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Quest Carbon Capture and Storage Project

ANNUAL SUMMARY REPORT -

ALBERTA DEPARTMENT OF ENERGY: 2019

March 2020
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 Quest CCS facility (Quest) and as agent for and on behalf of the AOSP Joint Venture and its participants, comprising Canadian Natural Upgrading Limited (60%), Chevron Canada Limited (20%) and 1745844 Alberta Limited (20%), as amended.

The purpose of Quest is to deploy technology to capture CO₂ produced at the Scotford Upgrader and to compress, transport, and inject the CO₂ for permanent storage in a saline formation near Thorhild, Alberta. Approximately 1.2 Mt/a of CO₂ will be captured, representing greater than 35% of the CO₂ produced from the Scotford upgrader.

In 2019, Quest surpassed 4 million tonnes of injected CO₂. It achieved the record of having stored underground the most CO₂ of any onshore CCS facility in the world with dedicated geological storage.

Reservoir performance and injectivity assessments thus far indicate 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. MMV activities are focused on operational monitoring and optimization.

A single leak from surface equipment was experienced in 2019 due to a seal flush tubing failure on the Quest Lean Amine pump (P-24602B). MMV data indicates that no CO₂ has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir to date.

In 2019 Shell conducted another open house for the local community and held an engagement with local government officials to provide updates on operations. Knowledge from Shell’s experience with Quest was shared with numerous industry, business, academic and non-government associations in 2019.

Quest has experienced a number of successes in the reporting period, including:

- Sustained, safe, and reliable operations
- Low levels of chemical loss from the ADIP-X process
- Dehydration unit performance continued to exceed expectations, with lower than expected water content, TEG carryover and unit losses of TEG
- Acquisition of the first monitor 2D VSP and 2D surface seismic at the 5-35 injection well
- Continued evidence that Quest will sustain adequate injectivity using the three wells for the duration of the project life
- Overall maintenance issues have been minimal
- Sharing of best practices by networking with other operating facilities continues to help improve maintenance practices and procedures
- Strong integrated project reliability performance with operational availability at 99.6%
- Maintaining local support through the extensive stakeholder engagement activities
• Continued participation of the Community Advisory Panel (CAP)
• International engagements with the Global CCS Institute to support public engagement, global knowledge sharing activities and numerous tours to the Scotford facility
• Completion of a United States Department of Energy-funded demonstration project for fibre based CO2 sensor technology
• Operating costs continue to be lower than forecasted
• Serialization of 1,787,416 credits in 2019 (including re-verification of previous periods)

Challenges for this reporting period were minor operational issues, including:
• Reformer burner degradation continued in the HMU’s as a result of flame instability at higher CO2 capture rates, resulting in capture rate restrictions
• Seal flush tubing leak on Lean Amine charge pump P-24602B

Quest has seen strong reliability performance through the reporting period to safely inject over 1.12 Mt of CO2 in 2019. Overall project injection has surpassed 4.8 Mt of CO2 to December 31, 2019.

Revenue streams generated by Quest are twofold: (i) the generation of offset credits for the net CO2 sequestered and additional offset credit generated for the CO2 captured, both under the Carbon Competitiveness Incentive Regulation (CCIR) which replaced the Specified Gas Emitters Regulation (SGER) on Jan 1, 2018.; 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 2018, the value of the offset credit was $30/tonne.

Quest continues to see operating efficiencies with the compressor given the more favourable subsurface pore space. The compressor continues to operate utilizing 13-15 MW versus 18 MW as full design.

Quest provides employment for 15 permanent full-time equivalent positions (FTEs) and an additional approximately 10 FTE allocated into existing positions. Quest generated expenditures of ~$25 million in 2019 in staffing, MMV, maintenance, and variable costs to the economy.

Quest continues to receive significant international interest from various technical organizations.
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Abbreviations

AEP ................................................................. Alberta Environment and Parks
AER ................................................................. Alberta Energy Regulator
AOSP ............................................................. Athabasca Oil Sands Project
ARC ................................................................. Alberta Research Council
BCS ................................................................. Basal Cambrian Sands
CCS ................................................................. carbon capture and storage
CO₂ ................................................................. carbon dioxide
FEED ............................................................. Front End Engineering and Design
FGR ................................................................. Flue Gas Recirculation
GHG ................................................................. greenhouse gases
HMUs .............................................................. hydrogen manufacturing units
InSAR ............................................................... Interferometric synthetic aperture radar
LBV ................................................................. line break valve
MMV ............................................................... measurement, monitoring and verification
ORM ............................................................... Opportunity Realization Manual
PSA ................................................................. pressure swing adsorber
RCM ............................................................... Reliability Centered Maintenance
RFA ................................................................. Regulatory Framework Assessment
ROW ............................................................... right-of-way
SAP ............................................................... Systems, Applications, Processes (Equipment Database Software)
TEG ............................................................... triethylene glycol
VSP ............................................................... vertical seismic profile
1 Overall Quest Design

The Scotford Upgrader, operated by Shell Canada Energy, as agent for and on behalf of the Athabasca Oil Sands Project (AOSP) Joint Venture and its participants, comprising Canadian Natural Upgrading Limited (60%), Chevron Canada Limited (20%) and 1745844 Alberta Limited (20%), is part of Shell's Scotford facility located northeast of Edmonton. The design concept for Quest is to remove CO₂ from the process gas streams of the three hydrogen-manufacturing units (HMUs), within the Scotford upgrader facility. This is done by using amine technology to capture CO₂ then compressing and dehydrating the captured CO₂ to a dense-phase state for efficient pipeline transportation to the subsurface storage area. Design, construction and start-up of the Quest project occurred from 2009 to 2015. Further details on these phases can be found in previous annual reporting submissions on Alberta's Open Government Resources website.

The operations phase at Quest started in September 2015. Quest has successfully captured and injected over 4.8 Mt of CO₂ in three injection wells (8-19, 7-11 and 5-35) to the end of 2019.

Quest facility locations are shown in Project Facility Locations, Figure 1-1.
Figure 1-1: Project Facility Locations.
2 Facility Construction Schedule

Construction reached mechanical completion on February 10, 2015 with all A and B deficiencies completed that were required for commissioning and start-up. For further details, please refer to past submissions.

3 Geological Formation Selection

Storage Area selection and assessment occurred between 2008 and 2013. No new activities related to this have occurred within the reporting period. For further details, please refer to past submissions.

Updates for the reporting period as to the Estimate of Storage Potential and Injectivity Assessment previously included in this section are now found in Sections 6.1.1 and 6.1.2.
4 Facility Operations – Capture Facilities

4.1 Operating Summary

The Quest CCS project focus for 2019 was to continue reliable and efficient capture and storage of CO₂ from operations. Table 4-1 outlines the performance summary of the capture unit. A discussion of the summary results can be found in the subsequent unit discussions.

Subsequent to the completion of the verification of the 1st reporting period, Alberta Environment and Parks (AEP) assigned a third-party auditor which resulted in two material audit findings regarding Quest injection gas online analyzer and the waste heat methodology. The audit findings for the online CO₂ analyzer and the waste heat methodology have been resolved as of Dec 31, 2019 and are reported below.

Going forward, Shell will continue to work with AEP and Alberta Energy (CCS Unit) on implications of the new Technology Innovation and Emissions Reduction (TIER) Regulation that replaced the Carbon Competitiveness Incentive Regulation (CCIR) on January 1, 2020.

Table 4-1: Quest Operating Summary 2019

<table>
<thead>
<tr>
<th>Quest Operating Summary</th>
<th>2015 Summary</th>
<th>2016 Summary</th>
<th>2017 Summary</th>
<th>2018 Summary</th>
<th>2019 Summary</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total CO₂ Injected</td>
<td>0.371</td>
<td>1.11</td>
<td>1.138</td>
<td>1.066</td>
<td>1.128</td>
<td>Mt CO₂</td>
</tr>
<tr>
<td>CO₂ Capture Ratio⁶</td>
<td>77.4</td>
<td>83.0</td>
<td>82.6</td>
<td>79.1</td>
<td>78.8</td>
<td>%</td>
</tr>
<tr>
<td>CO₂ Emissions from Capture, Transport and Storage</td>
<td>0.080³</td>
<td>0.238³</td>
<td>0.241³</td>
<td>0.241⁵</td>
<td>0.237⁵</td>
<td>Mt CO₂</td>
</tr>
<tr>
<td>Net Amount (CO₂ Avoided)</td>
<td>0.291³</td>
<td>0.870³</td>
<td>0.897³</td>
<td>0.826¹,²,³</td>
<td>0.891¹,²</td>
<td>Mt CO₂</td>
</tr>
<tr>
<td>Waste Heat Credits</td>
<td>0.022¹</td>
<td>0.062¹</td>
<td>0.051¹</td>
<td>0.044¹</td>
<td>0.044¹</td>
<td>Mt CO₂</td>
</tr>
</tbody>
</table>

1. Under SGER, waste heat credits were claimed from 2015-2017. As of Jan 1, 2018, under CCIR, waste heat was claimed under the Scotford Upgrader. Quest is an integrated operation within the Scotford Upgrader Complex, therefore, in 2018 and 2019 the Net CO₂ Avoided includes 0.044 Mt CO₂.
2. Under SGER, the reported indirect GHG emissions from imported steam for Quest was reduced by the Target (e.g. 20%), which is the required reduction in GHG intensity for large final emitters such as the Upgrader. Under CCIR, there is no target specified. As a result, the Target is set to 0% under CCIR.
3. 2015-2018 CO₂ emissions have been updated based on AEP’s audit close out on waste heat methodology. The revised emissions now include the addition of 3rd party verified waste heat claims.
4. The CO₂ capture ratio refers to the percentage of CO₂ captured from the syngas (raw hydrogen) feed stream to the absorbers.
5. Indirect GHG emission from imported electricity now capturing electricity usage from both the Upgrader Cogen (0.37 tCO₂/MWh) and the grid (0.64 tCO₂/MWh).

