Denbury

Corporate Presentation

May 2021

Cautionary Statements

Forward-Looking Statements: The data and/or statements contained in this presentation that are not historical facts are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, the timing and sustainability of the recent recovery in worldwide oil prices from their COVID-19 coronavirus caused downturn, financial forecasts, future hydrocarbon prices and their volatility, current or future liquidity sources or their adequacy to support our anticipated future activities, statements or predictions related to the scope, timing and economic aspects of the anticipated carbon capture, use and storage industry, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected production levels, oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows, availability of capital, borrowing capacity, price and availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, the nature of any future asset purchases or sales or the timing or proceeds thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, including Cedar Creek Anticline ("CCA"), or the availability of capital for CCA pipeline construction, or its ultimate cost or date of completion, timing of CO_2 injections and initial production responses in tertiary flooding projects, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, the impact of regulatory rulings or changes, outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions, and other variables surrounding operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," "may" or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; decisions as to production levels and/or pricing by OPEC or production levels by U.S. shale producers in future periods; levels of future capital expenditures; success of our risk management techniques; accuracy of our cost estimates; access to and terms of credit in the commercial banking or other debt markets; fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, floods, forest fires, or other natural occurrences; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including changes in tax or environmental laws or regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this presentation, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

Statement Regarding CO_2 Storage Associated with EOR: Our CO_2 EOR operations provide an environmentally responsible method of utilizing CO_2 for the primary purpose of oil recovery that also results in the associated underground storage of CO_2. Any reference in this presentation to storage of CO_2 associated with our EOR operations is not meant to encompass CO_2 stored for the primary purpose of carbon sequestration.

Statement Regarding Non-GAAP Financial Measures: This presentation also contains certain non-GAAP financial measures. Any non-GAAP measure included herein is accompanied by a reconciliation to the most directly comparable U.S. GAAP measure along with a statement on why the Company believes the measure is beneficial to investors, which statements are included at the end of this presentation.

Note to U.S. Investors: Current SEC rules regarding oil and gas reserves information allow oil and gas companies to disclose in filings with the SEC not only proved reserves, but also probable and possible reserves that meet the SEC's definitions of such terms. We disclose only proved reserves in our filings with the SEC. Denbury's proved reserves as of December 31, 2019 and December 31, 2020 were estimated by DeGolyer and MacNaughton, an independent petroleum engineering firm. In this presentation, we may make reference to probable and possible reserves, some of which have been estimated by our independent engineers and some of which have been estimated by Denbury's internal staff of engineers. In this presentation, we also may refer to one or more of estimates of original oil in place, resource or reserves "potential," barrels recoverable, "risked" and "unrisked" resource potential, estimated ultimate recovery (EUR) or other descriptions of volumes potentially recoverable, which in addition to reserves generally classifiable as probable and possible (2P and 3P reserves), include estimates of resources that do not rise to the standards for possible reserves, and which SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates, as well as the estimates of probable and possible reserves, are by their nature more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

Denbury Overview

A Unique Energy Business

- CO_2 Enhanced Oil Recovery (EOR) is our primary focus
- Low base decline rate and low capital intensity
- CO_2 expertise and assets position Denbury to lead in Carbon Capture, Use and Storage (CCUS)

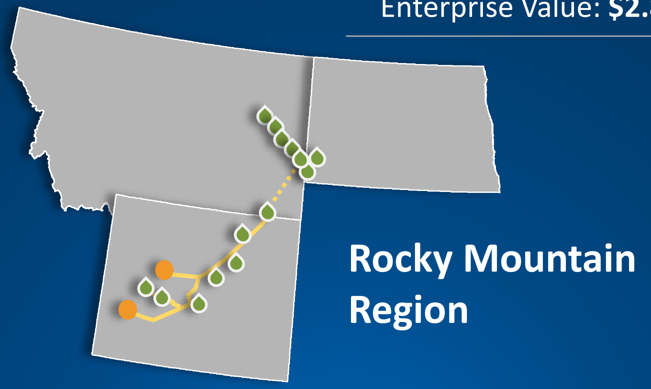
Fundamentally Geared to Crude Oil

- Industry-leading 97% oil production
- Superior crude quality (mid-30s API gravity, low sulfur)

Industry Leader in Reducing CO_2 Emissions

- Annually injecting ~3 million tons of industrial sourced CO_2 into our reservoirs
- Potential to reach full carbon neutrality this decade with CCUS, including downstream Scope 3 emissions

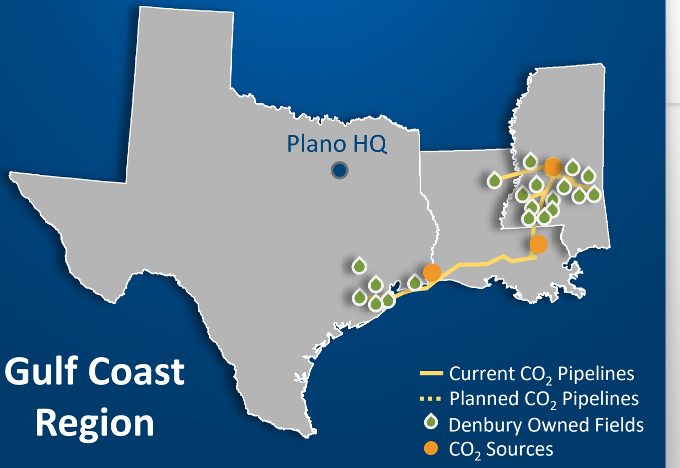
NYSE: **DEN**
Market Cap: **$2.7B**
Enterprise Value: **$2.8B**



1Q21 Production
47,357 BOE/d

YE20 Proved O&G Reserves
143 MMBOE

YE20 Proved CO_2 Reserves
5.7 Tcf



Strategically Advantaged Operations

- Vertically integrated CO_2 supply and distribution network with > 1,000 miles of CO_2 pipelines
- Cost structure largely independent from industry
- Asset base diversity mitigates single basin risk

Value Sustaining Organic Growth Upside

- Over 1 billion BOE proved + EOR and exploitation potential
- Ability to generate significant free cash flow at a low $40s oil price

Positioned for the Future

- Delevered balance sheet provides significant flexibility
- Strategic focus aligned with the Energy Transition

Powering the Energy Transition With World-Leading Carbon Solutions

Strategic Focus

Leading in Carbon Capture, Use and Storage, including Enhanced Oil Recovery

20+ years Experience Managing CO_2

Safely transporting, injecting and monitoring large-scale volumes of CO_2

1000+ miles of CO_2 Pipelines

Owned and operated, strategically located in the Gulf Coast and Rocky Mountain areas

Scope 3 Carbon Negative By 2030

Through increasing our use of captured industrial-sourced CO_2

Financial Strength and Flexibility

Maintain strong financial position, disciplined capital allocation

An Industry Leader in Reducing CO_2 Emissions

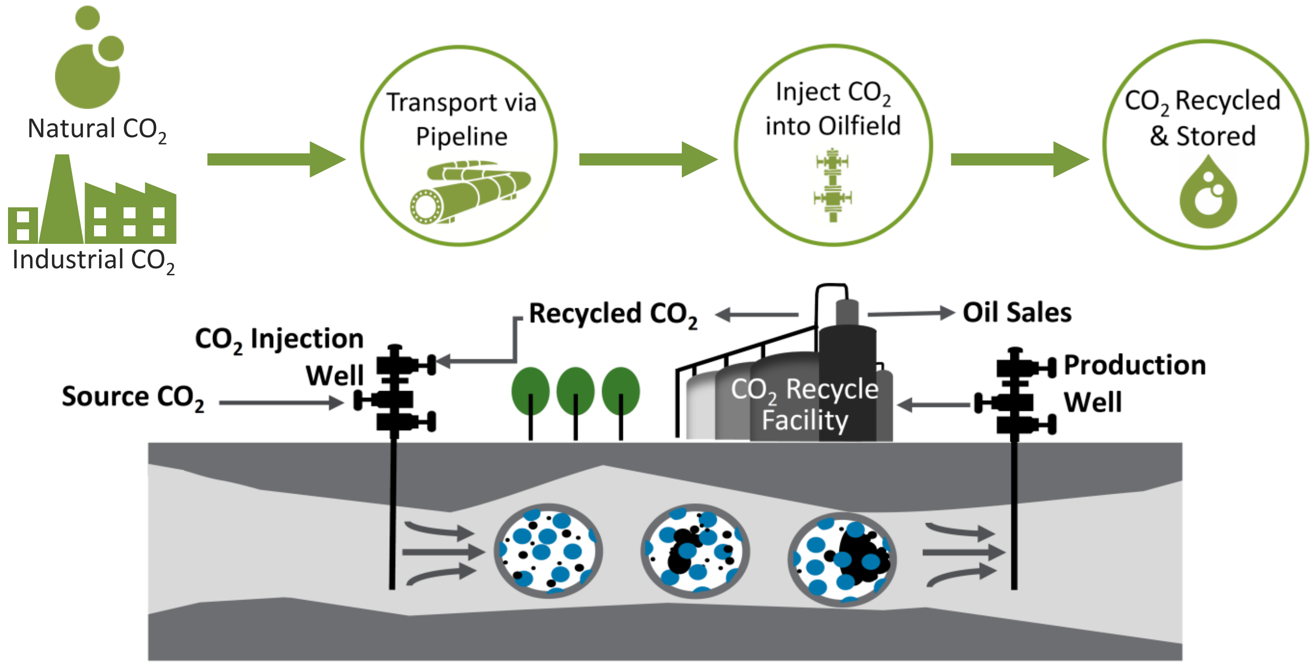
Environment

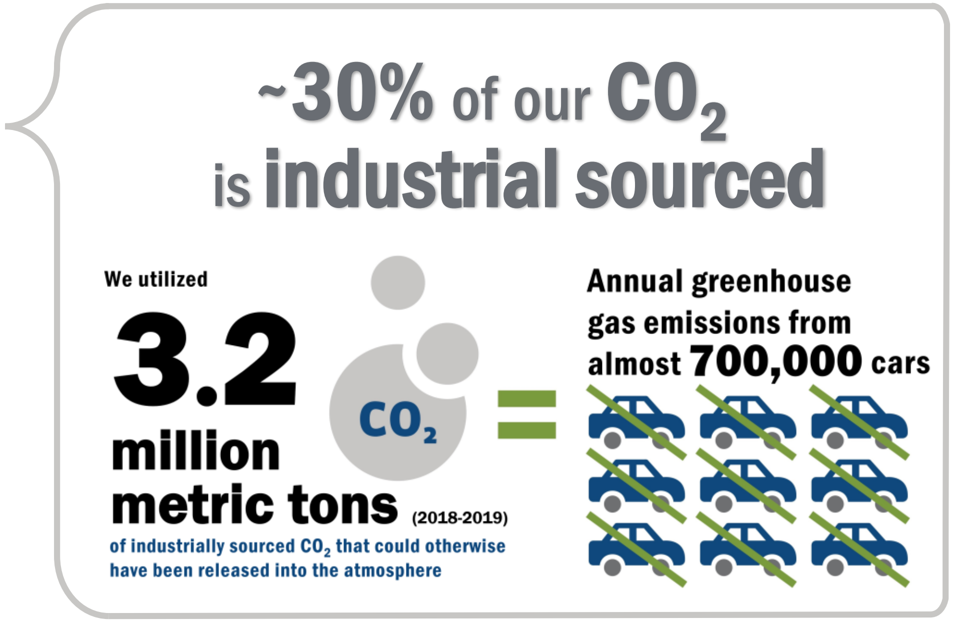
The only U.S. public company of scale where injecting CO_2 into the ground to produce oil is our primary business

Combined Scope 1 and Scope 2 CO_2 Emissions Net Negative

Average of 2018 and 2019

Combined Scope 1 & 2 Emissions		*Captured Industrial-Sourced CO_2*		*Net Negative CO_2 Emissions*
1.8 million metric tons	–	**3.2 million metric tons**	=	**– 1.4 million metric tons**





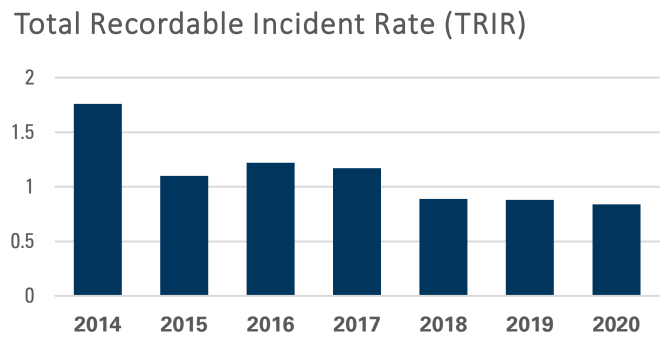
Committed to Operating Safely and Responsibly

Social

We maintain a long-standing commitment to the highest standards for the safety and development of our employees, contractors and local communities

- **Achieved our best** Total Recordable Incident Rate (**TRIR**) **in 2020**
- **Executive compensation** is explicitly **tied to safety targets**
- **Comprehensive training and development program** including safety, leadership, and diversity training
- **Matched >$250,000 employee charitable donations** over last 6 years
- CEO is the 2020/2021 **Chair of Dallas Board of the American Heart Association**

LIVE SAFE ZERO BY CHOICE



Recipient of the 2018
Excellence in Safety Award
by North Dakota Petroleum Council

DOING RIGHT

Consistent sustainability reporting (2014-2019) in accordance with GRI Standards.
Our most recent Corporate Responsibility Report can be accessed on our website at: ***csr.denbury.com***

Strong Corporate Governance

Governance

Strong corporate governance is essential to fulfilling our obligations to our stakeholders and to operating as a responsible corporate citizen

- **6 out of 7** directors are independent, including independent Chairman of the Board
- Long-standing **female board representation** since 2012
- ISS Governance **Rating of "1"** (top ranking)
- **Code of Conduct and Ethics Rated "A"** by NYSE Governance Services (Top 1%)
- Recently formed a **Sustainability Committee** of the Board of Directors

Dr. Kevin Meyers
Director Since 2011
Chairman of the Board, Compensation and Sustainability Committee

Chris Kendall
Joined Denbury in 2015
Director, President and Chief Executive Officer

Lynn Peterson
Director Since 2017
Nominating/Corporate Governance and Audit Committee*

Anthony Abate
Director Since 2020
Audit and Compensation Committee*

Caroline Angoorly
Director Since 2020
Sustainability and Nominating/Corporate Governance Committee*

James Chapman
Director Since 2020
Compensation and Nominating/Corporate Governance Committee*

