CO_2, EOR, and Carbon Capture: Regulators in the Know

October 28th, 2020

10:00amCT – 2:30pmCT

Hosted by the IOGCC Energy Resources, Research and Technology Committee

Chair, Lanny Schoeling

Vice Chair, Adam Peltz

IOGCC Regulatory Technical Liaison Intern, Bey Westcott

Agenda

10:00am	**Call to Order** Chair, Lanny Schoeling Vice Chair, Adam Peltz
10:05am	**Workshop Overview** Chuck Fox, CEO & President, Windy Cove Energy II
10:20am	**History of CO_2 Flooding**
10:30am	**The Technology – Reservoir**
10:45am	**Well Design, Surface Facilities, and Operations**
11:30am	**Regulatory**
11:50am	**Carbon Balance**
12:10pm	**30-minute Lunch Break**

Agenda

12:40pm	**Screening and Economics**
1:00pm	**45Q** Al Collins, Vice President, Public Policy and External Engagement, Low Carbon Ventures, OXY Petroleum
1:20pm	**Saline Reservoirs, Gas Fields, Unconventional** Chuck Fox, CEO & President, Windy Cove Energy II
1:30am	**Transportation**
1:35am	**10-minute Break**
1:45am	**Carbon Capture**
2:05pm	**Fitting It All Together**
2:30pm	**Adjourn**

WINDY COVE ENERGY II

CO_2, EOR and Carbon Capture: Regulators in the Know

1. Introduction

Course Objectives

- Understand the basic science of
  - CO_2 flooding and related techniques
  - Carbon capture
  - Transportation
  - Carbon storage (oil fields, gas fields, saline reservoirs and coal beds)
- Understand the regulatory scheme – wellbore integrity focus
- Understand economics of CO_2 flooding and how it relates to CO_2 price requirements and capture costs
- Understand basic monitoring strategies for both EOR and CCUS

Outline

Instructor – Chuck Fox

- Charles E. (Chuck) Fox is the CEO and a founder of Windy Cove Energy II, LLC, which develops oil and gas projects in the horizontal San Andres play of the Permian Basin.
- Previously Mr. Fox was the Vice President of Operations and Engineering for Kinder Morgan CO_2 Company. He was responsible for operating the 1.2 BCFD McElmo Dome and Doe Canyon CO_2 source fields, over 1000 miles of CO_2 and crude oil pipelines, and the SACROC, Yates and Katz oil fields where over 50,000 BOPD were produced. During his time at Kinder Morgan, the CO_2 Company went from zero oil production to become the second largest oil producer in Texas.
- Prior to joining Kinder Morgan, Mr. Fox worked for Shell Oil Company in various domestic and international assignments.
- Mr. Fox is a co-author of the Society of Petroleum Engineers monograph, "Practical Aspects of CO_2 Flooding" and an SPE Distinguished Lecturer. He holds a B.S. in mechanical engineering from Rice University and an M.S. in Petroleum Engineering from Stanford University. He is a professional engineer registered in New Mexico and Texas.

Is it lying if you don't update your photo?

What is Carbon Storage?

Transportation

↓

Capture

↓

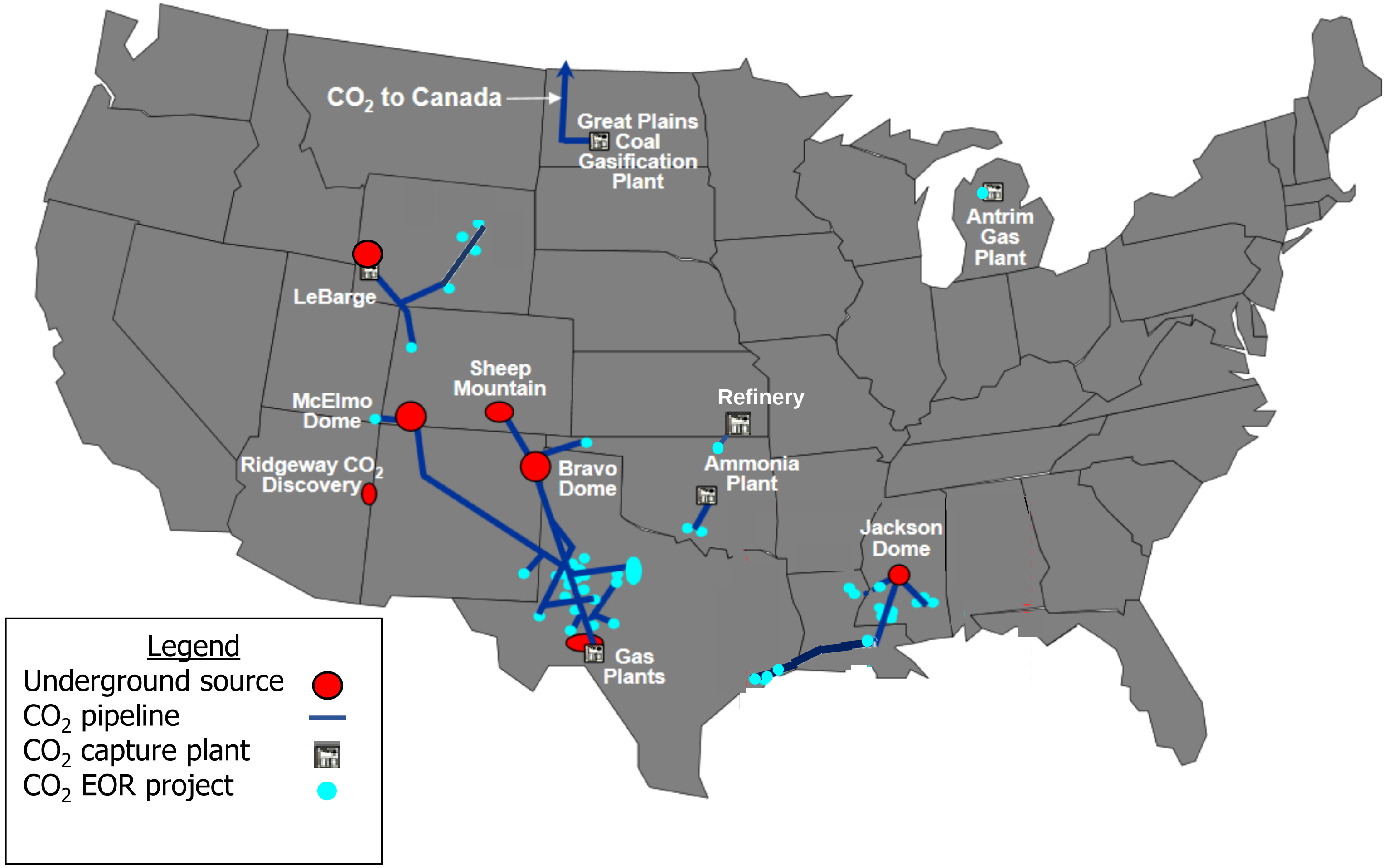
Storage

What is CCUS?

- Carbon Capture Utilization and Storage
- CCUS technologies involve the capture of carbon dioxide (CO_2) from fuel combustion or industrial processes, the transport of this CO_2 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 CO_2 storage in saline reservoir. Where is the utilization?
- CO_2 could be used to make other substances such as plastics, concrete or biofuels.
- The utilization that we will discuss is the use of CO_2 to produce oil. This process is followed by its internment in the subsurface.

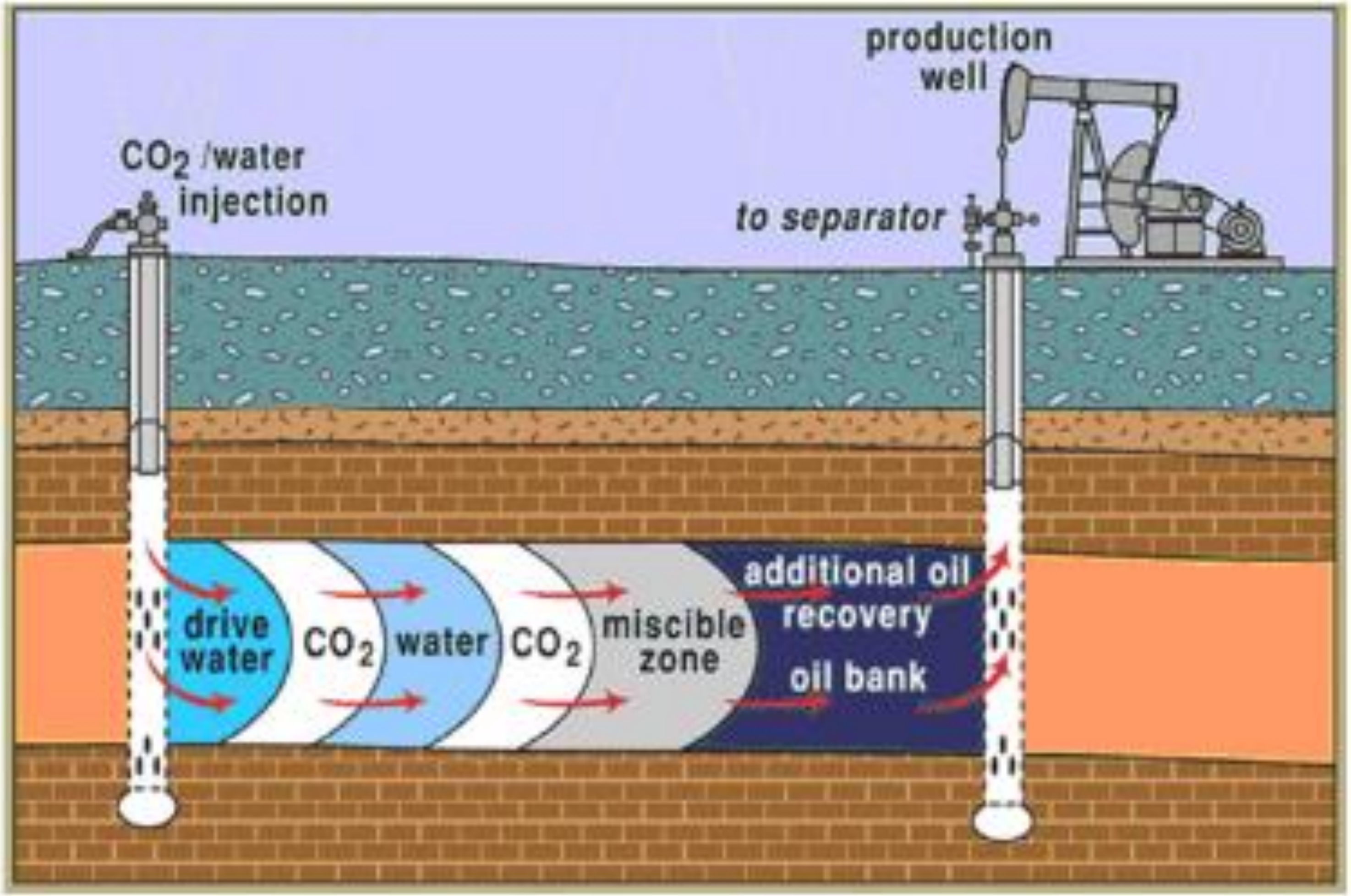
U.S. CO_2 EOR & CCUS Infrastructure

Over 250,000 BOPD were produced due to CO_2 injection in 2014



The map is updated from the source: Denbury Resources Inc. – "CO_2 Pipelines: Infrastructure for CO_2-EOR & CCS" (2009)

CO_2 Flooding Schematic



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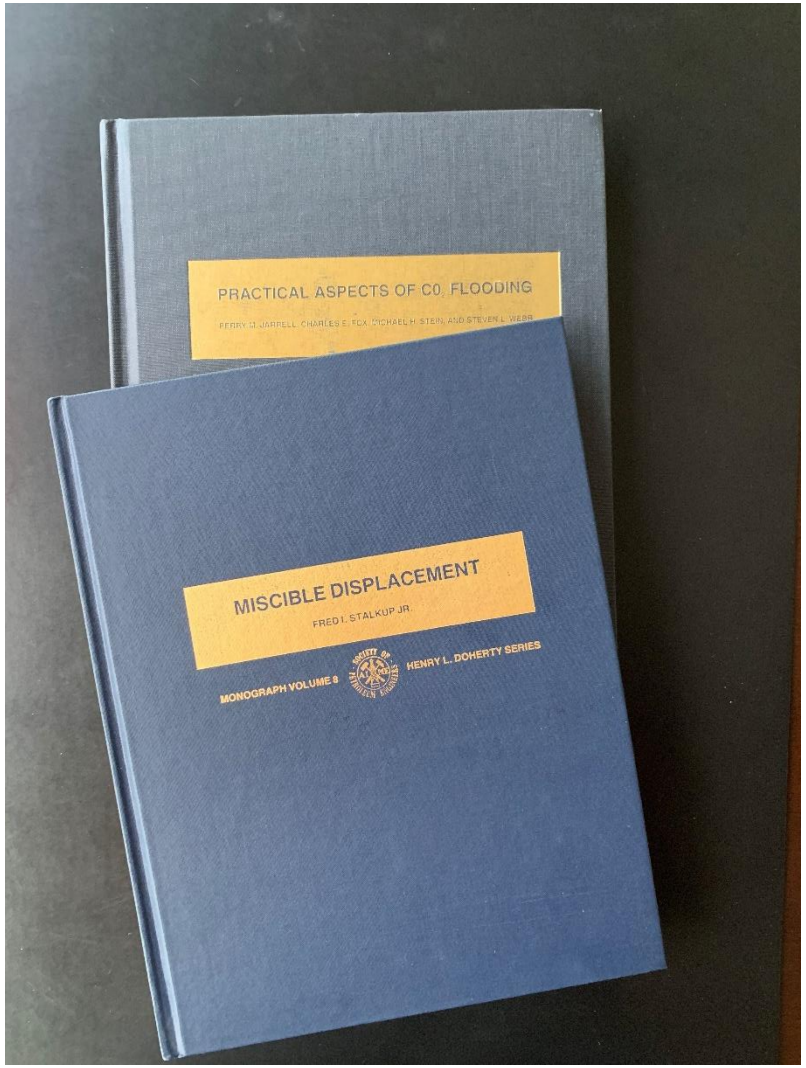
2. History of CO_2 Flooding

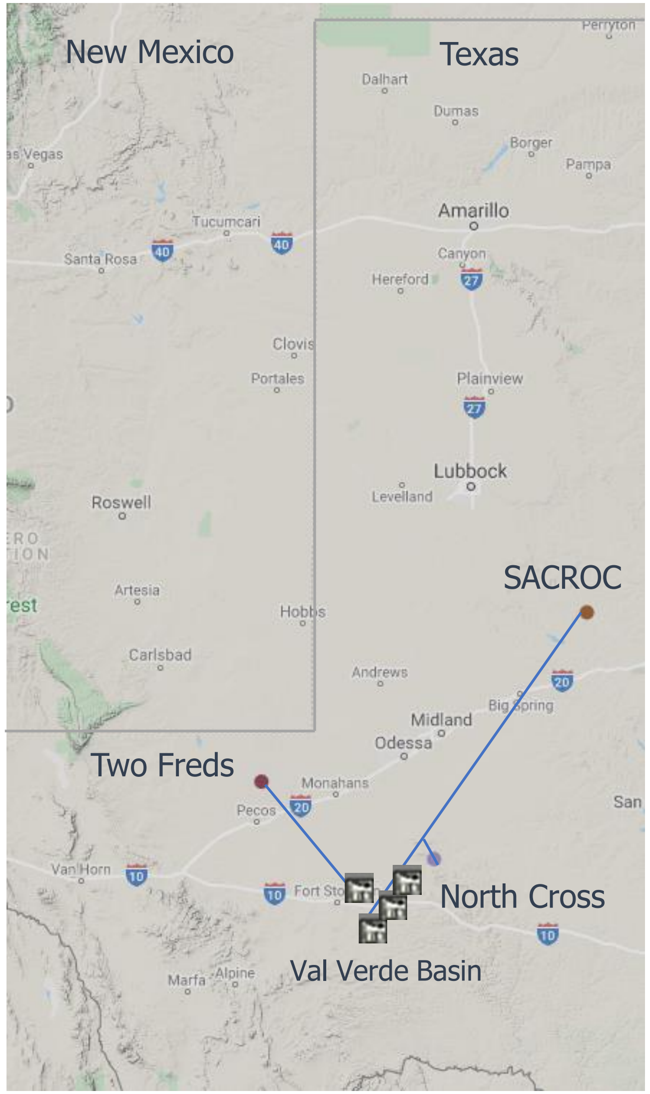
Science

- In 1952 a patent was issued for an oil recovery method with CO_2
- Laboratory research was published through the 1950s and 1960s – enough to encourage operators to initiate CO_2 EOR projects after the 1973 oil embargo
- The basic science of CO_2 miscible flooding was in place by the time the Society of Petroleum Engineers (SPE) published the "Miscible Displacement" monograph in 1983
- Enough field experience was gained over the next two decades for the SPE to publish the "Practical Aspects of CO_2 Flooding" monograph in 2002



Beginnings – 1970s

- CO_2 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
- CO_2 was being separated from the natural gas sales stream and vented at these plants
- This CO_2 was captured, dehydrated and compressed into pipelines
- Initial successes and the energy crisis caused by the Arab oil embargo lead to the search for more and larger CO_2 sources to expand CO_2 flooding to other reservoirs

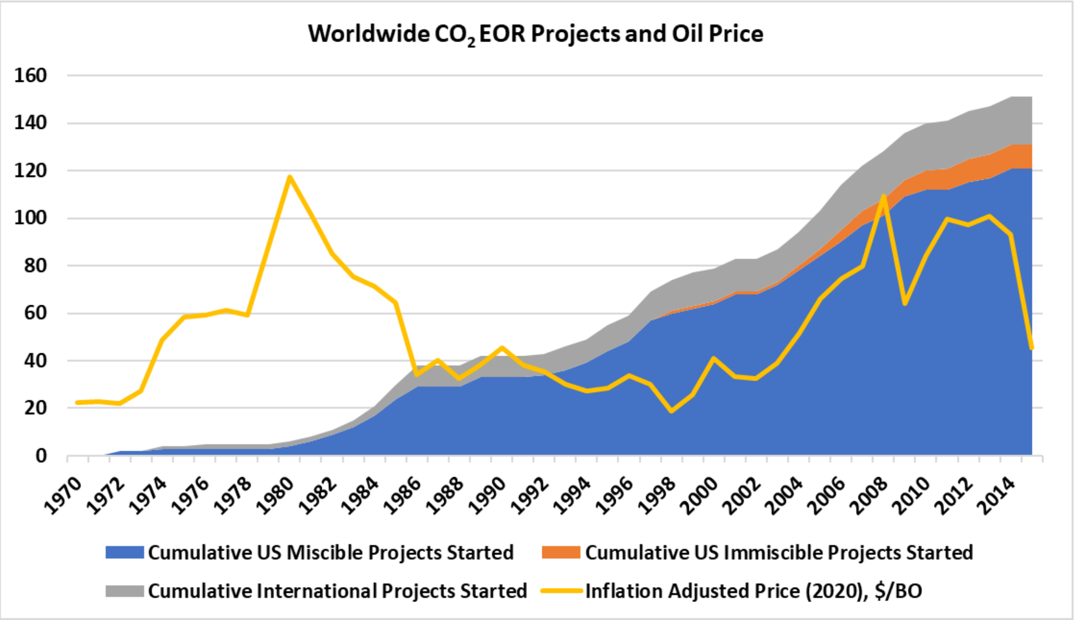


Growth & Retrenchment – 1980s & 1990s

- 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)

Rebirth & (Perhaps) Stagnation – 2000s



Sources: Oil & Gas Journal, 2010 Worldwide EOR Survey, April 19, 2010 & 2014 Worldwide EOR Survey April 7, 2014

- By 2000 and with over 25 years of CO_2 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 CO_2 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?

International Experience

- Canada
  - At least six projects were started from 1984 – 2005
  - The largest is Weyburn (Midale)
  - Weyburn uses CO_2 captured from the Great Plains Coal Gasification Plant in North Dakota
  - The Great Plains plant was a child of the energy crisis
- Trinidad
  - 5 immiscible floods
  - Started 1974 – 1990
  - Sourced from a refinery
- Brazil
  - 2 immiscible floods started in 1991 and 1999
  - 1 miscible flood started in 2009
- Turkey
  - 1 immiscible flood started in 1986
  - Underground source
- Hungary
  - 3 immiscible floods

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3. Reservoir Technology

Tertiary Recovery – After Waterflooding

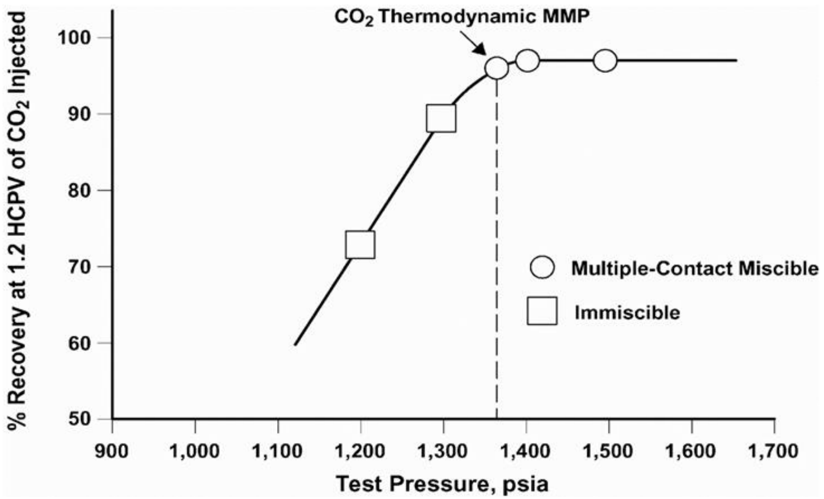
- Oil fields can be developed in stages: primary, secondary, tertiary
- Primary production
  - Almost without exception fields start in the primary phase
  - Wells may initially flow and then be pumped, or the wells could be pumped at the start
  - Eventually the reservoir pressure declines to a point where production rates are uneconomic
- Secondary operations
  - Some producing wells are converted to injection
  - Water or hydrocarbon gas is injected to increase pressure and move the oil from the injector to the producer
- Tertiary operations
  - Secondary recovery leaves oil behind
  - In the case of waterfloods, the injectant is changed to CO_2, steam, or polymer or surfactants are added to the water
- It's possible to skip a phase
- CO_2 injection is usually conducted after waterflooding

Solvents – Propane, NGLs, CO_2

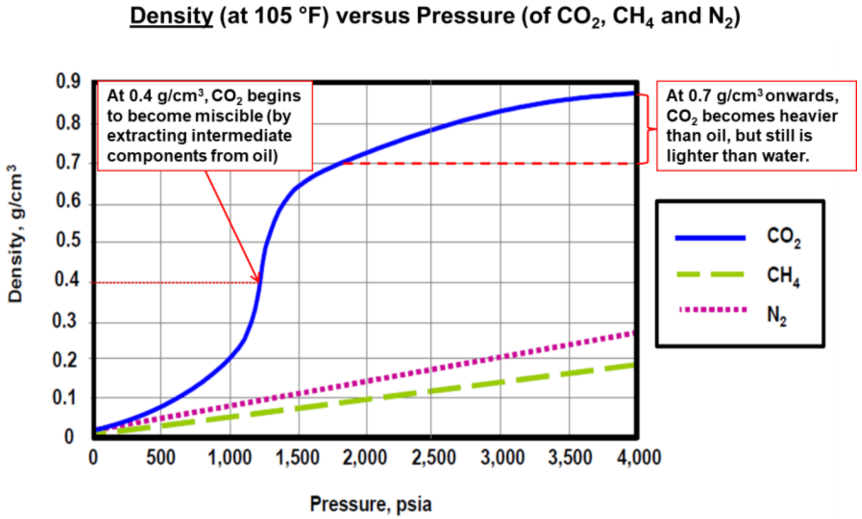
- Have you ever tried to rinse oil-based paint off a paintbrush with a garden hose?
  - Turpentine, a solvent, works much better
  - Propane, natural gas liquids and CO_2 can act like solvents in the reservoir and move oil that is trapped in the pores during a waterflood
- Miscibility
  - Substances are miscible if, when they are mixed, they form one phase
  - CO_2 acts like a solvent when it becomes miscible with the oil
- First contact vs. multiple contact miscibility
  - Oil is a complex substance with carbon chains with different numbers of carbon atoms
  - CO_2 is not miscible with all the components upon initial contact with the oil
  - As CO_2 moves through the reservoir the lighter components of the oil vaporize into the CO_2 ...causing the mixture to become more like the heavier components, eventually leading to its miscibility with the oil.
  - Similarly CO_2 condenses into the oil as it passes, making the oil more like CO_2