The reported CO₂ emissions for 2015 to 2018 have been revised as a result of AEP’s closeout of audit findings on allocation of integrated waste heat usage. Additional to this, calculation of CO₂ emissions for 2018 are also impacted by the CCIR, which became effective January 1⁵, 2018.
Under SGER, the reported indirect GHG emissions from imported steam for Quest was reduced by the target (e.g. 20%), which is the required reduction in GHG intensity for large final emitters such as the Upgrader. Under CCIR, there is no target specified. As a result, the target was set to 0% under CCIR.

In the Quest Offset Project Plan (OPP) the electricity generation for Quest was anticipated to be grid electricity. In recent years, there has been an increase in electricity from the gas turbine in the Scotford Upgrader Cogeneration Plant (Upgrader cogen) to Quest. On June 19, 2019, AEP provided approval for a deviation request to use the CCIR electricity benchmark of 0.37 tCO₂/MWh for Quest electricity directly connected to the Upgrader cogen, while the grid factor for 2019 was 0.64 tCO₂/MWh. For the 2018 and 2019 numbers in Table 4-1, Quest is capturing imported electricity from both the Upgrader cogen and the grid.

The following is a timeline of significant operational milestones for the 2019 calendar year:

- April 12, 2019: Reached milestone of 4 million tonnes injected since project start up
- November 22, 2019: Reached milestone of 1 million tonnes injected in 2019

4.1.1 Quest Audits and Credit Serialization

The Quest CCS Offset project underwent various audits and verifications in 2019:

- Alberta Energy conducted the Year 4 Injection certification audit in September and October 2019 to confirm the injected CO₂ volume of 1,089,058 tonnes.
- Alberta Environment and Parks (AEP) issued letter on May 9, 2019 stating the completion of the re-verification for the 1st Reporting Period (August 23, 2015 to October 31, 2015).
- Shell hired a third-party verifier to verify:
  - 3rd, 4th and 5th Reporting Periods with a claim for waste heat
  - 6th, 7th and 8th Reporting Periods

For 2019, the Quest CCS project serialized a total of 1,787,416 credits on the Alberta Emission Offset Registry:
4.2 Capture (Absorbers and Regeneration)

Solvent composition was mainly on target for 2019 operation vs. the specified formulation for ADIP-X from the design phase. CO₂ removal ratio performance has been as predicted. The annual CO₂ capture ratio was 77.4% for 2015, 83.0% for 2016, 82.6% in 2017, 79.1% in 2018, and 78.8% in 2019.

The main contributors to periods of reduced CO₂ capture in 2019 were as follows:

- Periods of lowered hydrogen production demand, planned slowdowns and trips in process units outside of Quest.
- Planned maintenance activities or trips in the Quest capture unit also contributed to periods of reduced capture. These periods are listed below:
  - February 11, 2019: Reduced capture due to HMU1 amine absorber level SIS transmitter (LT-241154) dropped out, resulting in the closure of XV-241020.
  - March 1, 2019: HMU2 LT-242155B was frozen and caused HMU2 absorber to trip. ESD for 8-19 was initiated to control the valve position due to a deficiency with the input value and actual valve position.
  - April 9, 2019: Reduced capture rate due to Quest compressor trip as a result of a failed analog card.
  - May 19, 2019: Reduced capture rates due to LP steam inlet valve (FV-246006) positioner failed. This caused the valve to close and loss of steam on E-24603B.
  - July 8-9, 2019: Quest compressor (C-24701) tripped due to 138kV transmission line trip.
- July 24, 2019: The lean amine charge pump, P-24602B was shut down due to seal flush tubing leak while P-24602A was isolated for motor bearing repair.
- September 12-13, 2019: Reduced capture due to IW 8-19 shut-in for well integrity test. High pipeline and TEG pressure was observed during this period, capture reduced on HMU1&2.
- October 3, 2019: Reduced capture rate due to IW 5-35 shut-in on lower master valve inspection with ice ball observed on the lower master valve.

The CO₂ stripper operation has been stable, and the CO₂ product sent to the compression unit has been on target for purity. There are no concerns on reactivity of the impurities or impact on the phase behavior. Performance has been as expected in terms of solvent regeneration. Table 5-3 in the transport section contains the average CO₂ product composition from the capture and dehydration units.

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

<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>Electricity (Capture/Dehydration)</td>
<td>12300</td>
<td>32800</td>
<td>32600</td>
<td>32200</td>
<td>32700</td>
<td>MWhₑ²</td>
</tr>
<tr>
<td>Low Pressure Steam</td>
<td>410</td>
<td>1263</td>
<td>1297</td>
<td>1204</td>
<td>1217</td>
<td>kT</td>
</tr>
<tr>
<td>Low Temperature High Pressure Steam</td>
<td>1.96</td>
<td>5.52</td>
<td>5.23</td>
<td>5.01</td>
<td>5.12</td>
<td>kT</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>178</td>
<td>230</td>
<td>237</td>
<td>258</td>
<td>256</td>
<td>ksm³</td>
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<tr>
<td>Wastewater</td>
<td>24900</td>
<td>80900</td>
<td>61900</td>
<td>57800</td>
<td>60700</td>
<td>m³</td>
</tr>
<tr>
<td>Energy/Heat Recovered</td>
<td>33600</td>
<td>96260</td>
<td>98554</td>
<td>95060</td>
<td>93955</td>
<td>MWhₜʰ¹</td>
</tr>
<tr>
<td>CO₂ Emissions for the Capture Process</td>
<td>0.030¹</td>
<td>0.083¹</td>
<td>0.095¹</td>
<td>0.195⁴</td>
<td>0.183⁴</td>
<td>Mt CO₂</td>
</tr>
</tbody>
</table>

1. 2015-2018 CO₂ emissions have been updated based on AEP’s audit close out on waste heat methodology. The revised emissions now include the addition of 3rd party verified waste heat claims.
2. The e subscript denotes electrical energy.
3. The th subscript denotes thermal energy.
4. Under SGER, the reported indirect GHG emissions from imported steam for Quest was reduced by the Target (e.g. 20%), which is the required reduction in GHG intensity for large final emitters such as the Upgrader. Under CCIR, there is no target specified. As a result, the Target is set to 0% under CCIR.

Electricity, and steam use are approximately on target with design specifications when pro-rated for actual CO₂ 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. In 2019, the operations team targeted approximately 50 ppmv water content to the pipeline, staying within the 84 ppmv spec. Heat recovery in the demin water heaters (cooling the CO₂ stripper reboiler steam condensate) is also approximately on target from design.
During the later part of 2016, it was observed that fouling of the lean/rich exchangers was impacting the rich amine inlet temperature to the stripper. A temperature drop of about 2°C was observed over the course of the year. As a result, reboiler duty increased. Cleaning of this exchanger was completed in the 2017 spring turnaround. The exchanger was back flushed by a third-party vendor in an attempt to remove any foulant, carbon or other debris. Since the exchanger cleaning, the stripper inlet temperature has continued to drop about 3°C for a total of 5°C since start-up. These heat exchangers are planned to be cleaned during the next turnaround.

Low levels of chemical loss from the ADIP-X process is a continued success for the Quest capture operations. Amine losses from the capture unit have been minimal since the initial commissioning/inventory and start-up phases. Certain amine contents started to drop below the designed composition at the end of 2017 and continued into 2019. Amine was introduced from the amine storage tank to the amine stripper in November 2019 to increase the amine contents.

In 2019, a management of change process was initiated to increase the name plate capacity of Quest from 3564tpd to 3836tpd. This was achieved by increasing the amine flow rates on HMU1&2 absorbers. Based on the test run results, the unit was re-rated to 3750 tpd, limited by the thermal well vibration constraint on the reboiler and the flame impingement issue on the reformer tubes.

CO₂ emissions for the capture process are primarily those linked to low-pressure steam use in the CO₂ stripper reboilers (~84% of total capture emissions), and from electricity for equipment in the capture system (~5% of capture emissions).

The most significant operational issue observed since start up has been foaming of the ADIP-X solution in the HMU absorbers. This leads to tray flooding and short duration reduction in CO₂ capture from the HMUs, with a small 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. DCS control schemes implemented in 2015 have been successful in mitigating some of these causes. However, the frequency of filter change-outs in the lean amine circuit due to carryover of carbon fines from the carbon filter into the lean amine circuit continued in the first half of 2016.

