CO₂, EOR and Carbon Capture: Regulators in the Know

November 9, 2020
What is Carbon Storage?

Transportation

Capture

Storage
What is CCUS?

• Carbon Capture Utilization and Storage
• CCUS technologies involve the capture of carbon dioxide (CO₂) from fuel combustion or industrial processes, the transport of this CO₂ via ship or pipeline, and either its use as a resource to create valuable products or services and/or its permanent storage deep underground in geological formations. (International Energy Agency, IEA)
  - I added the and/
• It seems that the IEA’s definition allows for CO₂ storage in a saline reservoir. Where is the utilization?
• CO₂ could be used to make other substances such as plastics, concrete, or biofuels.
• The utilization that we will discuss is the use of CO₂ to produce oil. This process is followed by its internment in the subsurface.
Over 250,000 BOPD were produced due to CO₂ injection in 2014

The map is updated from the source: Denbury Resources Inc. – “CO₂ Pipelines: Infrastructure for CO₂-EOR & CCS” (2009)
CO$_2$ Flooding Schematic
• CO₂ flooding began in earnest in January 1972 when Chevron began injection at the SACROC oil field
• Shell soon followed in April at North Cross
• Two years later in 1974, a small company, Orlapetco, began injection at Two Freds
• All the fields were connected to natural gas plants located in the Val Verde Basin via pipelines
• CO₂ was being separated from the natural gas sales stream and vented at these plants
• This CO₂ was captured, dehydrated and compressed into pipelines
• Initial successes and the energy crisis caused by the Arab oil embargo led to the search for more and larger CO₂ sources to expand CO₂ flooding to other reservoirs
Growth & Retrenchment – 1980s & 1990s

• Major sources of CO$_2$ and associated pipeline infrastructure were developed in the late 1970s and early 1980s
  - McElmo Dome, Bravo Dome and Sheep Mountain serviced the Permian Basin
  - Jackson Dome serviced the Gulf Coast
  - The Enid ammonia plant serviced Oklahoma
  - LaBarge serviced Wyoming and Colorado (LaBarge produces 30-40% of the world’s Helium)
  - Enid and LaBarge are anthropogenic sources

• The oil price drop in 1986 stalled growth until the mid-1990s

• The number of US projects increased from 3 in 1974 to 29 in 1986 to 39 in 1994 and 65 in 2000

Source: “Industry Experience with CO$_2$ for Enhanced Oil Recovery” Workshop on California Opportunities for CCUS/EOR (2012)
By 2000 and with over 25 years of CO₂ flood experience, the industry thought that the technical risks were well known.

The number of US projects doubled from 2000 to 2014 (but the projects were not as large as those started in the 1980s and which underwrote the CO₂ source and transportation infrastructure).

No projects commenced after 2014 when the oil price crashed (twice).

Will the industry sanction long term projects while the memory of price volatility remains vivid?

Have all the good floods been done?
Solvents – Propane, NGLs, CO₂

• Have you ever tried to rinse oil-based paint off a paintbrush with a garden hose?
  - Turpentine, a solvent, works much better
  - Propane, natural gas liquids and CO₂ can act like solvents in the reservoir and move oil that is trapped in the pores during a waterflood

• Miscibility
  - Substances are miscible if, when they are mixed, they form one phase
  - CO₂ acts like a solvent when it becomes miscible with the oil

• First contact vs. multiple contact miscibility
  - Oil is a complex substance comprised of carbon chains with different numbers of carbon atoms
  - CO₂ is not miscible with all the components upon initial contact with the oil
  - As CO₂ moves through the reservoir the lighter components of the oil vaporize into the CO₂ ...causing the mixture to become more like the heavier components, eventually leading to its miscibility with the oil.
  - Similarly CO₂ condenses into the oil as it passes, making the oil more like CO₂
More CO$_2$ More Oil

Cumulative Incremental Oil Recovery - %OOIP

Means San Andres Unit Simulation, 2:1 WAG

CO$_2$ Slug

0.8 HCPV

0.6 HCPV

0.4 HCPV

0.2 HCPV

The difference after 50 years between 0.2 HCPV and 0.4 HCPV ~ 4% OOIP
The difference after 50 years between 0.6 HCPV and 0.8 HCPV ~ 3.25% OOIP

After Hadlow, SPE 24928 (1992)
CO₂ Flood Production Systems

Potential for major alterations shown in red
Regulations

• Class II
  - Inject fluids associated with oil and natural gas production. Class II fluids are primarily brines (salt water) that are brought to the surface while producing oil and gas.
  - Categories: disposal wells, enhanced recovery wells, hydrocarbon storage wells
  - Enhanced recovery wells - fluids consisting of brine, fresh water, steam, polymers, or carbon dioxide are injected into oil-bearing formations to recover residual oil and in limited applications, natural gas.

