Denbury

IPAA Luncheon

June 12, 2019

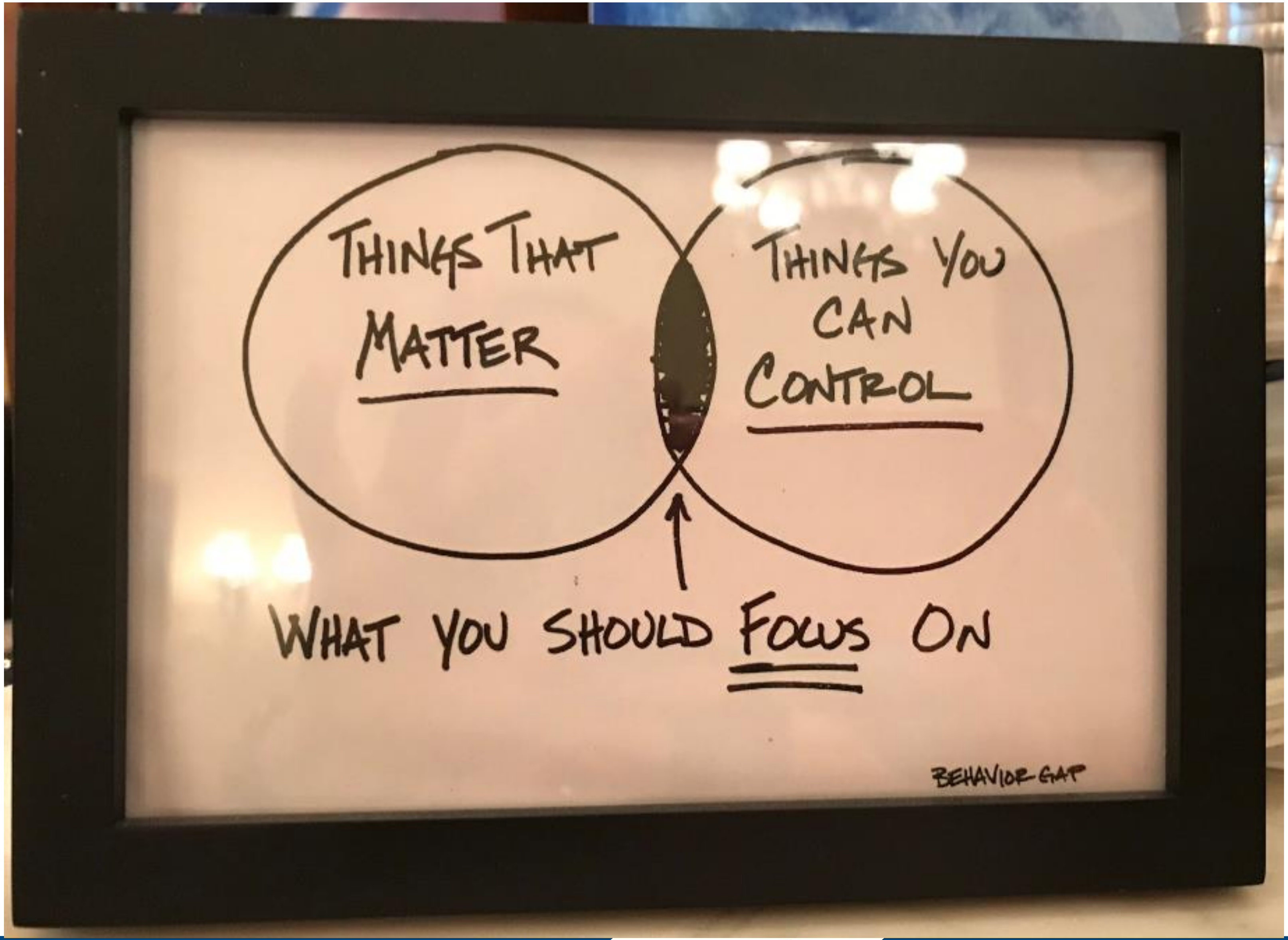
Cautionary Statements

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, financial forecasts, future hydrocarbon prices and their volatility, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to further reduce our debt levels or extend debt maturities, 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 proposed future asset purchases or sales or dispositions or the timing or proceeds thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, including CCA, or the availability of capital for CCA pipeline construction, or its ultimate cost or its 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, levels of tariffs or other trade restrictions, the likelihood, timing and impact of interest rate changes, the impact of regulatory rulings or changes, anticipated outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, long-term forecasts of production, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions, the likelihood and extent of an economic slowdown, and other variables surrounding our estimated original oil in place, 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; effects of our indebtedness; success of our risk management techniques; accuracy of our cost estimates; availability or 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, 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 Non-GAAP Financial Measures: This presentation also contains certain non-GAAP financial measures including free cash flows, adjusted cash flows from operations and adjusted EBITDAX. 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, 2017 and December 31, 2018 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.

Thoughts on Navigating in Today's Energy Market



Denbury – What We Are

A Unique Energy Business

- ~60% of production via CO_2 enhanced oil recovery (EOR)
- Vertically integrated CO_2 supply and distribution
- Cost structure largely independent from industry

Extraordinarily Geared to Crude Oil

- 97% oil, high exposure to Gulf Coast premium pricing
- Premium crude oil produced (~35 avg. API gravity, low sulfur content)

Value Sustaining with Organic Growth Upside

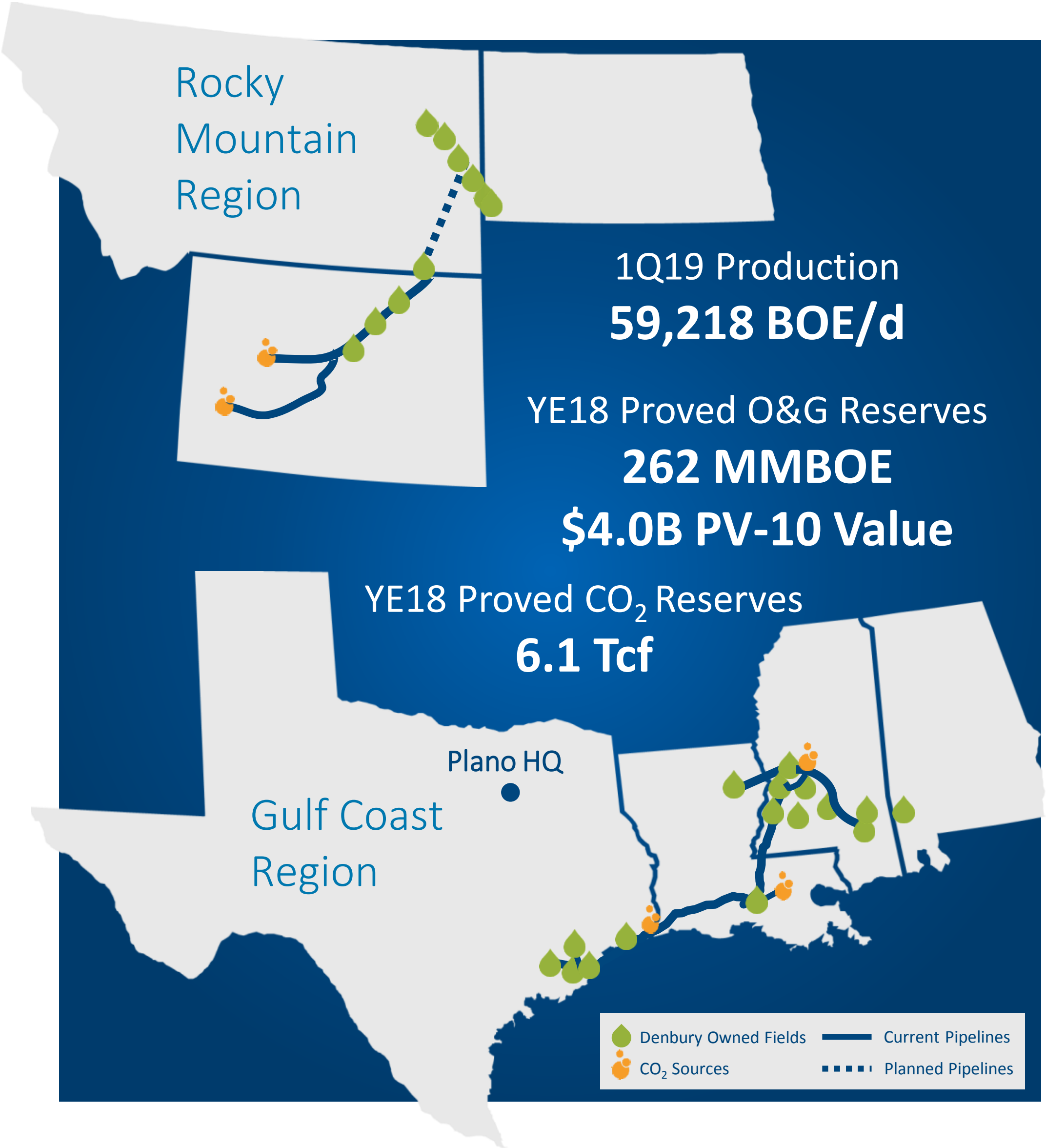
- Over 1 Billion BOE proved + EOR and exploitation potential

Intensely Focused on Execution and Results

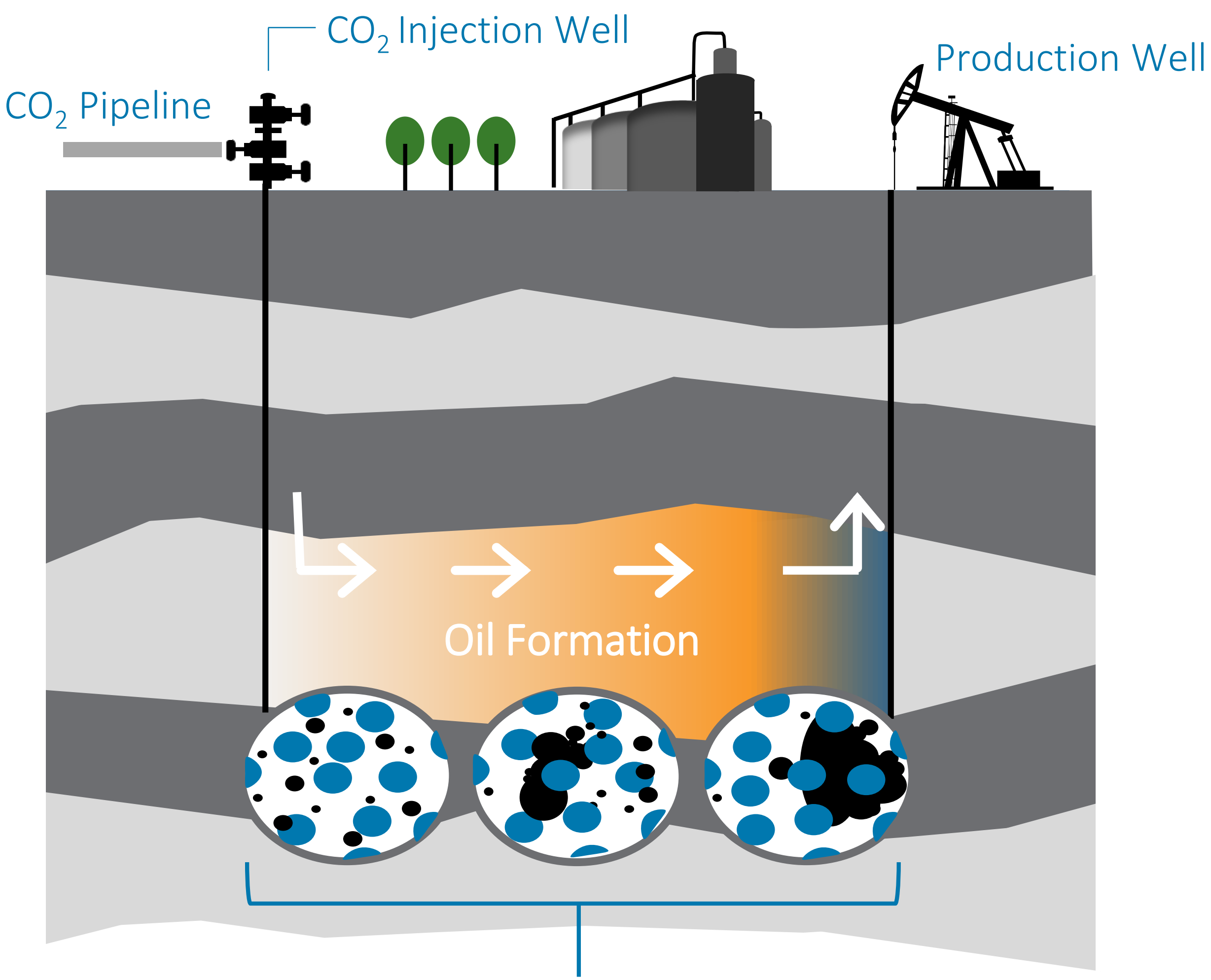
- Highly economic project portfolio at $50 oil
- Significant debt reduction and cost structure improvements since 2014
- Track record of spending within cash flow

A Carbon Conscious Producer

- Annually injecting over 3 million tons of industrial-sourced CO_2 into our reservoirs

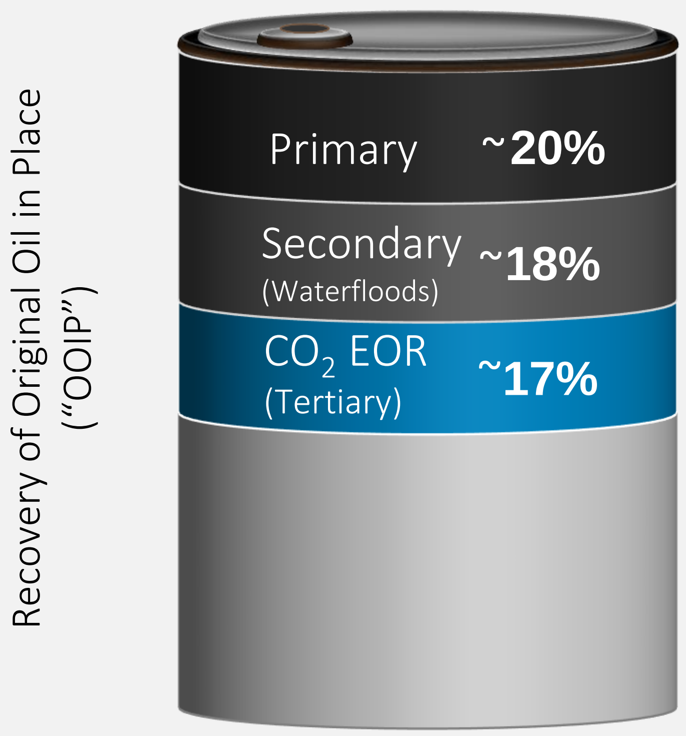


The CO_2 EOR Process



CO_2 moves through formation mixing with oil, expanding and moving it toward producing wells

CO_2 EOR can produce about as much oil as primary or secondary recovery[1]

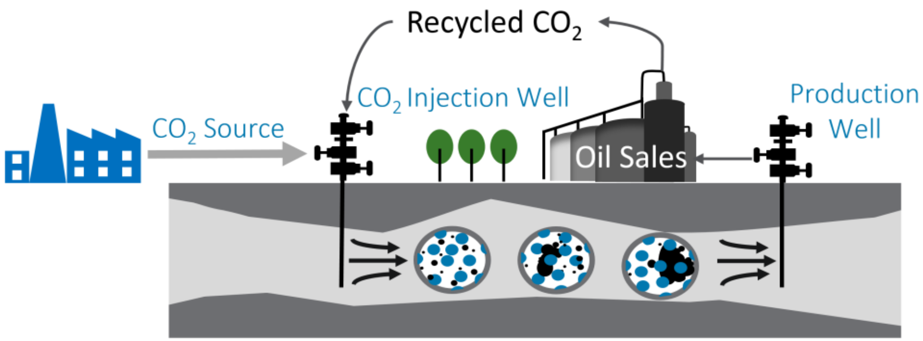


1) Based on OOIP at Denbury's Little Creek Field

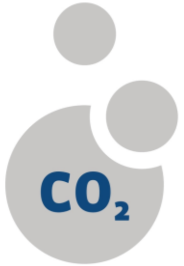
The Denbury Difference

CO_2 EOR Reduces Carbon Footprint

25-30% of our CO_2 is industrially sourced



We utilized
3.3 million metric tons (in 2018)
of industrially sourced CO_2 that could otherwise have been released into the atmosphere



