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A Gate-to-Gate Life Cycle Assessment for the CO₂-EOR Operations at Farnsworth Unit (FWU)

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Abstract: Greenhouse gas (GHG) emissions related to the Farnsworth Unit's (FWU) carbon dioxide enhanced oil recovery (CO₂-EOR) operations were accounted for through a gate-to-gate life cycle assessment (LCA) for a period of about 10 years, since start of injection to 2020, and predictions of 18 additional years of the CO₂-EOR operation were made. The CO₂ source for the FWU project has been 100% anthropogenically derived from the exhaust of an ethanol plant and a fertilizer plant. A cumulative amount of 5.25×10^6 tonnes of oil has been recovered through the injection of 1.64×10^6 tonnes of purchased CO₂, of which 92% was stored during the 10-year period. An LCA analysis conducted on the various unit emissions of the FWU process yielded a net negative (positive storage) of 1.31×10^6 tonnes of CO₂ equivalent, representing 79% of purchased CO₂. An optimized 18-year forecasted analysis estimated 86% storage of the forecasted 3.21×10^6 tonnes of purchased CO₂ with an equivalent 2.90×10^6 tonnes of crude oil produced by 2038. Major contributors to emissions were flaring/venting and energy usage for equipment. Improvements on the energy efficiency of equipment would reduce emissions further but this could be challenging. Improvement of injection capacity and elimination of venting/flaring or fugitive gas are methods more likely to be utilized for reducing net emissions and are the cases used for the optimized scenario in this work. This LCA illustrated the potential for the CO₂-EOR operations in the FWU to store more CO₂ with minimal emissions.

Keywords: life cycle analysis; CO₂-enhanced oil recovery; anthropogenic CO₂; global warming potential; greenhouse gas (GHG); carbon storage



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1. Introduction

Carbon dioxide (CO₂) atmospheric concentrations are high compared to the last 400 centuries and are still rising [1]. About 50% of the increase has been in the last forty years and is mainly attributed to human activities [1]. This has led to rising temperatures and climate change globally [2]. One (1) megawatt (MW) electrical coal fire plant releases up to eight (8) megatons of CO₂ yearly. About 75% and 50% of this amount is released by oil fired and natural gas combined-cycle electrical plants, respectively [3]. In the US, about 86% of anthropogenic greenhouse gas (GHG) emissions are from energy production, which includes principally the generation of power and transportation [4]. The oil and gas industry globally accounts for about 8% of anthropogenic carbon dioxide (CO₂) and 15% of the methane gas (CH₄) with 3% coming from upstream operations [5]. This increase in GHG emissions is believed to have an adverse impact on the environment. Improved energy efficiency of production equipment, use of renewable energy and low carbon fuels, and storage/sequestration of captured CO₂ are all potential emission reduction approaches with each having their inherent pros and cons [5]. From the works of Farajzadeh et al., CO₂-EOR incorporating carbon capture consumes a high amount of energy compared to the amount of crude produced [2]. This also significantly leads to an increase in emissions.

Geologic formations are estimated to have storage capacities of about 9×10^{11} tonnes of CO₂ globally with oil and gas fields alone offering capacities of about 1.3×10^{11} tonnes

of CO₂ [6]. Carbon dioxide can be sequestered as part of CO₂-enhanced oil recovery (EOR), a process used to increase oil production in use since the early 1970's [7]. Injection of pressurized CO₂ into oil reservoirs causes crude oil to swell, decreases viscosity thus increasing crude mobility, and develops miscibility as interfacial tension is reduced [8]. CO₂-EOR is common in the US in the Permian Basin, Rocky Mountains, Northern Plains, and Louisiana-Mississippi, all regions that have access to natural CO₂ and/or large natural gas processing plants that may produce high volumes of CO₂ as a by-product [9]. International CO₂-EOR projects include the Weyburn-Midale CO₂ project in Saskatchewan, Canada and the Lula field in the Santos Basin, Brazil (offshore) [10]. Notable international CCS include the Sleipner in Norway, In Salah in Algeria, Ketzin in Germany, k12B in Netherland [11] and the Gorgon project in Western Australia by Chevron, ExxonMobil and Shell [12].

Assuming a reservoir has the requisite caprock integrity, using CO₂ for EOR in low-performing or depleted oil reservoirs presents a number of advantages including incremental oil recovery, stabilization of the storage formation by repressurizing, and sequestration of CO₂ that can reduce the net CO₂ emission of the EOR project [13]. Carbon capture and storage (CCS) is a highly capital-intensive operation that becomes more economically viable when incorporated as part of an EOR project by producing crude oil which may not be extracted by primary and secondary recovery processes [14]. EOR can use natural or anthropogenic CO₂, but for GHG reduction anthropogenic sources from industrial processing plants (e.g., gas processing, fertilizer, and ethanol plants) and power-generating plants (e.g., coal, oil and natural gas power plants) would be used.

This paper does not consider the detailed technologies and processes involved in CO₂-EOR operations, but instead focuses on a GHG emission Life Cycle Assessment (LCA), of CO₂-EOR operations. This is a necessary analysis, because CO₂-EOR involves operations that may contribute to GHG emissions. These operations include processes from the upstream sector (capture and separation of carbon dioxide, facility construction and pipeline transportation), gate to gate (carbon dioxide dehydration, drilling of wells, oil production and processing, constructions of facilities, land usage, gas separation as well as venting and flaring) and down-stream sector (crude transport, refining and fuel combustion) [15].

Calculating and evaluating all inputs and outputs of environmental stressors and products potential impact on the environment describes LCA. By ISO 14000 environmental management standards, LCA is performed in phases: the scope/goal definition, the Life Cycle Inventory (LCI), Impact Assessment (Classification and Characterization), and interpretation/application [16]. The extent of these phases depends on the goal/scope defined. The issues addressed are the energy balance of the integrated system, substances that are emitted at a higher rate, and the part of the system linked to these emissions [17].

Thus, to undertake LCA, specific boundaries or areas of interest are to be determined for the analysis. There have been a number of studies that have looked into GHG emissions and its relation to the operations of CO₂-EOR [1,4,14–17]. The focus of this LCA is to estimate the total GHG emissions from the Farnsworth Unit (FWU) CO₂-EOR operation and further forecast emissions for another period of 18 years, a period proposed by the field operators to continue CO₂ injection. Within this projected operational period, the operators seek to incorporate a number of improved conditions to reduce emissions as will be discussed following sections. In this paper the focus is on emissions that contribute to Global Warming potential (GWP, kg CO₂eq/bbl. of crude produced), and as such the greenhouse emissions that will be considered are CO₂, CH₄, and Nitrous Oxide (N₂O). It is good to emphasize that 100% of the CO₂ used for EOR at the FWU came from anthropogenic sources (ethanol and fertilizer plants) or CO₂ from field production that is essentially 100% anthropogenic CO₂ previously injected into the field from the same anthropogenic sources. There was no CO₂ detected in the original reservoir oil [18].

