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Quest Carbon Capture and Storage Project

ANNUAL SUMMARY REPORT -

ALBERTA DEPARTMENT OF ENERGY: 2020

March 2021

Revised August 2021

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 Oil Sands Partnership (20%) and 1745844 Alberta Limited (20%), as amended.

The purpose of Quest 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. Approximately 1.2 Mt/a of CO_2 is being captured, representing greater than 35% of the CO_2 produced from the Scotford upgrader.

In 2020, Quest surpassed 5 million tonnes of injected CO_2.

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 and MMV data indicate that no CO_2 has migrated outside of the Basal Cambrian Sands (BCS) injection reservoir to date.

Despite the events of the 2020 global pandemic, an update and wellsite tour occurred to provide local government officials updates on operations. Knowledge from Shell's experience with Quest was shared with numerous industry, business, academic and non-government associations in 2020.

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

- Sustained, safe, and reliable operations.
- Overall maintenance issues have been minimal.
- 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.
- Successful shut down and unit start-up in support of other Upgrader related maintenance.
- Strong integrated project reliability performance with operational availability at 98.8%.
- 2020 MMV and Closure Plan update submitted February, approved and enacted in November.
- First successful halite remediation of a CCS injection well at IW 7-11.
- Operating costs continue to be stable.
- Sharing of best practices by networking with other operating facilities continues to help improve maintenance practices and procedures.
- Maintaining local support through the extensive stakeholder engagement activities.
- Continued participation of the Community Advisory Panel (CAP).

- International engagements with the IEAGHG and SPE to support public engagement, global knowledge sharing activities and virtual participation in a number of conferences and.
- Serialization of 1,694,980 credits in 2020

Challenges for this reporting period were minor operational issues, including:

- Reduction of maintenance activities in March due to evolution of COVID-19 safe work practices.
- Reformer burner degradation continued in the HMU's as a result of flame instability at higher CO_2 capture rates, resulting in capture rate restrictions.

Quest has seen strong reliability performance through the reporting period to safely inject over 0.941 Mt of CO_2 in 2020. Overall project injection has surpassed 5.7 Mt of CO_2 to December 31, 2020.

Revenue streams generated by Quest are twofold: (i) the generation of offset credits for the net CO_2 sequestered and additional offset credit generated for the CO_2 captured, under the Technology Innovation and Emissions Reduction Regulation (TIER), which replaced the Carbon Competitiveness Incentive Regulation (CCIR) on Jan 1, 2020; 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 2020, the value of the offset credit was $30/tonne.

Given the more favourable subsurface pore space, Quest continues to see operating efficiencies with the compressor. The compressor operated from 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 ~$30 million in 2020 in staffing, MMV, maintenance, and other costs to benefit of the local 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
CO_2 .... Carbon dioxide
DHP .... Down hole pressure
DMW .... Deep monitoring well
DTS .... Distributed temperature sensing
FEED .... Front End Engineering and Design
FGR .... Flue Gas Recirculation
GHG .... Greenhouse gases
GM .... Gas migration
HMUs .... Hydrogen manufacturing units
IEAGHG .... International Energy Agency Greenhouse Gas
InSAR .... Interferometric synthetic aperture radar
IW .... Injection Well
LBV .... Line break valve
MMV .... Measurement, monitoring and verification
MSM .... Microseismic monitoring
PNx .... Pulse neutron log
PSA .... Pressure swing adsorber
RCM .... Reliability Centered Maintenance
RFA .... Regulatory Framework Assessment
ROW .... Right-of way
SAP .... Systems, Applications, Processes (Equipment Database Software)
SCVF .... Surface casing vent flow
SEIS .... Surface seismic
TEG .... Triethylene glycol
TIER .... Technology Innovation and Emissions Reduction Regulation
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 Oil Sands Partnership (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 CO_2 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 CO_2 then compressing and dehydrating the captured CO_2 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 5.7 Mt of CO_2 in three injection wells (8-19, 7-11 and 5-35) to the end of 2020.

Quest facility locations are shown in Project Facility Locations, Figure 1-1.

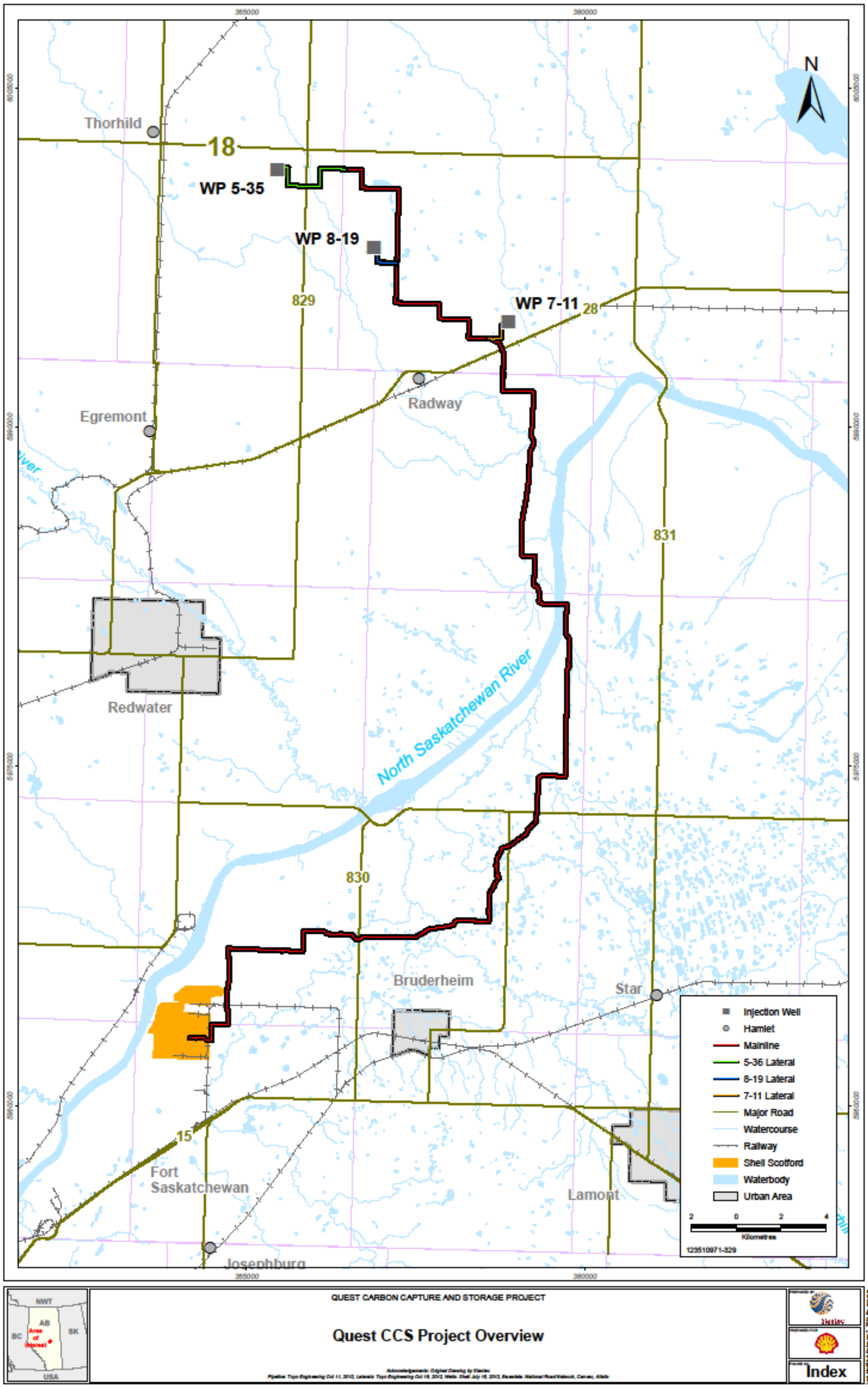


Figure 1-1: Project Facility Locations.

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 2020 was to continue reliable and efficient capture and storage of CO_2 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-specific discussions.

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 2020

Quest Operating Summary	2015 Summary	2016 Summary	2017 Summary	2018 Summary	2019 Summary	2020 Summary	Units
Total CO_2 Injected	0.371	1.11	1.138	1.066	1.128	0.941	Mt CO_2
CO_2 Capture Ratio[4]	77.4	83.0	82.6	79.1	78.8	76.8	%
CO_2 Emissions from Capture, Transport and Storage	0.080	0.238	0.241	0.241[5]	0.236[3,5]	0.205[5]	Mt CO_2
Net Amount (CO_2 Avoided)	0.291	0.870	0.897	0.826[1,2]	0.892[1,2,3]	0.736[1,2]	Mt CO_2
Waste Heat Credits	0.022[1]	0.062[1]	0.051[1]	0.044[1]	0.044[1]	0.038[1]	Mt CO_2

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 onwards the Net CO_2 Avoided includes the “Waste Heat Credits”.
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. 2019 CO_2 emissions have been updated to reflect the 3rd party verified numbers.
4. The CO_2 capture ratio refers to the percentage of CO_2 captured from the syngas (raw hydrogen) feed stream to the absorbers.
5. Starting in 2018, GHG emissions from imported electricity now capturing electricity usage from both the Upgrader Cogen and the grid.

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/TIER, there is no target specified. As a result, the target was set to 0% under CCIR/TIER.

In the Quest Offset Project Plan (OPP) the electricity generation for the Quest project 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/TIER electricity benchmark of 0.37 tCO_2/MWh for Quest electricity directly connected to the Upgrader Cogen, while the electricity grid displacement factor with line loss applied for 2020 was 0.57 tCO_2/MWh (Carbon Offset Emission Factors Handbook, 2020). For the 2018 onwards numbers in Table 4-1, Quest is capturing imported electricity from both the Upgrader Cogen and the grid. Shell reapplied for this deviation for the 2020 compliance year on January 14, 2021. Shell was granted this deviation from AEP on February 23, 2021.