Minimum Miscibility Pressure (MMP)

- CO_2 needs to be above the MMP to be miscible
- The MMP varies by oil type and its reservoir temperature
- The top plot shows the results of a slim tube test
  - At 1375 psia the oil recovery is above 90% and additional pressure increases will not improve recovery much
  - Below the MMP, CO_2 is immiscible, but still recovers oil by swelling the oil and reducing its viscosity
- The bottom plot shows the density of CO_2 vs. pressure
  - The MMP will be approximately equal to the pressure where the density of the CO_2 and oil are equal



Source: SPE Monograph 22, Practical Aspects of CO2 Flooding



Source: Basin Oriented Strategies – Permian Basin, ARI 2006

Impurities

- Impurities can raise (hurt) or lower (help) the MMP
- A formula (which is not given) exists to estimate the effect of impurities on the MMP
- Substances with critical temperatures (T_c) lower than CO_2's T_c raise the MMP
- Methane (CH_4) makes achieving miscibility harder
  - A mixture of 90% CO_2 and 10% CH_4 has an MMP 33% higher than pure CO_2
  - For an 80/20 mixture the MMP is 54% higher

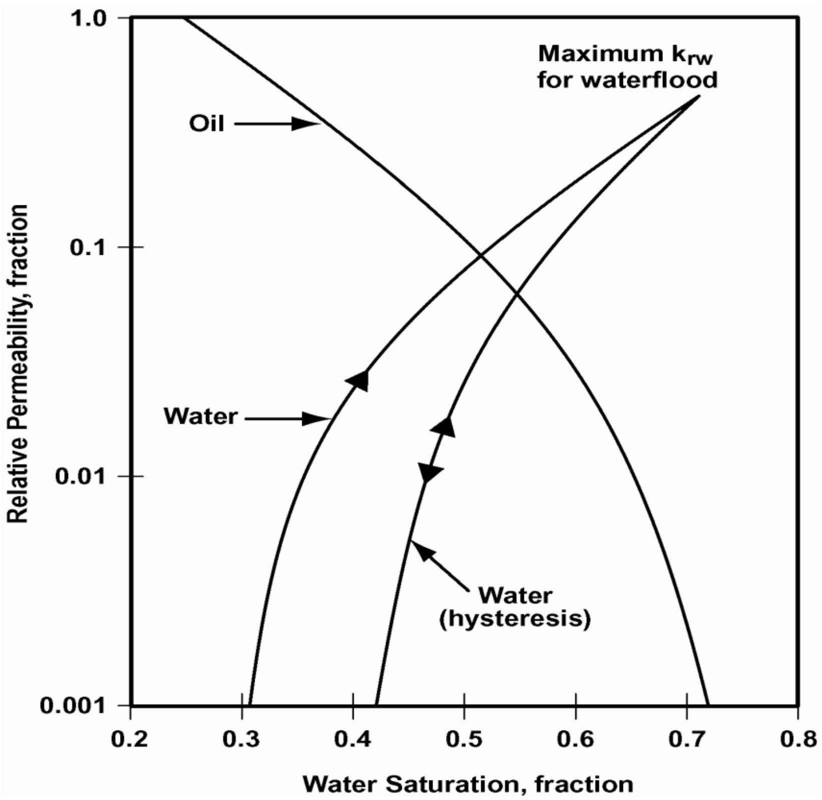
Gas	T_c (K)
Hydrogen	33.2
Nitrogen	126.2
Oxygen	154.6
Carbon Monoxide	132.9
Methane	190.6
Carbon Dioxide	304.2
Ethane	305.2
Hydrogen Sulfide	325.0
Propane	369.8
Butane	425.2
i-Butane	408.1
N-Pentane	469.6
i-Pentane	433.8
N-Heptane	507.4

Hurts

Helps

Relative Permeability Curves - 1

- It's easier for a fluid (such as oil) to flow through a rock if it's the only substance present
- If another fluid is present (such as water), it is relatively harder to move the oil
- Relative permeability curves illustrate this effect
- Immobile water and immobile oil exist in the pore space of the rock
- In this example 31% of the water is immobile and 28% (1 – 0.72) of the pore space is filled with immobile oil

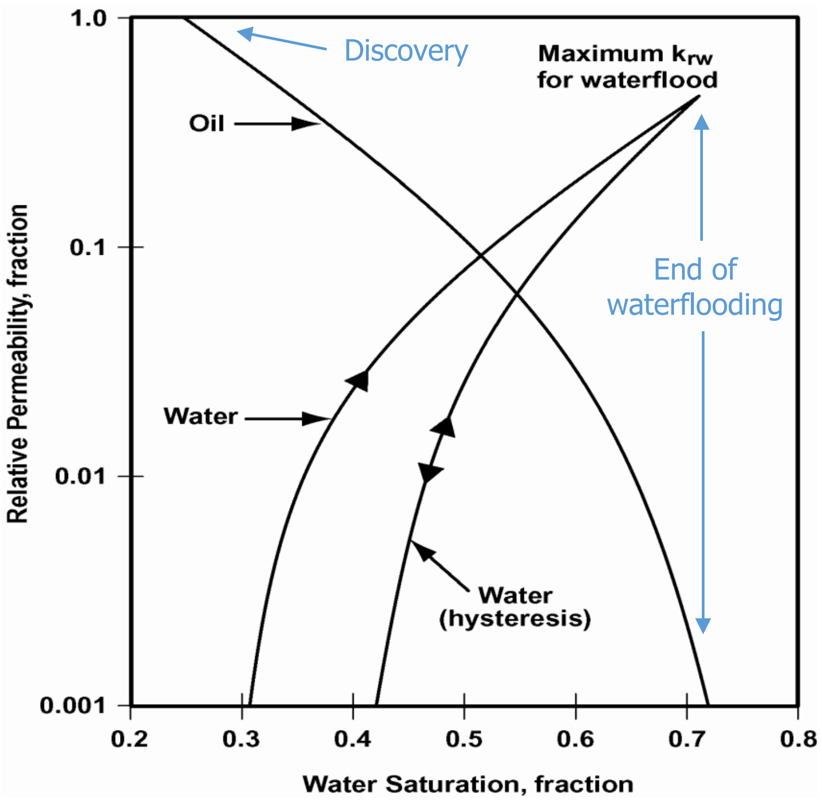


The water hysteresis curve is only present when CO_2 is injected. In this case there are three fluids competing for space to move. Since it is miscible with the oil, CO_2 follows the general shape of the oil relative permeability curve.

K_{rw} = relative permeability to water

Relative Permeability Curves - 2

- In this example, at discovery, the reservoir contains 25% water and 75% oil
  - The oil is at maximum mobility – relative permeability of 1.0
  - The water is immobile
- Oil is produced during primary
  - Oil's saturation declines as does its relative permeability
  - Eventually water becomes mobile
- Waterflooding begins
  - As more and more water is injected, the water saturation increases, and the oil saturation decreases
  - The relative permeability of oil decreases and the water permeability increases
  - At the end of the waterflood, the oil is essentially immobile
  - The residual oil saturation to waterflooding is 28% in this case
- CO_2 flooding begins
  - There are more curves, and it gets complicated
  - Key: the residual oil saturation to CO_2 flooding is 2 – 5% (the solvent is working)
  - Key: the water is harder to move
  - Key: a portion of the CO_2 ultimately becomes immobile



Total permeability for a fluid equals the rock permeability multiplied by the relative permeability

Other Processes

- Vertical Floods
  - Miscible or immiscible process
  - Inject CO_2 at the top of the reservoir
  - Use gravity to segregate the CO_2 and oil
  - Produce oil from the bottom of the reservoir – may involve recompleting downward
- Huff & Puff
  - Immiscible process
  - Inject CO_2 into a production well
  - Wait a few weeks and allow the CO_2 to make the oil more mobile
  - Produce
- Unconventional
  - Injection of CO_2 into shale reservoirs (huff & puff so far)
  - Seems to work at least technically
  - Low permeability increases recovery times when compared to CO_2 injection into conventional reservoirs

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4. Well Design, Surface Facilities & Operations

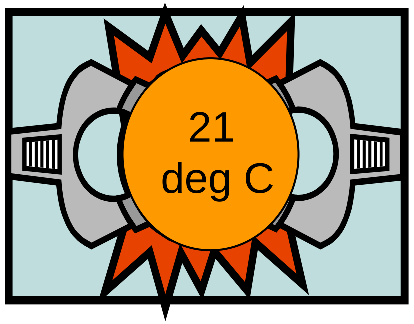
Waterflood & CO_2 Flood Differences

- CO_2 injection operations are at higher surface pressure than water injection operations
  - CO_2 is less dense than water, so a higher surface pressure is required to provide the same bottomhole pressure
  - Could require modification to wellheads
- Corrosion
  - Dry CO_2 poses no corrosion problem
  - The combination of water and CO_2 poses severe corrosion problems

CO_2 Properties – Compressible Fluid

Increase the pressure of 70ºF CO_2, Methane or Water in the 500-mile, 30" Cortez PL from 1800 psig to 1900 psig

Increase the temperature of 1800 psig CO_2, Methane or Water in the Cortez PL from 70ºF to 80ºF



Additions to inventory:
CO_2: 20 million lbs
Water: 0.8 million lbs
Methane: 18 million lbs

Pressures increase to :
CO_2: 2300 psig
Water: 2250 psi
Methane: 1910 psig

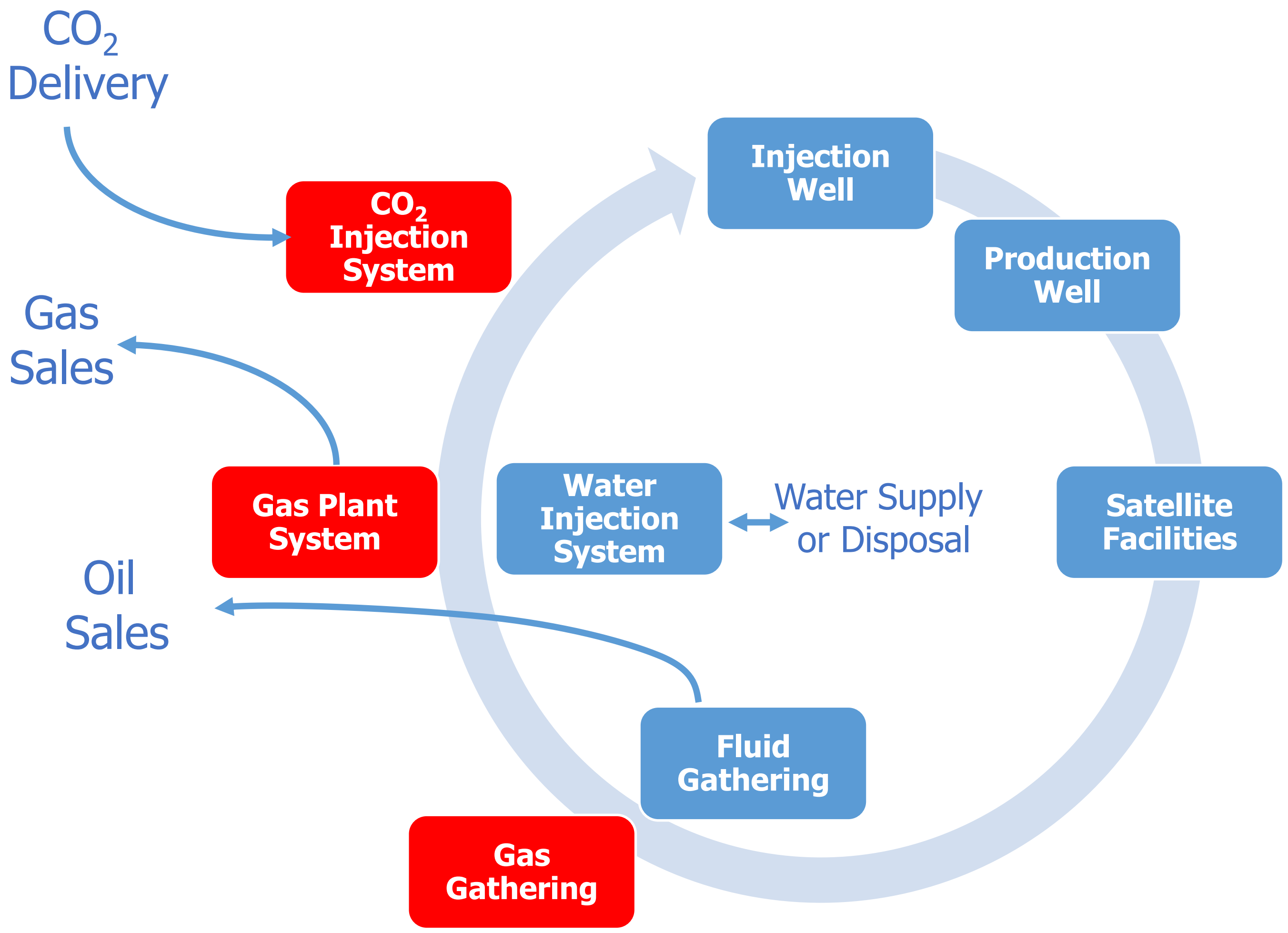
<u>Sometimes CO_2 acts more like a liquid and sometimes more like a gas</u>

Corrosion Mitigation

- Presence of H_2S
  - H_2S is normally thought of as a corrosive agent
  - It can create a passivating layer on steel (like aluminum oxide on aluminum) and reduce corrosion from carbonic acid
- Carbon Steel Specifications
  - Higher carbon content in carbon steel favors better adherence of protective corrosion products and corrosion inhibitors
- Corrosion Resistant Alloys
  - 316 stainless steel
  - 13 Chrome
  - Monel
- Plating and Coating
  - Nickel
  - Polyethylene
  - Thin film epoxy
- Elastomers
  - High durometer (<90)
  - Nitrile & Viton
- Injection of Corrosion Inhibitors
- Cement
- Corrosion mitigation has been solved

Corroded Tubing Coupling

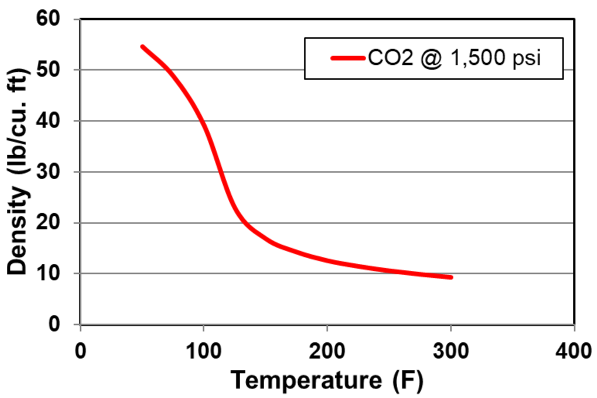
CO_2 Flood Production Systems



Potential for major alterations shown in red

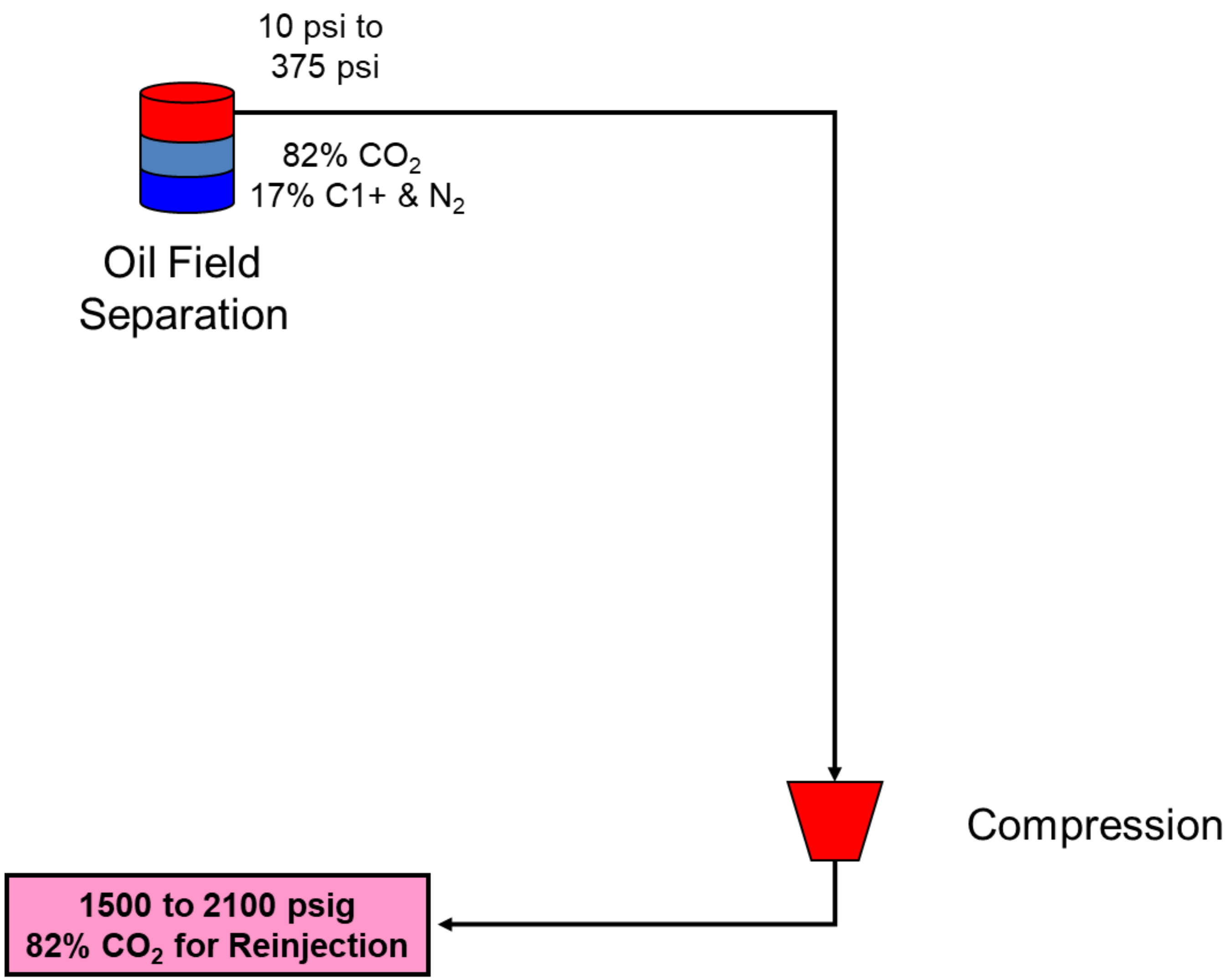
CO_2 Compressors and Pumps

Shop construction of a 5000 hp, 30 MMSCFD compressor

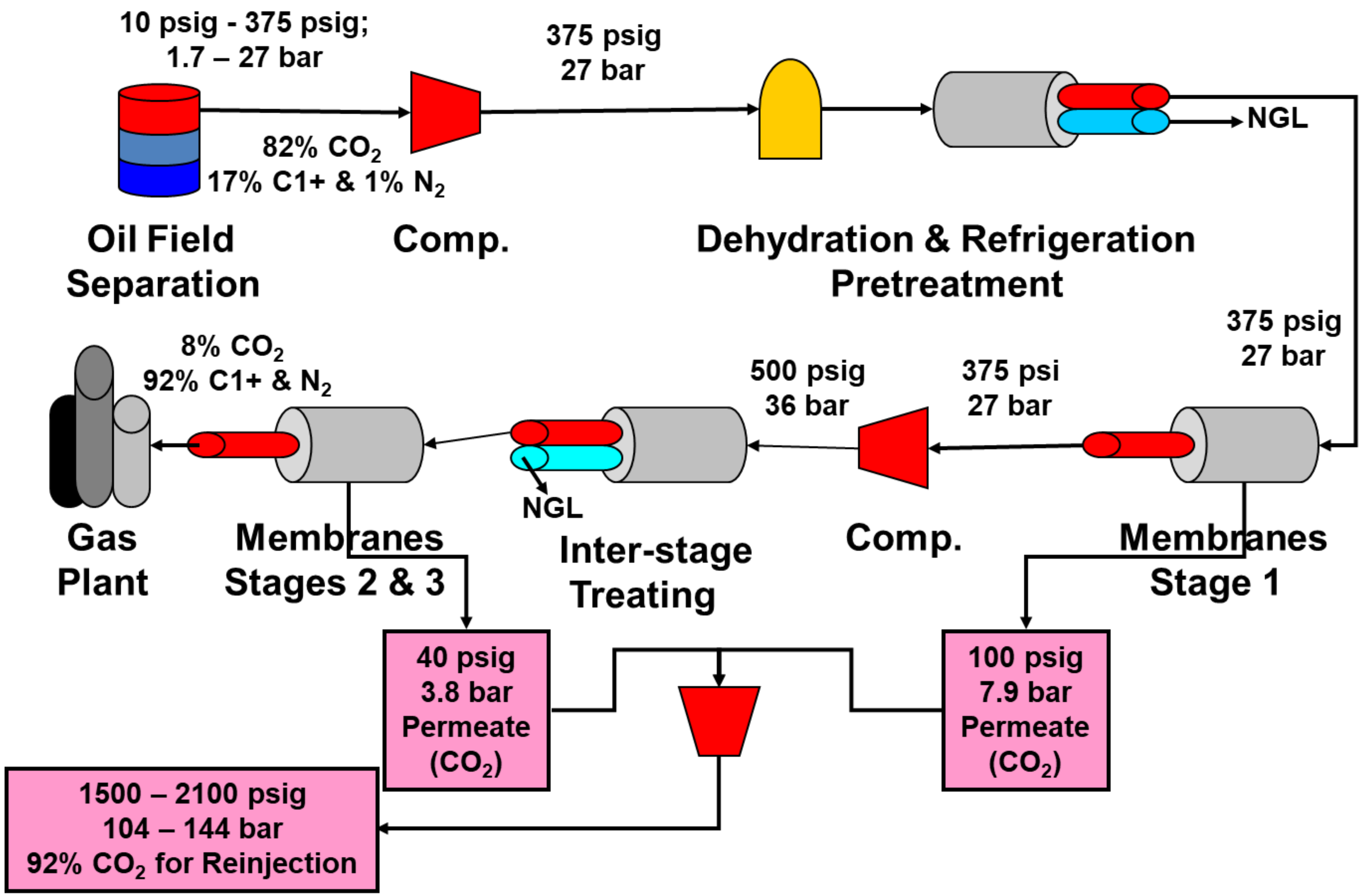


- CO_2 is recycled during the enhanced oil recovery process
- Compressors are used to increase the pressure
- Once cool CO_2's pressure is above about 1500 psi, it can be pumped, saving energy but increasing complexity
- CO_2 pipelines use pumps