1.1. Geological and Reservoir Description of FWU

The Farnsworth Unit is located in the northern part of Texas in Ochiltree County, situated on the northwestern shelf of the Anadarko Basin (Figure 1). The producing

reservoir is Morrow B sandstone, an incised valley fluvial sandstone deposited during the Regional Stage of the Lower -Pennsylvanian Morrowan period [18,19]. Overlying and underlying the Morrow B formation are late Pennsylvanian through to mid-Permian shales and limestones. The primary seals are the overlying Morrow shale and Thirteen Finger limestone with secondary seals overlying these units that include thousands of feet of limestones and interbedded dolomite, and evaporites. Morrow B sandstone is about 18 m thick and occurs at a depth of about 2301 m to 2423 m, with about 55 m to 61 m of the primary seal overlying the reservoir [19]. The Morrow B at FWU is a relatively coarse-grained sandstone interpreted as a fluvial deposit within an incised valley [20]. Rocks are subarkosic in composition and typically exhibit one or more sequences of basal conglomerates overlain by coarse-to-fine grained sandstone and capped by very fine sands that grade into the mudstones of the Morrow shale and then transition abruptly into the alternating limestones and shales that characterize the Thirteen Finger limestone. Porosity and permeability for the Morrow B averages 15% and 35 mD respectively [20]. Caprock integrity testing using mercury porosimetry and geo-mechanical (Brazil tension, unconfined compression, triaxial compression, and multi-stress compression) tests indicate the integrity of the caprock and its ability to ensure safe storage of injected CO₂ [21].

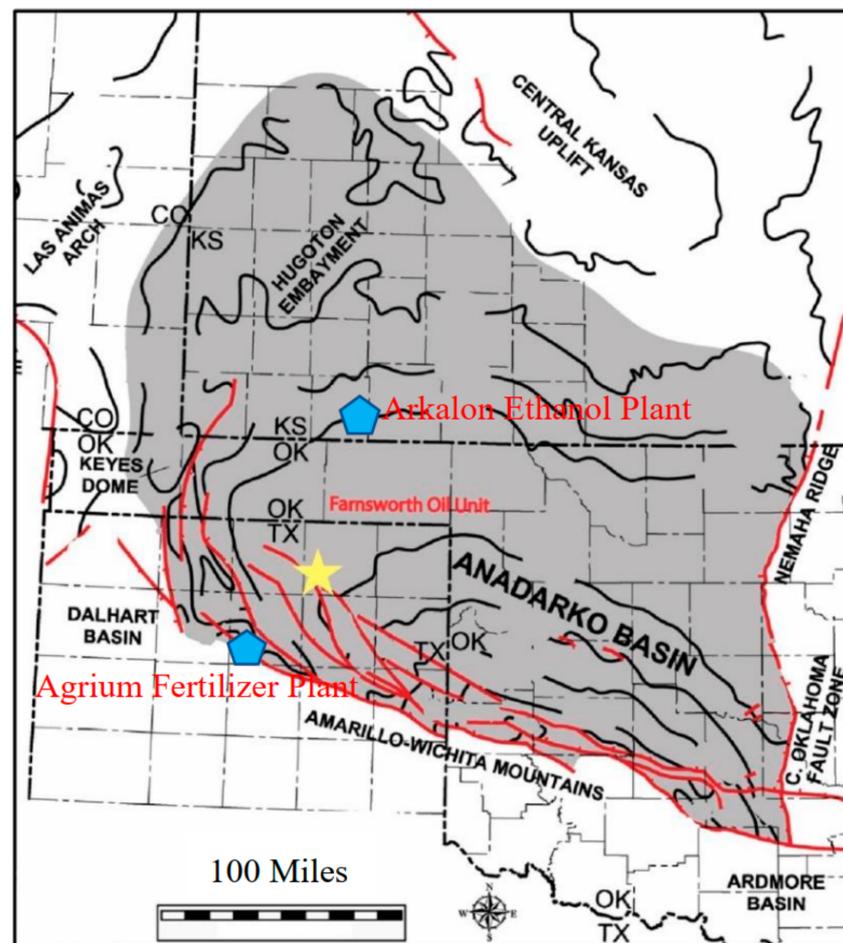


Figure 1. Location of the Farnsworth Unit (FWU) on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region. Blue pentagons indicate locations of Anthropogenic CO₂ sources.

Reservoir discovery was listed as 26 October 1955 and the FWU was unitized on 6 December 1963 by the operator with the initiation of water-flooding with fresh-water from the Ogallala Formation shortly thereafter. Table 1 gives a summary of initial reservoir

conditions. The field has two distinct sections that seemed to behave differently over its lifetime. Primary production was initially better in the eastern side in comparison to the western side, but the western performed much better during waterflooding [22]. This work focuses on the western side of the FWU.

Table 1. Initial reservoir conditions.

Reservoir Properties	Values
Oil initially in place	120 MM STB
Gas initially in place	41.48 BSCF
Reservoir pressure	2217.7 psia
Bubble point	2073.7 psia
Formation volume factor	1.192 RB/STB
Reservoir temperature	168 °F
Reservoir drive	Solution gas drive

1.2. Overview of CO₂-EOR Operations on the FWU

CO₂-EOR was initiated in the western portion of FWU in December 2010, and the present operator intends to continue CO₂-EOR until the economic limit of the field is reached. Initially, CO₂ came via pipeline from both the Arkalon ethanol plant in Liberal Kansas and the Agrium fertilizer plant in Borger, Texas. Currently the only source of CO₂ is from the Arkalon ethanol plant.

Figure 2 illustrates a simplified flow chart of the facilities, equipment and the CO₂-EOR processes at FWU. Three major processes are involved once CO₂ is delivered to the unit: CO₂ distribution, produced liquid handling, and produced gas handling.

