Gorgon Project
Carbon Dioxide Injection Project

Barrow Island Act 2003

Section 13 Approval Annual Operational Report
(1 July 2019 - 31 December 2019)

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Document Approvals

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1 Executive Summary

This report has been prepared to meet the requirements of Condition 11(a)(iii) of the *Barrow Island Act 2003* Section 13 Approval to Dispose of Carbon Dioxide by Injection into Subsurface Formation, dated 14th September 2009 ('the Section 13 Approval'). Condition 11(a)(iii) requires the first operational phase report to be submitted by the 31st March in the year after the calendar year during which the 'Commissioning Commencement Date' occurs. The 'Commissioning Commencement Date' occurred on 6th August 2019 with the commencement of reservoir carbon dioxide (CO_2) injection into the A-I2 injection well on drill centre A. This report therefore covers the 6-month period from 1stJuly 2019 to 31st December 2019.

During the reporting period, key activities have focused on:

- The ongoing installation, testing and commisioning of the DexPro™ licensed enthalpy-based gas recycle (refrigeration) scheme into the CO_2 compression modules to rectify the technical isues identifed during the 2017 pre-commissioning and start-up checks.
- Successful commissioning and commencement of injection operations utilising CO_2 from compression modules two and three.
- Monitoring data acquisition (baseline and operational).
- Investigation of lower than expected injectivity in the drill centre D pressure management water injection well D-WI1 and commissioning of the pressure management system.
- Progressing plans for the clean up of pressure management water producers on drill centres D and E and remediation of injectivity in the water injection well D-WI1.
- Progressing remaining regulatory approvals required to support commencment of reservoir CO_2 injection.

For the next reporting period, key activities will primarily focus on:

- Completing clean-up /remediation works on the pressure management well system to enable all wells to be operational by 31st May 2020.
- Ramping up carbon dioxide injection and pressure management operations.
- Undertaking monitoring activities.

2 Commencement of CO_2 Injection Operations

As reported in the 2018/2019 annual report, by the end of June 2019 the reservoir CO_2 pipeline, injection drill centres (DC) and compression module three had achieved 'Ready for Start-Up'. This enabled the commencement of reservoir CO_2 injection on 6th August 2019 into the A-I2 injection well on DC-A.

The start-up process involved several steps:

- Firstly pressuring the CO_2 pipeline to 6,000 kPag (60 barg) with industrial sourced dry CO_2. Industrial sourced dry CO_2 was also used to minimise the differential pressure between the wellheads and surface piping, with CO_2 cushion placed into all the CO_2 injectors sequentially up to ~ 8300 kPag (83 barg). The compressed reservoir CO_2 from compression module three at ~ 13,000 kPag (130 barg) was then introduced to the pipeline.

- The well start up sequence was as follows:

    - A-I2 well was opened first whilst the remainder of reservoir CO_2 was vented at DC-C. This was necessary to heat up the CO_2 pipeline to reach operating conditions.

    - Once the pipeline at DC-B had reached 50^{o}C, the well B-I6 was opened, followed by A-I1.

    - Once the pipeline heated up to DC-C, C-I7 and C-I8 were opened. At this time the average injection rate across the field was 67 MMscf/d or 41 kg/s.

    - The remaining four wells (B-I3, B-I4, B-I5 and C-I9ST1) were first started-up between early to mid-September, in preparation for compression module two start-up in October 2019.

- Compression module two commenced start-up on 10th October 2019, however the compressor had to be shut down due to a technical issue which was resolved on 22nd October 2019 rectified. This took the daily injection to ~ 149 MMscf/d (90 kg/s) which was the approximate CO_2 injection rate at the end of the reporting period (31st December 2019).

Injectivity was tested on a well by well basis with maximum rates proven as shown in Table 1. The key diagnostic parameter for assessing early injection performance is the reservoir pressure measured by permanent down-hole gauges. Pre-injection well performance forecasts were made for each CO_2 injection well. The actual performance, in terms of observed versus forecast bottom hole pressure (BHP), was much better than predicted which has required an adjustment of modelling parameters to obtain a good history match. Thus, injectivity is better than originally predicted for the first few months of CO_2 injection. It should be noted that it is still very early in the project's life, so extrapolating into the future is still uncertain.