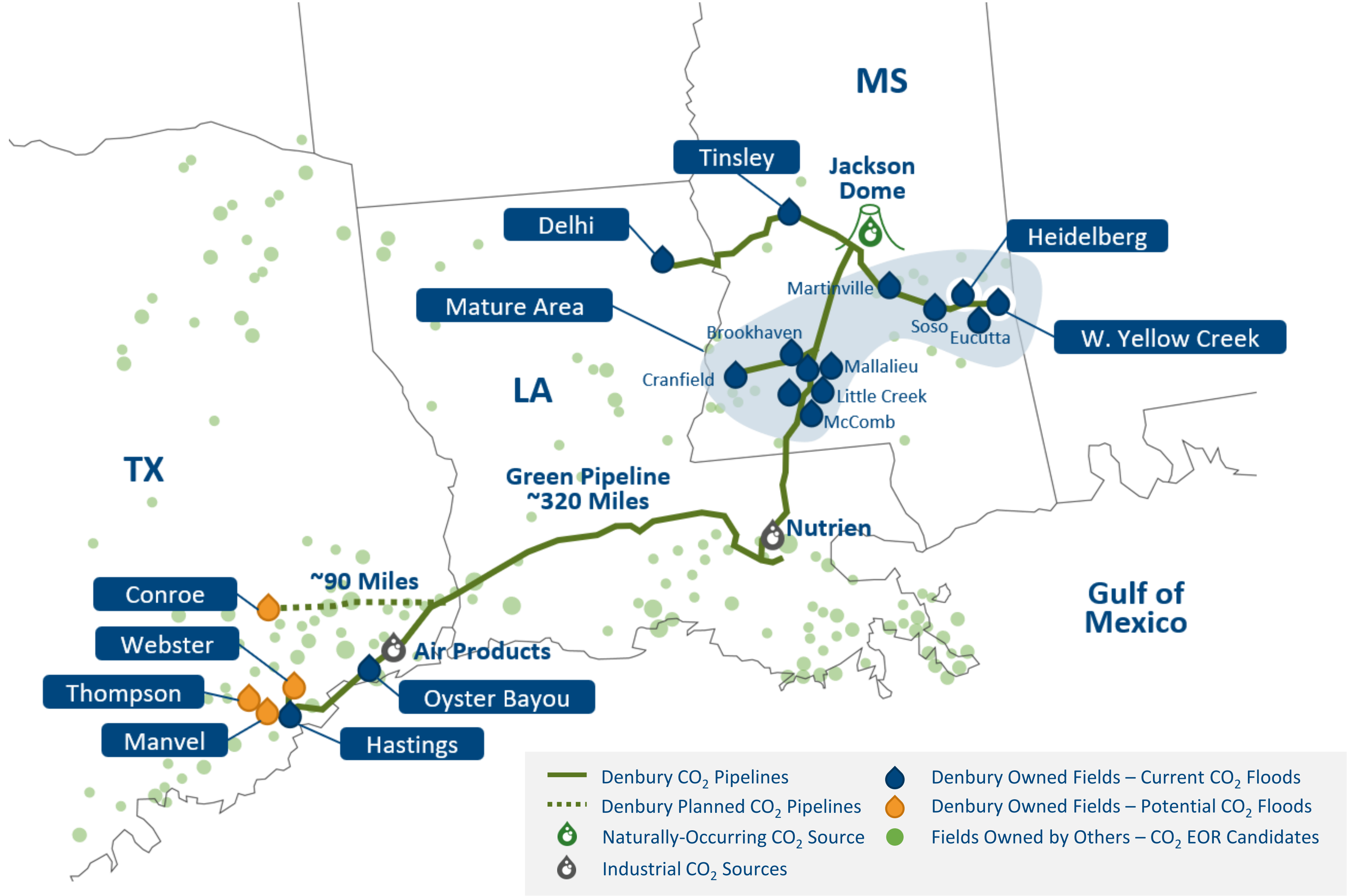
Brett Wiggs
Director Since 2020
Audit and Sustainability Committee

Cindy Yeilding
New Director 2021
Nominating/Corporate Governance and Sustainability Committee

See full biographies for the Board Members at www.denbury.com

*Reflects Committee Chairperson

Gulf Coast Region



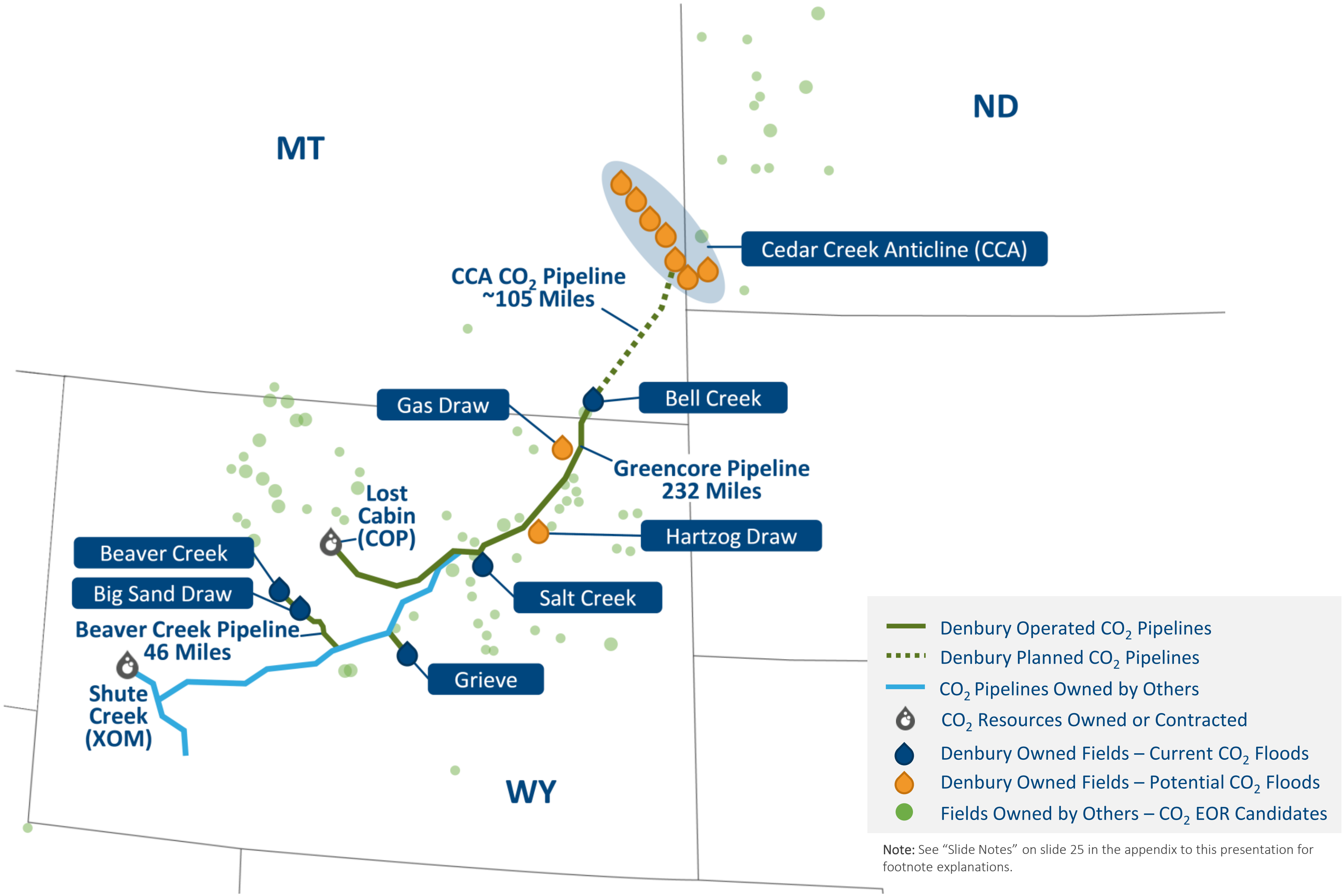
Note: See "Slide Notes" on slide 25 in the appendix to this presentation for footnote explanations.

YE20 Reserves Summary[1] (MMBOE)

Proved + Tertiary Potential	
Tertiary Reserves	
Proved	70
Potential	325
Non-Tertiary Reserves	
Proved	14
Total MMBOE[2]	**409**

Proved + Tertiary Potential by Field[3]	
Mature Area	25
Conroe	130
Delhi	20
Hastings	30 – 65
Heidelberg	25
Manvel	10
Oyster Bayou	20
Tinsley	25
Thompson	20 – 40
Webster[4]	40 – 75
W. Yellow Creek	5

Rocky Mountain Region



Note: See "Slide Notes" on slide 25 in the appendix to this presentation for footnote explanations.

YE20 Reserves Summary[1] (MMBOE)

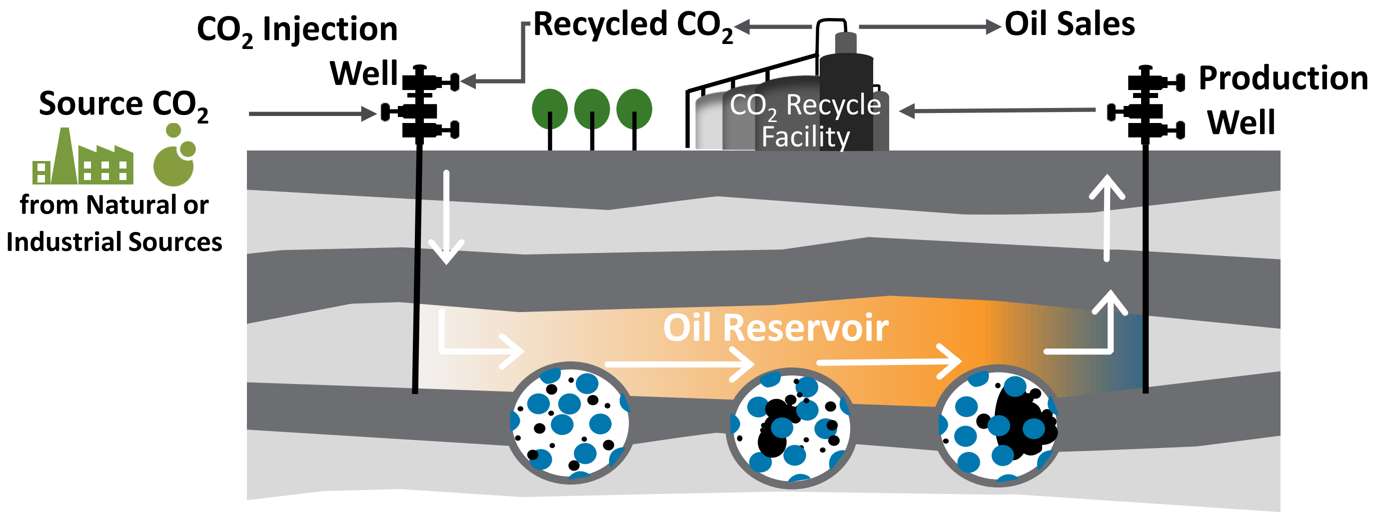
Proved + Tertiary Potential	
Tertiary Reserves	
Proved	12
Potential	547
Non-Tertiary Reserves	
Proved	47
Total MMBOE[2]	**606**

Proved + Tertiary Potential by Field[3]	
Bell Creek	30
Cedar Creek Anticline Area	400 – 500
Gas Draw	10
Grieve	4
Hartzog Draw	30 – 40
Salt Creek	25 – 35

The CO_2 EOR Process

CO_2 Enhanced Oil Recovery (EOR) can produce nearly as much oil from a reservoir as was produced in either primary or secondary recovery

CO_2 EOR Process Overview



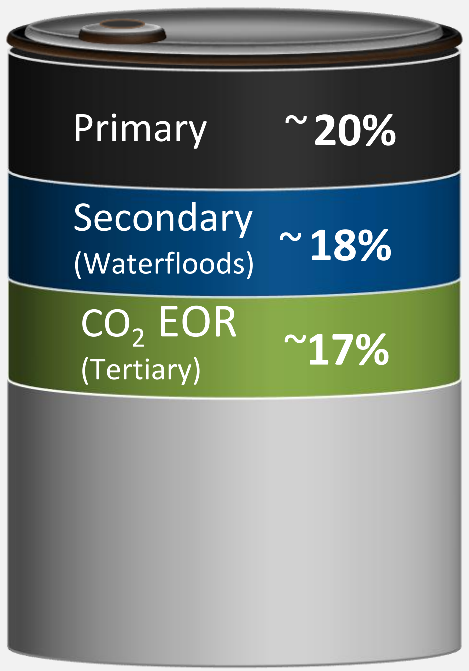
CO_2 is injected into the reservoir, moves through the reservoir, and combines with oil that it contacts

The CO_2/oil combination then continues moving through the reservoir and into nearby production wells

Once on the surface, the oil and CO_2 are separated, the oil is processed for sale and the produced CO_2 is recycled into the reservoir along with supplemental source CO_2

Nearly all of the source CO_2 volume associated with EOR operations ultimately remains in secure underground containment

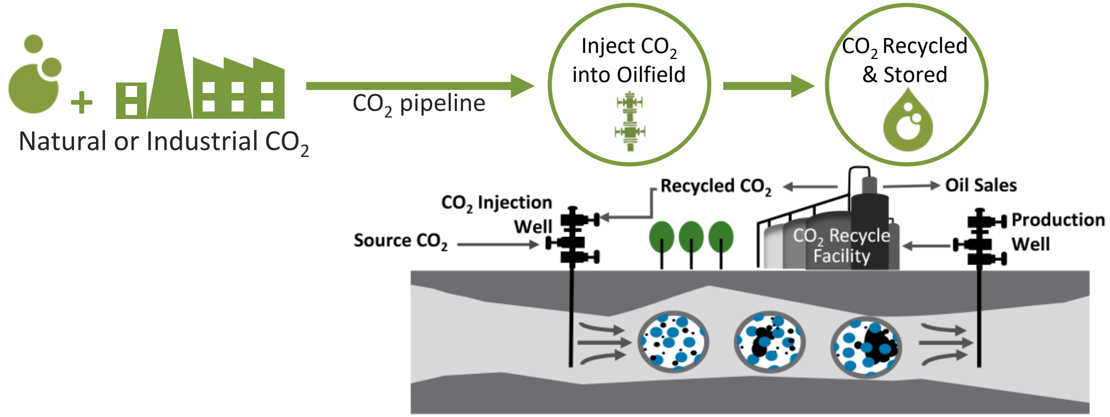
Example Recovery of Original Oil in Place