Quest reached the milestone of 5 million tonnes injected since project start up during 2020

4.1.1 Quest Audits and Credit Serialization

The Quest CCS Offset project underwent various audits and verifications in 2020:

- Alberta Energy conducted the Year 5 Injection certification audit (October 1, 2019 to September 30, 2020) in September and October 2020 to confirm the injected CO_2 volume of 979,722 tonnes.
- Shell hired a third-party verifier to verify:
  - 2019 Reporting Period (January 1, 2019 to December 31, 2019)

For 2020, the Quest CCS project serialized a total of 1,694,980 credits on the Alberta Emission Offset Registry:

Reporting Period		Base/Adddditional	Status	Date Serialized	Serialized Emission Offsets
9th (2019)	Jan 1, 2019 - Dec 31, 2019	Base	Serialized	13-May-2020	847,490
		Additional		8-Jun-2020	847,490

4.2 Capture (Absorbers and Regeneration)

Solvent composition was mainly on target for 2020 operation vs. the specified formulation for ADIP-X from the design phase. CO_2 removal ratio performance has been as predicted. The annual CO_2 capture ratio was 77.4% for 2015, 83.0% for 2016, 82.6% in 2017, 79.1% in 2018, 78.8% in 2019 and 76.8% in 2020.

The main contributors to periods of reduced CO_2 capture in 2020 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:

- January 2, 2020: HMU1&2 reduced rates due to valve repair.
- January 10, 2020: LBV began closing due to low hydraulic pressure.
- January 15, 2020: HMU1&2 running at reduced rates
- January 15, 2020: HMU3 tripped due to low steam to carbon ratio alarm.
- January 31, 2020: CO_2 vent stack valve acted erratic before opening to 90%, dropping pipeline pressure and causing the pipeline to trip.
- February 11, 2020: RHC shut down, causing HMU1&2 to run at reduced rates.
- March 16, 2020: Reduced capture due to Bonnet Leak.
- March 31, 2020: Reduced capture due to HMU3 running at reduced rates.

- April 18, 2020: Reduced capture due to HMU3 reduced rates from RHC compressor trip.
- May 7, 2020: Reduced capture rates on HMU1&2 due to reformer hot spots.
- May 18, 2020: Quest compressor tripped due to power disturbance.
- June 12, 2020: Absorber recirculation valve was acting erratic, amine flow from HMU3 reduced to manage amine flow.
- June 22, 2020: HMU1 went from 10 bed to 8 bed mode.
- July 3, 2020: Absorber recirculation valve was acting erratic, amine flow from HMU3 reduced to manage amine flow.
- July 26-September 19, 2020: Unit was not capturing due to a major outage in HMU 1&2.
- September 17-October 5, 2020: Reduced rates as HMU1&2 increase rates after Turnaround.
- October 7, 2020: CO_2 vent stack valve failed open at 100%, dropping pipeline pressure and causing the pipeline to trip.
- November 14, 2020: CO_2 vent stack valve failed open at 100%, dropping pipeline pressure and causing the pipeline to trip.
- November 14-November 19, 2020: Replaced Absorber recirculation valve between Quest and HMU3 causing lose of amine between the units.
- November 20-December 3, 2020: Work done to HMU2's PSA valve packing leaks, causing reduced CO_2 to Quest.

The CO_2 stripper operation has been stable, and the CO_2 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 5-2 in the transport section contains the average CO_2 product composition from the capture and dehydration units.

Table 4-2 is a summary of the Energy and Utilities consumption of the capture and dehydration units.

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

Energy and Utilities	2015 Usage	2016 Usage	2017 Usage	2018 Usage	2019 Usage	2020 Usage	Units
Electricity (Capture/Dehydration)	12300	32800	32600	32200	32700	27700	MWh_e[1]
Low Pressure Steam	410	1263	1297	1204	1217	1050	kT
Low Temperature High Pressure Steam	1.96	5.52	5.23	5.01	5.12	6.21	kT
Nitrogen	178	230	237	258	256	230	ksm^2
Wastewater	24900	80900	61900	57800	60700	50200	m^3
Energy/Heat Recovered	33600	96260	98554	95060	93955	78490	MWh_{th}[2]
CO_2 Emissions for the Capture Process	0.030	0.083	0.095	0.195[3]	0.182[3,4]	0.158[3]	Mt CO_2

1. The e subscript denotes electrical energy.
2. The th subscript denotes thermal energy.
3. 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/TIER, there is no target specified. As a result, the Target is set to 0% under CCIR.
4. 2019 CO_2 emissions have been updated to reflect the 3rd party verified numbers

Electricity, and steam use are 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. In 2020, 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 CO_2 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.

CO_2 emissions for the capture process are primarily those linked to low-pressure steam use in the CO_2 stripper reboilers (~84% of total capture emissions), and from electricity for equipment in the capture system (~4% 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 led 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 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.

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. When the filter was taken offline, there were no foaming events, and the frequency of filter changes was reduced. The carbon bed was taken offline in February 2018 after the foaming incident on HMU3. The carbon filter remained offline in 2020. Since the carbon bed has been offline, steady operation has been observed in the absorbers, and no foaming events have occurred.

4.3 Compression

In 2020, the compressor operated at lower discharge pressures than previous years. 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	Average 2016 Operation	Average 2017 Operation	Average 2018 Operation	Average 2019 Operation	Average 2020 Operation	Units
Suction Pressure	0.03	0.03	0.03	0.03	0.03	0.03	MPag
Discharge Pressure	9.6	10.0	10.1	10.5	9.8	9.7	MPag
Motor Electricity Demand	13.3	13.8	14.2	14.0	14.2	13.7	MW_e

4.4 Dehydration

The dehydration unit performance continued to exceed expectations in 2020. The system requirement was to meet the winter water content specification for the pipeline of 84 ppmv. Actual water content for 2020 was on average 41 ppmv, while maintaining the optimized nitrogen flow rates 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 in 2020 being <10ppmw of the total CO_2 injection stream, compared to the 27 ppmw expected in design. Dehydration unit losses of TEG were roughly 10,500 kg annually for 2020 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 2020 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 2020, the averaged NOx emissions with Quest operational and the FGR online are included below:

- HMU1: 26.19 kg/h, limit 76.5 kg/h
- HMU2: 26.31 kg/h, limit 76.5 kg/h
- HMU3: 66.99 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 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 stability inside the reforming furnace appeared 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 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 CO_2 stream sent to the pipeline.

From an efficiency perspective, the hydrogen production capability of the units remains largely unchanged in 2020 with Quest operating. 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. 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

In accordance with Shell's internal guidelines, all spills – regardless of size – are recorded for tracking purposes. Quest had no leaks or spills in 2020.

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

Characteristic	Specification	Units	Average Operating Data / Actual Limitations						Original Design
			2015	2016	2017	2018	2019	2020	
General									
Pipeline Inlet Pressure	Normal	MPag	9.4	9.8	9.9	10.3	9.6	9.7	10
	Maximum Operating	MPag	12	12	13.58	13.58	13.58	13.58	14
	Minimum Operating (based on CO_2 critical pressure 7.38 MPa)	MPag	8.5	8.8	8.7	8.8	8.8	8.8	8
	Design maximum	MPag	-	-	-	-	-	-	14.8 (at 60°C)
Pressure Loss from Inlet to Wellsite	Normal	MPa	0.6	0.6	0.6	0.9	0.6	0.6	0.4 (for 3 well scenario)
Temperature	Compressor Discharge	°C	130	130	128	131	131	126	130
	Pipeline Inlet after cooler	°C	43	43	41	41	41	42	43
	Upset Condition at Inlet	°C	-	-	-	-	-	-	60
	Injection Well 7-11 Inlet Temperature	°C	15	16	14	13	15	13	-
	Injection Well 8-19 Inlet Temperature	°C	12	12	11	9	12	10	-
	Injection Well 5-35 Inlet Temperature (as of Oct 19, 2018)	°C	-	-	-	6	7	6	-
Flow rates	Normal Transport Rate	Mt/a	1.04	1.11	1.14	1.06	1.14	0.94	1.2
	Design minimum	Mt/a	-	-	-	-	-	-	0.36
	Total Transported	Mt	0.371	1.11	1.14	1.06	1.14	0.94	-
Energy and Emissions	Total Electricity for Transport (compression)	MWh_e	41,527	119,426	121,593	119,396	143,453	124,199	-

	Total Transport Emissions (includes compression)	Mt CO_2eq	0.027	0.077	0.078	0.045[1]	0.054[1,2]	0.047[1]	-

1. Indirect GHG emission from imported electricity now capturing electricity usage from both the Upgrader Cogen (0.37 tCO_2/MWh) and the grid (0.57 tCO_2/MWh).
2. 2019 CO_2 emissions have been updated to reflect the 3rd party verified numbers

The pipeline operates with CO_2 in supercritical phase at the pipeline inlet (9.9 MPag, 41°C) and with CO_2 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.

CO_2 emissions from the transport component of the operation are primarily from the electricity used to power the compressor (98% 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 H_2 and CH_4 are lower than design. The average operating conditions to design values are available in Table 5-2.