Gas Handling Options - 1



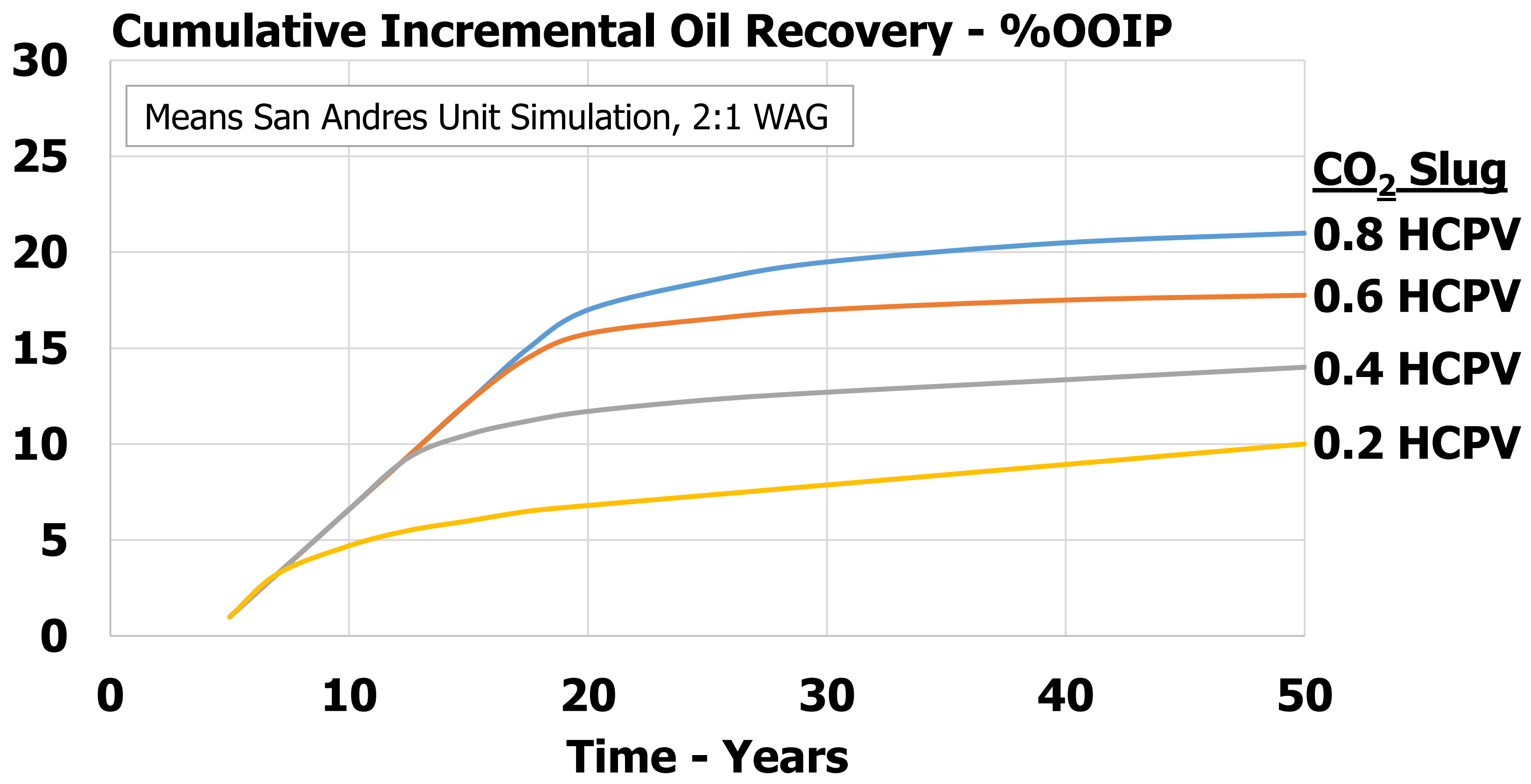
Gas Handling Options - 2



Additional Operational Considerations

- Reservoir Management/Managing CO_2
  - Purchase volumes
  - Recycle volumes
- Well Management
- Facilities Management
- Safety

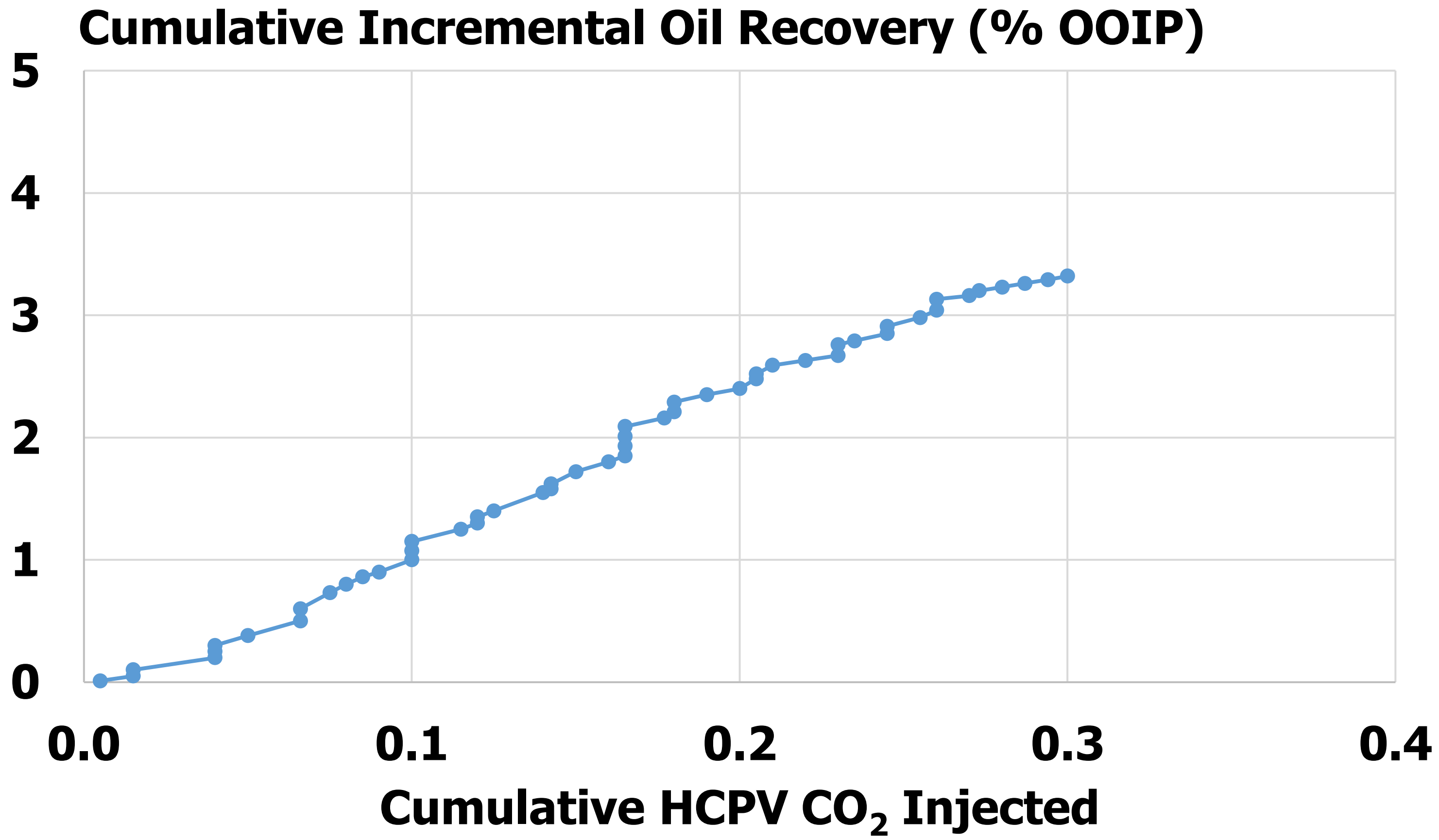
More CO_2 More Oil



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

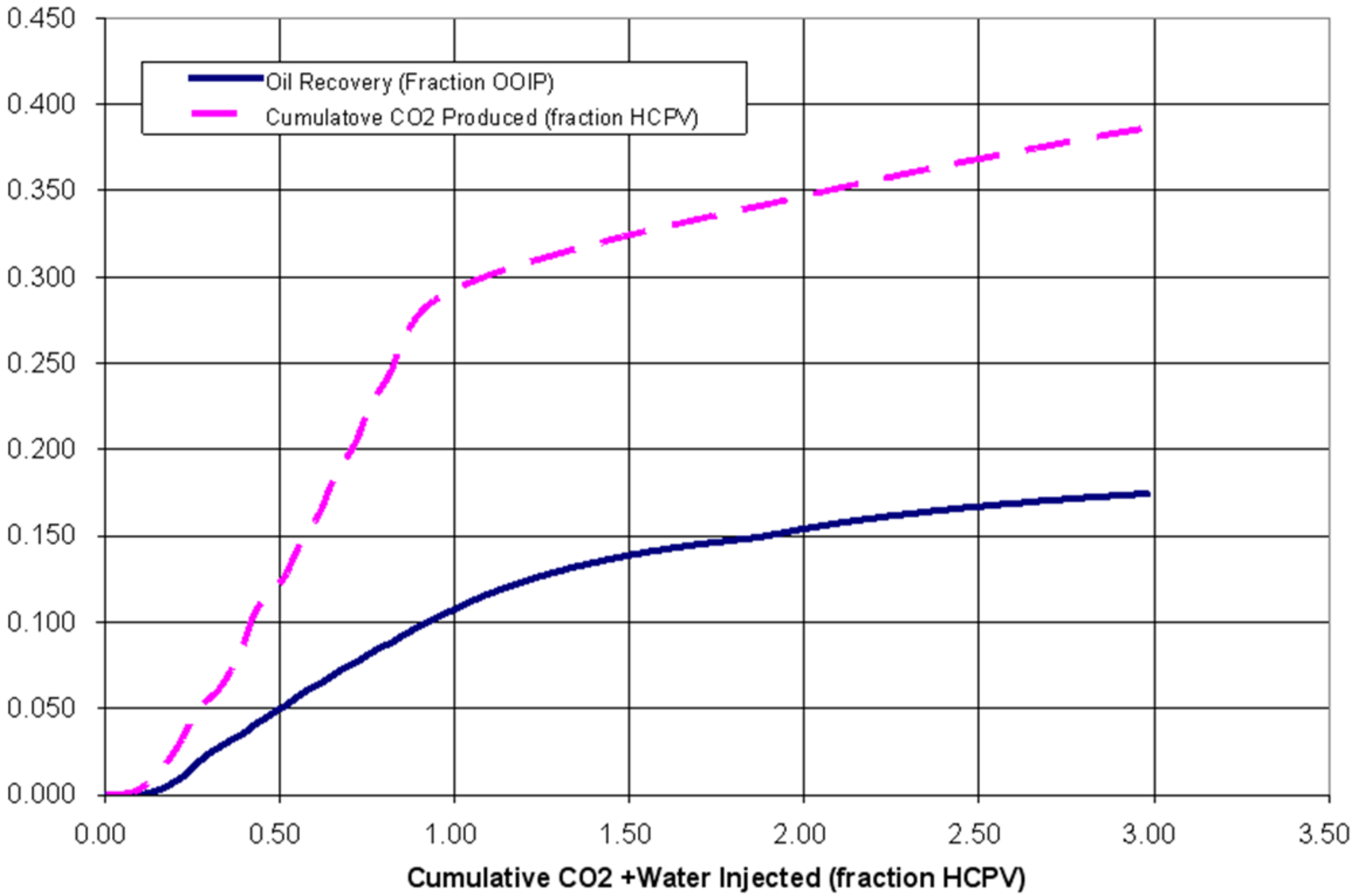
After Hadlow, SPE 24928 (1992)

Cum Incremental Oil Production vs. Cum CO_2 Injection



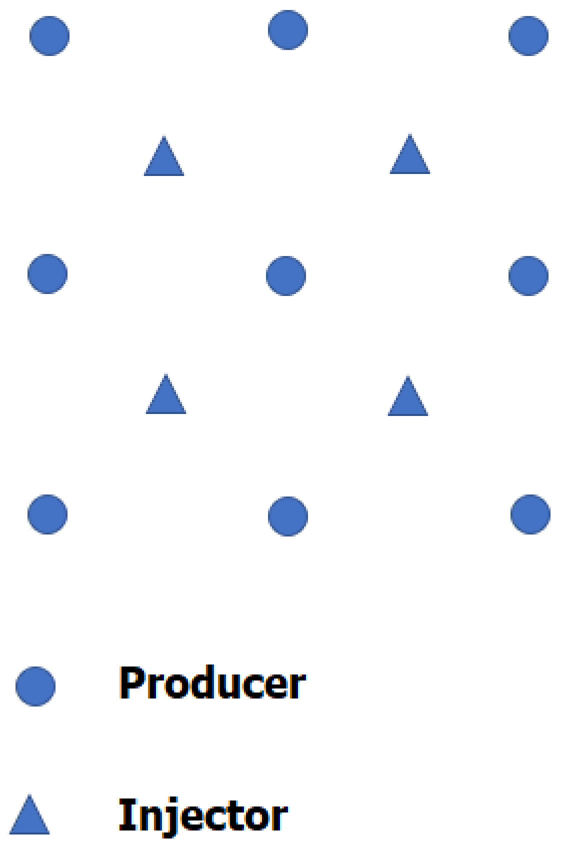
The vertical sections are caused by long water injection cycles
After Fig 8.6 SPE Monograph "Practical Aspects of CO_2 Flooding"

Dimensionless Tertiary CO_2 Flood Performance



WAG Management in Pattern Floods

- Optimize the WAG ratio
  - Start with continuous CO_2 injection
  - Then inject water alternately with CO_2 to remain within facility and CO_2 supply limits
  - WAGing may improve areal and vertical sweep

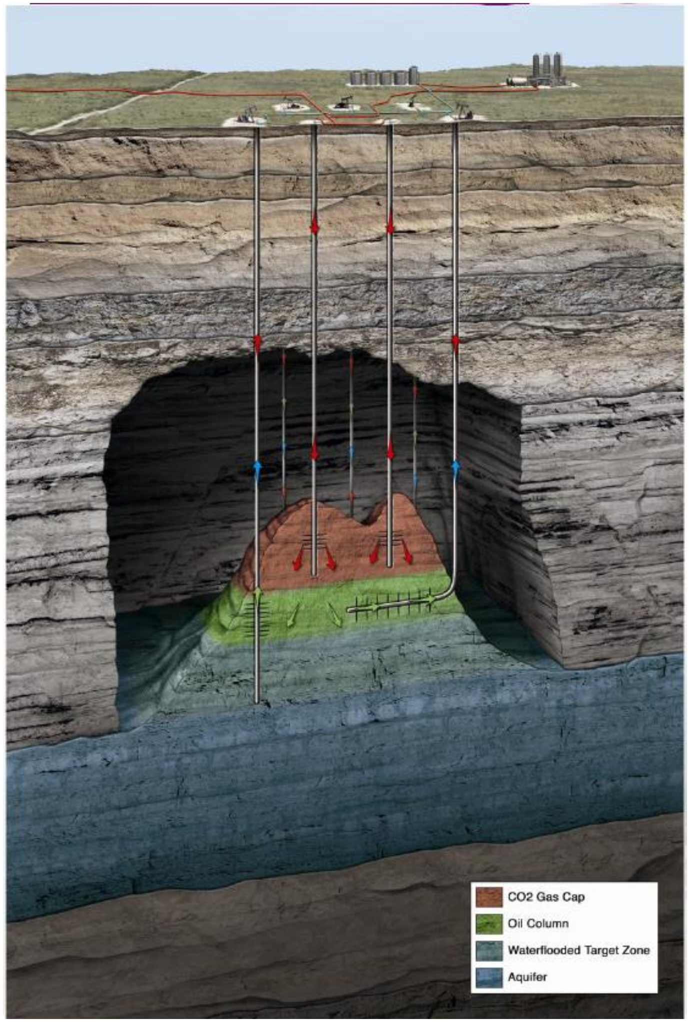


Pattern Flood

Well Management

- Artificial Lift
  - Decide on a lift strategy (gas lift of beam pump)
  - Manage WAG cycle to minimize lift changes
- Remedial Work
  - Lower pH, lower temperature
  - Increased gyp downhole (use phosphonate inhibitor)
  - Increased paraffin
  - Asphaltene deposition
- CO_2 Breakthrough
  - Increase WAG ratio
  - Cement squeezes/plugbacks
  - Gel polymer squeezes
  - Fiberglass liners
  - Selective production equipment
  - Selective injection equipment
  - Choke back production to help divert injected CO_2 elsewhere

Top Down CO_2 Floods



Bruce Howard, Wellman Case History
2013 CO_2 Conference

- Inject at the top of the reservoir
- Produce from the bottom – generally recompleting downward
- Logging observation well data can be used along with material balance to monitor advancement of the gas-oil contact.

Metering

An orifice meter is used to measure CO_2 at the inlet to the Cortez PL

- Custody transfer is usually done by orifice meters
- Orifice meters are accurate within 1%
- Important measurement factors include differential pressure, molecular weight and density
- At non-custody transfer points, turbine, wedge and Coriolis meters are used

Safety

Asphyxiation

High Pressures

Noise Levels

Frost Bite

10 – Minute Break

The workshop will continue at 11:30am CT

INTERSTATE
Oil & Gas
COMPACT COMMISSION

5. Regulations

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, freshwater, steam, polymers, or carbon dioxide are injected into oil-bearing formations to recover residual oil and in limited applications, natural gas.
- Class VI
  - Inject CO_2 into deep rock formations for the purpose of long-term underground storage or geologic sequestration (GS)

Source: epa.gov/uic

Class II

- Primarily focused on protecting drinking water
- Requirements for
  - Construction
  - Operation
  - Monitoring and testing
  - Reporting
  - Financial responsibility and closure
- In general the applicant needs to show that:
  - The injection formation is competent to contain the injected fluids
  - Nearby wells that penetrate the formation don't provide a pathway for injectant to migrate into potential drinking water reservoirs
  - The injection process does not cause the injectant to migrate, i.e. the injection pressure and injectant are compatible with the reservoir
  - The injection well itself, during its life and after abandonment, does not provide a conduit for the injectant to migrate into potential drinking water reservoirs (USDW)
  - This list is not exhaustive

Class VI

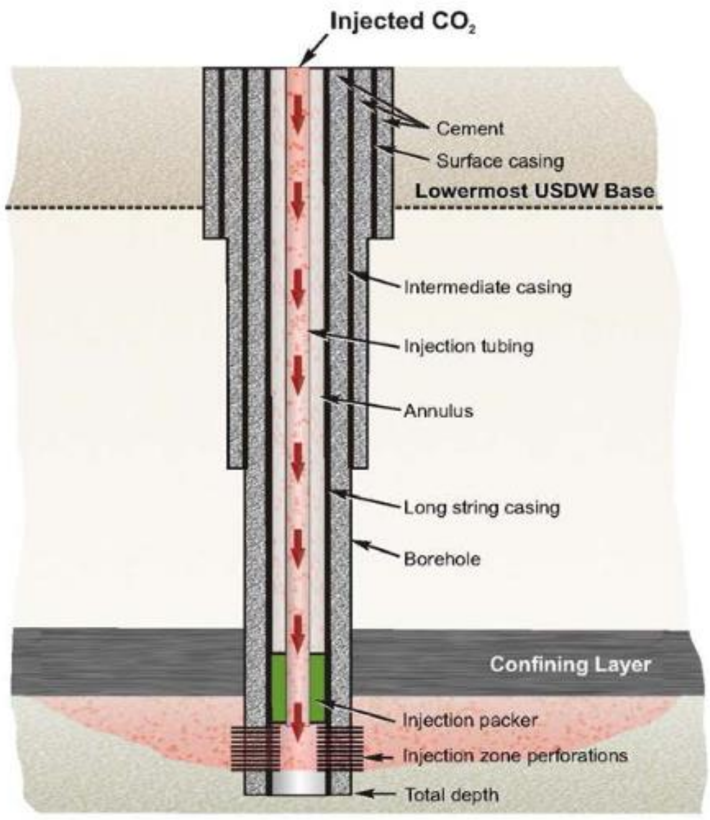
- Focused both on protecting drinking water and assuring long term storage of CO_2
- Address the unique nature of CO_2 injection for long term storage
  - Relative buoyancy of CO_2
  - Subsurface mobility
  - Corrosivity in the presence of water
  - Large anticipated injection volumes
- Requirements for
  - Siting (an additional requirement vs. Class II)
    - Extensive site characterization requirements
  - Construction
    - Materials must withstand contact with CO_2 over the life of the project
  - Operation
  - Monitoring and testing
    - Comprehensive monitoring requirements addressing well integrity, CO_2 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

Class VI Siting

- Characterize the area
  - Regional geology - hydrogeology, structural geology, faults, seismic history, geophysics
  - Confining and injection zones – thickness, facies, mineralogy, permeability, capillary pressure, geochemistry
  - Injection well – logs, formation testing, core tests, injectivity and fall off testing, fracture testing
  - Injectant – characterize and check compatibility
  - Existing wells in the AOR – gather information
- Area of Review (AOR)
  - The region surrounding the project where USDWs may be endangered
  - Defined by computational modeling
  - Project the lateral and vertical migration of the CO_2 plume until the plume ceases to move; pressure differentials are so low that CO_2 can't move into a USDW or the end of a fixed time to be determined by the UIC program director
  - Plan to simulate hundreds to thousands of years
  - Model must be updated (calibrated) at least every 5 years
  - Could lead to corrective action on existing wells

Class VI Construction

- Differences between Class II and Class VI
- Casing
  - Select corrosion resistant materials for entire project life (100s of years)
  - Leads to choosing materials like 13 Chrome for the bottom of the well
- Cement
  - Each string must be cemented to the surface
  - Not true for a Class II well
- Tubing
  - CO_2 resistant (at least inside)

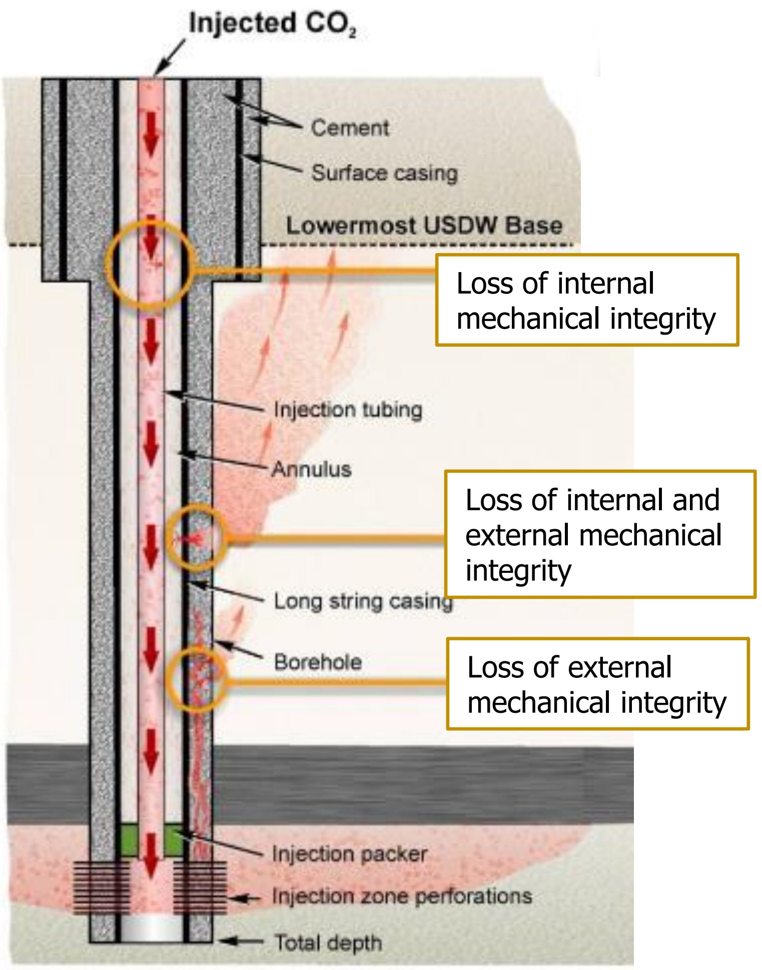


Schematic of Class VI Injection Well

Source: Fig. 3: EPA, Underground Injection Control (UIC) Class VI Well Construction Guidance

Monitoring and Testing

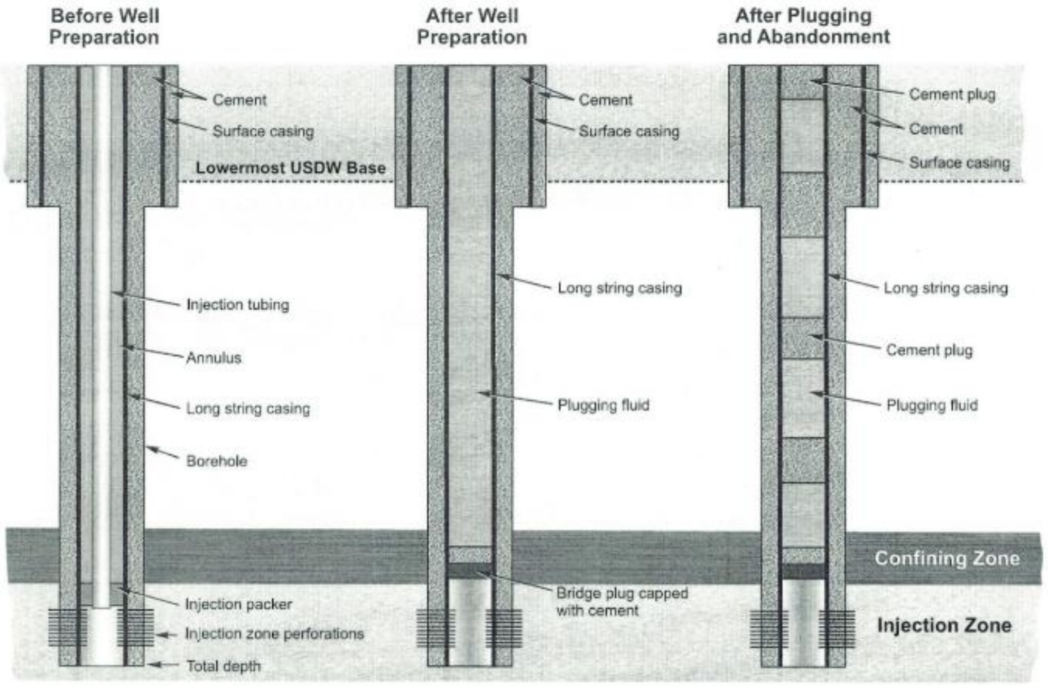
- Mechanical Integrity Testing (MIT)
  - Internal (pressure test the casing, tubing and packer)
    - During operations usually annulus pressure > tubing pressure
  - External (looking for flow in channels adjacent the wellbore)
    - O_2 activation, temperature & noise logs
- Operational Testing
  - CO_2 stream composition
  - Injection rate, volume and pressure
  - Corrosion monitoring (coupons & casing inspection logs)
  - Pressure fall-off (at least every 5 years)
- Ground water quality and geochemistry
  - Monitoring wells in the 1st permeable formation above the confining zone
- Plume and pressure front
  - Time lapse seismic surveys (likely choice)
  - Pressure monitoring wells in the injection zone
- Surface air and soil gas (maybe)



After Fig 2-1: EPA, Underground Injection Control (UIC) Class VI Well Testing and Monitoring Guidance

Closure

- Plugging
  - Final external MIT
  - Normal plug placement
  - Consider cements resistant to carbonic acid
- Post Injection Site Care
  - Plan for 50 years of monitoring and analysis
- Site Closure
  - Notification
  - Non-endangerment demonstration
  - Plugging monitoring wells



Source: Fig. 3: EPA, Underground Injection Control (UIC) Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance

Financial Responsibility

	Corrective Action and Phased Corrective Action	Injection Well Plugging	Post-injection Site Care and Site Closure	Emergency and Remedial Response
Trust Fund	Best			May be too little or too much money
Letter of Credit*	Best		May be unreliable for longer time periods (>20 years)	Most appropriate for ERR during operation
Surety Bond*	Good	Best	May be unavailable over longer time periods (>20 years)	
Insurance	Not ideal for operational phases			Best
Financial Test and Corporate Guarantee	Good, but provides no financial recourse if owner or operator fails			
Escrow Account	Good	Trust funds may be preferred over the mid and long term		Likely to perform poorly for uncertain risks

*Standby trust is needed in addition to the letter of credit or surety bond if EPA is implementing the program.