In June of 2016, the lean amine carbon filter was taken offline as a test run to observe the impact on absorber foaming and mechanical filter change outs. As a mitigation, use of the anti-foam was suspended, and amine quality was monitored. When the filter was taken offline, there were no foaming events, and the frequency of filter changes was reduced.

The carbon filter remained offline until November 2017. The carbon filter was placed into service mid-November 2017 with the new carbon load. Another operational issue, noticed after placing the carbon filter back in service, is that there is a potential for vapour/nitrogen used to displace the amine from the pre/post filters during a filter change to be directed into the process. This has
caused the P-24602 amine charge pumps to trip on low suction pressure. The carbon bed was taken offline again in February 2018 after the foaming incident on HMU3. The carbon filter remained offline in 2019. Since the carbon bed has been offline, steady operation has been observed in the absorbers, and no foaming events have occurred.

In March 2018, low pH carbonic acid water was observed leaking from a pre-existing defect in the weld overlay of the nozzle which allowed the corrosive low pH water to corrode the shell through a pinhole. Work was completed to plug the reinforcing pad which required Quest to shut down in order to isolate the exchanger for repair. Based on these findings, the same failure is expected in E-24601B. A new shell was ordered and is in the schedule to be installed.

In June 2019, housing retrofit was done on the pre-filters to solve the repetitive gulling issue during filter installation and filter elements manufacture was changed due to lead-time issues. The pre-filter change-out lengths have remained the same; however, there were periods throughout the year when the time required between change-outs increased.

### 4.3 Compression

In 2019, the compressor operated at lower discharge pressures than previous years. This is due to less rate testing on the wells. The objective was to collect pressure drop data in the lateral lines and well tubing by operating the wells at maximum rates. Table 4-3 below outlines the average operating conditions for the reporting period.

<table>
<thead>
<tr>
<th>Compressor Characteristic</th>
<th>Average 2015 Operation</th>
<th>Average 2016 Operation</th>
<th>Average 2017 Operation</th>
<th>Average 2018 Operation</th>
<th>Average 2019 Operation</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Suction Pressure</td>
<td>0.03</td>
<td>0.03</td>
<td>0.03</td>
<td>0.03</td>
<td>0.03</td>
<td>MPag</td>
</tr>
<tr>
<td>Discharge Pressure</td>
<td>9.6</td>
<td>10.0</td>
<td>10.1</td>
<td>10.5</td>
<td>9.8</td>
<td>MPag</td>
</tr>
<tr>
<td>Motor Electricity Demand</td>
<td>13.3</td>
<td>13.8</td>
<td>14.2</td>
<td>14.0</td>
<td>14.2</td>
<td>MWₑ</td>
</tr>
</tbody>
</table>

### 4.4 Dehydration

The dehydration unit performance continued to exceed expectations in 2019. The system requirement was to meet the winter water content specification for the pipeline of 84 ppmv.
Actual water content for 2019 was on average 42 ppmv, and this was achieved at a lower TEG purity than design (99.6% vs. 99.7%) while maintaining the optimized nitrogen flow rates described in Section 4.2.

Carryover of TEG into the CO₂ stream also appears to be significantly less than design, with the estimated losses in 2019 being <10ppmw of the total CO₂ injection stream, compared to the 27 ppmw expected in design. Dehydration unit losses of TEG were roughly 11,100kg annually for 2019 vs. the design makeup rate of 46,000 kg annually.

4.5 Upgrader Hydrogen Manufacturing Units

The 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 2019 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. For 2019, the averaged NOx emissions with Quest operational and the FGR online are included below:

- HMU1: 37.7 kg/h, limit 76.5 kg/h
- HMU2: 30.7 kg/h, limit 76.5 kg/h
- HMU3: 60.6 kg/h, limit 130 kg/h

When the FGR fan trips, NOx levels are below the new limits listed above; however, they exceed the old limits (pre-Quest) if the CO₂ capture ratio is not reduced.

One of the most significant differences in operation of the HMUs after CO₂ capture is a reduction in reformer fuel gas pressure. Fuel gas pressure reduces as increasing amounts of CO₂ 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 CO₂ capture ratio when the HMUs went into production turndown because of reductions in hydrogen demand at the Upgrader.

The flame stability inside the reforming furnace appeared to be influenced by increased CO₂ capture rates (i.e. a change in fuel gas composition), resulting in a looser flame pattern when compared to non-Quest operation in early 2015. As capture ratios are increased, the impact to flame stability increases. The spring 2018 turnaround revealed poor burner condition in the HMU2 reformer. With Quest online, the burners are physically cracking, coking, and breaking due
to changes in burner fuel composition and flow. Burner degradation has the potential to add to the already observed poor flame patterns and hot spots within the reformer. The above is also true for the HMU1 and HMU3 burners.

In November of 2018, HMU3 started to restrict the capture ratio to 78%. This was due to a temperature cycling phenomenon in row E of the reformer, which stems from the burners. Since the burners are in poor condition, this leads to poor air to fuel mixing. This reduction is expected to last until a burner change is performed. The burners were replaced in 2019 Spring turnaround on HMU3; however, the burners were replaced in kind. The flame instability issue will remain until a new type of burner is installed.

Since commissioning in 2015, hydrogen production losses due to hydrogen entrainment in the amine absorbers has remained low, at roughly 0.1% loss of total hydrogen production. This is indicated by the roughly 0.5 vol% hydrogen content in the CO₂ stream sent to the pipeline.

From an efficiency perspective, the hydrogen production capability of the units remains largely unchanged in 2019 with Quest operating. The loss of hydrogen via entrainment in the CO₂ absorbers and into the Quest pipeline meets design expectations and there is a negligible drop in overall hydrogen production capacities. 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-CO₂ Emissions to Air, Soil or Water

In accordance with Shell’s internal guidelines, all spills – regardless of size – are recorded for tracking purposes. Quest experienced one leak in 2019.

In July 2019, the seal flush tubing on Quest lean amine pump (P-24602B) failed resulting in a leak of lean amine. The ½ inch compression fitting/piping failed at the fitting connection on the tubing. A thicker tubing was replaced on P-24602A/B/C as the same failure is expected on all three pumps. The leak was mostly contained in the berm.

4.7 Operations Workforce

The Quest CCS facilities are currently 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. In mid-2016, major start-up and commissioning issues had been resolved or mitigated (e.g. absorber foaming, compressor reverse rotation), and unit reliability was consistent. At this point, the decision was
made to merge the Quest control room operator position with the existing operator position for the Scotford Upgrader hydrogen manufacturing units. Nightshift coverage is provided by a control room operator and a field operator, with a pipeline and wells operator on-call for emergencies. Maintenance support has been integrated into existing Scotford Upgrader maintenance department resources. 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 was stable during the reporting period. Table 5-1 below compares operating conditions to design values from the engineering phases of the project.

Table 5-1: Pipeline Design and Operating Conditions

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pipeline Inlet Pressure</td>
<td>Normal</td>
<td>MPag</td>
<td>9.4</td>
<td>9.8</td>
<td>9.9</td>
<td>10.3</td>
<td>9.6</td>
</tr>
<tr>
<td></td>
<td>Maximum Operating</td>
<td>MPag</td>
<td>12</td>
<td>12</td>
<td>13.58</td>
<td>13.58</td>
<td>13.58</td>
</tr>
<tr>
<td></td>
<td>Minimum Operating</td>
<td>MPag</td>
<td>8.5</td>
<td>8.8</td>
<td>8.7</td>
<td>8.8</td>
<td>8.8</td>
</tr>
<tr>
<td></td>
<td>Design maximum</td>
<td>MPag</td>
<td></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Pressure Loss from Inlet to Wellsite</td>
<td>Normal</td>
<td>MPa</td>
<td>0.6</td>
<td>0.6</td>
<td>0.6</td>
<td>0.9</td>
<td>0.6</td>
</tr>
<tr>
<td>Temperature</td>
<td>Compressor Discharge</td>
<td>°C</td>
<td>130</td>
<td>130</td>
<td>128</td>
<td>131</td>
<td>131</td>
</tr>
<tr>
<td></td>
<td>Pipeline Inlet after cooler</td>
<td>°C</td>
<td>43</td>
<td>43</td>
<td>41</td>
<td>41</td>
<td>41</td>
</tr>
<tr>
<td></td>
<td>Upset Condition at Inlet</td>
<td>°C</td>
<td></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Injection Well 7-11 Inlet Temperature</td>
<td>°C</td>
<td>15</td>
<td>16</td>
<td>14</td>
<td>13</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td>Injection Well 8-19 Inlet Temperature</td>
<td>°C</td>
<td>12</td>
<td>12</td>
<td>11</td>
<td>9</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td>Injection Well 5-35 Inlet Temperature (as of Oct 19, 2018)</td>
<td>°C</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Flow rates</td>
<td>Normal Transport Rate</td>
<td>Mt/a</td>
<td>1.04</td>
<td>1.11</td>
<td>1.14</td>
<td>1.06</td>
<td>1.14</td>
</tr>
<tr>
<td></td>
<td>Design minimum</td>
<td>Mt/a</td>
<td></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Total Transported</td>
<td>Mt</td>
<td>0.371</td>
<td>1.11</td>
<td>1.14</td>
<td>1.06</td>
<td>1.14</td>
</tr>
<tr>
<td>Energy and Emissions</td>
<td>Total Electricity for Transport (compression)</td>
<td>MWh</td>
<td>41,527</td>
<td>119,426</td>
<td>121,593</td>
<td>119,396</td>
<td>143,453</td>
</tr>
<tr>
<td></td>
<td>Total Transport Emissions (includes compression)</td>
<td>Mt CO₂eq</td>
<td>0.027</td>
<td>0.077</td>
<td>0.078</td>
<td>0.045 1</td>
<td>0.054 1</td>
</tr>
</tbody>
</table>