Table 5-2: Pipeline Fluid Composition

Component	Actual Operating 2015 (vol%)	Actual Operating 2016 (vol%)	Actual Operating 2017 (vol%)	Actual Operating 2018 (vol%)	Actual Operating 2019 (vol%)	Actual Operating 2020 (vol%)	Design Normal Composition	Design Upset Composition
CO_2	99.45	99.38	99.46	99.44	99.44	99.37	99.23	95.00
H_2	0.48	0.51	0.47	0.46	0.48	0.48	0.65	4.27
CH_4	0.06	0.06	0.06	0.06	0.05	0.05	0.09	0.57
CO	0.02	0.02	0.01	0.01	0.01	0.01	0.02	0.15
N_2	0	0	0	0	0	0	0	0.01
Total	100	100	100	100	100	100	100	100

Water Content and CO_2 Phase Change Management

Pipeline operation since start-up was below the winter water specification of 4 lb / MMscf (84 ppmv). The average for 2020 was 41 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). As of 2020 these inspections occur every 5 years.
- Annual Cathodic Protection surveys and Corrosion Probe monitoring is performed.
- 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.
- In 2020, an unmanned aerial vehicle (UAV) was used for inspections. This allows for inspections to be completed with less health and safety risks to personnel (no pilot required) and overall cost reduction. Aerial ROW surveys were completed quarterly in 2020 (March 3rd, June 3rd, September 9th and December 4th).

6 Facility Operations - Storage and Monitoring

This section provides an overview of the wells and MMV activities for the operational year 2020.

6.1 Storage Performance

Injection of CO_2 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, 2020, about 5.75 Mt CO_2 have been injected into the three wells as illustrated in Figure 6-1. The injection stream composition is described in detail in Table 5-2 and is shown in Figure 6-2.

Cumulatively, through the end of December 2020, about 2.51 Mt of C02 had been injected into the 7-11 well, 2.51 Mt of $C0_2$ into the 8-19 well, and 0.74 Mt of $C0_2$ 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.

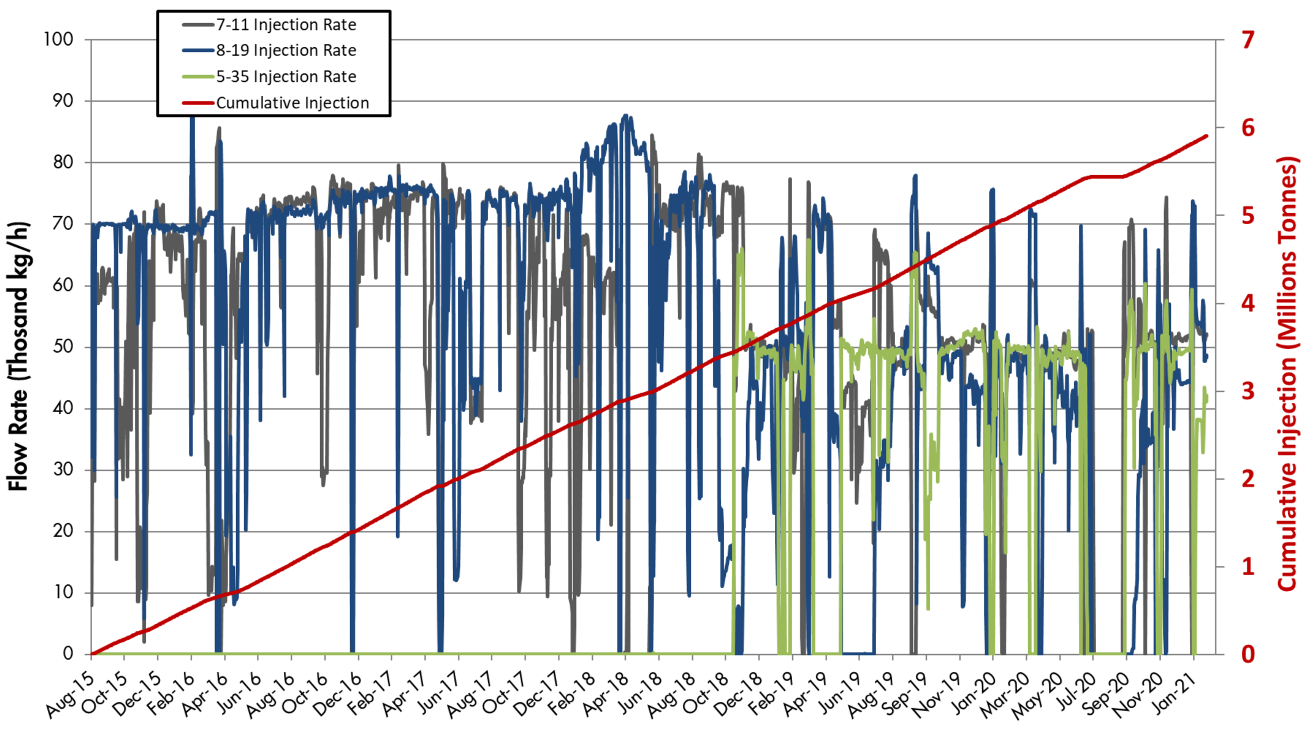


Figure 6-1: Quest Injection Totals: Cumulative CO_2 injected into the wells from start-up through to the end of 2020 (red). The blue, grey and green lines show the average hourly flow rates into each of the injection wells.

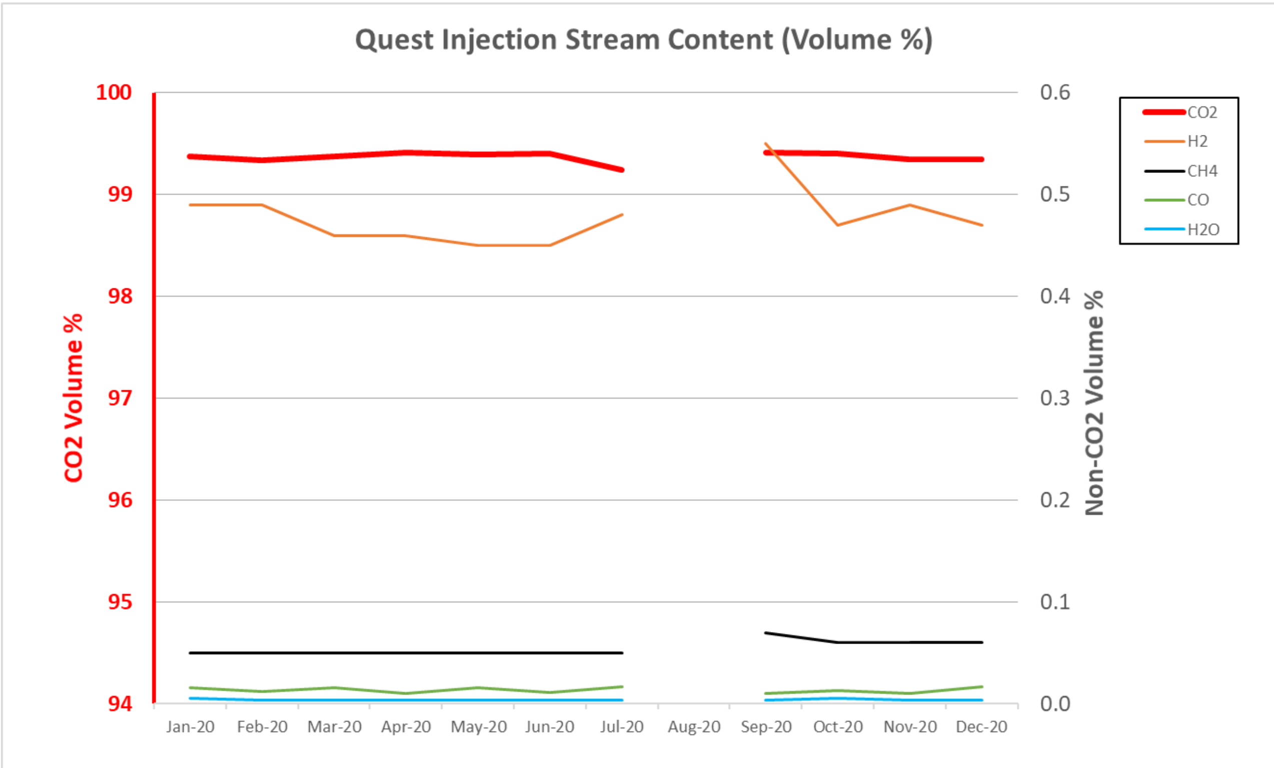


Figure 6-2: Quest Injection Stream Content: Average injection composition for 2020. From July 26th to Sept 19th, 2020 Quest was in turnaround and was not capturing any CO_2.

