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, our ability to capitalize on emerging from bankruptcy and our ability to succeed on a long-term basis, the extent and length of the time that the drop in worldwide oil demand due to the COVID-19 coronavirus will continue, financial forecasts, future hydrocarbon prices and their volatility, current or future liquidity sources or their adequacy to support our anticipated future activities, 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 CO₂ flooding of particular fields or areas, timing of CO₂ 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, CO₂ 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 and 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 our 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 and 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 CO₂ Storage Associated with EOR: Our CO₂ EOR operations provide an environmentally responsible method of utilizing CO₂ for the primary purpose of oil recovery that also results in the associated underground storage of CO₂. Any reference in this presentation to storage of CO₂ associated with our EOR operations is not meant to encompass CO₂ stored for the primary purpose of carbon sequestration.

Statement Regarding Non-GAAP Financial Measures: This presentation also contains certain non-GAAP financial measures including Adjusted EBITDA. 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, 2018 and December 31, 2019 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

- CO₂ Enhanced Oil Recovery (EOR) is our primary focus
- Low base decline rate and low capital intensity
- CO₂ 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 CO₂ Emissions

- Annually injecting >3 million tons of industrial sourced CO₂ into our reservoirs
- Potential to reach full carbon neutrality this decade with CCUS, including downstream Scope 3 emissions

Strategically Advantaged Operations

- Vertically integrated CO₂ supply and distribution network with >1,000 miles of CO₂ 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

NYSE: DEN
Market Cap: $1.5B
Enterprise Value: $1.6B
Industry-Leading Oil Weighting

3Q20

% Oil & Liquids Production

Source: Peer filings for the third quarter ended 9/30/2020. Peers include CLR, CRC, CXO, DVN, LPI, MRO, MUR, OAS, PDCE, PXD, SM, WLL, and WPX.

1) NGL production is not reported separately for this entity.
Leading Revenue and Operating Margin per BOE

Higher Revenue per BOE

Higher Operating Margin per BOE

Denbury’s EOR-focused operations generate the highest revenue per BOE among peers, driving a best-in-class operating margin

3Q20 Operating Margin per BOE

3Q20 Revenue per BOE

Peers include CLR, CRO, CXY, DVN, LPI, MRQ, MUR, OAS, OXY, PDCE, PXD, SM, WLL, and WPX.

Source: Company filings for the three months ending 9/30/2020.

1) Operating margin calculated as revenues less lifting costs. Lifting costs calculated as lease operating expenses, marketing/transportation expenses and production and ad valorem taxes.

2) Revenues exclude gain/loss on commodity derivatives.
**The CO₂ EOR Process**

CO₂ Enhanced Oil Recovery (EOR) can produce nearly as much oil from a reservoir as was produced in either primary or secondary recovery.

**CO₂ EOR Process Overview**

- **Source CO₂** from Natural or Industrial Sources
- **CO₂ Injection Well**
- **Recycled CO₂**
- **Oil Reservoir**
- **Oil Sales**
- **Production Well**
- **CO₂ Recycle Facility**

**Example Recovery of Original Oil in Place**

- **Primary** ~20%
- **Secondary** (Waterfloods) ~18%
- **CO₂ EOR** (Tertiary) ~17%

**Description**

- CO₂ is injected into the reservoir, moves through the reservoir, and combines with oil that it contacts.
- The CO₂/oil combination then continues moving through the reservoir and into nearby production wells.
- Once on the surface, the oil and CO₂ are separated, the oil is processed for sale and the produced CO₂ is recycled into the reservoir along with supplemental source CO₂.
- Nearly all of the source CO₂ volume associated with EOR operations ultimately remains in secure underground containment.
Significant CO₂ 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]

<table>
<thead>
<tr>
<th>Region</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permian</td>
<td>9-21</td>
</tr>
<tr>
<td>East &amp; Central Texas</td>
<td>6-15</td>
</tr>
<tr>
<td>Mid-Continent</td>
<td>6-13</td>
</tr>
<tr>
<td>California</td>
<td>3-7</td>
</tr>
<tr>
<td>South East Gulf Coast</td>
<td>3-7</td>
</tr>
<tr>
<td>Rockies</td>
<td>2-6</td>
</tr>
<tr>
<td>Other</td>
<td>0-5</td>
</tr>
<tr>
<td>Michigan/Illinois</td>
<td>2-4</td>
</tr>
<tr>
<td>Williston</td>
<td>1-3</td>
</tr>
<tr>
<td>Appalachia</td>
<td>1-2</td>
</tr>
</tbody>
</table>

[^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.

Denbury’s fields represent ~10% of total potential[^3]
**Gulf Coast Region**

---

### YE19 Reserves Summary (MMBOE)

<table>
<thead>
<tr>
<th></th>
<th>Proved + Tertiary Potential</th>
<th>Tertiary Reserves</th>
<th>Non-Tertiary Reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Proved</td>
<td>Potential</td>
<td>Proved</td>
</tr>
<tr>
<td></td>
<td>118</td>
<td>277</td>
<td>21</td>
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<tr>
<td>Total MMBOE</td>
<td>416</td>
<td></td>
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</table>