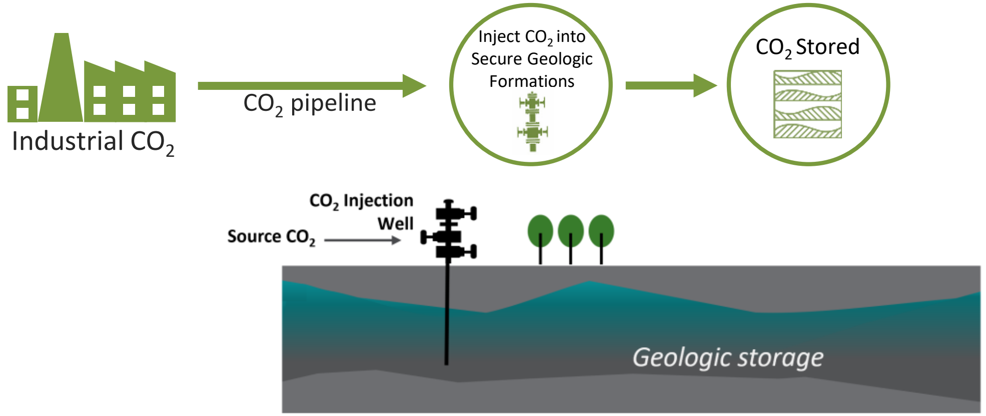
Carbon Capture, Use and Storage (CCUS) Overview

CCUS – both through CO_2 EOR or direct CO_2 injection – is a proven technology with the potential for safe, long-term, deep underground containment of billions of tons of industrial-sourced CO_2

CO_2 Stored in Association with EOR



CO_2 Directly Stored



A proven process

CCUS is an effective, low cost solution using existing, proven processes and technology

Experience gained from decades of safe CO_2 EOR operations translates directly into safe CCUS operations

Reduces atmospheric CO_2

CCUS has the potential to drive a significant reduction in atmospheric CO_2 emissions

The NPC's 2019 CCUS report identified a reasonable path where the volume of CO_2 captured in the U.S. would increase over the next 15 years to ~150 million tons per year, >500% above current levels

Supported by government policy

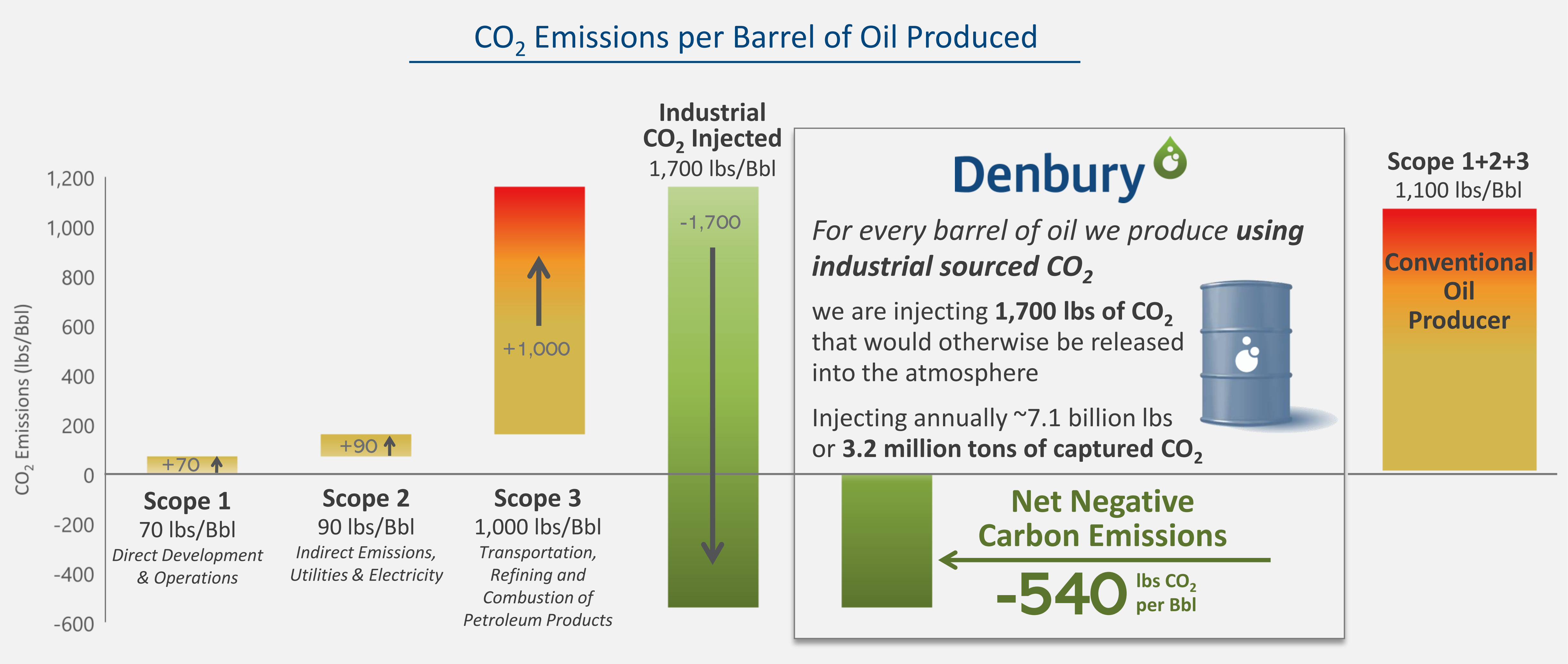
CCUS policy has bipartisan support and is critical to providing the economic and legal framework for investment in CCUS projects

The 45Q tax credit structure provides the capturing parties a tax credit of \$35/ton for CO_2 used in EOR operations and \$50/ton for CO_2 directly stored in geologic formations

Source: National Petroleum Council (NPC) 2019 Report, Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage.

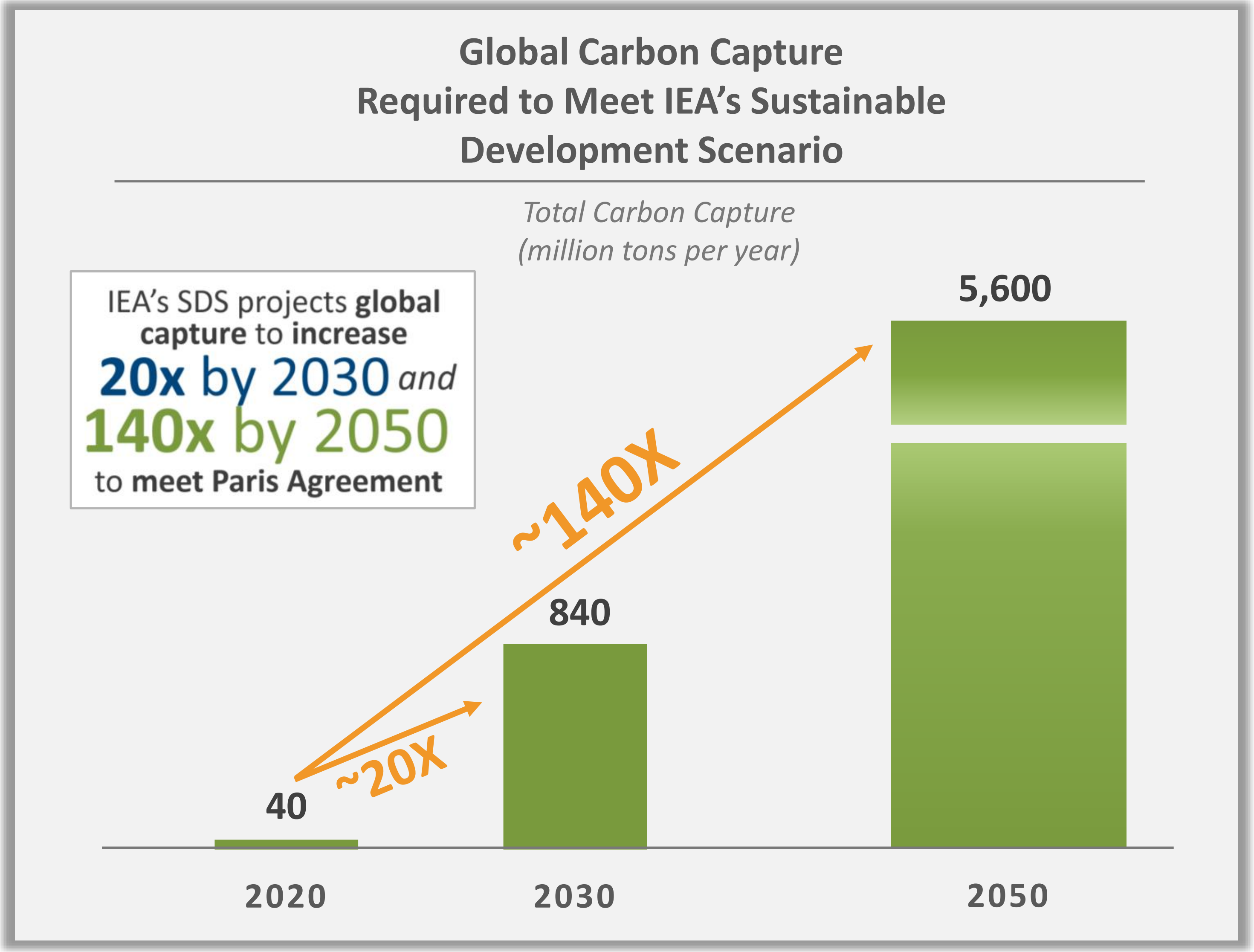
A Leading Producer of Low-Carbon Oil

~25% of Denbury's production is Scope 3 carbon negative through the use of industrial-sourced CO_2



Massive Expansion in CCUS Required to Meet Global Targets

- The IEA's Sustainable Development Scenario (SDS) outlines a carbon reduction pathway that is compliant with the Paris Agreement
- Multiple countries and companies have set targets aligned with emissions reduction goals
- Current U.S. administration set a target to reduce emissions ~50% by 2030 (below 2005 levels)
- Rapidly evolving economic and policy incentives to vastly increase CO_2 capture



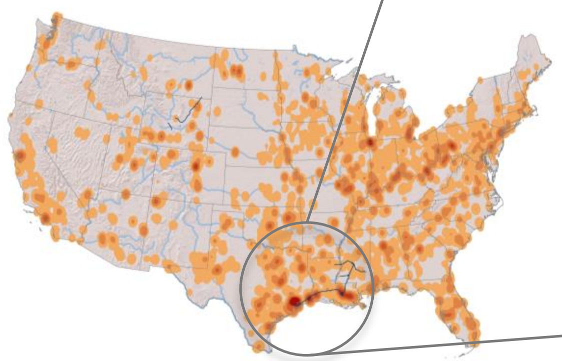
Industry-Leading Gulf Coast CCUS Infrastructure

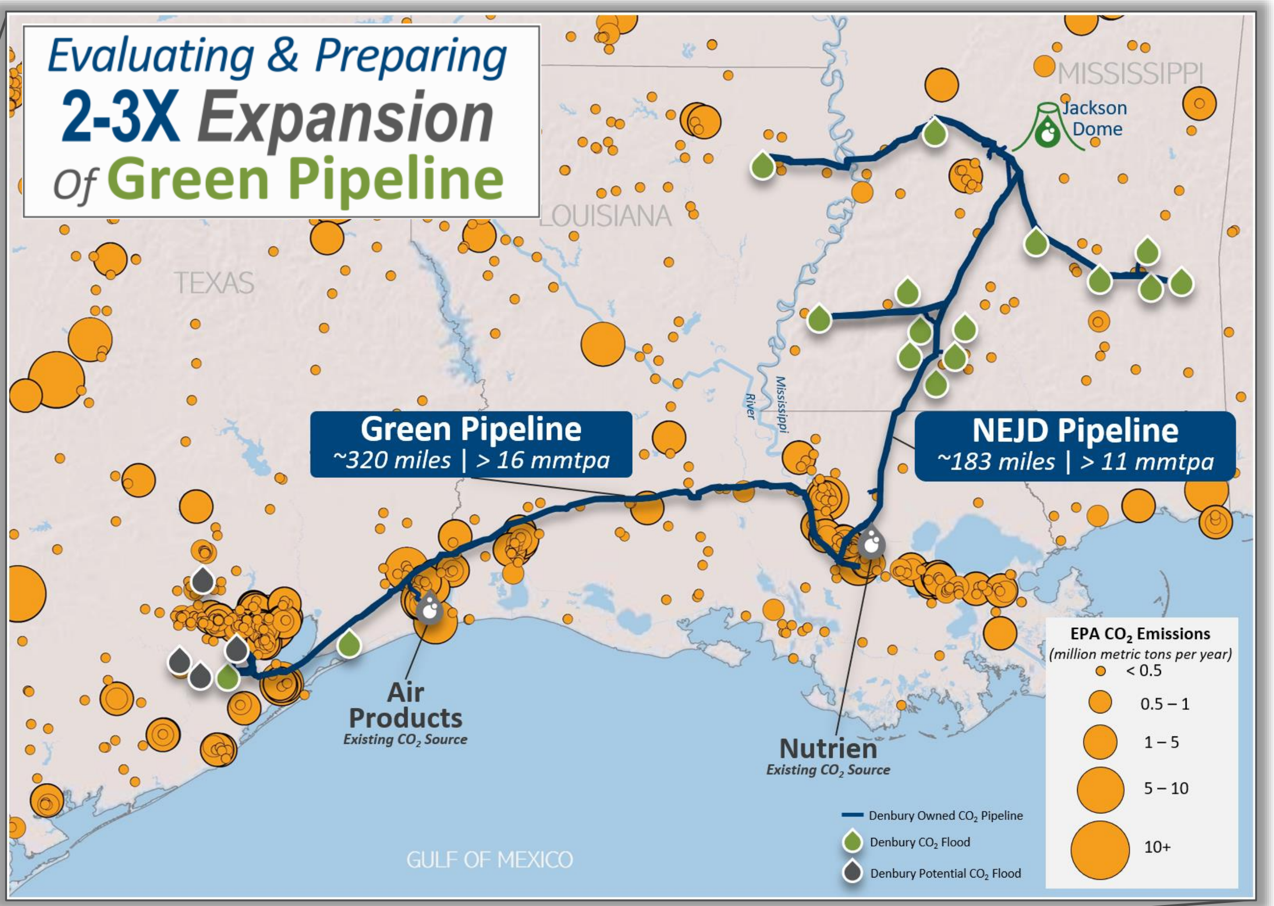
Spanning the highly concentrated CO_2 emissions corridor of the industrial Gulf Coast

CO_2 Emissions

~2.6 billion tons/year from stationary sources in the U.S.