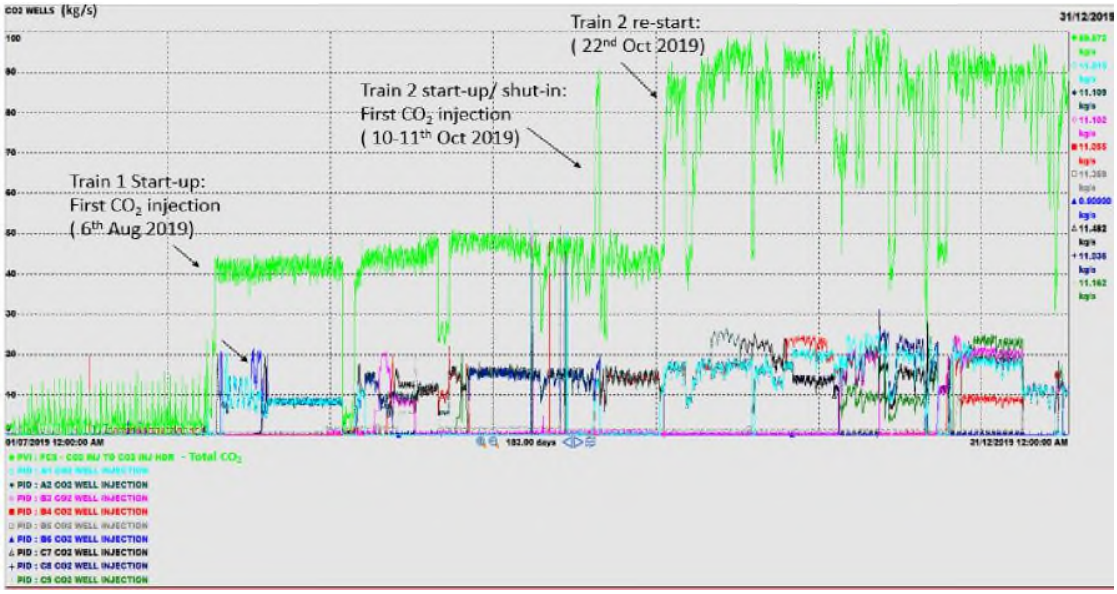

Figure 2-1: Total CO_2 rate and individual well rate between 1/7/2019 to 31/12/2019

Well	Maximum proven injection rate
A-I1	40.1 MMscf/d (24.5 kg/s)
A-I2	40.9 MMscf/d (25 kg/s)
B-I3	39.3 MMscf/d (24 kg/s)
B-I4	39.3 MMscf/d (24 kg/s)
B-I5	32.8 MMscf/d (20 kg/s)
B-I6	32.8 MMscf/d (20 kg/s)
C-I7	37.7 MMscf/d (23 kg/s)
C-I8	40.9 MMscf/d (25 kg/s)
C-I9ST1	40.9 MMscf/d (25 kg/s)

Table 2-1: Proven maximum injection rate for all CO_2 injectors

3 Status of Pressure Management System

At the end of the reporting period, the pressure management system was not yet operational however a comprehensive plan was put in place to address this. The effort focused on two key matters:

- Completion of pressure protection facility modifications on DC-E wells prior to their operation. The pressure protection (pressure safety valves) was required due to the occurrence of a limited volume of hydrocarbon in one of the water production wells (E-WP4).

- Determining the cause of lower than expected injectivity in the DC-D water injection well (D-WI1).

A comprehensive diagnostic plan was followed in relation to the DC-D injectivity response. This plan was broken into various stages which were executed during the reporting period. An overview of the stages and their findings is provided in Appendix A. The findings confirmed that in relation to the lower than expected injectivity in D-WI1:

- Gas did not seem to be a major contributing factor. The gas to liquid ratio (GLR) was in line with expectations of the Basis of Design, i.e. less the 18 scf/bbl.

- The main contributing factor is likely to be grease and debris carried over from the water producers when the wells were commissioned in May 2019.

Following the diagnostic activity on DC-D, DC-E wells were commissioned once the required pressure safety valves were delivered and installed (August 2019). Following the injectivity impairment discovered on the DC-D injection well, DC-E commissioning activities focused on:

- Confirming injectivity performance via an injectivity test, and

- Avoiding damage to E-WI2 while commissioning the water production wells.

The DC-E diagnostic program confirmed that the most likely cause of impairment in the DC-D injector (D-WP1) is near well-bore damage in the perforations due to the carry over of grease, perforation debris and some tubing corrosion material into the water injection well. The grease is likely to be a mix of pipe dope from completing the wells and tree grease used in the servicing and testing of the well-heads (both water production and injection).

In Q4 2019 a well clean-up / remediation plan was developed, the main objectives of which were:

- Prior to commencing production operations at DC-D and DC-E, clean-up water producers in order to avoid potential damage to the injection reservoir caused by the carryover of debris from the water producers (learning from DC-D).

- Remove the grease and debris believed to be clogging the perforations in D-WI1 to improve injectivity. Bypass the damage if required.

To undertake the above well clean-up / remediation scope equipment delivery to Barrow Island was required, as well as revisions to certain regulatory approvals. It therefore became clear that an extension to the *Petroleum Pipelines Act 1969* 'Consent to Operate' approval was required in relation to the pressure management wells condition which required the wells to be operational by 31st December 2019. An extension application was submitted to the Department of Mines Industry Regulation and Safety (DMIRS) in November 2019; in December 2019 DMIRS granted an extension to the 31st May 2020.

At the time of writing this report the scope of work to clean up water producers on DC-E had commenced; the DC-D water producers clean-up is planned to commence in late March/early April 2020 and the D-WI1 remediation scope is planned to commence in mid-April 2020. DC-E wells are anticipated to be operational by the end March/early April 2020 and DC-D wells by 31st May 2020.

Figure 2-1 Diagnostic activities on DC-D

4 Injection Rate / Volume / Composition:

The Section 13 Approval condition 11 requires the annual operations report to include information relating to injection rates, volumes injected, injection stream compositional variation and the gross and net abatement of greenhouse gas emissions arising from the injected reservoir CO_2. The table below contains the required information in relation to injection rates and volume for the reporting period. Injection rates were below the restriction limits set under condition 4 of the Section 13 Approval.

