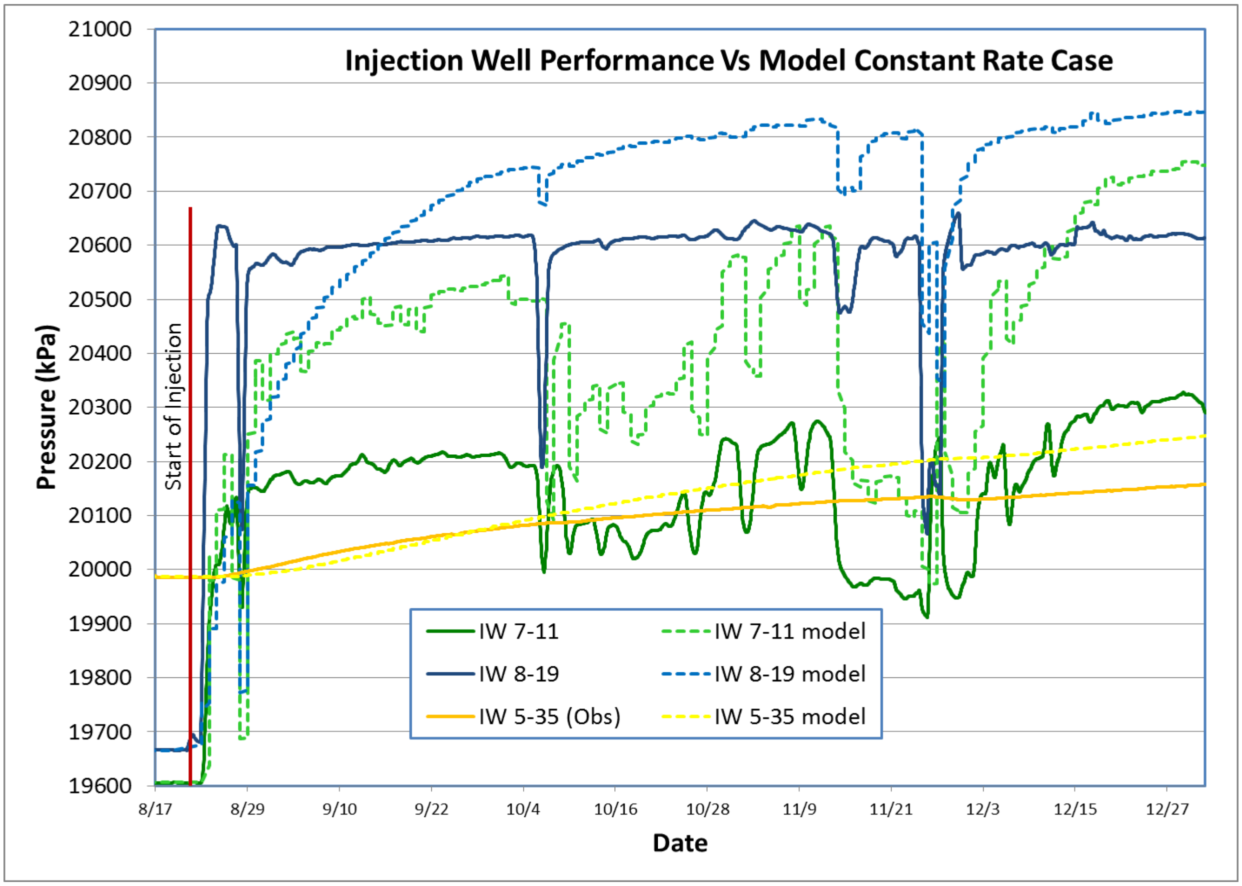


Figure 3-6: Actual Reservoir Pressure Response Vs Modeled Pressure Response

3.5 Initial Injectivity Assessment

The project was designed for a maximum injection rate of about 145 t/hr into three wells. Between August and December of 2015, injection rates have been up to 140 t/hr into two injection wells, the 8-19 and 7-11 wells. The 8-19 well has been injecting consistently at 70 t/hr over this time period with very little pressure build up (as illustrated by the solid blue line in Figure 3-6). Within the acceptable pressure tolerance of the system, it is quite likely the third well, 5-35, will not be needed to meet injectivity requirements.

It is therefore expected that the project will be capable of sustaining adequate injectivity 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 31st January 2015 (AER 2015: Appendix A). Each are considered very unlikely but are, in principle, capable of allowing CO_2 or BCS brine to migrate upwards out of the BCS storage complex.

Evaluation of data from the 2012 – 2013 drilling campaign and the most recent GEN -5 modeling of the BCS has confirmed that the pressure increase in the BCS will not reach a level sufficient to lift BCS brine to the BGWP (Base Groundwater Protection) zone even at the injection wells (AER, 2015, Section 5.3.1). Therefore, there is no perceived risk of brine leakage impacting groundwater unless there is a severe loss of containment. BCS pressure monitoring will be utilized to ascertain if there is a loss of containment that would give rise to a potential threat related to brine leakage far in advance of any impact above the storage complex. At that time, MMV plans would be updated appropriately.

Even if there was sufficient pressure, dynamic leak path modeling indicates that due to the pressure depletion of the Cooking Lake Formation, as well as flow into other deep aquifers, BCS brine cannot reach the BGWP zone unless it flows along an open migration pathway unconnected to the Cooking Lake Aquifer.

4 Facility Operations – Capture Facilities

4.1 Operating Summary

The Quest CCS project focus for 2015 was to complete commissioning and startup activities for the Quest capture, pipeline and wells systems, and handover the project to the Scotford operations team. Commercial operation for the integrated project from capture unit to wells was achieved in September 2015, and handover to Scotford Operations occurred in Q4 2015. Table 4-1 outlines the performance summary of the capture unit in 2015. A discussion of the summary results can be found in the subsequent unit discussions.

Table 4-1 Quest Operating Summary 2015

Quest Operating Summary	2015 Summary	Units
Total CO_2 Injected	0.371	Mt CO_2
CO_2 Capture Ratio	77.4	%
CO_2 Emissions from Capture, Transport and Storage	0.057	Mt CO_2
Net Amount (CO_2 Avoided)	0.314	Mt CO_2

2015 began with continued commissioning and startup related activities through Q1 and into Q2 2015. Handover of process systems from the project construction team to CSU operations for the capture/dehydration/compression units was 100% complete in early Q2.

Startup of the amine unit was conducted in late May 2015 following the Upgrader - turnaround when the HMUs were onstream and producing raw hydrogen for CO_2 removal. The following is a timeline of significant operational milestones in 2015:

- Q1 2015 – System commissioning and cleaning activities, amine/TEG first fills
- April 10-May 20: Upgrader Turnaround – final HMU tie-ins complete, utility systems and power unavailable intermittently
- May 23, 2015: HMU2 Routes Raw H2 to Absorber. Amine unit in operation and venting CO_2 through the stack on the Quest plot
- May 25, 2015: HMU2 Reliability Testing with Absorber online
- May 26, 2015: HMU3 Routes Raw H2 to Absorber
- May 28, 2015: CO_2 Compressor Starts for the first time – reverse rotation noted on shutdown
- May 28, 2015: HMU1 Routes Raw H2 to Absorber
- July 9, 2015 – Capture unit shutdown for CO_2 compressor modifications to resolve reverse rotation on shutdown
- August 13, 2015: Capture unit re-start in preparation for compressor start
- August 15 – 16, 2015: CO_2 Compressor re-start and shutdown testing

- August 18, 2015 Dehydration unit startup and compressor restart after testing completed successfully
- August 19-22, 2015 Pipeline first fill and pressure up
- August 23, 2015 First injection into 7-11 and 8-19 injection wells
- September 4, 2015: Performance Test A, Capacity test completed
    - 3094 tonnes of CO_2 were injected vs. 2960 tonnes required over 24 hours
- August 31 – September 20: Performance Test B, 20 day capture efficiency test completed
    - 20 days of continuous operation was achieved with an average capture ratio of 81% vs. 75% required. Injection during the period averaged 3115 tonnes/day with a CO_2 composition of >95% and CO_2 water content < 168 ppmv.
- August 29–September 28: Performance Test C, 30 day integrated reliability test completed, commercial operation achieved.
    - 30 days of continuous integrated operation (capture, transport, storage) was achieved at a throughput of 3122 tonne/day vs. 888 tonne/day required.
- November 2015: handover to Scotford Operations

4.2 Capture (Absorbers and Regeneration)

The capture unit cleaning was conducted using a series of hot steam condensate flushes and filtered circulation, removing particulates with mesh screens and filters. This included all equipment and piping in the amine circuit to minimize any potential post-startup foaming issues.

A successful startup of the amine unit was achieved in the final week of May, confirming that the Quest amine unit utilizing the Shell ADIP-X formulation was able to meet the design intent of removing approximately 80% of the CO_2 in the raw hydrogen stream from the Upgrader HMUs on a regular basis during the period. During this period, lean amine circulated through the absorbers to remove CO_2 from the raw hydrogen stream, and rich amine was circulating back to the CO_2 stripper to regenerate the amine. Stripped CO_2 from the amine regenerator (CO_2 stripper) was routed to the CO_2 vent stack during amine unit testing while commissioning and startup activities were progressing on the compression and dehydration units.

Solvent composition was on target for the majority of 2015 operation vs. the specified formulation for ADIP-X from the design phase, and CO_2 removal ratio performance has been as predicted. The annual CO_2 capture ratio was 77.4% for the period. The main contributors to periods of reduced CO_2 capture were as follows:

- Ramp up during August after initial injection (operation was in the 50-70% capture ratio range)
- Quest outage on October 6th for compressor anti-surge valve repairs
- Quest outage on November 24-25 due to the pipeline trip for LBV3 power issues. Capture ratio during outages is zero for the duration of the outage.

- Reduced CO_2 capture ratio during a period of low hydrogen demand at the Upgrader/Refinery in November 2015. Fuel gas pressure in the HMUs limits CO_2 capture ratio during these periods.

The CO_2 stripper operation has been extremely stable, and the CO_2 product sent to the compression unit has been on target for purity at all times. Performance has been as expected in terms of solvent regeneration. Table 5-3 in the transport section contains the average CO_2 product composition from the capture and dehydration units. Table 4-2 provides a summary of the utility and energy sources consumed during the injecting period in 2015.

Table 4-2 Energy and Utilities Consumption (Capture, Dehydration)

Energy and Utilities	**2015 Usage**	**Units**
Electricity (Capture/Dehydration)	12300	MWh_e
Low Pressure Steam	410	kT
Low Temperature High Pressure Steam	1.96	kT
Nitrogen	178	ksm^3
Wastewater	24900	m^3
Energy/Heat Recovered	33600	MWh_{th}[1]
CO_2 Emissions for the Capture Process	0.030	Mt CO_2

Electricity, steam, and water use are all approximately on target with design specifications when pro-rated for actual CO_2 throughput. Nitrogen use is significantly lower than expected due to optimizations made in the dehydration unit. Nitrogen stripping gas flow to the TEG stripper was reduced to avoid over-processing the TEG. The operations team targeted approximately 60 ppmv water content to the pipeline, staying within the 84 ppmv spec. Heat recovery in the demin water heaters (cooling the CO_2 stripper reboiler steam condensate) is also approximately on target from design.