1. Indirect GHG emission from imported electricity now capturing electricity usage from both the Upgrader Cogen (0.37 tCO₂/MWh) and the grid (0.64 tCO₂/MWh).
The pipeline operates with CO₂ in supercritical phase at the pipeline inlet (9.9 MPag, 41°C) and with CO₂ leaving the main pipeline to the wellsites in liquid phase (9.3 MPag, 14°C). These two phases are commonly lumped together as "dense phase" in industry. The phase transition from supercritical to liquid occurs roughly 15-30 km downstream from the pipeline inlet, based on a field temperature survey completed in 2015. Heat transfer with the soil, as was expected in the design phase, causes the majority of the temperature reduction in the pipeline.

CO₂ emissions from the transport component of the operation are primarily from the electricity used to power the compressor (99% of total transport emissions).

**Fluid Composition**

Fluid composition in the pipeline was very close to the design normal operating condition for most 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 5-2.

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

<table>
<thead>
<tr>
<th>Component</th>
<th>Actual Operating 2015 (vol%)</th>
<th>Actual Operating 2016 (vol%)</th>
<th>Actual Operating 2017 (vol%)</th>
<th>Actual Operating 2018 (vol%)</th>
<th>Actual Operating 2019 (vol%)</th>
<th>Design Normal Composition</th>
<th>Design Upset Composition</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>99.45</td>
<td>99.38</td>
<td>99.46</td>
<td>99.44</td>
<td>99.44</td>
<td>99.23</td>
<td>95.00</td>
</tr>
<tr>
<td>H₂</td>
<td>0.48</td>
<td>0.51</td>
<td>0.47</td>
<td>0.46</td>
<td>0.48</td>
<td>0.65</td>
<td>4.27</td>
</tr>
<tr>
<td>CH₄</td>
<td>0.06</td>
<td>0.06</td>
<td>0.06</td>
<td>0.06</td>
<td>0.05</td>
<td>0.09</td>
<td>0.57</td>
</tr>
<tr>
<td>CO</td>
<td>0.02</td>
<td>0.02</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
<td>0.02</td>
<td>0.15</td>
</tr>
<tr>
<td>N₂</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.01</td>
</tr>
<tr>
<td>Total</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
</tbody>
</table>

**Water Content and CO₂ Phase Change Management**

Pipeline operation since start-up was below the winter water specification of 4 lb / MMscf (84 ppmv). The average for 2019 was 42 ppmv. 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.
5.2 Pipeline Inspections

The following inspection and monitoring activities have also been conducted to ensure pipeline integrity:

- Daily operator rounds of the pipeline, well sites, and line break valves (LBVs).
- Non-destructive examination (ultrasonic thickness test) on above ground piping to identify possible corrosion of the pipeline based on Shell’s risk-based Inspection calculations. These intervals are subject to change depending on corrosion loop monitoring data tracked through Shell’s integrity management system (IMS).
- 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. The required AER in line inspection (ILI) interval is currently every 5 years. The next ILI inspection is scheduled for 2021.
- 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 are done quarterly as per an agreement with the AER. In August 2018, the frequency of flyover inspections was reduced from bi-weekly to quarterly. This was done to reduce the safety exposure during the aerial flights as well as program cost as previous flights had not yielded any significant findings. The Q3 2019 aerial inspection was missed due to a vendor timing and contracts and procurement conflict. The Q4 2019 flyover was completed by Canadian Helicopters Limited with no noteworthy findings. Moving forward, Shell has contracts in place with Ventus Geospatial Canada to utilize an unmanned aerial vehicle (UAV) for inspections. This will allow for inspections to be completed with less health and safety risks to personnel (no pilot required) and overall cost reduction.
6 Facility Operations - Storage and Monitoring

This section provides an overview of the wells and MMV activities for the operational year 2019.

6.1 Storage Performance

Injection of CO₂ into the 8-19 and 7-11 wells began on Aug 23, 2015, and 5-35 commenced injection October 19, 2018. As of Dec 31, 2019, about 4.8 Mt CO₂ have been injected into the three wells as illustrated in Figure 6-1. The injection stream composition is described in detail in Table 5-3 and is shown in Figure 6-2.

By the end of December 2019, about 2.15 Mt of CO₂ had been injected into the 7-11 well, 2.23 Mt of CO₂ into the 8-19 well, and 0.43 Mt of CO₂ into the 5-35 well. Figure 6-3, Figure 6-4 and Figure 6-5 show the daily average flow rates and P/T conditions at the wells during the injection period.

Figure 6-1: Quest Injection Totals: Cumulative CO₂ injected into the wells from start-up through to the end of 2019 (red). The blue, grey and green lines show the average hourly flow rates into each of the injection wells.
Figure 6-2: Quest Injection Stream Content: Average injection composition for 2019.
Figure 6-3: The 8-19 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection to the end of 2019.
Figure 6-4: The 7-11 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2019.
Figure 6-5: The 5-35 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2019.
6.1.1 Estimate of Storage Potential

Reservoir modelling continues to indicate that there is more than sufficient storage capacity for the full project volume of 27 Mt of CO₂. Refer to the AER Annual Report (2019) Section 3.5: Reservoir Capacity for discussion. The residual uncertainty in pore volume is unlikely to decrease much further since several years of performance data has now been collected and used to calibrate the reservoir model.

Table 6-1: Remaining capacity in the Sequestration Lease Area as of end 2019

<table>
<thead>
<tr>
<th>Year</th>
<th>Yearly Injection Total</th>
<th>Remaining Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-injection</td>
<td>-</td>
<td>27 Mt CO₂</td>
</tr>
<tr>
<td>2015</td>
<td>0.371 Mt</td>
<td>26.629 Mt CO₂</td>
</tr>
<tr>
<td>2016</td>
<td>1.108 Mt</td>
<td>25.521 Mt CO₂</td>
</tr>
<tr>
<td>2017</td>
<td>1.138 Mt</td>
<td>24.383 Mt CO₂</td>
</tr>
<tr>
<td>2018</td>
<td>1.066 Mt</td>
<td>23.317 Mt CO₂</td>
</tr>
<tr>
<td>2019</td>
<td>1.128 Mt</td>
<td>22.189 Mt CO₂</td>
</tr>
</tbody>
</table>

6.1.2 Injectivity Assessment

The project was designed for a maximum injection rate of about 145 t/hr into three wells. Since start-up in 2015, injection rates have been up to 155 t/hr. The 5-35 injection well was brought on in October 2018 for reasons of operational optionality.

Injection stream compositions and variations (Table 5-2) are within design scope and have not impacted capture or storage operations. There are no concerns on reactivity of the impurities or impact on the phase behavior.

Injectivity reductions have been observed following short well shut in periods; however, as the initial injectivity was very high, these injectivity reductions currently do not form an operational constraint. At this time, the cause of the injectivity reductions is unknown and understanding how to reduce or even reverse these injectivity reductions may be important for maintaining reliable CO₂ injection at Quest and other CCS wells.

It is expected that the project will be capable of sustaining adequate injectivity for the duration of the project life.

6.2 MMV Activities - Operational Monitoring

In 2019 MMV activities included: atmosphere, hydrosphere, geosphere, and well-based monitoring. The following is a summary of these activities:

Atmosphere Domain: Monitoring of CO₂ levels in the atmosphere at the injection well sites continued using the Light Source technology. Operator rounds daily at the injection well sites.

Hydrosphere Domain: Discrete sampling at select Landowner water wells before and after the 2019 VSP program in the vicinity of the 05-35 and 08-19 well sites.

Biosphere Domain: No activities took place regarding soil gas and soil surface CO₂ flux measurements.
Geosphere Domain: Monthly satellite image collection for InSAR continued. Since September 2017, a single frame centered over the 3 injection well pads was used for image collection. 2D VSP and 2D SEIS data were acquired at IW5-25 and IW8-19 well in Q1 2019.

Well based Monitoring: ongoing data collection via wellhead gauges, downhole gauges, downhole microseismic geophone array, and DTS lightboxes. Routine well maintenance and integrity activities (Section 2.4).