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Annual greenhouse gas emissions from over **690,000** cars

We Operate Responsibly and Safely

Investing in Communities

Consistently Improving Safety Performance

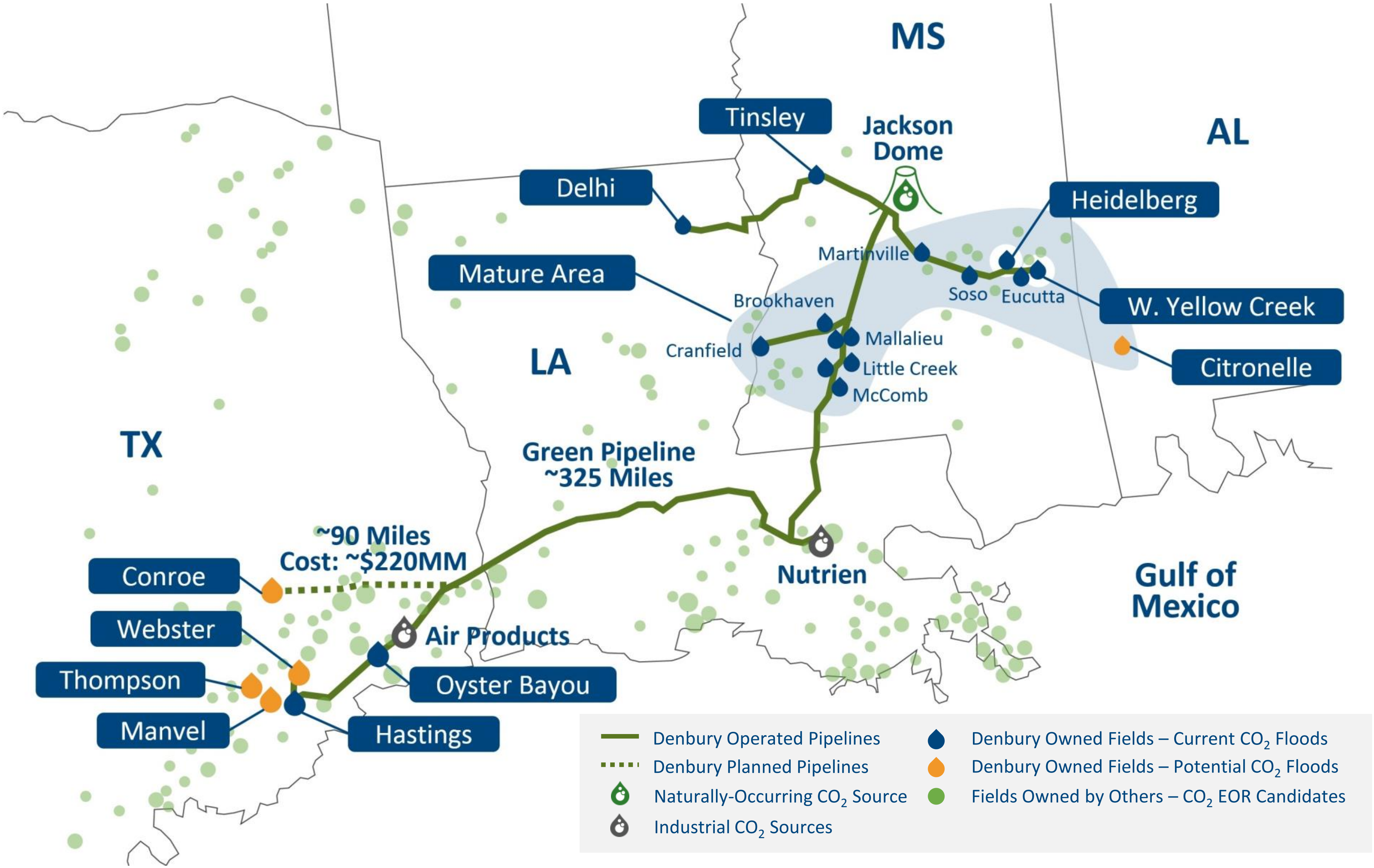
We Minimize Environmental Impact

Revitalizing Legacy Oil Fields

Protecting Wildlife

Our website contains our most recent Corporate Responsibility Report, prepared in accordance with GRI Sustainability Reporting Standards.

Gulf Coast Region



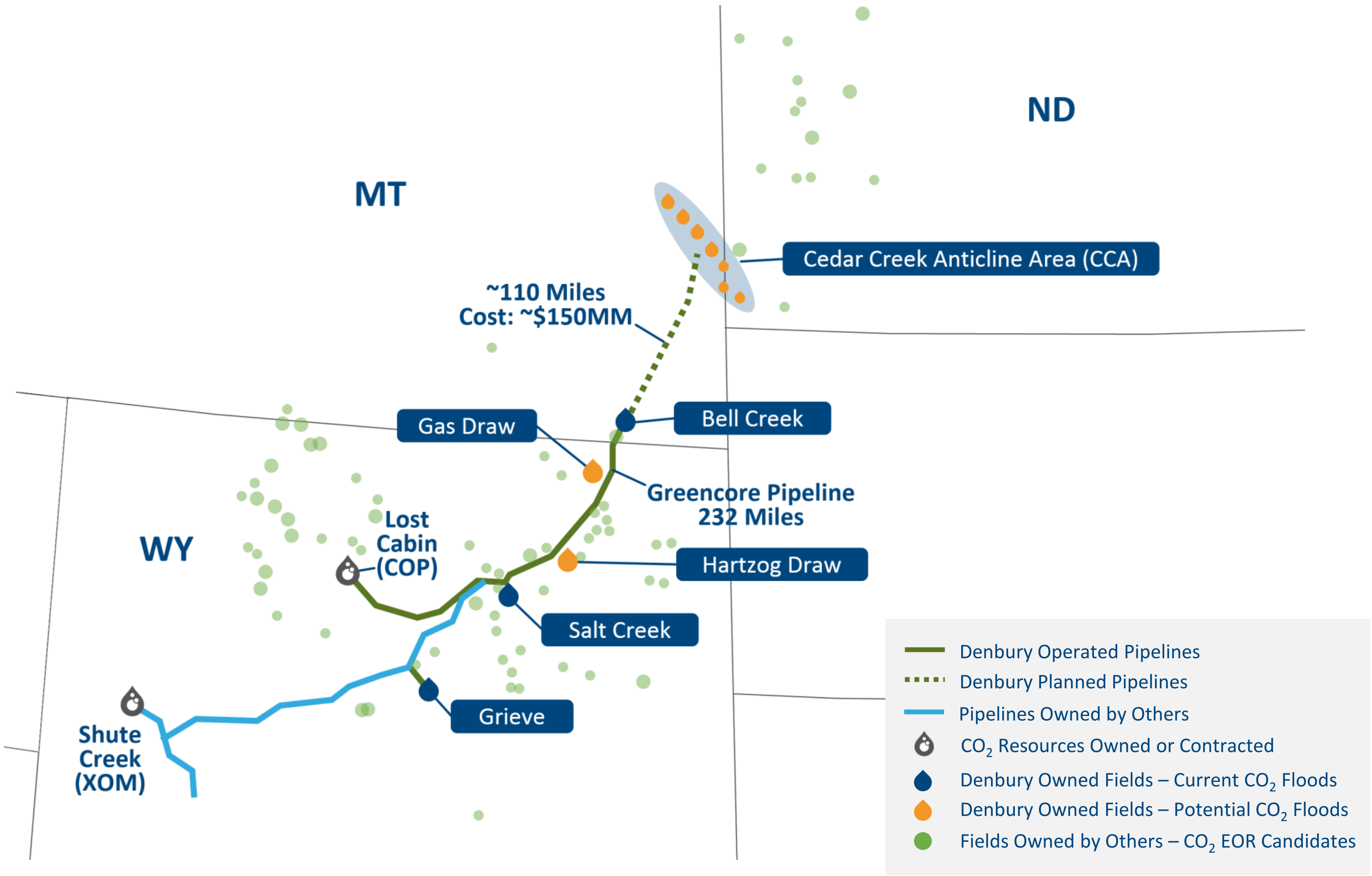
Reserves Summary[1] (MMBOE)

Proved + Tertiary Potential	
Tertiary Reserves	
Proved	127
Potential	301
Non-Tertiary Reserves	
Proved	24
Total MMBOE[2]	**452**

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

Note: See "Slide Notes" on slide 23 in the appendix to this presentation for footnote explanations.

Rocky Mountain Region



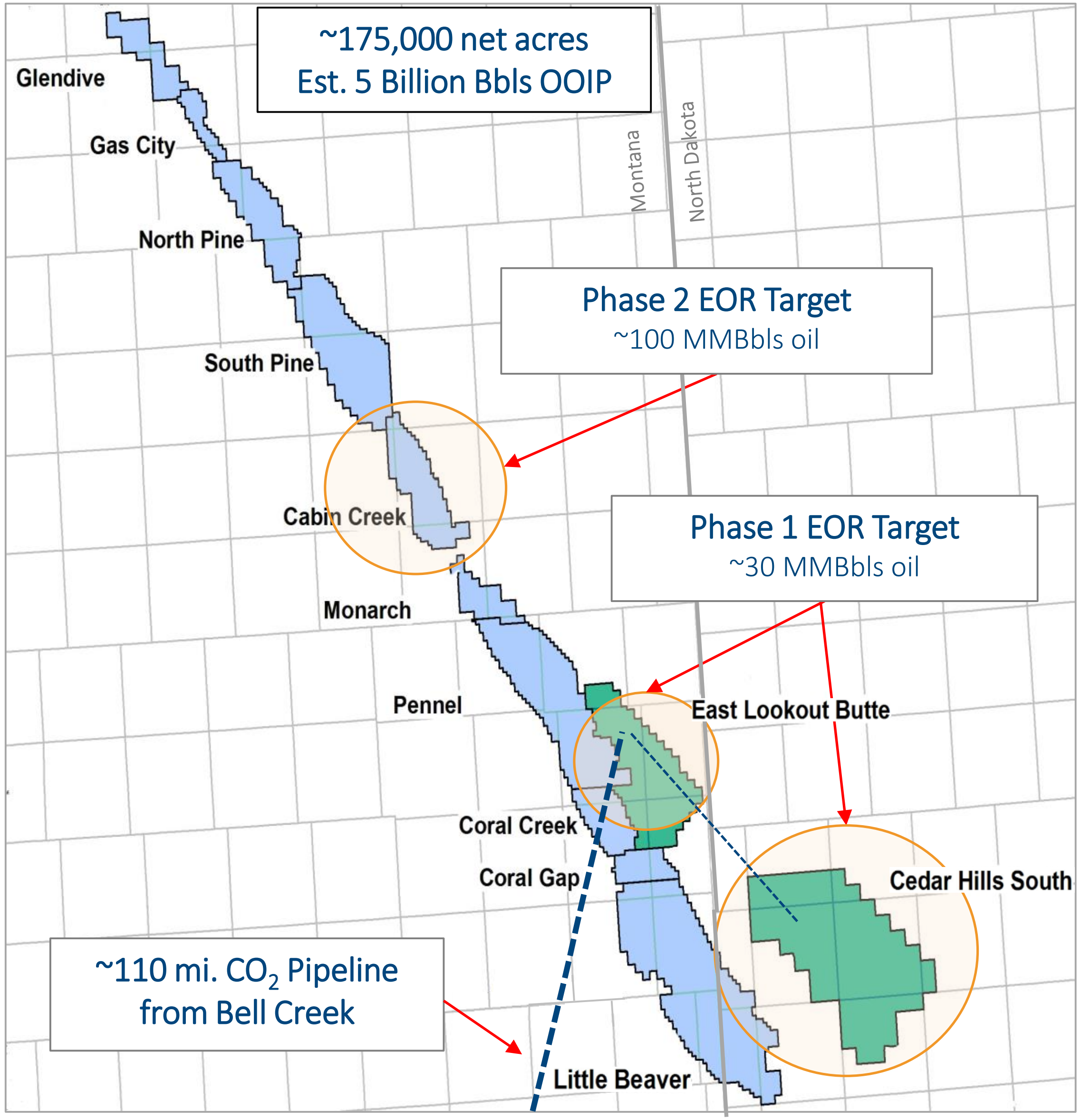
Reserves Summary[1] (MMBOE)

Proved + Tertiary Potential	
Tertiary Reserves	
Proved	24
Potential	536
Non-Tertiary Reserves	
Proved	88
Total MMBOE[2]	**648**

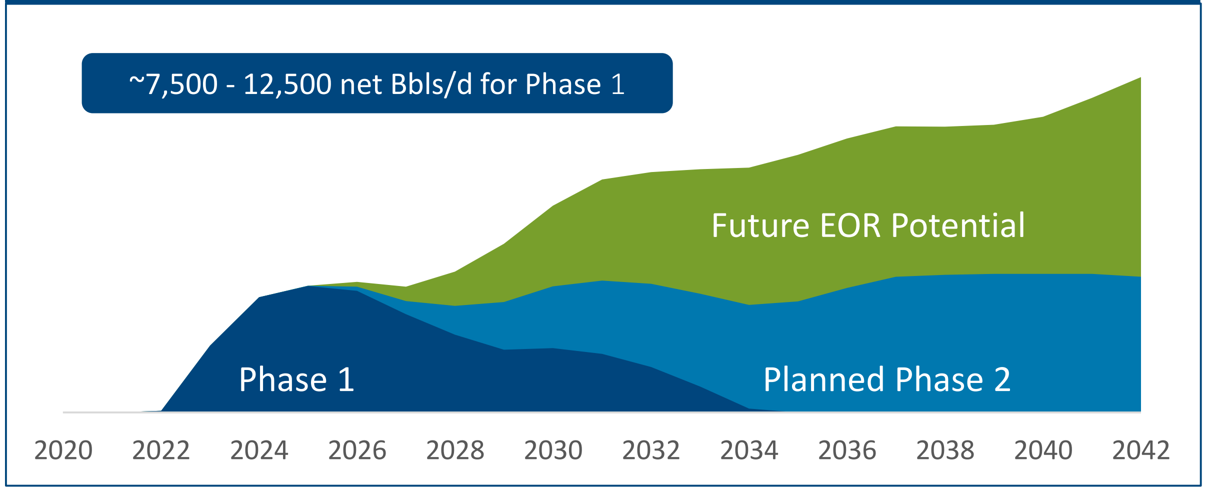
Proved + Tertiary Potential by Field[3]	
Bell Creek	20 – 40
Cedar Creek Anticline Area	400 – 500
Gas Draw	10
Grieve	5
Hartzog Draw	30 – 40
Salt Creek	25 – 35

Note: See "Slide Notes" on slide 23 in the appendix to this presentation for footnote explanations.