~230 million tons/year (~10% of total U.S.) within 30 miles of DEN Gulf Coast Infrastructure





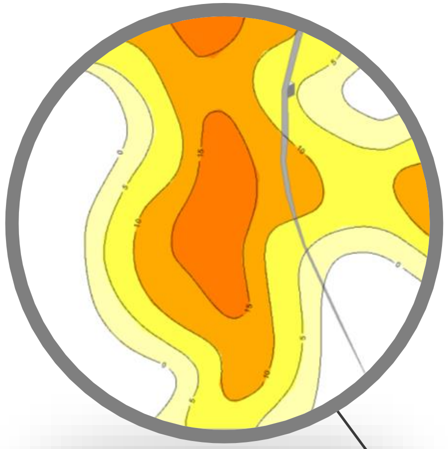
Transportation, Use & Storage

- Strategically located, high capacity network with ability to expand for maximum capacity and flexibility
- Immediate ability to contract takeaway of captured CO_2 for use in EOR operations
- Building a portfolio of permanent storage locations within close proximity to infrastructure

Source: National Petroleum Council (NPC) 2019 Report, Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage and 2019 EPA Greenhouse Gas Reporting Program data.

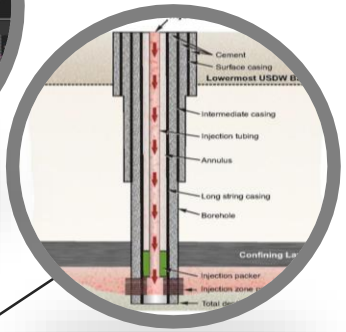
Denbury's Extensive CO_2 Experience is Ideally Suited for CCUS

Over 20+ years, we have transported and injected a combined ~185 million metric tons of natural and industrial CO_2



Geologic Site Characterization

- Detailed analysis and modeling to ensure suitability of target reservoirs for long-term containment of injected CO_2

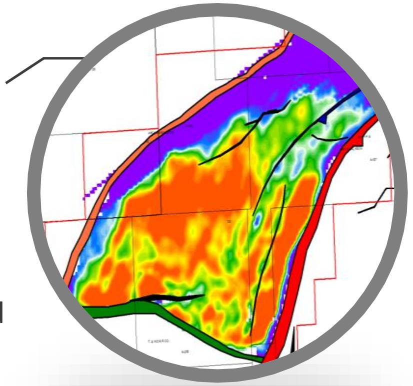


Secure Wellbore Design & Advanced Monitoring

- Wellbores constructed to isolate targeted formations and protect freshwater with emphasis on corrosion prevention, detection, and mitigation
- Routine temperature logging to verify behind-pipe integrity
- Leveraging automated data collection to quickly identify and respond to unexpected conditions
- Enhanced well plugging criteria applied to all abandoned wells to ensure secure CO_2 containment

Subsurface Surveillance

- 4D seismic imaging to aid in observation of CO_2 placement and conformance
- Sophisticated well logging
- Extensive use of fluid sampling and tracers
- Reservoir simulation modeling



CO_2 Handling & Processing Expertise

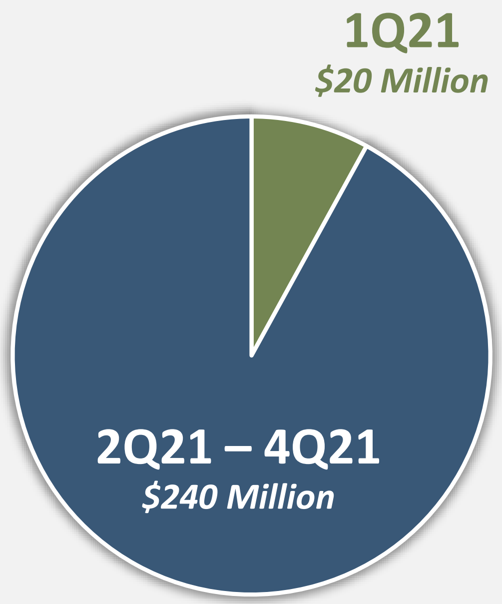
- Processing over 3.5 billion cubic feet (180,000 metric tons) of CO_2 per day
- Proven expertise in designing, building, and operating CO_2 pipelines, processing facilities, and gathering/distribution systems

Denbury Carbon Solutions Strategy

Secure CO_2 Transportation & Storage Agreements	Providing emitters with a full range of CO_2 offtake services
Develop Portfolio of CO_2 Storage Sites	Increasing scale, ensuring system reliability and adding flexibility
Replace Naturally Sourced CO_2 in EOR Operations	Reducing Denbury's carbon footprint while increasing production of low carbon-intensity blue oil
Prepare for 2-3X Infrastructure Expansion	Ensuring sufficient capacity to meet anticipated demand
Pursue Strategic Partnerships	Open to considering opportunities across the value chain

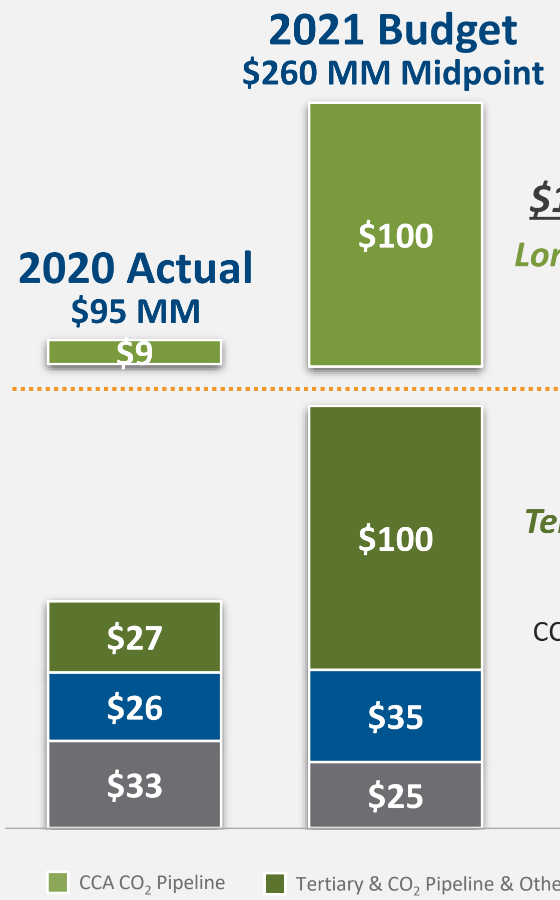
2021 Development Capital

Capital ($MM)



Development capital spend ramps up 2Q21 – 4Q21

2021 Budget Capital
$250 – $270 MM[1]



$100 MM CCA CO_2 Pipeline

Long-Term Infrastructure Capital

$160 MM Base Capital

Tertiary & CO_2 Pipeline & Other

Tinsley Perry CO_2 Pilot
Oyster Bayou A1 Redevelopment
CCA CO_2 Facilities & Well work ($50 MM)

Non-Tertiary

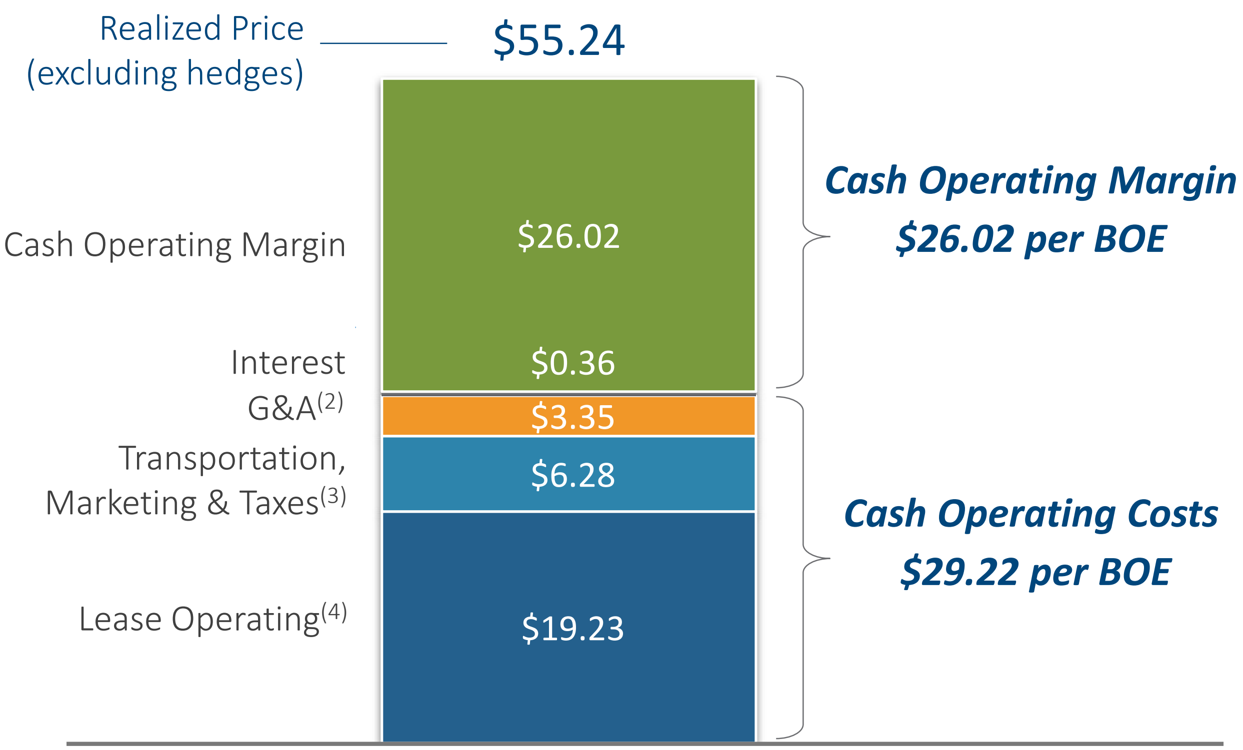
Maintenance Activities

1) Amounts presented exclude $5 - $7 million of capitalized interest.
2) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

1Q21 Operating Margin and Production

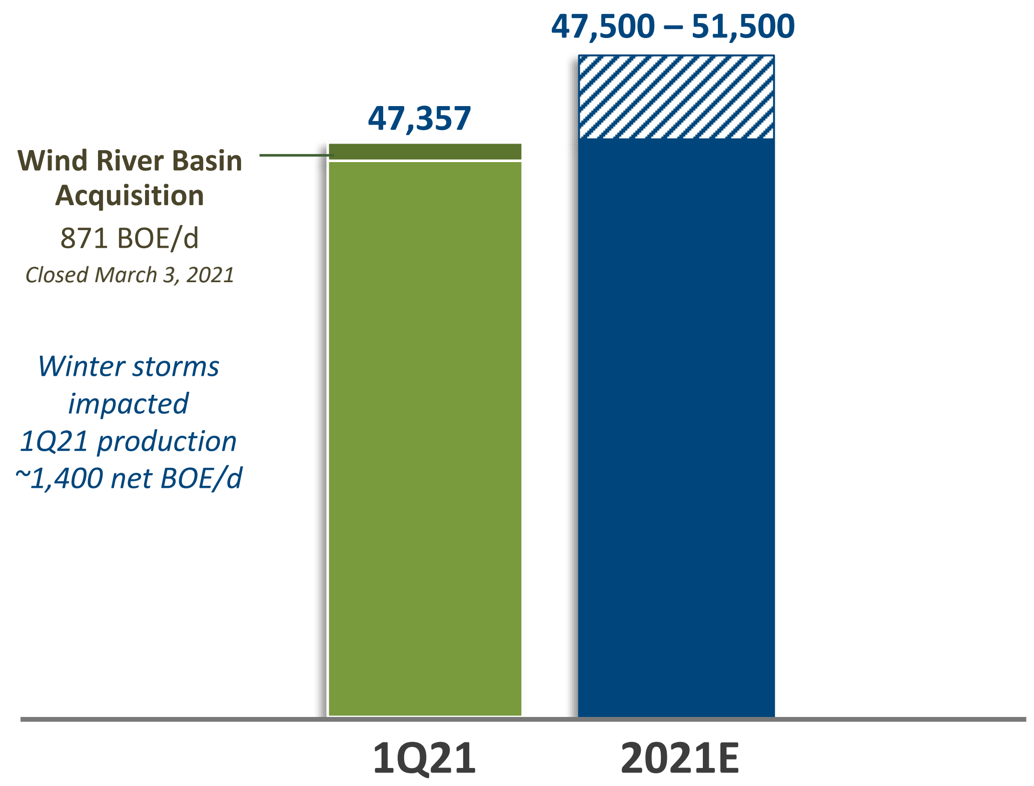
1Q21 Operating Margin ($/BOE)[1]

47% Cash Operating Margin[1]



Production (BOE/d)

Production expected to step up in 2Q21 and remain relatively flat 2Q21 – 4Q21



1) Excludes impacts of hedging and selected items of other expense and CO_2 operating margin.
2) G&A excludes non-cash compensation of approximately $18 million ($4.15/BOE).
3) Includes transportation, marketing and taxes other than income.
4) Includes $15 million 1Q21 utility credit. See slide 33 for a detail of operating expenses.