### Proved + Tertiary Potential by Field

<table>
<thead>
<tr>
<th>Field</th>
<th>Proved + Tertiary Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mature Area</td>
<td>25</td>
</tr>
<tr>
<td>Conroe</td>
<td>130</td>
</tr>
<tr>
<td>Delhi</td>
<td>20</td>
</tr>
<tr>
<td>Hastings</td>
<td>30 – 65</td>
</tr>
<tr>
<td>Heidelberg</td>
<td>25</td>
</tr>
<tr>
<td>Manvel</td>
<td>10</td>
</tr>
<tr>
<td>Oyster Bayou</td>
<td>20</td>
</tr>
<tr>
<td>Tinsley</td>
<td>25</td>
</tr>
<tr>
<td>Thompson</td>
<td>20 – 40</td>
</tr>
<tr>
<td>Webster</td>
<td>40 – 75</td>
</tr>
<tr>
<td>W. Yellow Creek</td>
<td>5</td>
</tr>
</tbody>
</table>

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*Note: See “Slide Notes” on slide 27 in the appendix to this presentation for footnote explanations.*
Rocky Mountain Region

**YE19 Reserves Summary**(1) (MMBOE)

<table>
<thead>
<tr>
<th></th>
<th>Proved + Tertiary Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tertiary Reserves</strong></td>
<td></td>
</tr>
<tr>
<td>Proved</td>
<td>21</td>
</tr>
<tr>
<td>Potential</td>
<td>538</td>
</tr>
<tr>
<td><strong>Non-Tertiary Reserves</strong></td>
<td></td>
</tr>
<tr>
<td>Proved</td>
<td>71</td>
</tr>
<tr>
<td><strong>Total MMBOE</strong>(2)</td>
<td>630</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Proved + Tertiary Potential by Field</strong>(3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bell Creek</td>
</tr>
<tr>
<td>Cedar Creek Anticline Area</td>
</tr>
<tr>
<td>Gas Draw</td>
</tr>
<tr>
<td>Grieve</td>
</tr>
<tr>
<td>Hartzog Draw</td>
</tr>
<tr>
<td>Salt Creek</td>
</tr>
</tbody>
</table>

**Note:** See "Slide Notes" on slide 27 in the appendix to this presentation for footnote explanations.

**Pending Acquisition**
Pending Bolt-On Acquisition of Wyoming CO₂ EOR Fields

Supports Denbury’s CO₂ EOR focused strategy, utilizing 100% industrial sourced CO₂

**Beaver Creek / Big Sand Draw Oil Fields**

**Transaction Highlights**
- $12 million purchase price includes 46-mile CO₂ pipeline
- Net proved reserves of ~13.7 MMBOE (93% oil), including 5.5 MMBOE of PUD reserves with est. development cost < $5/BOE
- Annually utilizes nearly 400,000 tons of industrial sourced CO₂

**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
- 3Q 2020 net production ~2,800 BOE/d (85% oil)
- Expect to close acquisition in 1Q 2021
CCA EOR Development Potential >400 MMBbl

Key organic growth opportunity utilizing 100% industrial sourced CO₂

CO₂ Pipeline from Bell Creek
- ~$100 MM remaining of $150 MM total 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 ~18-24 months after first injection
- ~$140 MM development capital (excl. CO₂ pipeline) to initial tertiary production; $500 MM total capital over 15 years
- Economics support CO₂ pipeline

Phase 2
- Targets ~100 MMBbls of recoverable oil in Interlake, Stony Mountain and Red River formations in Cabin Creek
- Est. development ~2 years after Phase 1
- Total capex of ~$500–$600 MM over multiple decades

Future Phases – Remainder of CCA
- >300 MMBbl EOR potential in multiple formations

Est. 5 Billion Bbls OOIP
~175,000 net acres

~105 mi. CO₂ Pipeline from Bell Creek
$150 million

Phase 1 EOR Target
~30 MMBbls oil

Phase 2 EOR Target
~100 MMBbls oil
New Denbury: Positioned for the Future

“We are better positioned to compete in a dynamic and evolving energy market and capitalize on the many opportunities ahead, including leveraging our expertise and our strategic assets into an emerging carbon capture, use and storage business.”

– Chris Kendall

Management & Corporate Structure
4 new and 3 continuing Board members
No changes to management team
Renamed to Denbury Inc. and new NYSE ticker: DEN

Strong Balance Sheet & Financial Discipline
Maintaining a conservative balance sheet is a top priority
Disciplined approach to capital allocation and cost control

Strategic Growth & Acquisitions
Positioned to be an opportunistic aggregator of assets that align with our strategy
Delevered balance sheet creates significant flexibility

Leader in Reducing CO₂ Emissions
Annually injecting >3 million metric tons of industrial-sourced CO₂ into our reservoirs
Potential to reach full carbon neutrality this decade with CCUS, including downstream Scope 3 emissions

Untapped potential in CO₂ EOR & Emerging CCUS Business
CCA CO₂ EOR development is our key organic growth opportunity; plan to move forward as soon as practical
CCUS Gulf Coast opportunities are materializing rapidly; plan to leverage our infrastructure and expertise to be a leader in this emerging business

Restructured Denbury can generate significant free cash flow at a low $40s oil price
Key Accomplishments of Reorganization

- Eliminated $2.1 billion in bond debt
- Significantly improved leverage metrics
- Reduced annual cash interest by $170 million (~$9/BOE)
- Established new $575 million credit facility with $85 million drawn as of September 30, 2020
- Eliminated ~$9 million ($0.50/BOE) from annual overhead costs by relocating corporate headquarters
- On October 30, 2020 reacquired the NEJD and Free State CO₂ Pipelines, further reducing debt and lowering interest expense while maximizing flexibility for future CCUS operations