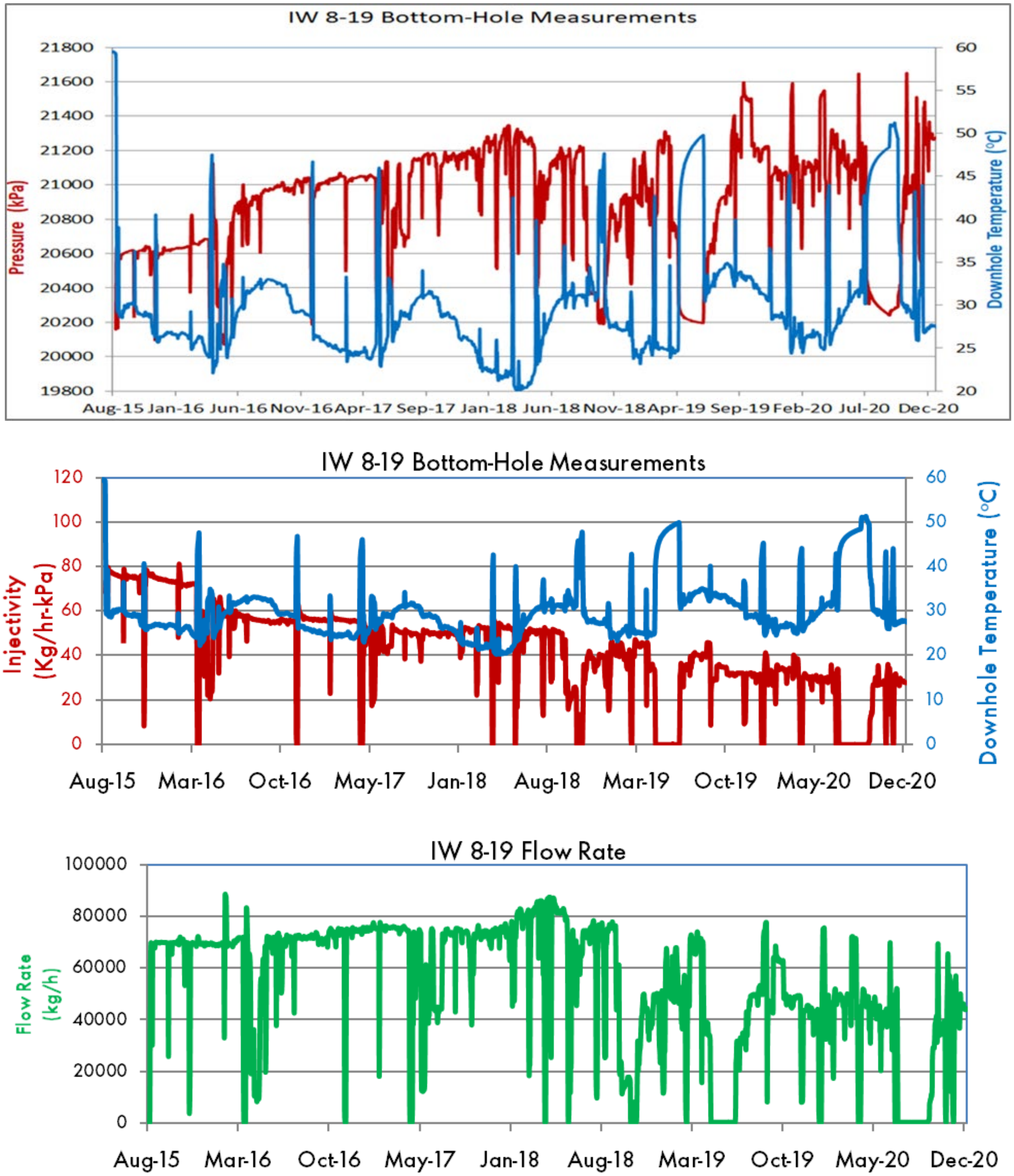
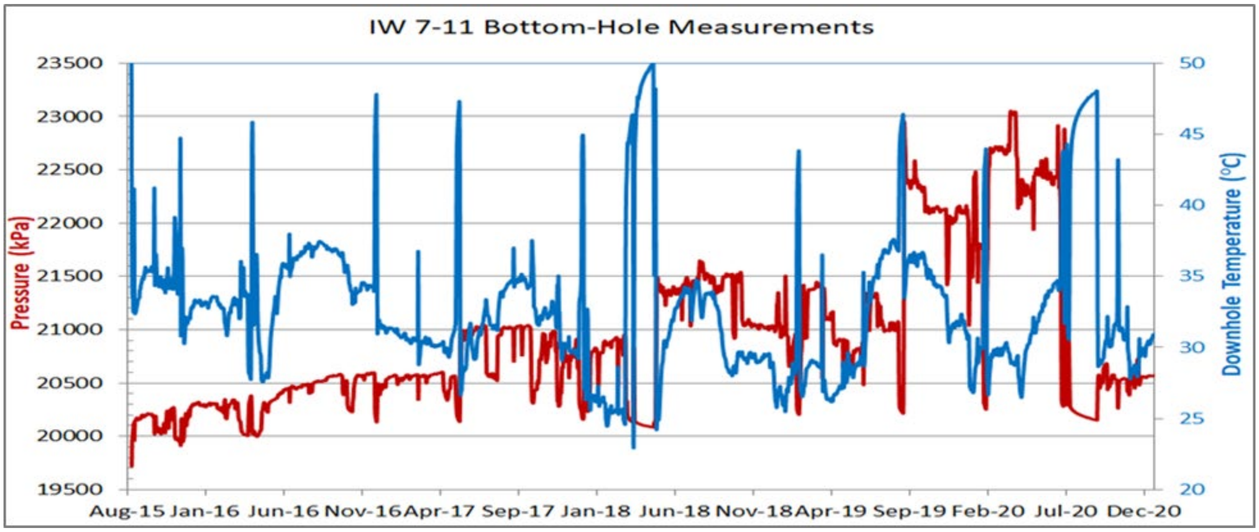
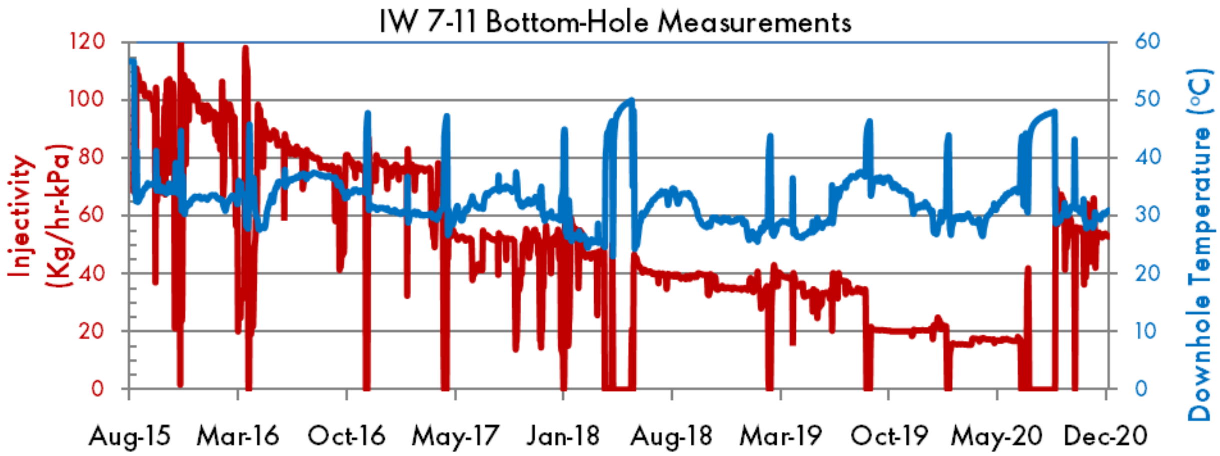


Figure 6-3: The 8-19 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection to the end of 2020.





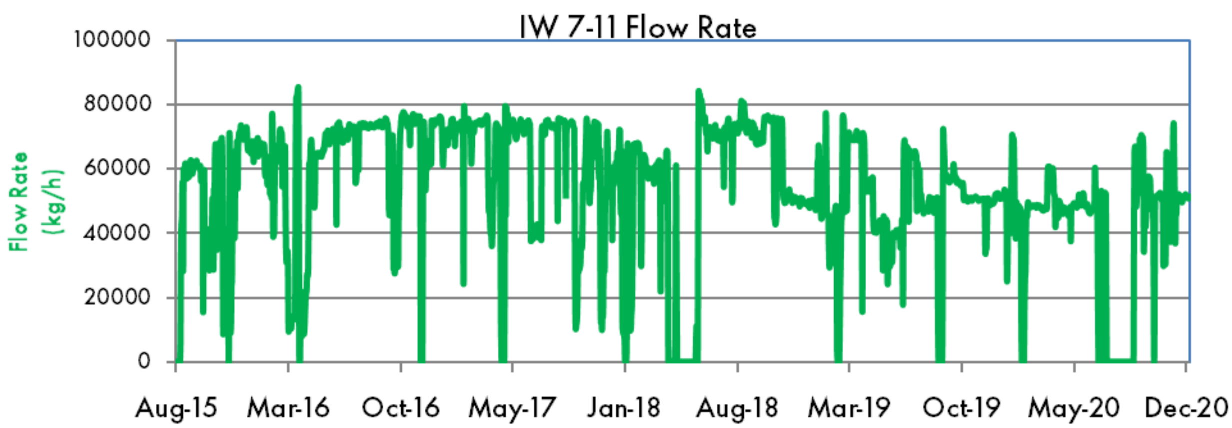


Figure 6-4: The 7-11 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2020.