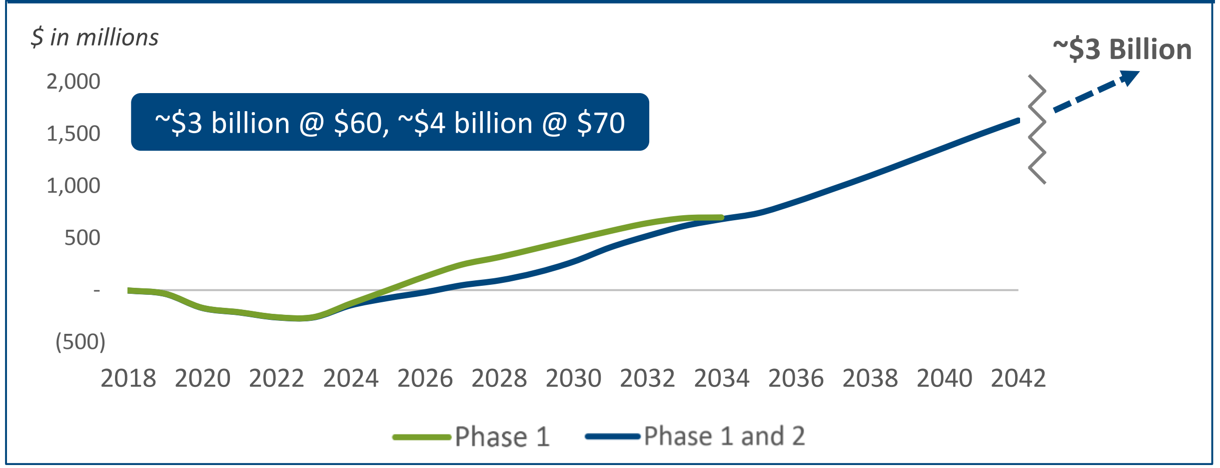
>400 MMBBL EOR Potential at Cedar Creek Anticline



Est. Incremental EOR Production



Est. Cumulative Net Cash Flow @ $60 oil



CCA Exploitation

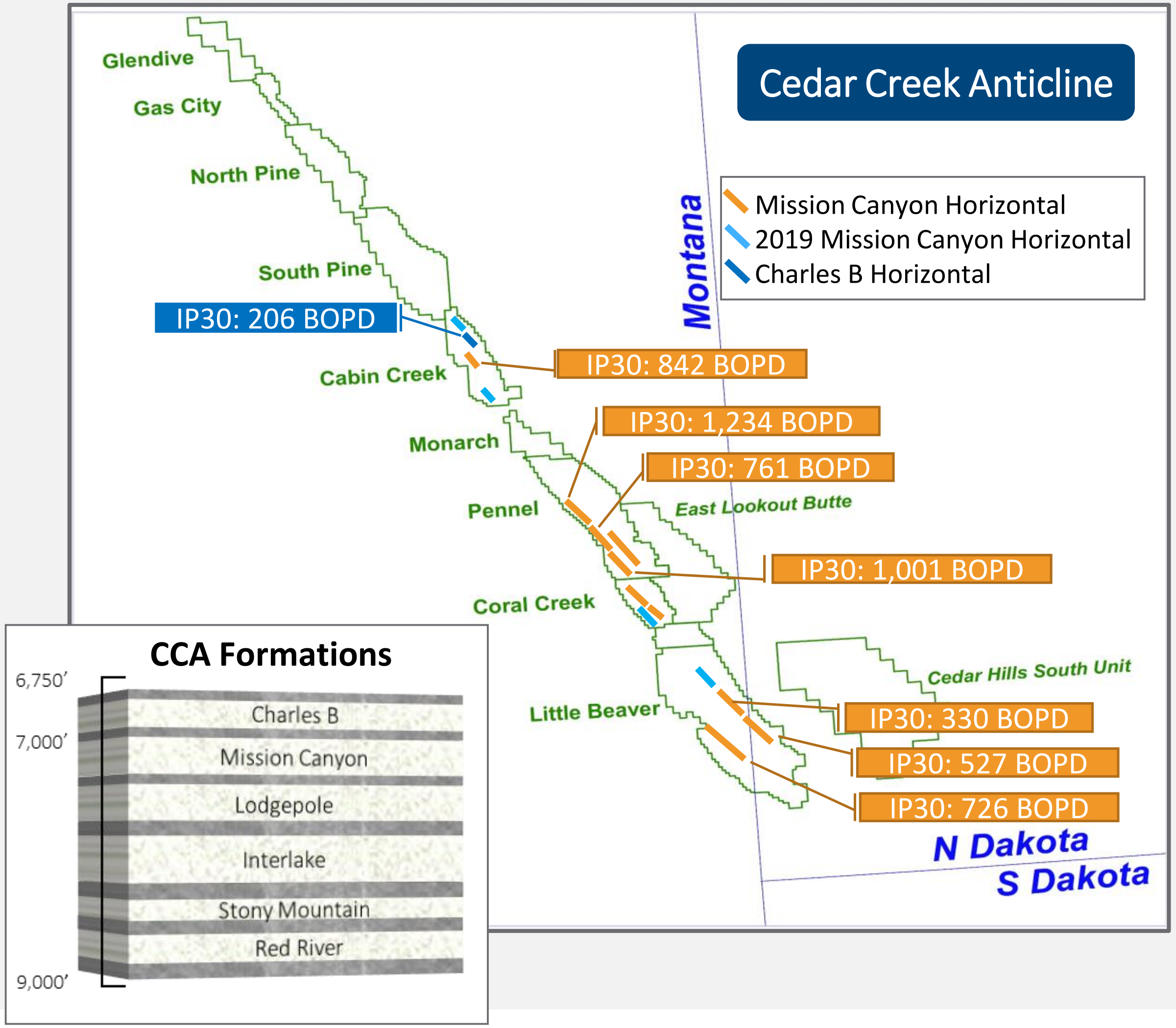
Continued Mission Canyon Success, Play-Opening Initial Charles B Test

Mission Canyon

- Extended play to the north and to the south with Cabin Creek and Little Beaver tests
- Up to four wells planned for 2H19
- Reduced drilling and completion cost per lateral foot by > 20%
- Strong program economics @ $50/Bbl
  - > 50% ROR to date
- Up to 14 additional well locations identified

Charles B

- First well online early 1Q; 206 BOPD IP30
- Sustained high oil cut (~75%); strong potential for waterflood & EOR
- Multiple potential productive Charles B benches identified
  - Testing lower Charles B in 2H19
- Charles B potential identified across the northern part of CCA, from Cabin Creek to Glendive
- Up to 14 potential well locations identified



Bell Creek >50% Production Growth Over Last Two Years

Continuing Field Development

Phase 5

- Capital spend $28MM
- Initial response in 2018
- >2,500 incremental net Bbl/d at end of 1Q19

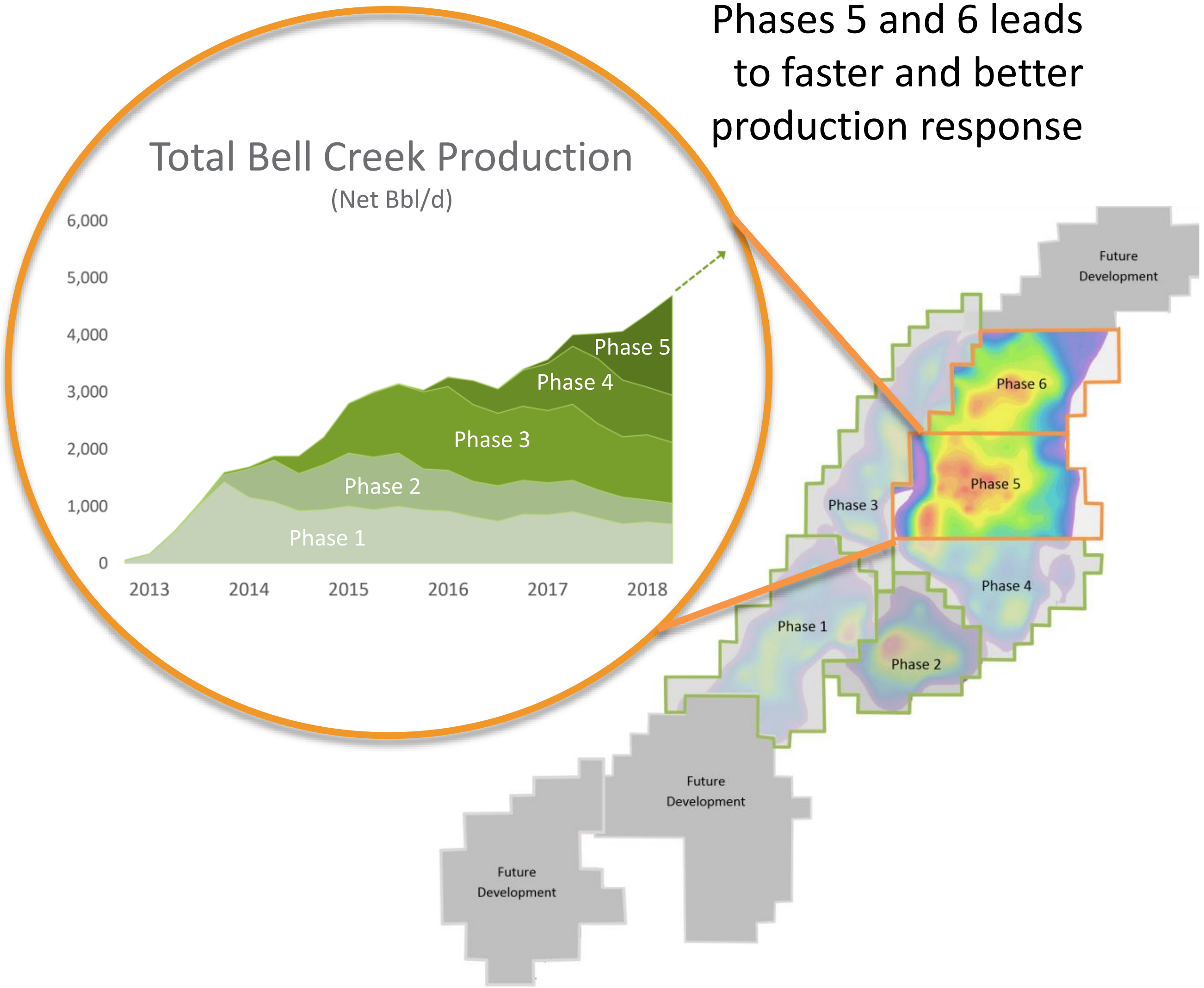
Phase 6

- Commenced CO_2 injection in April 2019
- Expect results similar to Phase 5
- Production response anticipated in 1Q20

Phases 1-4

- Production from 1Q19 development well sustained at >500 Bbl/d
- Growing set of incremental development opportunities

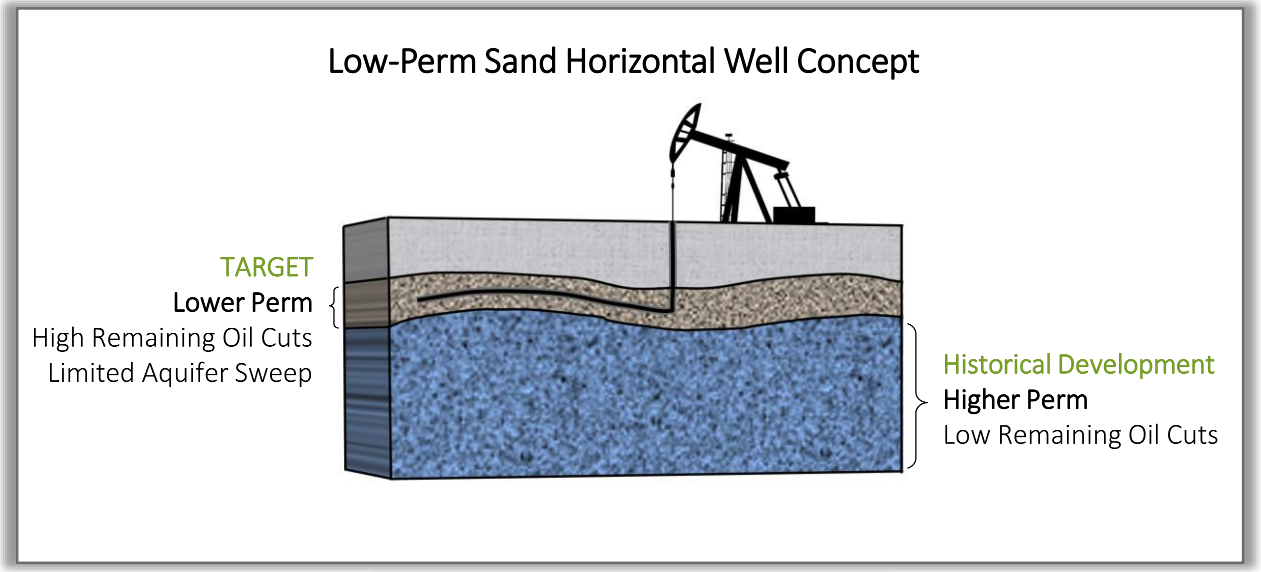
Best rock quality in Phases 5 and 6 leads to faster and better production response

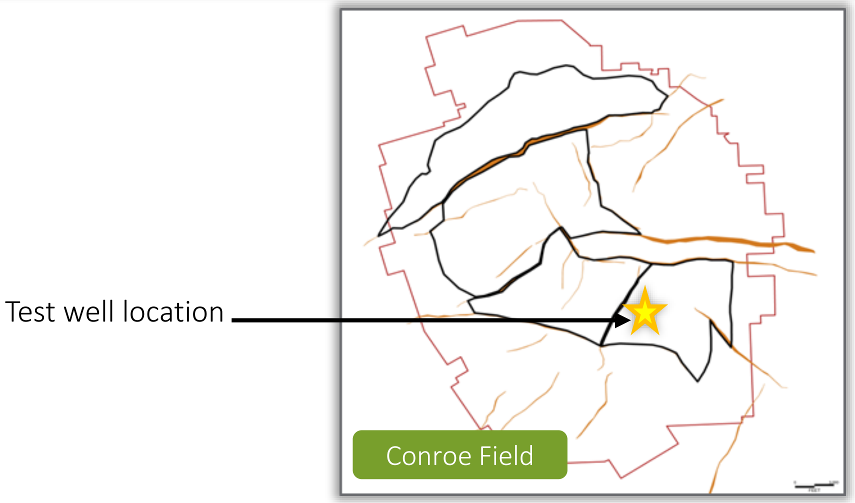


Unswept Low-Perm Oil Potential – Conroe Field 2A Sand

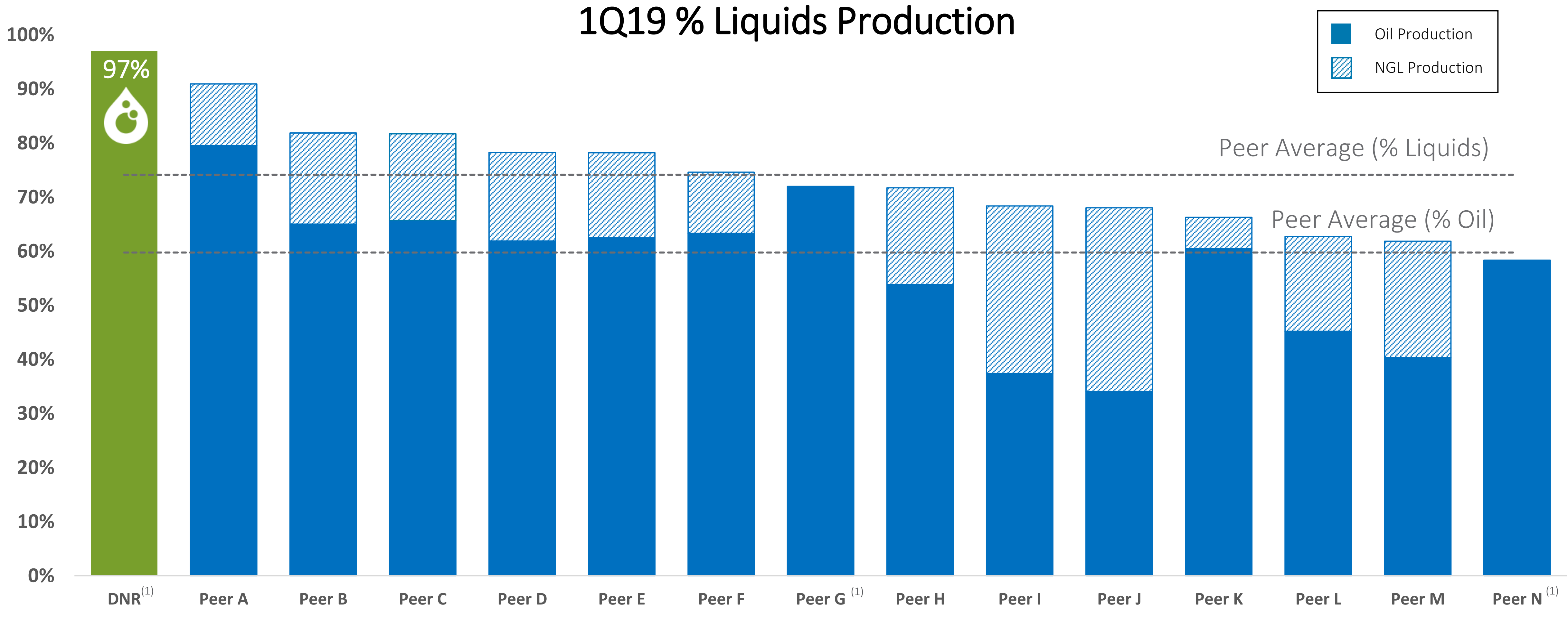
Promising Initial Well Results

- Target is 2A Sand in Conroe Field
  - 20-60% oil cuts in current vertical producers
  - Lower quality reservoir not effectively swept by past vertical well development
- Simple, low cost horizontal well development
  - Estimated drilling and completion cost ~$3MM
  - No fracture stimulation required
  - Will utilize existing production infrastructure
- First well drilled and completed in early 2Q19
  - Positive hydrocarbon indications throughout lateral
  - Flow test results expected in 2Q19
- Potential for >20 drilling locations in 2A Sand only
- Additional potential in comparable Conroe sands