From Table 4.3: Instruments Best Suited for GS Activities; Research and Analysis in Support of UIC Class VI Program Financial Responsibility Requirements and Guidance, EPA

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

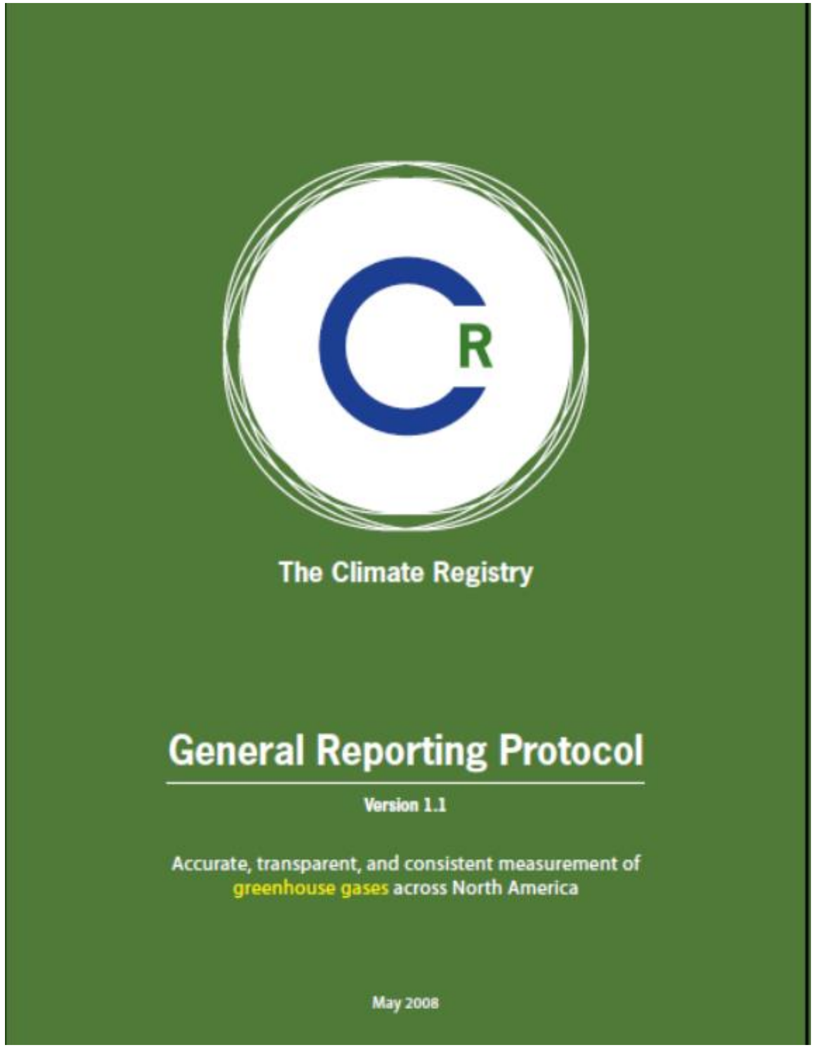
WINDY COVE ENERGY II

6. Carbon Balance

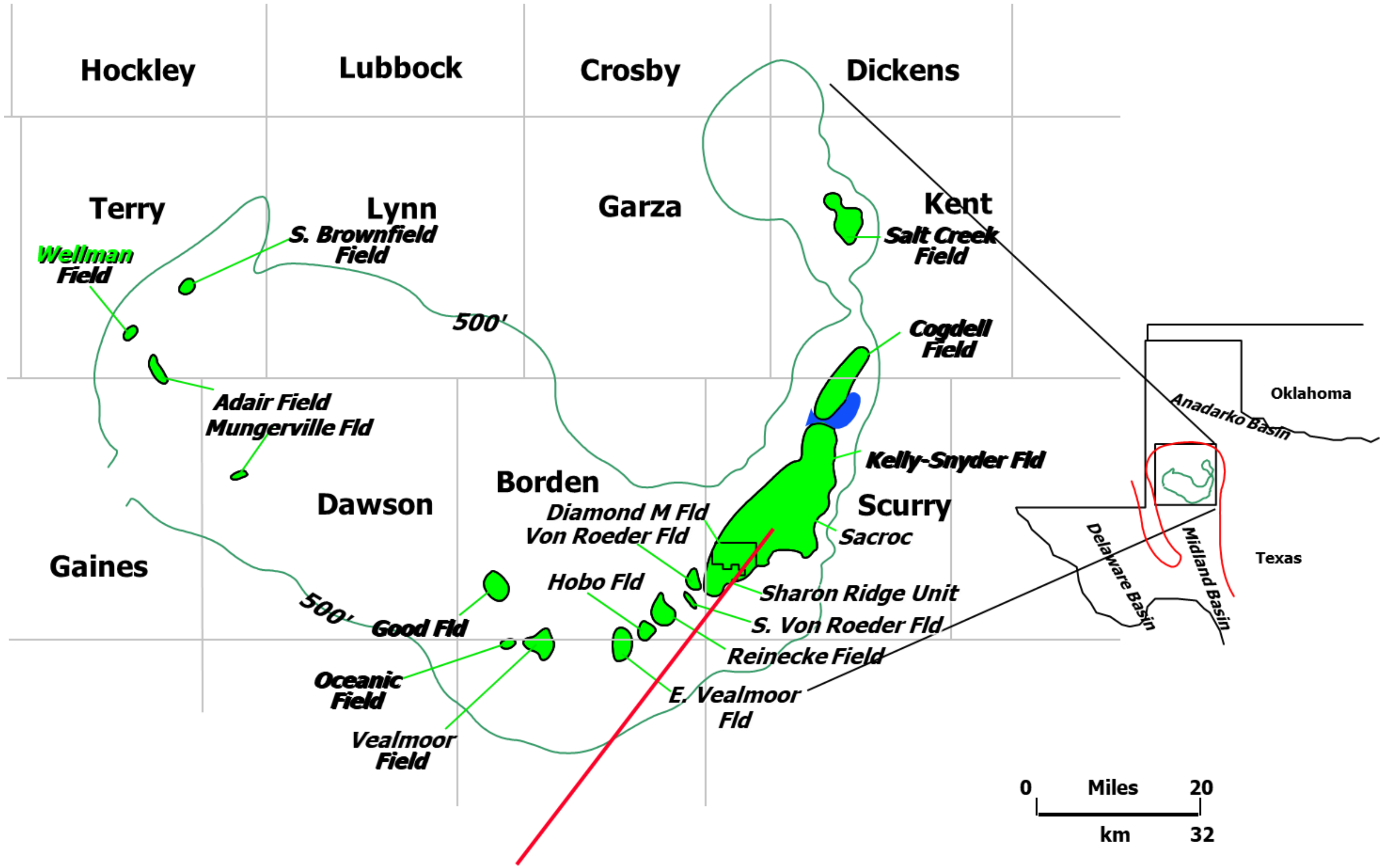
The following was extracted from a presentation to a Society of Petroleum Engineers section meeting in 2008

EOR Carbon Balance

- Calculate carbon emissions for SACROC in 2007 using CA Registry methods (mostly)
- Compare various emission sources
- Comment on how you can make your calculations
- Look at short term and long-term carbon balance calculations for the SACROC oil field

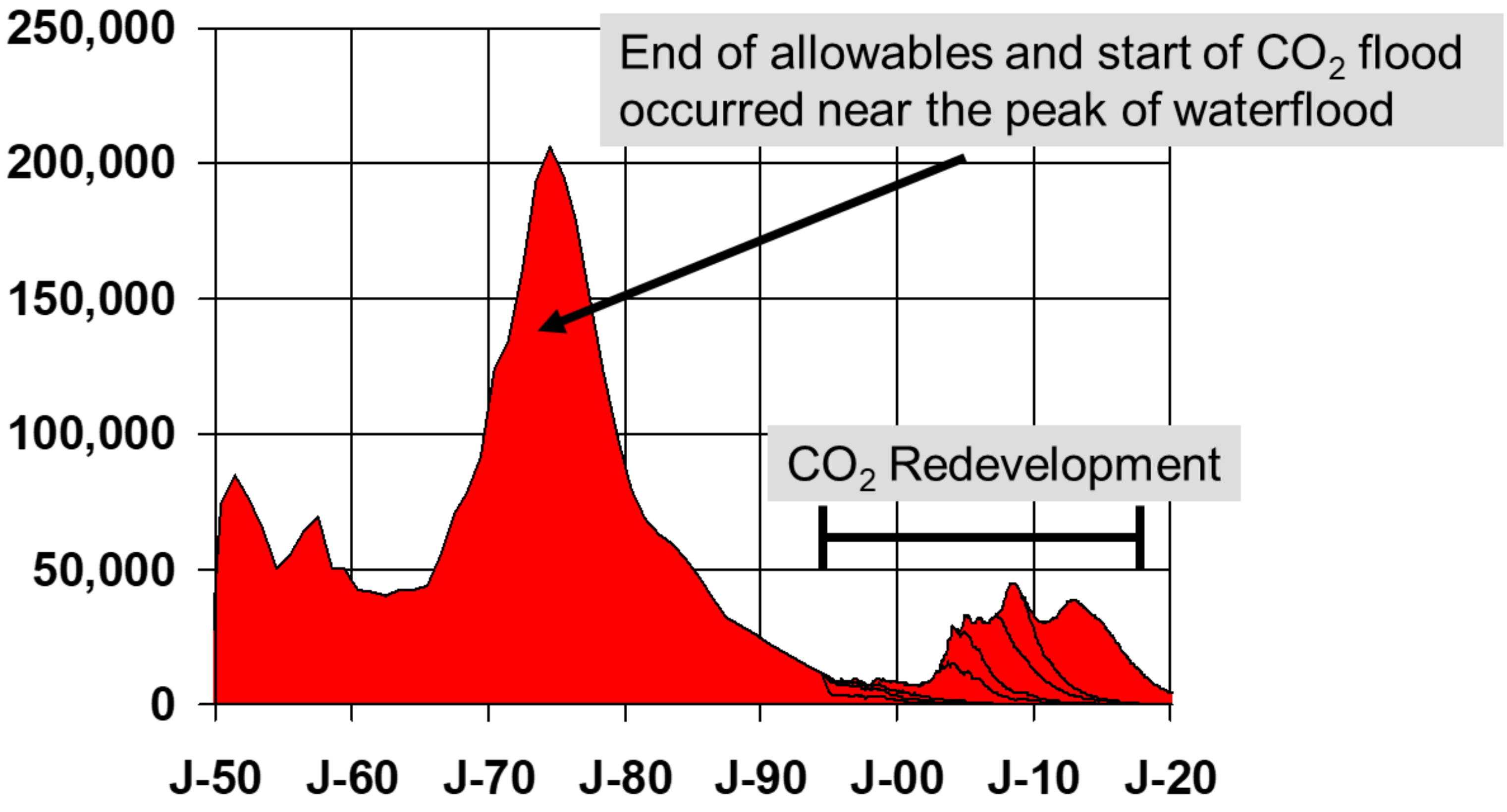


SACROC



Hockley
Lubbock
Crosby
Dickens
Terry
Lynn
Garza
Kent
Wellman Field
S. Brownfield Field
Salt Creek Field
500'
Cogdell Field
Adair Field
Mungerville Fld
Kelly-Snyder Fld
Borden
Dawson
Scurry
Diamond M Fld
Von Roeder Fld
Sacroc
Gaines
Hobo Fld
Sharon Ridge Unit
500'
Good Fld
S. Von Roeder Fld
Reinecke Field
Oceanic Field
E. Vealmoor Fld
Vealmoor Field
Oklahoma
Anadarko Basin
Texas
Delaware Basin
Midland Basin
0 Miles 20
km 32

Oil Production



Basis – SACROC Complex 2007

- Production
  - 27,635 BOPD
  - 624,000 BWPD
  - 75,000 MCFD HC Gas
  - 637,000 MCFD CO_2
- Injection
  - 582,000 BWPD into reservoir
  - 892,000 MCFD (CO_2 + HC)
  - 212,000 MCFD Purch
- 835 Wells
- 57 Compressors & Pumps >1000 HP
- 225,500 HP in 2007
  - Added five 5000 hp compressors later
- Handles 120 MMCFD for 3rd Parties (16 MW)
- Snyder Gas Plant
  - 15,000 BBL NGL/Day
  - 20 MMCFD HC gas

2007 Emissions

- Approximately 1 million tonnes* CO_2e
- Primarily energy use – metered
  - Direct
  - Indirect
- Calculations based on
  - Metered volumes
  - Estimated factors
- California Registry Methodology
  - Except for indirect emissions

*tonne – metric ton; 19 MSCF CO_2 ~ 1 tonne

Gas Fired Power Plant

397,500 tonnes in 2007

- 103 MW (net) Combined Cycle Plant
- Two LM6000 turbines
  - 45 MW each
- One HRSG
  - Heat Recovery Steam Generator
  - 18 MW
- Burns 19.8 MMCFD (20,300 MMBTU/day)
- Heat Rate – 8000 kW/MMBTU
- 0.44 tonnes/MW-hr

Purchased Power - Indirect

409,600 tonnes in 2007
336,900 tonnes in 2007*
***No 3rd party gas processing**

- Purchase 107 MW
- Total power needs = 210 MW
  - 30% Wells/ESP
  - 20% Water General
  - 14% Inlet Compression
  - 34% Recompression
  - 1% CO_2 Recovery
  - 1% CO_2 Pumps

Reciprocating Engines

89,000 tonnes in 2007

- Cooper Bessemer
- Caterpillar
- White Superior
- Dresser Rand

- 2 stroke, lean burn
- 4 stroke lean burn

- Purpose
  - Sales
  - Gas gathering
  - Third party gas return

- Metered

Flares

61,400 tonnes in 2007

- CO_2 Membrane Facility
- CO_2 Membrane Topping Unit
- Snyder Gas Plant
- Two metered sources:
  - "Flared" CO_2
  - Gas burned

Heaters and Boilers

54,100 tonnes in 2007

- NGL treating and gas conditioning for CO_2 separation
- MDEA
- MEA
- CO_2 Recovery
- Metered gas usage

Vented Emissions

34,500 tonnes in 2007

- Compressors
- Heaters
- Reciprocating Engines
- Turbines

- Based on maintenance factors

Fugitive Emissions

1200 tonnes in 2007

- SGP (non refrigerant)
  - 343 tonnes
- Compressor area
  - 178 tonnes
- Process area
  - 132 tonnes
- Refrigerants (vehicles/offices)
  - 87 tonnes
- Power Plant
  - 39 tonnes
- Misc.
  - 390 tonn

Mobile Emissions

500 tonnes in 2007

- Gasoline and diesel usage for
  - Heavy duty vehicles
  - Light trucks
  - Passenger cars
  - Forklifts
  - Lawn mowers

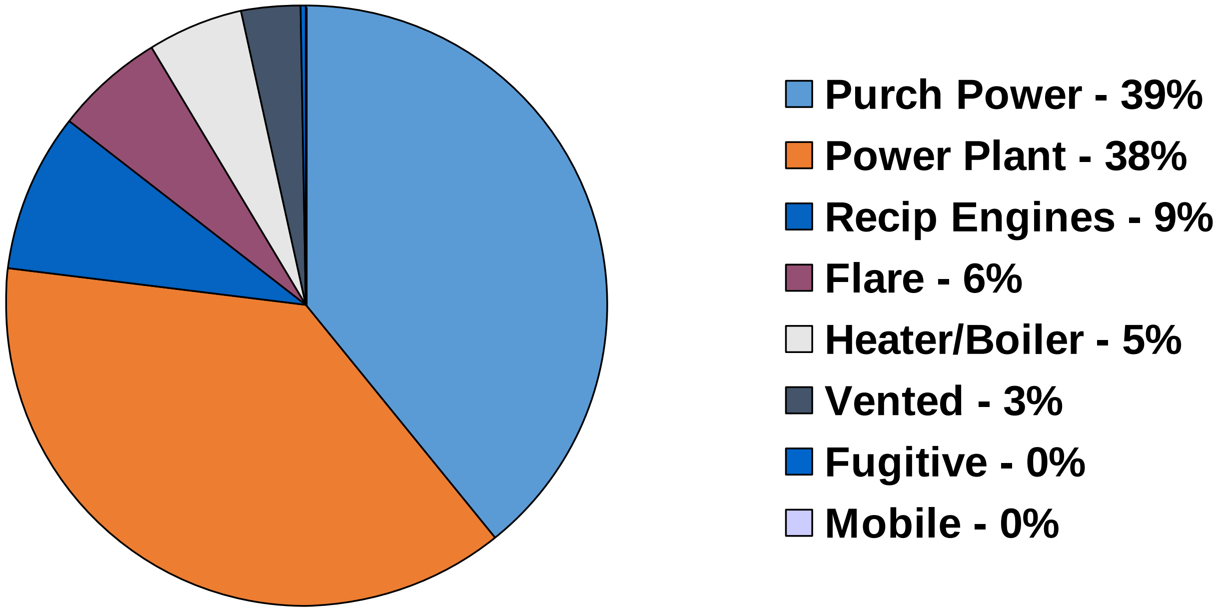
How These Were Numbers Derived

Combustion Emissions from a Stationary Flare

Specie	HC Gas Burned MMBTU	Emission t/MMBTU	Emission t	t CO2e/ t emitted specie	t CO2e
CO_2	525.6	0.05306	27.88834	1	27.88834
N_2O	525.6	9 E-7	0.000473	310	0.14664
Methane	525.6	9 E-7	0.000473	21	0.00993

Based on fuel usage

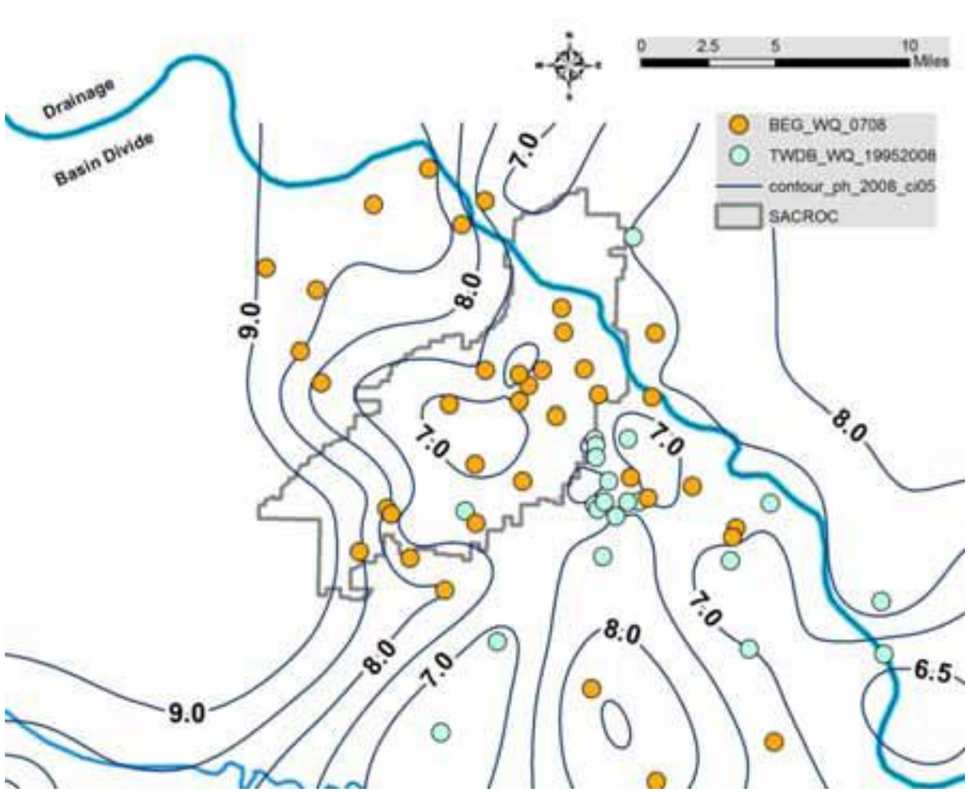
SACROC Complex GHG Emissions



1,046,000 Tonnes Total Complex

972,800 Tonnes CO_2 Flood

Smyth Study



Conclusion:
Unable to find leakage

Figure 7. Contours of pH measured by BEG and TWDB in Scurry County between 1995 and 2008. Contour interval = 0.5 pH units.

Retention

- Federal Register/Vol 75/No 68/Apr 10, 2009/P. 16584 :

  "There are several EOR operations in the Permian Basin of Texas. One study showed that retention rates (for CO_2) for 8 reservoirs ranged from 38% to 100% and averaged 71%, but many of these projects are not mature enough to predict final retention."

- **Implication: If it is not retained, it is emitted – NOT SO!**

- Retention is a term of art
- From <u>Practical Aspects of CO_2 Flooding</u> (SPE Monograph 22)

  "Retention: the amount of CO_2 remaining in the reservoir at any given time, which equals the amount of CO_2 injected less the amount of CO_2 produced. This normally is expressed as a percentage."