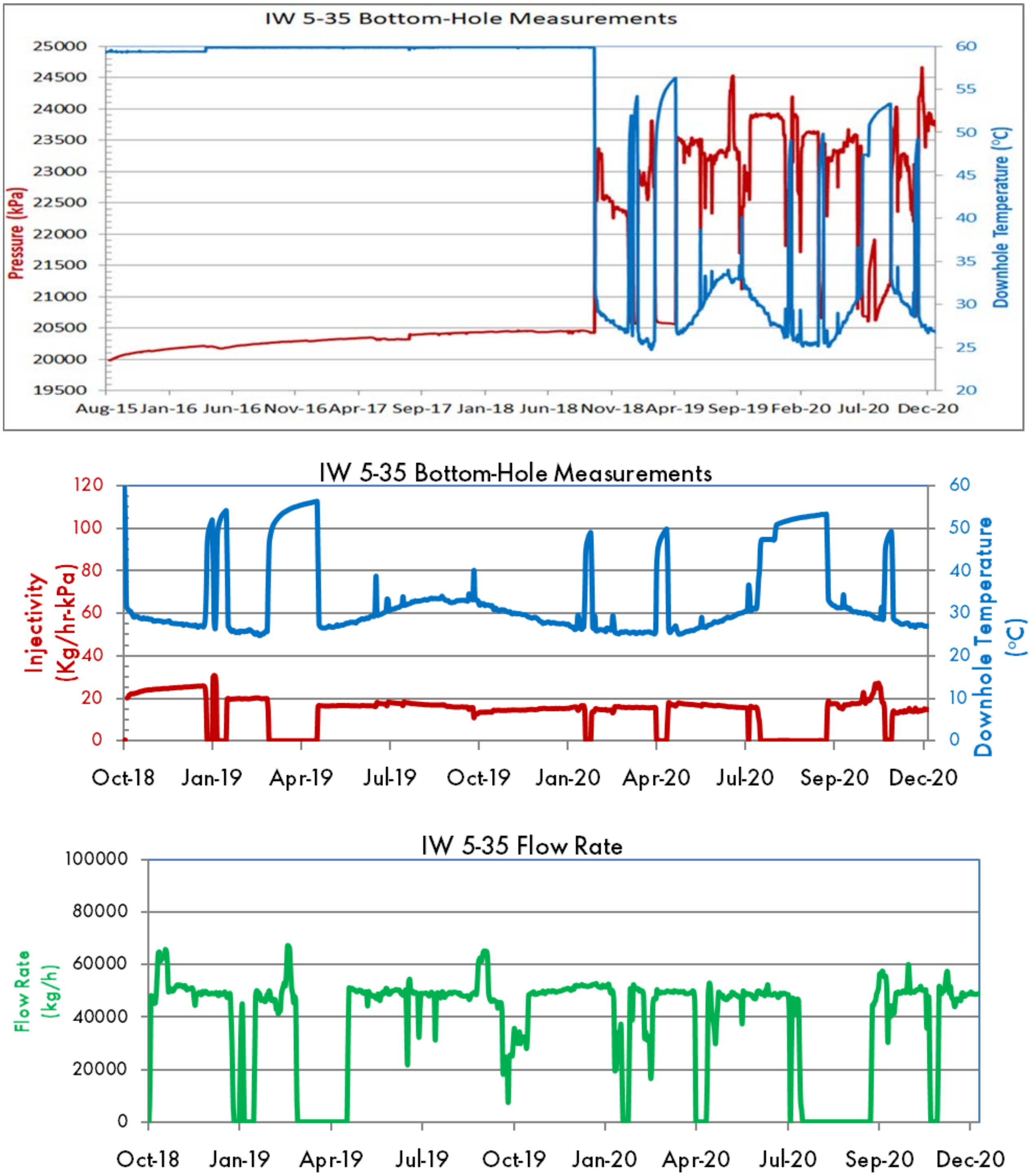


Figure 6-5: The 5-35 Injection Well: Average daily P/T conditions at the wellhead and down-hole during injection in 2020.

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 CO_2. Refer to the AER Annual Report (2020) 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 2020

Year	Yearly Injection Total	Remaining Capacity
Pre-injection	-	27 Mt CO_2
2015	0.371Mt	26.629 Mt CO_2
2016	1.108 Mt	25.521 Mt CO_2
2017	1.138 Mt	24.383 Mt CO_2
2018	1.066 Mt	23.317 Mt CO_2
2019	1.128 Mt	22.189 Mt CO_2
2020	0.941 Mt	21.248 Mt CO_2

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 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 were observed following short well shut in periods associated with well interventions. As the initial injectivity was very high, these injectivity reductions did not form an operational constraint with three wells available for injection. If the injectivity trend continued unmitigated, it has the potential to develop into an operational limit for the Quest CCS operation.

The most probable cause of the injectivity reductions was determined to be halite deposition in the well casing, perforations and near wellbore area. A halite remediation treatment was thus selected as the injectivity remediation operation, utilizing hot water to dissolve halite. IW 7-11 was selected for the halite remediation trial as it had experienced the greatest degree of injectivity reductions. The trial was performed in July 2020 and successfully increased injectivity by at least 260%.

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 2020 MMV activities included: atmosphere, hydrosphere, geosphere, and well-based monitoring. The following is a summary of these activities:

Atmosphere Domain: Monitoring of CO_2 levels in the atmosphere at the injection well sites continued using the LightSource technology. Operator rounds daily at the injection well sites.

Hydrosphere Domain: In addition to continuously monitoring of the Quest Groundwater wells, discrete sampling Project wells was done in Q4 2020. Further details on the hydrosphere monitoring activities can be found in 2020 AER Annual Scheme Report, Appendix A.

Biosphere Domain: No activities took place regarding soil gas and soil surface CO_2 flux measurements.

Geosphere Domain: Monthly satellite image collection for InSAR continued. Since September 2017, a single frame centered over the 3 injection well pads has been 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 of the AER Annual Scheme Report).

A new MMV plan was submitted to Alberta Energy and the AER on the 23 February 2017. The 2017 MMV plan was approved on 11 May 2017 and was in effect until 11 May 2020. Due to the events of 2020, the 2017 MMV Plan validation period was extended to 1 December 2020. The 2020 MMV Plan was approved 25 November 2020 and will expire on 25 November 2023. The reporting thus focuses on both 2017 and 2020 MMV Plan activities.

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.

The Tiering system was further refined in the 2020 MMV Plan to focus on the critical risks that address containment through direct, continuous monitoring. Refer to the 2020 MMV Plan Section 4.9.1 for a further discussion of this update.

No trigger events were identified during 2020 that would indicate a loss of containment. As a result, the Tier 1 technologies are reported in Table 6-2 (2017 MMV Plan) and Table 6-3 (2020 MMV Plan).

With the data collected so far, CO_2 injection within the BCS is conforming to model predictions, based on:

- The existing time-lapse seismic monitoring results indicate that the size of the CO_2 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 CO_2 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 2020 a significant pressure fall-off was recorded during the 2020 turnaround, 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 2020 can be found in the 2020 AER Annual Status Report [1].

Table 6-2: Overall assessment of trigger events used to assess loss of containment in 2020 using the 2017 MMV Plan.

Tier	Technology ^	Trigger	2020
Tier 1	IW DHP	Measuring greater than 26 Mpa	
	DMW DHP	Anomalous pressure increase above background levels	
	MSM	Sustained clustering of events with a spatial pattern indicative of fracturing upwards	
	DTS	Sustained temperature anomaly outside casing	
Tier 1 - when available	Pulsed Neutron log	Indication of CO_2 out of zone	All IWs
	SCVF	Change in geochemical composition indicating presence of project CO_2	Evaluated in 2019, and planned for 2021.
	VSP2D	Identification of a coherent and continuous amplitude anomaly above the storage complex	Monitor survey executed in Q1/2019
	SEIS3D	Identification of a coherent and continuous amplitude anomaly above the storage complex	not applicable yet
	SEIS2D	Identification of a coherent and continuous amplitude anomaly above the storage complex	Monitor survey executed in Q1/2019

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

Legend: no trigger event; trigger event; not evaluated

Table 6-3: Overall assessment of trigger events used to assess loss of containment in 2020 using the 2017 MMV Plan.

Tier	Technology ^	Trigger	2020
Tier 1	IW DHP	Measuring greater than 26 Mpa or less than 20Mpa	
	IW Tubing/Casing Annular Pressure	Anomalous pressue response	
	DMW DHP	Anomalous pressure increase above background levels	

^ based on Table 4-3 of the 2020 MMV Plan

Legend: no trigger event; trigger event; not evaluated

6.3 Wells Activities

6.3.1 Injection Wells

In 2020 the injection wells (8-19, 7-11 and 5-35) underwent routine work including WIT (wellhead integrity testing - wellhead maintenance and pressure testing) and packer isolation tests. Tubing integrity logging (caliper) and hydraulic isolation logging (PNx) was undertaken at all the injection wells.

A successful halite remediation treatment was executed at IW 7-11 in July 2020. With a series of planned workovers and a large turnaround window in Q3 2020, it was decided to investigate the cause of the identified injectivity reductions and remediate. A downhole video log captured in April 2018 on IW 7-11 well provided visual evidence of a scale deposit plugging perforations, and along with the hydraulic isolation logs acquired in July, a dielectic log and downhole solid samples were retrieved from the sumps, which indicated halite deposition in the casing.

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 quarterly maintenance checks performed on the downhole gauges, and also downloading pressure and basic water quality data. A sampling event occurred in Q4 2020 and will continue as per the 2020 MMV Plan through 2021.

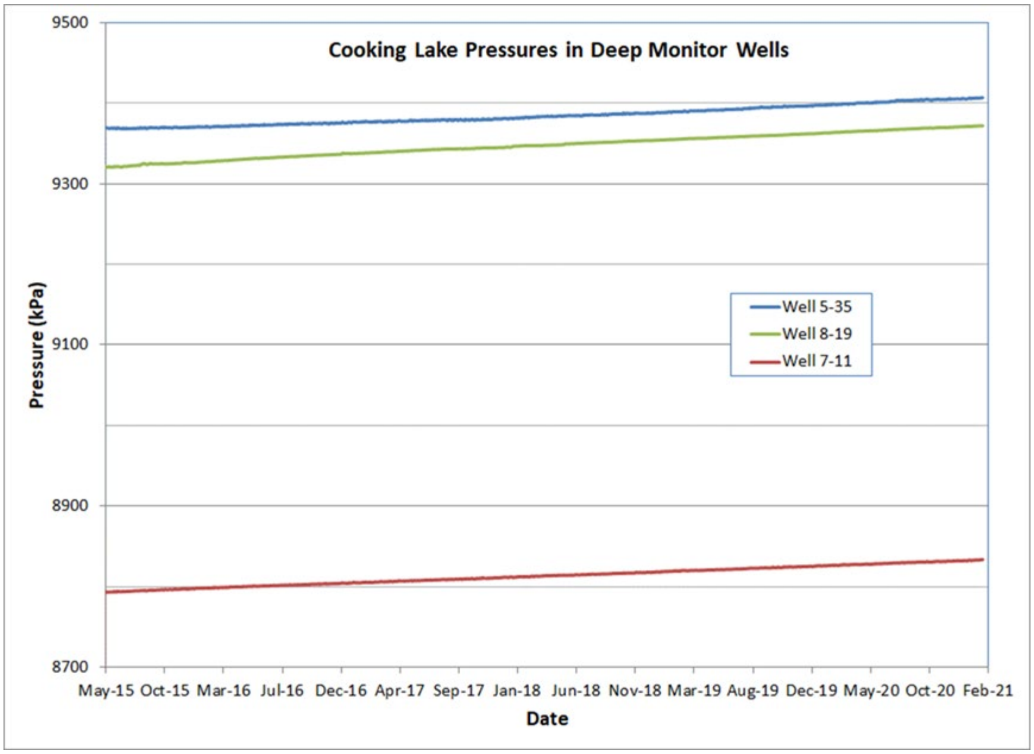


Figure 6-6: Quest DMW pressure history before and during injection.