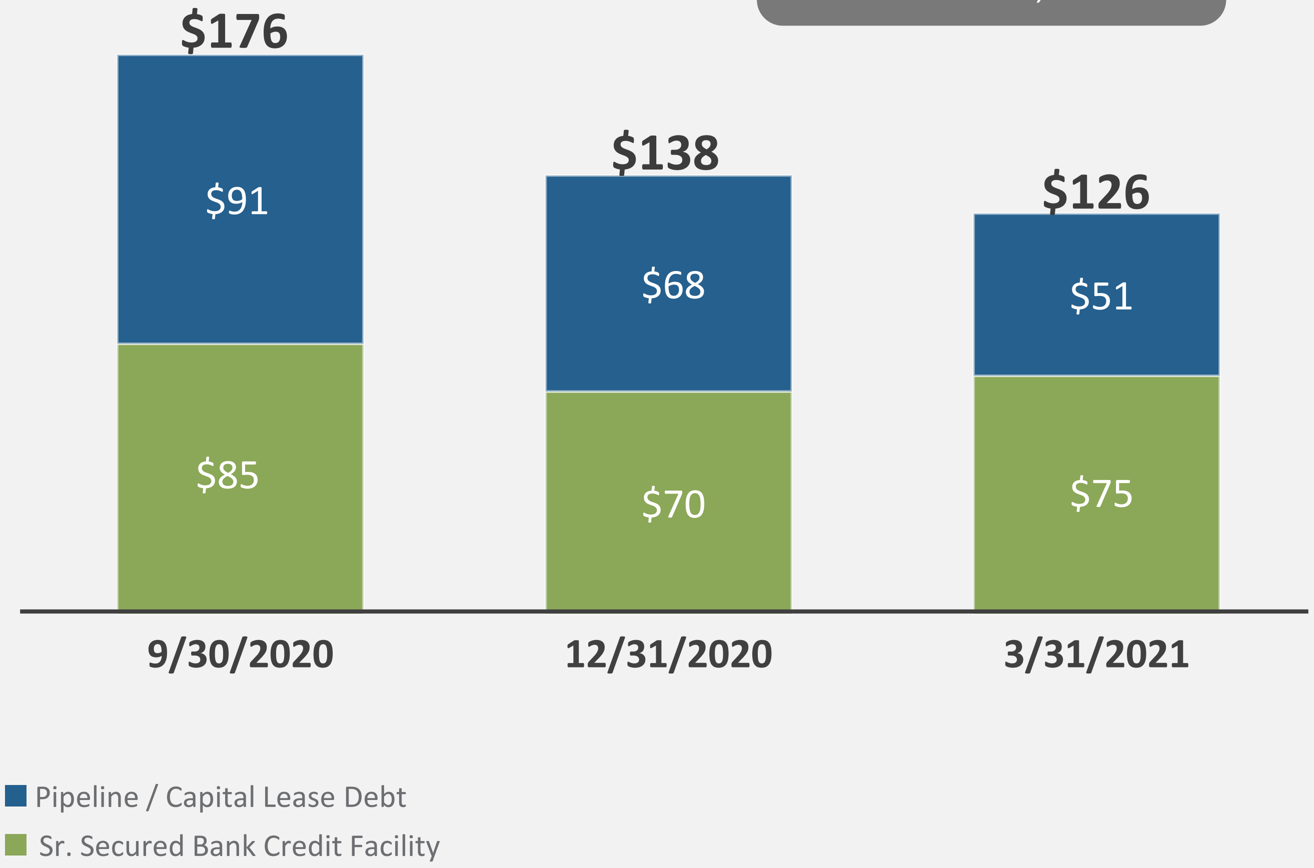
Debt Profile and Liquidity

Leverage ratio of 0.4x as of March 31, 2021

Total Debt

(In millions)

$483 million total liquidity including unrestricted cash at March 31, 2021



Credit Facility Overview

Sr. Secured Bank Credit Facility

- $575 million borrowing base
- $477 million availability at March 31, 2021
  - $75 million drawn
  - $23 million of letters of credit issued
- Reaffirmed April 2021; next semi-annual redetermination in November 2021
- Maturity Date: January 30, 2024
- Financial Covenants:
  - Total Debt / EBITDAX: < 3.50x at the end of each quarter
  - Current Ratio: > 1.00x at the end of each quarter

Cedar Creek Anticline – A World Class CO_2 EOR Project

> 400 MMBbl total recovery potential using 100% industrial-sourced CO_2

CO_2 Pipeline to CCA from Bell Creek

- Plan to install in 2H 2021; ~$100 MM anticipated 2021 capital spend
- Services all CCA EOR development phases; represents < $0.50/Bbl across total project
- All key permits in place

Phase 1

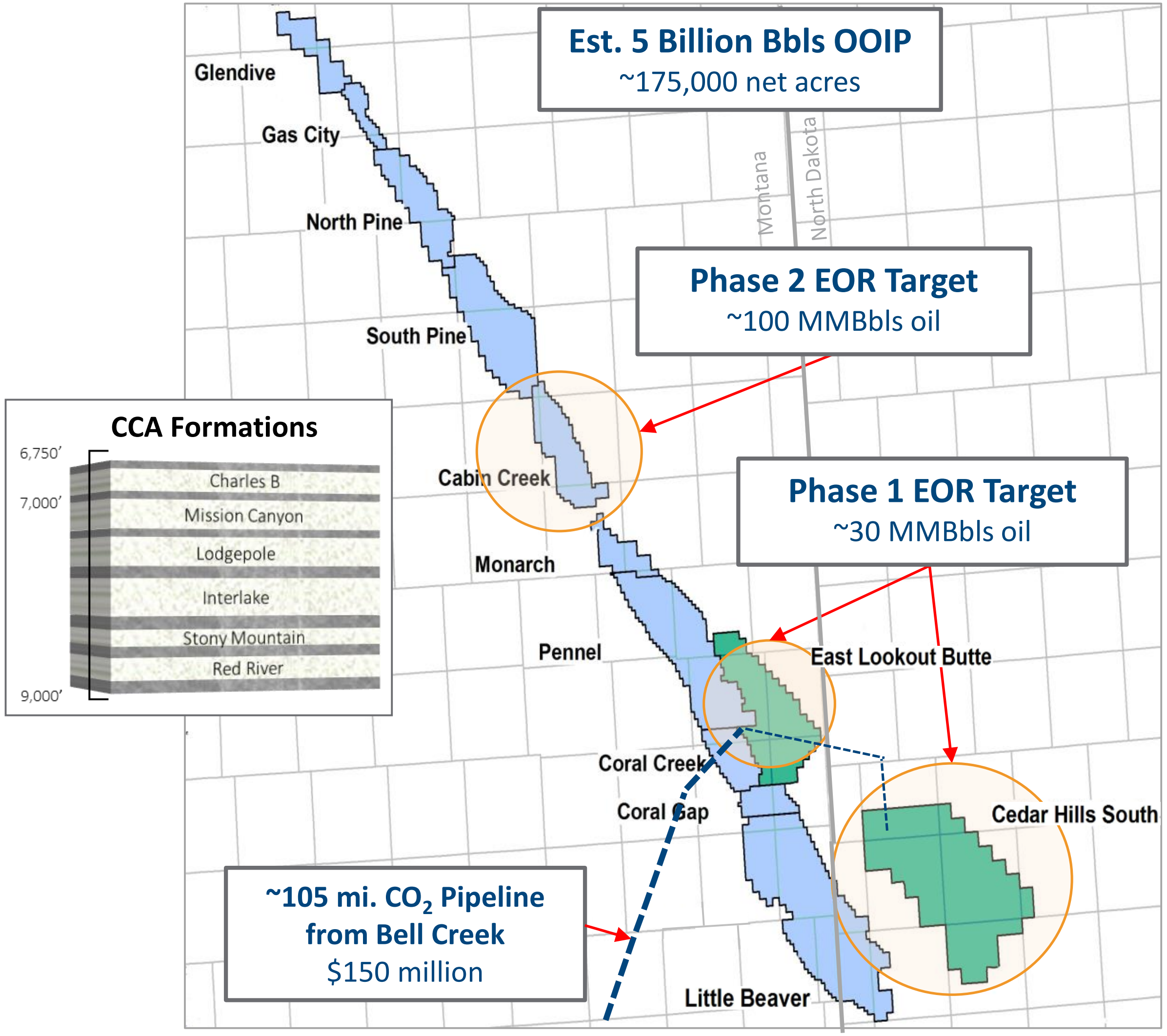
- Targets ~30 MMBbls of recoverable oil in Red River formation in East Lookout Butte and Cedar Hills South
- First production expected in 2H23
- Total capex (excl. CO_2 pipeline) ~$500 MM over 15 years

Phase 2

- Targets ~100 MMBbls of recoverable oil in Interlake, Stony Mountain and Red River formations in Cabin Creek
- Development expected to commence in 2024
- Total capex of ~$500 – $600 MM over multiple decades

Future Phases – Remainder of CCA

- > 300 MMBbl EOR potential in multiple formations



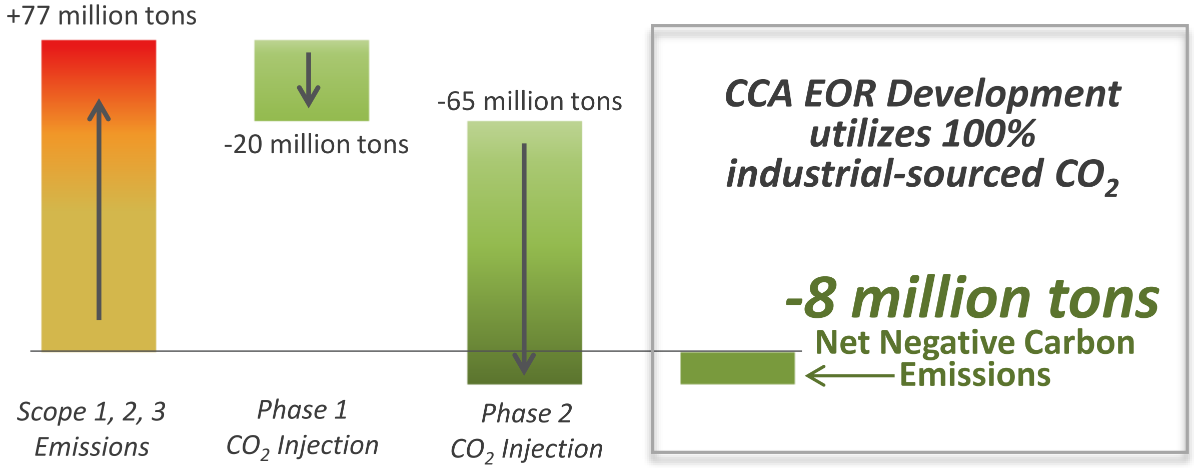
CCA EOR – A Scope 3 Carbon Negative Development

Phases 1 & 2 will collectively store ~85 million metric tons of industrial-sourced CO_2

Additional Development Details

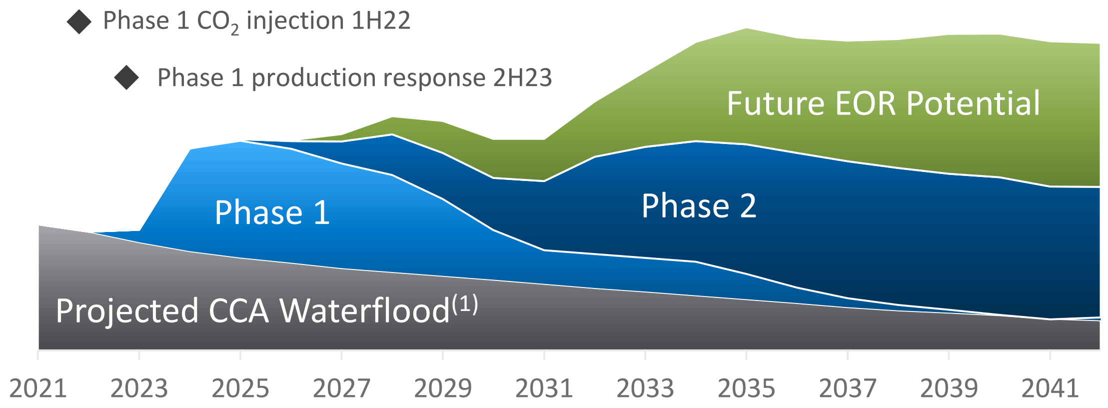
- Evaluating further enhancements to project based on potential availability of additional CO_2
- Evaluating financing alternatives for the CO_2 pipeline construction
- Anticipated $10-15/Bbl Phase 1 and 2 tertiary lifting cost expected to meaningfully reduce overall corporate LOE/BOE

CO2 Emissions – Scope 3 Negative

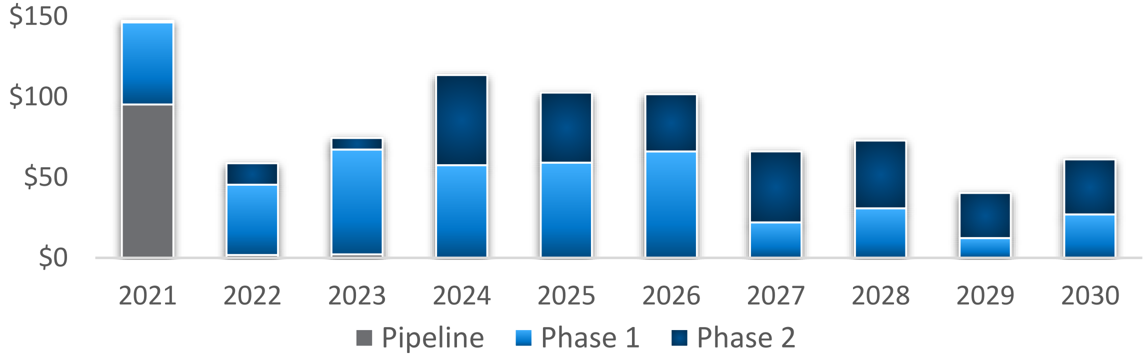


Phase 1 incremental peak production 7,500 – 12,500 net Bbls/d

Estimated Production Profile



Estimated Capital Profile



1) CCA waterflood proved production profile at $50/Bbl NYMEX

Acquisition of Wyoming Wind River Basin CO_2 EOR Fields

Supports Denbury's CO_2 EOR focused strategy, utilizing 100% industrial-sourced CO_2