A success story for the Quest unit operation to-date has been the low levels of chemical loss from the ADIP-x process. Amine losses from the capture unit reduced to negligible after the initial commissioning/inventory and startup phases. No fresh amine makeup was required from the storage tanks to the amine circuit during the 4th quarter, while circulating amine composition stayed on target.

CO_2 emissions for the capture process are primarily from low pressure steam use in the CO_2 stripper reboilers (65% of total capture emissions), and electricity for equipment in the capture system (26% of capture emissions).

The most significant operational issue observed has been foaming of the ADIP-X solution in the HMU absorbers, leading to tray flooding and short duration reduction in CO_2 capture from the HMUs, with a small impact to stability in the hydrogen plants themselves. The most severe event resulted in significant carryover of amine to the HMU1/2 PSAs. The cause has been attributed to several initiating factors: rapid changes in gas flows to the absorbers, carbon fines entrainment in the system, high gas rates to the absorbers and general system impurities.

[1] e subscript denotes electrical energy, th subscript denotes thermal energy

To mitigate the foaming/flooding issue, DCS control schemes were implemented to manage periods of high absorber feed gas rates and high tray pressure drop (indication of a foaming/flooding event) to automatically initiate a partial bypass of raw hydrogen gas around the absorber to alleviate the foaming/flooding issue in the absorber trayed section. The operations team has learned to manage the events with the use of anti-foam injection when proactively observing the onset of foaming. System cleanliness has also improved with better amine filter change-out procedures, minimizing carbon levels in the system.

One nuisance issue observed is the frequency of filter change-outs in the lean amine circuit. This has been attributed to carryover of carbon fines from the carbon filter into the lean amine circuit. As a learning for future change-outs of the carbon filter media, a back-flushing procedure to prepare the carbon filter for service will be employed to ensure that it is left with minimal amounts of carbon fines present.

4.3 Compression

System cleaning of the compression unit was conducted using high pressure nitrogen blows.

The startup of the compressor proceeded without major issues, but the initial shutdown of the machine resulted in rapid deceleration of the motor and reverse rotation up to 500 rpm. No damage to the machine was noted. As this was considered a high potential risk for future shutdowns, an engineering study was undertaken to evaluate what modifications would be required. The solution defined was to add additional blow-off capacity to the compressor's 4^{th}, 5^{th} and 6^{th} stages, as these stages were not depressuring fast enough on a shutdown of the compressor. This was occurring due to the large volume of compressed CO_2 in the piping and knockout vessels, resulting in a "braking" force on the compressor impeller blades when the driving force was no longer active. Details of the change can be found in section 1.3 of the detailed report.

Modifications occurred in July and August, and a restart of the compressor and subsequent testing occurred August 15-16. Operating pressures up to 12 MPag were deemed safe, but pressures above this still resulted in reverse rotation of the motor on a shutdown, so the maximum operating pressure was de-rated, and the automated shutdown of the compressor was changed from 14 MPag to 12 MPag. Engineering was completed in 2015 to specify a long term solution for the compressor to bring its discharge pressure capabilities back to 14 MPag.

The compressor operated at low discharge pressures during most of 2015, as the operating strategy was to minimize pipeline pressure within system constraints to reduce compression electricity demand. Table 4-3 below outlines the average operating conditions for the reporting period.

Table 4-3: Typical Compressor Operating Data

Compressor Characteristic	Average 2015 Operation	Units
Suction Pressure	0.03	MPag
Discharge Pressure	9.6	MPag
Motor Electricity Demand	13.3	MW_e

The surge line was re-tested in October 2015, and resulted in a shift of the line to lower flow rates, allowing the machine to operate with less anti-surge (recycle) flow during periods of reduced CO_2 throughput, and thus less electrical demand.

The other significant change to the process design in the compression unit was re-routing the 2nd stage compressor knock-out water from the reflux drum to the amine drain drum. This was required due to hydraulic limitations in the system. At low operating pressures on the compressor, there was not enough pressure to push the knockout water into the stripper reflux drum.

4.4 Dehydration

System cleaning of the dehydration unit was conducted similar to the amine unit, using a hot steam condensate circulation/filtration and flush arrangement.

The dehydration unit performance exceeded expectations. The system requirement was to meet the winter water content specification for the pipeline of 84 ppmv. Actual water content for 2015 was on average 46 ppmv, and this was achieved at a lower TEG purity than design (99.5% vs. 99.7%). Meeting the specification at a lower purity resulted in the nitrogen stripping gas optimization opportunity described in section 4.2.

Carryover of TEG into the CO_2 stream also appears to be significantly less than design, with the estimated losses being <5ppmw of the total CO_2 injection stream, compared to the 27 ppmw expected in design. Dehydration unit losses of TEG are on track to be roughly 6,000 kg annually vs. the design makeup rate of 46,000 kg annually.

4.5 Upgrader Hydrogen Manufacturing Units

The addition of CO_2 removal within the hydrogen plant upstream of the PSA has proven to be successful, but only after a few control system modifications. After initial startup of the absorbers within the hydrogen plant circuits, the immediate observation was that automated control of reformer firing and process temperature was very poor when compared to pre-Quest operation. Temperature oscillations within the units were exaggerated to the point of several near-miss unit trips, with one actual unit trip during system testing on HMU3 due to high reformer outlet temperature. The issues were rectified by a combination of control system changes:

- Amine flow control to each individual absorber was automated via ratio control with the raw hydrogen gas flow to each absorber to maintain a constant gas composition feeding the PSA. This was important because hydrogen plant rates change based on consumer hydrogen demand frequently.
- Steam methane reformer firing control tuning, and implementation of aggressive feed-forward control of reformer fuel makeup rate using PSA tail gas and natural gas flow and heating value information.

The implementation of FGR (flue gas recirculation) technology, in combination with the installation of low-NOx burners has allowed all 3 HMUs to meet their NOx level commitments without contravention in 2015 while operating with Quest online. Operation of the FGR has been by direct flow control to achieve the desired NOx level. Installed capacity of the FGR allows operation within a wide range of NOx generation levels, so the system has been operated to maximize furnace efficiency (low FGR flow), while ensuring that enough FGR flow is routed to the burners to maintain NOx levels close to baseline pre-Quest. Normal NOx emissions with Quest operational and FGR online has been in the range of:

HMU1: 30 - 40 kg/h, limit 76.5 kg/h
HMU2: 25 - 35 kg/h, limit 76.5 kg/h
HMU3: 35 - 55 kg/h, limit 130 kg/h

When the FGR fan trips, NOx levels are below the new limits listed above, but exceed the old limits, pre-Quest, if the CO_2 capture ratio is not reduced.

One of the most significant differences in operation of the HMUs after CO_2 capture is a reduction in reformer fuel gas pressure. Fuel gas pressure reduces as increasing amounts of CO_2 are removed from the raw hydrogen stream, in turn reducing the volume of tail gas generated in the PSA for use as reformer fuel. Low fuel gas pressure was a limiting factor for increased CO_2 capture ratio when the HMUs went into production turndown because of reductions in hydrogen demand at the Upgrader.

The flame pattern inside the reforming furnace did appear to be influenced by increased CO_2 capture rates (i.e. a change in fuel gas composition), resulting in a looser flame pattern when compared to non-Quest operation earlier in 2015. This has not proven to be a significant issue.

Hydrogen production losses due to hydrogen entrainment in the amine absorbers have been low, at roughly 0.1% loss of total hydrogen production. This is indicated by the roughly 0.5vol% hydrogen content in the CO_2 stream sent to the pipeline.

Reliability tests were conducted on the first of the three HMUs brought online in May. The tests were conducted to evaluate the impact of unit upsets in the Quest amine circuit on the stability of hydrogen production from the HMUs due to the potential for severe production consequences associated with a loss of hydrogen in the RHC units at the Upgrader. The three tests conducted were: a) rapid opening of the absorber bypass valve, b) loss of amine flow to the absorber, and c) trip of the FGR fan. The results were very promising and provided the control systems personnel with information to modify control loops to better respond to the upsets. Tests a and b resulted in short periods of instability in the hydrogen plants (<30 minutes), but hydrogen production was maintained for the duration of the upset. Test c (FGR fan trip) resulted in a negligible impact to hydrogen plant operation, but resulted in a significant rise in NOx emissions, but below current environmental limits.

The Upgrader HMUs have been relatively unaffected from a reliability perspective with the addition of CO_2 capture facilities. From an efficiency perspective, the hydrogen production capability of the units remains largely unchanged with the addition of the

Quest CO_2 removal mode. The loss of hydrogen via entrainment in the CO_2 absorbers and into the Quest pipeline meets design expectations and there is a negligible drop in overall hydrogen production capacities. Preliminary information available is showing a marginal improvement in fuel efficiency in the reformers as a result of removing CO_2 from the reformer burner fuel. Removing this heat sink in the burner reduces the amount of natural gas required to fuel the reforming reaction. Flue gas recirculation addition to the reformer combustion air stream is running below design expectations. While the addition of the flue gas recirculation results in fuel efficiency improvements in the reformer, NOx emissions are slightly elevated from baseline.

4.6 Non-CO_2 Emissions to Air, Soil or Water

There were no noted spills/releases to air, soil or water within the Quest capture unit during the 2015 operating period.

4.7 Operations Manpower

The Quest CCS facilities, at the end of 2015, were operated 24 hours a day, 7 days a week by the Scotford Upgrader operations team. The dayshift includes a control room operator, field operator for the Quest plot (capture, compression, dehydration), and a pipeline and wells operator. Only a control room operator and a field operator, with a pipeline and wells operator on-call for emergencies, cover the nightshift. Maintenance support has been integrated into existing Scotford Upgrader maintenance department resources, and staff support (engineering, specialists, administration, and management) has been rolled into the existing team supporting the hydrogen manufacturing units.

5 Facility Operations – Transportation

5.1 Pipeline Design and Operating Conditions

Pipeline operation began 2015 under a nitrogen pad for preservation, awaiting startup of the capture unit prior to first fill. The pipeline first fill with CO_2 occurred August 19 – 22, 2015 after successful completion of the compressor modifications and testing. The first fill procedure utilized recommendations from the flow assurance report to respect phase behavior and hydrate formation potential, and included hold steps for leak checks and temperature equalization. Pipeline operation was very stable during the reporting period. Table 5-1 below compares operating conditions in 2015 to design values from the engineering phases of the project.