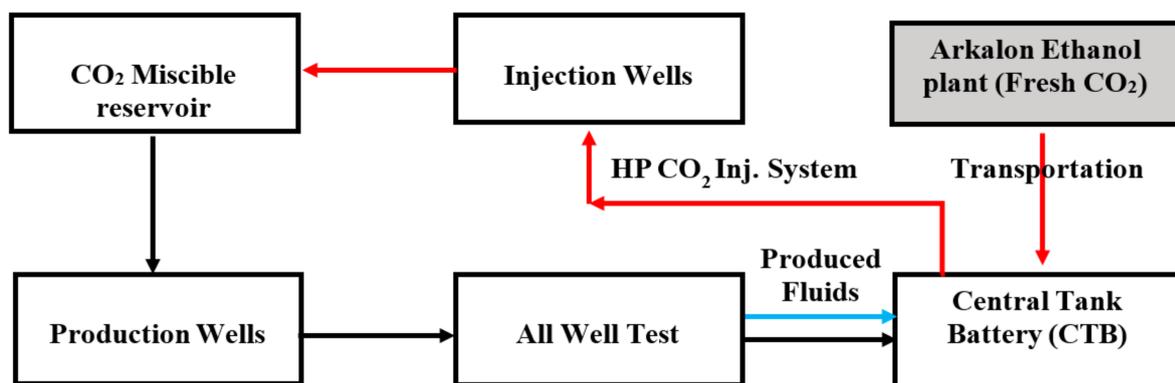


Figure 2. Simplified flow chart representing an overview of the CO₂-EOR Operations of FWU (Red lines indicate injection fluids, black: produced fluids and blue: gas from AWT).

Delivered CO₂ and recycled CO₂ are transported via pipeline from the Central Bank Battery (CTB) CO₂ distribution units to water alternating gas (WAG) injectors. Produced fluids go to several central gathering system (All Well Test (AWT)) locations where each site consists of a central gathering line, vessels for fluid separation, and individual well test separators, after which fluids are transferred to the CTB. At the CTB the separation of gas, crude, and brine continues using a series of vessels and storage tanks based on density differences and resident time to separate the fluids. Flow meters are used to record both daily purchased and produced volumes of CO₂.

The FWU currently operates thirty two producing wells and seventeen injection wells with three injection manifolds which have valves to switch between water and CO₂. Separated crude oil has 2930 ppm CO₂ (0.293%) and is sold out of tanks. The gas (89–93% CO₂) mixture is produced with less than 690 ppm i.e., 0.069% water and is reinjected using reciprocal compression and high-pressure horizontal pumps. Thus, no dehydration is

required. The minimum miscible pressure (MMP) of the reservoir crude oil and CO₂ was determined to be 4200 psia [23].

Figure 3 shows CO₂ production and injection volumes from the FWU between December 2010 and 1 September 2020 as well as oil and water production and disposition. As of this period the purchased CO₂ is 1.64×10^6 tonnes, with 1.51×10^6 tonnes (92% of purchased) being stored and a crude oil production of 4.76×10^6 barrels.

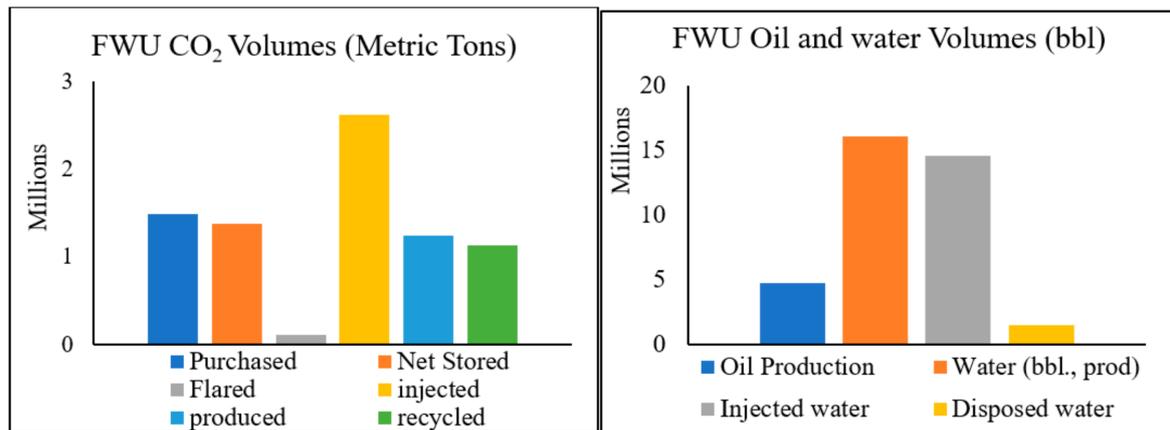


Figure 3. Production and injection data gathered from the FWU from December 2010 to August 2020.

2. Materials and Methods

The LCA approach employed in this project followed in part the framework established by ISO [16] as mentioned in previous sections, and the Plains CO₂ Reduction (PCOR) LCA approach by DOE-NETL [24]. The PCOR approach comes with a spreadsheet model allowing users to modify specific fields and CO₂-EOR operations to suit their needs. The model includes a cycle analysis from a coal fired power plant retrofitted with CO₂ capture through to a CO₂-EOR operation to the transportation of crude to refineries and finally to end users, usually for combustion. This LCA is a complete cradle-to-grave cycle, which has the upstream, gate to gate and downstream representing the end nodes of the cycle. Our work focuses on the operations within the FWU or a gate to gate analysis of the CO₂-EOR operations. Where the required FWU data were unavailable they were estimated from the literature [25–27] and the National Energy Technology laboratory (NETL) databases [28,29] (Figure 3). In addition, because this model was quite generic and lacked certain variations with respect to FWU operations, a number of modifications were made based on a couple of scenarios:

Scenario 1: Perform an LCA specific to the FWU and compare with a more generalized CO₂-EOR operations from 2010 to 2020 (period for which CO₂-EOR has been in operation at the FWU).

- For general CO₂-EOR, gas separation would be considered but not in the case for FWU because all recycled gases are reinjected.
- The percentage of water content in gas is insignificant hence a dehydration component is not included in study.
- There is an insignificant percentage of CO₂ and lighter hydrocarbons in separated crude oil and water hence estimates of gases or volatile oil components (VOC) vented on storage are omitted.
- Based on the geological description and study, it is very unlikely for formation leakages to occur.

Scenario 2: Perform a FWU LCA for a forecasted CO₂-EOR for a period of 18-year (2020 to 2038) model run with bottomhole pressure and oil rate target constraints as proposed by the field operator. This would also look at two scenarios; an optimized operational condition to reduce emissions or reach a net-zero carbon operational condition and to

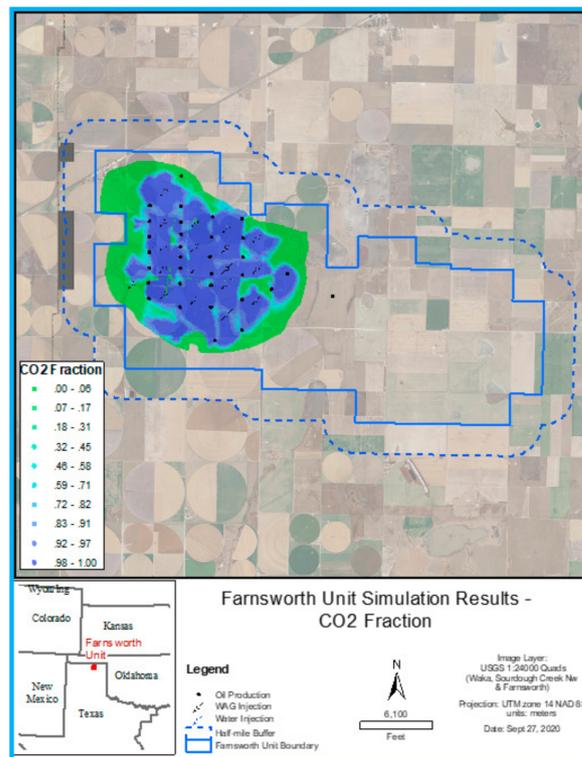
ensure higher percent of injected CO₂ storage as encouraged by the US government 45Q incentives versus current operational practices as used in task one.