Pre-packed plan supported a fast and efficient 53 day process

- Entered in Restructuring Support Agreement (RSA) with banks, second lien and convertible noteholders
- Filed pre-packed reorganization plan under Chapter 11
- Court Confirmed Plan of Reorganization
- Emerged from Chapter 11 Proceedings

- July 28
- July 30
- Sept 2
- Sept 18
Substantially Reduced Cash Breakeven Cost Post-Restructuring

<table>
<thead>
<tr>
<th>3Q20 Summary ($)BOE, excluding interest</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Realized Price (including hedges)</td>
<td>$42.27</td>
</tr>
<tr>
<td>Cash Operating Margin</td>
<td>$14.71</td>
</tr>
<tr>
<td>G&amp;A(2)</td>
<td>$3.54</td>
</tr>
<tr>
<td>Transportation, Marketing &amp; Taxes</td>
<td>$5.08</td>
</tr>
<tr>
<td>Lifting Cost(3)</td>
<td>$18.94</td>
</tr>
</tbody>
</table>

**Cash Operating Margin $14.71 per BOE**

**Cash Operating Costs $27.56 per BOE**

**Reduced go-forward cash costs by ~$10 per BOE**

- ~$170 million ($9/boe) annual reduction in cash interest
- ~$9 million ($0.50/boe) annual reduction in overhead costs through relocation of corporate headquarters

---

1) Excludes selected items of interest, other expense and CO2 operating margin.
2) G&A excludes non-cash compensation of approximately $0.6 million ($0.12/BOE).
3) Lifting Cost excludes receipt of insurance settlement of $15.4 million ($3.37/BOE). See slide 33 for a detail of operating expenses.
2020 Capital and Production Guidance

**Capital Details**

<table>
<thead>
<tr>
<th>Year</th>
<th>Capital (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>YTD 2020</td>
<td>$78 million</td>
</tr>
<tr>
<td>1Q20</td>
<td>$23</td>
</tr>
<tr>
<td>2Q20</td>
<td>$19</td>
</tr>
<tr>
<td>3Q20</td>
<td>$9</td>
</tr>
<tr>
<td>4Q20</td>
<td>$27</td>
</tr>
<tr>
<td>FY 2020E</td>
<td>$35 - $105 million</td>
</tr>
</tbody>
</table>

**Capital Expenditure Highlights**

- **Tertiary**
  - Oyster Bayou A2 Development Expansion
  - CCA CO₂ Facilities and Wellwork

- **Non-Tertiary**
  - Maintenance Capital

- **CO₂ Pipeline & Other**
  - CCA CO₂ pipe prepared for installation

**Continuing Production (BOE/d)**

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Production (BOE/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1Q20</td>
<td>55,185</td>
</tr>
<tr>
<td>2Q20</td>
<td>50,190</td>
</tr>
<tr>
<td>3Q20</td>
<td>49,686</td>
</tr>
<tr>
<td>2020E</td>
<td>50,900 – 51,400</td>
</tr>
</tbody>
</table>

Note: amounts presented exclude capitalized interest and 2020E represents an estimate.
1. Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.
Continued Strong Governance with a Post-Reorganization Board

**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%)
- **4 new and 3 continuing** members
- Recently formed a **Sustainability Committee** of the Board of Directors

**3 Continuing Board Members**

- 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*, Audit and Sustainability Committee

**4 New Board Members**

- Anthony Abate
  - New Director 2020
  - Audit* and Compensation Committee
- Caroline Angoorly
  - New Director 2020
  - Sustainability* and Nominating/Corporate Governance Committee
- James Chapman
  - New Director 2020
  - Compensation* and Nominating/Corporate Governance Committee
- Brett Wiggs
  - New Director 2020
  - Audit Committee

*Reflects Committee Chairperson

See full biographies for the Board Members at www.denbury.com
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 2019
• 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

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
An Industry Leader in Reducing CO₂ Emissions

Environment

The only U.S. public company of scale where injecting CO₂ into the ground to produce oil is our primary business

Combined Scope 1 and Scope 2 CO₂ Emissions Net Negative
Average of 2018 and 2019

Combined Scope 1 & 2 Emissions
1.8 million metric tons

Captured Industrial-Sourced CO₂
3.2 million metric tons

Net Negative CO₂ Emissions
– 1.4 million metric tons

~30% of our CO₂ is industrial sourced

We utilized 3.2 million metric tons (2018-2019) of industrially sourced CO₂ that could otherwise have been released into the atmosphere

Annual greenhouse gas emissions from almost 700,000 cars
Carbon Capture, Use and Storage (CCUS) Overview

CCUS – both through CO₂ EOR or direct CO₂ injection – is a proven technology with the potential for safe, long-term, deep underground containment of hundreds of millions of tons of industrial sourced CO₂.

**CO₂ Stored in Association with EOR**

- Natural or Industrial CO₂ + CO₂ pipeline → CO₂ injection into Oilfield → CO₂ Recycled & Stored

**CO₂ Directly Stored**

- Industrial CO₂ + CO₂ pipeline → CO₂ injection into Saline Formations → CO₂ Stored

**A proven process**

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

Experience gained from decades of safe CO₂ EOR operations translates directly into safe CCUS operations.