Table 5-1: Pipeline Design and Operating Conditions

Characteristic	Specification	Units	2015 Average Operating Data / Actual Limitations	Original Design
General				
Pipeline Inlet Pressure	Normal	MPag	9.4	10
	Maximum Operating	MPag	12	14
	Minimum Operating (based on CO_2 critical pressure 7.38 MPa)	MPag	8.5	8
	Design maximum	MPag		14.8 (at 60°C)
Pressure Loss from Inlet to Wellsite	Normal	MPa	0.6	0.4 (for 3 well scenario)
Temperature	Compressor Discharge	°C	130	130
	Pipeline Inlet after cooler	°C	43	43
	Upset Condition at Inlet	°C	-	60
	Injection Well 7-11 Inlet Temperature	°C	15	
	Injection Well 8-19 Inlet Temperature	°C	12	
Flow rates	Normal Transport Rate	Mt/a	1.04	1.2
	Design minimum	Mt/a	-	0.36
	2015 Total Transported	Mt	0.371	-
Energy and Emissions	2015 Total Electricity for Transport (compression)	MWh_e	41527	-
	2015 Total Transport Emissions (includes compression)	Mt CO2eq	0.027	-

During 2015, the pipeline operated with CO_2 in the supercritical phase at the pipeline inlet (9.4 MPag, 43°C) and left the main pipeline to the wellsites in the liquid phase (8.8 MPag, 10-15°C). These two phases are commonly lumped together as "dense phase" in industry. The phase transition from supercritical phase to liquid occurs roughly in the 15-30 km region down the line, based on a field temperature survey. Heat transfer with the soil, as was expected in the design phase, has caused the majority of the temperature reduction in the pipeline.

CO_2 emissions from the transport component of the operation, 0.027 Mt CO2eq, were primarily from the electricity used to power the compressor (99% of total transport emissions).

The only significant issue to report has been the reliability of the power supply to the LBV stations on the pipeline route. The current setup at each LBV station consists of a solar panel and a battery bank, to cover nighttime and over-cast day operation. Due to issues with shading of the solar panel by other equipment, one particular LBV station has had several near miss loss of power trips, and one actual event that caused a shutdown of the entire CO_2 pipeline, as a loss of power initiates a closure of the LBV at that station. A future fix is in progress to address this reliability issue, but it was mitigated in the interim via field charging of the batteries and a replacement of the batteries in use at that LBV site.

Pipeline and laterals/well dimensions as-installed can be found in table 5-2.

Table 5-2: Pipeline Dimensional Data

Main Flow Line Data				
Characteristic	**Specification**	**Units**	**2015 Data**	**Value from Design Phase or As-installed**
Dimensions	Length	km	-	~64
	Size	inches, NPS	-	12
	Wall thickness	mm	-	12.7 (11.4 +1.3 corrosion allowance)
Laterals Data				
Dimensions	Length	km	-	3 laterals:~1, 1.6 and 3.8
	Size	inches, NPS	-	6
	Wall thickness	mm	-	7.9 (6.6+1.3 corrosion allowance)
Reservoir pressure		MPag	Refer to section 6	22 – 33.3
Reservoir temperature		°C	Refer to section 6	63
Well bore tubing diameter		inches, NPS	-	3.5
Well depth		m	-	2,070

Fluid composition in the pipeline was very close to the design normal operating condition for the majority of the operating period. On average, entrained components such as H2 and CH4 are lower than design. The average operating conditions to design values are available in table 5-3.

Table 5-3: Pipeline Fluid Composition

Component	Actual Operating 2015 (vol%)	Design Normal Composition	Design Upset Composition
CO_2	99.45	99.23	95.00
H_2	0.48	0.65	4.27
CH_4	0.06	0.09	0.57
CO	0.02	0.02	0.15
N_2	0	0.00	0.01
Total	**100**	**100**	**100**

Capacity for the Future

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 CO_2 Phase Change Management

Pipeline operation for the duration of the 2015 operating period was below the winter water specification of 4 lb / MMscf (84 ppmv). The average for 2015 was 46 ppmv, with the operations team targeting 60 ppmv to minimize over processing in the dehydration unit during the latter portion of the year. At this level, hydrate formation is not a concern during normal operation, and zero corrosion is expected. Flow to the pipeline is stopped automatically when the water content reaches 8 lb / MMscf (168 ppmv).

The pipeline system is currently protected from excessive vapour generation, and rapid temperature reduction, when coming out of dense / liquid phase during operation by a low pressure shutdown, currently set to 7 MPag.

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, operating in Shell Technology Centre Calgary (STCC), 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) are 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.

In the event of a single LBV closure, the LBV computer will send a signal to all LBVs to close, thus minimizing loss of containment. Closure of an LBV is expected to take 30 seconds from the open position to the fully closed position, thus minimizing the pressure surge (caused by the kinetic energy of the fluid) at an LBV.

After emergency shutdown due to a pipeline leak or rupture and following repairs of the line, 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.

Pipeline Leak Detection

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 Coriolis-type mass flow meters at the Shell Scotford boundary limit and at the wellhead are of custody transfer accuracy.

Automated and manual emergency shutdown systems were installed on the pipeline. An automated shutdown initiates when pressure transmitters on the line indicate a low pressure situation, or a high rate of change in pipeline pressure. Both pressure transmitters at one or more LBV stations must indicate a pressure below the trip point to initiate an automated pipeline shutdown.

Emergency shutdowns can be initiated manually from each of the well sites or from the Shell Scotford control room when pressure, temperature, and flow transmitters indicate upset conditions. The pipeline utilizes the ATMOS leak detection system that senses flow, temperature, and pressure fluctuations to determine whether there is a potential for a leak. Audible and visual alarms are generated at the Shell Scotford Upgrader control room in response to a potential leak. Emergency operating procedures are in place to respond to these alarms.

Corrosion Protection

Following regulatory requirements and the Pipeline Integrity Management Plan, cathodic protection has been installed for the pipeline, including the laterals. Installation includes the following:

- Impressed current anodes and anode leads
- Impressed current rectifiers
- Calcined petroleum coke breeze and bentonite chips
- Vent pipes and anode junction boxes
- Monitoring test stations
- Thermite welds for pipe connections and coating repair at those locations
- Temporary magnesium anodes at designated test stations

Inspection

An in-line inspection tool (smart pig) run of the pipeline will be performed in 2016 to verify pipeline integrity. Frequency of future inspections will be based on results from this inspection, other surface inspections, and ongoing monitoring results.

The following inspection/monitoring activities were conducted in 2015 or will be conducted in 2016 to ensure pipeline integrity.

- Operator rounds of the pipeline and wellsites with appropriate frequency.
- 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 aerial flights to check ROW condition for ground or soil disturbances and third party activity in the area

6 Facility Operations - Storage and Monitoring

This section provides an overview of the wells and MMV activities for baseline information gathering pre-injection and for the initial monitoring post-injection. Data collection for the purposes of gaining baseline information and related studies has been ongoing. For more detailed information, refer to the Fourth Annual Status Report to the AER.

6.1 Storage Performance

Injection of CO_2 into the 8-19 and 7-11 wells began on Aug 23, 2015, and as of Dec 31, about 0.371 Mt CO_2 have been injected into the two wells as illustrated in Figure 6.1. The injection stream composition is described in detail in Table 5.1 of this report.

Injection into the 5-35 well was not required at this time for the following reasons:

1) The 7-11 and 8-19 wells have adequate injection capacity between them for all available CO_2.

2) The downhole pressure gauge at the 5-35 well provides useful information for the BCS as a deep monitor well. This will help calibrate the reservoir model for the far field response of the injection at the other two wells.

3) The lack of injection reduces some of the MMV requirements at the 5-35 well site, which in turn reduces MMV costs. For example: there is no need to record a monitor VSP survey in 2015, since without injection, there is no change in reservoir saturations.

In order to simplify the expected response at the 5-35 well, the injection at the 8-19 well was held as constant as possible at roughly 70 tonnes/hour, while the 7-11 well was allowed to vary to accommodate the remaining CO_2. As a result, by the end of December, 2015, 0.16 Mt of $C0_2$ had been injected into the 7-11 well and 0.21 Mt of $C0_2$ had been injected into the 8-19 well. Figures 6.2 and 6.3 show the daily average flow rates and P/T conditions at 7-11 and 8-19 during the injection period.

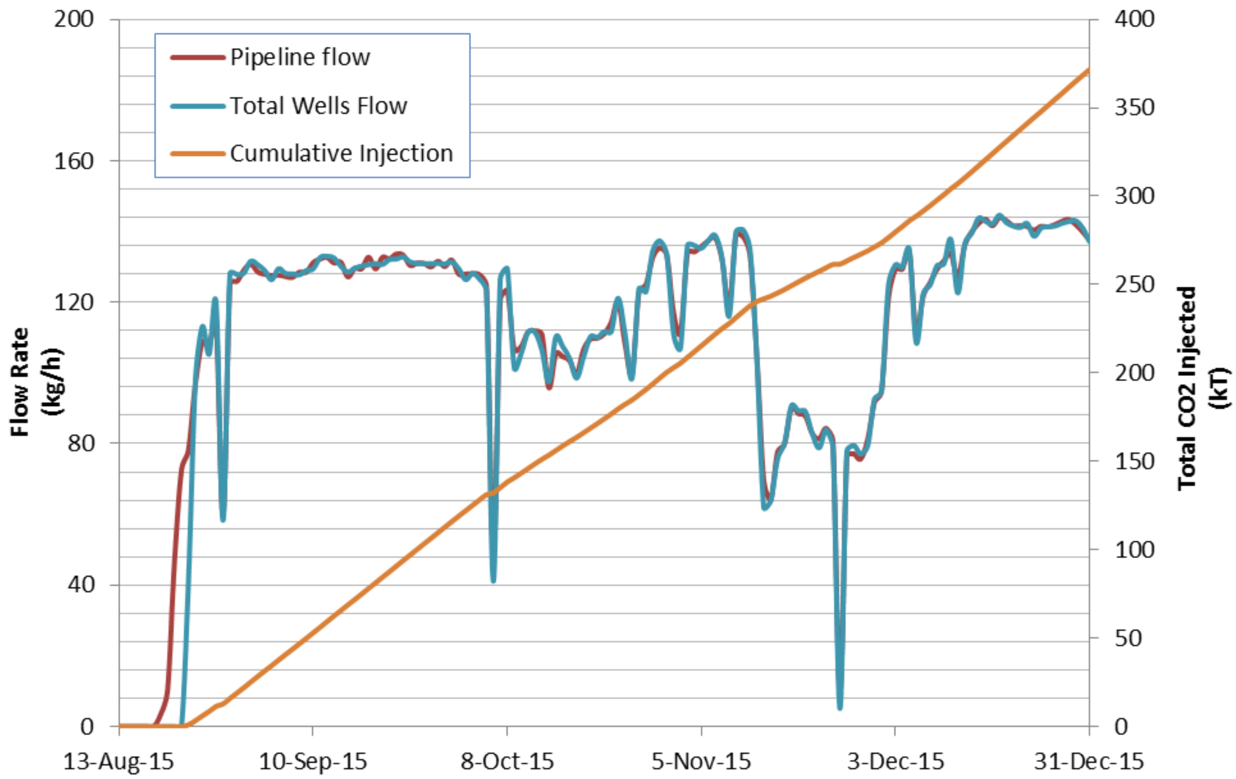


Figure 6-1: Quest Injection Totals: The orange line shows the cumulative CO_2 injected into the wells from start-up through to the end of 2015. The blue and red lines show the average hourly flow rates into the wells and the pipeline. Note that the pipeline fill began a week before the wells were started.