Industry-Leading Oil Weighting

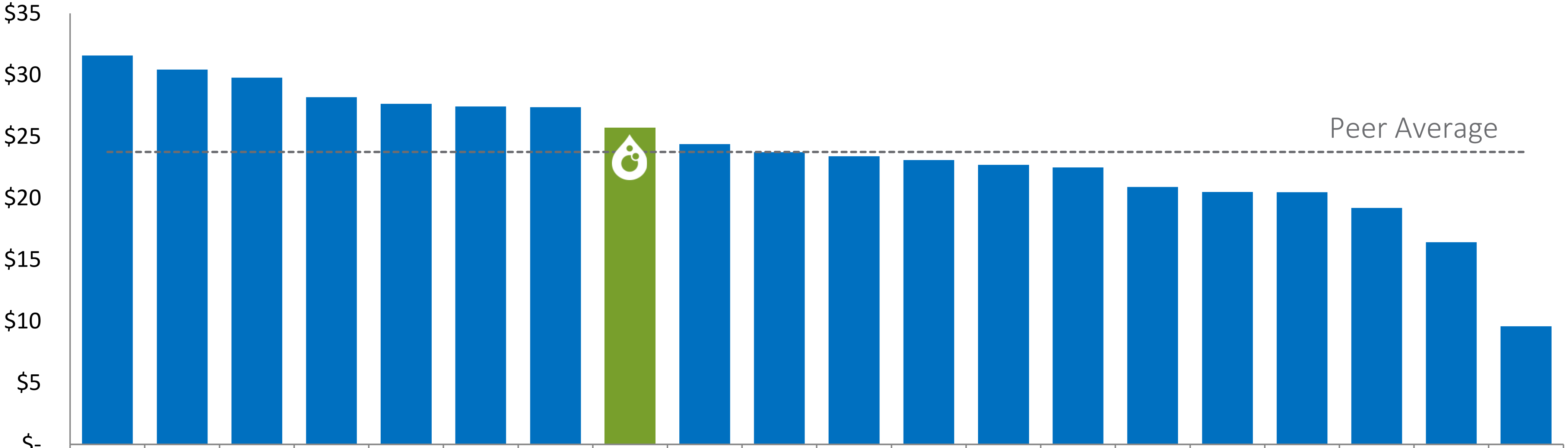


Source: Bloomberg and Company filings for the fourth quarter ended 3/31/2019. Peers include CLR, CPG, CRC, CRZO, EPE, LPI, MUR, OAS, OXY, PDCE, SM, SN, WLL, and WPX.

1) NGL production is not reported separately for this entity.

Competitive Operating Margin

1Q19 Peer Operating Margins ($/BOE)



	Peer A	Peer B	Peer C	Peer D	Peer E	Peer F	Peer G	DNR	Peer H	Peer I	Peer J	Peer K	Peer L	Peer M	Peer N	Peer O	Peer P	Peer Q	Peer R	Peer S
Operating Margin per BOE [1]	31.58	30.44	29.78	28.20	27.66	27.44	27.39	25.73	24.39	23.74	23.41	23.09	22.71	22.50	20.91	20.51	20.49	19.20	16.41	9.59
Lifting Cost per BOE [2]	10.21	9.62	14.90	9.62	9.67	8.12	22.95	29.54	11.90	11.02	13.23	10.54	11.92	6.13	9.94	11.35	5.10	10.63	14.41	10.26
Revenue per BOE [3]	41.79	40.06	44.68	37.82	37.33	35.56	50.34	55.27	36.29	34.76	36.64	33.63	34.63	28.63	30.85	31.86	25.59	29.83	30.82	19.85

Highest revenue per BOE in the peer group

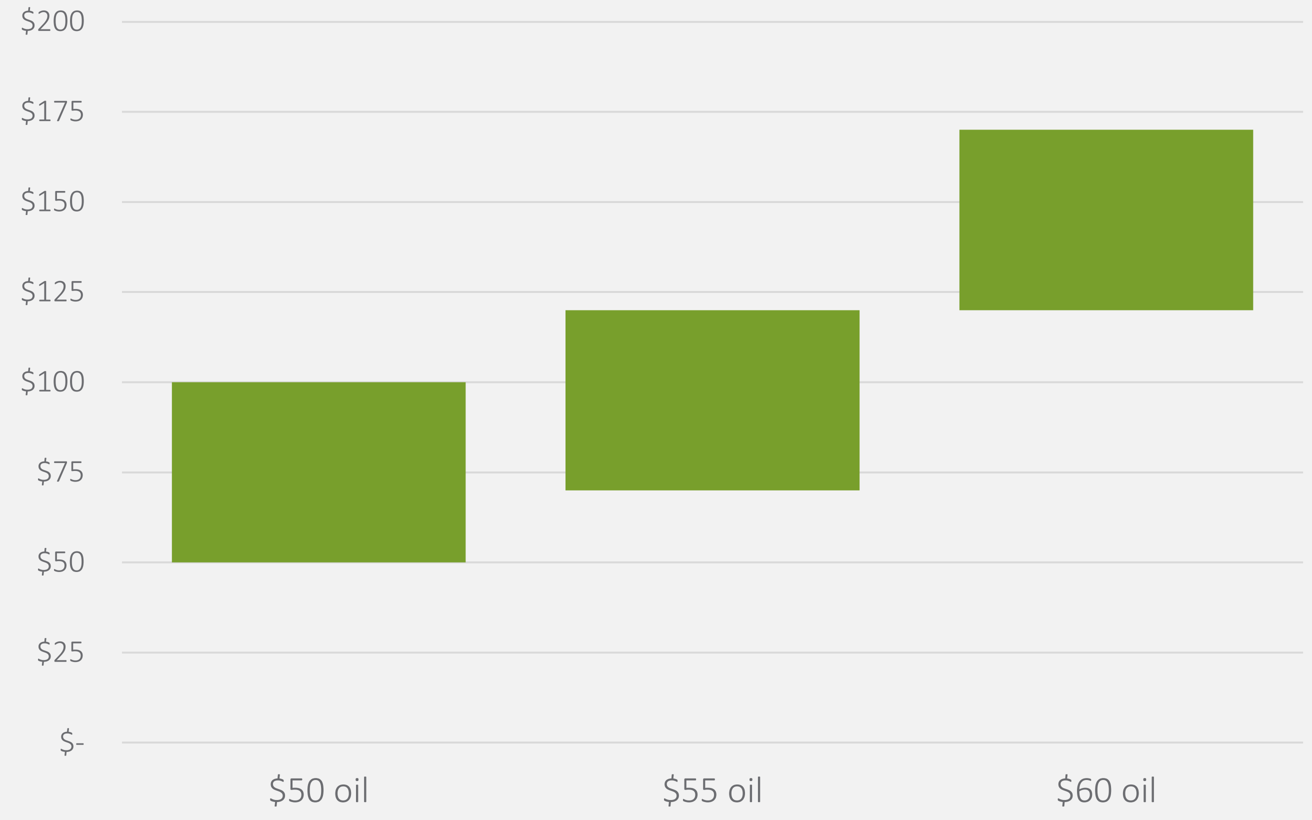
Source: Company filings for the first quarter ended 3/31/2019. Peers include CLR, CRC, CRZO, CXO, DVN, EPE, LPI, MRO, MUR, NBL, OAS, OXY, PDCE, PXD, RRC, SM, SN, WLL, and WPX.

1) Operating margin calculated as revenues less lifting costs (see 2 below).
2) Lifting cost calculated as lease operating expenses, marketing/transportation expenses and production and ad valorem taxes.
3) Revenues exclude gain/loss on derivative settlements.

Generating Significant Free Cash in 2019

2019E Free Cash Flow Range, Including Hedges(1)

In millions, unless otherwise noted



Excluding hedges, each $5 change in oil price impacts cash flow by ~$100 million

2019E Sources & Uses @ $50 oil(1)

In millions	2019
Adjusted cash flow from operations(2)	$420 – $470
Interest payments treated as debt reduction	(85)
Adjusted total, net	$335 – $385
Development capital	$240 – $260
Capitalized interest	30 – 40
Total capital costs	$270 – $300
Free cash flow	$50 – $100

1) Currently estimated ranges based upon forecasts and assumptions as of February 27, 2019, and referenced prices where applicable.
2) Cash flow from operations before working capital changes (a non-GAAP measure). See press release attached as Exhibit 99.1 to the Form 8-K filed May 7, 2019 for additional information indicating why the Company believes this non-GAAP measure is useful for investors.

Summary of Debt Exchange Offers

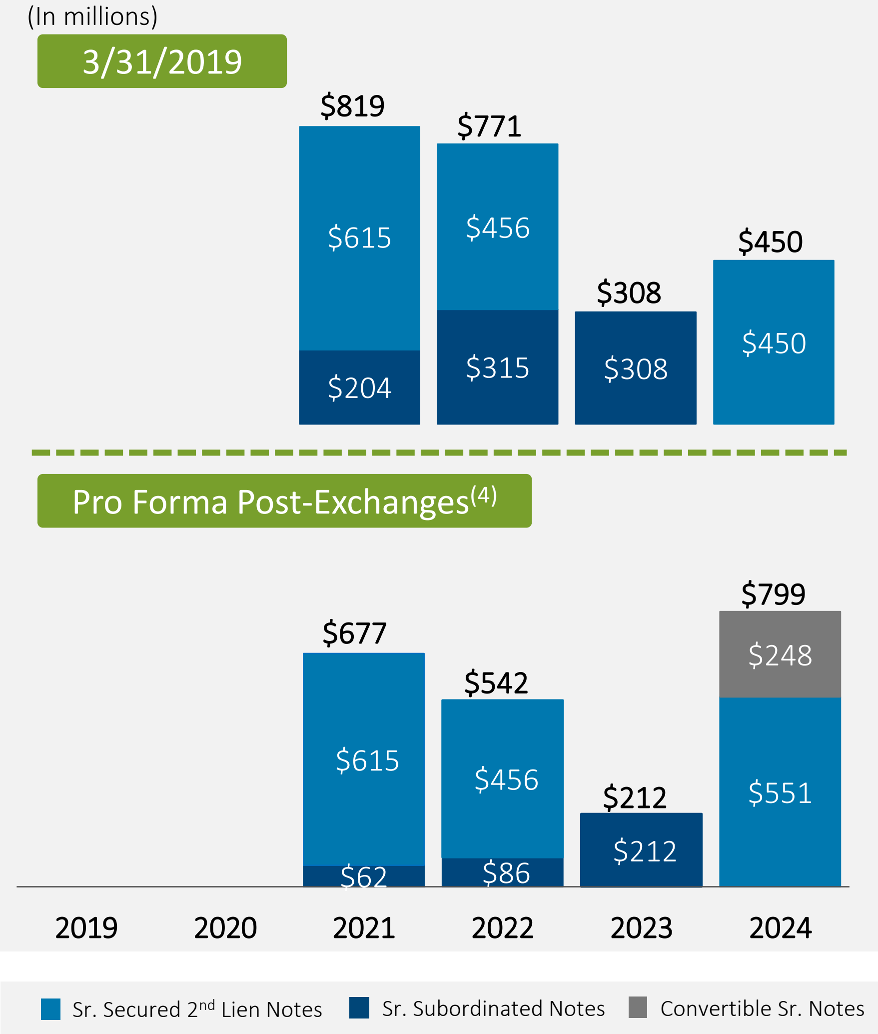
Transaction Summary

- Entered into private exchange agreements with holders of **$234.2 million** of Senior Subordinated Notes due 2021, 2022 and 2023 for:
  - **$48.5 million** cash, **$36.6 million** New 7¾% Senior Secured Second Lien Notes due 2024 (New Second Lien Notes) and **$149.1 million** of New 6⅜% Convertible Senior Notes due 2024 (New Convertible Senior Notes)
  - Also will exchange **$168.0 million** of 7½% Senior Secured Second Lien Notes due 2024 for **same amount** of New Second Lien Notes
- Commenced exchange offers to Eligible Holders(1) of remaining **$380.3 million** of Senior Subordinated Notes due 2021 and 2022 for a mix of cash, New Second Lien Notes and New Convertible Senior Notes for the same exchange consideration provided in private exchanges(2)
- Also commenced exchange offers to Eligible Holders(1) of remaining **$282.0 million** of 7½% Senior Secured Second Lien Notes due 2024 to exchange into **same amount** of New Second Lien Notes(3)

Impact to Denbury

- Extends maturities without increasing interest expense
- Creates pathway for up to **$248.0 million** additional debt reduction and corresponding improvement of Debt/EBITDAX by approximately one half turn through potential conversion of new convertible notes
  - New Convertible Senior Notes will be convertible on a basis of 370 shares of Denbury common stock per $1,000 principal ($2.70 per share) upon Denbury's stock reaching a volume-weighted average price of $2.43 for 10 out of 15 consecutive trading days

Notes Maturity Profile

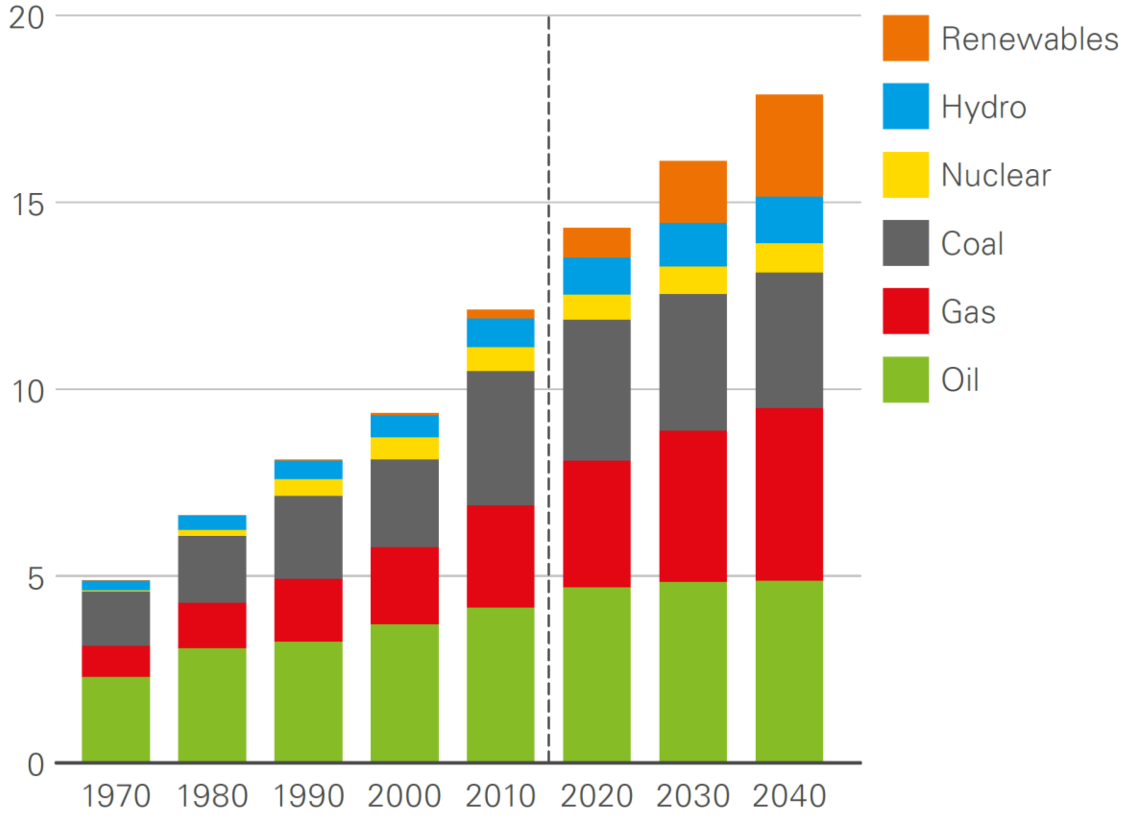


1) Are either a "qualified institutional buyer" under Rule 144A or not a "U.S. person" under Regulation S as defined under applicable securities laws.
2) Exchange of 2021 Subordinated Notes will receive priority in acceptance over 2022 Subordinated Notes if offer is oversubscribed. Maximum consideration limits for all exchanges are: $120 million cash, $557.9 million New Second Lien Notes and $248 million of New Convertible Senior Notes.
3) Consummation of all exchanges conditioned upon a minimum issuance of $300 million aggregate of New Second Lien Notes and $200 million of New Convertible Senior Notes.
4) Pro forma amounts are presented on an as-adjusted basis after giving effect to the private exchange transactions and full subscription of exchange offers, representing an assumed participation rate of approximately 61% of the remaining principal amount outstanding after the private exchange transactions, and with no proration applied.