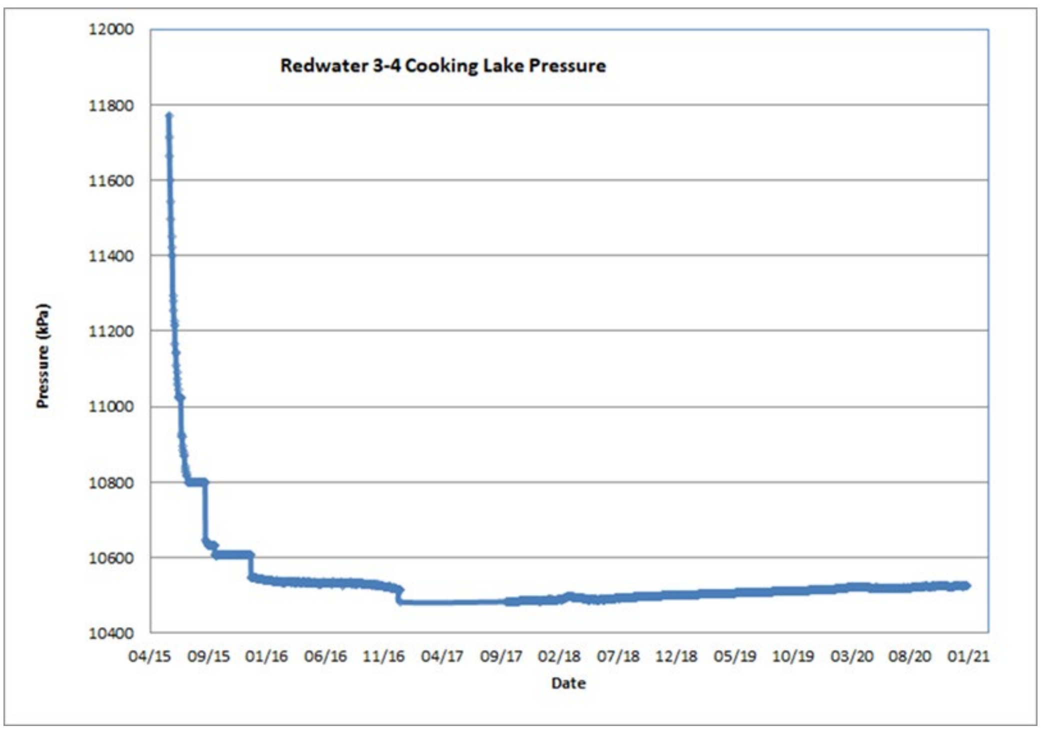


Figure 6-7: Quest 3-4 DMW pressure history.

6.3.3 Surface Casing Vent Flow and Gas Migration Monitoring

Following the 2012-2013 drilling campaign, Gas Migrations (GM) were observed on the two new injection wells, IW 5-35 and IW 7-11, in February and March 2013 respectively. Surface Casing Vent Flows (SCVF) were also observed on these two wells and reported as non-serious as per Interim Directive 2003-01. However, since these two wells had a SCVF and a GM, they were automatically classified as serious, as per Bulletin 2009-07, with a mandate to remediate them before August 31st, 2013.

Shell requested and received approval to postpone the repair of IW 5-35 and IW 7-11 SCVFs and GMs to the time of well abandonment. Annual SCVF, Gas Migration testing and groundwater monitoring was conducted and reported annually to the AER under this approval.

In 2020 Shell submitted an amendment request to the AER to reduce the frequency of SCVF and Gas Migration testing. As per the AER approval dated September 28th, 2020 Shell is required to perform SCVF and in-soil gas migration testing in 2021 (2 year frequency) and 2024 (3 year frequency). As per this approval SCVF and GM was not performed in 2020.

The next planned SCVF and GM testing for the IW 7-11 and IW 5-35 wells is in 2021.

The go-forward schedule for SCVF & GM testing will be re-established after the data in 2021 and 2024 has been reviewed and in conjunction with other monitoring tools that are part of the MMV Plan.

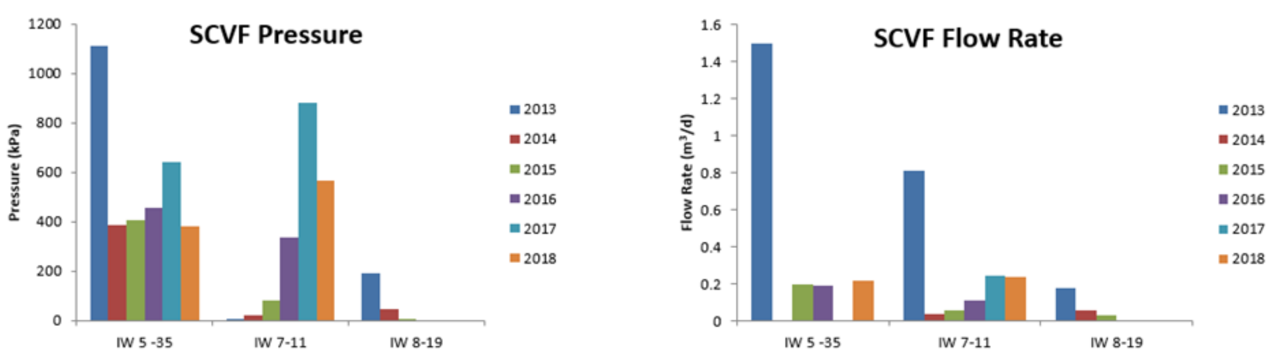


Figure 6-8: SCVF Pressure and Flow rate summary graphs for IW 5-35, IW 7-11 and IW 8-19.

7 Facility Operations - Maintenance and Repairs

A simulator for HMU/Quest is currently being utilized and maintained to increase operator competency in the Quest unit, which results in longer run time and reliability. Training plans and maintenance procedures for maintenance personnel are complete and include vendor training for key components (analysers and the compressor). Wherever possible, Shell has leveraged existing processes, systems and procedures to facilitate a smooth transition of the Quest project into Scotford routine maintenance and operations.

Spare part requirements based on reliability centred maintenance (RCM) have been purchased and delivered.

All essential maintenance processes are in place.

Maintenance and repairs during 2020 are as follows:

- P-24602A/B/C seal flush line replacement due to B failure.
- V-24604/09 filter retrofit complete (New internal filter rod design to reduce maintenance and filter costs).
- P-24607 bearing replaced along with motor
- P-24602A motor rebuild
- UV-247003 feedback positioner failed tripping C-24702, positioner replaced.
- FV-702204/304 positioner replacement.
- FAT/SAT testing complete and new caustic facility in service.
- P-24801 TEG check valve cut out and replaced.
- P-24610A/B demin pump overhaul.
- V-24607 hole above LP condensate nozzle requiring shutdown and repair. (design flaw)
- Replaced insulation soft covers with hard insulation in certain areas due to freezing of instruments.
- MH-24602 internal leaks repaired
- HVAC repairs due to inadequate heating and cooling in Quest O/I and substations.
- Wellsite WIT/SIT and Isolation logs 7-11/8-19/5-35
- Wellsite 7-11halite remediation
- Power installed at 7-11 to Quest operations trailer
- Pig receiver modifications at LBV 3 and LBV 6
- Found E-24704 outlet nozzle leaking, inspected and requires s/d for repair

2020 Maintenance

- Permanent caustic skid completed and online
- V-24607 LP condensate bonnet failure and valve replacement
- V-24607 nozzle repair and weld overlay
- E-24601B new shell installed
- P-24607 pump replacement and d/s check valve
- Reboilers and C-24701 4th stage suction and discharge thermowells replaced
- C-24701 compressor building main HVAC sensor replacement
- P-24601B outboard bearing pump seal leak repaired
- P-24602A Motor rebuild
- E-24704 inspection and plug
- P-24801B discharge check valve replaced
- P-24602A outboard motor seal replaced
- E-44014 bundle replacement in HMU3
- P-24601A seal replaced
- P-24612 pump replaced
- UV-247003 feedback positioner replaced (C-24701 trip)
- MH-24602 repaired

2020 Pipeline and Wellsite Maintenance

- Connect Energy Onboarded as Electrical/Instrumentation Contractor
- Well Site 1 Office Trailer HVAC added to Bird Scope
- Well Site FV Repairs as required
- Cathodic Protection CIT Test
- Cathodic Protection Rectifier Reprogramming
- Pig Receiver Modifications Complete
- Shell DAR Team Soil Assessments
- PLC Re-Programming related to Troll Probe Comm
- LBV Trip Testing Complete
- ROW Drainage repairs as required through Landowner Complaint
- Pipeline Drone Inspections
- Injection DHCV Testing
- Annulus Fluid Shots

- Well Site 1 Office Trailer Power and IT Completed
- LBV EFOY Modifications MOC 35073
- LBV EFOY Battery Replacements
- LBV EFOY Upgrade (LBV 2-6)
- Clean Harbours set up to clean out Office Trailer Sewer as required
- Well Site 3 Man Gate Access and Egress walkway improvements
- Well Site 3 Site berm modifications complete (Flood Mitigation)
- Well Site 3 Flood remediation, Pump offsite
- Well Site 1 Injection Well Halite Remediation
- County Road Repair (due to Halite remediation traffic)
- Pipeline Marker Maintenance as required

Quest maintenance issues have been minimal for a facility entering into 6 years of runtime. Quest continues to strive for the highest reliability and is always searching for better designs and technology that will equate into longer more predictable maintenance scheduling thus reducing overall maintenance costs. Sharing of best practices with other operating facilities continues to help improve maintenance practices and procedures.