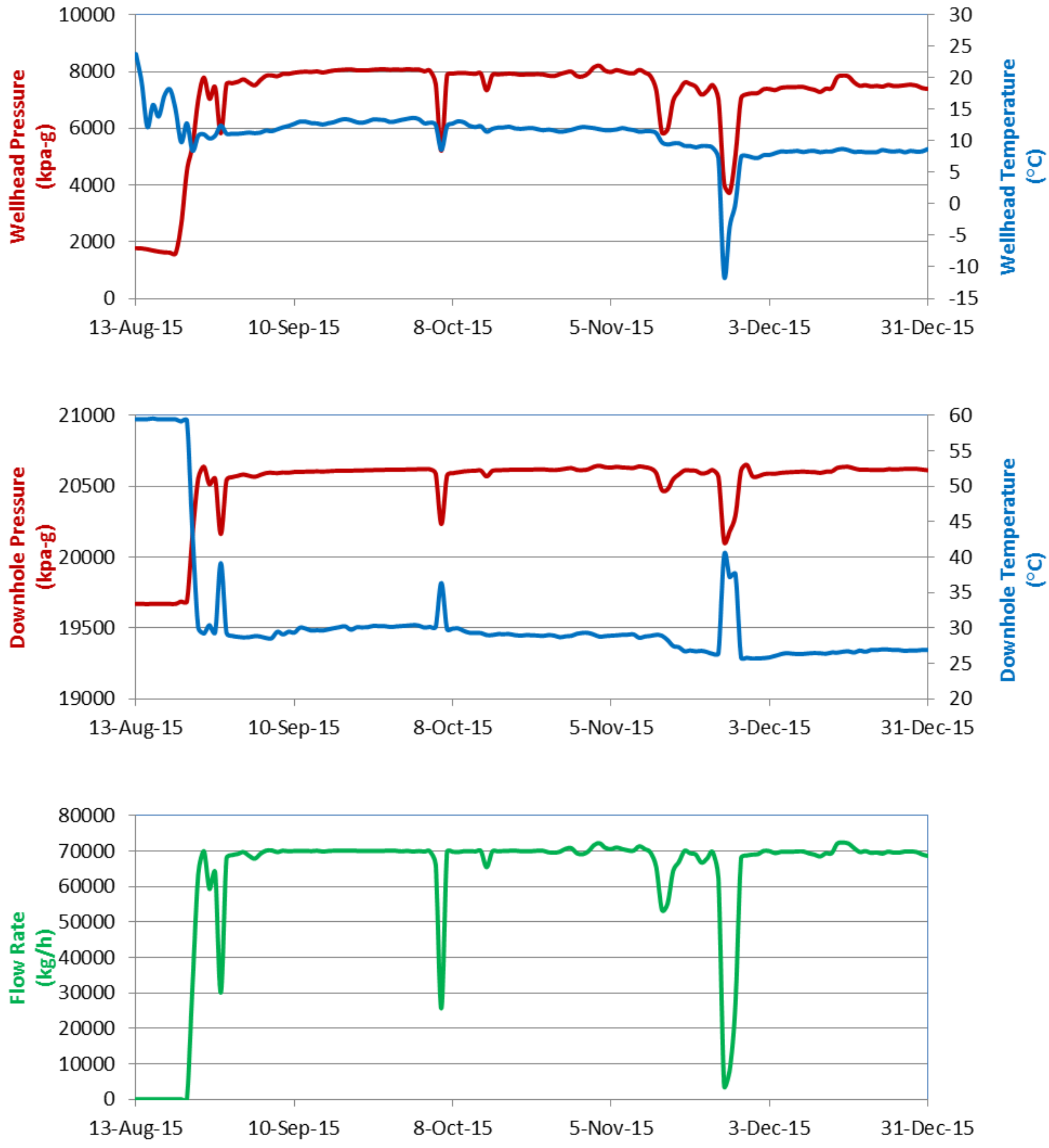


Figure 6-2 The 8-19 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2015.

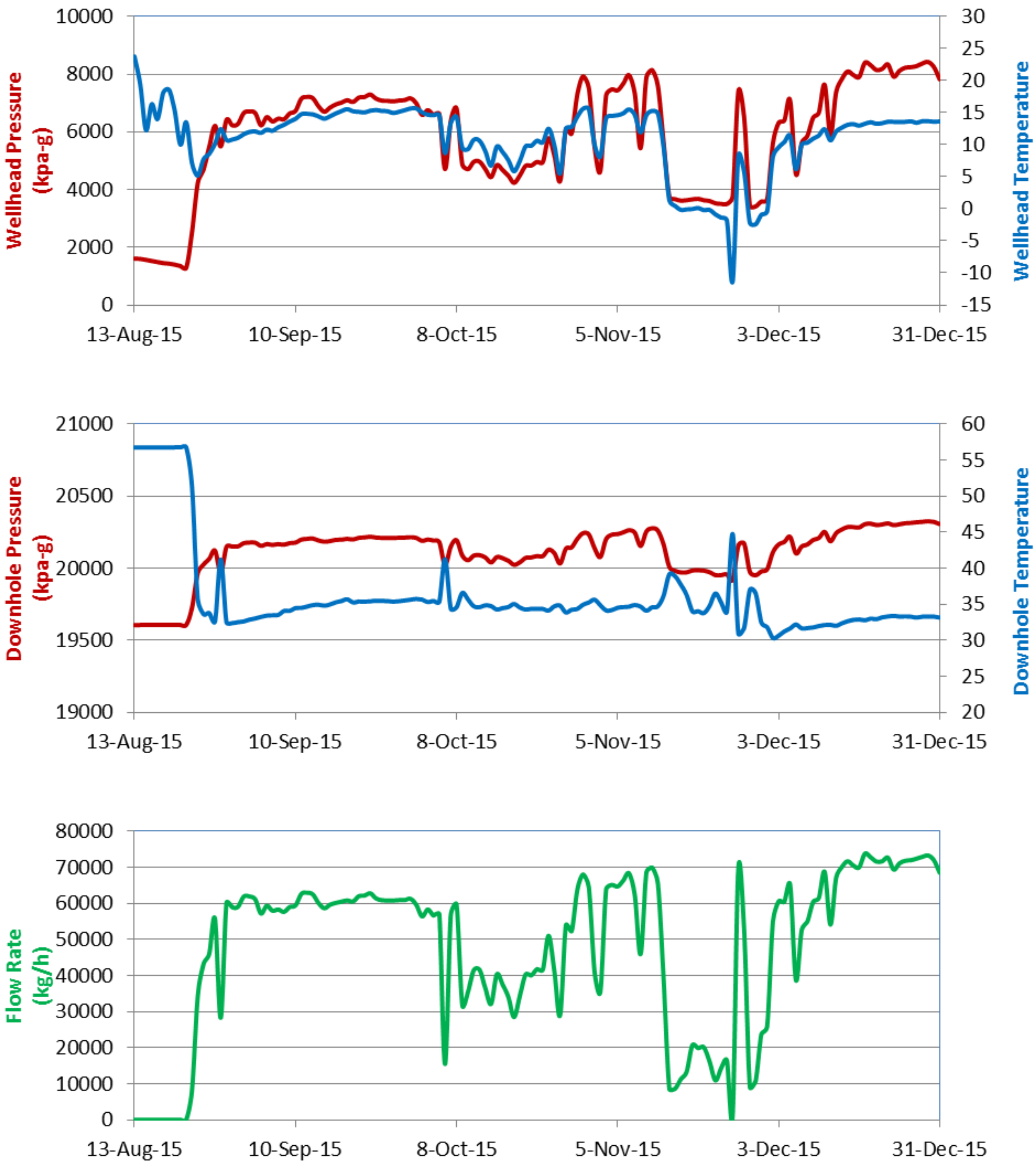


Figure 6-3 The 7-11 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2015.

6.2 MMV Activities

Early in 2015, the MMV activities focused on gathering some additional baseline data and preparing for the start of injection. Since injection began in August, MMV activities have shifted to operational monitoring. Table 6-1 provides an overview of the planned monitoring activities as per the MMV plan that was submitted to the AER in January 2015 [AER 2015 Annual Report, Appendix A].

6.2.1 Atmosphere Activities

A CO2 field release test was successfully completed in June 2015 at pad 8-19 prior to start of injection to support the development of the LightSource technology. The release test involved emitting CO2 at ambient temperature to the atmosphere. A total of 27 releases were completed, each lasted in general about 30 mins with a release rate of about 300 kg/hr (at NTP). The tests demonstrated the detectability of all controlled releases. In addition to the LightSource system, EC (Eddy CoVariance) data collection continued at the 8-19 well site until the end of 2015.

6.2.2 Hydrosphere/Biosphere Activities

During 2015, HBMP (Hydrosphere Biosphere Monitoring Plan) monitoring activities included:

- Quarterly groundwater well sampling of the project groundwater wells located on the 3 injection well pads
- Quarterly groundwater well sampling of landowner groundwater wells
- A single shallow soil sampling (down to about 90cm depth) event on plots within a 6 km radius of the injection well pads
- A single soil gas (using probes installed at a depth of 0.8 to 1.0 m) and soil surface CO_2 flux(using chambers placed on soil surface) sampling event around each injection well prior to start of injection.

Additional groundwater well testing/sampling was undertaken in conjunction with the February 2015 baseline VSP campaign. Please refer to Appendix A of the 2015 AER Report for further details.

6.2.3 Geosphere Activities

The baseline VSP was acquired in Q1 2015, to allow for frozen ground and data collection prior to first CO_2 injection at the sites. Eight walk-away VSP lines were acquired at each injection well location. The survey used the DAS fibers in each well to record the data via a lightsource box.

The microseismic array in the 8-19 monitoring well was re-installed on April 12th, 2015. After the installation, the sensor orientations were calibrated using vibroseis surface shots at four different locations surrounding well DMW 8-19.