**Reduces atmospheric CO₂**

CCUS has the potential to drive a significant reduction in atmospheric CO₂ emissions.

The NPC’s 2019 CCUS report identified a reasonable path where the volume of CO₂ 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 CO₂ used in EOR operations and $50/ton for CO₂ 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.
Denbury is Strategically Positioned to Lead in CCUS

**Gulf Coast pipeline network provides extensive framework for CCUS operations**

**Gulf Coast Infrastructure Highlights**

- Strategically located, 100% owned Green CO₂ pipeline along the Gulf Coast can transport >800 MMcf/d (>16 MM tons/year) of CO₂
- Extensive (~830 miles) pipeline network ideally suited for transporting captured CO₂ to either EOR or permanent storage sites
- Multiple CO₂ sources and EOR injection sites provide operational flexibility to ensure reliable CCUS operations

~140 MM tons / year\(^1\) of CO₂ are currently emitted within ~15 miles of Denbury’s Green Pipeline corridor, an estimated 40% of which has a capture cost <$50/ton

---

1) 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
Eliminated $2.1 billion in bond debt and reduced annual cash interest by $165 million

**Debt Restructuring Highlights**

- **Pre-Restructuring Net Debt:** $2,281 million
  - Sr. Subordinated Notes: $246 million
  - Sr. Secured 2nd Lien Notes: $226 million
  - Convertible Sr. Notes: $56 million
  - Sr. Secured Credit Facility, Net of Cash: $1,593 million

- **Post-Restructuring Net Debt:** $1,593 million
  - Sr. Subordinated Notes: $160 million
  - Sr. Secured 2nd Lien Notes: $91 million
  - Convertible Sr. Notes: $63 million

**NEJD and Free State Pipeline transactions reduced debt by $25 million**

**Capital Structure Overview**

**New Equity Summary**
- Initial 50 million shares outstanding
- Former holders of Second Lien Notes received 95% of new equity
- Former holders of Convertible Notes received 5% of new equity plus 100% of Series A Warrants
- Former holders of Sr. Sub. Notes received ~55% of Series B Warrants
- Existing Shareholders received ~45% of Series B Warrants

**New Sr. Secured Credit Facility**
- $575 million borrowing base
- $437 million availability at Sept 30, 2020
  - $85 million drawn
  - $53 million of letters of credit issued
- Semi-annual redeterminations beginning May 1, 2021
- Maturity Date: January 30, 2024
- Financial Covenants:
  - Total Debt / EBITDAX: < 3.50x at 12/31/2020
  - Current Ratio: > 1.00x at 12/31/2020

1) Series A Warrants represent rights to purchase 2.6 MM shares at $32.59 per share and Series B Warrants represent rights to purchase 2.9 MM shares at $35.41 per share.
2) Sr. Secured Credit Facility borrowings and cash were $265 million and $209 million, respectively, at June 30, 2020. Sr. Secured Credit Facility borrowings and cash were $85 million and $22 million, respectively, at September 30, 2020.
Denbury Reacquires NEJD and Free State Pipelines

Reduces debt and lowers cash interest while maximizing flexibility for future CCUS operations

Transaction Highlights

Summary

▪ Reacquired the NEJD Pipeline for $70 million and the Free State Pipeline for $22.5 million

Details

▪ Remaining $70 million in NEJD financing lease payments to be paid in four equal payments on January 31, April 30, July 31 and October 31, 2021
▪ Reacquired Free State Pipeline with a single payment of $22.5 million on October 30, 2020

Benefits

▪ Reduces total debt by $25 million
▪ Lowers annual cash interest expense
▪ All Gulf Coast CO₂ pipelines now 100% owned and operated, ensuring maximum flexibility for future CCUS operations
<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>4Q</td>
<td>FY</td>
<td>1H</td>
</tr>
<tr>
<td><strong>Fixed Price</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Swaps</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NYMEX</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WTI</td>
<td>Volumes Hedged (Bbls/d)</td>
<td>13,500</td>
<td>26,000</td>
</tr>
<tr>
<td></td>
<td>Swap Price(^{(1)})</td>
<td>$40.52</td>
<td>$42.54</td>
</tr>
<tr>
<td>Argus LLS</td>
<td>Volumes Hedged (Bbls/d)</td>
<td>7,500</td>
<td>–</td>
</tr>
<tr>
<td></td>
<td>Swap Price(^{(1)})</td>
<td>$51.67</td>
<td>–</td>
</tr>
<tr>
<td><strong>3-Way</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Collars</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NYMEX</td>
<td>WTI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Volumes Hedged (Bbls/d)</td>
<td>9,500</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Sold Put Price(^{(1)(2)})</td>
<td>$47.93</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Floor Price(^{(1)})</td>
<td>$57.00</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Ceiling Price(^{(1)})</td>
<td>$63.25</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Argus LLS</td>
<td>Volumes Hedged (Bbls/d)</td>
<td>5,000</td>
<td>–</td>
</tr>
<tr>
<td>Sold Put Price(^{(1)(2)})</td>
<td>$52.80</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Floor Price(^{(1)})</td>
<td>$61.63</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Ceiling Price(^{(1)})</td>
<td>$70.35</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>WTI</td>
<td>Volumes Hedged (Bbls/d)</td>
<td>–</td>
<td>3,000</td>
</tr>
<tr>
<td>Floor Price(^{(1)})</td>
<td>–</td>
<td>$45.00</td>
<td>–</td>
</tr>
<tr>
<td>Ceiling Price(^{(1)})</td>
<td>–</td>
<td>$50.95</td>
<td>–</td>
</tr>
<tr>
<td><strong>Total Volumes Hedged</strong></td>
<td>35,500</td>
<td>29,000</td>
<td>8,500</td>
</tr>
<tr>
<td>% of 3Q20 Volumes (BOE/d)</td>
<td>71%</td>
<td>58%</td>
<td>17%</td>
</tr>
<tr>
<td><strong>3-Way Collars – Weighted Avg. Floor Less Sold Put (All)</strong></td>
<td>$8.99</td>
<td>–</td>
<td>–</td>
</tr>
</tbody>
</table>