The 2017 MMV plan includes a tiered system to review and assess the MMV data. Tier 1 technologies form the basis for assessing whether or not there is an indication of loss of containment. Depending on the outcome of that assessment, further analysis or investigation of the Tier 2 technologies will be undertaken and then, if needed, Tier 3 technologies will be assessed.

No trigger events were identified during 2019 that would indicate a loss of containment (Table 6-2). As a result, the focus of this report is on Tier 1 technologies.

With the data collected so far, CO₂ injection within the BCS is conforming to model predictions, based on:

- The existing time-lapse seismic monitoring results indicate that the size of the CO₂ plumes, as measured by the monitor VSPs is much smaller than the maximum plume lengths predicted from the Gen 4 model. This is another indication that the reservoir is behaving better than expected, and that the displacement of brine by the CO₂ may be more effective than the initial pre-injection modelling predicted.

- Assessment of the pressure data indicates that the reservoir has more than enough capacity for the full life of this project.

- In 2018 and 2019 a few time-significant pressure fall-offs were recorded and this enabled a calibration of conformance to shut-in stabilized pressures. The modelled borehole pressures show that the reservoir model pressure fall-off response is similar to those observed in the longer more stabilized pressure fall-offs. With this additional calibration it is reasonable to use the model for pressure prediction forecasting for injection rates similar to those observed to date.

Further details of the MMV activities undertaken and observations made during 2019 can be found in the 2019 AER Annual Status Report [1].
Table 6-2: Overall assessment of trigger events used to assess loss of containment in 2019

<table>
<thead>
<tr>
<th>Tier</th>
<th>Technology^</th>
<th>Trigger</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tier 1</td>
<td>IW DHP</td>
<td>Measuring greater than 26 Mpa</td>
<td></td>
</tr>
<tr>
<td></td>
<td>DMW DHP</td>
<td>Anomalous pressure increase above background levels</td>
<td></td>
</tr>
<tr>
<td></td>
<td>MSM</td>
<td>Sustained clustering of events with a spatial pattern indicative of fracturing upwards</td>
<td></td>
</tr>
<tr>
<td></td>
<td>DTS</td>
<td>Sustained temperature anomaly outside casing</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Pulsed Neutron log</td>
<td>Indication of CO₂ out of zone</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SCVF</td>
<td>Change in geochemical composition indicating presence of project CO₂</td>
<td></td>
</tr>
<tr>
<td>Tier 1 - when available</td>
<td>VSP2D</td>
<td>Identification of a coherent and continuous amplitude anomaly above the storage complex</td>
<td>not applicable yet</td>
</tr>
<tr>
<td></td>
<td>SEIS3D</td>
<td>Identification of a coherent and continuous amplitude anomaly above the storage complex</td>
<td>Monitor survey executed in Q1/2019</td>
</tr>
<tr>
<td></td>
<td>SEIS2D</td>
<td>Identification of a coherent and continuous amplitude anomaly above the storage complex</td>
<td>not evaluated</td>
</tr>
</tbody>
</table>

^ based on Table 4-3 of the 2017 MMV Plan

Legend: no trigger event, trigger event, not evaluated

6.3 Wells Activities

6.3.1 Injection Wells

In 2019 the injection wells (8-19, 7-11 and 5-35) underwent routine work including a WIT (wellhead integrity testing - wellhead maintenance and pressure testing) and a packer isolation test. Tubing integrity logging (caliper) and hydraulic isolation logging (PNx) was undertaken at 5-35.

Figure 6-3, Figure 6-4, and Figure 6-5 show the daily average flow rates and P/T conditions at the three injection wells during the injection period.

6.3.2 Monitor wells

Discrete pressure measurements were acquired in the Cooking Lake in DMW 7-11, DMW 8-19 and DMW 5-35 through MDT/XPT sampling during the 2012/2013 drilling campaign. Continuous pressure data in the Cooking Lake Formation via four monitoring wells, DMW 7-11, DMW 8-19, and DMW 5-35 and the farther field DMW 3-4 has been ongoing since Q3, 2015, as illustrated in Figure 6-6 and Figure 6-7.

Project groundwater monitoring wells had maintenance checks performed on the downhole gauges and downloading pressure and basic water quality data. As per the MMV Tiering system, no discrete groundwater and gas sampling is planned to occur on the Project groundwater wells unless there is evidence of potential loss of CO₂ containment or as requested.
Figure 6-6: Quest DMW pressure history before and during injection.

Figure 6-7: Quest 3-4 DMW pressure history.
6.3.3 Surface Casing Vent Flow and Gas Migration Monitoring

As required, annual testing was completed in 2019 for surface casing vent flow (SCVF) and gas migration (GM) at the injection pads. Reports were sent to the AER in July 2019.

The SCVF flow test results for IW 5-35 and IW 7-11 are summarized in Figure 6-8. Measurements at the IW 5-35 well are at similar levels to those observed historically. The IW 7-11 SCVF declined to zero in 2019. The IW 8-19 SCVF tested at zero for a fourth consecutive year.

Gas migration testing, as per the suggested method in AER Directive 20 - appendix 2, was performed on both wells. Previously, the gas migrations observed on IW 5-35 and IW 7-11 occurred as bubbles in the well cellars. The gas migration measurements at 30 cm from the wellhead are inside the well cellar which is typically water filled. In 2019 and 2018 the gas concentration measurements at 30 cm were whole air measurements collected via methane meter suspended over the well cellar. Consistent with 2018 results, the 2019 gas migration detections were limited to the well cellar. Measurements taken from soil gas sampling core holes did not detect any hydrocarbon lower explosive limits (LELs).

In April 2019 the IW 5-35 wellsite was flooded with freshwater (meltwater and rainwater) and bubbles were observed in two locations near the wellhead but outside the standard gas migration testing area. The locations were marked and in June 2019, gas migration testing was also performed on these two marked locations as a precaution. Each of the soil gas testing core holes were tested for LELs and CO₂. No LELs were detected at either of the test location core holes. A soil gas sample was acquired at both locations and submitted for analysis despite field observations. The gas isotopic analysis results indicate that the CO₂ present in the sample is atmospheric. No methane or other hydrocarbons were identified in the samples. Therefore, the observed bubbles at IW 5-35 are unlikely indicative of additional or further migrated gas.

Overall, while gas migration remains at IW 5-35 and IW 7-11; it remains consistent in composition and isotopic signature and has very limited impact and no potential for concern beyond the lease.

Figure 6-8: SCVF Pressure and Flow rate summary graphs for IW 5-35, IW 7-11 and IW 8-19.
Facility Operations - Maintenance and Repairs

A simulator for HMU/Quest is currently used and maintained to increase operator competency in the Quest unit. This should result in longer run time and reliability. Training plans and maintenance procedures for the maintenance personnel were completed and included vendor training for key components (analysers, compressor). Wherever possible, Shell has leveraged existing processes, systems and procedures to facilitate a smooth transition of Quest into Scotford routine maintenance and operations.

Spare part requirements based on reliability centred maintenance were purchased and delivered. The amine filter supplier was changed due to availability and cost.

All essential maintenance processes are in place and have received internal approvals.

Maintenance and repairs during 2019:

- Well site FV-702104/204 (limited rates Mar 4)/304 sticking in cold weather, positioner replacement.
- Amine charge pump logic MOC completed to make axial vibration trip 2 out of 2 to increase reliability.
- Amine charge pump P-24602A axial probe replacement. False indication which caused Quest trip and unplanned down time of Quest.
- P-24602A/B/C seal flush line replacement due to B failure (July 24/2020).
- V-24604/09 filter retrofit complete (New internal filter rod design to reduce maintenance and filter costs).
- C-24701 tripped as a result of exciter panel analog card failure; card was replaced and compressor restarted.
- Quest creep study and testing completed to safely increase CO₂ rates from 3550 tpd to 3750 tpd.
- The new Boreal line of site detection in C-24701 building, E-24706/07 and Quest well sites required servicing and calibration along with training for on site Shell instruments technicians.
- Started civil work for new permanent caustic facility in Quest, all concrete work completed (completion of piping and caustic building second quarter 2020).
- Loss of communication MOC completed to provide time delay for DCS alarms (cooling tower plume interfere with SCADA communication system).
- Replaced insulation soft covers with hard insulation in certain areas due to freezing of instruments.
- Valve bonnet failure requiring installation of quill and injection on V-24607 LP condensate valve
- HP condensate sample point tee pinhole leak downstream LV-248003 cut out and repaired.
• Logic changes on DCS surrounding amine filter swings and amine auto pump starts to avoid nuisance trips.

• C-24701 trip due to factory voltage drop logic, MOC created to change to Shell settings and avoid power bump trips.

• C-24701 HVAC repairs due to inadequate heating in compressor building.