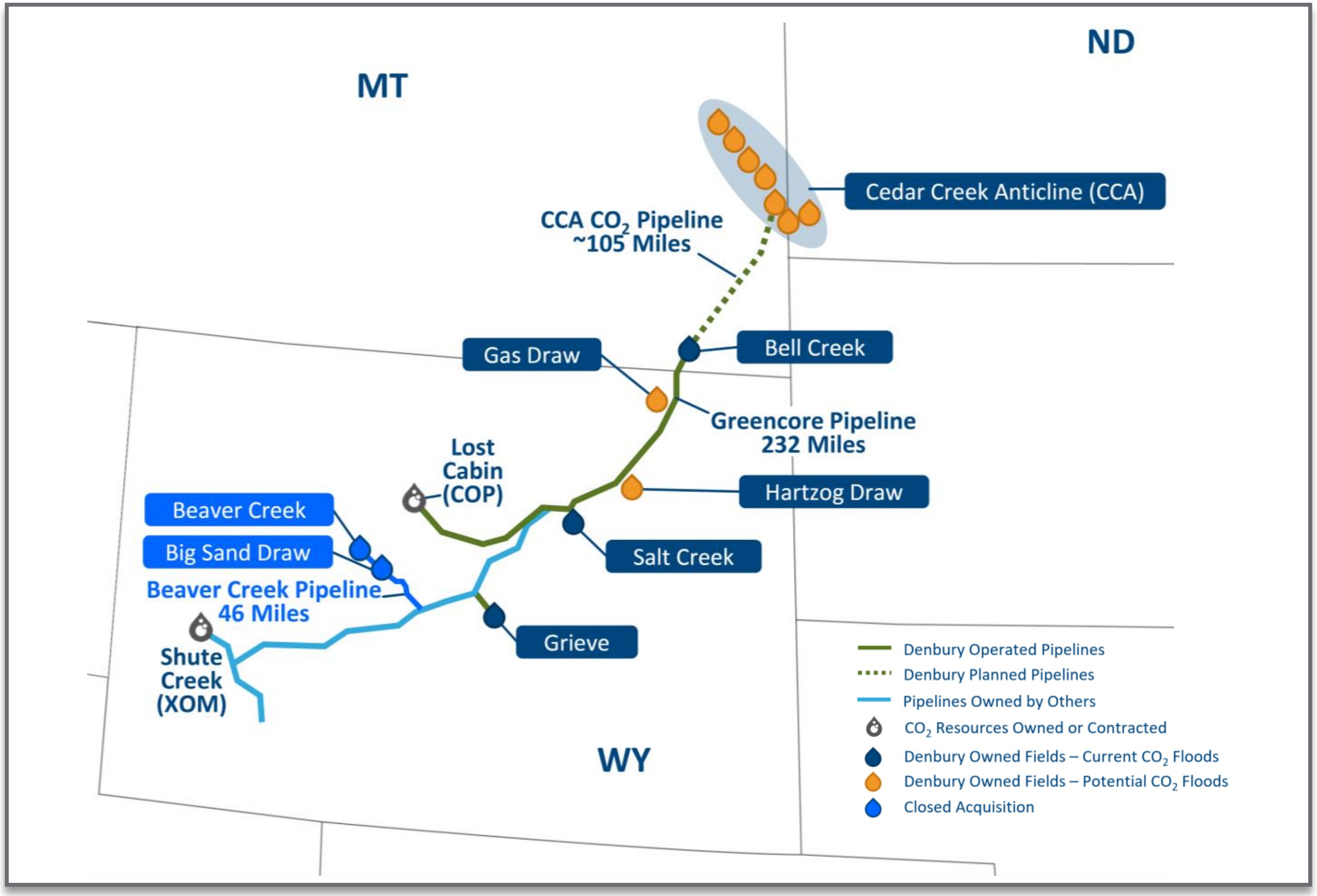
Beaver Creek / Big Sand Draw Oil Fields

Transaction Highlights

- \$10.7 million purchase price (after initial closing adjustments) includes 46-mile CO_2 pipeline closed March 3, 2021
- Potential net reserves 13.7 MMBOE
- Annually utilizes nearly 400,000 tons of industrial-sourced CO_2

Additional Details

- ~100% working interest and ~83% net revenue interest
- Agreement provides for two contingent payments of \$4MM each in 2021 and 2022 if NYMEX WTI oil price averages at least \$50/Bbl in those calendar years
- March month average ~2,700 BOE/d; net 1Q21 impact 871 BOE/d



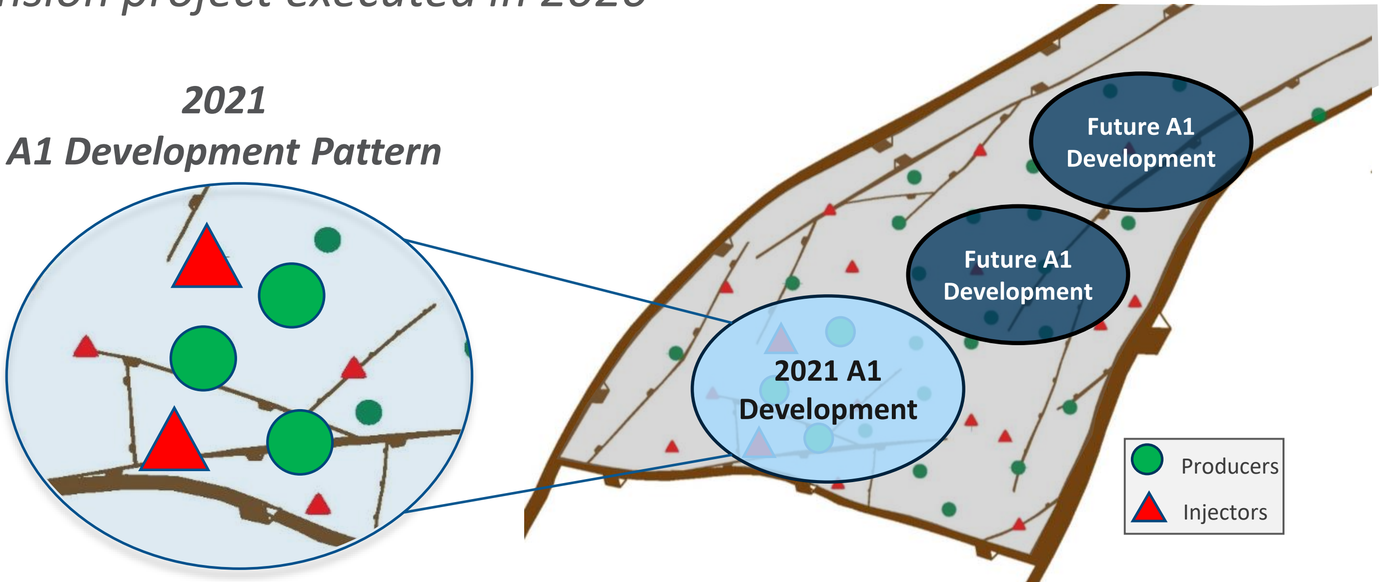
2021 Tertiary Capital - Oyster Bayou A1 Development Expansion

Continues success from A2 Development Expansion project executed in 2020

Development Overview

- A1 Development Expansion
  - 3 development areas, expands upon successful in-field analogs
  - Targets A1 Lower reservoirs
- 2021 capital spend ~$5 million
  - 2 producer conversions, 1 new drill producer and 2 injector conversions
- Future Development
  - Additional opportunities in A1 and A2 reservoirs

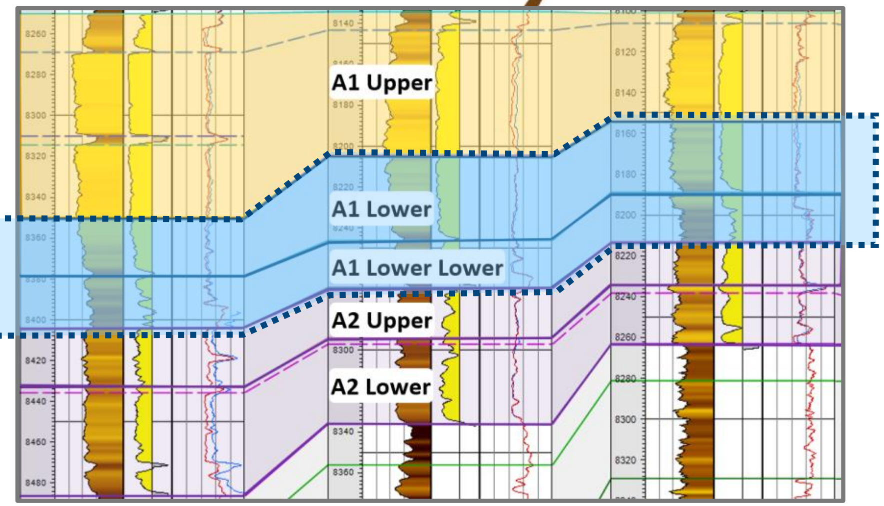
2021
A1 Development Pattern



Producing zone in other phases

2021 Development Expansion targeting A1 reservoir

2020 *Development Expansion targeting A2 reservoir*

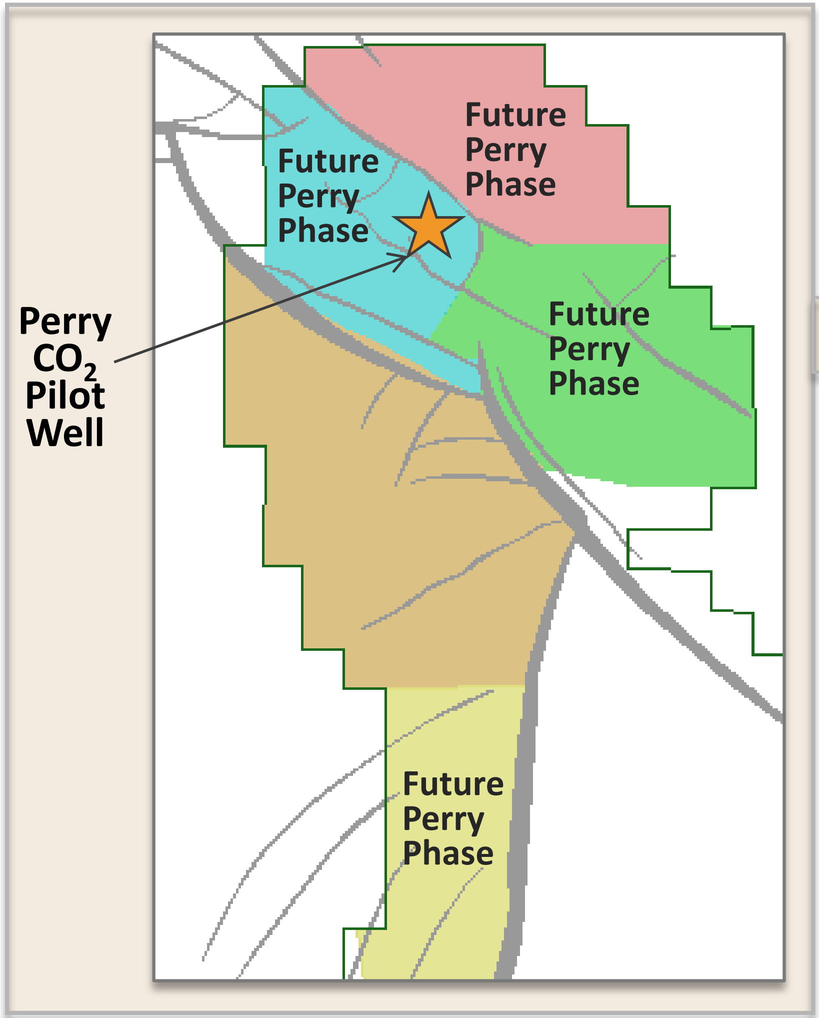


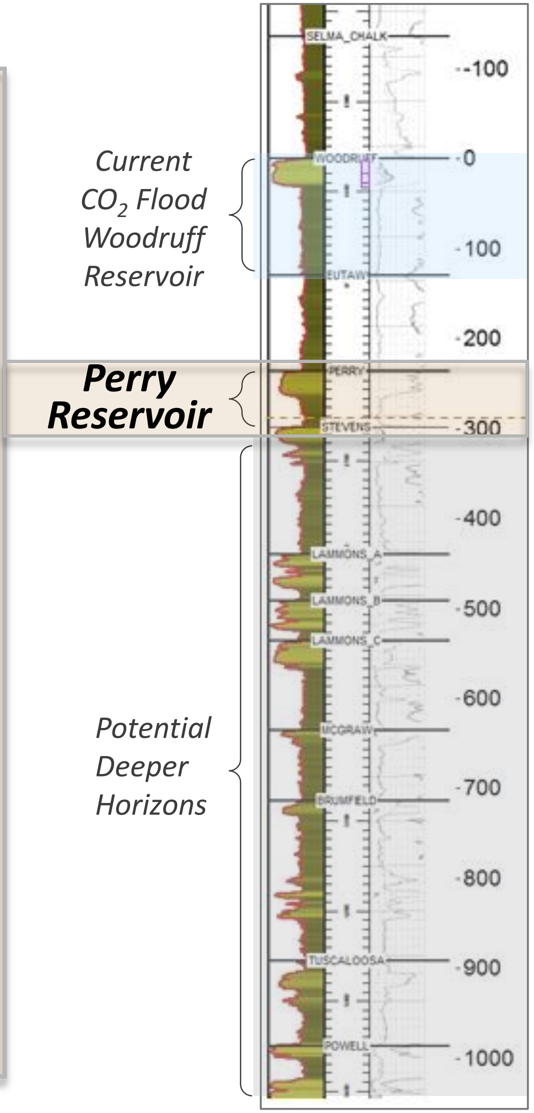
2021 Tertiary Capital – Tinsley Perry CO_2 Pilot

2021 pilot unlocks development target of > 10 MMBbls

Development Overview

- New CO_2 flood in Tinsley
  - Targets high residual oil saturation
  - Horizontal development to achieve higher reservoir processing rates
  - Leverages Tinsley's existing CO_2 infrastructure
- 2021 capital spend ~$7 MM
  - 1 new horizontal producer, 1 horizontal injector conversion and 2 recompletions
- Future Development
  - 4 phases, ~20 horizontal wells
  - Opportunity for multi-year phased development





Slide Notes

Slide 8 – Gulf Coast Region

1) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/20 SEC pricing ($39.57 per Bbl for crude oil and $1.99 per MMBtu for natural gas). Potential includes probable and possible tertiary reserves estimated by the Company as of 12/31/19, using the mid-point of ranges, based upon a variety of recovery factors and long-term oil price assumptions, which also may include estimates of resources that do not rise to the standards of possible reserves. See slide 2, "Cautionary Statements" for additional information.
2) Total reserves in the table represent total proved plus potential tertiary reserves, using the mid-point of ranges, plus proved non-tertiary reserves, but excluding additional potential related to non-tertiary exploitation opportunities.
3) Field reserves shown are estimated proved plus potential tertiary reserves.
4) Potential tertiary oil reserves represent 100% of Denbury's current working interest in Webster. Any future tertiary development would be subject to elective partner participation that would result in a reduction of Denbury's current working interest.