1) Averages are volume weighted.
2) If oil prices were to average less than the sold put price, receipts on settlement would be limited to the difference between the floor price and sold put.
Our Vision

To be recognized as the world leader in CO₂ Enhanced Oil Recovery, significant in scale, financially secure, and strategically positioned through our expertise and our assets to lead the industry in the emerging Carbon Capture, Use and Storage (CCUS) business
Appendix
Slide Notes

Slide 8 – Gulf Coast Region

1) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/19 SEC pricing ($55.69 per Bbl for crude oil and $2.58 per MMBtu for natural gas) and have not been adjusted for the March 2020 sale of half of the Company’s working interest position in Webster, Thompson, Manvel and East Hastings totaling 4.1 million barrels of non-tertiary reserves. 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 12/31/19 SEC pricing ($55.69 per Bbl for crude oil and $2.58 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.
**CO₂ EOR is a Proven Process**

### Significant CO₂ 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 CO₂ 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)
### Gulf Coast CO₂ Supply

**Jackson Dome**
- Proved CO₂ reserves as of 12/31/19: ~4.8 Tcf
- Additional probable CO₂ reserves as of 12/31/19: ~0.9 Tcf

**Industrial-Sourced CO₂**

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

### Rocky Mountain CO₂ Supply

**LaBarge Area**
- Estimated field size: 750 square miles
- Estimated recoverable CO₂: 100 Tcf

**Shute Creek – ExxonMobil Operated**
- Proved reserves as of 12/31/19: ~1.1 Tcf
- Denbury has a 1/3 overriding royalty interest and could receive up to ~115 MMcf/d of CO₂ by 2021 at current plant capacity

**Lost Cabin – ConocoPhillips Operated**
- Potential to receive up to 40 MMcf/d of CO₂

---

1) Reported on a gross (8/8th’s) basis.
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 CO₂ injection in April 2020 and first production in 2Q20
- 2 out of 4 producers responding at ~420 net BOE/d at the end of October, in line with expectations
- Additional development opportunities in A1 and A2 reservoirs
Houston Acreage Land Sale Update

Transaction Highlights

- $49 million closed as of December 2020
  - $20 million closed in 2018-2019
  - $14 million closed in July 2020
  - $11 million closed in October 2020
  - $4 million closed in December 2020
- $30 - $50 million estimated value in remaining acreage

**Conroe**
Commercial and residential development surface acreage
Sold ~2,500 acres
Remaining ~150 acres

**Webster**
Commercial development surface acreage
Sold ~30 acres
Remaining ~400 acres
Multiple parcels along I-45 frontage road
### Production by Area