- A flexible compressor capacity—expanded to meet large volumes of recycled CO₂, thus flaring or venting of excess recycled gases would occur only during maintenance periods (due to high cost of backup compressors).
- Conversion of existing water injectors to WAG wells to add to existing WAG wells.
- All purchased and produced gases would be reinjected within the 12-year period.
- All produced water is reinjected in the WAG process, hence treatment of produced water is omitted.
- Surveillance is put in place (pipelines, wellheads, wells and other surface equipment) to meet requirements in the Texas Administrative Code (TAC) rules for the Texas Railroad Commission (TRRC) Oil and Gas Division to report and quantify leaks, and to minimize leakage of GHG from surface equipment.
- The option for gas powered/energy efficient compressors other than electric power is also considered.

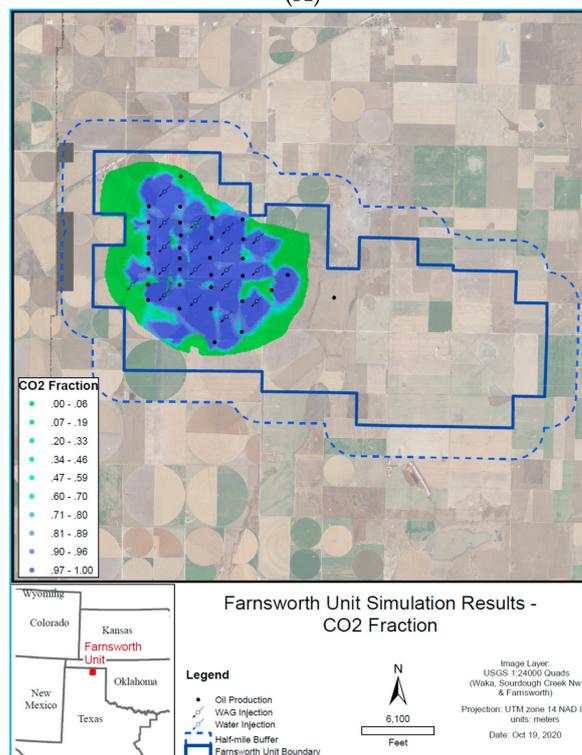
Based on a maximum monitoring area (MMA) defined by the operator as the boundary of the FWU with $\frac{1}{2}$ mile buffer zone (minimum required by Subpart RR). Figure 4 shows a simulated tertiary CO₂ flood for 22 years (2010 to 2020 plus the additional 12 years projected operational period) shown in Figure 4A in addition to 5 years post-injection monitoring shown in Figure 4B. These demonstrate the stored CO₂ remains within the boundary of the FWU with little change during the 5 years post-injection. The geologic seals are expected to contain the injected CO₂ within the Morrow B formation. Abandoned wells are properly plugged and very unlikely to have any leaks. Mechanical integrity testing (MIT) as per the Underground Injection Control (UIC) program is also conducted and provides evidence of mechanical integrity, therefore no leakage is expected through injection/production wells [30,31]. Further, regular analysis of fluids from Ogallala aquifer wells around FWU as well as soil gas and atmospheric monitoring by the Southwest Regional Partnership on Carbon Sequestration (SW) shows no indications or unusual occurrences of CO₂, brine or hydrocarbons since 2013.

2.1. Life Cycle Inventory

Site-specific data inputs from the FWU within a set system boundary were used in this analysis. A flow chart indicating major processes within the scope of the analysis is presented in Figure 5. Data collection and treatment, allocation (impact of products or processes operations on the environment) and calculation, and data quality checks would be done at this stage. Rates of fluid production were major inputs to the model, as well as other process key to GHG relation to the CO₂-EOR operation, such as fluid injection (CO₂ and brine), gas and liquid separation, gas compression, crude and brine storage, gas venting and flaring, produced gas, gas combustion for heat, and gas separation. Initially gas separation was taken into consideration analyzing three common processing techniques; Ryan-Homes, refrigeration/fractionation, and membrane [15]. They were each taken into account in this gate to gate LCA. Specific FWU fluid volumes, incremental oil recovery, produced brine, gas injection, and production were used for Task 1. Other comparable data to DOE-NETL (2013) [15,28], and NETL Unit Process Library [32] were also utilized in the study.



(A)



(B)

Figure 4. CO₂ Plume Extent (A) Before; (B) 5 years post-injection.

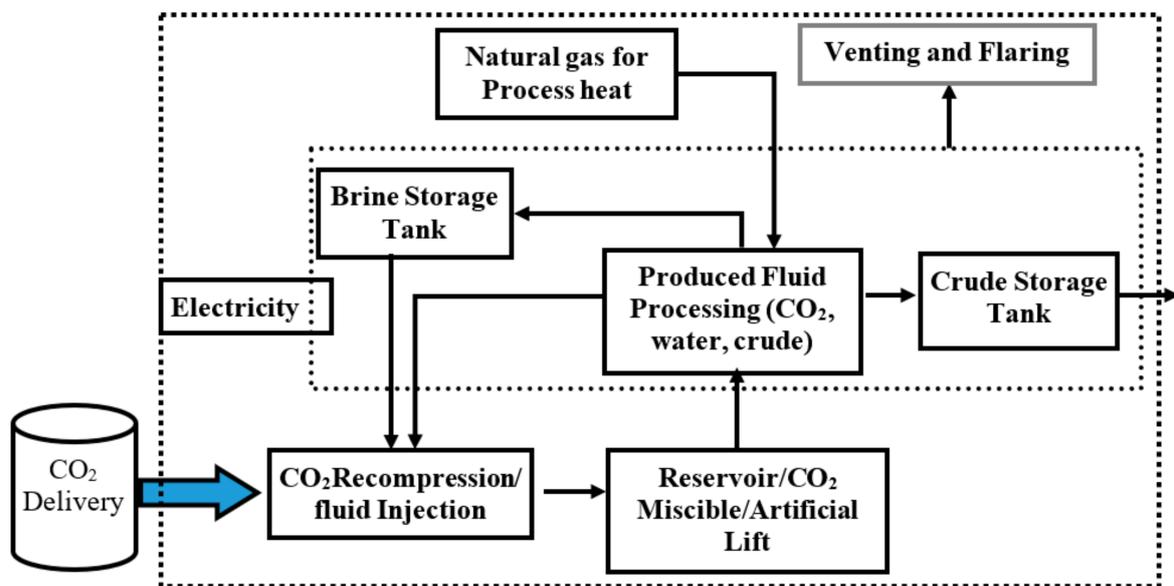


Figure 5. A simplified boundary/scope of Life Cycle Inventory for CO₂-EOR at the FWU.