2019 Maintenance

• Permanent caustic skid civil work started 4th quarter 2019
• V-24607 LP condensate bonnet failure
• LV-248003 HP condensate sample tee replacement
• E-24601B new shell ordered and delivered
• P-24607 pump replacement and d/s check valve
• C-24701 analog card in exciter PLC failed
• C-24701 compressor building main HVAC sensor replacement
• P-24601B outboard bearing pump seal leak repaired
• V-24604/09 filter retrofit complete
• E-24707C fan replacement
• P-24602B seal flush line replacement (Tubing failed)
• P-24602B motor replacement
• P-24602A outboard motor seal replaced

2019 Pipeline Maintenance

• Wellsite flow controller positioner’s replacement due to high nitrogen usage at well site FV’s
• Changed out LBV1 EFOY unit in March/2019
• SCADA MOC to increase timer for “loss of communication alarms to DCS” (caused by chemicals cooling tower plume with line of sight to well site1)
• 5-35 (Hydraulic logging Jan 29/19)
• 5-35 lower master packing leak repaired
• Quest truck replacement and maintenance as required (Purchased Dec 2019)
• Quest well site office trailer purchase
• Road and site ground maintenance as required
• Full ROW inspection, ground repair and vegetation control
• MMV building HVAC repairs
• Identification of wellsite #3 drainage issues and future repair plan (execution spring 2019)
• Security cameras set up at all LBV's and well sites
• Fluid Shots (CWI) at well site 7-11/8-19/5-35
• SCVF and Gas Migration testing complete at 7-11/8-19/5-35
• 5-35 wing valve leak repaired
• 5-35 flow cross top ring gasket replacement
• WIT Complete at 7-11/8-19/5-35 (Well integrity testing)

2019 Wellsite and MMV Maintenance
• Injection well fluid shots and top up of N₂ in the annulus at all 3 injection wells.
• Replaced the wellhead flow cross, top, and corresponding ring gaskets at IW 5-35
• Greasing and injection of stem packing into valve stems Lower Master Valve, Upper Master Valve and Flow Wing Valve on the IW 5-35 wellhead
• Replacement of one Paladin A/D converter at the DMW 8-19 junction box.
• Replacement of battery at DMW 3-4.
• Maintenance of groundwater well Troll gauges included in the installation of new sensors in the gauges for pH, ORP, EC and temperature.
• Well site IT servers were remediated.

Overall maintenance issues have been minimal. Sharing of best practices by networking with other operating facilities continues to help improve maintenance practices and procedures.
8 Regulatory Approvals

8.1 Regulatory Overview

Regulatory submissions in 2019 followed the schedule set forth by the approval. Regulatory approvals in 2019 addressed the ongoing operations and optimization of safe operations.

8.2 Regulatory Hurdles

There were no significant regulatory hurdles in 2019.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to Quest for the 2019 reporting period.

Table 8-1: Regulatory Approval Status

<table>
<thead>
<tr>
<th>Approval or Permit</th>
<th>Regulator</th>
<th>Status and Timing of Approval/Permit</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Injection and Storage</td>
<td>AER</td>
<td>Submitted March 31, 2019</td>
<td>Annual Report</td>
</tr>
<tr>
<td>Quest Carbon Capture and Storage Project 2018 Annual Status Report</td>
<td>AER</td>
<td>Submitted July 29th, 2019</td>
<td>Submission in accordance with conditional approval of September 4, 2013 regarding Shell’s request to defer repair of SCVF and GM for IW 5-35 and IW 7-11.</td>
</tr>
<tr>
<td>Annual Submission for SCVF and GM testing.</td>
<td>AER</td>
<td>Received approval renewal on February 7, 2019</td>
<td>Water Act Approval No. 70013-02-00</td>
</tr>
</tbody>
</table>

8.4 Next Regulatory Steps

The regulatory requirements will be focused on demonstrating compliance with existing agreements. With ongoing operations, minor changes may be required to improve operational efficiency while ensuring safe performance.

Expected submissions for 2020 include:

- 2020 MMV plan submission
- 2020 Closure plan submission
- 2019 Annual status report to AER
- 2019 Net revenue position of statement of project costs and projects revenues (as per additional credits agreement)
9 Public Engagement

9.1 Stakeholder engagement for the Quest CCS Facility

Upon start-up of the Quest CCS facility, stakeholder engagement focused on multiple streams: community relations, sharing of CCS knowledge and CCS advocacy.

9.2 Community Relations

The following community stakeholder engagement activities took place for Quest in:

1) Updates to municipal governments
2) Working to resolve public concerns
3) Participation in the Community Advisory Panel (CAP)
4) Emergency Response

Municipal Government Updates

Annual updates were offered to municipal governments at their council sessions to provide updates on Quest operations. Updates were provided to the following municipalities in 2019:

- February 12, 2019 – Thorhild County
- March 12, 2019 – Strathcona County

No major issues were raised specific to the Quest facility and questions were answered immediately at the council sessions.

Public Concerns

Shell has a comprehensive public concerns process that is designed to encourage community feedback. In 2019, Shell recorded eight concerns related to Quest operations. Three concerns were related to crop loss. These concerns were associated with the weed management program and ongoing recovery of the soil following pipeline construction. Engagement with landowners continues as Shell works with impacted stakeholders to find the most appropriate actions to address these impacts. Three concerns were related to the quarterly testing of water wells. These concerns were related to water well maintenance rather than the testing of the wells themselves (not related to Shell’s activity). One concern was related to the potential for a landowner’s water well to be impacted by Shell MMV activities. One concern was related to water pooling on the 5-35 well pad. While a project to deal with the water pooling issue was completed in the summer of 2019, heavy rainfall through the spring and summer made it was necessary to haul water off-site.

Participation on Community Advisory Panel (CAP)

To involve the public in the development of the MMV plan, a Community Advisory Panel (CAP) was formed in 2012. The CAP comprises of local community members, academics, emergency responders, the AER and public health professionals. 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 2019, the Quest CAP met on June 12 to review the latest MMV data. New
representatives were in attendance from Thorhild County and the Alberta Energy Regulator (AER). The terms of reference was updated to reflect the current state now that Quest has been operational for a few years.

**Emergency Response**

Groundtruthing – an activity to update contact information and to communicate information about the project for residents within the emergency response zone – was conducted in 2019 for the bi-annual update of the emergency response plan. Stakeholders were invited to meet with Shell during the groundtruthing process.

### 9.3 CCS Knowledge Sharing

Global interest into our experience with the Quest facility continued in 2019.

As such, members of the Quest team attended or hosted numerous conferences, workshops and tours. Table 9-1 below gives an overview of the 2019 activities.

The following are a list of Quest CCS publications by Shell in 2019:
Table 9-1: 2019 Knowledge Sharing

<table>
<thead>
<tr>
<th>2019 Conferences/Workshops/Tours</th>
<th>Date</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon Capture Coalition Workshop</td>
<td>January 22</td>
<td>Houston, TX</td>
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<tr>
<td>CSA Standard Working Group</td>
<td>February 6</td>
<td>Online</td>
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<tr>
<td>API CCS Working Group</td>
<td>February 11</td>
<td>USA</td>
</tr>
<tr>
<td>NAIT Carbon Productivity Workshop</td>
<td>February 24</td>
<td>Edmonton, AB</td>
</tr>
<tr>
<td>Int. CCS Knowledge Centre</td>
<td>March 6</td>
<td>Regina, SK</td>
</tr>
<tr>
<td>SINOPEC</td>
<td>March 7</td>
<td>Fort Saskatchewan, AB</td>
</tr>
<tr>
<td>API CCS Working Group</td>
<td>March 12</td>
<td>USA</td>
</tr>
<tr>
<td>U of A Economics and Environment class tour</td>
<td>March 22</td>
<td>Fort Saskatchewan, AB</td>
</tr>
<tr>
<td>API CCS Working Group</td>
<td>April 11</td>
<td>USA</td>
</tr>
<tr>
<td>NRCAN (Minister Sohi) Tour</td>
<td>April 24</td>
<td>Fort Saskatchewan, AB</td>
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<tr>
<td>GeoConvention</td>
<td>May 13-15</td>
<td>Calgary, AB</td>
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<tr>
<td>GRC 2019 - Carbon Capture, Utilization and Storage</td>
<td>May 5-10</td>
<td>Geneva, Switzerland</td>
</tr>
<tr>
<td>API CCS Working Group</td>
<td>May 23</td>
<td>USA</td>
</tr>
<tr>
<td>GoA Annual Report presentation</td>
<td>May 29</td>
<td>Edmonton, AB</td>
</tr>
<tr>
<td>CAP Meeting</td>
<td>June 12</td>
<td>Thorhild, AB</td>
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<tr>
<td>Equinor - Northern Lights CCS Workshop</td>
<td>June 17</td>
<td>Online</td>
</tr>
<tr>
<td>GOA Review - MMV and Closure Plans</td>
<td>June 18</td>
<td>Edmonton, AB</td>
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<tr>
<td>AIHA Tour (Conservative MPs)</td>
<td>July 19</td>
<td>Fort Saskatchewan, AB</td>
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<tr>
<td>JEAGHG Summer School</td>
<td>July 8</td>
<td>Regina, SK</td>
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<tr>
<td>Kuwait KOC/KNPC Tour</td>
<td>September 24</td>
<td>Fort Saskatchewan, AB</td>
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<tr>
<td>45Q and IRS meeting</td>
<td>September 25</td>
<td>Washington, DC</td>
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<tr>
<td>EU SECURE Delegation Tour</td>
<td>September 27</td>
<td>Fort Saskatchewan, AB</td>
</tr>
<tr>
<td>API CCS Working Group</td>
<td>December 13</td>
<td>USA</td>
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</table>
The Quest team also publishes work to share findings and lessons learned from experience in operating the facility. The following are a list of Quest CCS publications by Shell in 2019:

9.4 Quest Advocacy

Quest advocacy activities in 2019 were largely related to the milestone of capturing 4 million tonnes of CO₂. Among the key messages shared:

- Quest is exceeding expectations.
  - In less than four years, the Quest carbon capture and storage (CCS) facility has captured and safely stored four million tonnes of CO₂, ahead of schedule and at a lower cost than anticipated. Four million tonnes of CO₂ is equal to the annual emissions from about one million cars.
  - Quest is breaking records. Quest has now stored underground the most CO₂ of any onshore CCS facility in the world with dedicated geological storage.