#### Average Daily Production by Area (BOE/d)

<table>
<thead>
<tr>
<th>Field</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>1Q20</th>
<th>2Q20</th>
<th>3Q20</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delhi</td>
<td>4,155</td>
<td>4,869</td>
<td>4,368</td>
<td>4,324</td>
<td>3,813</td>
<td>3,529</td>
<td>3,208</td>
</tr>
<tr>
<td>Hastings</td>
<td>4,829</td>
<td>4,830</td>
<td>5,596</td>
<td>5,403</td>
<td>5,232</td>
<td>4,722</td>
<td>4,473</td>
</tr>
<tr>
<td>Heidelberg</td>
<td>5,128</td>
<td>4,851</td>
<td>4,355</td>
<td>4,195</td>
<td>4,371</td>
<td>4,366</td>
<td>4,256</td>
</tr>
<tr>
<td>Oyster Bayou</td>
<td>5,083</td>
<td>5,007</td>
<td>4,843</td>
<td>4,345</td>
<td>3,999</td>
<td>3,871</td>
<td>3,526</td>
</tr>
<tr>
<td>Tinsley</td>
<td>7,192</td>
<td>6,430</td>
<td>5,530</td>
<td>4,608</td>
<td>4,355</td>
<td>3,788</td>
<td>4,042</td>
</tr>
<tr>
<td>Bell Creek</td>
<td>3,121</td>
<td>3,313</td>
<td>4,113</td>
<td>5,228</td>
<td>5,731</td>
<td>5,715</td>
<td>5,551</td>
</tr>
<tr>
<td>Salt Creek</td>
<td>–</td>
<td>1,115</td>
<td>2,109</td>
<td>2,143</td>
<td>2,149</td>
<td>1,386</td>
<td>2,167</td>
</tr>
<tr>
<td>West Yellow Creek</td>
<td>–</td>
<td>13</td>
<td>205</td>
<td>640</td>
<td>775</td>
<td>695</td>
<td>588</td>
</tr>
<tr>
<td>Mature area(^1) and other</td>
<td>8,252</td>
<td>7,078</td>
<td>6,709</td>
<td>6,475</td>
<td>6,436</td>
<td>5,256</td>
<td>5,683</td>
</tr>
<tr>
<td><strong>Total tertiary production</strong></td>
<td>37,760</td>
<td>37,506</td>
<td>37,828</td>
<td>37,361</td>
<td>36,861</td>
<td>33,328</td>
<td>33,494</td>
</tr>
<tr>
<td>Gulf Coast non-tertiary</td>
<td>4,742</td>
<td>4,439</td>
<td>4,391</td>
<td>4,201</td>
<td>4,173</td>
<td>3,805</td>
<td>3,728</td>
</tr>
<tr>
<td>Cedar Creek Anticline</td>
<td>16,322</td>
<td>14,754</td>
<td>14,837</td>
<td>14,090</td>
<td>13,046</td>
<td>11,988</td>
<td>11,485</td>
</tr>
<tr>
<td>Other Rockies non-tertiary</td>
<td>1,844</td>
<td>1,537</td>
<td>1,431</td>
<td>1,262</td>
<td>1,105</td>
<td>1,069</td>
<td>979</td>
</tr>
<tr>
<td><strong>Total non-tertiary production</strong></td>
<td>22,908</td>
<td>20,730</td>
<td>20,659</td>
<td>19,553</td>
<td>18,324</td>
<td>16,862</td>
<td>16,192</td>
</tr>
<tr>
<td><strong>Total continuing production</strong></td>
<td>60,668</td>
<td>58,236</td>
<td>58,487</td>
<td>56,914</td>
<td>55,185</td>
<td>50,190</td>
<td>49,686</td>
</tr>
<tr>
<td>Property divestitures(^2)</td>
<td>3,335</td>
<td>2,062</td>
<td>1,854</td>
<td>1,299</td>
<td>780</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td><strong>Total production</strong></td>
<td>64,003</td>
<td>60,298</td>
<td>60,341</td>
<td>58,213</td>
<td>55,965</td>
<td>50,190</td>
<td>49,686</td>
</tr>
</tbody>
</table>

1. Mature area includes Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb, and Soso fields.
2. Includes production from non-tertiary production in the Rocky Mountain region related to the sale of remaining non-core assets in the Williston Basin of North Dakota and Montana, which closed in the third quarter of 2016, and other minor property divestitures, 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.

---

1,800 BOE/d production shut-in as of 9/30/20
## Analysis of Total Operating Costs

**Ability to flex operating costs in a low oil price environment**

<table>
<thead>
<tr>
<th>LOE Cost Type ($/BOE)</th>
<th>Correlation with Oil Price</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>1Q20</th>
<th>2Q20</th>
<th>3Q20</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Costs</td>
<td>High</td>
<td>$2.16</td>
<td>$2.86</td>
<td>$3.07</td>
<td>$3.05</td>
<td>$2.98</td>
<td>$2.65</td>
<td>$2.28</td>
</tr>
<tr>
<td>Power &amp; Fuel</td>
<td>Moderate</td>
<td>5.29</td>
<td>5.97</td>
<td>6.32</td>
<td>6.34</td>
<td>6.38</td>
<td>5.99</td>
<td>6.05</td>
</tr>
<tr>
<td>Labor &amp; Overhead</td>
<td>Low</td>
<td>5.41</td>
<td>6.32</td>
<td>6.61</td>
<td>7.11</td>
<td>6.52</td>
<td>6.34</td>
<td>6.41</td>
</tr>
<tr>
<td>Repairs &amp; Maintenance</td>
<td>Moderate</td>
<td>0.84</td>
<td>0.84</td>
<td>0.91</td>
<td>0.99</td>
<td>0.77</td>
<td>0.60</td>
<td>0.74</td>
</tr>
<tr>
<td>Chemicals</td>
<td>Moderate</td>
<td>1.02</td>
<td>1.04</td>
<td>1.06</td>
<td>1.04</td>
<td>1.06</td>
<td>0.81</td>
<td>0.79</td>
</tr>
<tr>
<td>Workovers</td>
<td>High</td>
<td>1.87</td>
<td>2.44</td>
<td>2.96</td>
<td>2.57</td>
<td>2.31</td>
<td>0.57</td>
<td>1.45</td>
</tr>
<tr>
<td>Other</td>
<td>Low</td>
<td>0.97</td>
<td>1.06</td>
<td>1.31</td>
<td>1.36</td>
<td>1.44</td>
<td>0.84</td>
<td>1.22</td>
</tr>
</tbody>
</table>

*Total Normalized LOE*(1) $17.56 $20.53 $22.24 $22.46 $21.46 $17.80 $18.94

*Special or Unusual Items*(2) 0.15 (0.18) — — — — ($3.37)

*Total LOE* $17.71 $20.35 $22.24 $22.46 $21.46 $17.80 $15.57

<table>
<thead>
<tr>
<th>Oil Price</th>
<th>NYMEX Oil Price</th>
<th>Realized Oil Price*(3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016</td>
<td>$43.41</td>
<td>$41.12</td>
</tr>
<tr>
<td>2017</td>
<td>$50.96</td>
<td>$50.64</td>
</tr>
<tr>
<td>2018</td>
<td>$64.81</td>
<td>$66.11</td>
</tr>
<tr>
<td>2019</td>
<td>$57.03</td>
<td>$58.26</td>
</tr>
<tr>
<td>1Q20</td>
<td>$46.35</td>
<td>$45.96</td>
</tr>
<tr>
<td>2Q20</td>
<td>$28.42</td>
<td>$24.39</td>
</tr>
<tr>
<td>3Q20</td>
<td>$40.87</td>
<td>$39.23</td>
</tr>
</tbody>
</table>