Fractionation/refrigeration operates by chilling a gas stream, which separates CO₂ from hydrocarbon (HC) gases. Distillation columns are then used to separate the HC gases. This technique can be reconfigured to bypass distillation columns, thus reducing the energy consumption. The Ryan-Holmes separation technique also involves the separation of CO₂, lighter HC, and NGL by a refrigeration vessel, a de-methanizer, and HC separation columns. For the membrane process, the rate of permeation through a porous medium between two different gases is the principle utilized for its separation technique. This comes with a pre-treatment; compression of gas to about 3.45 MPa, dehydration, and chilling. Energy requirements and material usage vary widely among these techniques [15].

For Scenario 2, volumes or fluid injection and production rates used were from forecasted simulation data. The Electric Reliability Council of Texas (ERCOT) grid mix emission factor of 411 kg CO_{2e}/MWh [33] was specified as the electricity delivered to the FWU [28]. Other parameters such as brine and hydrocarbon gas production, which might not readily be available for the forecasting aspect of this analysis (Scenario 2) were estimated using various correlations [28].

Summary of Forecasting Model Description

Fluid transport dynamics were investigated through a compositional numerical reservoir simulation model. The model was used to perform a history matching simulation for primary, secondary and tertiary recovery processes for the FWU. The duration for the primary and secondary processes was 55 years, and for tertiary (CO₂ flood) the duration was between December 2010 and August 2019. Hydraulic flow units (HFU) as delineated by Rose-Coss et al. [20] were utilized to characterize heterogeneity of the reservoir. Porosity and permeability relationships were also established based on depositional and diagenetic facies described from cores and thin sections from 51 wells. The HFUs and parameters of Corey's correlations corresponding to each permeability porosity relation were used as parameters to history match the primary and secondary production data through a machine learning based methodology [34]. X, Y, and Z directional permeability multipliers and Corey coefficients of three phase relative permeabilities were parameters considered for tuning. Comparing simulation results with field data, it was observed that the history-matched case was consistent with oil production, gas injection, and production data. The Table 2 summarizes estimated volumes from the model.

Table 2. Summary of predicted volumes.

Parameter	Unit	Value
Max cumulative oil production	MM bbl	19.3
Max cumulative CO ₂ storage	MM tonnes	2.98
Max % Storage of purchased CO ₂	percentage	92.9%

2.2. Emissions/Emission Factor Estimations

The contributions of each unit process to GHG emissions within the boundary of the CO₂-EOR operations were estimated using a functional unit of kilograms -CO₂—equivalent (kgCO₂eq) to signify the quantity of CO₂ per barrel of crude oil produced. The 100-year GWP coefficients of 298 for N₂O and 34 for CH₄, to convert amounts of N₂O and CH₄ to equivalent CO₂, were applied [16].

Separation of gas and liquids could lead to the release of volatile organic compounds (VOC) due to the changes in temperature and pressure conditions, which are either flared or vented. Storage of crude and brine may result in VOC emissions as a result of flashing, working, and standing losses. These are recovered by vapor recovery equipment and directed to flaring and venting units. A 99% conversion efficiency of flared gases to CO₂ was used in this study (for each kg of CH₄ flared, 0.99 kg is converted to CO₂eq) [25]. The required amount of fuel and electricity for each unit process is estimated based on the amount of product to be processed. The equivalent mass of carbon dioxide emitted as a result of generating these amounts of energy is estimated. Table 3 gives a summary of key parameters, units, and their associated values used in modelling the LCA for CO₂-EOR. Aside from site-specific data, all other data sets (mostly emission factors to specific unit operations) were gathered from literature as indicated in the table representing tempo-geographical and associated technical characteristics of CO₂-EOR. Venting and flaring volumes for Scenario 2 were assumed to be the difference between the purchased and stored CO₂, arising mainly as results of compressor maintenance/break down.

Table 3. Summary of parameter/factors and Input values.

Parameters	Unit	Values	Reference
Crude oil produced	bbl crude		Operator/forecast
Crude oil density	kg crude/bbl	135	Operator/forecast
Net CO ₂ utilization rate	Mscf CO ₂ /bbl		Operator/forecast
Purchased CO ₂ requirement	kg CO ₂		Operator/forecast
Fugitive loss rate of purchased CO ₂	%	2.0%	[13]
CO ₂ produced (recycled)	kg CO ₂		Operator/forecast
CO ₂ injected	kg CO ₂		Operator/forecast
CO ₂ stored	kg CO ₂		Operator/forecast
CO ₂ leakage rate from storage over 100-year time period	% CO ₂ stored	0.5%	[25]
Hydrocarbon gas production rate	kg gas/kg crude		Operator/forecast
Brine production rate	kg brine/kg crude		Operator/forecast
Well footprint	Acre	0.25	[25]
Number of wells	Count	49	Operator/forecast
Emissions per m ² of repurposed land	kg CO ₂ eq/m ²	7.5	[32]
Water disposal well construction	kg CO ₂ eq/bbl	1.0	[32]
Injection well construction	kg CO ₂ eq/bbl	1.2	[32]
artificial lift pump electricity rate	kWh/kg crude	1.18×10^{-1}	[32]
Compressor power factor	MW/[tonne recycled CO ₂ /day]	2.70×10^{-3}	[25]
CO ₂ pump power factor	MW/[tonne injected CO ₂ /day]	1.91×10^{-4}	[25]
Compressor CO ₂ emissions rate (direct to atmosphere)	kg CO ₂ eq/MW-day	63.6	[25]
Brine injection pump electricity rate	kWh/kg brine injected	7.87×10^{-4}	[34]
VOC uncontrolled emissions rate to venting and flaring	kg VOC/kg crude	8.70×10^{-3}	[25]

Table 3. Cont.