- Retention = Net Utilization/Gross Utilization

Carbon Balance 2007

Purchased	4.08 Mt
Direct/Indirect Emissions	- 0.97 Mt
Total Sequestered	3.11 Mt
Oil Production	10.1 MMBO
CO_2e Emitted/BO	0.1 t/BO
	1.8 Mcf/BO

Field Life Carbon Balance

EOR Production[1]	185 million BO
Purchased[2]	260.0 Mt
Direct/Indirect Emissions[3]	- 18.5 Mt
Capital Emissions[4]	- 2.0 Mt
Total Sequestered	239.5 Mt

92% stored

[1]10% of 1.85 billion bbl OOIP

[2]Not all purchased CO2 was anthropogenic

[3]CO_2e emitted 0.1 t/BO

[4]530 tonnes/$1 million GDP, $3.5 billion of capital

Additionality

- If you don’t assume that this oil replaces oil that would have been produced elsewhere, you need to included the emissions from the use of oil

0.43 tonnes/BO – EPA

134 lb/mcf or 0.06 tonnes/mcf - EIA

Field Life Carbon Balance w/ Additionality

Purchased	260.0 Mt
Direct/Indirect Emissions	- 18.5 Mt
Capital Emissions	- 2.0 Mt
Oil/Gas Product Emissions	- 97.0 Mt
Total Sequestered	124.5 Mt

Sequestering 48% of purchased injection

Conclusion

- GHG emissions at EOR fields are tied almost exclusively to energy consumption
  - electric power
  - gas fired reciprocating engines
  - heat
- GHG emission calculations are tedious
- EOR can sequester CO_2

30 – Minute Lunch Break

The workshop will continue at 12:40pm CT

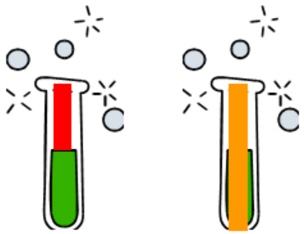
INTERSTATE Oil & Gas COMPACT COMMISSION

WINDY COVE ENERGY II

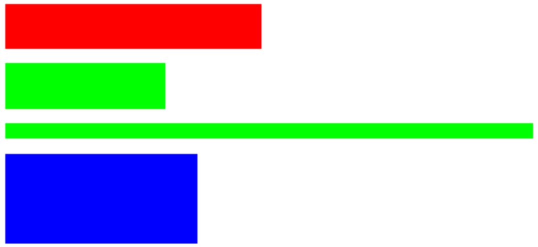
7. Screening & Economics

First Considerations

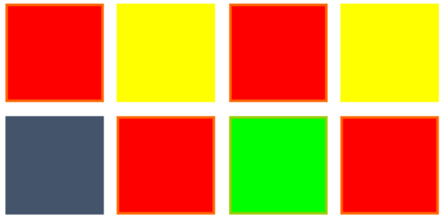
Distance from
CO_2 Pipeline/Source



Miscibility
(in most cases)



Heterogeneity/Loss Zones



Lease Considerations

Screening Criteria for Miscible CO_2 Flooding

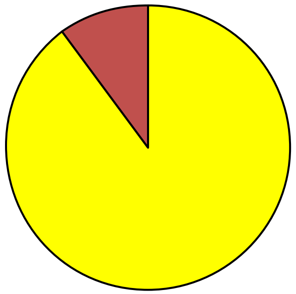
Oil and reservoir characteristic	Requirement
API Oil Gravity	> 25 degrees (except in case of dead oils)
Viscosity	< 10 cp (except in case of dead oils)
Depth	> 3000 ft
Temperature	80 – 285° F
Residual Oil	>25 %
MMP Achievable	Yes (commonly determined empirically using laboratory slim tube tests)
Other positive factors	Good waterflood performance (good sweep efficiency, reasonable throughput rates and good voidage balance)
Negative factors	Severe reservoir heterogeneity, adjacent loss zones (gas caps), dominant fracture systems

Screening Criteria for Immiscible CO_2 Flooding

Oil and reservoir characteristic	Requirement
API Oil Gravity	> 16 degrees
Viscosity	< 50 cp
Depth	No Consideration (NC)
Temperature	80 – 285° F
Residual Oil	>25 %
Reservoir Pressure	If greater than Yellig-Metcalfe MMP → Can vaporize lighter oil components (which is a more favorable case)
Other positive factors	Good waterflood performance (good sweep efficiency, reasonable throughput rates and good voidage balance)
Negative factors	Severe reservoir heterogeneity, adjacent loss zones (gas caps), dominant fracture systems

Estimating Oil Recovery & CO_2 Utilization

Oil Recovery



CO_2 floods normally produce 8 – 16% of the original oil in place (OOIP) during injection of the initial CO_2 slug (30 – 50% of the hydrocarbon pore volume, HCPV). The slug size of better CO_2 floods will be increased over time to increase the recovery up to perhaps 20%.

CO_2 Utilization

In the Permian Basin CO_2 floods often purchase 5 – 6 MCF CO_2 per bbl of oil produced and recycle an equivalent amount during the initial slug. Gulf Coast CO_2 floods purchase less and recycle more.

- Example oil field: 100 MMBOOIP
- Oil recovery
  - 10% recovery efficiency
  - 10 MMBO recovered due to CO_2 injection
- CO_2 required
  - 5.5 MCF/BO
  - 55 BCF (i.e. MM MCF) CO_2 purchased
  - 55 BCF CO_2 recycled
  - 110 BCF CO_2 injected

Estimating CO_2 Injectivity, Time & Rate

As a first pass, CO_2 injection (converted into reservoir barrels) equals water injection during the waterflood. 2 MCF ≈ 1 BW. WAG may reduce water injection by 50% for part of the water injection cycle.

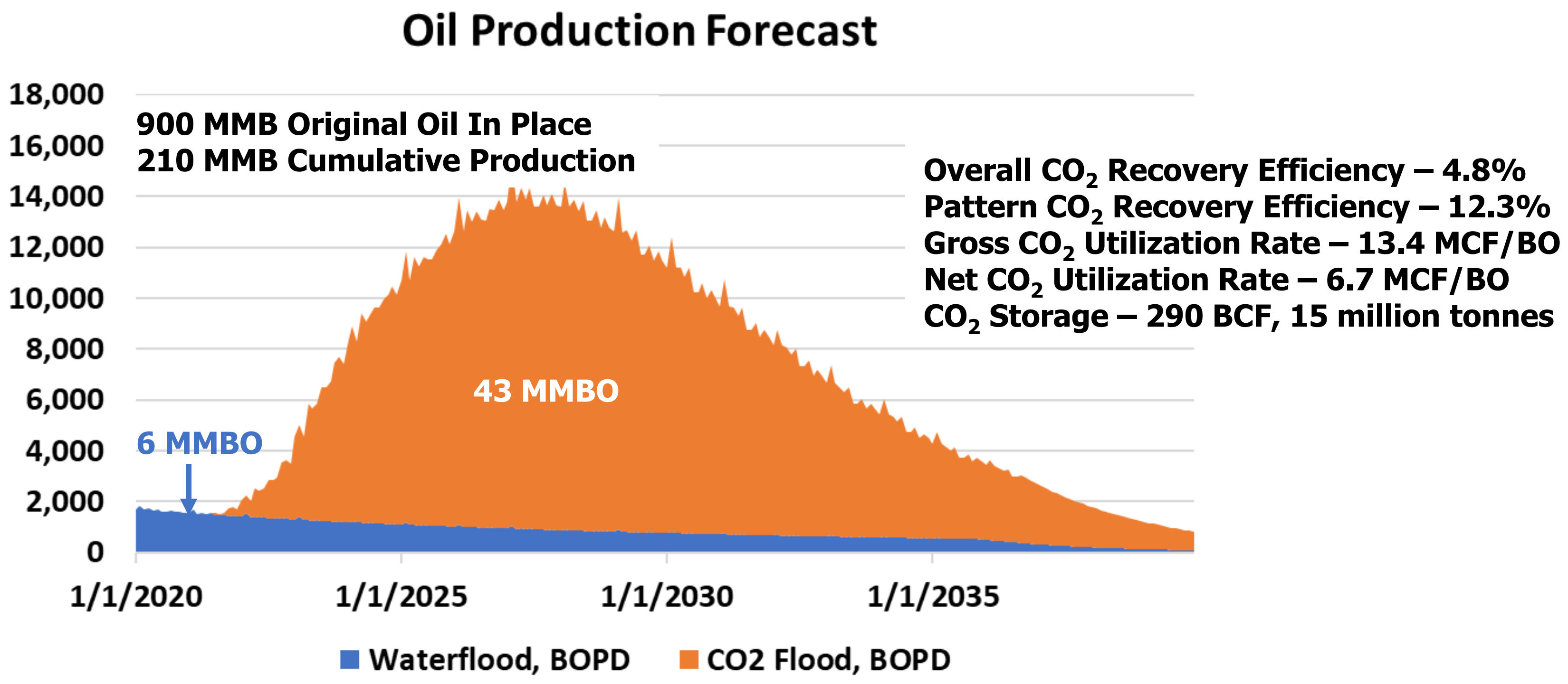
The project life can be estimated since we know the amount of CO_2 to be injected and the rate. We assume one-half the time water is injected.

Experience shows that the maximum rate of oil production for the San Andres reservoir is 1/10th of the rate of the reservoir injection rate which is generally equal to the waterflood water injection rate.

- Example (cont'd): 25 injectors injecting 1000 BWPD
- Injection rate
  - 25 MBWPD
  - 2 MCF/BO
  - 50 MMCFD
- Project life
  - 110 BCF injected
  - 6 years at 50 MMCFD
  - 12 years if injecting water ½ of the time
  - If water injects at ½ the rate of CO_2 injection, then project life is 15 years
- Maximum oil rate
  - 25 MBWPD
  - 1/10 of injection is oil at the maximum
  - 2500 BOPD maximum rate
- Question: Is producing 10 MMBO over 12 – 15 years with a maximum rate of 2500 BOPD interesting?

Example Economics

- Large field in the Permian Basin (benefits from economies of scale)
- Original analysis performed in 2015
- Start date was delayed 5 years for this analysis
- Oil and CO_2 were repriced

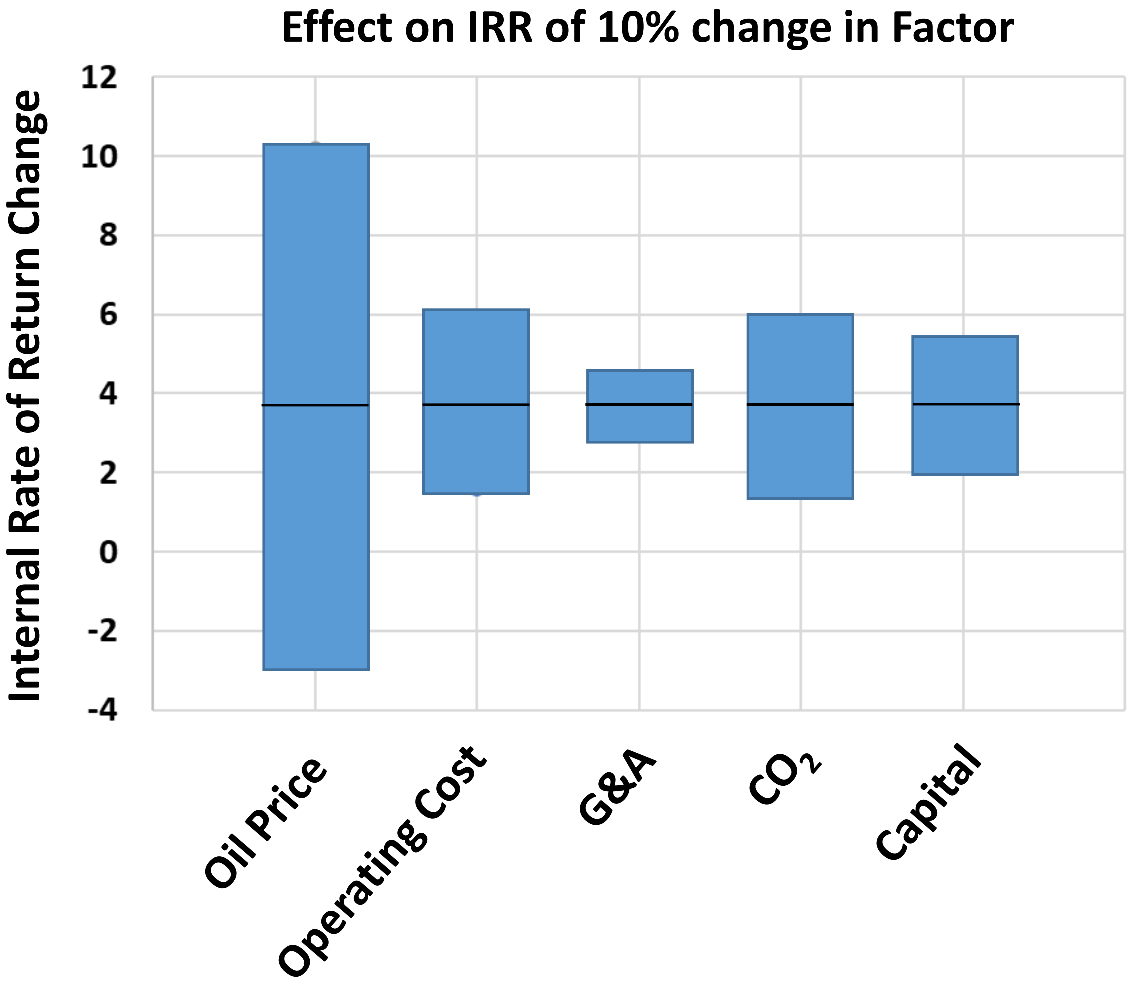


CO_2 Flood Economics at $50/BO

$ in millions	Undiscounted Cash Flows, $	Cash Flows Discounted at 10%, $
Revenues	1,702	803
Operating costs	(591)	(280)
Production taxes	(77)	(35)
G&A (overhead)	(152)	(85)
CO_2 purchases ($1.50/MCF)	(462)	(246)
Capital expenditures	(340)	(235)
Net cash flow	79	(77)

- This project will not be funded
- Additional metrics (before federal income tax)
  - IRR – 4% (11% excluding G&A)
  - Payout – 11.2 years (9.5 years excluding G&A)
  - CO_2 price as a % of oil price – 3.0%
- If the oil price were $60/BO
  - IRR – 16% (22% excluding G&A)
  - Payout – 8.6 years (6.2 years excluding G&A)
  - CO_2 price as a % of oil price – 2.5%
- The project would be on the edge of funding (long payout)

Profitability Dominated by Oil and CO_2 Prices



This chart is for the $50/BO case

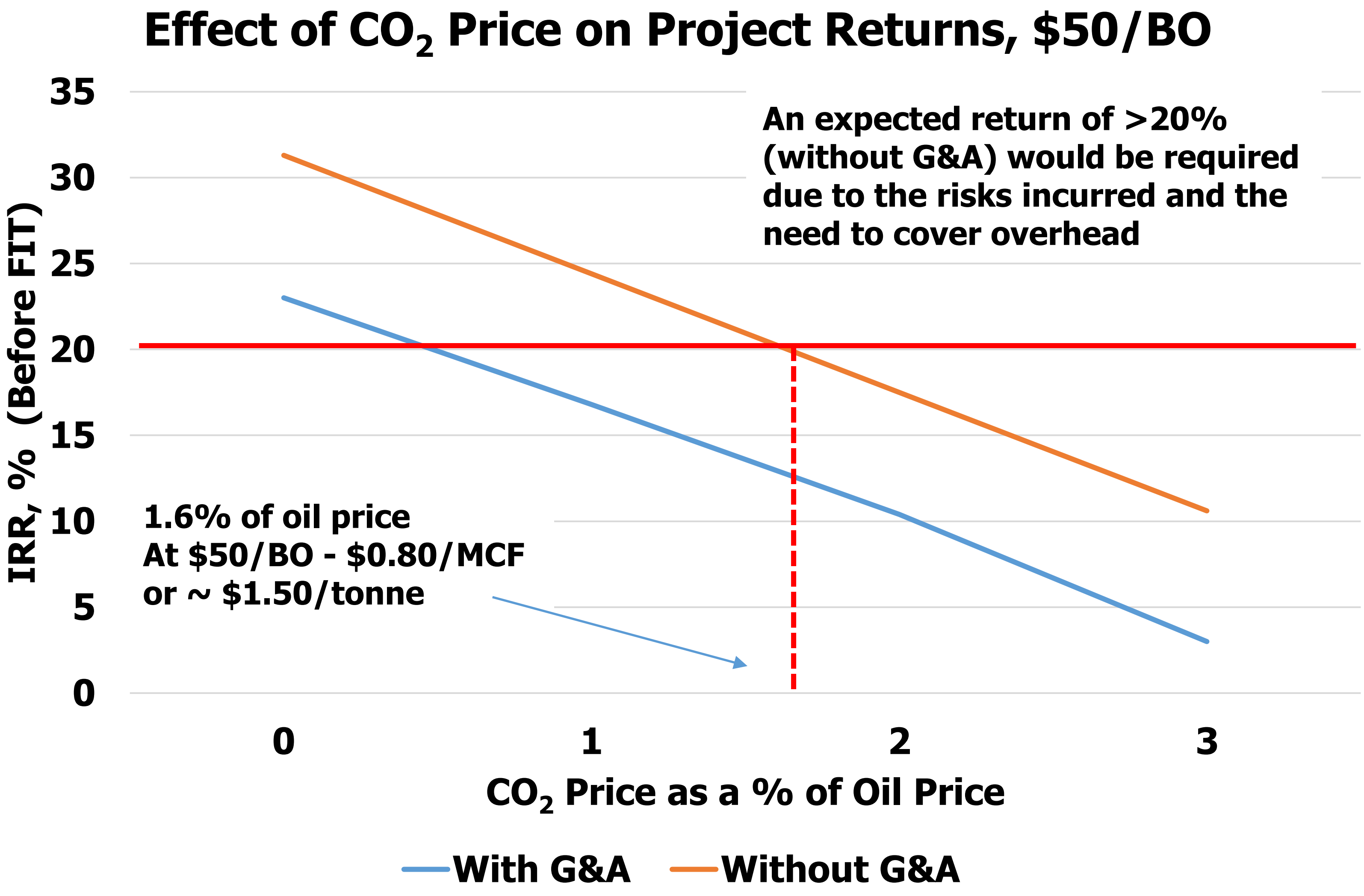
Many variables affect the operating and capital costs

Prior to reaching peak production in an area, forecasting the volume of oil produced in a specific month with the accuracy required to hedge production is difficult

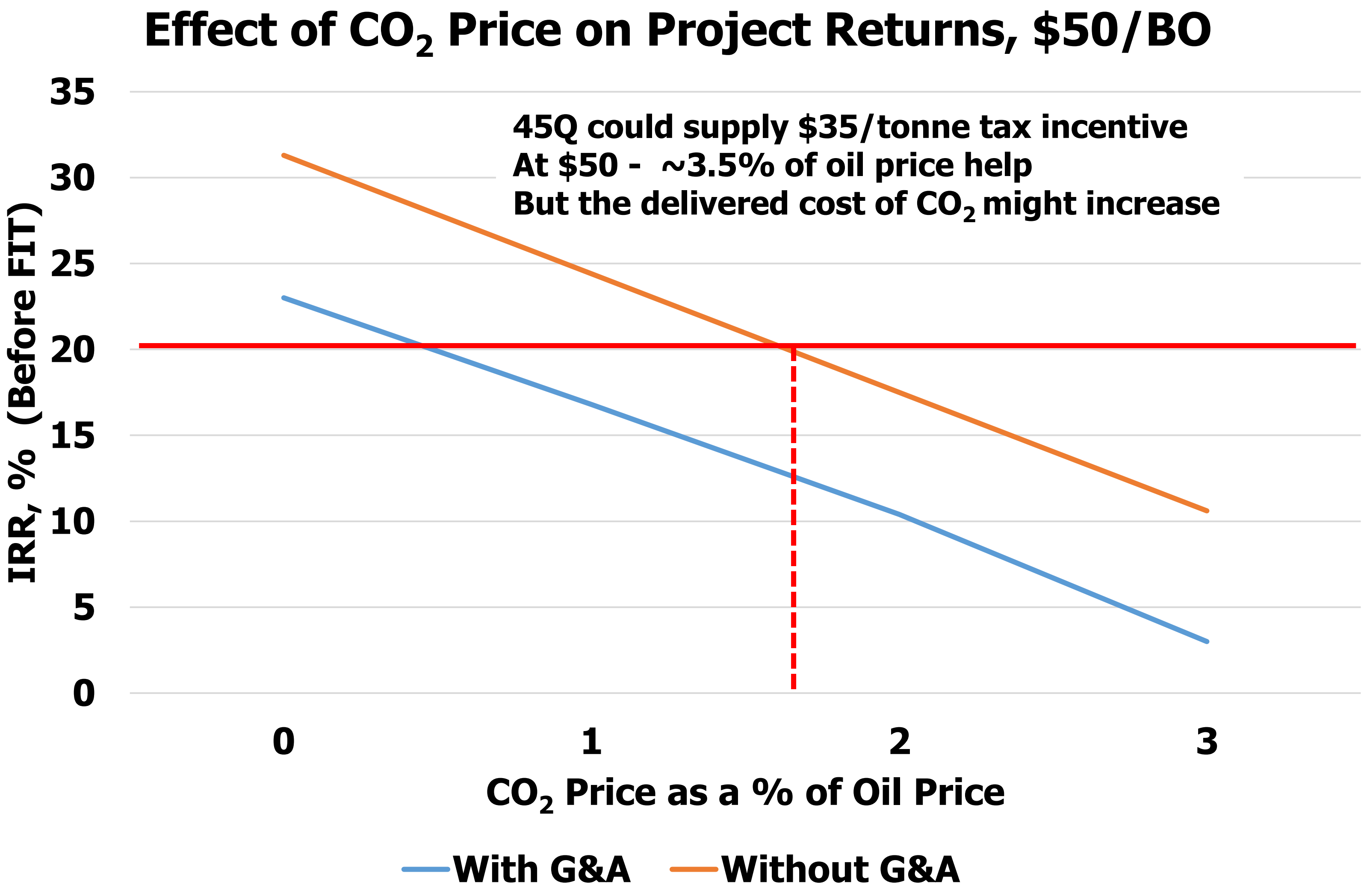
Producers often wish to tie CO_2 prices to oil prices

The incremental G&A in this case might be reduced if the project were developed by a large company

Lower CO_2 Prices Are Critical



But Wait – 45Q to the Rescue



Final Thoughts

- CO_2 floods have long payouts
  - May not fit the financial requirements of many companies
  - Exposes an investment to variations in oil prices that cannot be hedged
- CO_2 floods need higher oil prices
  - Generally > $60/BO
- CO_2 floods require large capital commitments
- The CO_2 price is a large factor in determining profitability
  - The project discussed is large and benefits from economies of scale (economically marginal with a CO_2 price of 2.5% of oil price)
  - Most smaller projects require delivered CO_2 prices of 2% of oil price (i.e. $100/BO requires $2.00/MCF)
- Incentives like 45Q could push projects over the goal line if capture costs are low enough

WINDY COVE ENERGY II

8. 45Q

Prepared by Oxy

OXY LOW CARBON VENTURES

Al Collins
VP Public Policy & External Engagement
Oxy Low Carbon Ventures

OXY LOW CARBON VENTURES

Bipartisan FUTURE Act Reforms 45Q

Section 45Q provides a performance-based tax credit for carbon capture projects when an eligible project has:

- Securely stored captured carbon in geologic formations, i.e. oil fields and saline formations; or
- Beneficially used captured carbon as a feedstock to produce fuels, chemicals, and products

Key Elements Reformed

1. Increased Credit Value
2. Expanded Eligibility
3. Credit cap lifted
4. Redefined capture thresholds
5. Increased transferability

Value Depends on Project Type

$35/ton	CO_2 Stored Geologically through EOR
$35/ton	CO_2 Utilization outside EOR
$50/ton	CO_2 stored in other geologic formations outside EOR

Tax credit increases linearly from 2017 to 2026 from previous 45Q tax credit base values

Adapted from GPI Primer: 45Q Tax Credit for Carbon Capture Projects

45Q Eligibility

The party eligible to claim the tax credit is the owner of the capture equipment. That party must physically or contractually ensure the storage or utilization of the CO2 or CO and may elect to transfer the credit to another party that stores or puts the CO_2 or CO to beneficial use.