- Costs of CCS are coming down
  - If Quest were to be built again today, it would cost 20-30% less to build and operate, thanks to a variety of factors including replication, capital efficiency improvements and a lower cost environment.
  - Shell is sharing knowledge and lessons learned about Quest, together with our government and joint venture partners, to help bring down future costs that will help CCS scale up globally.
  - Quest was made possible through funding for CCS from the governments of Alberta and Canada (C$745 million and C$120 million). It’s through these funding arrangements that we are publicly sharing Quest’s designs and lessons learned.

- Canada can be a leader in CCS and clean tech
- CCS is viable in the energy transition

A news release was distributed on May 23, with most coverage occurring that day. The communications campaign around the 4 million tonne milestone was successful in generating earned media coverage in key markets across Canada. A paid social media campaign followed the announcement. Overall, social media reaction to the coverage and paid campaign was net positive in nature.
10 Costs and Revenues

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

10.1 Capex Costs

Table 10-1 reflects the project’s incurred capital phase costs. The categories follow those used by Shell over the life of the project to track project costs. Total capital costs required to reach commercial operation on October 1, 2015 were approximately $790 million, versus the original estimate of $874 million.

Table 10-1: Project Incurred Capital Costs (.000)

<table>
<thead>
<tr>
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<tr>
<td>Overall Venture Costs</td>
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<tr>
<td>Shell Labor, &amp; Commissioning</td>
<td>19,470</td>
<td>5,414</td>
<td>32,638</td>
<td>23,466</td>
<td>57,311</td>
<td>28,753</td>
<td>147,582</td>
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<tr>
<td>Sub Total</td>
<td>19,470</td>
<td>5,414</td>
<td>32,638</td>
<td>23,466</td>
<td>57,311</td>
<td>28,753</td>
<td>147,582</td>
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<tr>
<td>Tie-in Work / Brownfield Work</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Tie-In/ Turnaround Work Capture</td>
<td>0</td>
<td>0</td>
<td>7,331</td>
<td>10,234</td>
<td>10,430</td>
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<td>Tie-In Work Pipeline</td>
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<td>196</td>
<td>518</td>
<td>334</td>
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<td>Sub Total</td>
<td>0</td>
<td>0</td>
<td>7,527</td>
<td>10,753</td>
<td>10,764</td>
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<td>Capture Facility*</td>
<td>52,671</td>
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<td>Engineering</td>
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<td>32,799</td>
<td>5,180</td>
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<td>Construction Management</td>
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<td>16,967</td>
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<td>42,315</td>
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<td>Subcontracts</td>
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<td>Indirects / Freight</td>
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<td>FGR Mods/HMU Revamps</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
<td>Sub Total</td>
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<td>210,141</td>
<td>120,640</td>
<td>-3,803</td>
<td>437,419</td>
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<tr>
<td>SUBSURFACE - Wells*</td>
<td>63,175</td>
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<td>Injection Wells</td>
<td>1,090</td>
<td>17,970</td>
<td>3,641</td>
<td>167</td>
<td>1,776</td>
<td>24,643</td>
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<tr>
<td>Monitor Wells</td>
<td>0</td>
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<td>54</td>
<td>-20</td>
<td>571</td>
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<td>Water Wells</td>
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<td>-53</td>
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<td>0</td>
<td>1,569</td>
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<td>Other MMV</td>
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<td>3,309</td>
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<td>1,862</td>
<td>12,123</td>
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<tr>
<td>Sub Total</td>
<td>63,175</td>
<td>1,090</td>
<td>22,558</td>
<td>6,951</td>
<td>5,443</td>
<td>4,209</td>
<td>40,251</td>
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**Table 10-2: Project Operating Costs (.000)**

<table>
<thead>
<tr>
<th></th>
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</thead>
<tbody>
<tr>
<td>Power</td>
<td>3,717.70</td>
<td>4,513.96</td>
<td>7,562.80</td>
<td>9,056.83</td>
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<tr>
<td>Steam</td>
<td>8,414.46</td>
<td>8,834.50</td>
<td>5,464.59</td>
<td>6,284.98</td>
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<tr>
<td>Compressed Air</td>
<td>67.67</td>
<td>62.59</td>
<td>50.19</td>
<td>54.05</td>
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<tr>
<td>Cooling Water</td>
<td>427.95</td>
<td>389.81</td>
<td>379.14</td>
<td>446.29</td>
</tr>
<tr>
<td>Direct Labour and Personnel Costs</td>
<td>7,829.42</td>
<td>5,787.86</td>
<td>7,383.90</td>
<td>7,129.00</td>
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<tr>
<td>Maintenance Materials and Technical Services</td>
<td>969.42</td>
<td>942.63</td>
<td>1,435.98</td>
<td>1,286.74</td>
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<tr>
<td>Property Tax</td>
<td>2,003.72</td>
<td>2,000.28</td>
<td>1,842.73</td>
<td>1,916.60</td>
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<td>Sequestration Opex¹</td>
<td>7,052.85</td>
<td>6,797.59</td>
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<td>0.00</td>
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<tr>
<td>MMV after Operations</td>
<td>1,690.41</td>
<td>1,655.74</td>
<td>625.64</td>
<td>381.34</td>
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<td>Post Closure Stewardship Fund</td>
<td>272.07</td>
<td>264.28</td>
<td>243.33</td>
<td>250.48</td>
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<td>Other Well Costs</td>
<td>431.49</td>
<td>442.12</td>
<td>102.74</td>
<td>214.11</td>
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<td>Subsurface Tenure Costs</td>
<td>362.50</td>
<td>420.00</td>
<td>400.10</td>
<td>454.20</td>
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<td>Pipeline - Inspection and Pigging</td>
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<td>175.36</td>
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<td>Amine²</td>
<td>340.67</td>
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<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Chemicals</td>
<td>20.35</td>
<td>97.92</td>
<td>150.69</td>
<td>157.71</td>
</tr>
<tr>
<td>Vendor rebates</td>
<td>-122.32</td>
<td>-100.36</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Corporate and Other Costs</td>
<td>119.24</td>
<td>205.95</td>
<td>133.08</td>
<td>302.39</td>
</tr>
<tr>
<td>Sustaining Capital³</td>
<td>0.00</td>
<td>54.89</td>
<td>0.00</td>
<td>432.41</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>33,743.37</strong></td>
<td><strong>32,710.26</strong></td>
<td><strong>25,950.27</strong></td>
<td><strong>28,506.61</strong></td>
</tr>
</tbody>
</table>
Notes:
1. Methodology for fixed overhead allocations captured under Sequestration Opex was reviewed in 2017. It is now distributed to the appropriate categories prospectively (from 2018).
2. Some amine loss was observed in 2019. A total of 20m³ of amine was added to the amine stripper from the amine reservoir tank, however no new amine has been procured.
3. Sustaining Capital has been captured as an operating cost as per the Funding Agreement guidance.
10.3 Revenues

Revenues reflect both capital and operational funding, as well as CO₂ reduction credits received up to December 31, 2019.

The value of CO₂ emission offset credits reported in a given year do not reflect the CO₂ volumes injected in that year due to the time taken to verify injection volumes and issue credits. The value of CO₂ emission offset credits in 2019 relate to 1,787,416 base and additional credits serialized during the year (valued at $30/tonne). As per the multi-credit agreement signed with the Province of Alberta, additional credits are expected one year after base credits are issued and reported in the period in which they are received.