• Class VI
  - Inject CO₂ into deep rock formations for the purpose of long-term underground storage or geologic sequestration (GS)

Source: epa.gov/uic
Class VI

• Focused both on protecting drinking water and assuring long term storage of CO₂
• Address the unique nature of CO₂ injection for long term storage
  - Relative buoyancy of CO₂
  - Subsurface mobility
  - Corrosivity in the presence of water
  - Large anticipated injection volumes

• Requirements for
  - Siting (an additional requirement vs. Class II)
    • Extensive site characterization requirements
  - Construction
    • Materials must withstand contact with CO₂ over the life of the project
  - Operation
  - Monitoring and testing
    • Comprehensive monitoring requirements addressing well integrity, CO₂ injection & storage and groundwater quality during injection and post-injection site care
  - Reporting
  - Closure
  - Financial responsibility
    • Assure the availability of funds for the life of the project, including post-injection care and emergency response
Transition of Class II to Class VI

• Geologic storage of CO$_2$ can continue to be permitted under the Class II program
• Use of anthropogenic CO$_2$ in enhanced recovery (ER) operations does not necessitate a Class VI permit
• Class VI site closure requirements are not required for Class II CO$_2$ injection operations
• ER operations that are focused on oil or gas operations will be managed under Class II. If O&G recovery is no longer a significant aspect and if Class II cannot manage the increased risk to USDWs, then the operation should be transferred to Class VI.

From: Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI
EOR Carbon Balance

• Calculate carbon emissions for SACROC in 2007 using CA Registry methods (mostly)
• Compare various emission sources
• Look at long-term carbon balance calculations for the SACROC oil field
2007 SACROC Complex GHG Emissions

1,046,000 Tonnes Total Complex
972,800 Tonnes CO₂ Flood

- Purch Power: 39%
- Power Plant: 38%
- Recip Engines: 9%
- Flare: 6%
- Heater/Boiler: 5%
- Vented: 3%
- Fugitive: 0%
- Mobile: 0%
## Field Life Carbon Balance

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOR Production</td>
<td>185 million BO</td>
</tr>
<tr>
<td>Purchased</td>
<td>260.0 Mt</td>
</tr>
<tr>
<td>Direct/Indirect Emissions</td>
<td>- 18.5 Mt</td>
</tr>
<tr>
<td>Capital Emissions</td>
<td>- 2.0 Mt</td>
</tr>
<tr>
<td>Total Sequestered</td>
<td>239.5 Mt</td>
</tr>
</tbody>
</table>

1. 10% of 1.85 billion bbl OOIP
2. Not all purchased CO₂ was anthropogenic
3. CO₂e emitted 0.1 t/BO
4. 530 tonnes/$1 million GDP, $3.5 billion of capital

92% stored
Time Scales and Permanence

- Physical trapping dominates early
- Residual and solubility trapping dominates in the 10s to 100s of years time frame
- Mineral precipitation will typically be a long timeframe mechanism
- For oil, gas and saline reservoirs

**Figure 5.18** Schematic showing the time evolution of various CO₂ storage mechanisms operating in deep saline formations, during and after injection. Assessing storage capacity is complicated by the different time and spatial scales over which these processes occur.

**Figure 5.9** Storage security depends on a combination of physical and geochemical trapping. Over time, the physical process of residual CO₂ trapping and geochemical processes of solubility trapping and mineral trapping increase.

Source: IPCC, Carbon Dioxide Capture and Storage
Lower CO₂ Prices Are Critical

Effect of CO₂ Price on Project Returns, $50/BO

An expected return of >20% (without G&A) would be required due to the risks incurred and the need to cover overhead.

1.6% of oil price
At $50/BO - $0.80/MCF
or ~ $15/tonne

CO₂ Price as a % of Oil Price

With G&A
Without G&A
But Wait – 45Q to the Rescue

Effect of CO₂ Price on Project Returns, $50/BO

45Q could supply $35/tonne tax incentive
At $50 - ~3.5% of oil price help
But the delivered cost of CO₂ might increase

IRR, % (Before FIT)

CO₂ Price as a % of Oil Price

With G&A

Without G&A
Cost

- According to a 2017 Forbes article*
  - Used data from U.S. EIA and NETL
  - Capturing CO₂ from a new supercritical coal plant adds $59/MW-hr to electricity costs
  - Or the CO₂ capture cost is $70.70/tonne ($3.70/MCF)
  - Tax credits for wind and solar are ~$20-$25/MW-hr

- Capturing CO₂ from a natural gas plant likely costs more

- The cost to capture, dehydrate and compress pure CO₂
  - From 0 to 2000 psig is approximately $11/tonne ($0.60/MCF)

- Principle: If you have nearly pure CO₂, you can capture it at a price that an oil field can pay for if you are close enough even without tax incentives. If you don’t have government incentives, you won’t capture non-pure CO₂ for use in oil fields.

Southern Company’s Kemper County IGCC plant with CO₂ capture was originally forecast to cost $2.2 billion. As of 2017 the completion cost had risen to $7.3 billion. Southern decided to switch to natural gas.

*Forbes Online: Carbon Capture And Storage: An Expensive Option for Reducing U.S. Emissions
CCS Has Unfavorable Economics

After: Global GHG Abatement Cost Curve v2.0, McKinsey & Company
CCUS Is Also Challenged

• But ...
• We know based on studies at SACROC and elsewhere that CO₂ will stay in the ground
• We know CCUS can work economically in some cases
  - Val Verde Basin natural gas/CO₂ separation plants provided CO₂ to start CO₂ flooding in 1970s
  - Dakota Gasification Plant supplies Canadian floods
  - CVR Refinery in Coffeyville, KS supplies the Burbank field in OK
  - Ethanol plants in Michigan supply oil fields
• What works - nearly pure CO₂ sources near oil fields which only require dehydration and compression
• Tax credits such as 45Q help pay to transport CO₂ farther from the pure CO₂ sources
• If CCUS (or CCS) is to expand beyond nearly pure sources, society must provide more incentives than it has, or a technological breakthrough (direct air capture?) must occur