Table 6-1: Summary of specific MMV activities in 2015

Domain	Activity planned for 2015 ^	Executed	Comment
Atmopshere			
	LightSource measurements at pads 8-19, 7-11, & 5-35	✓	controlled CO_2 release test successfully executed in June 2015 instead of May 2015
	Eddy covariance measurements at pad 8-19	✓	measurements were extended beyond June 2015 to end of year 2015
Biosphere			
	Soil sampling event at existing and new plots with a 6 km radius of the injection well pads	✓	completed prior to start of injection
	Targeted soil gas and soil surface CO_2 flux measurements at each of the injection well pads	✓	completed two sampling events: one prior to and one post start of injection
Hydrosphere			
	Downhole pH & EC monitoring at Project groundwater wells	✓	
	Quarterly discrete sampling at Project groundwater wells	✓	three sampling events took place prior to start of injection; one sampling event took place post start of injection
	Quarterly discrete sampling at landowner wells within 1km of each injection well pad	✓	three sampling events took place prior to start of injection; one sampling event took place post start of injection
	Once per year for landowner wells located within expected CO_2 plume size	✓	covered under 'landowner wells within 1km of each injection well pad', as CO_2 plume size < 1km
	Landowner wells associated with VSP surveys: pre- and post-campaign	✓	occurred prior to start of injection
Geopshere			
	Injection rate monitoring	✓	
	Annulus pressure monitoring	✓	
	DHPT monitoring at all 3 DMWs	✓	
	DHPT monitoring at all 3 IWs	✓	
	DHP monitoring at Redwater 3-4	✓	
	WHPT monitoring at all 3 IWs	✓	
	Mechanical well integrity testing (packer isolation test) and tubing caliper log of IWs		to be completed within about 6 months after start of injection, expected to take place in Q1-2 2016
	Routine well maintenance, including Temperature & RST logs and measurement of hold-up depths (HUD) of IWs at which injection started		to be completed within about 6 months after start of injection, expected to take place in Q1-2 2016
	MSM at DMW 8-19	✓	
	DTS monitoring at IWs	✓	work in progress to move towards automated data download; currently, field visits required to download data
	DAS monitoring at IWs	✓, ✗	used for VSP survey data collection; no continuous data collection implemented yet
	8 walkaway VSP surveys around each injection well using DAS fibers in Q1	✓	
	InSAR: monthly satellite image collection	✓	
corrosion coupons	corrosion coupons at injection skids		
SCVF/GM	annually by June 30th	✓	
Injected CO_2	analysis of captured CO_2 at Scotford Upgrader	✓	

6.2.4 MMV Infrastructure

A private, secure network was installed and operational in Q1 2015, to transmit all data types between well sites, the Scotford Upgrader, the Calgary office, and relevant external parties.

DTS data are currently stored locally at a pad, and data retrieval requires a field visit. Work is in progress to move towards a more automated, online data access/retrieval system. To this end, three computer systems were purchased in 2015.

All remaining equipment installations associated with the LightSource technology were completed at the three injection well pads in 2015 prior to start of injection.

Twenty semi-permanent soil gas probes were installed in a radial fashion around each injector well, with five probes each along a north, south, west, east direction.

6.3 Wells Activities

6.3.1 Injection Wells

In March, 2015 each of the three injection wells were prepared for injection by pulling the suspension plug, running a RST log, and installing a flapper valve. In addition, a wellhead integrity test was performed on the three injection wells. The status of the 8-19 well was then changed from 'Test' to 'Injection'. Figures 6.1 and 6.2 show the daily average flow rates and P/T conditions at 7-11 and 8-19 during the injection period.

6.3.2 Monitor wells

In May, 2015, two wells were perforated in the Cooking Lake Formation, the 8-19 Deep Monitor Well (DMW) and 3-4 DMW, and a pressure-temperature gauge was installed in each location. Furthermore, a new Microseismic Monitoring (MSM) array was run into the 8-19 DMW.

The pressures have been very stable in the DMWs near the injection wells as illustrated in Figure 6.4. The reservoir pressure in the 3-4 well was supercharged due to the hydrostatic overbalance of the completion fluid. This left the well near 12 MPa, see Figure 6.5, which fell off exponentially to stabilize at about 10.5 MPa by year end.

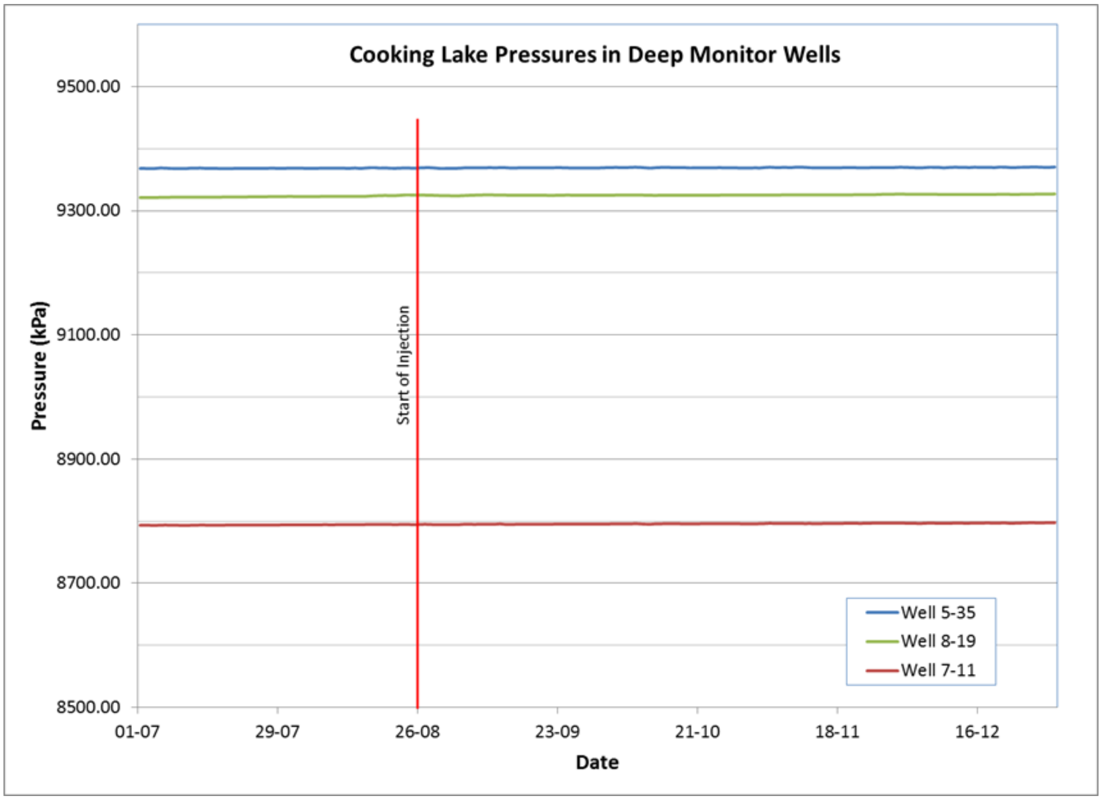


Figure 6-4. Quest DMW pressure history before and after injection

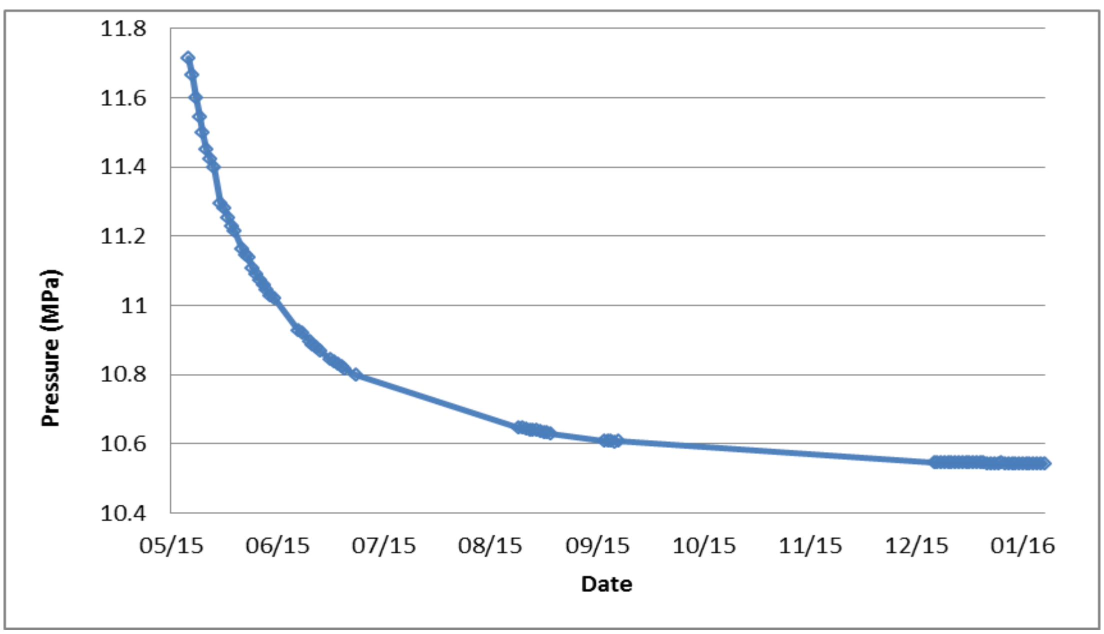


Figure 6-5 Quest 3-4 DMW pressure history before and after injection

6.3.3 Surface Casing Vent Flow and Gas Migration Monitoring

As required, annual testing was completed in 2015 for Surface Casing Vent Flow (SCVF) and Gas Migration (GM) at the injection pads. Reports were sent to AER in June 2015.

The measurements indicate that flow rates in wells IW 5-35 and IW 7-11 are steady and low. Pressure at the IW 5-35 well is at the same level as the last measurement in March 2014 and there is a slight increase at IW 7-11. Note that the pressure at IW 7-11 is still very low. The result from the SCVF measurements on IW 8-19 shows that both pressure and flow rates have decreased since the last measurement in March 2014.

In addition to the SCVF pressure and flow rate readings, SCVF samples for laboratory analyses were collected from IW 5-35, IW 7-11, and IW 8-19 in June 2015.

The compositional results indicate that the SCVF gas in the IW wells is predominately methane. For IW 5-35, CH4 concentration was 93.7%. For IW 7-11, CH4 concentration was 81.3% (N2 concentration was 14.9%). For IW 8-19, CH4 concentration was 30.9% (N2 concentration was 54.6%). For the GM gas samples, CH4 concentration was 5.3% at IW 7-11 and 4.2% at IW 5-35.

The gas migrations were observed on IW 5-35 and IW 7-11 as bubbles in the cellar. Results from June 2015, show the highest recorded gas content value is at or below 57% LEL 30cm away from the IW 5-35 wellhead and 80% LEL 30cm away from the IW 7-11 (note: wind was swirling), falls below 1% LEL in both wells 2 m away from the wellheads, and then reaches 0% LEL beyond 3m from each wellhead in every direction. The recorded gas migrations have very limited impact and pose no potential for concern.

6.4 Operational Monitoring

6.4.1 Summary of Operational Monitoring

- Atmosphere Monitoring: Monitoring of CO_2 levels within the atmosphere continued using the LightSource and EC systems.
- Hydrosphere Monitoring: One discrete sampling event took place post start of injection at the project groundwater wells located on the 3 injection well pads, and landowner groundwater wells within 1 km of the injection well pads.
- Biosphere Monitoring: One sampling event of soil gas and soil surface CO_2 flux measurements was undertaken on each injection pad.
- Geosphere Monitoring: monthly satellite image collection
- Well based Monitoring: ongoing, continuous data collection via wellhead gauges, downhole gauges, downhole microseismic geophone array, and DTS lightboxes.

6.4.2 Containment

To-date, no trigger events have been identified that would indicate a loss of containment. In other words, data to-date indicate that no CO_2 has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir during this reporting period.

Note that as the project progresses, it is expected that based on current performance, the focus of assessing 'containment trigger events' will be on a limited and reduced number of monitoring technologies.

6.4.3 Conformance

Three technologies have been identified to evaluate conformance:

- Time-lapse seismic data:

  Not assessed since start of injection, as the first monitor VSP survey will not take place until Q1 2016.