Condition Reference	Information Required	Information
11 (d)(i)	Average annual rate of injection	2,844 ksm^3 per day (5,235 tonnes per day) calculated from commencement of injection on 6th August to 31st December 2019
11 (d)(ii)	Injection rate range	Minimum: 295 ksm^3 per day (543 tonnes per day) Maximum: 4,454 ksm^3 per day (8,199 tonnes per day)
11(d)(iii)	Total volume of reservoir CO_2 injected*[1]	420,932 ksm^3 (774,912 tonnes)
11(d)(v)	Gross and net abatement of greenhouse gas emissions arising from the injected carbon dioxide	Gross abatement: 888,493.17 tonnes CO_2e*[2] Net abatement: Chevron is currently engaged with the Department of Jobs, Tourism, Science and Innovation to determine the specific requirements in relation to the reporting of the net abatement of greenhouse gas emissions arising from the injected carbon dioxide.

Table 4-1 Injection Rate, Volume Injected Information

Appendix B contains information on the injection stream compositional variation for the period August to December 2019. The injection stream composition was within restriction limits set under condition 3 of the Section 13 Approval. There were no exceedances of 3% (mol) hydrocarbon during the reporting period.

1 Reservoir CO_2 refers to gases in the injection stream consisting predominantly of CO_2 together with incidental associated substances (e.g. hydrocarbon). This total volume injected represents the mass of reservoir CO_2 injected, not the greenhouse gas equivalent (CO_{2e}) in tonnes of those gases.

2 At this time these are estimates of greenhouse gas equivalent (CO_{2e}) which will be confirmed in the annual reporting required under the Commonwealth *National Greenhouse and Energy Reporting Act 2007.*

5 Work Performed During the Reporting Period

5.1 Well Work Activity

During the reporting period the following key well work was undertaken:

- Executed pressure management wells diagnostic programme (1st July to 31st December 2019), including production logging tool (PLT) run on D-WI1 during the diagnostic stage.

- CO_2 injection wells were prepared for injection, including installation of CO_2 cushion up to 8300 kPag (83 barg) to minimise differential pressure between pipeline and well.

- Pressure safety valves were installed and operational at DC-E in September 2019 prior to the commissioning of the wells.

- E-WP4 pressure build up: Real-time pressure monitoring was made feasible from October 2019 after the de-isolation of the pipework post installation of safety valves in DC-E. Since the pressure bleed-off in March 2019, the pressure build-up rate has decreased indicating that the source is likely being depleted, given that the last tubing head and annulus pressure recorded on 31st December 2019 were 860 kPag (124 psig) and 2,000 kPag (290 psig). This is significantly lower than the highest pressure observed prior to the bleed-off in March 2019, which was ~ 16,536 kPag (2,400 psig). The most likely source of the gas is a small low saturation gas zone within the perforation interval in the Dupuy Formation.

5.2 Subsurface Activity

Some key subsurface work during the reporting period included:

- Preparation for CO_2 injection: A detailed plan was prepared to support commissioning and start-up of the CO_2 injection wells, including:

  - OLGA modelling with Chevron's Energy Technology Company to determine the requirement of CO_2 cushion followed by subsequent installation to each wellhead up to ~ 8300 kPag (83 bar).

  - Optimization of start-up sequence of drill centre / wells to ensure pipeline is heated-up.

  - Well start-up / ramp-up plan and step-rate tests.

- Monitoring CO_2 injection performance: Since 6th August 2019, CO_2 injection wells were progressively opened to flow, and step-rate tests were conducted while monitoring pressures at the well head (WHP) and downhole gauge (DHGP). All wells were commissioned and started-up during the first six weeks of operations, allowing the calibration of correlations between DHGP and WHP.

  After the second compression module started-up on 22nd October 2019, the additional CO_2 volume allowed testing of each well to its maximum design rate to prove injectivity. Additionally, interference testing involved conducting pressure fall-off tests where different wells were shut-in while monitoring the pressure

response at offset wells to understand the potential overlap of drainage area between wells and drill centers.

Finally, the pressure gauges installed at the electric-submersible pumps (ESP) on the DC-D and DC-E water producers were closely monitored to identify the timing for the pressure response created by CO_2 injection, which ultimately confirmed lateral continuity and connectivity across the reservoir.

- Gen 10 simulation model (2018-19): After start-up, the actual injection rates at the well-level were input to control the model, and together with the operational constraints used to predict the BHP and WHP. These modelled pressures were compared with the actual recorded pressures, and rock/fluid properties were modified to achieve a history match. This recurrent process is conducted on a monthly basis to improve the predictability of the model.

- Gen 11 static modelling: Work continued on the Gen 11 long-term reservoir model, incorporating new static data, updated seismic interpretation, petrophysical interpretation and depositional interpretation. This model will be calibrated with early injection/production data and will be used as the model to assess project risks going forward.

- Gen 11 simulation model (2020+): Work continued on the long-term reservoir model, incorporating updated seismic interpretation, petrophysical interpretation, depositional model interpretation as inputs to static modeling process. This model will be calibrated with actual injection data. Once completed in 2020, it will be used as the model to assess project risks going forward.

- Commenced the required annual review of the 'CO_2 Disposal Management Plan'.

5.3 Monitoring Programme Activity

During the reporting period monitoring activities moved from collection of baseline data to early injection data. Below is a summary of the monitoring activities.

5.3.1 3D Seismic Data

No significant new processing of the baseline data set was performed during the reporting period. Interpretation of the reprocessed baseline seismic data has continued during the reporting period and is being used as a key input to the Gen 11 static model. A seismic interpretation report will be submitted to DMIRS in 2020.

5.3.2 Cased Hole Logging

No additional cased hole logging was performed in the Reservoir Surveillance wells during the reporting period.