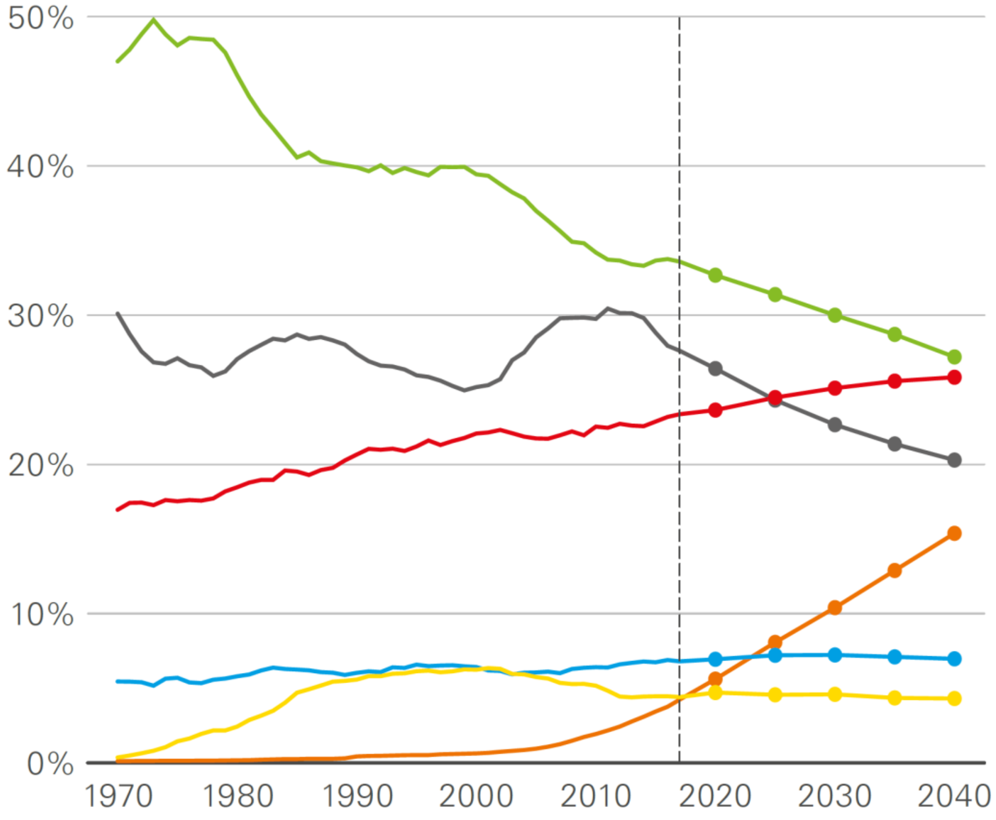
Oil Remains the Top Primary Energy Source Through 2040

Primary energy consumption by fuel

Billion toe

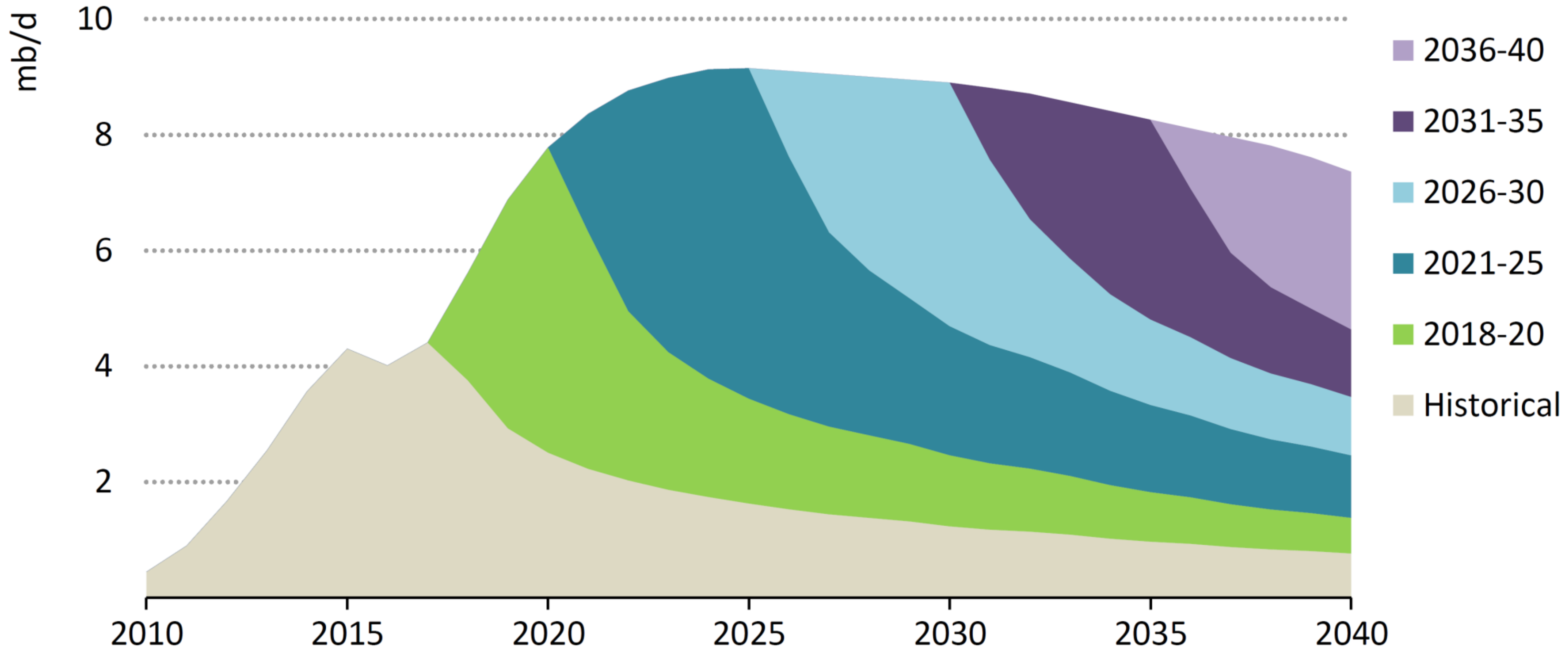


Shares of primary energy



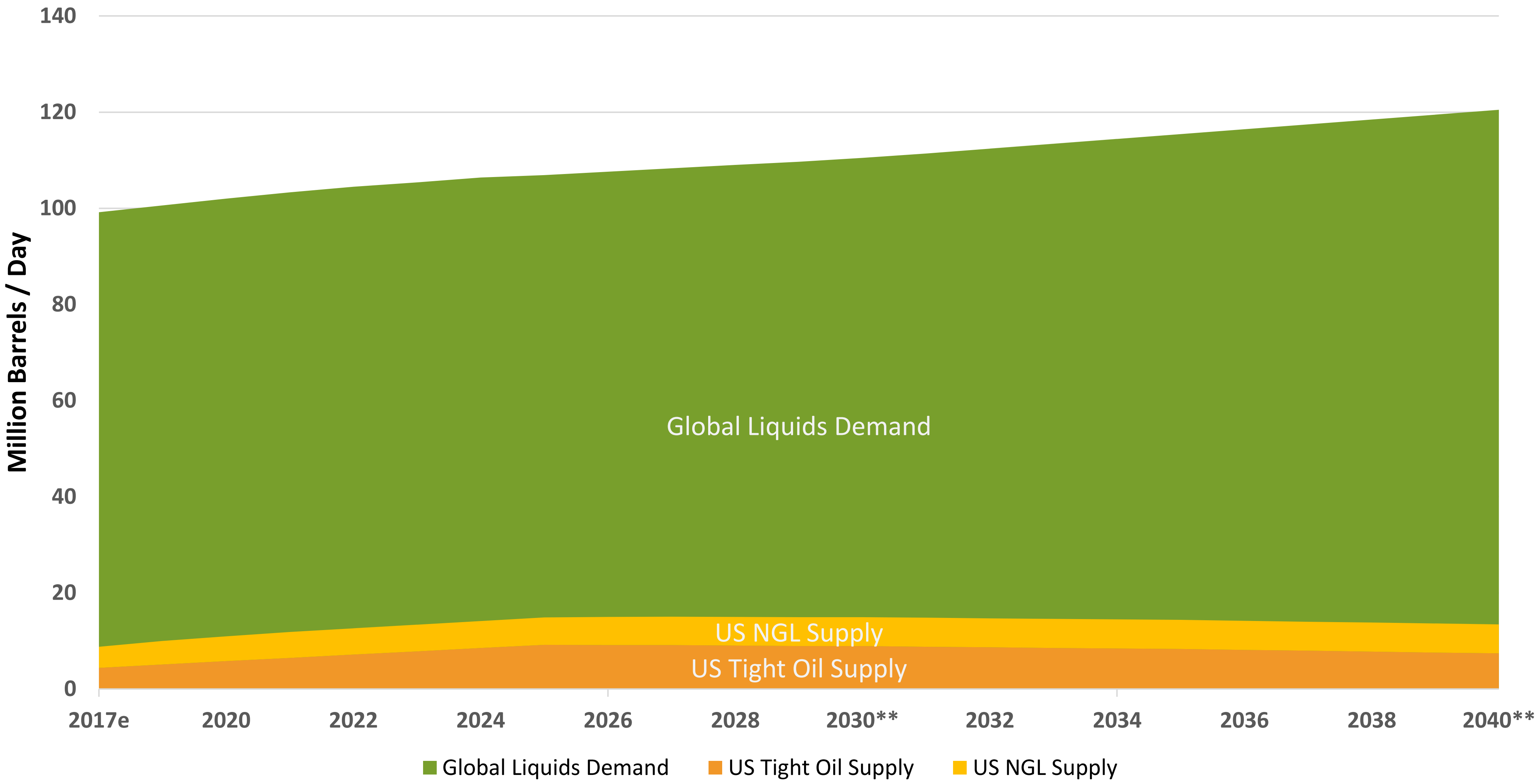
Source: BP Energy Outlook, 2019

US Tight Oil Production Expected to Peak ~2025



Source: IEA World Energy Outlook 2018

US Tight Oil & NGL Production vs Total Global Liquids Demand



**Data obtained from the IEA World Energy Outlook 2018 between 2017E, 2025, 2030, 2035 and 2040 was interpolated.
US Tight Oil and Global Demand obtained from IEA World Energy Outlook 2018
US NGL Production obtained from EIA Annual Energy Outlook 2019

Uncommon Company, Extraordinary Potential

Extreme Oil Gearing	» Industry Leading Oil Weighting » Strong Operating Margin » Favorable Crude Quality & Significant Exposure to Premium Pricing
Operating Advantages	» Vertically Integrated CO_2 Supply and Infrastructure » Cost Structure Largely Independent from Industry » Operating Outside Constrained Basins
Significant Organic Growth Potential	» EOR Project at CCA with >400 MMBBL Potential » Significant Additional EOR Development » Growing Portfolio of Short-Cycle Opportunities
Financial Discipline	» Generating Free Cash Flow at $50 Oil » Quality Asset Base Provides Capital Flexibility » Strong Liquidity

Q&A

Appendix

Slide Notes

Slide 7 – Gulf Coast Region

1) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/18 SEC pricing. Potential includes probable and possible tertiary reserves estimated by the Company as of 12/31/18, 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.

Slide 8 – Rocky Mountain Region

1) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/18 SEC pricing. Potential includes probable and possible tertiary reserves estimated by the Company as of 12/31/18, 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.

2019 Goals and Focus Areas

Operational

Operate Safely and Responsibly

- Improve on record-levels of health, safety and environmental performance

Drive Organic EOR Growth

- Bell Creek Phases 5 & 6
- Heidelberg Christmas

Expand Exploitation Opportunity Set

- CCA Mission Canyon
- CCA Charles B
- Gulf Coast Unswept Low-Perm

Progress CCA EOR Development

- Procure CO_2 pipeline pipe in 2019
- Position for CO_2 pipeline installation in 2020, first CCA CO_2 injection in early 2021

Financial

Generate Significant Free Cash

- Free cash target of $50-$100 million at $50 oil; $120 - $170 million at $60 oil
- Strong hedge book provides upside exposure while protecting downside

Strengthen Balance Sheet

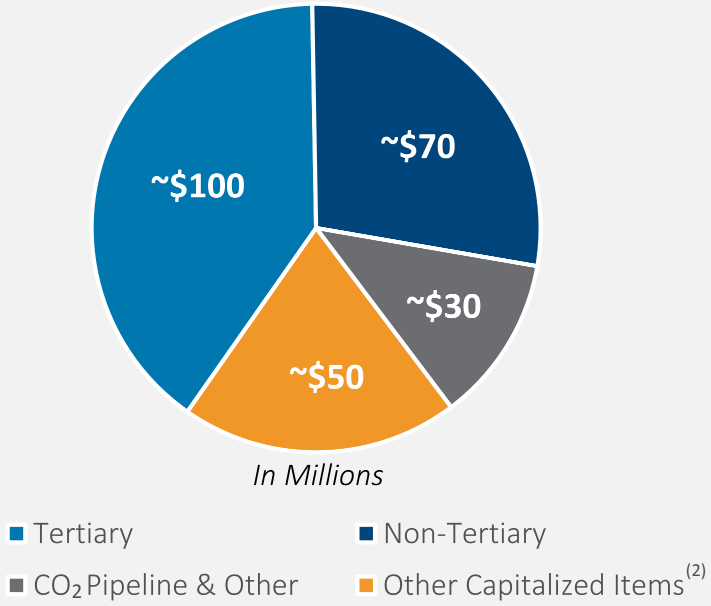
- Continue to prioritize debt reduction
- Specific focus on extending near-term maturities

2019 Capital Plan Reduced 20-25% from 2018

2019E Development Capital Budget [1]

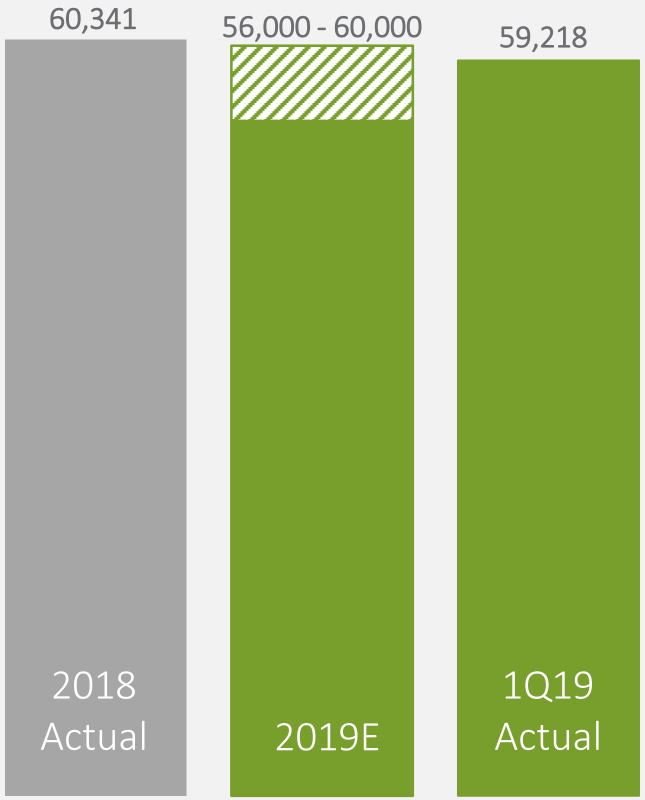
~$75MM Reduction from 2018

2019E
$240 - $260 Million



1) Amounts presented exclude $30 - $40 million of capitalized interest.
2) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

2019E Production Guidance (BOE/d)