- Downhole Pressure Temperature Gauges:

  As discussed in Section 3.4, preliminary assessment of the pressure data indicates that the reservoir has more than enough capacity for the full life of this project. In addition, the smaller than expected pressure response indicates that it is extremely unlikely that injection induced faulting or fracturing could occur.

- InSAR:

  Not assessed since start of injection. The first assessment is planned for after about 1 year of injection. Note: a request has been submitted to extend the submission of the special report on InSAR efficacy (Condition 16 of AER Approval 11837C) to March 31st, 2017, in order to allow for sufficient injection history to be able to assess the efficacy of the InSAR program.

7 Facility Operations - Maintenance and Repairs

Review and approvals of maintenance plans - including identification of key maintenance activities, were completed in early 2015. Training plans and maintenance procedures for the maintenance personnel are complete and have included vendor training for key components (analysers, compressor). Wherever possible, Shell has leveraged existing processes, systems and procedures to facilitate a smooth transition of the Quest project into Site routine maintenance and operations.

Spare parts requirements based on vendor-supplied information have been purchased, with successful delivery of all kit in February 2015. Completion of outstanding Reliability Centered Maintenance (RCM) studies has facilitated creation and population of SAP (equipment database system).

All essential Maintenance processes were in place prior to Start Up and received the appropriate internal approvals to allow the team to advance to the Start Up phase.

Post startup, in August, regular maintenance plans implemented through SAP based on RCM reports for the capture facility, pipeline and wells have provided a steady and reliable operation.

Maintenance and repairs since startup in the capture facility are as follows:

- Amine filter change-out rate higher than expected possibly due to carbon filter passing.
- Replaced insulation soft covers with hard insulation in certain areas due to freezing of instruments.
- Changes to the High Pressure Low Temperature (HPLT) steam condensate traps implemented
- Repaired brass impro seal on amine charge pump
- Replaced outboard seal on amine charge pump (possible seal defect)
- Replaced outboard seal on condensate pump
- Repairs to CO_2 compressor 8th stage casing drain (repaired on planned outage)
- Replaced CO_2 compressor kickback positioner and regulator due to unstable movement at low outputs (repaired on planned outage)

Pipeline maintenance and repairs since startup are as follows:

- Flow controllers to the well sites were repaired to limit nitrogen usage
- LBV sites removed anti-climb devices on the communication towers to allow more sunlight directly on to solar panels.
- LBV voltage trip was lowered to avoid nuisance trips of pipeline and six new batteries were replaced due to damage from the low voltage condition.

Overall maintenance issues have been minimal for a new construction startup. Sharing of best practices by networking with external operating facilities continues to help improve maintenance practices and procedures.

8 Regulatory Approvals

8.1 Regulatory Overview

Regulatory approvals in 2015 culminated with the awarding of a Commercial Operations Certificate for Quest in September, which marked the completion of construction and commissioning stage and allowed the project to begin full commercial capture and sequestration of CO_2. Over the year, additional regulatory activities included the approval of a major update to the MMV plan, changing the wells' status in preparation for injection, and the acceptance of the long term Pipeline Agreement for crossing the Astotin and Beaverhill Creeks and the North Saskatchewan River.

8.2 Regulatory Hurdles

There were no significant regulatory hurdles in 2015. In order to account for new information about MMV technologies, there were a number of requests for changes to the Carbon Dioxide Disposal and Containment Agreement. In several cases, the AER asked for clarifying explanations and were satisfied with the responses. In general, approvals were obtained in a timely manner and no activities were impacted.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to the Project for the 2015 reporting period.

Table 8-1: Regulatory Approval Status

Approval or Permit	Regulator	Status and Timing of Approval/Permit	Comments
Quest CCS Project			
Commercial Operations Certificate	GoA	Submitted Sep. 28, 2015, Approved Sep. 29, 2015	Successful achievement of three tests for the Quest Project following the completion of construction and commissioning, as described in Schedule F of the CCS Funding Agreement
MMV Plan			
Quest CCS Project MMV Plan Update	AER	Submitted Jan. 31, 2015: Approved Mar. 20, 2015	Acceptance of proposed changes to the MMV plan
MMV Plan for Carbon Sequestration Leases 5911050001 to 5911050006 inclusive	GoA	Submitted Feb. 25, 2015: Approved Mar. 27, 2015	MMV Plan is approved by Government of Alberta under section 15 and section 19(2) of the Carbon Sequestration Tenure Regulation

CO_2 Pipeline			
PLA 110611 (Long term Pipeline Agreement for Astotin Creek Crossing NE 13-56-21 W4M)		Submitted Apr. 22, 2015: Approved Apr. 27, 2015	Amendment from Short Term to Long Term Agreement
PLA 110614 (Long term Pipeline Agreement for North Saskatchewan Crossing NW 36-57-20 W4M)		Submitted Apr. 16, 2015: Approved Apr. 27, 2015	Amendment from Short Term to Long Term Agreement
PLA 110737 (Long term Pipeline Agreement for Beaverhill Creek Crossing NW 16-56-20 W4M)		Submitted Apr. 4, 2011: Approved May 4, 2015	Amendment from Short Term to Long Term Agreement
CO_2 Injection and Storage			
Consent for Observation in the Undisposed Crown 3-4 wellbore	AER	Submitted Jan. 25, 2015: Approved Feb 12, 2015	Request to install downhole pressure gauge in the Cooking Lake Formation
Amendment to "Carbon Dioxide Disposal and Containment, Approval No. 11837A"	AER	Submitted Oct. 14, 2014: Approved Mar. 12, 2015 - Approval No. 11837B	Directive 65/51 application for the 7-11 and 5-35 wells – requirements have been me and, the wells are ready for injection
Special Report #3 – Tracer Feasibility Report	AER	Submitted Jun. 16, 2014: Approved Mar23, 2015	Fulfillment of clause 13 of AER Approval No. 11837B
Well License Amendment – License 0421182	AER	Approved Mar30, 2015	Change well status from TEST to INJECTION
Amendment to "Carbon Dioxide Disposal and Containment, Approval No. 11837B"	AER	Submitted Apr. 21, 2015: Approved May 12, 2015 - Approval No. 11837C	Revise Table 1 to remove the maximum injection rate restriction per well
InSAR Efficacy Report	AER	Submitted: April 20, 2015, Approved May 27, 2015	Clause 16 of CO_2 Disposal and Containment Approval 11837C is extended to July 31, 2016
Well License Amendment – License 0405594	AER	Approved June 4, 2015	Change well status from TEST to OBSERVATION
Surface Casing Vent Flow and Gas Migration Annual Report	AER	Submitted Jun.30, 2015 Accepted, pending approval	Fulfills the requirement outlined in the MMV plan for well monitoring
Microseismic Raw Data Retention Plan	AER	Submitted: Apr. 21, 2015, Approved Jul. 8, 2015	Approved proposal to store only MS trigger files

8.4 Next Regulatory Steps

Next year will be the first full year of commercial operations. As a result, the regulatory requirements will be focused on demonstrating compliance with existing agreements. As the project proceeds however, minor changes may be required to improve operational efficiency while ensuring safe performance. One early example is the alignment of work on the wells with work on capture facility, which will require a delay in the timing of some logging work required for the injecting wells. A request for this delay was submitted in January 2016.

9 Public Engagement

9.0 Background

Shell conducted a thorough public engagement and consultation program for the Quest CCS project, which has been ongoing since 2008. Stakeholder engagement began with 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.

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 response to landowner feedback, efforts were made to accommodate stakeholder concerns. Several re-routes of the pipeline 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.

9.1 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.

9.2 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.

9.3 Stakeholder Engagement

Stakeholder engagement activities for Quest continued throughout 2015. Activities fell into three main categories:

1) Updates to town, city, and county councils through regularly scheduled meetings,
2) Project information sessions to the public, and
3) Community involvement in the MMV Plan development and communication of results through participation in the Community Advisory Panel (CAP).

9.3.1 Government Authority Updates

Annual updates were given to town and county authorities at their council sessions to provide the most recent project progress information. Specifically, updates were provided to the following municipalities:

- April 8, 2015 – Thorhild County
- November 10, 2015 - Thorhild County
- November 24, 2015 – Fort Saskatchewan

Shell’s updates to the above councils were well received. No major issues were raised and all questions posed by each of the councils were general in nature and answered immediately at the council sessions. Council updates will continue throughout 2016.

9.3.2 Public Information Sessions

To provide the broader public with the opportunity to hear the most recent updates on the project and to provide a forum for questions and answers, open houses were held in the Quest impacted areas. These sessions were as follows:

- May 12, 2015 – Thorhild Community Center
- May 20, 2015 – Radway Agricentre

The open houses were advertised to the greater public through local advertising.

The Quest Launch in November comprised both Scotford on-site and off-site celebrations. Key community stakeholders were also invited to the on-site Quest Launch.

- November 6, 2015 - Quest launch event (on-site)
- November 14, 2015 - Quest launch community celebration (Radway Agricentre)

These public information sessions were generally well received with the attendees primarily looking for updates to the project. No major concerns or objections were raised with respect to the project at any of these public information sessions and any concerns that were raised have been addressed. There are no outstanding issues. The project team is currently reviewing the plan for timing of open houses or other types of public information forums for 2016.

9.3.3 MMV plan community involvement through Community Advisory Panel (CAP)

To involve the greater public in the development of the MMV plan, a Community Advisory Panel (CAP) was formed in 2012. The CAP comprises local community members including educators, business owners, emergency responders, and medical professionals as well as academics and AER representation. The mandate of the panel is to provide input to the Quest Project on the design and implementation of the MMV Plan on behalf of the broader community and to help ensure that results from the program are communicated in a clear and transparent manner.

In 2015 each meeting started with a project update followed by specific topics summarized below:

- April 9, 2015 – Update on MMV baseline program progress to date, construction update
- December 14, 2015 – Overview of operational MMV monitoring data and results, overview of commercial tests, sharing results of the first 90 days of injection.
- In addition, a lunch meeting was held with CAP members and Shell Vice Presidents July 16, 2015.

CAP meetings will be continued in 2016.

9.5 Issues Identified

Based on face-to-face discussions and feedback from stakeholders throughout 2015 engagement activities, the following issues were raised.

- Emergency Response plan robustness
- Well water quality
- Pipeline right-of-way reclamation
- Timing of payment for losses to landowner on pipeline route
- Impact of proximity to injection well on property value
- Competence of 3rd party water testing contractor

- Local government official concerned about climate change not being real and Quest being a waste of taxpayer money

9.6 Issue Management

Shell's External Relations team and members from the Quest Project Team met regularly with key stakeholders. Any issues arising from stakeholder interactions were identified and mitigation/resolution actions determined and acted upon wherever possible. In most cases, further information was provided on concerns/inquiries that helped ease the concern. All concerns were responded to timely, and solutions were put in place were possible and appropriate. This included changes to how Shell completed payments for pipeline-related losses and use of different well-water contractors to accommodate landowner wishes.