Planning has commenced to test a fibre-optic Distributed Acoustic Sensing Vertical Seismic Profiling (DAS-VSP) in the reservoir surveillance well A-RS1 in collaboration with Curtin University. The plan is to repeat the walk-above and walk-away geometries used to acquire the wireline VSP in 2015, then compare data quality to determine if DAS-VSP would be a viable alternative acquisition methodology.

5.3.3 Passive Microseismic

5.3.3.1 CO_2 Data Well

The collection of baseline data in the CO_2 Data Well, which commenced in early 2017, concluded during the reporting period. No microseismic events were recorded in the Area of Interest (AOI) during the 2.5-year baseline period. Operational data collection commenced with the commencement of CO_2 injection into the Dupuy Formation on 6th August 2019.

Chevron has contracted Schlumberger (SLB) to monitor and process the passive seismic data from the CO_2 Data Well.

Injection related microseismicity commenced on 4th September 2019 and has continued to the end of the reporting period. A total of 301 microseismic events have been detected, 94 of which have been located. Most events are in the injection interval, with events at depths of between 1850m and 2250m. The moment magnitudes of the 94 located events range from -0.2 to -2.4. The table below provides an indication of how the Gorgon events compare to other events of different magnitude.

	Domain	Magnitude Range	Event Class	Fault Size	Displacement Scale	Event Type
Felt at Surface	Seismology "Seismic Harzard"	8 or more	Great	100 -1000 km	4-40 m	Earthquake
		6 to 8	Large	10 -100 km	0.4-4 m	
		4 to 6	Moderate	1 -10 km	40-400 mm	
		2 to 4	Small	0.1 -1 km	4-40 mm	
Gorgon Events	Microseismic Monitoring	0 to 2	Micro	10-100 m	0.4-4 mm	Microearthquake
		-2 to 0	Nano	1-10 m	0.04-0.4 mm	
		-4 to -2	Pico	0.1-1 m	0.004-0.04 mm	
	Lab Tests	-6 to -4	Femto	1-10 cm	0.0004-0.004 mm	Acoustic emission
		-8 to -6	Atto	1 -10 mm	0.00004-0.0004 mm	

Figure 4-1 Microseismicity Event Magnitudes

The frequency and magnitude of microseismicity is consistent with other analogue CO_2 injection projects (e.g. Quest) and with the Gorgon CO_2 pre-injection expectations.

Analysis of SLB's located microseismic events has highlighted that the velocity model and Q (seismic attenuation) model needs improvement to increase accuracy of the event locations and the event magnitudes. This work will be completed during Q1, 2020.

Above Zone Pressure:

During the reporting period, pressure has been observed to increase slightly (7psi) in a gauge directly above the Basal Barrow Group Shale. The pressure changes correlate closely with the pressure measured in a DC-B injection well (B-I6) located very close to the CO_2 Data Well gauge. This pressure change is on top of a larger amplitude regional trend of increasing pressure which was occurring prior to the commencement of CO_2 injection; the source of this regional trend is not understood.

5.3.3.2 Near-surface Array

Recording of baseline near surface passive seismicity, which commenced in December 2018, continued during the reporting period.

Chevron has contracted Baker Hughes (BHGE) to monitor and process these near surface passive seismic data, by integrating both the CO_2 Data Well and the near surface passive seismic data into a single analysis. This integrated analysis provides the most accurate positioning and magnitudes.

No microseismic events were recorded in the AOI during the 8-month baseline period. CO_2 injection started on 6th August 2019 into the Dupuy Formation. Injection related microseismicity started on 25 September 2019 and has continued through Q4 2019. A total of 283 microseismic events have been detected, 67 of which have been located. Most events are in the injection interval, with events at depths of between 1841m and 2576m. The moment magnitudes of the 67 located events range from -0.4 to -2.2.

The frequency and magnitude of microseismicity is consistent with other CO_2 injection projects and with the Gorgon CO_2 project pre-injection expectations.

5.3.3.3 Passive Microseismic Preliminary Data Interpretation

The detection and location of micro-seismic events induced by pressure changes in the reservoir as a result of CO_2 injection was expected. The magnitude of these events is sufficiently small as to not be concerning. During the time period between 2009 and 2013/2014, lessons learned from other CO_2 injection projects (both pilots and commercial scale e.g. Quest in Canada) indicated that microseismicity should be expected, and that it is better to have reliable data to understand the effects of pressure changes on the injection interval and over/under-burden. Chevron therefore included microseismicity in its monitoring programme in 2015. The Illinois State Geological Survey / Schlumberger Carbon Services peer review (2016-2017), commissioned by Department of Mines Industry Regulation and Safety (DMIRS), acknowledged that microseismicity events of less than moment magnitude 2 should be expected and that the monitoring system is designed to understand fault plane properties for larger felt events. Thus, the current frequency and magnitude of events is not concerning and does not alter the risk assessment of the project.

As described in section 5.3.3 above, a pressure change has been observed at the downhole gauge installed in the CO_2 Data Well, located to the west of DC-B. At the time of writing this report, some preliminary interpretation has been undertaken utilizing the Gen10 reservoir simulation model to better understand the potential location and source of the pressure response in the CO_2 Data Well. Several alternatives attempted to represent a vertical pressure path from the Dupuy Formation through the Basal Barrow Group Shale, which could be near the well or further away. Considering the resolution of the model (100 m x 100 m x 1 m grid-cells), one plausible history matched realization is that a vertical conduit (e.g. a small fracture) exists within 100 m of the CO_2 Data Well. For the modelled vertical conduit to match the observed gauge response requires an effective vertical permeability of 1 millidarcy. This realization matches both the trends observed during B-I6 injection period (higher slope) and shut-in period (lower slope). A vertical conduit with low vertical permeability is very unlikely to create CO_2 migration above the Dupuy Formation as the horizontal permeability of the perforated sands where CO_2 is being injected is multiple orders of magnitude larger and dominates the preferential flow path.