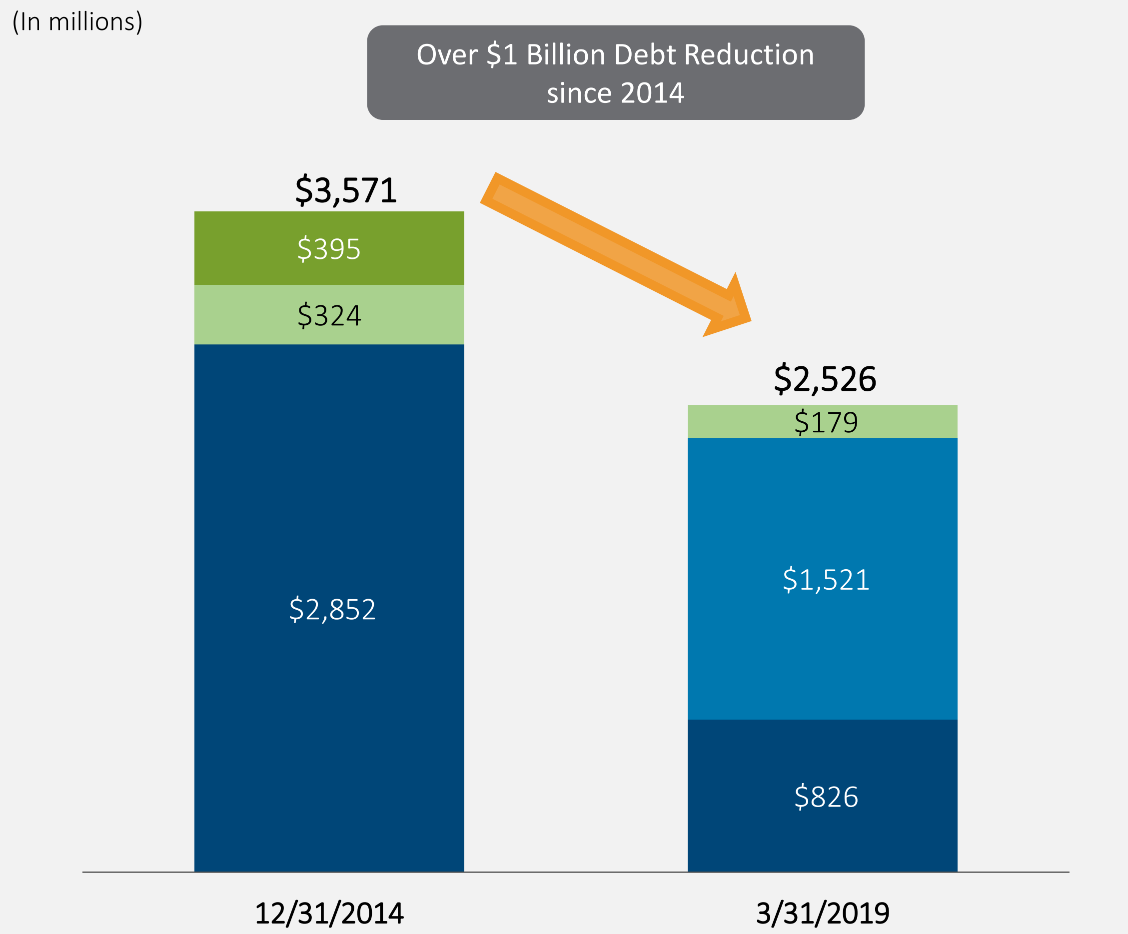


2019 Significant Capital Projects

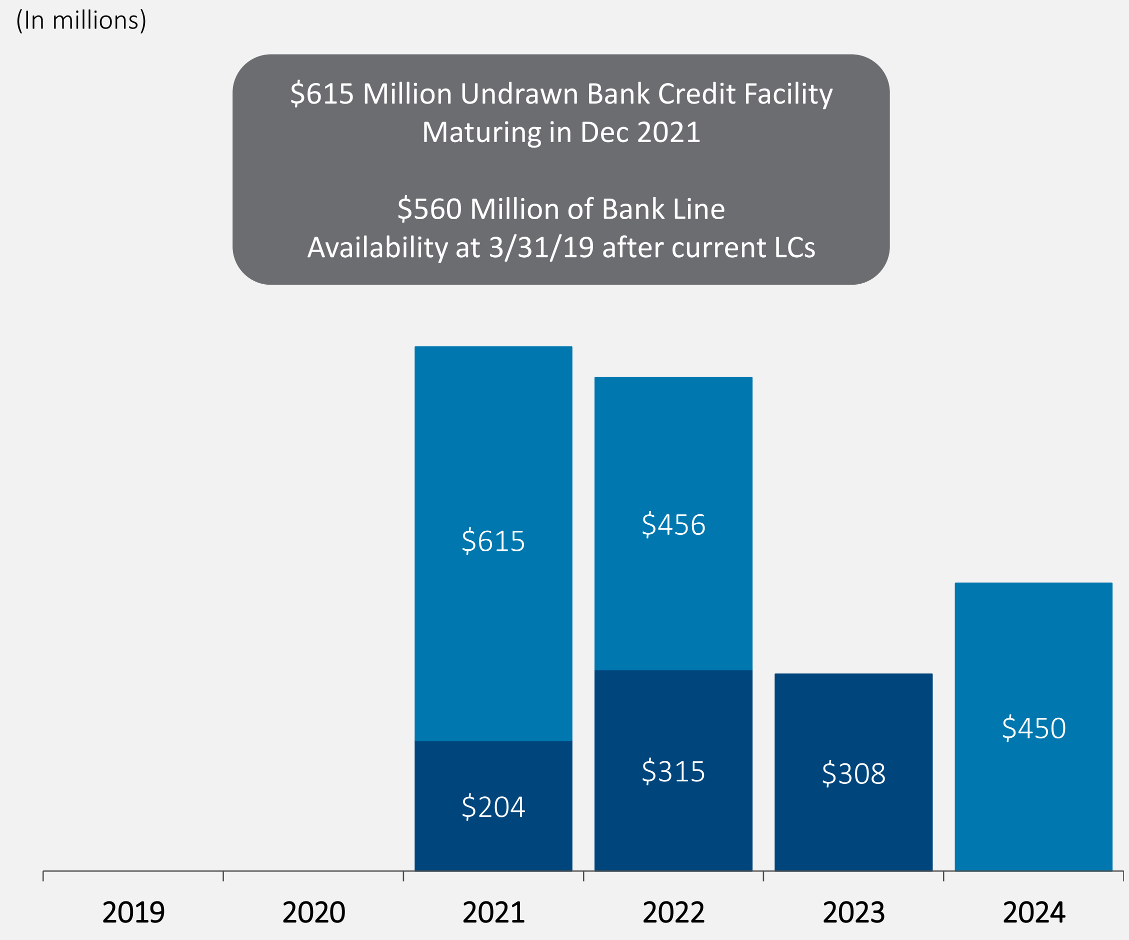
Tertiary		***Timing***
Bell Creek Field	Phase 6 Development	1Q-3Q
Heidelberg Field	Christmas Development	1Q-3Q
Non-Tertiary		
Cedar Creek Anticline	Mission Canyon/ Charles B Exploitation	3Q-4Q
Conroe Field	2A Sand Exploitation	1Q-2Q
Tinsley Field	Cotton Valley Exploitation	1Q-2Q
CO_2 Pipeline & Other		
Cedar Creek Anticline	EOR Pipeline Construction	1Q-4Q

Improving Leverage Profile

Debt Principal Reduction Since 12/31/14



3/31/19 Debt Maturity Profile



Sr. Secured Bank Credit Facility | Pipeline / Capital Lease Debt | Sr. Secured 2nd Lien Notes | Sr. Subordinated Notes

Significantly Improving Leverage Metrics

	3/31/19 Leverage Ratio		3/31/18 Leverage Ratio	
	Trailing 12 months (incl. hedges)	Trailing 12 months (excl. hedges)	Trailing 12 months (incl. hedges)	Trailing 12 months (excl. hedges)
Adjusted EBITDAX[1] (Millions)	580	714	488	542
Net Debt Principal[2] (Millions)	2,508	2,508	2,697	2,697
Net Debt/Adjusted EBITDAX[1]	4.3x	3.5x	5.5x	5.0x
Average Realized Oil Price ($/Bbl)	$57.95	$64.24	$51.53	$54.08

1) A non-GAAP measure. See press release attached as Exhibit 99.1 to the Form 8-K filed May 7, 2019 for additional information, as well as slide 43 indicating why the Company believes this non-GAAP measure is useful for investors.
2) Net debt principal balance as of March 31, 2019 and 2018 is inclusive of debt issuance costs and net of cash & cash equivalents.

Hedge Positions – as of May 31, 2019

Downside Protection with Significant Upside Potential

			2019		2020		
			2Q	2H	1H	2H	FY20
Fixed Price Swaps	WTI NYMEX	*Volumes Hedged (Bbls/d)*	*3,500*	–	*2,000*	*2,000*	*2,000*
		Swap Price[1]	$59.05	–	$60.59	$60.59	$60.59
	Argus LLS	*Volumes Hedged (Bbls/d)*	*13,000*	*13,000*	*4,000*	*4,000*	*4,000*
		Swap Price[1]	$64.69	$64.69	$62.41	$62.41	$62.41
3-Way Collars	WTI NYMEX	*Volumes Hedged (Bbls/d)*	*18,500*	*22,000*	*10,000*	*8,000*	*8,995*
		Sold Put Price[1][2]	$48.84	$48.55	$49.37	$49.69	$49.51
		Floor Price[1][2]	$56.84	$56.55	$58.99	$59.22	$59.09
		Ceiling Price[1]	$69.94	$69.17	$66.48	$67.01	$66.71
	Argus LLS	*Volumes Hedged (Bbls/d)*	*5,500*	*5,500*	*4,500*	*2,500*	*3,495*
		Sold Put Price[1][2]	$54.73	$54.73	$53.89	$54.40	$54.07
		Floor Price[1][2]	$63.09	$63.09	$63.89	$64.40	$64.07
		Ceiling Price[1]	$79.93	$79.93	$72.55	$76.59	$74.00
Total Volumes Hedged			40,500	40,500	20,500	16,500	18,489
% of 1Q19 Production (BOE/d)			68%	68%	35%	28%	31%

Weighted Average Floor Prices	2019 2Q	2019 2H	2020 1H	2020 2H	FY20
WTI NYMEX	$57.19	$56.55	$59.26	$59.50	$59.37
Argus LLS	$64.22	$64.22	$63.19	$63.18	$63.19

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 price.

Exploitation – Gulf Coast Unswept Low-Perm Oil Potential

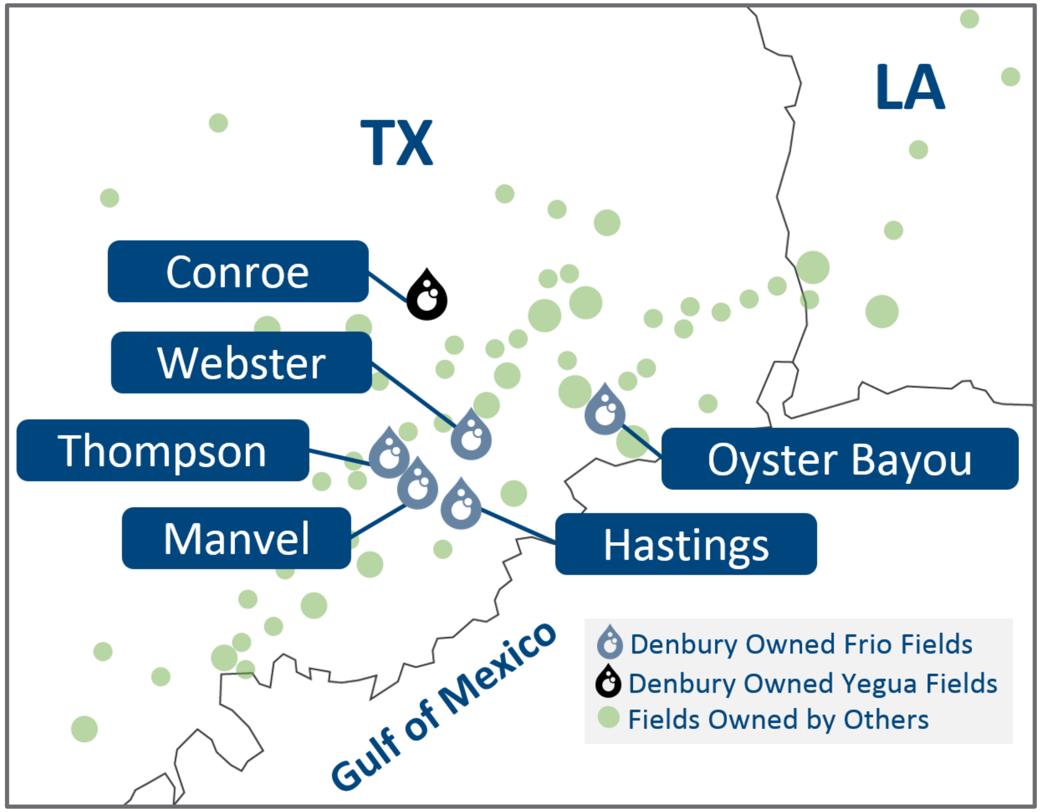
Gulf Coast Exploitation

Opportunity

- Targeting horizontal well opportunities
  - Low perm portions of reservoir with low aquifer sweep
  - High remaining oil saturation
- Proven concept in Gulf Coast reservoirs
- Candidate sands identified in multiple Denbury Fields
  - Conroe
  - Webster
  - Thompson
  - Manvel
  - Hastings
  - Oyster Bayou

Path Forward

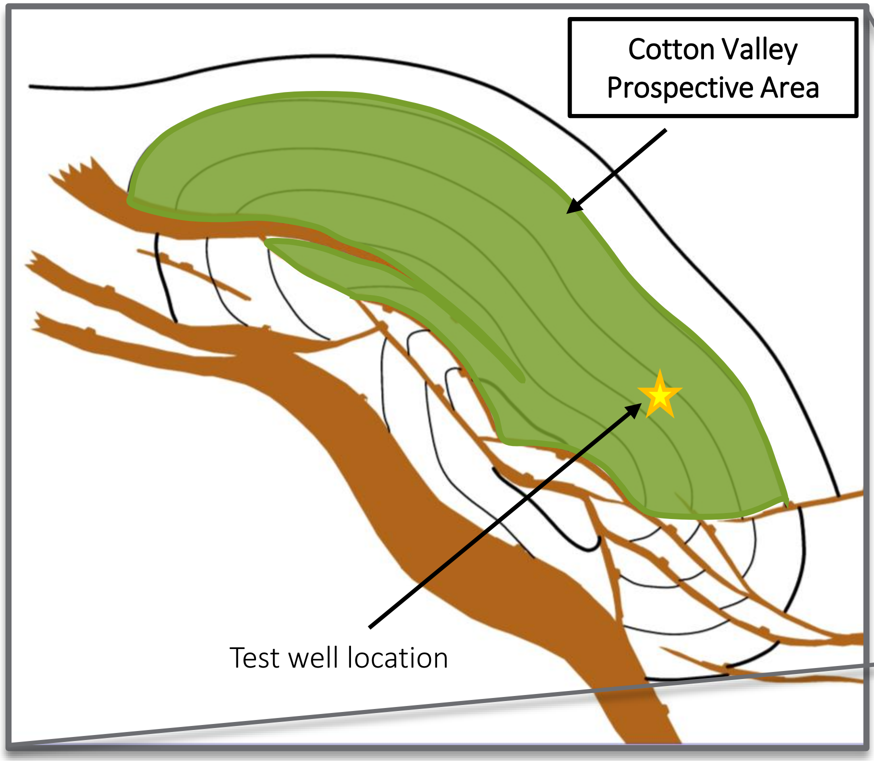
- Conroe 2A Sand test in 2Q19
- Complete initial review of all fields in 2019 & plan additional drilling as early as 2H19