Parameters	Unit	Values	Reference
Flare rate (% of vented VOC that is flared)	%	95%	[25]
Combustion efficiency	%	99%	[15]
Natural gas usage rate	kg natural gas/kg crude	3.09×10^{-3}	[32]
Natural gas delivered CO ₂ emissions factor	kg CO ₂ /kg natural gas	1.68×10^{-1}	[32]
Natural gas delivered CH ₄ emissions factor	kg CH ₄ /kg natural gas	1.81×10^{-2}	[32]
Natural gas delivered N ₂ O emissions factor	kg N ₂ O/kg natural gas	4.60×10^{-6}	[34]
Natural gas combustion CO ₂ emissions factor	kg CO ₂ /kg natural gas combusted	2.75	[32]
Natural gas combustion CH ₄ emissions factor	kg CH ₄ /kg natural gas combusted	5.26×10^{-5}	[32]
Natural gas combustion N ₂ O emissions factor	kg N ₂ O/kg natural gas combusted	5.03×10^{-5}	[32]
Produced water methane content	kg CH ₄ /bbl water	1.50×10^{-3}	[32]
Brine disposal pump electricity rate	kWh/kg brine disposal injected	3.30×10^{-3}	[32]
ERCOT mix, electricity delivered carbon emission factor	kg CO ₂ eq/MWh	4.11×10^2	[32]

3. Results and Discussion

This study focuses on the estimations of the GHG emissions for the CO₂-EOR operations at the FWU for a period of about ten years from December 2010 to September 2020 for which CO₂ injection has already occurred, and for another projected 18-year period (2020–2038) with optimized operational conditions. These estimates account for emissions that are direct functions of the mass of CO₂ and oil production volume, hence the functional unit of kgCO₂eq/bbl of crude oil produced. The first scenario accounted for the emissions of the FWU and compared these to a base case, which included gas separation options. The second task also focused on a projected optimized operation and a comparison of GHG emissions to a base case of current existing conditions on the FWU. Emissions were estimated and presented on the basis of various units within the CO₂-EOR field that are key contributors to emissions within the system. The goal here was to identify specific units to optimize to aid in the reduction of GHG emissions. Cumulated purchased CO₂ amounted to 1.64×10^6 tonnes, with 1.51×10^6 tonnes (92% of purchased) stored and a corresponding crude oil production of 4.76×10^6 barrels represent estimates from the operator which were utilized in Scenario 1 (Figure 3). Scenario 2 utilized the forecast (Table 2).

3.1. Scenario 1

(a) Gas Separation

Economics dictate whether hydrocarbon gas and CO₂ are separated from the produced gas. There are at least two reasons to separate hydrocarbon gas before reinjecting the produced gas. The first reason is if the impurities in the produced CO₂ increase the MMP in the reservoir above the fracture pressure or high enough to significantly increase cost, and the second is if the value of the recovered gases is more than the cost of separation, or more likely a combination of the two. In the base case in Scenario 1 gas separation techniques considered are the fractionation/refrigeration, Ryan–Holmes, and membrane. The energy requirements and material usage vary widely among these techniques. Table 4 represents emission factors and Table 5 represents total mass emissions for refrigeration/fractionation, Ryan–Holmes and membrane gas processing techniques, respectively. For both Ryan–Holmes and membrane separation, natural gas usage accounts for the majority of emissions in their operations with electricity being the key source of emission for refrigeration/fractionation. The natural gas upstream represents the emissions from the recovery of natural gas delivered to the plant; this in many situations is a small quantity since the plant utilizes part of the gases separated in the combustion processes.

These are estimates generalized for the processes of these techniques with actual production and injection data from FWU, and the results are similar to published studies [9,15,24].

Table 4. Emission Factors of major components of Gas Separation units.

	Factors (kgCO ₂ eq/bbl)		
	Fract/Ref	Ryan-Holmes	Membrane
Electricity	1.4988	-	2.3641
Natural gas upstream	0.0004	1.3608	33.3343
Natural gas combustion	0.0014	12.0493	15.6464
Diesel Usage	-	0.1933	-
Fugitive emissions	-	-	0.1815
SUM	1.5006	13.6035	51.5262

Table 5. Mass Emissions of major components of gas Separation units.

	Emission (kgCO ₂ eq)		
	Fract/Ref	Ryan-Holmes	Membrane
Electricity	7,137,323	-	11,257,801
Natural gas upstream	1892	64,80,307	158,738,878
Natural gas combustion	6661	57,379,327	74,508,567
Diesel Usage	-	920,532	-
Fugitive emissions	-	-	864,146
SUM	7,145,875	64,780,167	245,369,392

(b) FWU CO₂-EOR Processes

Table 6 highlights the emission factors and mass emissions of key unit processes as defined in the boundary of the LCA. Gas compression and injection electricity accounted for 47% (7.41 kgCO₂eq/bbl. and 35.31×10^6 kgCO₂eq) of GHG emissions from equipment in the CO₂-EOR system. Thus, improving the energy efficiency of compression would significantly reduce the life-cycle GHG emissions. Unfortunately, increasing the efficiency of compressors is technically challenging [9]. Differences in the life cycle emissions of compressors, however, may differ depending on the energy source since each source has its emission factor (660 kgCO₂/MWh for coal powered plant, 423 kgCO₂/MWh for natural gas powered, etc.). The ERCOT power factor of 411 kgCO₂/MWh is lower due to the inclusion of renewable (wind, hydro) energy source components as part of its power generation mix and probably represents the source of power to the FWU. Artificial lifting of crude oil and associated produced water and gases comes next with estimates of about 4.44 kgCO₂eq/bbl and 21.12×10^6 kgCO₂eq. These estimates were made based on the volumes of fluids produced. A factor of 0.118 kWh/kg crude lifted [25] was used. From this the amount of energy required to lift the volumes of fluids produced and the associated quantity of potential emissions was estimated. These values are not exact representations of emissions from artificial lift from the FWU, since there are different kinds of lifting mechanisms employed in the field (sucker rods and submersible pumps) and in many of the wells artificial lift was not initially required. Thus, this value is expected to be an overestimate, but the idea presented here is to show how much CO₂ would have been emitted if all of the produced fluids were acquired through artificial lift. Artificial lift is quite energy intensive and is used throughout the production period once a well is put on artificial lift. Construction and land use also account for significant GHG emissions directly through energy use, construction of facilities, well drilling, and other processes and indirectly in land use effects on existing vegetation, repurposing land and so on. Using a factor for an emission per square meter of repurposed land of 7.46 kgCO₂/m² [29], emissions were estimated at 2.98 kgCO₂eq/bbl corresponding to a mass of 14.18×10^6 kgCO₂eq. These

processes and their GHG emissions could be classified as indirect as associated GHG emissions are due to the processes or energy usage. Flaring and venting which in this study is classified as a direct emission accounted for an estimated 60% of GHG emissions through the 10-year period of CO₂-EOR. This was highest in the early stages of CO₂ injection, but reduced as compressors for reinjection came online. On a longer-term scale, most venting and flaring occurs during times when compressors are offline for maintenance or repairs. The cumulative quantity of equivalent CO₂ flared within the period from December 2010 to August 2020 was 117.52×10^6 KgCO₂eq with an emission factor of 24.68 kgCO₂eq/bbl. This is the highest source of emissions amongst the CO₂-EOR processes. Though there could be challenges with respect to improving on the efficiency of equipment to reduce GHG emissions, analysts have suggested that reduction of fugitive GHG emissions of vented and flared CO₂ and methane would be more easily achieved. This effect is reflected in Scenario 2 of this study. Based on the geological description and the mechanical integrity tests performed on the field's reservoir cap rocks, emissions due to leakages from the geologic storage formation were estimated to be zero (0%) of the stored CO₂ [21].