8 Regulatory Approvals

8.1 Regulatory Overview

Regulatory submissions in 2020 followed the schedule set forth by the approval. Regulatory approvals in 2020 addressed the ongoing operations and optimization of safe operations.

8.2 Regulatory Hurdles

There were no significant regulatory hurdles in 2020.

8.3 Regulatory Filings Status

Table 8-1 lists the regulatory approvals status relevant to Quest for the 2020 reporting period.

Table 8-1: Regulatory Approval Status

Approval or Permit	Regulator	Status and Timing of Approval/Permit	Comments
CO_2 Injection and Storage			
2020 Net revenue position of statement of project costs and projects revenues	AEP	Submitted February 8th, 2020	Submission in accordance with Additional Credits Agreement
2020 MMV Plan and Closure Plan Updates	GOA/AER	Submitted February 23, 2020 Approved November 25, 2020	Approval delayed due to events of 2020.
Quest Carbon Capture and Storage Project 2019 Annual Status Report	AER	Submitted March 31, 2020	Annual Report.
Carbon Dioxide Disposal & Containment Approval No. 11837C Request for extension time-lapse casing and cement integrity Logs	AER	Submitted May 5, 2020. Approved May 6, 2020.	The time-lapse casing and cement integrity logs for the 03/07-11-059-20W4/0 and 00/08-19-059-20W4/0 wells are deferred to the end of 2021
Repair of SCVF and GM, Revised Shell Quest Deferral Approval	AER	Submitted August 21, 2020 Approved September 28, 2020	Shell must conduct and report both a SCVF test and an in-soil gas migration test during frost-free months by September 30th, 2021 and September 30th, 2024.

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 2021 include:

- 2021 Annual status report to AER
- 2021 SCVF/GM submissions
- 2021 Hydrogeochemical study in support of 2020 MMV Plan groundwater monitoring activities.

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

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 2020:

- April 23, 2020 – Strathcona County
- September 8, 2020 – Thorhild County

No major issues were raised specific to the Quest facility. Thorhild County council expressed appreciation for Shell's performance in the community. Questions from council members were answered immediately at the council sessions.

Public Concerns

Shell has a comprehensive public concerns process that is designed to encourage community feedback.

In 2020, Shell recorded four concerns related to Quest operations:

- Concern related to subsidence along the pipeline right-of-way. Shell continues to progress remediation on lands experiencing crop loss following pipeline construction.
- Concern related to what is being injected into the Quest wells as one neighbour had been misinformed that Quest was injecting a slurry and asked for an MSDS. The neighbor was provided with the correct information and a one-to-one call was held to help answer questions.
- Concern related to water flow near the 5-35 well pad. A project to deal with a water pooling issue was completed in the summer of 2019, and in the initial investigation it was determined this new issue was not caused by Quest.
- Concern related to noise caused during the shutdown of Quest operations at Scotford for the Turnaround work in 2020.

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 local community members, academics, emergency responders, the AER and public health professionals. The mandate of the panel is to provide input to Quest 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 2020, the CAP met on May 26 in a virtual format, providing the latest MMV and community information.

Emergency Response

Groundtruthing was last completed in June 2019 and will be conducted again in 2021. No emergency response exercises were held with the community in 2020.

9.3 CCS Knowledge Sharing

Despite the events of the COVID-19 pandemic, which significantly impacted travel, global interest into our experience with the Quest facility continued in 2020.

As such, members of the Quest team attended or hosted numerous conferences, workshops and tours. Table 9-1 below gives an overview of the 2020 activities. All applicable restrictions associated with the COVID pandemic were followed for all of these engagements.

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 2020:

Harvey, S., Halladay, A., O'Brien, S., Hopkins, J., & Henderson, N. (2020). Quest CCS Facility: Time-Lapse Seismic Campaign. Geoconvention 2020. Calgary.

Harvey, S., O'Brien, S., & Halladay, A. (2020). Quest CCS facility: Microseismic Observations. GeoConvention 2020. Calgary.

Kassam, S. (2020). The Quest CCS Operation-The Road to 5 Million Tonnes. SPE Canada Virtual Unconventional Resource Conference. SS05: Carbon Capture, Utilization and Storage. Calgary: Society of Petroleum Engineers.

Kuehl, H., Hopkins, J., Harvey, S., & Grimm, J. (2020). Application of 3D LSRTM to an onshore walkaway VSP for CO_2 monitoring. SEG Technical Program Expanded Abstracts (pp. 3803-3807). Society of Exploration Geophysicists. doi:10.1190/segam2020-3420166.1

Smith, N. (2020). Over Five Million Tonnes of CO_2 Sequestered at the Quest CCS Facility. SPE/CHOA (Canadian Heavy Oil Association) Slugging It Out Conference. Calgary.

Tawiah, P., Duer, J., Bryant, S. L., Larter, S., O'Brien, S., & Dong, M. (2020). CO_2 injectivity behaviour under non-isothermal conditions--Field observations and assessments from the Quest CCS operation. International Journal of Greenhouse Gas Control, 92, 102843.

In addition, two agreements to share Quest geophysical data were reached with GeoTomo and NORSAR. The data are to be used in assessing new research and technology to improve processing and analysis of the geophysical data.

Table 9-1: 2020 Knowledge Sharing

2020 Conferences/Workshops/Tours	Date	Location
API CCS Working Group	January 21	USA
Aquistore Knowledge Sharing	January 24	Calgary, AB (Virtual)
Cenovus Knowledge Sharing	January 28	Calgary, AB
API CCS Working Group	February 24	USA
Lehigh Cement Tour	March 10	Fort Saskatchewan, AB
Mitsubishi Knowledge Share	March 16	Virtual
NZT Halite Workshop	March 26	Virtual
API CCS Working Group	April 1	USA
Aquistore Knowledge Sharing	April 19	Calgary, AB (Virtual)
Equinor Knowledge Sharing	May 19	Virtual
API CCS Working Group	May 27	USA
CAP Meeting	June 12	Thorhild, AB
Media Announcements – 5 Million Tonnes	July	Alberta
IEAGHG Summer School Conference	July 8	Regina, SK
API CCS Working Group	July 21	USA
SPE - CHOA Slugging it Out	September 10	Calgary, AB (Virtual)
Kuwait KOC/KNPC Tour	September 24	Fort Saskatchewan, AB
45Q and IRS meeting	September 25	Washington, DC
SPE – Virtual Heavy Oil and Unconventional Resources Conference (CCUS session)	September 30	Virtual
SEG Workshop	October 15	Virtual
SEAFOM Workshop	October 16	Virtual
Mathworks Energy Conference	October 20	Virtual
GeoConvention	Sept 21-23	Calgary, AB
API CCS Working Group	October 26	USA
Aquistore AGM	November 3	Virtual

API CCS Working Group	November 11	USA
ITB-IEAGHG CCS Course	November 12	Virtual
JOGMEC, Mitsubishi Knowledge Share	November 26	Virtual
IEAGHG Risk Management Network Webinar	December 2	Virtual

9.4 Quest Advocacy

Quest advocacy activities in 2020 were largely related to the milestone of capturing 5 million tonnes of CO_2. Among the key messages shared:

1. Quest proves that CCS works well
2. Costs of CCS are lower than expected
3. CCS is a key technology that can help decarbonize some of the most difficult emissions from Canada's energy system

A news release was distributed on July 10, with most coverage occurring that day. The communications campaign around the 5 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)

	FEED	CAPITAL / CONSTRUCTION					
	2009 - 2011	FISCAL 2011	FISCAL 2012	FISCAL 2013	FISCAL 2014	FISCAL 2015/16	Total Capex to reach Commercial Operation
	Jan 1, 2009 - Dec 31, 2011	Jan 1, 2012 - Mar 31, 2012	Apr 1, 2012 - Mar 31, 2013	Apr 1, 2013 - Mar 31, 2014	Apr 1, 2014 - Mar 31, 2015	Apr 1, 2015 - Mar 31, 2017	
Overall Venture Costs							
Shell Labor, & Commissioning	19,470	5,414	32,638	23,466	57,311	28,753	147,582
Sub Total	19,470	5,414	32,638	23,466	57,311	28,753	147,582
Tie-in Work /Brownfield Work							
Tie-In/Turnaround Work Capture	0	0	7,331	10,234	10,430	7,924	35,919
Tie-In Work Pipeline		0	196	518	334	150	1,199
Sub Total	0	0	7,527	10,753	10,764	8,074	37,118
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	39	38,562
Material		6,092	42,315	56,502	7,466	-5,155	107,220
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	-3,803	437,419
SUBSURFACE - Wells*	63,175						
Injection Wells		1,090	17,970	3,641	167	1,776	24,643
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	1,862	12,123
Sub Total	63,175	1,090	22,558	6,951	5,443	4,209	40,251

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	29	87,496
Sub Total	4,035	576	6,150	87,706	32,936	93	127,460
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**	**37,326**	**789,830**

Notes:

1. Although Quest began its operating phase in Q4 2015, some remaining capital costs continued to flow through beyond the date Quest reached commercial operation
2. Shell Labour costs during FEED phase are shown as aggregates against categories notated with an asterisk (*)

10.2 Opex Costs

Operating costs associated with the venture for the first five years of commercial operations are shown in Table 10-2 below.