During the next reporting period, close monitoring of the above zone pressure will continue and, in particular, the impact of the pressure management system (once operational).

5.3.4 InSAR

Chevron contracted TRE Altamira Inc. (TRE) to acquire baseline InSAR survey data every 16 days from 29th July 2015 to 22nd June 2019. Data from this baseline period was processed during September 2019 to create pre-injection ground deformation maps, using TRE's proprietary SqueeSAR algorithm to process the high-resolution Cosmo-SkyMed (CSK) radar data.

Key findings from the InSAR baseline period are:

- Cumulative deformation over the entire Barrow Island ranges from -54 mm to +39 mm over the 4-yr period. This ground movement occurs to the south and west of the CO_2 injection area.
- Minimal ground deformation (3 mm or less) was observed near the CO_2 injection areas and within the 5-yr CO_2 plume boundaries.
- The water production well E-WP4 shows +9 mm of uplift within a 3-yr span (mid-2015 to mid-2018) and subsidence of -5 mm in the last year (mid-2018 to mid-2019).

The CO_2 injection monitoring period began on the 23rd June 2019. Radar data is acquired every 8 days by the CSK and every 11 days by the TerraSAR-X satellite. Processing of this ongoing monitoring data will be completed every 6-months after the start of CO_2 injection. This phase of monitoring will provide 2-D (vertical and east-west) measurements by using imagery acquired from two satellite orbits.

5.3.5 Groundwater & Soil Gas Monitoring

During the reporting period, two monitoring events were conducted: in September 2019 (reduced scope) and November 2019 (full scope).

A reduced scope of groundwater and soil gas monitoring was conducted in September 2019 to monitor conditions following the commencement of CO_2 injection. The reduced scope entailed *in situ* measurement of compositional gases (using GA5000), measurement of groundwater field parameters (using YSI ProDSS) and downloading data from continuous CO_2 monitors (initially, three continuous monitors were deployed, however, one logger failed to obtain data as a result of logger malfunction and has been removed from the well). An overview of results from the September 2019 round are provided below:

- *In situ* compositional gas concentrations were generally consistent with results from previous rounds (baseline data)

- Groundwater field parameters were generally consistent with previous rounds (baseline data) apart from redox potential. Redox results indicate there is a general trend of conditions changing from strongly reducing to strongly/slightly reducing and slightly oxidising in one location. Due to issues with the equipment supplier (failed to deliver equipment) an alternative water quality meter was sourced at short notice. However, the replacement water quality meter had a limited length of data cable, and therefore *in situ* groundwater parameters could not be recorded within the screened portion of monitoring wells Control Site 1, DC-D, DC-E, P18J, X53J and X62J.

A full scope of groundwater and soil gas monitoring was conducted in November 2019 to compare conditions to the baseline conditions established prior to CO_2 injection. The full scope entailed soil gas sampling and analysis at all wells (using Tedlar bags); groundwater quality sampling and analysis at all wells; *in situ* soil gas monitoring (using GA5000) at all wells; *in situ* groundwater field parameter measurements (using YSI ProDSS) at all wells; and redeployment of the continuous CO_2 monitors at two wells. We are currently awaiting receipt of the full laboratory analysis.

A baseline report is being prepared that captures all data from July 2016 to March 2019. The objective of the report is to understand baseline conditions prior to CO_2 injection and to establish assessment criteria for ongoing monitoring events following commencement of CO_2 injection in August 2019.

The full parameter suite for baseline and ongoing analysis of groundwater and soil gas is contained in Appendix C.

5.3.6 Remote Sensing

During the reporting period, plans were progressed to purchase pre-injection high resolution satellite imagery and the purchase of 2020 imagery for post commencement of CO_2 injection analysis. In late October 2019 aerial imagery (10cm resolution) was captured over the whole island.

5.4 Subsurface Modelling

5.4.1 Gen 10 modelling

The Gen 10 model is the first one to incorporate development well results from the 2013/2015 drilling campaign and includes updated facies and petrophysical properties. It is a single realization and was intended as an early injection forecasting and calibration tool ahead of further static modelling.

The Gen 10 dynamic model was built in Petrel using Intersect as the reservoir simulator. This model has been used for several purposes:

- Compare predictions of DHGP and WHP for actual rates with recorded pressures and allow modification of rock/fluid properties to achieve a history match and improve the predictability of the model.
- Develop short-term CO_2 injection forecast based on expected supply and predict pressure behavior at the well- and reservoir-level.
- Develop an understanding of the impact on reservoir CO_2 injectivity caused by reduced compressor outlet pressure resulting from the installation of the dew-point control measures within the CO_2 compression modules.
- Provide greater understanding of the short-term effect of the pressure management system effectiveness.
- Used as input to modelling of CO_2 seismic detectability to determine the timing of the first repeat 3D seismic survey.

The Gen 10 model was provided to DMIRS on 26th November 2019 (as requested). The data contained pressure forecasts for all wells during the CO_2 injection field life (2019-2068) and beyond (until 2019), as per base case injection scenario. The Gen 10 model is not intended to be used for risk assessments, longer term plume models, well count forecasts, etc. That will be the function of the Gen 11 model.