Table 6. Mass Emissions and Factors for EOR units (Task 1).

Unit Processes	Emission 10 ⁶ kg CO ₂ eq	Factors kg CO ₂ eq/bbl
Construction/Land use	14.18	2.98
Artificial lift	21.12	4.44
CO ₂ compression, and injection (Electricity)	35.31	7.41
Brine injection (Electricity)	3.43	0.72
Brine disposal (Electricity)	1.11	0.23
Flared/Vented	117.52	24.68

(c) Comparative Analysis of Gate to Gate Results

Table 7 (mass emission) and Table 8 (emissions factors), sums up the overall total emissions and emission factors for the CO₂-EOR processes both with (Base cases) and without (FWU) gas separation techniques. Total net storage factors and net CO₂ storage, were estimated as; total emission factors minus initial storage factor, and total emissions minus initial CO₂ storage. For the base cases, the total emissions from CO₂-EOR operations in order of increasing total emissions and emission factors are Fractionation/ Refrigeration, Ryan-Holmes, and Membrane. In comparison, FWU without gas separation recorded the lowest. The net storage and net storage factors resulted in negative net values for all scenarios. This is an indication of a pay-off to global warming reduction and/or a positive outcome to environmental intervention, that is, much more CO₂ is stored in the formations than is emitted to the atmosphere. The major difference is the use of gas separation. Refrigeration/fractionation has a greater advantage with regards to emissions due to its low energy consumption. This is because the fractionation process could be configured to bypass distillation columns, thus reducing energy that would have been consumed by such columns. However, when it comes to efficiency in separation of gases, the Ryan-Holmes and membrane processes both are highly effective in recovering natural gas liquids but come with a higher energy penalty, as can be seen from the results.

Table 7. Total Emission and Net Storage for cases considered.

	Total Emissions 10 ⁶ kgCO ₂ eq	Net Storage 10 ⁶ kgCO ₂ eq	Purchased Stored %
Refrigeration/fractionation	217.53	−1161.86	78.80
Ryan-Holmes	275.16	−1104.22	74.95
Membrane	454.93	−924.46	62.94
FWU (No Gas Separation)	210.38	−1169.00	79.28

Table 8. Summary of emission factors for Task 1 and Task 2.

Process	Emission Factor kgCO ₂ eq/bbl	Net Storage Factor kgCO ₂ eq/bbl
Refrigeration/fractionation	42	−247.70
Ryan-Holmes	54	−235.60
Membrane	92	−197.85
FWU (No Gas Separation)	40	−249.20
FWU (Forecast-opt)	10	−130.01
FWU (Forecast-Base)	28	−112.00

3.2. Scenario 2

(a) Forecasted FWU CO₂-EOR with Optimized Conditions

Scenario 2 considers an 18-year forecast of the CO₂-EOR operations, a time range chosen because that concludes with the probable expiration date of a 45Q tax credit. The scenario assumes all purchased CO₂ (2.91×10^6 Metric tons) will be injected and stored within the 18-year period. Assumptions also consider that adequate compressor capacity precludes venting or flaring and (during compressor optimum performance except failure or maintenance), injection of all produced gas and water. Our emission estimates were made factoring all these conditions. A base case of the current condition as applied in Scenario 1 for FWU was also applied to this forecasted CO₂ purchased volume. For the base case, venting and flaring accounted for the majority of emissions with 17.9 kgCO₂eq/bbl (345.28×10^6 kgCO₂eq), and compression and artificial lift energy being the next major source of GHG contributors in both the optimized and base case. For the same volume of crude oil produced, the energy requirement for artificial lift is likely to be the same in both cases for the same period of time. Differences between the two cases arise as a result of fugitive emissions from equipment as well as from venting and flaring. Total estimated emission factors for both the forecasted base and optimized scenarios are shown in Table 8 with detailed estimates on individual operations in Figure 6. A net negative storage factor of −130 kgCO₂eq/bbl and −112 kgCO₂eq/bbl corresponding to 86% of the purchased CO₂ for the optimized case and 74.3% for base case was found. As this LCA excludes all fugitive emissions, this is an indication that energy consumption by process equipment is a key contributor to GHG emissions. Flaring and venting, being a direct emission of GHG, is a major component in the CO₂-EOR process which increased emissions in all cases. A reduction in this one key source could significantly reduce total emissions. This could be achieved through a reduction in time needed for repair and maintenance or through other operational methods.

Table 8 summarizes the emission factors of the various case studies, using volume estimates in Figure 3 for Scenario 1 and Table 2 for Scenario 2 (projected). The factors in both cases are not directly comparable due to different volumes of CO₂ and crude oil used in their estimates. These estimates (emission factors) can be compared to other gate to gate CO₂-EOR GHG LCA even with the inclusion of a gas processing facility. Figure 7 gives a number of CO₂-EOR operations and their estimated emission factors that range 60 kgCO₂eq to 175 kgCO₂eq compared to Scenario 1 for FWU of about 40 kgCO₂eq.