Annual carbon capture thresholds

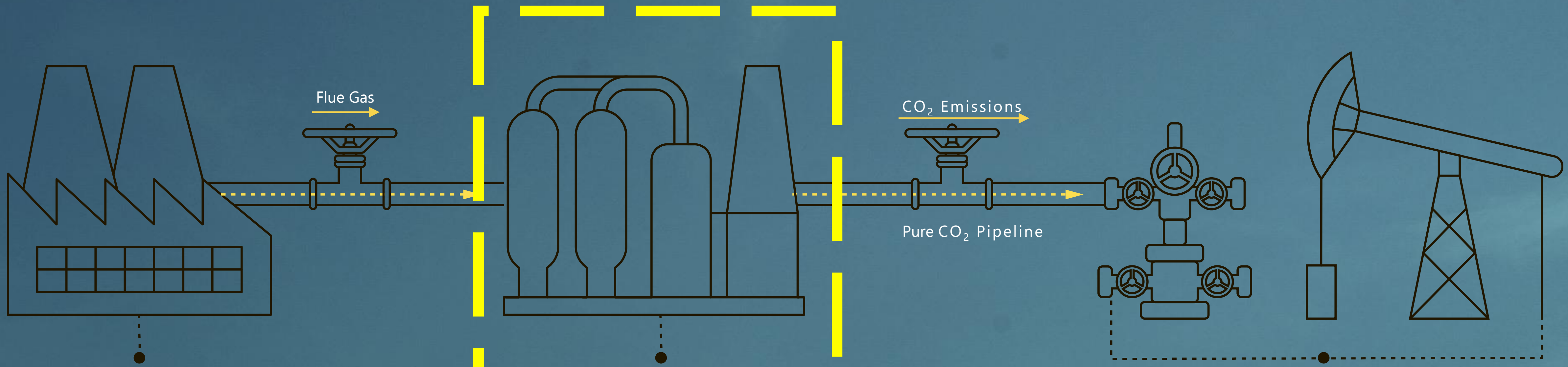
25,000–500,000 metric tons of CO_2/CO --------- Beneficial use products other than EOR projects	**At least 100,00 Metric tons of CO_2/CO** --------- All other industrial facilities (other than electrical generating units, including direct air capture)	**At least 500,000 metric tons of CO_2/CO** --------- Electric generating units

Type of carbon: The type of carbon that can be captured includes all carbon oxides, including CO2 or CO.

Timing: Eligible projects that begin construction within six years of the FUTURE Act's enactment (i.e., before January 1, 2024) can claim the credit for up to 12 years after being placed in service.

Adapted from GPI Primer: 45Q Tax Credit for Carbon Capture Projects

Model 45Q Credit Allocation for Industrial Capture



Industrial Emissions Source

CO_2 CAPTURE PLANT

The owner of the carbon capture equipment is the party eligible to claim the 45Q tax credit

Must physically or contractually ensure permanent CO_2 storage

Permanent CO_2 Sequestration in geologic formations

EPA Monitor Reporting and Verification plans certify permanent storage

SEQUESTRATION 101:

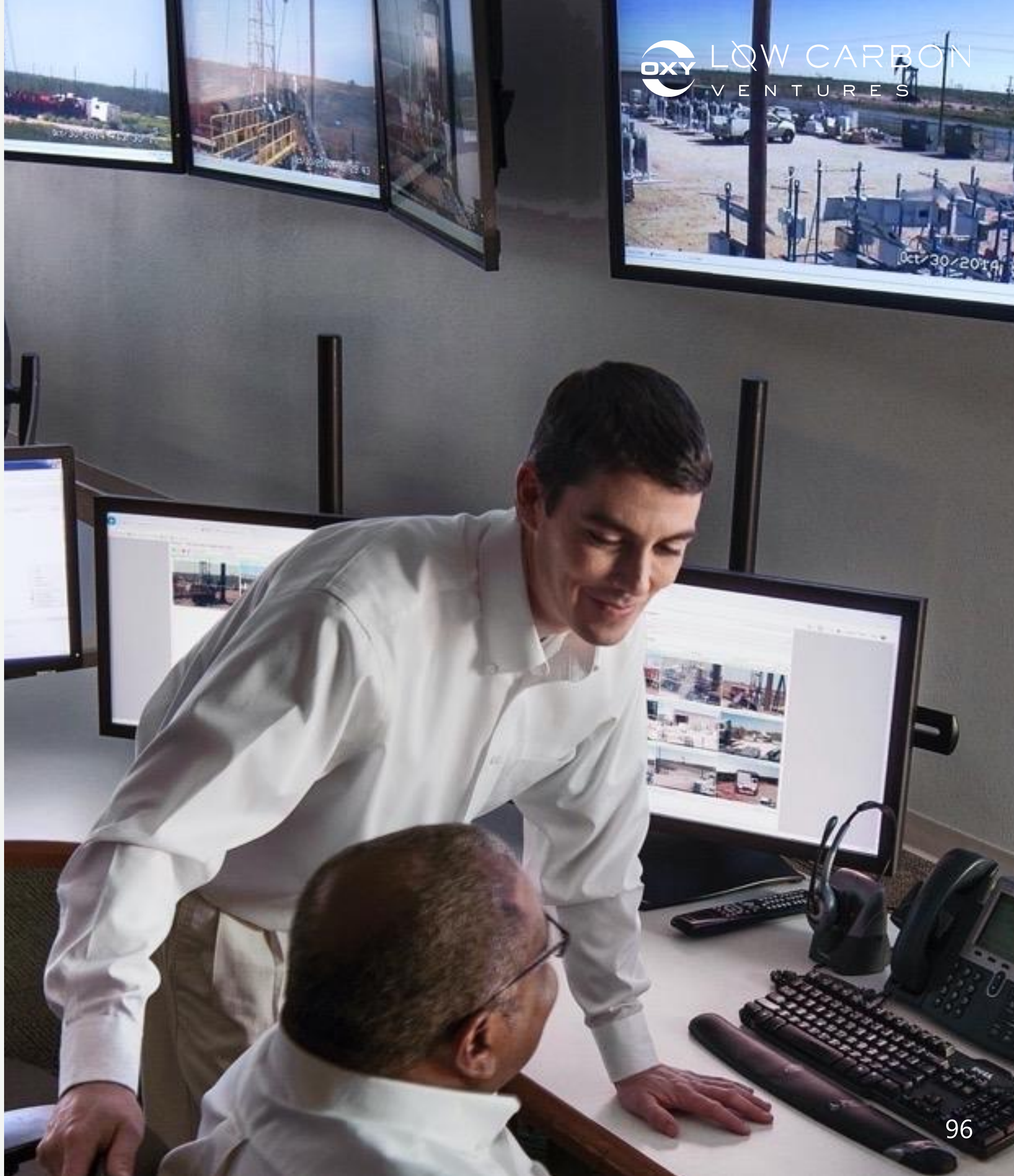
MRV Programs

Monitoring, Reporting & Verification

- Oxy developed the first two U.S. EPA-approved MRVs.
- MRVs include a transparent methodology and accounting protocol for calculating, monitoring and public reporting of sequestered CO_2
- Oxy surface equipment designed with redundancy and failsafe programs.
- Remote monitoring & intervention technologies maximize site safety and mitigate risk
- Flow meters, pressure sensors and temperature gauges throughout facilities monitor surface and subsurface activity with exception surveillance and alarm systems

MRV Programs Include:

- Loss detection and repair programs
- Mechanical integrity programs
- Preventative maintenance programs
- Infrared inspections and monitoring
- Regular field inspections

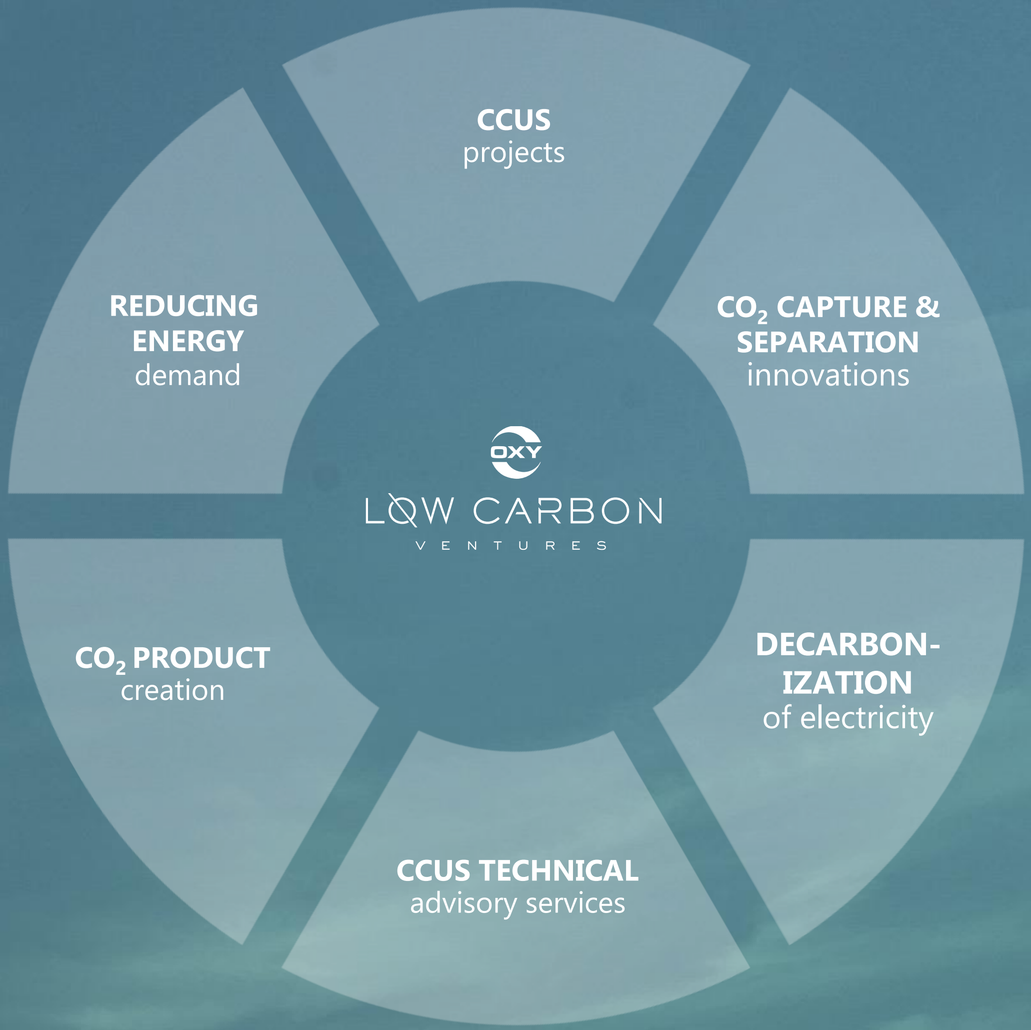


Oxy Low Carbon Ventures

Oxy Low Carbon Ventures was formed to sustainably enhance Occidental's business, while providing impactful global emissions reduction solutions.

This group is dedicated to:

- Global Leadership in providing low-carbon solutions and advisory services to support a sustainable energy and development future
- Leveraging our 40 years of expertise in carbon management and large-scale carbon dioxide separation, transportation, use and storage to develop CCUS projects
- Directly reducing Occidental's Scope 1–3 emissions
- Increasing energy efficiency



White Energy and Oxy

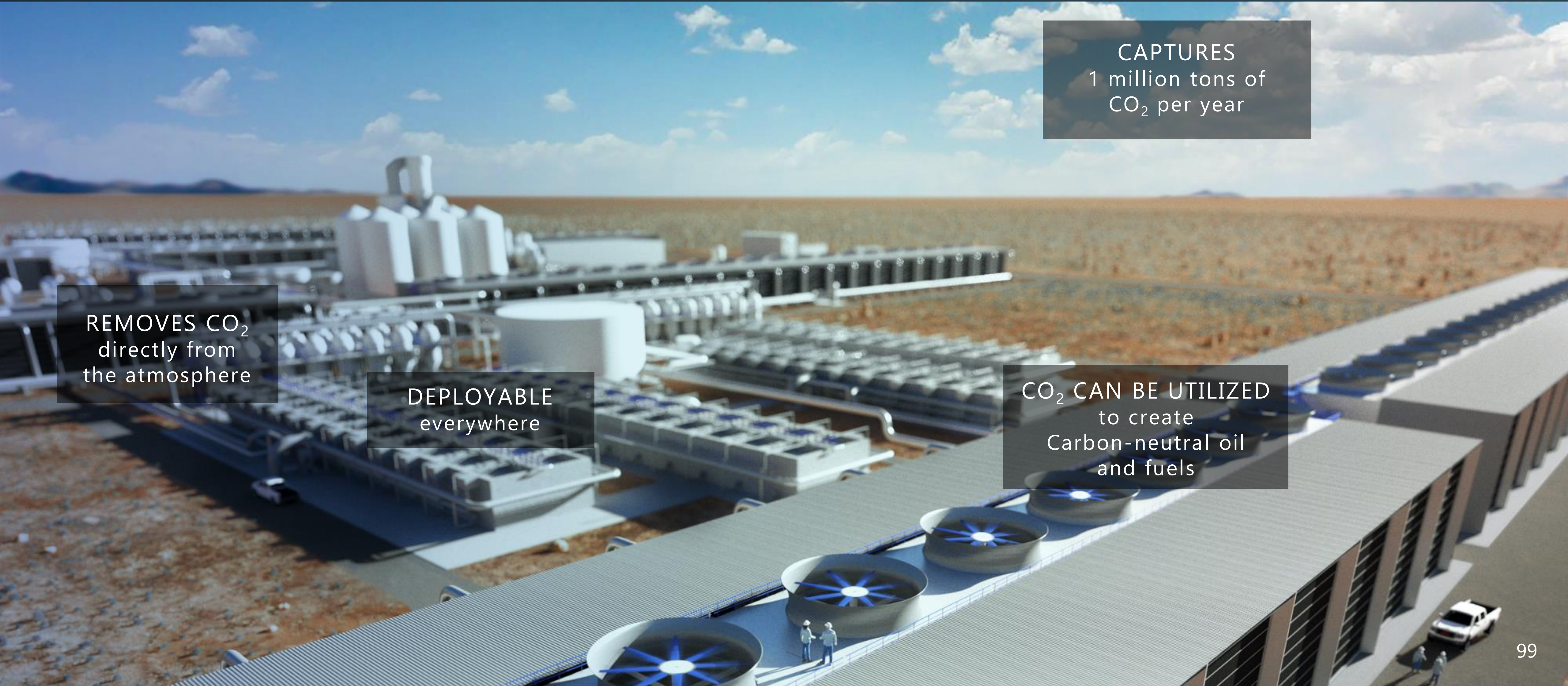
Project Overview

- First announced project under the FUTURE Act (45Q)
- Develop carbon capture and transport of CO_2 from White Energy's two ethanol plants in the Texas panhandle
- Capture up to 700,000 MTPA CO_2
- Transport captured CO_2 to an approved CARB/MRV field in the Permian Basin

White Energy is a producer of biofuels in Texas. The company owns and operates two ethanol plants with the capacity to produce 250 million gallons per year.

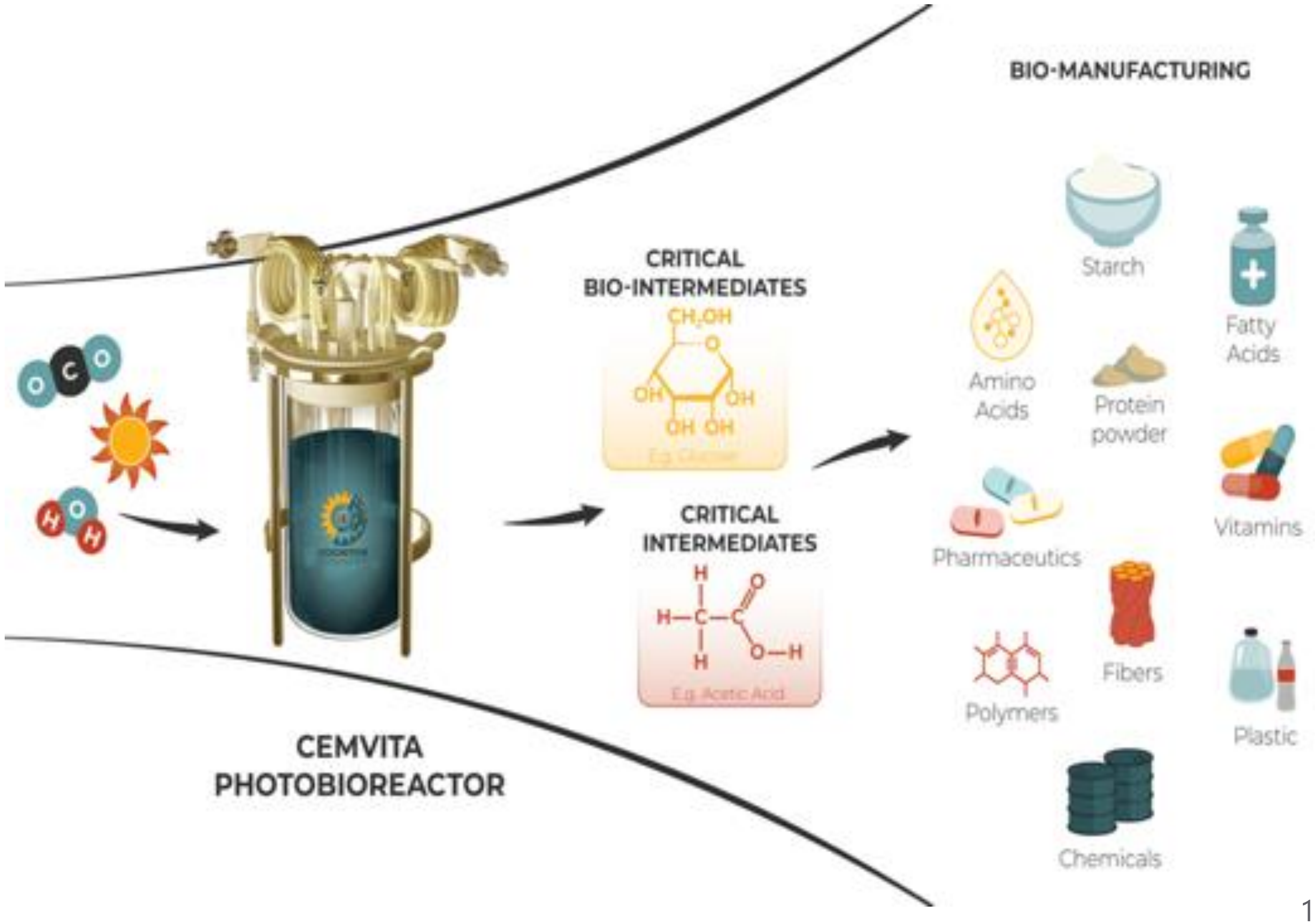
Carbon Engineering

Direct Air Capture Technology

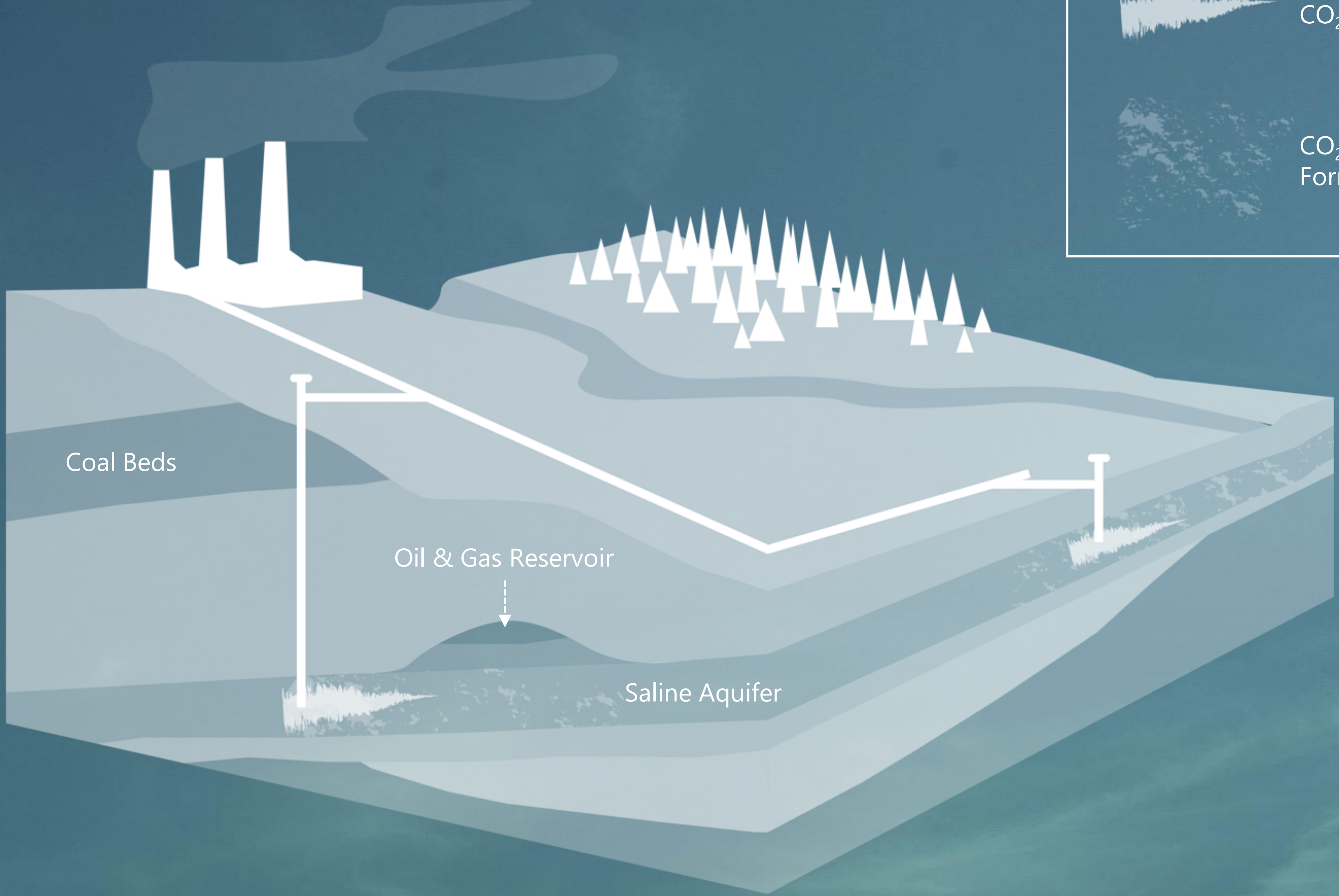


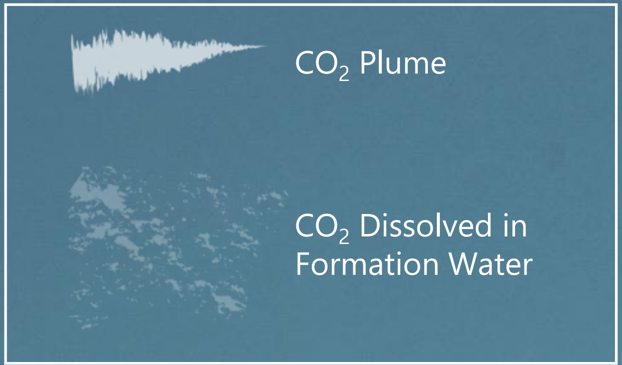
Cemvita Factory

- Using genetically engineered Cyanobacteria to make products
- Bio-ethylene, Bio-VCM
- Oxy Low Carbon Ventures leveraging chemical expertise to advise on development of technology