Slide 9 – Rocky Mountain Region

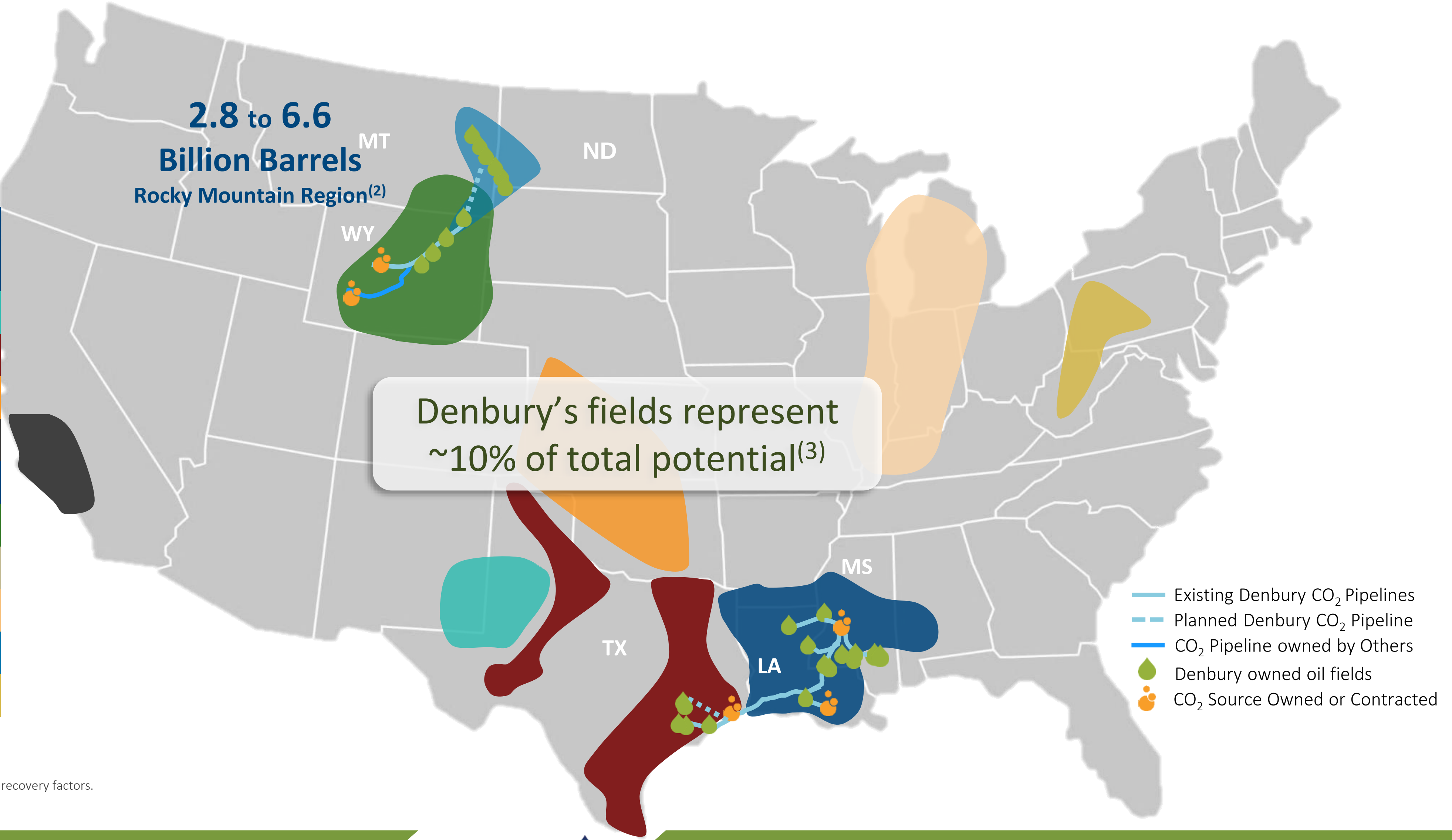
1) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/20 SEC pricing ($39.57 per Bbl for crude oil and $1.99 per MMBtu for natural gas). Potential includes probable and possible tertiary reserves estimated by the Company as of 12/31/19, using the mid-point of ranges, based upon a variety of recovery factors and long-term oil price assumptions, which also may include estimates of resources that do not rise to the standards of possible reserves. See slide 2, "Cautionary Statements" for additional information.
2) Total reserves in the table represent total proved plus potential tertiary reserves, using the mid-point of ranges, plus proved non-tertiary reserves, but excluding additional potential related to non-tertiary exploitation opportunities.
3) Field reserves shown are estimated proved plus potential tertiary reserves.

Appendix

Significant CO_2 EOR Potential in the U.S.

Denbury's assets and pipeline infrastructure are well positioned in key EOR potential basins

33-83 Billion Barrels of Technically Recoverable Oil[1,2]	
Permian	9-21
East & Central Texas	6-15
Mid-Continent	6-13
California	3-7
South East Gulf Coast	3-7
Rockies	2-6
Other	0-5
Michigan/Illinois	2-4
Williston	1-3
Appalachia	1-2



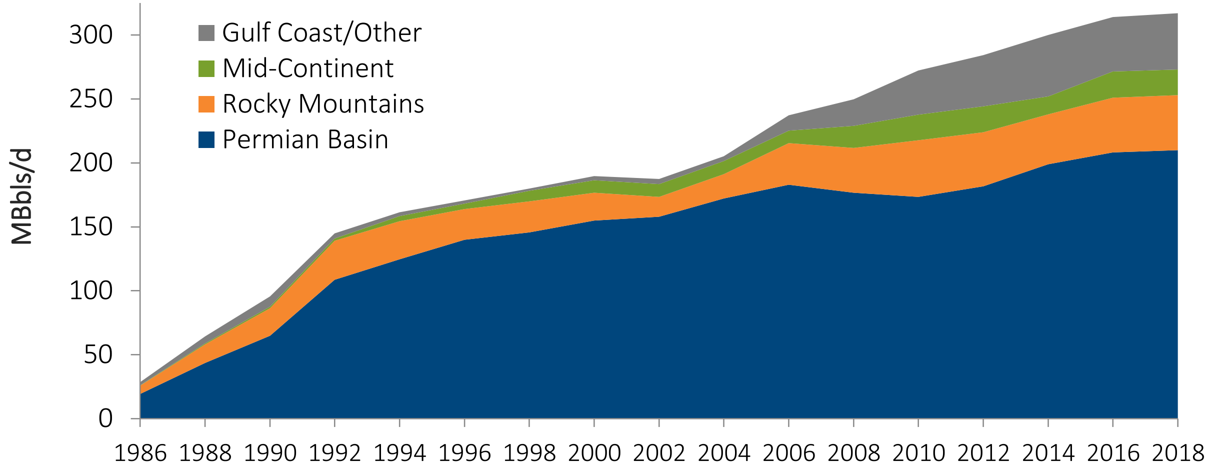
1) Source: 2013 DOE NETL Next Gen EOR.
2) Total estimated recoveries on a gross basis utilizing CO2 EOR.
3) Using approximate mid-points of ranges, based on a variety of recovery factors.

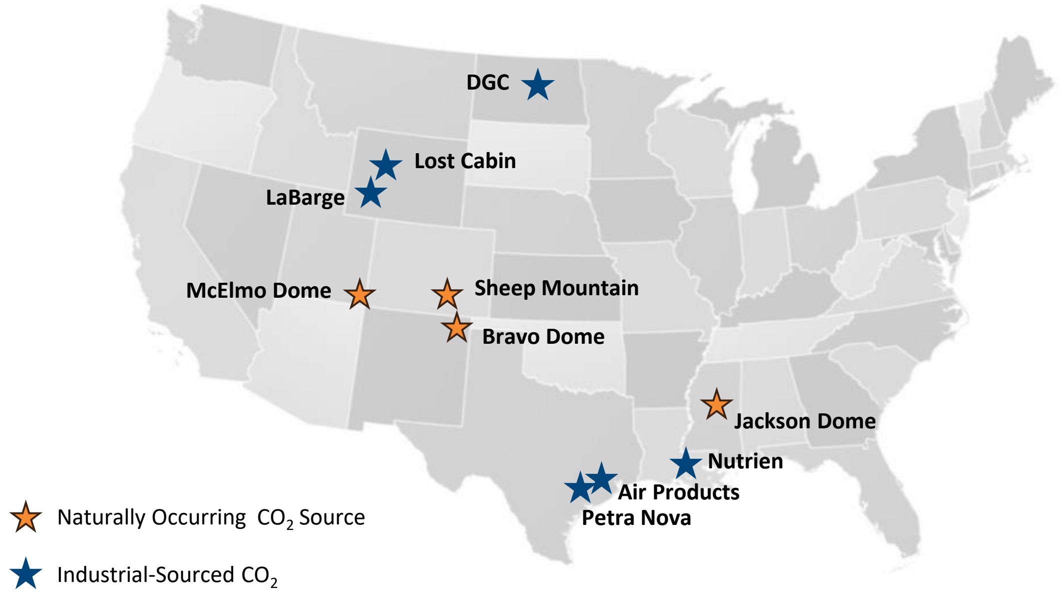
CO_2 EOR is a Proven Process

Significant CO_2 EOR Operators by Region	
Gulf Coast Region	
» Denbury	» Hilcorp
Permian Basin Region	
» Occidental	» Kinder Morgan
Rocky Mountain Region	
» Denbury	» FDL
» Devon	» Chevron
Canada	
» Whitecap	» Cardinal Energy

Significant CO_2 Supply by Region
Gulf Coast Region – Source (User)
» Jackson Dome, MS (Denbury)
» Air Products (Denbury)
» Nutrien (Denbury)
» Petra Nova (Hilcorp)
Permian Basin Region – Source (Owner)
» Bravo Dome, NM (Kinder Morgan, Occidental)
» McElmo Dome, CO (ExxonMobil, Kinder Morgan)
» Sheep Mountain, CO (ExxonMobil, Occidental)
Rocky Mountain Region – Source (Owner)
» LaBarge, WY (ExxonMobil, Denbury)
» Lost Cabin, WY (ConocoPhillips)
Canada – Source (User)
» Dakota Gasification (Whitecap, Apache)

CO_2 EOR Oil Production by Region[1]





1) Source: Advanced Resources International for data through 2014; state EOR data 2015-2018.

Abundant CO_2 Supply & No Significant Capital Required for Several Years

Gulf Coast CO_2 Supply	Rocky Mountain CO_2 Supply

Jackson Dome

- Proved CO_2 reserves as of 12/31/20: ~4.6 Tcf[1]
- Additional probable CO_2 reserves as of 12/31/20: ~0.9 Tcf

Industrial-Sourced CO_2

Current Sources

- Air Products (hydrogen plant): ~45 MMcf/d
- Nutrien (ammonia products): ~20 MMcf/d

LaBarge Area

- Estimated field size: 750 square miles
- Estimated recoverable CO_2: 100 Tcf

Shute Creek – ExxonMobil Operated

- Proved reserves as of 12/31/20: ~1.1 Tcf
- Denbury has a 1/3 overriding royalty interest and could receive up to ~115 MMcf/d of CO_2 by 2021 at current plant capacity

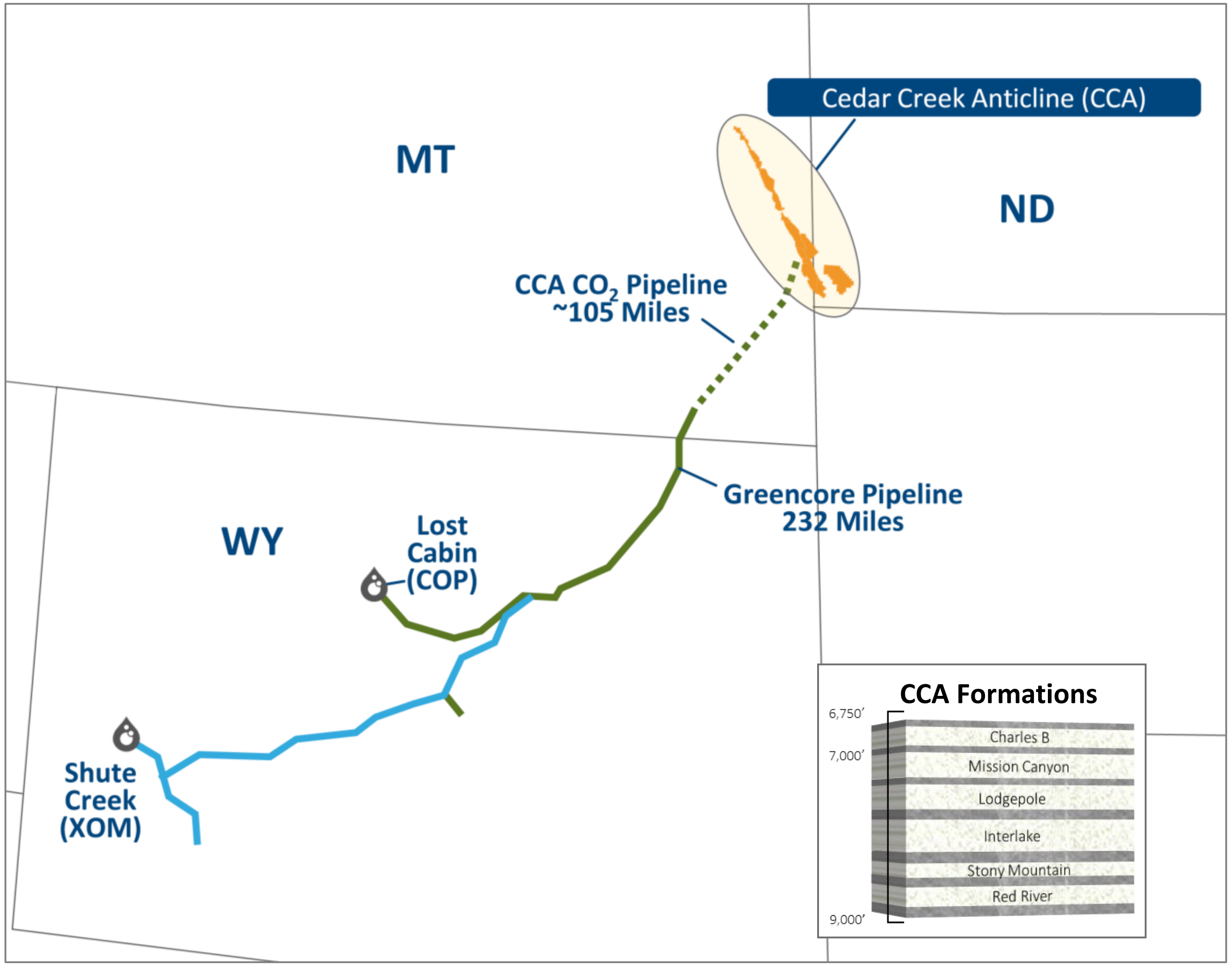
Lost Cabin – ConocoPhillips Operated

- Potential to receive up to 30 MMcf/d of CO_2

1) Reported on a gross (8/8th's) basis.