Table 10-3: Project Revenues

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<tbody>
<tr>
<td>Operation</td>
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<td>Operation</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Revenue from CO₂ Sold</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Transport Tariff</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Pipeline Tolls</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Revenues from incremental oil production due to CO₂ injection</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Revenue for providing storage services</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other incomes - Alberta innovates Grant, NRCan Funding &amp; GoA Funding</td>
<td>573,345,455</td>
<td>29,451,644</td>
<td>30,100,000</td>
<td>30,796,466</td>
<td>30,049,934</td>
<td>177,601,957</td>
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<tr>
<td>CO₂ emission offset credits</td>
<td>3,330,800</td>
<td>34,702,760</td>
<td>63,146,160</td>
<td>53,622,480</td>
<td>349,200,000</td>
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<tr>
<td><strong>Total Revenues</strong></td>
<td><strong>573,345,455</strong></td>
<td><strong>32,782,444</strong></td>
<td><strong>64,802,760</strong></td>
<td><strong>93,942,626</strong></td>
<td><strong>83,672,414</strong></td>
<td><strong>526,801,957</strong></td>
</tr>
</tbody>
</table>

Forecast Assumptions:
- Quest does not enter a Net Revenue position before September 31, 2025
- Estimate 6.1MT CO₂ avoided over next 6 years
- Double credits received; each CO₂ reduction credit valued at $30

10.4 Funding Status

Quest received a total of $6.3 million from the Alberta Innovates program. Quest met the criteria of allowable expenses for the $120 million National Resources of Canada. 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. Quest has now been in the operating funding phase for four years.

Funding during operations is determined by the net tonnes of carbon dioxide sequestered in each year pursuant to section 4.2 of the Funding Agreement.
### Table 10-4: Government Funding Granted and anticipated ($'000)

Government funding granted through construction of the Quest project.

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</thead>
<tbody>
<tr>
<td>NRCan Funding</td>
<td>3,226</td>
<td>1,817</td>
<td>1,303</td>
<td></td>
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<td></td>
<td></td>
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<td></td>
<td>108,000</td>
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<td>12,000</td>
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<tr>
<td>GoA Funding</td>
<td>130,000</td>
<td>115,000</td>
<td>53,000</td>
<td>149,000</td>
<td>29,452</td>
<td>30,100</td>
<td>30,796</td>
<td>30,050</td>
<td>177,602</td>
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<td></td>
</tr>
<tr>
<td>Total Funding</td>
<td>3,226</td>
<td>1,817</td>
<td>1,303</td>
<td>238,000</td>
<td>115,000</td>
<td>53,000</td>
<td>161,000</td>
<td>29,452</td>
<td>30,100</td>
<td>30,796</td>
<td>30,050</td>
<td>177,602</td>
</tr>
<tr>
<td>Cu. Gov't Funding as Percentage of Total Project Spend</td>
<td>0.3%</td>
<td>0.4%</td>
<td>0.5%</td>
<td>19.8%</td>
<td>29.2%</td>
<td>33.5%</td>
<td>46.6%</td>
<td>48.9%</td>
<td>51.4%</td>
<td>53.9%</td>
<td>56.3%</td>
<td>70.8%</td>
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</table>
11 Project Timeline

The timeline for major maintenance activities in the Quest operating period is shown in Table 11-1.

Table 11-1: Operating Timeline

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<tr>
<td></td>
<td>Q3</td>
<td>Q4</td>
<td>Q1</td>
<td>Q2</td>
<td>Q3</td>
<td>Q4</td>
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<td>Capture Facility</td>
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<tr>
<td>Compressor Inspection</td>
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<tr>
<td>E-24601 Repair</td>
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<tr>
<td>Quest Creep Test Run</td>
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<tr>
<td>Pipeline and Wells Surface Facility</td>
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<tr>
<td>Pipeline Inspection</td>
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<tr>
<td>Storage and Subsurface</td>
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<tr>
<td>5-35 Commissioning</td>
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</tbody>
</table>
12 General Project Assessment

Project Successes in 2019:

Operational MMV Data Acquisition
- In 2019 continued monitoring occurred including discrete groundwater well sampling related to the VSP and ongoing well-based monitoring. Routine logging and well integrity testing were also completed on the IWs.
- In May 2019, Quest reached the milestone of 4 million tonnes of CO₂ injected. It achieved the record of having stored underground the most CO₂ of any onshore CCS facility in the world with dedicated geological storage.

Networking within Industry
- Networking with other industrial operating facilities continued to help better identify maintenance practices and procedures. Technical knowledge was also shared and gained through numerous technical conference presentations and workshop attendance.

Stakeholder Engagement
- Stakeholder management continues to be a priority for Quest. In 2019, Shell continued engagement sessions within the community and responded to stakeholder concerns. Although Shell has built on years of successful community engagement, we realize we must continue this dialogue.
- Quest continues to attract interest from various industries, government and non-government organizations. Shell attended and provided information to many organizations/stakeholders at conferences and meetings over the course of the year.

Provincial Government Milestones
- The funding provided by the Government of Alberta for Quest is contingent on a series of milestones that were agreed upon in the agreement. Funding payments are based on successful completion of these. All milestones to this point have been passed as scheduled.
- Continued funding of the project occurs by annual funding installment payments (for up to 10 years) and through credits.

Technical Successes
- 4 Million tonnes of CO₂ was successfully stored in April of 2019.
- In 2019, the low levels of chemical loss from the ADIP-x process continued, with amine introduced from the storage tanks to the stripper to increase certain amine constituents.
- All three HMUs met their NOx level commitments without contravention in 2019 with continued capability to maintain NOx levels slightly elevated from pre-Quest baseline.
- Name plate capacity increased from 3564 tpd to 3750 tpd.
- Strong integrated project reliability performance with operational availability at 99.6%.
- Annual CO₂ capture ratio was maintained at 78.8% in the fourth full year of operations.
Injection certification, audits, offset verifications and updates to waste heat claims were completed, with serialization of 1,787,416 credits, registered on the Alberta Emission Offset Registry.

Approvals granted for Quest to utilize the CCIR electricity benchmark for electricity utilized directly from on-site co-generation unit.

**Challenges in 2019:**

There have been minor operational challenges to Quest, but none that have been insurmountable to date. A description of these challenges and activities undertaken to address them is listed below.

**Regulatory Changes and Credit Serialization**

- Further clarification of the CCIR introduced in 2018, as well as audit findings and approvals of waste heat methodology and calculations have impacted the net CO₂ numbers for Quest.

**Technical Challenges**

- Reformers burners are in poor condition due to change in burner fuel composition with CO₂ capture, this is observed in all HMU's. In 2019, HMU3 capture rate was limited due to the flame instability and temperature controllability. These issues will continue until a new type of burner is utilized (replacement in 2019 on HMU3 was in-kind).
- Frozen level transmitter in HMU2 LT-242155B resulted in an absorber trip.
- Failure of seal flush tubing on the Quest Lean Amine pump (P-24602B) occurred - resulting in a leak of lean amine.
- Well injectivity reductions after short shut-ins are being investigated and potential options considered.

**12.1 Indirect Albertan and Canadian Economic Benefits**

Quest is an integrated operation that spans upstream through to downstream processes. In the development and construction of Quest, the project had over 2000 people contribute to its success. The workforce included: trades workers, engineers, geologists, geophysicists, technicians, environmental professionals, land professionals, administrative professionals, and management. At peak construction, the project had over 800 workers spanning a period of over 2 years.

In 2019, the main beneficiaries of Quest operations were third-party contractors. These contractors were responsible for the following activities:

- Field work done to monitor the hydrosphere properties of the storage area surface and groundwater regions
- Routine well maintenance, logging and SCVF testing
- Maintenance and repair contracts around $2-4 million per year.
Ongoing benefits during operations include:

- Employment for ~25 full-time equivalent people.
- Property tax sent to the municipal governments of Strathcona County, Thorhild County, Lamont County, and Sturgeon County.
- Recognition from the international community of Canada and Alberta as leaders in CCS deployment through policy, regulation, and funding.

In addition to the above, discussions began in 2014 with the US Department of Energy 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.

During 2018 fibre-based sensors were deployed in 8 of 9 of the Quest groundwater wells as a CO2 sensor demonstration project. The technology trial was deemed successful, and the instrumentation was demobilized in mid-2019.

Partnerships such as this assist in raising the profile of both Quest operations and the leadership of the Alberta and Canadian governments in supporting sustainable resource development through innovation and government-industrial collaboration.
13 Next Steps

The focus for Quest is to maintain reliable and 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 CCS as a necessary technology required to help meet climate targets.

Quest will continue with the following activities to enable this:

• Capture of operational issues and lessons learned in order to retain institutional memory and facilitate improvements in processes and procedures.
• Enact permanent solution to mitigate the low PH water leaving the Quest facility.
• New MMV and closure plans to be submitted in 2020.
• Regulatory activities will focus on demonstrating compliance with existing agreements.
• Public engagement activities and advocacy will continue to ensure public knowledge and acceptance of Quest operations. Ongoing reporting will continue to the Province of Alberta in accordance with the respective funding agreements.
• Active sharing of CCS knowledge through publications and participation in conferences, workshops, and tours into 2020.
• Continue working with AEP and Alberta Energy (CCS Unit) on evolving regulations (i.e. TIER) and the long-term viability of CCS within Alberta.
• With the improved operating performance and economic performance versus design, understand the revenue and cost forecast better to determine impacts to the net revenue statement.
• Working on energy saving opportunities to reduce variable cost pressures of steam and electricity on Quest.
14 References

[1] AER, 2019, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, 2019 ANNUAL STATUS REPORT, will be available at: https://open.alberta.ca/dataset?tags=CCS+knowledge+sharing+program&tags=Quest+Carbon+Capture+and+Storage+project