---

1) Normalized LOE excludes special or unusual items (see footnote 2 below).
2) Special or unusual items consist of cost to return Thompson field to production following weather-related flooding in 2016, clean up and repair costs associated with Hurricane Harvey ($3MM) offset by an adjustment for pricing related to one of our industrial CO₂ sources ($7MM) in 2017 and an insurance settlement reimbursement in the amount of $15.4 million related to 2013 well incident in the Delhi field.
3) Excludes derivative settlements.
<table>
<thead>
<tr>
<th>Tertiary oil fields</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>1Q20</th>
<th>2Q20</th>
<th>3Q20</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gulf Coast region</td>
<td>($1.35)</td>
<td>$0.06</td>
<td>$2.73</td>
<td>$3.07</td>
<td>$0.84</td>
<td>($3.69)</td>
<td>($1.48)</td>
</tr>
<tr>
<td>Rocky Mountain region</td>
<td>(2.16)</td>
<td>(0.96)</td>
<td>(1.81)</td>
<td>(2.18)</td>
<td>(3.28)</td>
<td>(2.83)</td>
<td>(1.92)</td>
</tr>
<tr>
<td>Gulf Coast Non-Tertiary</td>
<td>(1.89)</td>
<td>1.26</td>
<td>4.28</td>
<td>4.77</td>
<td>3.52</td>
<td>(2.81)</td>
<td>(0.50)</td>
</tr>
<tr>
<td>Cedar Creek Anticline</td>
<td>(3.77)</td>
<td>(1.43)</td>
<td>(1.30)</td>
<td>(1.78)</td>
<td>(2.34)</td>
<td>(5.71)</td>
<td>(1.95)</td>
</tr>
<tr>
<td>Other Rockies Non-Tertiary</td>
<td>(8.63)</td>
<td>(2.72)</td>
<td>(2.87)</td>
<td>(4.35)</td>
<td>(5.11)</td>
<td>(6.27)</td>
<td>(4.62)</td>
</tr>
<tr>
<td>Denbury totals</td>
<td>($2.29)</td>
<td>($0.32)</td>
<td>$1.30</td>
<td>$1.23</td>
<td>($0.38)</td>
<td>($4.03)</td>
<td>($1.64)</td>
</tr>
</tbody>
</table>
### CO₂ Cost & NYMEX Oil Price

#### Industrial-Sourced CO₂ %
- Q1 2015: 18%
- Q2 2015: 22%
- Q3 2015: 22%
- Q4 2015: 23%
- Q1 2016: 25%
- Q2 2016: 22%
- Q3 2016: 26%
- Q4 2016: 24%
- Q1 2017: 25%
- Q2 2017: 28%
- Q3 2017: 29%
- Q4 2017: 34%
- Q1 2018: 29%
- Q2 2018: 28%
- Q3 2018: 26%
- Q4 2018: 25%
- Q1 2019: 23%
- Q2 2019: 25%
- Q3 2019: 30%
- Q4 2019: 36%
- Q1 2020: 33%

#### NYMEX Crude Oil Price / Bbl
- Q1 2015: 48.8
- Q2 2015: 57.9
- Q3 2015: 46.7
- Q4 2015: 42.1
- Q1 2016: 33.7
- Q2 2016: 45.5
- Q3 2016: 45.0
- Q4 2016: 49.2
- Q1 2017: 51.9
- Q2 2017: 48.3
- Q3 2017: 48.1
- Q4 2017: 55.4
- Q1 2018: 62.9
- Q2 2018: 67.8
- Q3 2018: 69.6
- Q4 2018: 58.8
- Q1 2019: 54.8
- Q2 2019: 59.8
- Q3 2019: 56.3
- Q4 2019: 57.0
- Q1 2020: 46.3

1. Excludes DD&A on CO₂ wells and facilities; includes Gulf Coast & Rocky Mountain industrial-source CO₂ costs.
2. CO₂ costs include workovers carried out at Jackson Dome in Q3 2017 and Q4 2015 of $3 million ($0.08 per Mcf) and $3 million ($0.05 per Mcf), respectively, and a downward adjustment in Q4 2017 for pricing related to one of our industrial CO₂ sources of $7 million ($0.12 per Mcf).
New Senior Secured Bank Credit Facility Info

Commitments & borrowing base
- Borrowing Base / Commitment level: $575 million
- Lender group comprised of same 14 banks as were part of the pre-petition credit facility

Scheduled redeterminations
- Semiannually – May 1st and November 1st, next redetermination is May 2021

Maturity date
- January 30, 2024

Hedging requirements
- At December 31, 2020, hedge agreements covering anticipated total proved developed producing reserves in an amount not less than:
  - 65% for the period 8/1/2020 – 7/31/2021
  - 35% for the period 8/1/2021 – 7/31/2022
- Hedges may not exceed 85% of estimated proved production on a monthly basis

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 in first year after emergence. After one year, 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