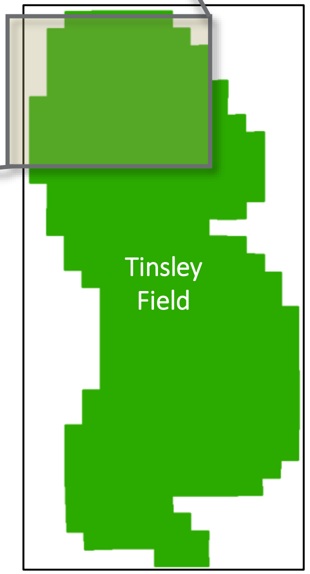


Tinsley – Significant Gas Condensate Resource Potential

Positive Initial Well Results

- First well reached target depth in 1Q19
  - Logged >100' Cotton Valley net pay
    - Likely gas condensate
    - Estimated 3-8 MMBOE recoverable resource range through multiple vertical well development
  - Additional oil potential
    - >100' net pay above Cotton Valley interval
    - Strong offset oil production in Mooringsport through Hosston formations
- Currently conducting flow test
  - Results expected in 2Q19
  - High quality gas composition
- Will evaluate test results to determine development plans



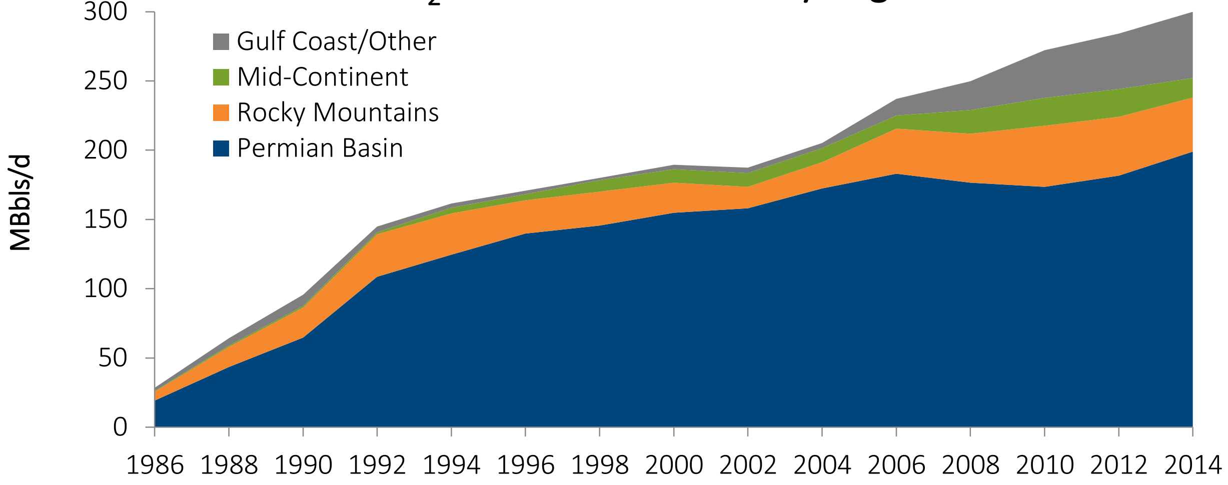


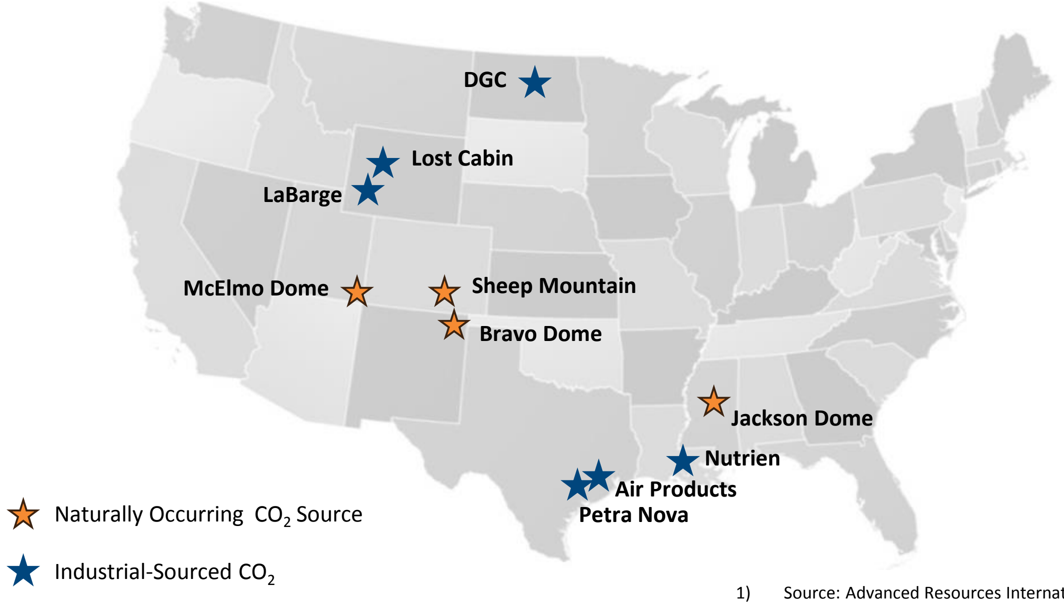
CO_2 EOR is a Proven Process

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

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

CO_2 EOR Oil Production by Region[1]



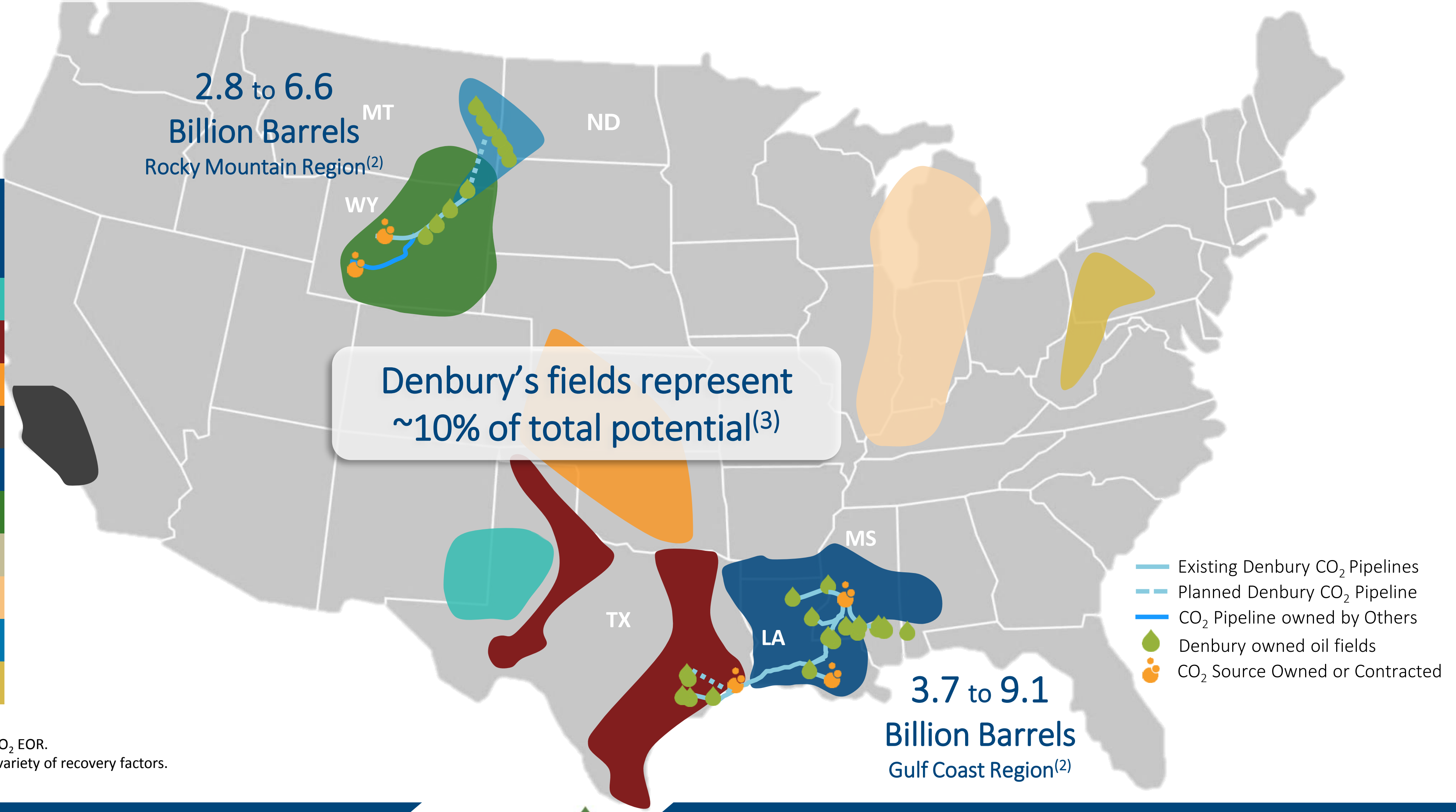


1) Source: Advanced Resources International

Significant Running Room with CO_2 EOR

Up to 83 Billion Barrels of Technically Recoverable Oil – U.S Lower 48[(1)(2)]

33-83 Billion of Technically Recoverable Oil[(1,2)] (amounts in billions of barrels)	
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

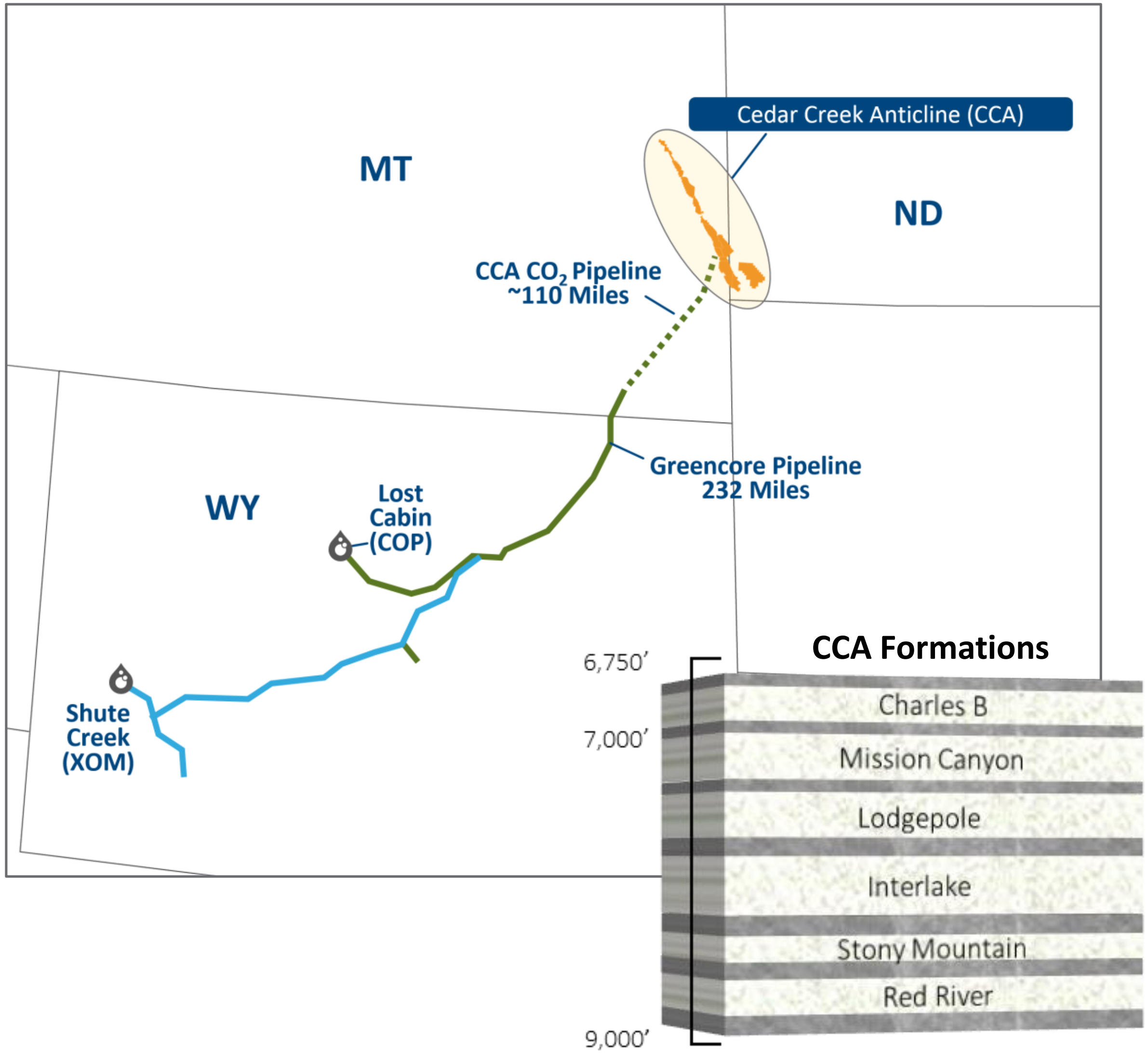


1) Source: 2013 DOE NETL Next Gen EOR.
2) Total estimated recoveries on a gross basis utilizing CO_2 EOR.
3) Using approximate mid-points of ranges, based on a variety of recovery factors.

CO_2 EOR Development at CCA

Cedar Creek Anticline Overview

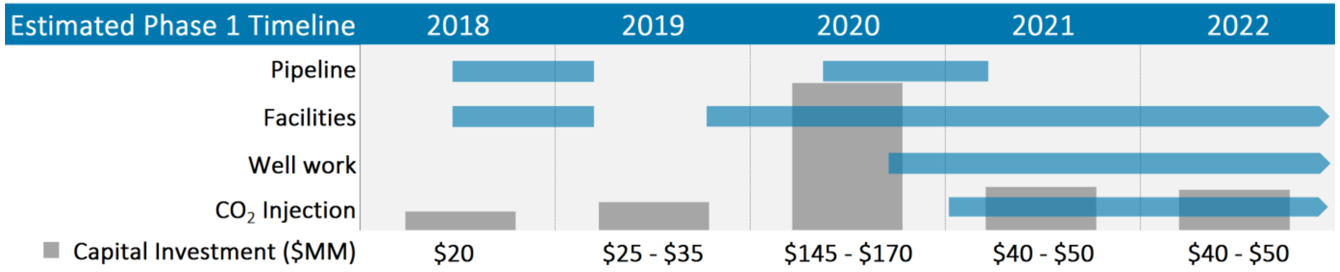
EOR Formation Details	
Initial Formations Targeted	Red River Interlake Stony Mountain
Field Discovery Timeframe (Oil)	1930's (Discovery) 1950's (Development)
Formation Type	Carbonate
Depth	7,000 – 9,000 ft
Original Reservoir Pressure	3,600 – 4,140 psi
CO_2 Flood Type	Miscible
API Gravity	29-38
Average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