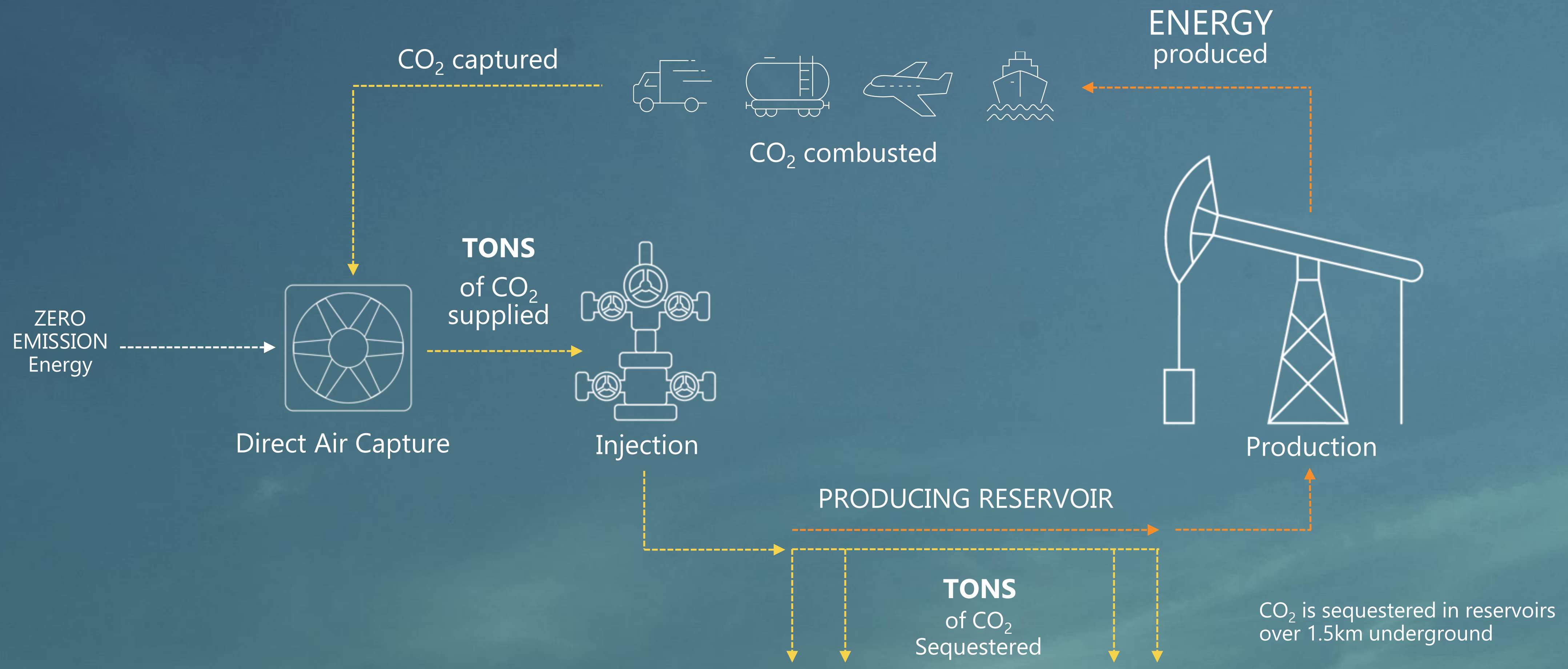
Dedicated Sequestration Hubs





The Carbon-Neutral Energy Cycle

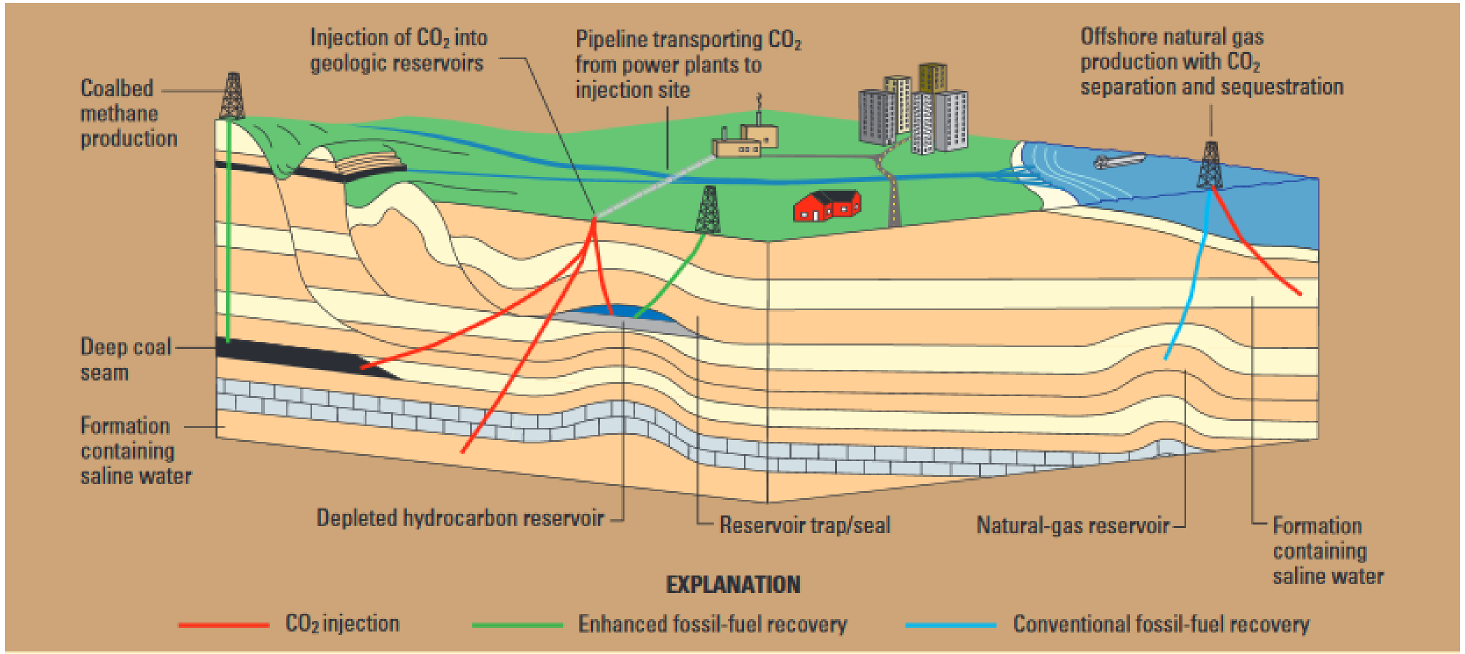
Sequestering carbon. Creating a carbon-neutral fuel.



WINDY COVE ENERGY II

9. Other Storage Options: Gas Fields, Saline Reservoirs and Coal Beds

Options



	Oil and gas reservoirs	Formations containing saline water	Unmineable coal beds
Advantages:	• Well-characterized volume • Known seal • Potential fuel recovery to offset cost	• Largest capacity (~250 to 900 gigatons carbon) • Wide distribution	• Adjacent to many large power plants (CO_2 source) • Potential fuel (methane) recovery to offset cost
Disadvantages:	• Smallest capacity (~25 gigatons carbon) • Limited in number • Requires infrastructure to transport CO_2	• Poorly characterized • Greatest geologic uncertainty • Unknown seal effectiveness	• Poorly characterized • Difficult to define "unmineable" coal • Potential coal resources may be rendered unusable
Environmental issues:	Potential for mobilization of ground-water contaminants; leakage of CO_2 and CO_2-saturated saline water; induced seismicity		
Regulatory issues:	Determination of rules affecting injection wells; multiple regulatory jurisdictions (State, Federal, local); post-injection ownership and liability		

Source: "Carbon Sequestration to Mitigate Climate Change", Factsheet 2008-3097, U.S. Department of Interior, U.S. Geological Survey, December 2008.

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

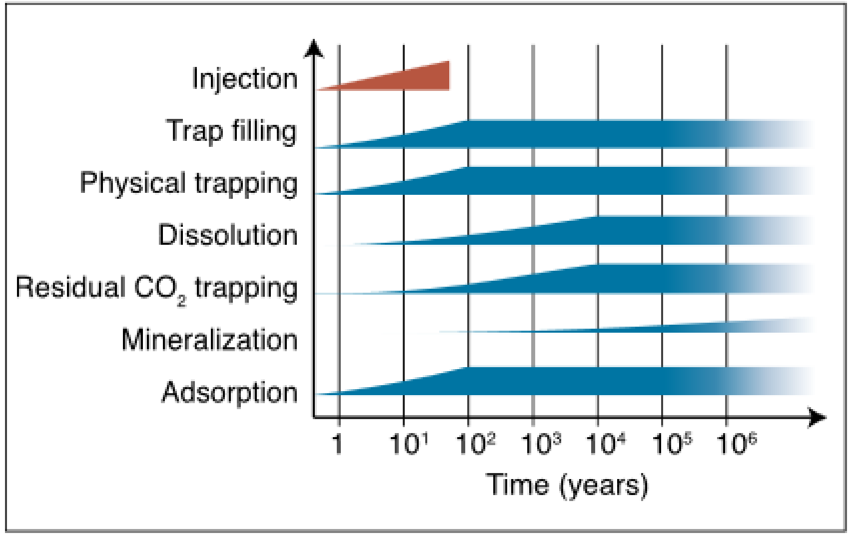


Figure 5.18 Schematic showing the time evolution of various CO_2 storage mechanisms operating in deep saline formations, during and after injection. Assessing storage capacity is complicated by the different time and spatial scales over which these processes occur.

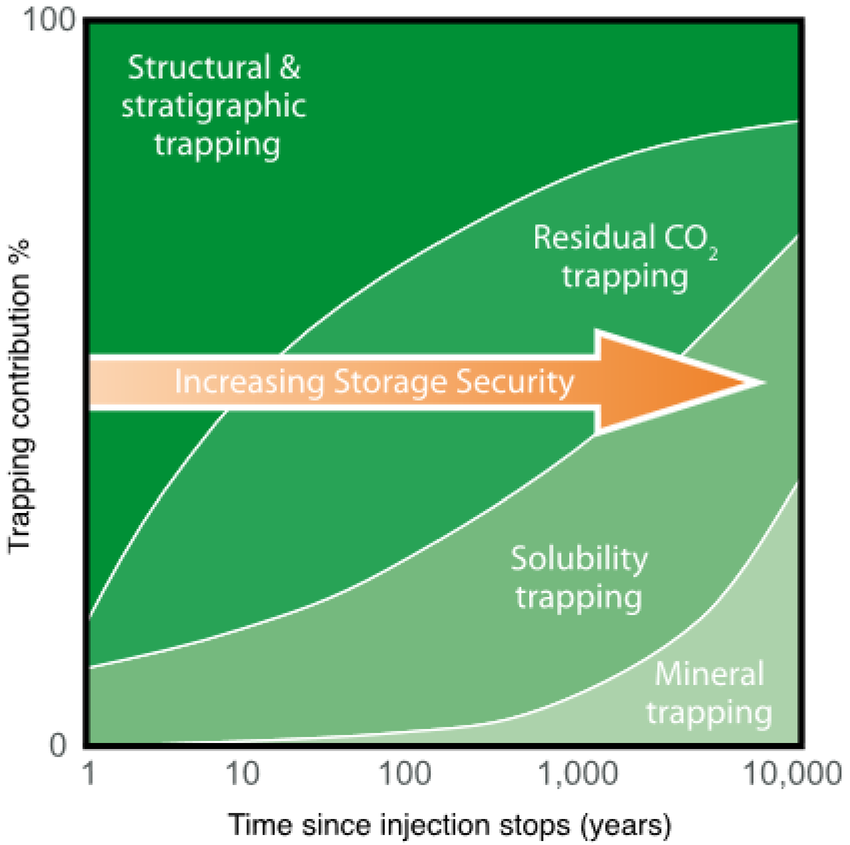


Figure 5.9 Storage security depends on a combination of physical and geochemical trapping. Over time, the physical process of residual CO_2 trapping and geochemical processes of solubility trapping and mineral trapping increase.

Source: IPCC, Carbon Dioxide Capture and Storage

Gas Field Example – In Salah

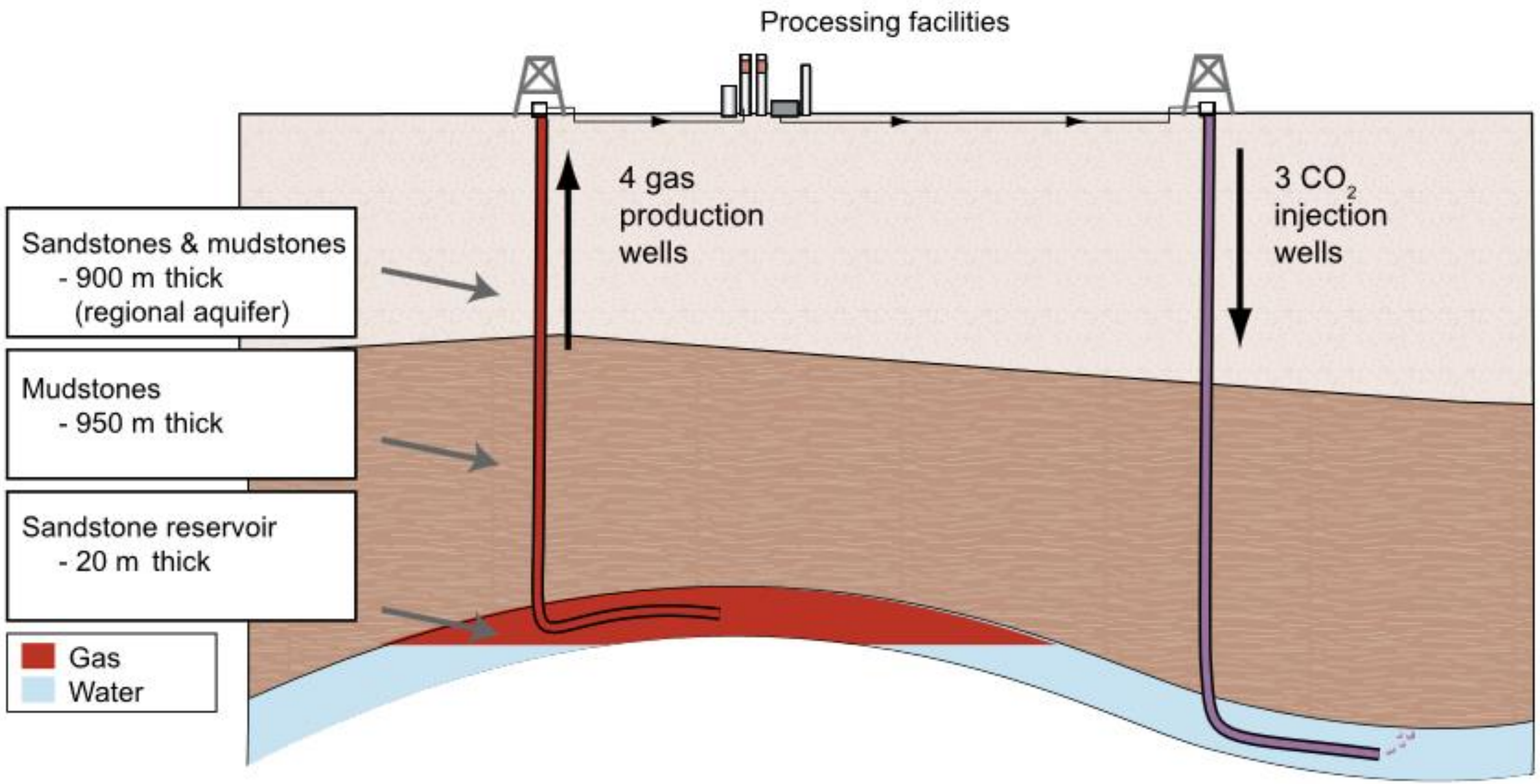
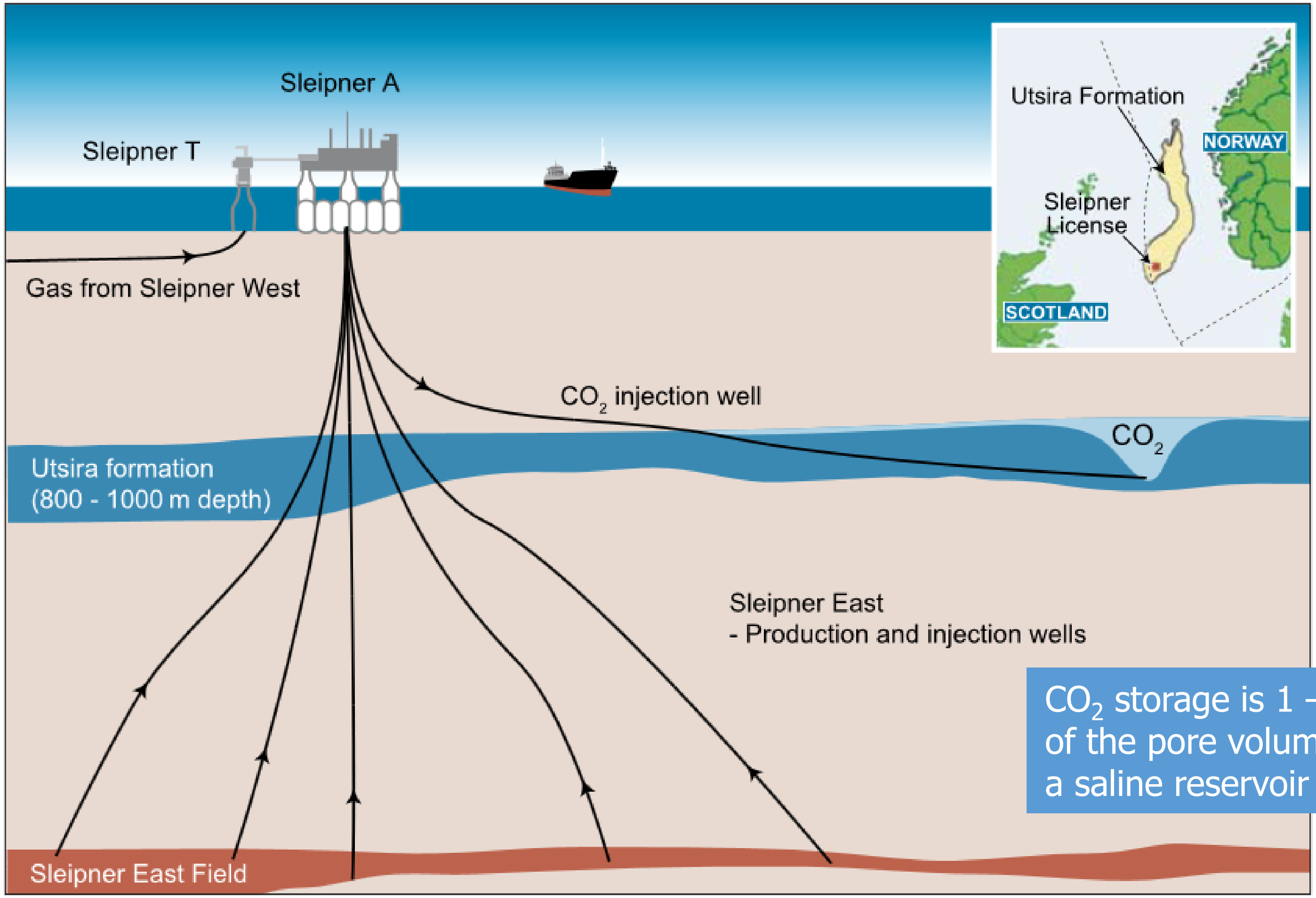


Figure 5.5 Schematic of the In Salah Gas Project, Algeria. One MtCO_2 will be stored annually in the gas reservoir. Long-reach horizontal wells with slotted intervals of up to 1.5 km are used to inject CO_2 into the water-filled parts of the gas reservoir.

Source: IPCC, Carbon Dioxide Capture and Storage

Saline Reservoir Example – Sleipner



CO_2 storage is 1 – 4% of the pore volume in a saline reservoir

Figure 5.4 Simplified diagram of the Sleipner CO_2 Storage Project. Inset: location and extent of the Utsira formation.

Source: IPCC, Carbon Dioxide Capture and Storage

Coal Bed Methane

- Coal contains permeable fractures (cleats)
- Between cleats solid coal has numerous micropores
- Coal can adsorb many gases
- If CO_2 is injected, it will displace methane enhancing recovery (revenue source)
- Unfortunately, CO_2 swells the coal which may adversely affect permeability

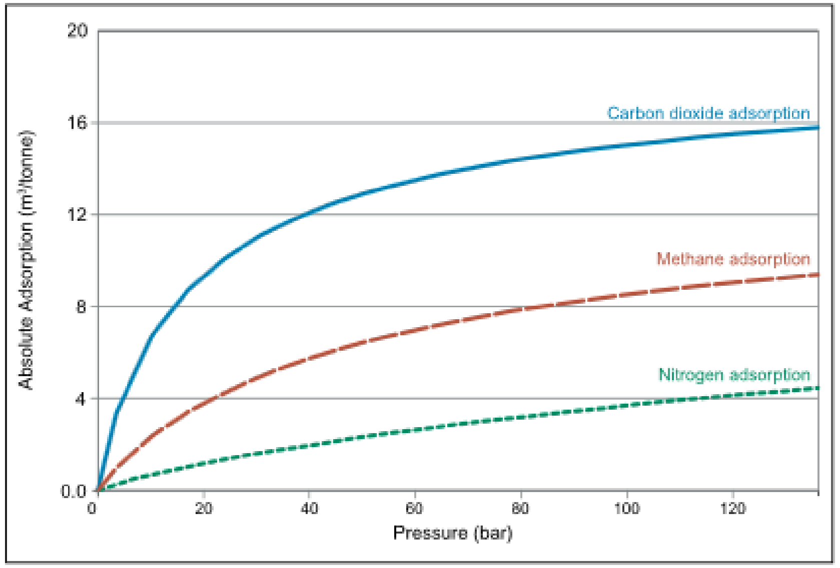


Figure 5.17 Pure gas absolute adsorption in standard cubic feet per tonne (SCF per tonne) on Tiffany Coals at 55°C (after Gasem et al., 2002).

Source: IPCC, Carbon Dioxide Capture and Storage

The adsorption isotherms (above) show that CO_2 preferentially adsorbs onto the coal. If the pressure is maintained, the CO_2 should stay trapped. Further, it seems that absorption gradually replaces adsorption, and the CO_2 diffuses or "dissolves" in the coal.