10 Costs and Revenues

10.1 Capex Costs

The Quest project has reached commercial operation and while the asset has switched to operation, there are some remaining closeout capital costs to come through. Table 10-1 reflects the projects incurred costs to the end of 2015 and will be subject to minimal changes as final invoices are processed. The categories follow those used by Shell over the life of the Project to track project costs.

The final cost estimate for the project is $790 million versus the original $874 million. Development costs for the Project for the FEED stage (January 1, 2009 to December 31, 2011) are included in 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 Project Incurred Capital Costs

	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 - December 31, 2016	Total Capex
Overall Venture Costs	19,470						
Shell Labour, & Commissioning	19,470	5,414	32,638	23,466	57,311	29,057	147,886
Tie-in Work /Brownfield Work							
Tie-In/Turnaround Work Capture	0	0	7,331	10,234	10,430	7,938	35,934
Tie-In Work Pipeline		0	196	518	334	161	1,209
Sub Total	0	0	7,527	10,753	10,764	8,099	37,143
Capture Facility*	52,671						
Engineering		6,662	40,889	32,799	5,180	1,378	86,907
Construction Management		0	218	16,967	21,338	31	38,554
Material		6,092	42,315	56,502	7,466	-5,080	107,295
Site Labor		0	0	9,456	36,038	0	45,494
Subcontracts		0	0	1,380	7,799	-37	9,143
Mod Yard Labor Including Pipe Fab		0	14,250	60,697	29,832	0	104,780
Indirects / Freight		0	15	32,339	12,987	-28	45,314
FGR Mods/HMU Revamps		0	0	0	0	0	0
Sub Total	52,671	12,753	97,688	210,141	120,640	-3,736	437,486
SUBSURFACE - Wells*	63,175						
Injection Wells		1,090	17,970	3,641	167	1,833	24,700
Monitor Wells		0	1,311	54	-20	571	1,916
Water Wells		0	1,620	-53	1	0	1,569
Other MMV		0	1,657	3,309	5,295	1,925	12,186
Sub Total	63,175	1,090	22,558	6,951	5,443	4,329	40,370
PIPELINES - TOE*	4,035						
Engineering		576	4,272	2,782	1,085	51	8,766
Materials		0	1,878	24,823	4,485	12	31,199
Services		0	0	60,101	27,366	11	87,477
Sub Total	4,035	576	6,150	87,706	32,936	74	127,441
Total Contingency, Inflation & Mrkt Escalation	0	0	0	0	0	0	0
Sub Total	0	0	0	0	0	0	0
Grand Total	139,351	19,832	166,561	339,016	227,094	37,823	790,326

* Shell labour costs during FEED are booked here.

10.2 Opex Costs

Quest started commercial operations on October 1, 2015 hence the costs indicated below are only for a 3 month period.

It is important to note that these costs are not representative of a typical operations spend as automatic unit allocations are only adjusted for at the beginning of the year; as a result, $1.1M of 2015 costs will be reflected in 2016.

Additionally, some costs were carried under Capital for consistency throughout the year.

The majority of Quest spend is Canadian content and less than 5% of total spend is in foreign currency (USD and Euros). Foreign exchange rate is managed through treasury at a daily spot rate with minimal effect on total spend.

Table 10-2 Project Operating Costs (,000)

Item	2015 October 1 , 2015 - December 31, 2015	Estimated Operating Costs for 2016
Steam, Electricity & General utilities	1,490.87	11,235
Maintenance	106.98	853
Operations labour	722.59	3,092
Operations Materials & Equipment	1.12	793
MMV Costs	637.07	3,583
Operations General Services	19.24	2,625
Indirect costs	186.11	1,781
Property Tax	392.62	1,611
land, Pore space rental		438
PCSF		334
Sustaining Capital		
Turnarounds		
Total	3,556.60	26,345

10.3 Revenues

Revenues reflect funding received and to be received (Table 10-3) until commercial operation. Ongoing revenues during operations will be determined on the basis of credits received for the CO2 volumes stored, along with the additional credits received as per the multi-credit agreement signed with the Province of Alberta.

Table 10-3: 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 – Sept 30, 2015
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 through construction of Quest project.

Government Funding	2009 April 1, 2009 - March 31, 2010	2010 April 1, 2010 - March 31, 2011	2011 April 1, 2011 - March 31, 2012	2012 April 1, 2012 - March 31, 2013	2013 April 1, 2013 - March 31, 2014	2014 April 1, 2014 - March 31, 2015	2015 April 1, 2015 - September 30, 2015	Operating October 1, 2015 - 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	0.3%	0.4%	0.5%	17.6%	25.9%	29.7%	41.3%	62.8%

10.4 Funding Status

To date, the Project has received a total of $6.6 million from the Alberta Innovates program, which has 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 remaining 10% holdback received after commercial operation. 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, $100 million in October 2013, $15 million in April 2014, $38 million in October 2014, $15 million in March 2015 and a further $149 million at Commercial operation in October 2015. The project has now moved into the operating funding phase of the project.

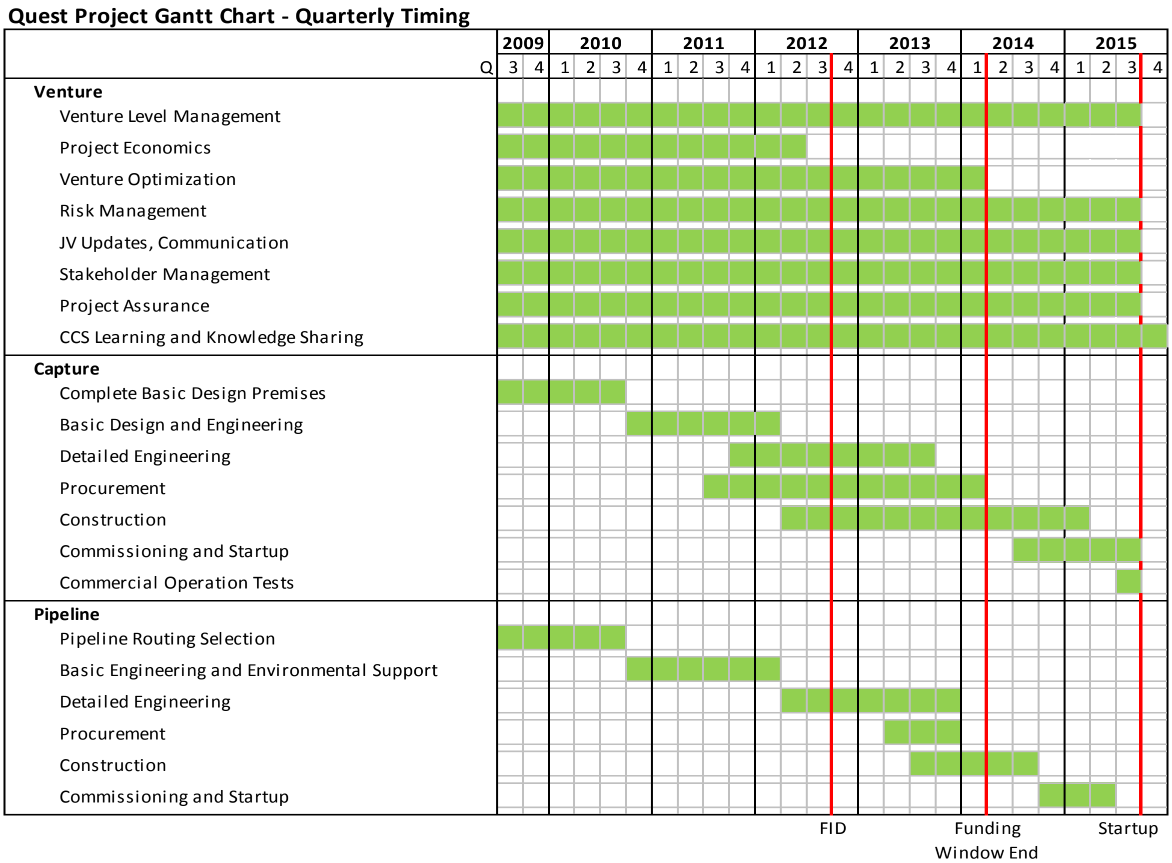
11 Project Timeline

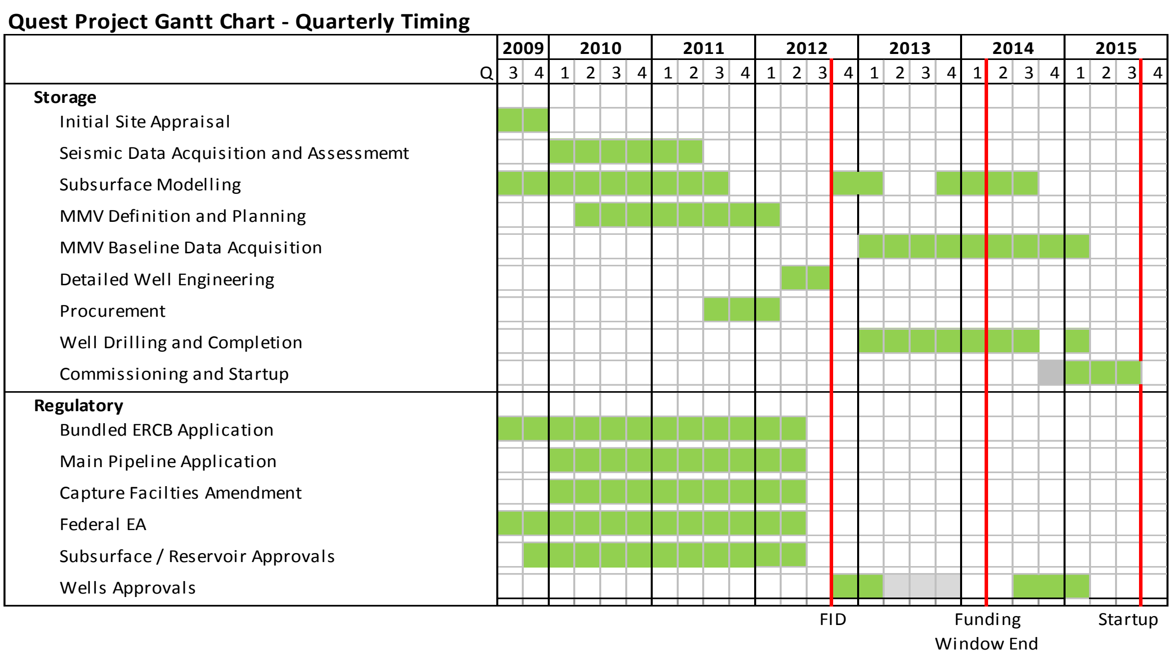
The timeline for the Project is shown in Table 11-1. The only departure from the project timeline is the advancement of the completion of the Capture Commercial Operation Tests, which was originally scheduled to run into Q4 2015, but all tests were completed by the end of Q3 2015.

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

The projected forecast for CO_2 injected is as submitted in Schedule "C" Projected Payment Schedule after the Achievement of Commercial Operation

Table 11-1: Project Timeline





12 General Project Assessment

The Project schedule, as noted in Section 11, was largely maintained with the actual achievement of commercial operation on September 28, 2015. Project development costs were on budget, the final capital costs were under budget, and operating costs are projected to be under budget as well based on lower power requirements.