5.4.2 Gen 11 modelling

During the reporting period, work continued on the Gen 11 static reservoir model suite. These models will incorporate the latest Dupuy subsurface characterization (interpretation, seismic, well tops, well data, core and early dynamic data) and will be used for operational decisions, plume forecasting, risk assessment, long term monitoring and identification of low side mitigation strategies.

A successful Gen 11 model will be auditable, easily manipulated and able to integrate new data as it becomes available. It is intended that the Gen 11 models will replace the older models currently held by DMIRS to demonstrate injected reservoir CO_2 containment and risk management.

5.4.3 3D Mechanical Earth Model

Work to create a new 3D Mechanical Earth Model continued during the reporting period. 1D models were created for each of the CO_2 injection wells, calibrated to data from the wells with core (CO_2 Data Well, A-RS1 and C-RS2). These were then used in conjunction with the Petrel structural framework to create a 3D Mechanical Earth Model. This includes the full overburden section. At the end of the reporting period, work was continuing on the testing and calibration of the model.

5.5 DMIRS Due Diligence

No activities during the reporting period.

5.6 Data Collection Summary

5.6.1 Core / Rock Mechanics Testing:

Petrography, core flood testing and digital core analysis on samples from A-RS1 and C-RS2 wells was completed and submitted to DMIRS on 16 October 2019 (transmittal number ABU191000125).

5.6.2 Monitoring Data

With the commencement of CO_2 injection during the reporting period, the baseline monitoring period ended. The following monitoring data was collected during the reporting period:

- Groundwater / soil gas.
- Aerial imagery data
- Passive microseismic data.
- InSAR data.
- Reservoir pressure data

5.7 Project Approvals

During the reporting period, the following key approval applications required to support injection operations were submitted and / or obtained:

- On 30 July 2019, the Department of Water and Environmental Regulation granted an *Environmental Protection Act 1986* Part V amendment to the Gas Treatment Plant Licence L9102 relating to reservoir CO_2 injection.

- On 30 July 2019 DMIRS granted a conditional 'Consent to Operate' the PL93 facilities under the *Petroleum Pipelines Act 1969*. The Consent had a condition requiring the pressure management wells to be operational by 31st December 2019. Following a November 2019 Chevron application, on 13th December 2019 DMIRS approved an extension to this condition to 31st May 2020.

In addition to the above, the GJV has continued to engage with the Environment Protection Authority on the *Environmental Protection Act 1986* Section 46(1) inquiry into the interpretation of the starting point for commencement of the reservoir CO_2 injection system required under Condition 26 of Ministerial Statement 800. This inquiry is ongoing.

5.8 Section 13 Approval Compliance

In compliance with Condition 9 of the Section 13 Approval, Chevron completed an internal audit regarding compliance with the Section 13 Approval conditions during the period 1st September 2018 to 31st August 2019. In November 2019 Chevron submitted a Compliance Report containing the outcome of the internal audit to the Barrow Island Act Minister (ABU191001149).

The audit identified a potential non compliance in relation to the method used to monitor hydrocarbon in the injection stream. This related to commissioning and start up issues which prevented the the online analysers being operational. Weekly manual sampling of the stream was implemented which confirmed that hydrocarbon limits under the Section 13 Approval have been met during the reporting period.

6 Risk Review

As specified in the Section 13 Approval condition 11d (vi), the annual report is to include "*any recognized circumstances that might indicate that the risks associated with injected carbon dioxide have changed."* The risks associated with the project are described in section 6 of the CO_2 Disposal Management Plan and it is Chevron's view that based on the early injection data obtained to date the risks as described have not changed.

7 Proposed Work Plan for Next Reporting Period (2020)

Outlined below is a summary of the currently planned work scopes for 2020. In relation to work scopes involving site works, at the time of writing this report, it is currently uncertain what if any impact the COVID-19 pandemic may have on the execution of these scopes of work.

7.1 Planned Facilities Works / Operations

The following key activities are planned for the next reporting period:

- Completion of the required modifications to compression module one; commissioning and start-up.
- Ramping up of reservoir CO_2 injection operations once the full compression capacity is available.
- Pressure Management:
  - Clean-up of water production wells at DC-E; start-up of all wells on DC-E and monitor performance.
  - Clean-up of water production wells at DC-D; then rectify D-WI1 using work-over rig to (1) clean up grease/debris inside tubing and casing, then (2) re-perforate the well in the Flacourt Formation to recover injectivity. Startup all DC-D wells and monitor performance.
- Planned maintenance for the CO_2 compression, pipeline and injection facilities will be in accordance with the (CMMS) Computerised Maintenance Management System.

7.2 Planned subsurface activities

The following key activities are planned for the next reporting period:

- Subsurface modelling: Completion of the Gen 11 reservoir model. This will include calibration to the early dynamic data/observations, including interference pressure signals, early injectivity, bottom-hole pressure changes, etc.
- Calibrate the new 3D – Mechanical Earth Model. Use the InSAR measurements to predict changes in distributuon of subsurface pressure.
- An update of the subsurface uncertainty management plan and risk management plan will be completed in Q3/Q4 2020. This will use all of the subsurface data

available at the time. It will also allow time for the impact of the pressure management system to be included in the assessment.

- Annual review of the CO_2 Disposal Management Plan (as required by the Section 13 Approval).