10 – Minute Break

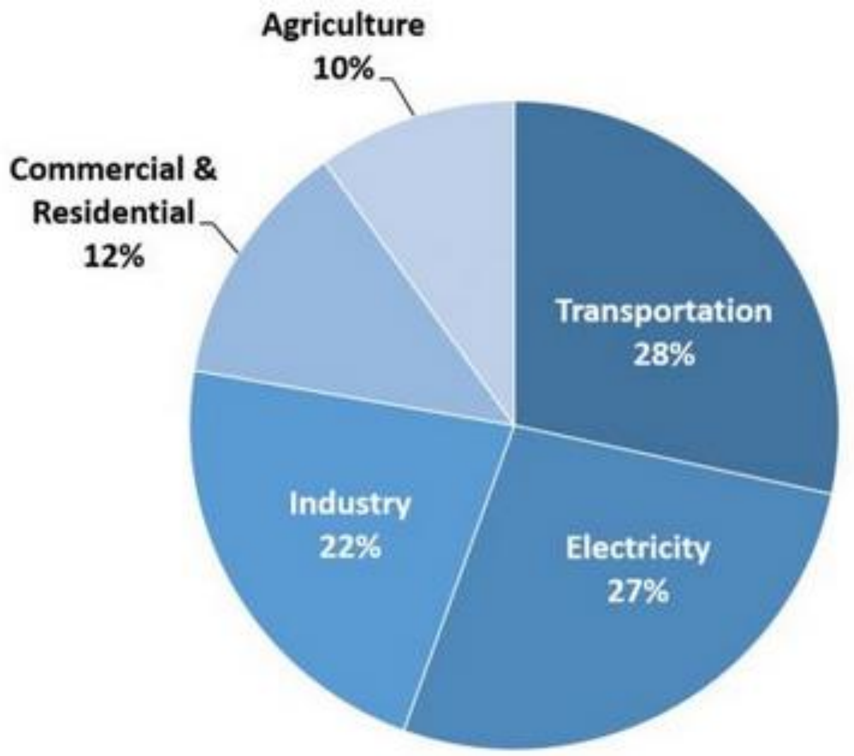
The workshop will continue at 1:45pm CT

INTERSTATE Oil & Gas COMPACT COMMISSION

WINDY COVE ENERGY II

Capture & Transportation

Sources of Greenhouse Gas Emissions

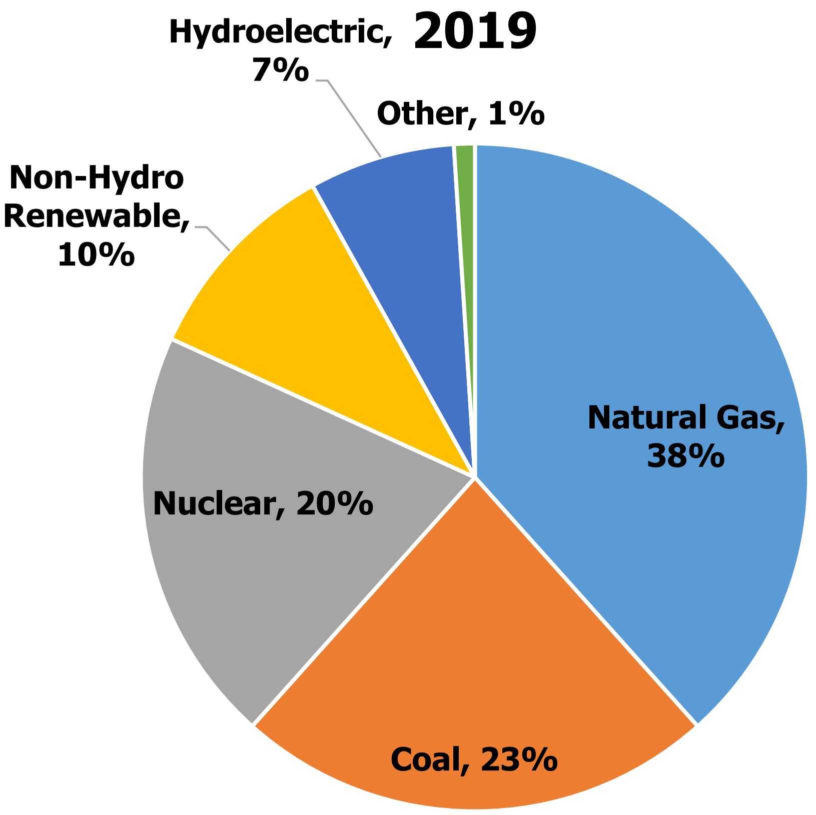


80-85% of GHG emissions are from CO_2

2018 U.S. GHG Emissions – 6,677 tonnes

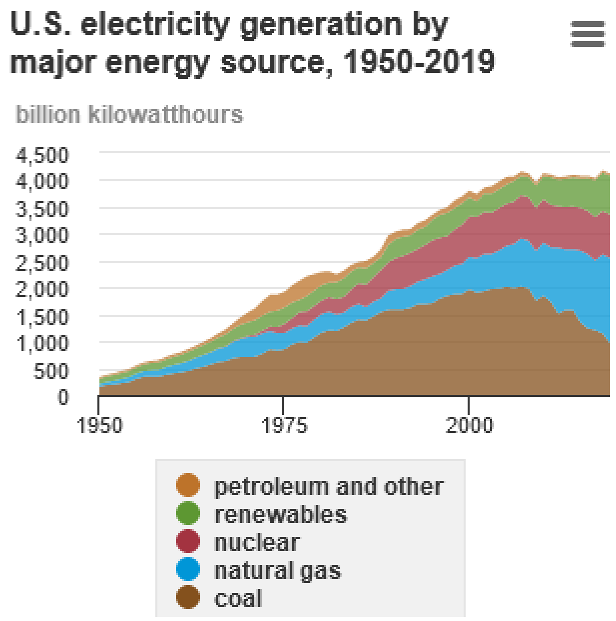
Source: https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions

U.S. Electricity Generation



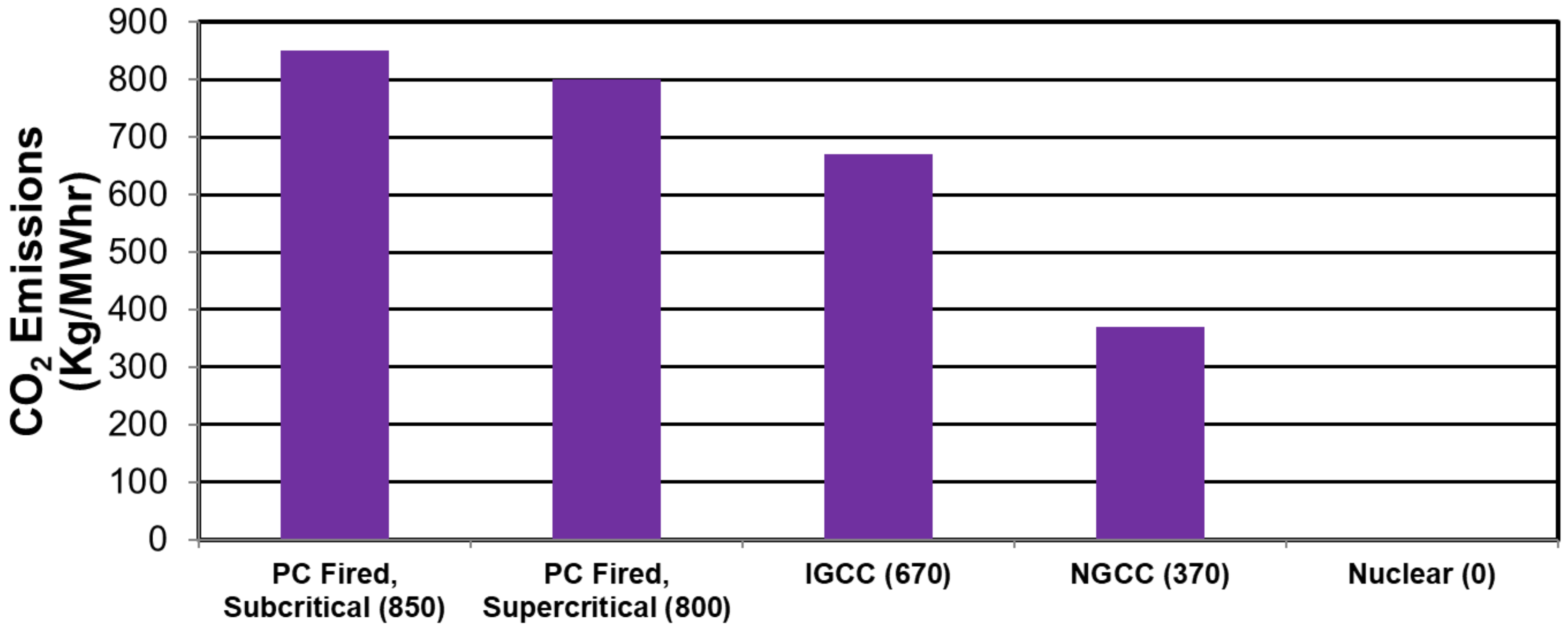
Natural gas and coal are the major sources of CO_2 for CCUS

Coal use is rapidly declining



Source: EIA.gov

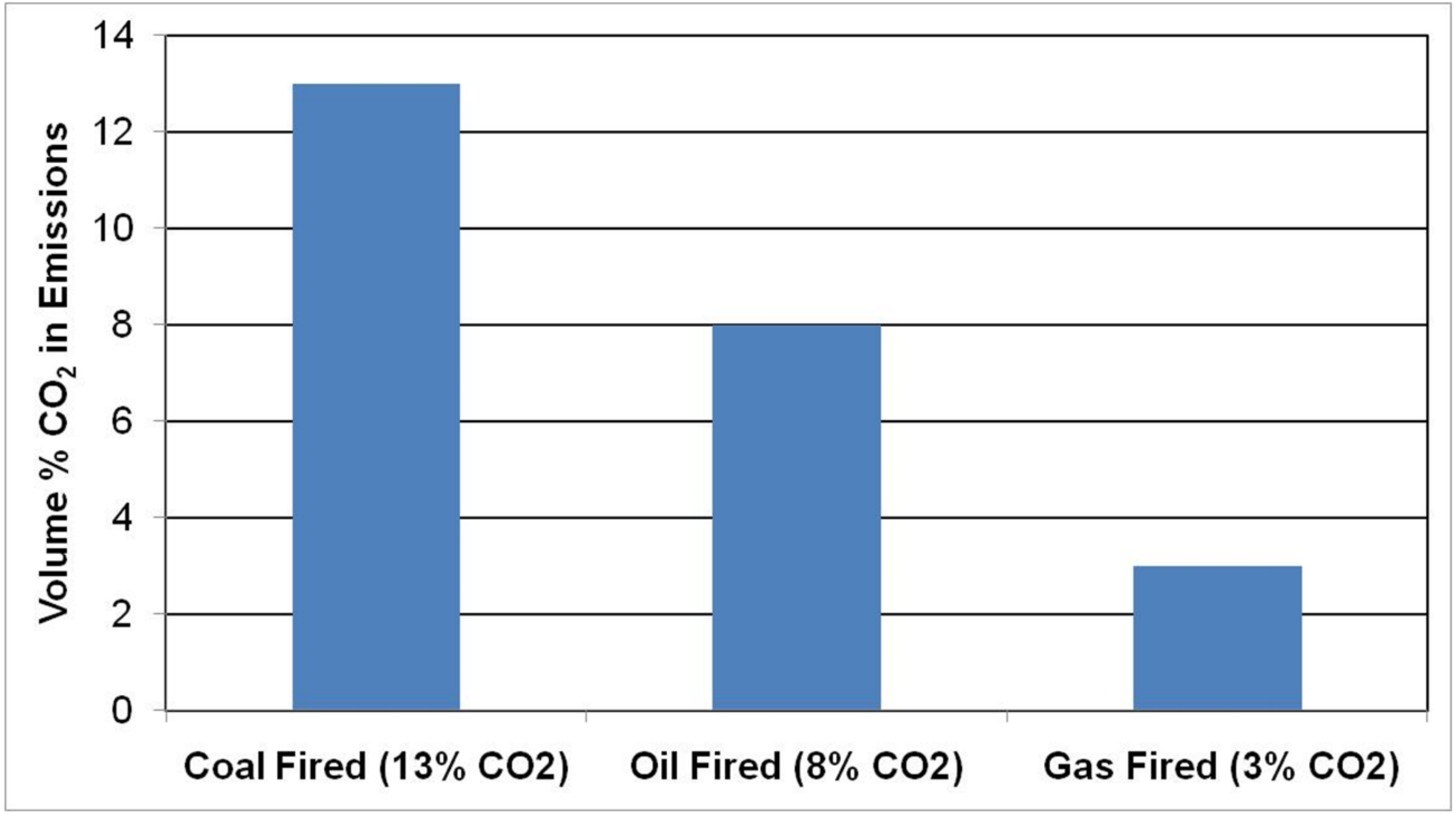
CO_2 Emissions from Power Plants



- PC-Fired-Subcritical → Pulverized-coal fired plant with subcritical steam cycle
- PC-Fired-Supercritical → Pulverized-coal fired plant with supercritical steam cycle
- IGCC → Integrated coal gasification combined cycle plant
- NGCC → Natural-gas-fired combined cycle (NGCC) plant

Source: Bechtel

CO_2 Content in the Flue Gas



Source: Mariz, C.L. “Carbon Dioxide Recovery: Large Scale Design Trends”, JCPT, July 1998

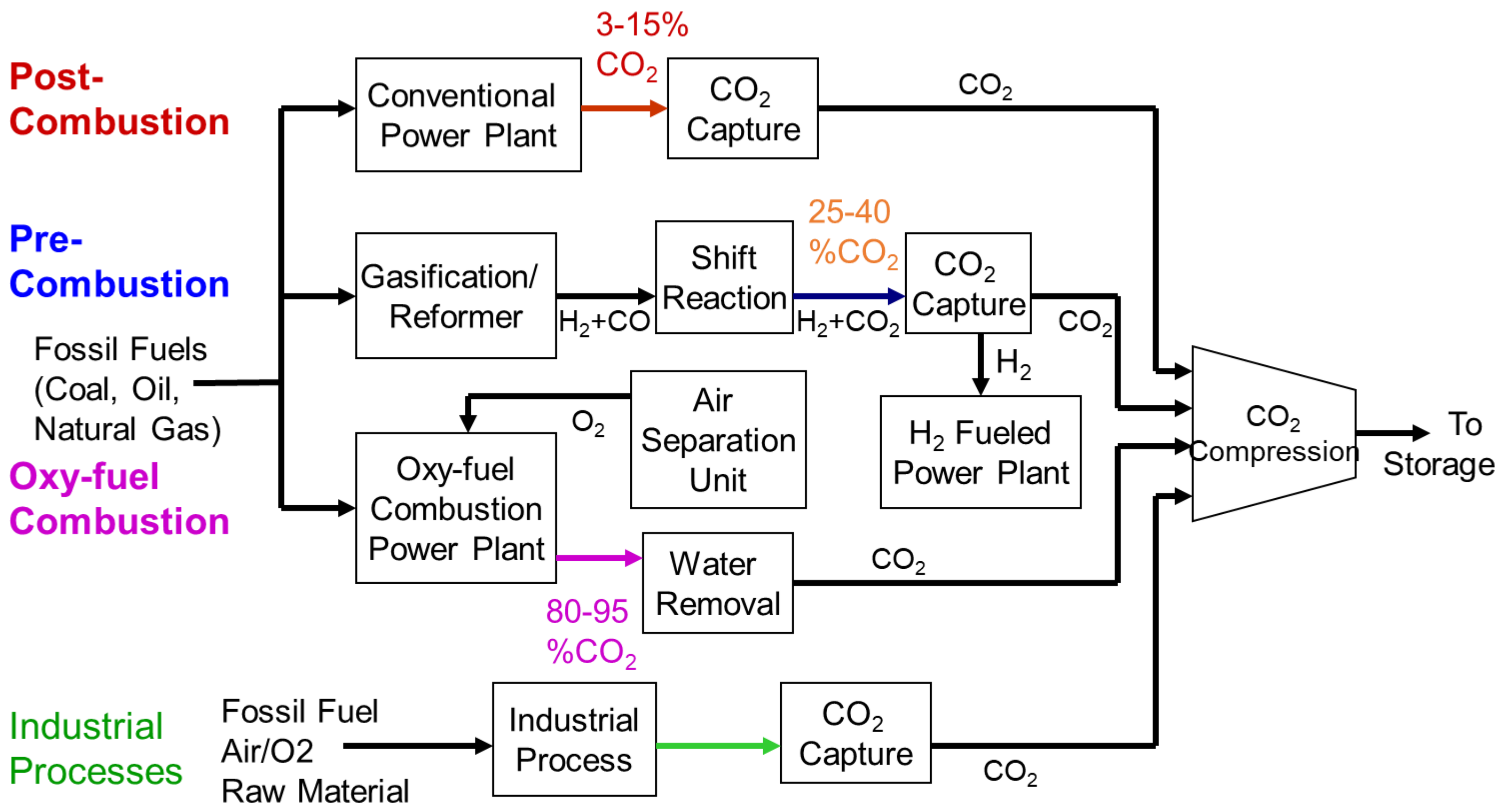
Power/Non-Power Emission Sources

Process	Percent CO_2 in Gas	World Emissions (Mt/yr)[1]	Percent of World Emissions	Average Emission per Source (Mt/yr) [1]
Power Plant[2]	3-15	10,539	79.0	2.13
Cement	2	932	7.0	0.79
Refinery	3-13	798	6.0	1.25
Steel Mill	15	630	4.7	3.50
Ethylene	12	258	1.9	1.08
Ammonia	100	113	0.8	0.58
Other		105	0.6	0.49
Total		13,375	100.0	

[1]Million tonnes per year
[2]The average annual emission from a coal plant is 3.96 Mt/yr

Source: Table 2.3 IPCC Report – Carbon Dioxide Capture and Storage, 2005

Capture Methods



Ammonia Plants 100 % CO_2, Refineries 12 – 75% CO_2

Cement Plants 15-25 % CO_2, Iron and Steel Works 15-20 % CO_2

Cost

- According to a 2017 Forbes article*
  - Used data from U.S. EIA and NETL
  - Capturing CO_2 from a new supercritical coal plant adds $59/MW-hr to electricity costs
  - Or the CO_2 capture cost is $70.70/tonne ($3.70/MCF)
  - Tax credits for wind and solar are ~$20-$25/MW-hr
- Capturing CO_2 from a natural gas plant likely costs more
- The cost to capture, dehydrate and compress pure CO_2
  - From 0 to 2000 psig is approximately $11/tonne ($0.60/MCF)
- Principle: If you have nearly pure CO_2, 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 CO_2 for use in oil fields.

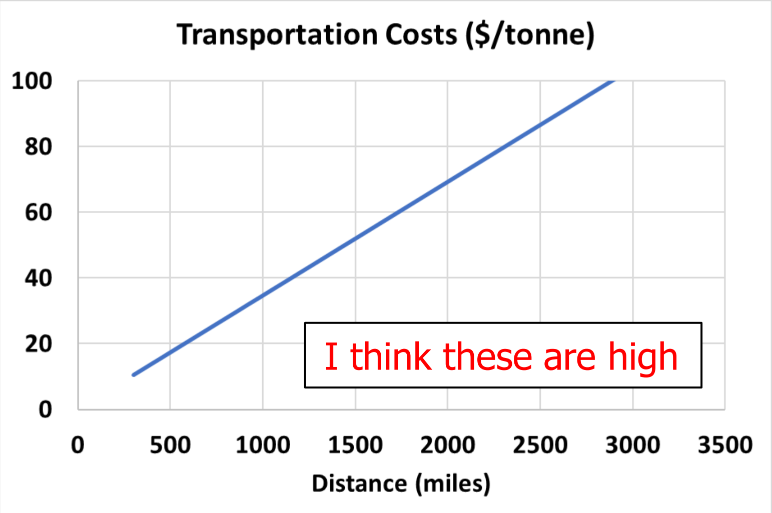
Kemper County Coal Plant
Source: Wiki Commons

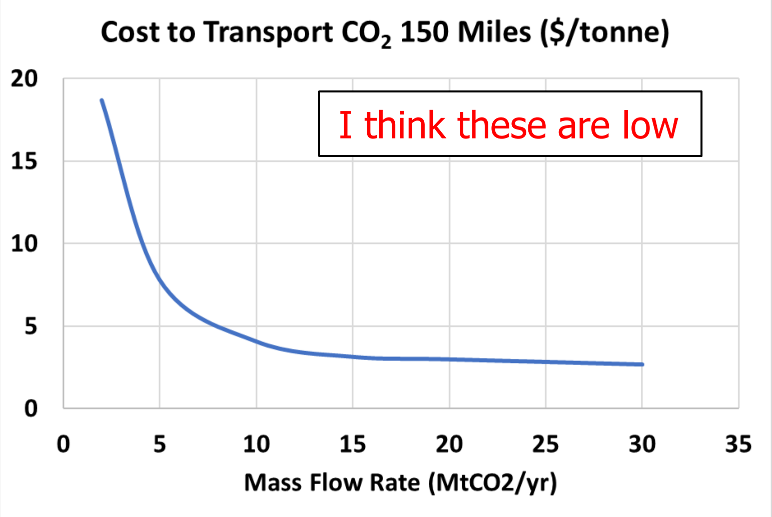
Southern Company's Kemper County IGCC plant with CO_2 capture was originally forecast to cost $2.2 billion. As of 2017 the completion cost had risen to $7.3 billion. Southern decided to switch to natural gas.

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

CO_2 Pipeline Transportation

- Practiced for almost 50 years
- Regulated by PHMSA under 49CFR195
- Operates at higher pressures generally 1450 – 2600 psig





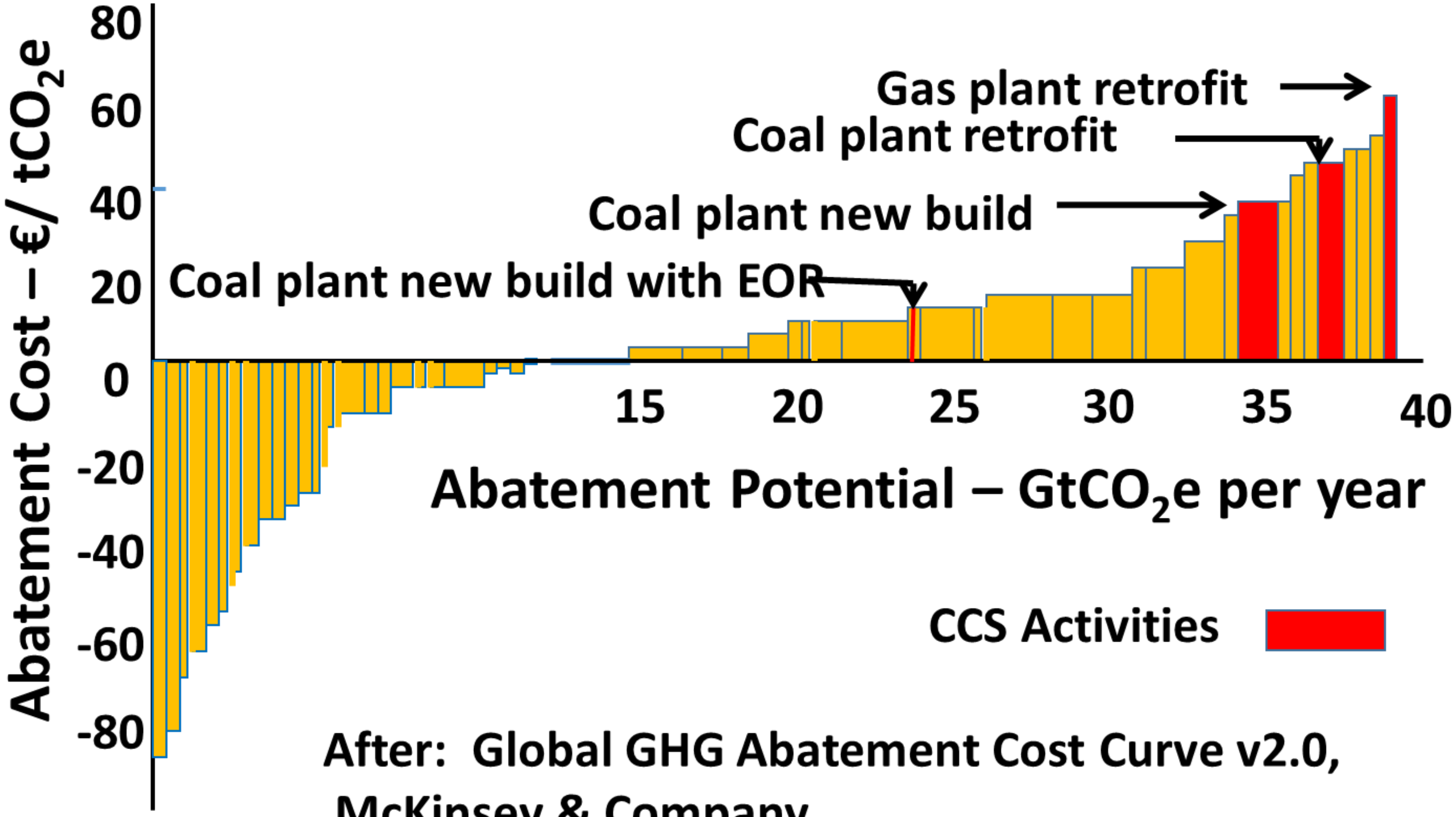
After Figures 4.5 and 4.6 in IPPC Carbon Capture and Storage Report, 2005 and updated for inflation

Common U.S. Quality Specifications

CO_2	95%	Min	MMP Concern
Nitrogen	4%	Max	MMP Concern
Hydrocarbons	5%	Max	MMP Concern
Water	30 lbs/MMcf	Max	Corrosion
Oxygen	10 ppm	Max	Corrosion
H_2S	10 – 200 ppm	Max	Safety
Glycol	0.3 gal/MMcf	Max	Operations
Temperature	120 deg F	Max	Materials

12. Fitting It All Together

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 CO_2 will stay in the ground
- We know CCUS can work economically in some cases
  - Val Verde Basin natural gas/CO_2 separation plants provided CO_2 to start CO_2 flooding in 1970s
  - Dakota Gasification Plant (IGCC) 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 CO_2 sources near oil fields which only require dehydration and compression
- Tax credits such as 45Q help pay to transport CO_2 farther from the pure CO_2 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

Thank you for joining us today!

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Please submit topic ideas to Amy Childers at

amy.childers@iogcc.state.ok.us   or 405-522-8384