12.1 Project Successes – 2015

Capital Cost Management

Quest has achieved its Capital costs significantly below the original Investment Proposal by managing and mitigating risks from cost and scheduling pressures along with utilizing the following:

1) Modularization of the fabrication

2) Strong cost focus through no change mandate

3) Being significantly Engineered prior to investment decision

4) Good adherence to Operational Readiness practices.

Detailed Engineering

As built drawings were completed for the facility and transferred to the Scotford library by mid October.

Construction Work

Construction was complete in February 2015 (final tie-ins accepted) and all systems were handed over to the Commissioning & Start up team

Baseline MMV Data Acquisition

A baseline walkaway VSP was completed in February 2015 at all 3-injection wells.

Commissioning and Start up

The Commissioning team completed the final cleaning of all areas of the facility by end of March 2015. The Amine unit as well as the regeneration was successfully started up in late May. The compressor and dehydration units were started up in August. Pipeline was filled and injection into the first well was achieved on August 23rd. The sustainable operating tests were all passed on September 28th.

Networking within Industry

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

Stakeholder Engagement

Stakeholder management continues to be a priority for Shell. The high level of stakeholder involvement continued into 2015. In 2016, plans remain for continued use of Open Houses, Quest Cafes, and maintaining strong relationships with the Community Advisory Panel. Although we have built on the strength of the engagements, we realize that these can be fragile and must be cultivated.

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.

Provincial Government Milestones

Critical to the Project funding for the Government of Alberta is a series of milestones that have been agreed upon 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. All milestones to this point have been passed as scheduled.

Quest received certification for the commercial operating tests on September 30th completing the construction/start up milestones for the project.

Through CS&U and post start up, there were no noted spills/releases to air, soil or water within the Quest capture unit during the 2015 operating period.

Technical Successes

Post start up, several technical successes have been noted including the low levels of chemical loss from the ADIP-x process, significantly lower carryover of TEG into CO_2 vs. design with estimated losses on track to be roughly 6,000 kg annually vs. the design makeup rate of 46,000 kg annually.

Furthermore, implementation of FGR (flue gas recirculation) technology, in combination with the installation of low-NOx burners has allowed all 3 HMUs to meet their NOx level commitments without contravention in 2015 with the capability to maintain NOx levels close to baseline values pre-Quest.

On the subsurface side, injection into the 5-35 well was deemed not to be necessary to meet injectivity requirements, resulting in a significant savings in MMV. In addition, the uncertainty in the capacity of the BCS storage complex, has been further reduced post injection with strong evidence to support the assessment of BCS having more than sufficient capacity to store the required volume for 25 MT of CO_2 over the life of this project with negligible likelihood of fracturing, fault reactivation, or CO_2 leakage.

It is therefore expected that the project will be capable of sustaining adequate injectivity for the duration of the project life; therefore, no further well development should be required for injectivity requirements.

The surge line was re-tested in October 2015, and resulted in a shift of the line to lower flow rates, allowing the machine to operate with less anti-surge (recycle) flow during periods of reduced CO_2 throughput, and thus less electrical demand.

Strong integrated project reliability performance since initial injection in August, achieving an uptime of 98.3%. Mechanical availability for the reporting period was 98.7%, beating the project premise of 95.4%.

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.

Schedule challenge

As the commissioning progressed towards the start up date, the operating complex did a risk evaluation of the agreed upon start up sequence whereby start up on Quest would utilize HMU 3 volumes as HMU 1 and 2 were undergoing turnaround activities. A conclusion was reached that with the susceptibility to swings in the HMU's performance impacting Residual Hydro Conversion unit performance, interruption to HMU 3 operation while the other HMU's were not available for back up was not tolerable. This essentially delayed the startup of the facility for seven weeks. The team reexamined the start up sequence and prepared a new plan utilizing HMU 2 first right after the turnaround, immediately followed by HMU 1. Learnings from these two startups were then applied to the HMU 3 start up a few days later.

Technical Challenges

During the startup testing, two issues came to light. Upon testing the emergency shutdown of the compressor, it was discovered that between the two blowdown lines and the recycle line, insufficient volumes could be moved away from the high pressure side of the compressor resulting in it stopping abruptly and to spin in reverse for a period of time. No damage was done to the machine at the pressures it was tested at however; damage was possible had the compressor been operating at full design pressures. Together with the compressor manufacturer, Fluor process and machinery engineers as well as Shell process and machinery engineers, the data of the test was reviewed along with all design data verified. It was concluded that the eighth stage nozzle did not allow sufficient volume to move through both the eighth stage blowdown and recycle line restricting the blowdown volume through those lines and that the extra volume in the interstage piping and knockout vessel volumes may not have been adequately considered. A dynamic model of the compressor and associated piping was prepared by Shell and a third party vendor to simulate the impact of several possible solutions. Fluor put together the mechanical and structural design for the selected option from the simulations and the Shell commissioning team procured, fabricated and installed the solution. The compressor blowdown was successfully retested in the latter half of August .

The second issue, was related to attaining stable operation of HMU 3 in particular while achieving CO_2 capture ratios close to design. The reduction in operating pressure of the reformer fuel gas system due to lower PSA off gas volumes resulted in operation close to the low pressure differential reformer trip point, and was undesirable from a safety/reliability perspective. After consultation with instrumentation and burner specialist, it was agreed that a timing delay could be put on the shutdown during transitions between different PSA operating modes to enable the fuel gas pressure to stabilize. This solution was implemented in latter half of October and resulted in the unit being able to run at or slightly above the 80% recovery rates.

During operation a few issues have been addressed. First, foaming of the ADIP-X solution in the HMU absorbers, leading to tray flooding and a short duration reduction in CO_2 capture from the HMUs along with an impact to stability in the hydrogen plants themselves. The cause has been attributed to several initiating factors: rapid changes in gas flows to the absorbers, carbon fines entrainment in the system, high gas rates to the absorbers and general system impurities. Several actions were taken to mitigate the foaming issue, DCS control schemes were implemented, an anti-foam injection utilized, as well as system cleanliness has also improved with better amine filter change-out procedures, minimizing carbon levels in the system.

One nuisance issue observed is the frequency of filter change-outs in the lean amine circuit which was attributed to carryover of carbon fines from the carbon filter into the lean amine. As a learning for future change-outs of the carbon filter media, a back-flushing procedure to prepare the carbon filter for service will be employed to ensure that it is left with minimal amounts of carbon fines present.

The startup of the compressor proceeded without major issues, but the initial shutdown of the machine resulted in rapid deceleration of the motor and reverse rotation up to 500 rpm. No damage to the machine was noted, however this posed a high potential risk for asset damage during future shutdowns. Modifications were made to add additional blow-off capacity to the compressor's 4^{th}, 5^{th} and 6^{th} stages, as these stages were not depressuring fast enough on a shutdown due to the large volume of compressed CO_2 in the piping and knockout vessels. The above modifications enabled operating pressures up to 12 MPag safely, but pressures above this still resulted in reverse rotation of the motor on a shutdown. As a result, the maximum operating pressure was de-rated, and the automated shutdown of the compressor was changed from 14 MPag to 12 MPag. Engineering was completed in 2015 to specify a long term solution for the compressor to bring its discharge pressure capabilities back to 14 MPag

At low operating pressures on the compressor, there was insufficient pressure to move KO water into the stripper reflux drum, as such the 2^{nd} stage compressor knock-out water from the reflux drum was re-routed to the amine drain drum. This was required due to hydraulic limitations in the system.

Poor reliability of the power supply to the LBV stations on the pipeline route was noted post start-up due to shading of the solar panel by other equipment. The issue was pronounced at one particular LBV station with several near-miss loss of power trips, and one actual event that caused a shutdown of the entire CO_2 pipeline. Interim mitigation measures are in place until a future fix is implemented to address this reliability issue.

Landowners

Several landowners were not satisfied with the level of clean-up on their sections of right of way and have requested additional work be done. Shell's Land Agent was engaged to expedite the process for following up on concerns and addressing with either additional work or compensation as needed.

12.2 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:

- Completion of Construction work and start up at the Scotford Upgrader site
- Field work done to monitor the hydrosphere and biosphere properties of the storage area surface and groundwater regions

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 and supporting Operations of Quest.

Discussions began in 2014 with the US DOE to utilize Quest as a project to develop and deploy additional MMV technologies to support either reduced technology cost or improved monitoring for containment security. Work continued in 2015 with deployment of some of these technologies and consists primarily of detailed engineering with field deployment expected in 2016. Partnerships such as this with the US DOE will assist in raising the profile of Quest and emphasize the Leadership demonstrated by Alberta and Canada in support of sustainable development of resources through innovation.

Benefits post start-up for the local communities, Alberta, and Canada include:

- Full time employment for an additional 13 people.
- Tax additions to the local governments of Strathcona County, Thorhild, Lamont, Sturgeon County Alberta, and Canada.
- Strathcona County to benefit from increased international attention for visits to Scotford.
- Recognition by the international community of Canada and Alberta as leaders in CCS deployment.
- Maintenance and repair contracts around $5 million per year.

13 Next Steps

With the achievement of commercial operations, Quest has been embedded in Shell Scotford Operations and the focus will now shift to maintain reliable, efficient operations. Sustainable operations are not only critical in order to continue to meet the requirements of the funding agreement with the Government of Alberta, but also to affirm the position of Quest as an innovative and achievable technology on the global stage.

Capture of operational issues and lessons learned in order to retain institutional memory and facilitate improvements in processes and procedures – for example for back-flushing procedure noted to prepare the carbon filter for service will be employed to ensure that it is left with minimal amounts of carbon fines present and decrease the frequency for change outs.

An in-line inspection tool (smart pig) run of the pipeline will be performed in 2016 to verify pipeline integrity and assist with determination of the frequency of ongoing inspections in conjunction with surface inspections, and ongoing monitoring results.

A fix for the solar panels on the pipeline will be implemented to improve power supply reliability to the LBV stations.

Microseismic data will continue to be collected as committed in the MMV plan along with monitoring of the hydrosphere and biosphere post injection. Work will continue to move towards a more automated, online data access/retrieval system of DTS data.

Reservoir model to be recalibrated using available operational data.

Regulatory activities will focus on demonstrating compliance with existing agreements as well as awaiting formal approval of the Surface Casing Vent Flow and Gas Migration Annual Report.

Public engagement activities will continue to ensure continued public knowledge of Quest's operations. The Community Advisory Panel will continue in 2016 and continue to update the group on Quest activities as our focus now shifts to sustaining reliable operations. Ongoing reporting will continue to the Province of Alberta in accordance with the respective funding agreements.

14 References

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4. Alfaro, M.C., Bourne, S and Dean, M., 2015. Technical Feasibility of InSAR for CO2 Storage Monitoring and Leak Detection – 2015 Update (Draft). Shell Canada, Heavy Oil Controlled Document, Quest CCS Project

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7. Special Report 3, 2014. Tracer Feasibility Report submitted to the AER on 16th June 2014.