- Interpretation of all dynamic reservoir data collected during the year. Detailed analysis of all dynamic performance data versus short term forecasts. Support project decisions as required. CO_2 injection allocation across the nine CO_2 injection wells based on reservoir performance.

- Supervision of pressure management remediation and start-up activities.

7.3 Planned Monitoring Activities

The following monitoring related activities are planned for the next reporting period (refer to Appendix D):

- Soil gas and groundwater monitoring data (quarterly basis). Review of November 2019 sampling period laboratory analysis.

- InSAR data collection with 6 monthly processed data and reports.

- Purchase of high resolution satellite imagery for pre and post commencement of resservoir CO_2 injection (i.e. 2020 imagery). Assessment of encountered vegetation health anomalies (if any).

- Capture of passive microseismic data from the CO_2 Data Well and the pilot near surface array. Expand pilot array to full array during the year.

- Monitor pressure and temperature from the surface and down-hole gauges in CO_2 injection wells and pressure management water production wells.

- Above zone pressure monitoring in the CO_2 Data Well.

- Cased hole saturation logging in A-RS1 and C-RS2.

- Production logging tool acquisition in nine CO_2 injection wells.

- Commence planning for the 2021 surface seismic survey and VSPs.

7.4 Forecast of Injection Rate / Volume for 2020

Based on current estimates, during 2020 approximately 3.2 million tonnes of CO_2 is anticipated to be injected. This would bring the cumulative amount injected since commencement of injection to approximately 4 million tonnes. Once all compression modules are operational the injection rate is anticipated to be approximately 210 MMscfd spread across all nine injection.

APPENDIX A: Overview of Diagnostic Programme DC-D and DC-E

Stage	DC-D Diagnostic Activity Description	Findings
1	**24th July 2019: Trialed a faster ESP ramp-up in the water production wells.** The purpose of the faster ramp-up was to overcome the suspected gas break-out by increasing fluid velocity.	No improvement in injectivity
2	**9th August 2019: Ran pressure gauge in D- WI1 while water was being injected:** The main objective of the pressure gauge run was to detect the presence of a gas plug during injection or static conditions.	Both the static gradient survey (SGS) and flowing gradient survey (FGS) results showed no indication of gas plug. The FGS also indicated that we were largely injecting water with a small amount of gas.
3A	**21st September 2019: Injectivity test with brine utilizing surface pump**: The main objectives were to do an injectivity test on D- WI1 with brine and to run the Production Logging Tool (PLT) to measure the injection distribution profile.	The measured injectivity with brine was 15 b/d/psi and the PLT showed only the Upper Flacourt and top of the Lower Flacourt were taking most of the fluid. The recovered tool was covered with grease and solids with high iron contents.
3B	**24th to 25th September 2019: Flow DC-D water producers via temporary surface pipping into the Injector D-WI1:** The main objective was to measure the gas to liquid ratio (GLR) in the produced Dupuy Formation water with a multiphase meter and PVT samples.	Multiphase meter indicated no significant gas for both D-WP1 and D-WP2. GLR from the meter is in the range of 12-20 scf/bbl (versus Basis of Design of 18 scf/bbl).

Stage	DC-E Commissioning Activity Description	Outcome
4A	**3rd October 2019 E-WI2 injectivity test with brine utilizing surface pump:** The objective of the injectivity test in E-WI1 with brine was to determine if the low injectivity seen at D-WI1 was due to well completion activity or damage during well start-up. Like Stage 3A the PLT was also ran for an injection profile.	The measured injectivity with brine was at 380 b/d/psi, which matched the expected performance based on the Kh calculated from wireline logs. This indicates that the low injectivity seen in D-WI1 was due damage created during the initial water production well start-up in May 2019. Unfortunately, no result was obtained from the PLT as the spinner was covered with grease.
4B	**10th to 13th October 2019: Attempted clean-up of DC-E water producer wells via filter to E-WI2:** The main objective of this stage was to commission the ESPs on the 2 water producers well and at the same time attempt to clean-up the wells by producing the wells via an in-line filter before injecting the produced water into E-WI1. The other objective was to measure the GLR of the produced water with the multiphase meter and PVT samples.	The ESPs were successfully commissioned but well clean-up was stopped due to continued plugging of the filters and injection tubing head pressure (ITHP) increasing overtime. GLR from the multiphase meter is in the range of 11 to 40 scf/bbl. A mix of sand, ferrous material and grease were retrieved from the filters.

APPENDIX B Injection Stream Compositional Data

Month	Monthly Average	Minimum	Maximum
CO_2 % (mol)			
August	98.4%	98.4%	98.4%
September	98.4%	98.4%	98.4%
October	98.4%	98.4%	98.4%
November	99.0%	99.7%	98.4%
December	99.7%	99.7%	99.7%
Hydrocarbon % (mol)			
August	1.5%	1.5%	1.5%
September	1.5%	1.5%	1.5%
October	1.5%	1.5%	1.5%
November	0.9%	0.3%	1.5%
December	0.3%	0.3%	0.3%
Hydrogen Sulphide (parts per million volume)			
August	109	50	132
September	116	91	130
October	107	85	125
November	63	33	91
December	125	102	149
Nitrogen (parts per million volume)			
August	505	513	507
September	506	509	507
October	507	508	507
November	63	508	300
December	62	82	79

Month	Monthly Average	Minimum	Maximum
Water (parts per million volume)			
August	486	419	728
September	564	421	806
October	653	480	1031
November	682	421	907
December	640	419	1008

Low Volume Chemical Substances Allowed under CO_2 Disposal Management Plan (Section 5.1)

