40 CFR 98 Subpart RR – Geologic Sequestration of Carbon Dioxide

Annual Monitoring Report

Reporting Period: January 1 – December 31, 2020

Company Name: Exxon Mobil Corporation

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GHGRP ID: 523107

Facility Name: Shute Creek Treating Facility – AGI

Facility Address: P.O. Box 1300
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Executive Summary

ExxonMobil began monitoring efforts pursuant to the final ExxonMobil Shute Creek Treating Facility (SCTF) Monitoring, Reporting, and Verification (MRV) Plan for the Acid Gas Injection (AGI) process on January 1st, 2018. The final MRV plan was approved by EPA effective June 25th, 2018. The MRV plan identification number is 1002150-1.

Summary of Monitoring Activities

ExxonMobil's program for monitoring potential leakage pathways in the AGI process including detection methods and locations is summarized in Table 1.

Table 1. AGI Monitoring Program

Leakage Pathway	Detection Monitoring Program	Monitoring Location
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead
Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	N/A – Leakage pathway is highly improbable	N/A

40 CFR 98.446 (f) (12)

(i) A narrative history of the monitoring efforts conducted over the previous calendar year, including a listing of all monitoring equipment that was operated, its period of operation, and any relevant tests or surveys that were conducted.

The SCTF AGI facility and wells have been operational since 2005 and ExxonMobil has continued to operate the monitoring equipment for the duration of injection.

The flow rate of CO_2 injected is measured with a volumetric flow meter for each injection well and is monitored continuously through the DCS surveillance system, allowing the flow rate to be compiled quarterly. Flow meters are calibrated according to manufacturer recommendation and the calibration and accuracy requirements in 40 CFR 98.3(i). Flow meter calibrations are traceable to National Institute of Standards and Technology (NIST). Flow meters were calibrated in April, July, and October in 2020.

The injected CO_2 stream is measured upstream of the volumetric flow meters with a continuous gas composition analyzer. The continuous composition measurements are averaged over each quarterly period to determine the quarterly CO_2 composition of the injected stream as required.

The CO_2 analyzers are calibrated according to manufacturer recommendations. The analyzers were calibrated in July of 2020.

Field personnel conducts daily visual inspections of the AGI facilities and weekly inspections of the AGI well sites, unless weather or site conditions present risk to personnel, to allow for potential leaks to be identified and addresses early and proactively. Completed inspections are documented electronically.

On an annual basis, the AGI subsurface and wellhead valves are leak tested for mechanical integrity testing as required by the WOGCC. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised. The wellhead valve tests for both AGI 2-18 and AGI 3-14 were completed on August 19, 2020.

Inline inspections are conducted of the AGI flow lines through the use of a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised. Inline inspections are done every 6 years for each well in alignment with plant shutdowns that occur every 3 years. AGI 2-18 was pigged on July 16, 2019 as part of the 2019 turnaround. AGI 3-14 was pigged during the 2016 turnaround.

To monitor potential leaks, gas detectors are operated continuously except as necessary for maintenance and calibration. Gas detectors are operated and calibrated according to manufacturer recommendations and API standards. Calibrations were completed in March, May, September, and November of 2020. Additionally, all field personnel are required to wear H2S monitors for safety reasons, which are bump tested daily. These alarms trigger at 10 ppm, so even a miniscule amount of gas leakage would trigger an alarm.

In accordance with the risk-based calculation approach of the MRV plan, any surface leakage would be detected and managed as an upset event and calculated for that event based on operating conditions at that time. The continuous surveillance of operating parameters and continuous gas detection identifies leaks better than an annual leak survey would due to the fact that the gas detectors are in operation at all times and prevents high-risk exposure to plant personnel. Any leakage events are reported under Subpart RR as required. In March 2020, one leak event occurred on a pressure transmitter at the surface of wellhead 3-14. The leak was due to gas blow by of an O-Ring. A PHAST (Process Hazard Analysis Software) dispersion model was created utilizing gas composition and field data to reflect actual events. As a result of the O-Ring failure, 185.6 pounds of CO2 (0.084 mtonnes) was released.

(ii) A description of any changes to the monitoring program that you concluded were not material changes warranting submission of revised MRV plan under 98.448(d).

ExxonMobil has reviewed the MRV plan and concluded that there are no non-material changes to the EPA approved MRV Plan for the 2020 reporting period.

(iii) A narrative history of any monitoring anomalies that were detected in the previous calendar year and how they were investigated or resolved.

ExxonMobil has determined that no anomalies were detected in the previous calendar year.

(iv) A description of any surface leakages of CO_2, including a discussion of all methodologies and technologies involved in detecting and quantifying the surface leakages and any assumptions and uncertainties involved in calculating the amount of CO_2 emitted.

A single event of surface leakage of CO2 was detected in the previous calendar year. As detailed in section **(i)**, gas blow by of an O-Ring resulted in a leak on the pressure transmitter at the surface of wellhead 3-14. As a result of the O-ring failure, 185.6 pounds of CO2 was leaked. The methodology of quantification of the surface leakage involved utilizing a PHAST model with gas composition and field data inputs to create a dispersion model that reflected actual events.

Operating parameters are continuously monitored by qualified technicians through the facility surveillance DCS. Field personnel routinely visited the surface facilities and conducted visual inspections during the reporting year. In addition, ExxonMobil used gas detectors and personal H_2S monitors to detect potential small leaks that would trigger an immediate response. ExxonMobil will continue to monitor equipment and all other pathways for leakage during the injection year.