Table 10-2: Project Operating Costs ($'000)

Cost Category	Oct 1, 2015 – Dec 31, 2016	2017 Jan 1 – Dec 31	2018 Jan 1 – Dec 31	2019 Jan 1 – Dec 31	2020 Jan1 – Dec 31
Power	3,717.70	4,513.96	7,562.80	9,056.83	6,985.35
Steam	8,414.46	8,834.50	5,464.59	6,284.98	7,355.33
Compressed Air	67.67	62.59	50.19	54.05	66.04
Cooling Water	427.95	389.81	379.14	446.29	474.71
Direct Labour and Personnel Costs	7,829.42	5,787.86	7,383.90	7,129.00	8,355.62
Maintenance Materials and Technical Services	969.42	942.63	1,435.98	1,286.74	2,252.79
Property Tax	2,003.72	2,000.28	1,842.73	1,916.60	1,959.60
Sequestration Opex[1]	7,052.85	6,797.59	0.00	0.00	0.00
MMV after Operations	1,690.41	1,655.74	625.64	381.34	1,335.51
Post Closure Stewardship Fund	272.07	264.28	243.33	250.48	225.34
Other Well Costs	431.49	442.12	102.74	214.11	1,104.13
Subsurface Tenure Costs	362.50	420.00	400.10	454.20	410.20
Pipeline - Inspection and Pigging	145.78	340.49	175.36	139.47	259.69
Amine[2]	340.67	0.00	0.00	0.00	0.00
Chemicals	20.35	97.92	150.69	157.71	134.41
Vendor rebates	-122.32	-100.36	0.00	0.00	0.00
Corporate and Other Costs	119.24	205.95	133.08	302.39	508.98
Sustaining Capital[3]	0.00	54.89	0.00	432.41	63.30
Total	**33,743.37**	**32,710.26**	**25,950.27**	**28,506.61**	**31,491.01**

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) to provide greater transparency.
2. Some amine loss was observed in 2019. A total of 20m^3 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 Cost Per Tonne

Cost per tonne (CPT) in Table 10-3 has been calculated based on the capital and operating costs outlined in Section 10.2 above, and the gross CO_2 captured (injected) and net CO_2 avoided volumes outlined in Section 4.1.

Table 10-3: Cost Per Tonne

Cost per Tonne Summary	2015 ($)	2016 ($)	2017 ($)	2018 ($)	2019 ($)	2020 ($)
Operating Cost Per Tonne Captured	N/A[3]	27.25	28.73	24.34	25.27	33.48
Operating Cost per Tonne Avoided[1]	N/A[3]	34.70	36.47	31.42	31.96	42.79
Total Cost per Tonne Captured[2]	N/A[3]	81.90	81.92	81.13	78.95	97.86
Total Cost per Tonne Avoided[1, 2]	N/A[3]	104.30	103.97	104.72	99.84	125.07

Notes:

1. Where required, volumes of CO_2 avoided for previous years have been updated to reflect the 3rd party verified numbers.
2. Total Cost Per Tonne is calculated using an annualized capital cost. This rate is dependent on economic inputs, including inflation and discount rates, which are adjusted each reporting period.
3. CPT has not been calculated for 2015. The project was only capturing CO_2 for 131 days and in commercial operation for 92 days. Due to the transition into commercial operations, extrapolation of costs and volumes would not provide an appropriate cost per tonne metric for the 2015 year.

10.4 Revenues

Revenues reflect both capital and operational funding, as well as CO_2 reduction credits received up to December 31, 2020. The value of CO_2 emission offset credits reported each year do not reflect the CO_2 volumes injected in that year due to the time taken to verify injection volumes and issue credits. The value of CO_2 emission offset credits in 2020 relate to 2,111,562 base and additional credits serialized during the year. 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 10-4: Project Revenues ($'000)

Revenue Stream	2009 – 2015 Construction	2016 Operation	2017 Operation	2018 Operation	2019 Operation	2020 Operation	Aggregate Revenues Forecast[2] (2021 – 2025)
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	573,345	29,452	30,100	30,796	30,050	27,033	150,569
CO_2 emission offset credits[1]		3,226	32,287	68,884	63,735	82,380	320,000
Total Revenues	**573,345**	**32,677**	**62,387**	**99,680**	**93,785**	**109,413**	**470,569**

Notes:

1. CO_2 emission offset credits have been restated. Serialized credits sold have been restated to reflect the weighted average sale price achieved for each parcel of credits sold. Serialized credits used for compliance reflect the fund price during the year of retirement from the registry (i.e. $20/credit 2016, $30/credit 2017-2020). All remaining serialized credits still held have been restated to $40/credit to reflect the TIER fund price increase outlined in Ministerial Order 36/2020 [Environment and Parks] Technology Innovation and Emissions Reduction credit amount order.
2. Shell Forecast Assumptions:
   - Estimated 4.0MT CO_2 avoided over the next 5 years.
   - Double credits are received; each CO_2 reduction credit valued at current fund price ($40/tonne).

10.5 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. 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 achievement of commercial operation in October 2015. Quest has now been in the operating funding phase for five 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 10-5: Government Funding Granted and anticipated ($'000)

Government funding granted through construction of the Quest project.

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Operating 2016**	**Operating 2017**	**Operating 2018**	**Operating 2019**	**Operating 2020**	**Forecast Operating[1]**
Government Funding	Jan 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 - Sep 30, 2015	Oct 1, 2015 - Sep 30, 2016	Oct 1, 2016 - Sep 30, 2017	Oct 1, 2017 - Sep 30, 2018	Oct 1, 2018 - Sep 30, 2019	Oct 1, 2019 – Sep 30, 2020	Oct 1, 2020 - Mar 31, 2026
Alberta Innovates Grant	3,226	1,817	1,303										
NRCan Funding				108,000			12,000						
GoA Funding				130,000	115,000	53,000	149,000	29,452	30,100	30,796	30,050	27,033	150,569
Total Funding	**3,226**	**1,817**	**1,303**	**238,000**	**115,000**	**53,000**	**161,000**	**29,452**	**30,100**	**30,796**	**30,050**	**27,033**	**150,569**

Cu. Gov't Funding as Percentage of Total Project Spend	0.3%	0.4%	0.5%	19.5%	28.7%	32.9%	45.8%	48.2%	50.6%	53.0%	55.4%	57.6%	69.6%

11 Project Timeline

The timeline for major maintenance activities in the Quest operating period through 2020 is shown in Table 11-1.

Table 11-1: Operating Timeline

Operations Timeline	2015	2016	2017	2018	2019	2020
Capture Facility						
Compressor Inspection			Q2			
E-24601 Repair				Q2		
Quest Creep Test Run					Q3	
Pipeline and Wells Surface Facility						
Pipeline Inspection		Q4				
Storage and Subsurface						
5-35 Commissioning				Q3		
7-11 Halite Remediation						Q3

12 General Project Assessment

Project Successes in 2020:

Operational MMV Data Acquisition

- A new MMV Plan was approved in November.
- In 2020 monitoring continued including one discrete sampling event at the project groundwater wells. Routine logging and well integrity testing were completed on the IWs.

Networking within Industry

- Networking with other industrial operating facilities continued to help better identify maintenance practices and procedures. Despite the challenges of 2020 amid the global pandemic. technical knowledge sharing continued through numerous technical conference presentations, workshop attendance, and knowledge sharing meetings.

Stakeholder Engagement

- Stakeholder management continues to be a priority for Quest. In 2020, 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

- 5 Million tonnes of CO_2 were successfully stored in April of 2020.
- No leaks or spills in 2020.
- A successful halite remediation of IW 7-11 occurred in July 2020.
- Annual CO_2 capture ratio was maintained at 76.8% in the fifth full year of operations.
- Compressor operated at lower average discharge pressures than previous years, 9.7MPag.
- Strong integrated project reliability performance with overall operational availability at 98.8% from start-up through 2020.
- Compressor availability was 99.8% in 2020.
- All three HMUs met their NOx level commitments without contravention in 2020 with continued capability to maintain NOx levels slightly elevated from pre-Quest baseline.
- Enacted permanent solution to mitigate the low PH water leaving the Quest facility.
- Injection certification, audits, offset verifications and updates to waste heat claims were completed, with serialization of 1,694,980 credits in 2020, registered on the Alberta Emission Offset Registry.

- Approvals granted in February for Quest to continue to utilize the CCIR electricity benchmark for electricity directly connected directly to the on-site co-generation unit.

Challenges in 2020:

There have been minor operational challenges to Quest, but none that have been insurmountable to date. The required COVID-19 response actions resulted in adaptations to the way we conducted operational and maintenance activities. In Q3, the Quest unit took advantage of the downtime in HMU 1&2 to perform a number of maintenance tasks, contributing to the already high reliability.

A description of these challenges and activities undertaken to address them is listed below.

Regulatory Changes and Credit Serialization

- Introduction of the new Technology Innovation and Emissions Reduction (TIER) Regulation that replaced the Carbon Competitiveness Incentive Regulation (CCIR) on January 1, 2020.

Technical Challenges

- Adapting to scheduling and execution of activities in the early days of COVID-19 restrictions.
- Maintenance work was identified to address reliability of the LightSource system.

12.1 Indirect Albertan and Canadian Economic Benefits

Quest is an in 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 2020, the main beneficiaries of Quest operations, in addition to the Quest Project owners, 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 and logging
- 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 of Alberta as a leader in CCS deployment through policy, regulation, and funding.

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:

- Use lessons learned to retain institutional memory and facilitate improvements in processes and procedures.
- Regulatory activities to demonstrate compliance with existing agreements.
- Public engagement activities and advocacy to build public knowledge and acceptance of CCS operations.
- Active sharing of CCS knowledge through publications and participation in conferences and workshops.
- Work with AEP and Alberta Energy (CCS Unit) on evolving regulations (i.e. TIER) and the long-term viability of CCS within Alberta.
- Work on energy-saving opportunities to reduce variable cost pressures of steam and electricity on Quest.
- Focus on optimizing operational costs.
- 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.

14 References

[1] AER, 2020, SHELL CANADA LIMITED, Quest Carbon Capture and Storage Project, 2020 ANNUAL STATUS REPORT, will be available at: https://open.alberta.ca/dataset?tags=CCS+knowledge+sharing+program&tags=Quest+Carbon+Capture+and+Storage+project