CCA CO_2 EOR Development

EOR Formation Details	
Initial Formations Targeted	Red River, Interlake, Stony Mountain
Field Discovery Timeframe (Oil)	1930's (Discovery), 1950's (Development)
Formation Type	Dolomite
Depth	7,000 – 9,000 ft
Original Reservoir Pressure	3,600 – 4,140 psi
CO_2 Flood Type	Miscible
API Gravity	29-38
Average Perm	5 md
Average Porosity	11.4%
OOIP	~5 Billion Barrels
Oil Recovered to Date	~700 Million Barrels
Est. Tertiary Recovery Factor	8 – 15%



Oyster Bayou A2 Development Expansion

Development Overview

New A2 Development Expansion

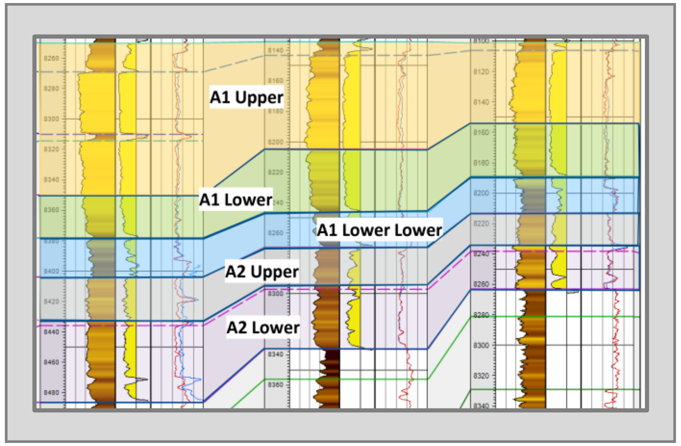
- Expanding A2 reservoir development in adjacent down-dip area
- Field compression capacity increased by 30 MMcf/d
- Total capital spend $10 million
- ~1.2 MMBbl proved reserves

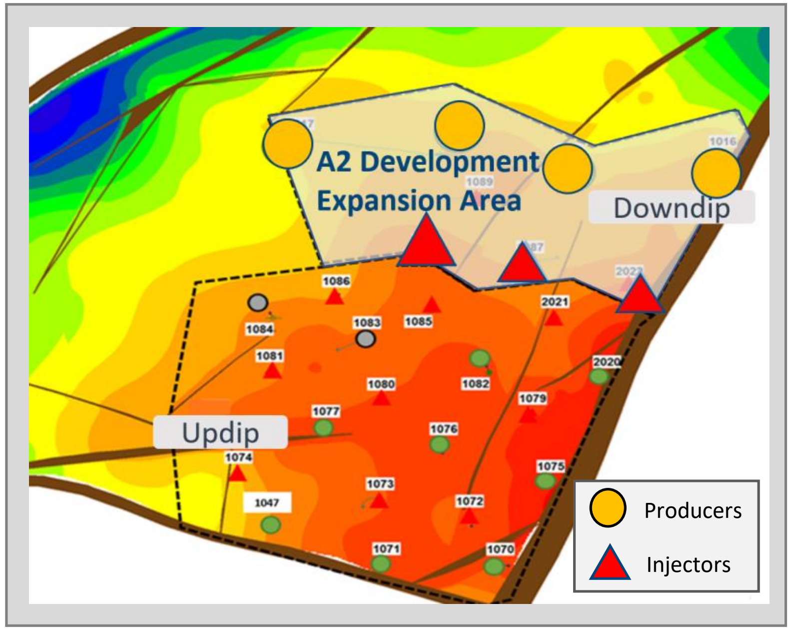
Project milestones

- Construction started in January 2020 and completed in early 2Q20
- Commenced CO_2 injection in April 2020 and first production in 2Q20
- 2 out of 4 producers responding at ~350 net BOE/d at the end of January, in line with expectations
- Additional development opportunities in A1 and A2 reservoirs

Producing zone in other phases

Development Expansion targeting A2 reservoir





Production by Area

Average Daily Production by Area (BOE/d)

Field	2018	2019	1Q20	2Q20	3Q20	4Q20	2020	1Q21
Delhi	4,368	4,324	3,813	3,529	3,208	3,132	3,419	2,925
Hastings	5,596	5,403	5,232	4,722	4,473	4,598	4,755	4,226
Heidelberg	4,355	4,195	4,371	4,366	4,256	4,198	4,297	4,054
Oyster Bayou	4,843	4,345	3,999	3,871	3,526	3,880	3,818	3,554
Tinsley	5,530	4,608	4,355	3,788	4,042	3,654	3,959	3,424
Bell Creek	4,113	5,228	5,731	5,715	5,551	5,079	5,518	4,614
Other Rockies(1)	2,116	2,196	2,199	1,393	2,167	2,007	1,942	2,573
Mature area(2) and other	6,907	7,062	7,161	5,944	6,271	6,332	6,427	6,098
Total tertiary production	37,828	37,361	36,861	33,328	33,494	32,880	34,135	31,468
Gulf Coast non-tertiary	4,391	4,201	4,173	3,805	3,728	3,523	3,807	3,621
Cedar Creek Anticline	14,837	14,090	13,046	11,988	11,485	11,433	11,985	11,150
Other Rockies non-tertiary	1,431	1,262	1,105	1,069	979	969	1,030	1,118
Total non-tertiary production	20,659	19,553	18,324	16,862	16,192	15,925	16,822	15,889
Total continuing production	58,487	56,914	55,185	50,190	49,686	48,805	50,957	47,357
Property divestitures(3)	1,854	1,299	780	–	–	–	194	–
Total production	60,341	58,213	55,965	50,190	49,686	48,805	51,151	47,357

1) Includes Big Sand Draw and Beaver Creek fields acquired on March 3, 2021.
2) Mature area includes Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb, and Soso fields.
3) Includes production from Lockhart Crossing Field sold in the third quarter of 2018, Citronelle Field sold in July 2019 and non-tertiary production related to the March 2020 sale of half of our nearly 100% working interests in Webster, Thompson, Manvel, and East Hastings fields.

Analysis of Total Operating Costs

Ability to flex operating costs in a low oil price environment

LOE Cost Type ($/BOE)	Correlation with Oil Price	**2018**	**2019**	1Q20	2Q20	3Q20	4Q20	**2020**	1Q21
CO_2 Costs	High	$3.07	$3.05	$2.98	$2.65	$2.28	$2.80	$2.69	$3.14
Power & Fuel	Moderate	6.32	6.34	6.38	5.99	6.05	6.61	6.26	3.87
Labor & Overhead	Low	6.61	7.11	6.52	6.34	6.41	6.30	6.39	7.30
Repairs & Maintenance	Moderate	0.91	0.99	0.77	0.60	0.74	0.71	0.71	0.77
Chemicals	Moderate	1.06	1.04	1.06	0.81	0.79	0.89	0.89	0.95
Workovers	High	2.96	2.57	2.31	0.57	1.45	1.77	1.55	2.00
Other	Low	1.31	1.36	1.44	0.84	(2.15)	0.91	0.29	1.20
Total LOE[1]		$22.24	$22.46	$21.46	$17.80	$15.57	$19.99	$18.78	$19.23
Oil Price									
NYMEX Oil Price		*$64.81*	*$57.03*	*$46.35*	*$28.42*	*$40.87*	*$42.66*	*$39.59*	*$57.82*
Realized Oil Price[2]		*$66.11*	*$58.26*	*$45.96*	*$24.39*	*$39.23*	*$40.63*	*$37.78*	*$56.28*

1) Includes a 3Q20 insurance settlement reimbursement of $15 million related to the 2013 well incident in the Delhi field and 1Q21 utility credit of $15 million.
2) Excludes derivative settlements.

NYMEX Oil Differential Summary

NYMEX Oil Differentials

$ per barrel	**2018**	**2019**	1Q20	2Q20	3Q20	4Q20	**2020**	1Q21
Tertiary oil fields								
Gulf Coast region	*$2.73*	*$3.07*	*$0.84*	*($3.69)*	*($1.48)*	*($1.91)*	*($0.87)*	*($1.54)*
Rocky Mountain region	*(1.81)*	*(2.18)*	*(3.28)*	*(2.83)*	*(1.92)*	*(2.14)*	*(2.34)*	*(1.81)*
Gulf Coast Non-Tertiary	4.28	4.77	3.52	(2.81)	(0.50)	(1.25)	0.51	0.05
Cedar Creek Anticline	(1.30)	(1.78)	(2.34)	(5.71)	(1.95)	(2.27)	(2.96)	(1.66)
Other Rockies Non-Tertiary	(2.87)	(4.35)	(5.11)	(6.27)	(4.62)	(4.78)	(5.23)	(3.85)
Denbury totals	$1.30	$1.23	($0.38)	($4.03)	($1.64)	($2.03)	($1.81)	($1.54)

Hedge Portfolio – As of May 5, 2021

NYMEX Oil Hedges		2021			2022	
		2Q	3Q	4Q	1H	2H
Fixed-Price Swaps	***Volumes Hedged (Bbls/d)***	***29,000***	***29,000***	***29,000***	***15,500***	***8,000***
	Swap Price[1]	$43.86	$43.86	$43.86	$49.01	$55.85
Collars	***Volumes Hedged (Bbls/d)***	***4,000***	***4,000***	***4,000***	***8,000***	***7,000***
	Floor Price[1]	$46.25	$46.25	$46.25	$49.69	$49.64
	Ceiling Price[1]	$53.04	$53.04	$53.04	$62.16	$61.66
	Total Volumes Hedged	**33,000**	**33,000**	**33,000**	**23,500**	**15,000**

1) Averages are volume weighted.

2021 Guidance – As of May 5, 2021

	1Q21 Actual	2021 Guidance
Development Capital	$20 million	$250 – $270 million[1] full year
Production	47,357 BOE/d	47,500 – 51,500 BOE/d full year
Realized Oil Differentials (NYMEX)	($1.54) per barrel	($1.50) – ($2.00) per barrel
Lifting Cost (LOE / BOE)	$19.23 / BOE[2]	$22 - $24 / BOE full year
G&A *(total including stock compensation)*	$32 million	$13 – $17 million per quarter (2Q-4Q)
Stock Compensation	$18 million	$2 – $3 million per quarter (2Q-4Q)
DD&A	$39 million	$42 – $45 million per quarter (2Q-4Q)
Diluted Shares	50.3 million shares[3]	51 – 52 million shares

Development Capital trend increasing throughout 2021 driven by CCA CO_2 spend

Production expected to increase from 1Q21 levels and remain relatively flat 2Q21 – 4Q21

1) Amounts presented exclude $5 - $7 million of capitalized interest.
2) Includes $15 million 1Q21 utility credit. See slide 33 for a detail of operating expenses.
3) Net loss per share (GAAP measure) is calculated using 50.3 million shares and Adjusted net income per share (non-GAAP measure) is calculated using 51.2 million shares.

Senior Secured Bank Credit Facility Info

Commitments & borrowing base	▪ Borrowing Base / Commitment level: $575 million
Scheduled redeterminations	▪ Semiannually – May 1st and November 1st, next redetermination is May 2021
Maturity date	▪ January 30, 2024
Permitted additional debt	▪ Up to $150 million unsecured, in the aggregate, with automatic borrowing base reduction by 25% of amount borrowed ▪ Junior lien debt only permitted with consent of majority lenders
Dividends and stock repurchases	▪ No dividends or stock repurchases prior to September 18, 2021. Commencing September 18, 2021, such transactions are permitted if the Company has accumulated Free Cash Flow (as defined in credit facility) as long as (1) leverage is less than 2x, (2) availability under the credit facility is at least 20%, and (3) no event of default or borrowing base deficiency exists.
Asset sales	▪ Oil and gas property sales and/or hedge terminations >5% of borrowing base would likely result in borrowing base reduction
Anti-hoarding provisions	▪ If unrestricted cash in accounts > $75 million at the end of any week, must prepay excess borrowings next business day
Pricing grid	see table below
Covenants	▪ Total Debt / EBITDAX (as defined): < 3.50x at the end of each quarter ▪ Current Ratio: > 1.00x at the end of each quarter ▪ Hedges may not exceed 85% of estimated proved production on a monthly basis

Pricing grid:

Level	Borrowing Base Utilization	Libor margin[1] (bps)	ABR margin (bps)	Undrawn pricing (bps)
I	$\leq$ 25.0%	300.0	200.0	50.0
II	$\leq$ 50.0%	325.0	225.0	50.0
III	$\leq$ 75.0%	350.0	250.0	50.0
IV	$\leq$ 90.0%	375.0	275.0	50.0
V	> 90.0%	400.0	300.0	50.0

1) Minimum LIBOR rate 1%

Non-GAAP Measures

Reconciliation of net income (loss) (GAAP measure) to adjusted EBITDAX (non-GAAP measure)

	2020					2021	
	Predecessor		Combined (non-GAAP)[1]	Successor	Combined (non-GAAP)[1]	Successor	Combined (non-GAAP)[1]
In millions	Q1	Q2	Q3	Q4	FY	Q1	TTM
Net income (loss) (GAAP measure)	$74	($697)	($806)	($53)	($1,483)	($70)	($1,626)
Adjustments to reconcile to Adjusted EBITDAX							
Interest expense	20	21	8	1	50	2	32
Income tax expense (benefit)	(11)	(102)	(304)	(3)	(419)	0	(409)
Depletion, depreciation, and amortization	97	55	42	41	234	39	177
Noncash fair value losses (gains) on commodity derivatives	(122)	86	18	80	62	77	261
Stock-based compensation	2	1	1	8	12	18	28
Gain on debt extinguishment	(19)	—	—	—	(19)	—	—
Write-down of oil and natural gas properties	73	662	262	1	998	14	939
Reorganization items, net	—	—	850	—	850	—	850
Noncash, non-recurring and other	2	13	22	2	41	2	39
Adjusted EBITDAX (non-GAAP measure)	$116	$39	$93	$77	$326	$82	$291

1) Combined results for the three months ended September 30, 2020, year ended December 31, 2020 and trailing twelve months ended March 31, 2021 are provided for illustrative purposes and are derived from the financial statement line items from the successor and predecessor periods in order to assist investors in understanding the comparability of the Company's financial and operational results for the applicable periods. A non-GAAP measure.

Adjusted EBITDAX is a non-GAAP financial measure which management uses and is calculated based upon (but not identical to) a financial covenant related to "Consolidated EBITDAX" in the Company's senior secured bank credit facility, which excludes certain items that are included in net income, the most directly comparable GAAP financial measure. Items excluded include interest, income taxes, depletion, depreciation, and amortization, and items that the Company believes affect the comparability of operating results such as items whose timing and/or amount cannot be reasonably estimated or are non-recurring. Management believes Adjusted EBITDAX may be helpful to investors in order to assess the Company's operating performance as compared to that of other companies in its industry, without regard to financing methods, capital structure or historical costs basis. It is also commonly used by third parties to assess leverage and the Company's ability to incur and service debt and fund capital expenditures. Adjusted EBITDAX should not be considered in isolation, as a substitute for, or more meaningful than, net income, cash flow from operations, or any other measure reported in accordance with GAAP. Adjusted EBITDAX may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDAX, EBITDAX or EBITDA in the same manner.