<table>
<thead>
<tr>
<th>Level</th>
<th>Borrowing Base Utilization</th>
<th>Libor margin(1) (bps)</th>
<th>ABR margin (bps)</th>
<th>Undrawn pricing (bps)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>≤ 25.0%</td>
<td>300.0</td>
<td>200.0</td>
<td>50.0</td>
</tr>
<tr>
<td>II</td>
<td>≤ 50.0%</td>
<td>325.0</td>
<td>225.0</td>
<td>50.0</td>
</tr>
<tr>
<td>III</td>
<td>≤ 75.0%</td>
<td>350.0</td>
<td>250.0</td>
<td>50.0</td>
</tr>
<tr>
<td>IV</td>
<td>≤ 90.0%</td>
<td>375.0</td>
<td>275.0</td>
<td>50.0</td>
</tr>
<tr>
<td>V</td>
<td>&gt; 90.0%</td>
<td>400.0</td>
<td>300.0</td>
<td>50.0</td>
</tr>
</tbody>
</table>

1) Minimum LIBOR rate 1%

Covenants
- Total Debt / EBITDAX (as defined): < 3.50x at 12/31/2020
- Current Ratio: > 1.00x at 12/31/2020
Non-GAAP Measures

Reconciliation of net income (loss) (GAAP measure) to adjusted cash flows from operations (non-GAAP measure) to cash flows from operations (GAAP measure)

<table>
<thead>
<tr>
<th>In millions</th>
<th>2019 Predecessor</th>
<th>2020 Predecessor</th>
<th>Combined (non-GAAP)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Q1</td>
<td>Q2</td>
<td>Q3</td>
</tr>
<tr>
<td>Net income (loss) (GAAP measure)</td>
<td>($26)</td>
<td>$147</td>
<td>$73</td>
</tr>
<tr>
<td>Adjustments to reconcile to adjusted cash flows from operations</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depletion, depreciation, and amortization</td>
<td>57</td>
<td>58</td>
<td>55</td>
</tr>
<tr>
<td>Deferred income taxes</td>
<td>(9)</td>
<td>62</td>
<td>38</td>
</tr>
<tr>
<td>Stock-based compensation</td>
<td>3</td>
<td>4</td>
<td>3</td>
</tr>
<tr>
<td>Noncash fair value losses (gains) on commodity derivatives</td>
<td>92</td>
<td>(26)</td>
<td>(35)</td>
</tr>
<tr>
<td>Gain on debt extinguishment</td>
<td>—</td>
<td>(100)</td>
<td>(6)</td>
</tr>
<tr>
<td>Write-down of oil and natural gas properties</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Reorganization items</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Other</td>
<td>2</td>
<td>0</td>
<td>(2)</td>
</tr>
<tr>
<td>Adjusted cash flows from operations (non-GAAP measure)</td>
<td>$119</td>
<td>$145</td>
<td>$126</td>
</tr>
<tr>
<td>Net change in assets and liabilities relating to operations</td>
<td>(55)</td>
<td>4</td>
<td>5</td>
</tr>
<tr>
<td>Cash flows from operations (GAAP measure)</td>
<td>$64</td>
<td>$149</td>
<td>$131</td>
</tr>
</tbody>
</table>

1) Combined results for the three months ended September 30, 2020 are provided for illustrative purposes and are derived from the financial statement line items from the successor and predecessor periods included in the third quarter. A non-GAAP measure. See press release attached as exhibit 99.1 to the Form 8-K filed November 16, 2020 for additional information indicating why the Company believes this non-GAAP measure is useful for investors.

Adjusted cash flows from operations is a non-GAAP measure that represents cash flows provided by operations before changes in assets and liabilities, as summarized from the Company's Consolidated Statements of Cash Flows. Adjusted cash flows from operations measures the cash flows earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. Management believes that it is important to consider this additional measure, along with cash flows from operations, as it believes the non-GAAP measure can often be a better way to discuss changes in operating trends in its business caused by changes in production, prices, operating costs and related factors, without regard to whether the earned or incurred item was collected or paid during that period.
Reconciliation of net income (loss) (GAAP measure) to adjusted EBITDAX (non-GAAP measure)

1) Combined results for the three months ended September 30, 2020 are provided for illustrative purposes and are derived from the financial statement line items from the successor and predecessor periods included in the third quarter. A non-GAAP measure. See press release attached as exhibit 99.1 to the Form 8-K filed November 16, 2020 for additional information indicating why the Company believes this non-GAAP measure is useful for investors.

2) Includes expenses incurred before the petition date and after the Emergence Date related to advisor and professional fees associated with the restructuring of $16 million and $8 million during the quarter ended September 30, 2020 and June 30, 2020, respectively, but excludes an insurance reimbursement of $15 million during the quarter ended September 30, 2020, as the related expenses were not adjusted when originally incurred.

3) This calculation excludes pro forma adjustments related to qualified acquisitions or dispositions under the Company’s senior secured bank credit facility. Third quarter of 2020 adjusted EBITDAX includes an insurance reimbursement of $15 million, as EBITDAX was not adjusted for the related expenses when originally incurred, and second quarter of 2020 adjusted EBITDAX includes $12 million of expense in connection with the cash retention and incentive compensation resulting from the modification of compensation arrangements for 21 of the Company’s executives and senior managers.

Adjusted EBITDAX (non-GAAP measure) 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.