Month	Monthly Average	Minimum	Maximum
Corrosion Inhibitor (parts per million volume)			
August	0.8	0.7	1.1
September	0.8	0.7	1.1
October	0.8	0.7	3.8
November	0.8	0.6	4.4
December	0.8	0.6	4.5

Month	Monthly Average	Minimum	Maximum
MEG %			
August	0.0	0.0	0.0
September	0.0	0.0	0.0
October	0.0	0.0	0.0
November	0.0	0.0	0.0
December	0.0	0.0	0.0

APPENDIX C Groundwater / soil gas analysis suite

Full parameter suite - Groundwater

Groundwater Monitoring Wells	Monitoring Suite	Instrument
CS2 – (CONTROL AREA) DC-A P18J DC-E U22J CS1 – (T24) CO_2 DATA WELL DC-B DC-C X62J X53J DC-D (Y58J)	**Field Parameters** pH Pressure Electrical conductivity Dissolved oxygen Redox potential	YSI EXO01
	Dissolved Gases Carbon Dioxide (CO_2) Oxygen (O_2) Hydrogen Sulfide (H_2S) Hydrogen (H_2) Helium (He) Nitrogen (N_2) C_1-C_{12}+ Isotopes ($6^{13}C_1$ – C_3 of DIC, $6^{13}CO_2$)	Summa Canisters
	Groundwater Monitoring Suite pH EC TDS Total Inorganic Carbon (TIC) Alkalinity Carbon Dioxide Total Recoverable Hydrocarbons (TRH) Monocyclic Aromatic Hydrocarbons (MAH) Cations (Na^+, Ca^{2+}, Mg^{2+}, K) Anions (CO_3^{2-}, Cl^-, SO_4^{2-} and Br^-) Trace metals (Ba, Fe, Mn and Zn) Sulfide and unionised sulfide Nutrients (ammonium, nitrate-N, nitrite-N, total kjeldahl N, total N and total P)	Laboratory analysis

Full Parameter Suite – Soil Gas

Soil Gas Monitoring Wells	Soil Gas Parameters	Instrument
CS2 – (CONTROL AREA) DC-A P18J DC-E U22J CS1 – (T24) CO_2 DATA WELL DC-B DC-C X62J X53J DC-D (Y58J)	Carbon monoxide (CO) Carbon dioxide (CO_2) Hydrogen Sulphide (H_2S) Methane (CH_4) Oxygen (O_2) Barometric pressure	GA5000 Ground Gas Analyser
	Ionisable gases	MiniRae 3000 PID
	Carbon dioxide (CO_2) Oxygen (O_2) Carbon monoxide (CO) Nitrogen (N_2) Carbon ($C_1 – C_6+$) Isotopes ($6^{13}C$ of CO_2, $6^{13}C$ of C_1-C_5) Helium (He) Hydrogen (H_2)	Tedlar bag

APPENDIX D Monitoring Data collection

Technique	Monitoring Purpose				Collected During 1 Jul to 31 Dec 2019 Reporting Period	Planned for 2020 Reporting Period
	CO_2 Distribution in subsurface	CO_2 Seepage / Leakage	Reservoir Pressure	Induced Seismicity		
Time-lapse Seismic	/	/	X	X	No	No
Time-lapse VSP	/	/	X	X	No	No
Passive Microseismic	X	X	/ *1	/	Yes	Yes
InSAR	/*1	X	/ *1	/*1	Yes	Yes
Injection Well Monitoring	/	X	/	X	Yes	Yes
Reservoir Surveillance Well Monitoring	/	/	/	X	Yes	Yes
Pressure Management Wells Monitoring	/*4	X	/	X	Yes	Yes
Groundwater	X	/*2	X	X	Yes	Yes
Soil Gas	X	/*3	X	X	Yes	Yes
Remote Sensing	X	/*1 *3	X	X	Yes	Yes
*1 Indicator only *2 Near surface seepage/leakage only *3 Surface seepage/leakage only *4 In later years if CO_2 plume migrates to wells						

APPENDIX E Acronyms and abbreviations

The following acronyms and abbreviations may have been used in this document.

3D	Three dimensional
BI Act	*Barrow Island Act 2003*
BHP	Bottom hole pressure
BI Act Minister	means the Minister to whom the administration of the Barrow Island Act is for the time being committed
CO_2	Means gases consisting predominantly of CO_2 recovered during gas processing on Barrow Island
DC	Drill centre
DHGP	Downhole gauge
DMIRS	Department of Mines, Industry Regulation and Safety
ESP	Electrical submersible pump
Gen	Generation
GJV	Gorgon Joint Venturers
GRL	Gas to liquid ratio
kPag	kilopascal gauge
m	Metres
MMscfd	Million standard cubic feet per day
PL93	*Petroleum Pipelines Act 1969* Carbon Dioxide Injection Pipeline and Wells Pipeline Licence PL93 dated 1 December 2011.
Section 13 Approval	Section 13 Approval means the document dated 14 September 2009 setting out the conditions and restrictions of the Gorgon Gas Processing and Infrastructure Project Agreement Minister's approval granted to the Joint Venturers (as defined in that document) under section 13 of the Act to inject carbon dioxide into the Dupuy Formation beneath Barrow Island as varied, added to or substituted for in accordance with condition 19 of that document.
sm^3	Standard cubic metre
TCF	Trillion cubic feet

VSP	Vertical Seismic Profile
WHP	Well head pressure