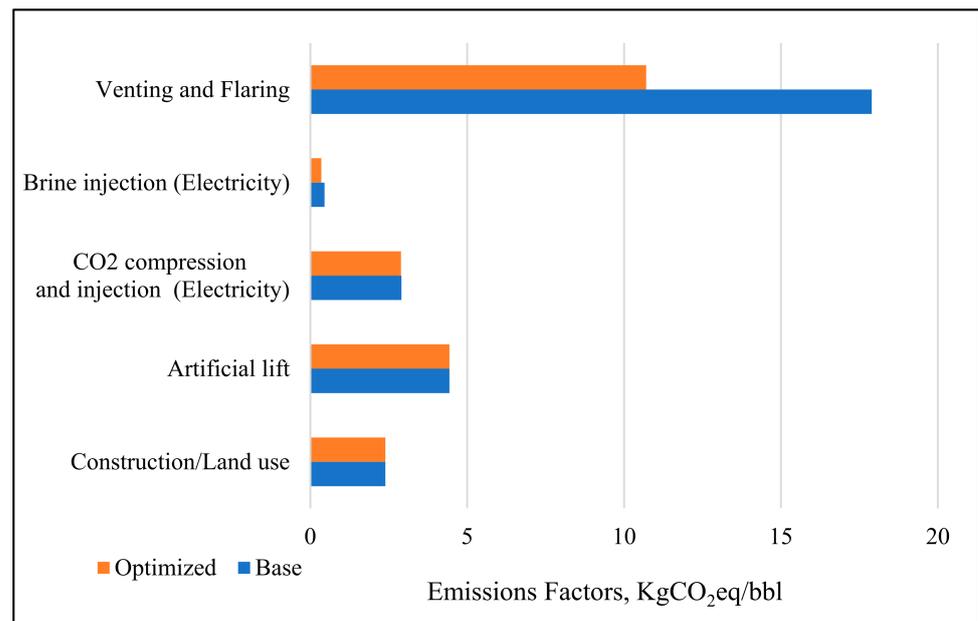


Figure 6. FWU emission factors for Base and forecasted optimized cases.

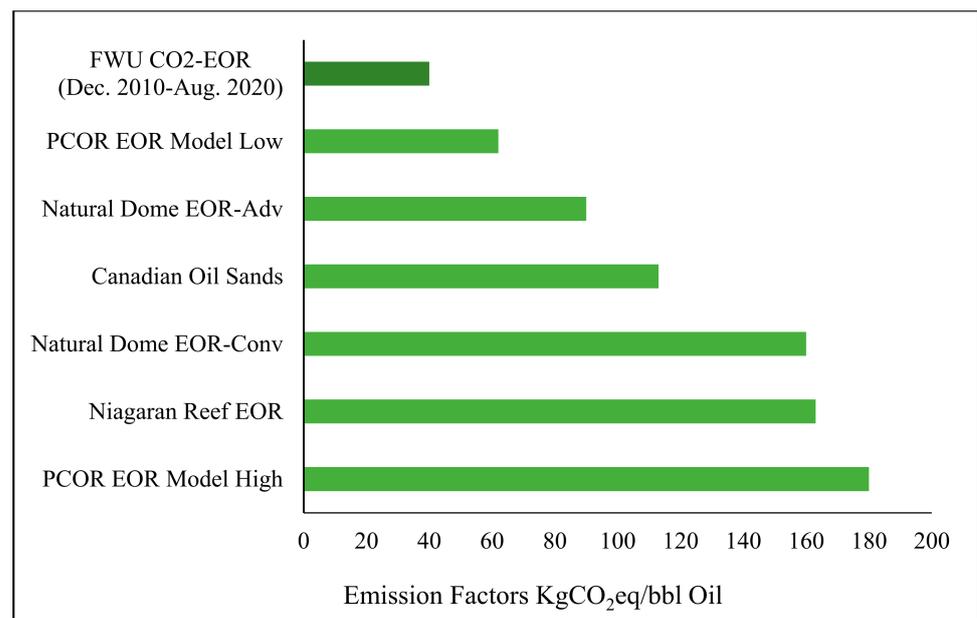


Figure 7. Reproduced gate-to-gate emission factors of other CO₂-EOR fields [9], in comparison to FWU CO₂-EOR.

4. Summary and Conclusions

Emissions of GHGs such as CO₂, CH₄, and N₂O are considered as major pollutions and have become a source of concern in efforts to slow the pace of global warming. This study presents a GHG LCA for the FWU for a period during which CO₂-EOR has been in operation (about 10 years) and a projected future operation of 18 years. For these cases, GHG emissions were estimated for a number of CO₂-EOR processes, fugitive emissions, and from flaring/venting. Data from the operator as well as simulated and forecasted fluid volumes were utilized in estimating emissions. Data gathered by the operator through monitoring and metering recorded 1.64×10^6 tonnes (1.49×10^9 kgCO₂eq) of CO₂ purchased, with 92% being stored during the 10 years CO₂-EOR has been in operation. A gate-to-gate LCA

of the GHG emissions estimated a net negative 2.25×10^6 tonnes (1.19×10^6 kgCO₂eq) of CO₂ representing storage of 79% of purchased CO₂. For this period, venting and flaring accounted for the highest source of emissions with compressor energy consumption being the next-highest. Improving conditions through an optimized process (Scenario 2) for a forecasted period of operations lowering or eliminating fugitive emissions and including flaring/venting only during maintenance of compressors yielded 86% (130 kgCO₂eq/bbl) of projected purchased volumes of 3.21×10^6 tonnes of CO₂ compared to a forecasted base case estimated at 74% of the purchased CO₂.

A very significant consideration for the implementation of the forecasted optimized scenario would be economics and technology that dictate the amount of CO₂ to be purchased as well as to be stored. These factors can also dictate how a CO₂-EOR operation might be designed. Higher crude oil prices might create a favorable condition for the use of CO₂ due to the ratio between the cost of oil price and cost of CO₂. A drop in CO₂ cost might encourage CO₂ use for EOR, and a change in tax policy might change either side of the equation. The financial incentive of the 45Q tax credit from the current U.S. tax policy for both capture and storage of CO₂ is currently providing another motivation for CO₂-EOR operators to retain more CO₂.

This GHG life-cycle assessment is an indication that the integration of CO₂-EOR and carbon storage, such as seen at FWU, is one approach to minimize net GHG emissions to the atmosphere. This study presents specific emission estimates for the FWU and could give useful information to field operators with regards to GHG emissions of their operations. The basic processes and methodologies could easily be followed in other fields.

Key unit processes have been demonstrated to be major contributors to emissions that operators need to take notice of and seek to improve for reduced GHG emissions. Energy consumption for process equipment is a significant input and a major cause of GHG emissions. Improving on the energy efficiency of equipment and the use of alternative clean energy sources are sure ways of reducing emissions from this source. These changes may be technologically challenging, or in some cases beyond the control of field operators. In our study, flaring and venting accounted for the largest source of emissions in all scenarios examined. Reducing emissions from this source is believed to be easier compared to the challenging issues of improving the energy efficiency of equipment. Proper monitoring, smart and quick sealing of fugitive sources and the avoidance of flaring/venting as much as possible could reduce emissions. Expanding compressor capacities and/or backup compressors are ways of ensuring sufficient gas recycle capacity and hence emission reductions, though these could be capital intensive and project economics would play a major role in this decision. The FWU has a simpler operational boundary, hence its low gate-to-gate emission factors as compared to other studies mentioned earlier. Added complexity of operational processes as seen in some fields could lead to an increase in sources of emissions; however, reducing the direct emission of GHGs via venting and flaring should provide beneficial in almost all cases.

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