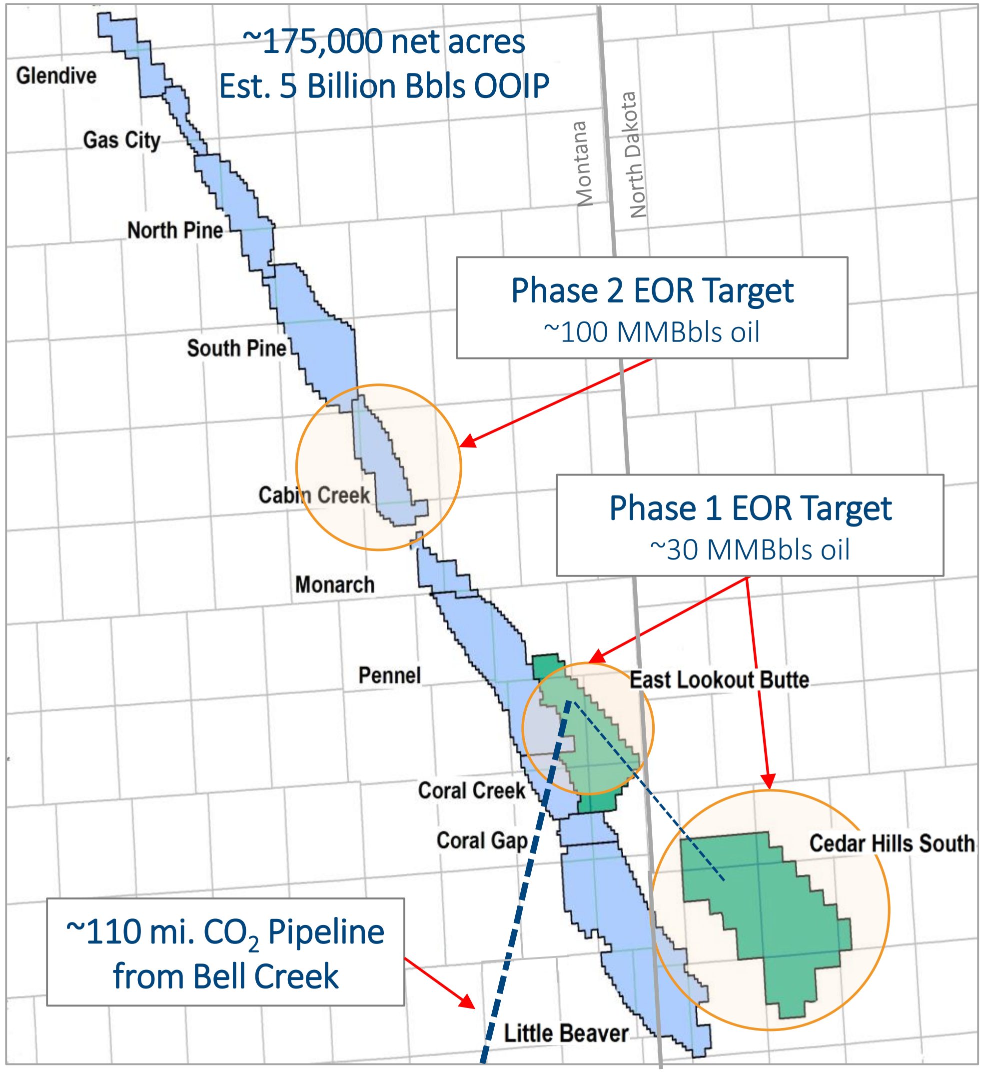


EOR Potential >400 MMBBL at Cedar Creek Anticline

Development Summary

- Phase 1 – Red River formation development at East Lookout Butte and Cedar Hills South
  - Targets ~30 MMBbls of recoverable oil; first tertiary production expected second half of 2022/early 2023, with peak production achieved in 2024/2025
  - Excluding CO_2 pipeline, ~$150 MM development capital to initial tertiary production; ~$400 MM total capital over 15-year period
  - Requires $150 MM CO_2 pipeline that will service all future CCA EOR development
    - Pipeline cost represents <$0.50/Bbl across total CCA EOR potential
  - Expect to internally fund development using available cash flow, will also evaluate external capital sources for pipeline
- Phase 2 - Cabin Creek development in Interlake, Stony Mountain and Red River formations
  - Targets ~100 MMBbls of recoverable oil
  - Development estimated to begin in 2024; fully funded from Phase 1 cash flow
  - Estimated total capital of $500 – $600 MM over multiple decades
- Future Phases – Remainder of CCA
  - > 300 MMBbl EOR potential in multiple formations



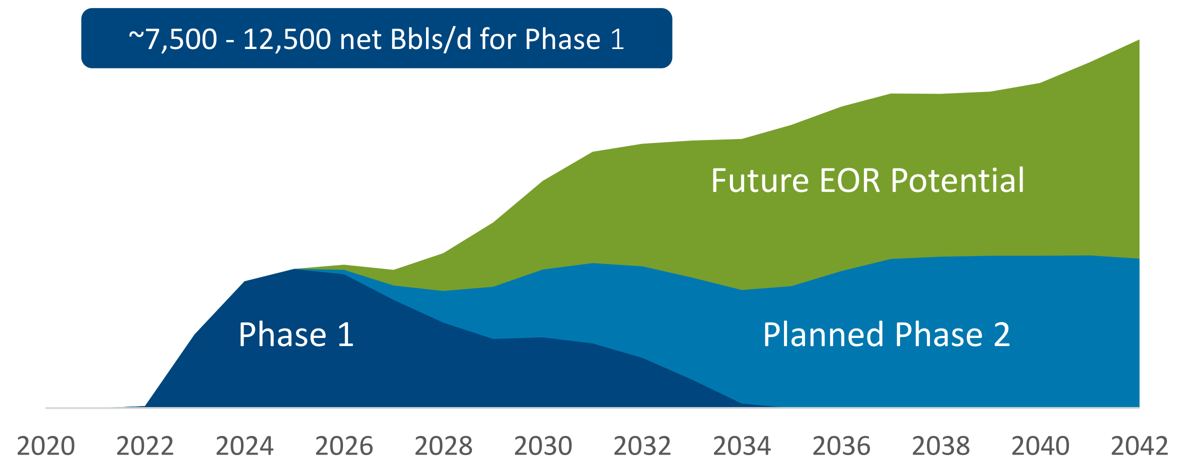


CCA – Decades of Sustainable Production and Free Cash Flow

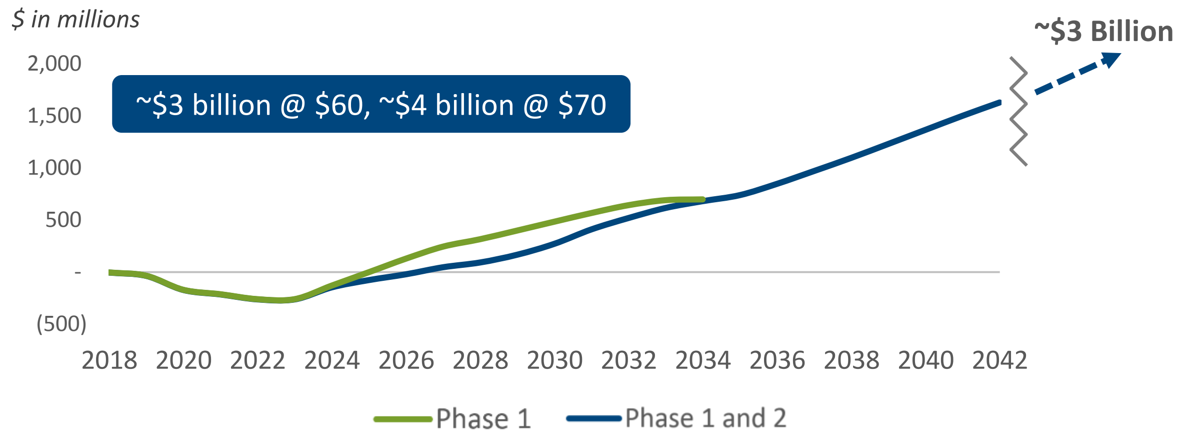
CCA Project Highlights

- Phase 1 and 2 estimated incremental tertiary production of 7,500 – 12,500 Bbls/d
  - Potential to significantly increase production over time subject to CO_2 availability and other factors
- Phase 1 investment, including full CO_2 pipeline, attractive at $50 oil
  - Initial pipeline investment benefits all incremental development
- Phase 1 payout expected within 2 years after first production at $60 oil; future phases funded from project cash flow
- Potential to generate ~$3 billion of cumulative free cash flow from Phases 1 and 2 at $60 oil
- Expect tertiary LOE to average $10-$15/Bbl

Est. Incremental EOR Production



Est. Cumulative Net Cash Flow @ $60 oil



Abundant CO_2 Supply & No Significant Capital Required for Several Years

Gulf Coast CO_2 Supply

Jackson Dome

- Proved CO_2 reserves as of 12/31/18: ~5.0 Tcf(1)
- Additional probable CO_2 reserves as of 12/31/18: ~0.9 Tcf

Industrial-Sourced CO_2

Current Sources

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

Future Potential Sources

- Lake Charles Methanol (methanol plant)(2)

Rocky Mountain CO_2 Supply

LaBarge Area

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

Shute Creek – ExxonMobil Operated

- Proved reserves as of 12/31/18: ~1.2 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

- Denbury estimated to receive 35-40 MMcf/d of CO_2

1) Reported on a gross (8/8th's) basis.
2) Planned but not currently under construction. Estimated CO_2 capture date could be as early as 2023, with estimated potential CO_2 volumes >200 MMcf/d.

Senior Secured Bank Credit Facility Info

Commitments & borrowing base	▪ Borrowing Base / Commitment level: $615 million ▪ Lender group comprised of 14 banks with largest individual commitment representing ~11% of the total
Scheduled redeterminations	▪ Semiannually – May 1st and November 1st
Maturity date	▪ December 9, 2021, subject to springing maturities beginning in February 2021
Permitted bond repurchases	▪ Up to $225 million of bond repurchases – ~$148 million of repurchases currently permitted – Additional ~$77 million of repurchases permitted when total leverage ratio is below 4x after giving effect to such repurchases
Junior lien debt	▪ Up to $1.65 billion of junior lien debt (subject to customary requirements) (~$129 million remaining)
Anti-hoarding provisions	▪ If > $250 million borrowed, unrestricted cash held in accounts is limited to $225 million
Pricing grid	see below
Covenants	▪ Total Debt / EBITDAX: < 5.25x with step down to < 4.5x at 3/31/2021 ▪ Senior Secured Debt[(1)] / EBITDAX: < 2.50x ▪ Interest Coverage Ratio: > 1.25x ▪ Current Ratio: > 1.00x

Pricing grid:

Level	Borrowing Base Utilization	Libor margin (bps)	ABR margin (bps)	Undrawn pricing (bps)
V	> 90.0%	375.0	275.0	50.0
IV	≤ 90.0%	350.0	250.0	50.0
III	≤ 75.0%	325.0	225.0	50.0
II	≤ 50.0%	300.0	200.0	50.0
I	≤ 25.0%	275.0	175.0	50.0

1) Based solely on bank debt.

Production by Area

Average Daily Production (BOE/d)

Field	2016	2017	1Q18	2Q18	3Q18	4Q18	2018	1Q19
Delhi	4,155	4,869	4,169	4,391	4,383	4,526	4,368	4,474
Hastings	4,829	4,830	5,704	5,716	5,486	5,480	5,596	5,539
Heidelberg	5,128	4,851	4,445	4,330	4,376	4,269	4,355	3,987
Oyster Bayou	5,083	5,007	5,056	4,961	4,578	4,785	4,843	4,740
Tinsley	7,192	6,430	6,053	5,755	5,294	5,033	5,530	4,659
Bell Creek	3,121	3,313	4,050	4,010	3,970	4,421	4,113	4,650
Salt Creek	—	1,115	2,002	2,049	2,274	2,107	2,109	2,057
West Yellow Creek	—	2	57	142	240	375	205	436
Mature area[1] and other	8,252	7,089	6,726	6,725	6,618	6,768	6,709	6,531
Total tertiary production	37,760	37,506	38,262	38,079	37,219	37,764	37,828	37,073
Gulf Coast non-tertiary	6,271	5,952	5,692	6,236	5,992	5,799	5,930	5,845
Cedar Creek Anticline	16,322	14,754	14,437	15,742	14,208	14,961	14,837	14,987
Other Rockies non-tertiary	1,844	1,537	1,485	1,490	1,409	1,343	1,431	1,313
Total non-tertiary production	24,437	22,243	21,614	23,468	21,609	22,103	22,198	22,145
Total continuing production	62,197	59,749	59,876	61,547	58,828	59,867	60,026	59,218
Property divestitures[2]	1,806	549	462	447	353	—	315	—
Total production	64,003	60,298	60,338	61,994	59,181	59,867	60,341	59,218

1) Mature area includes Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb, and Soso fields.
2) Includes production from Lockhart Crossing Field sold in the third quarter of 2018, 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.

NYMEX Oil Differential Summary

Six consecutive quarters of company-wide positive differential to NYMEX

Crude Oil Differentials

$ per barrel	2016	2017	1Q18	2Q18	3Q18	4Q18	2018	1Q19
Tertiary Oil Fields								
Gulf Coast Region	$(1.35)	$0.06	$1.87	$0.85	$3.01	$5.20	$2.73	$4.07
Rocky Mountain Region	(2.16)	(0.96)	0.22	(1.10)	(0.86)	(4.88)	(1.81)	(2.01)
Gulf Coast Non-Tertiary	(1.89)	1.26	3.26	2.73	4.42	6.24	4.28	5.45
Cedar Creek Anticline	(3.77)	(1.43)	(0.11)	(0.67)	(0.31)	(3.93)	(1.30)	(2.69)
Other Rockies Non-Tertiary	(8.63)	(2.72)	(1.30)	(1.96)	(1.92)	(6.58)	(2.87)	(4.80)
Denbury Totals	$(2.29)	$(0.32)	$1.29	$0.39	$1.84	$1.69	$1.30	$1.63

During 1Q19, ~60% of our crude oil was exposed to Gulf Coast premium pricing

Analysis of Total Operating Costs

Total Operating Costs

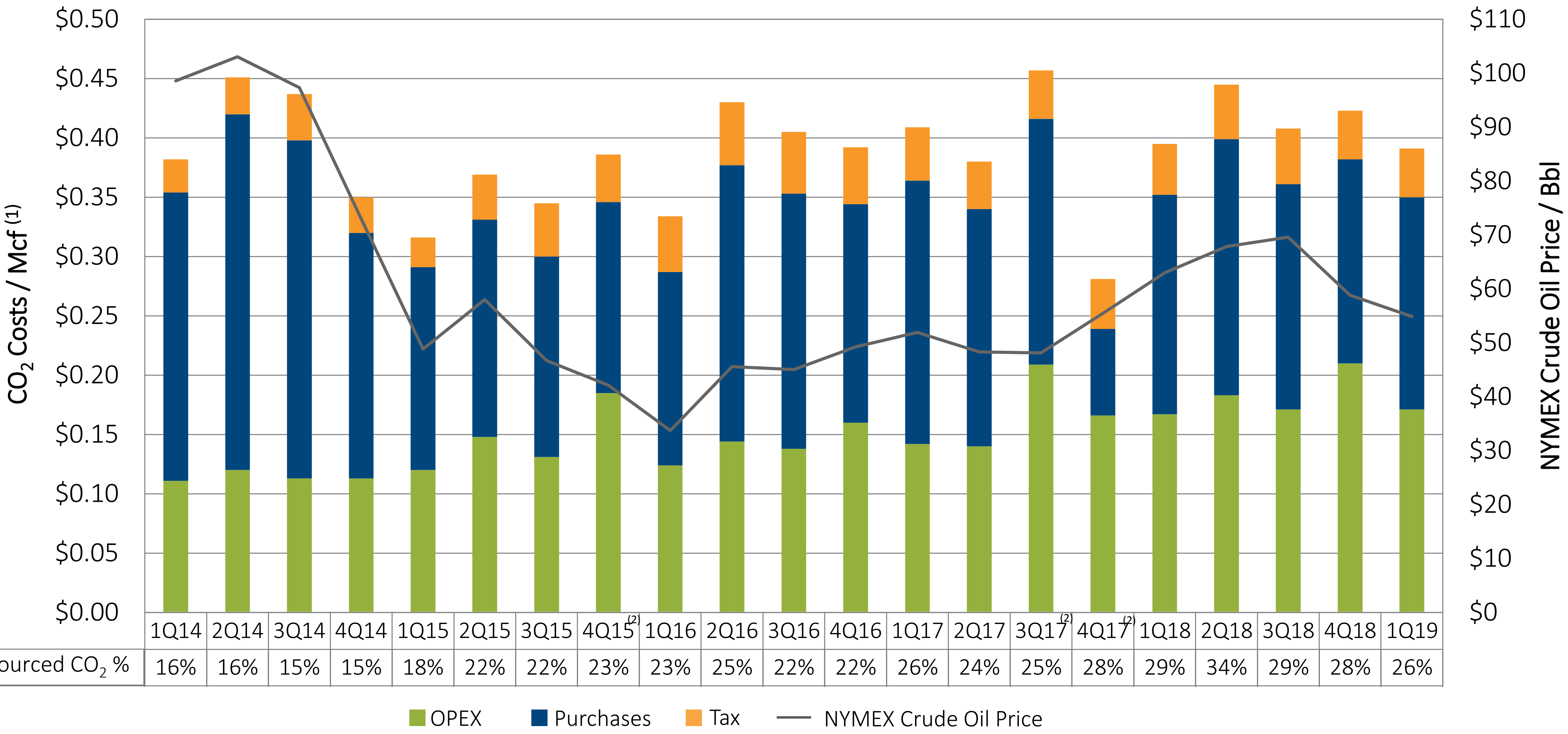
$ per BOE	2016	2017	1Q18	2Q18	3Q18	4Q18	2018	1Q19
CO_2 Costs	$2.16	$2.86	$3.09	$2.92	$2.63	$3.62	$3.07	$3.90
Power & Fuel	5.29	5.97	6.68	6.19	6.31	6.08	6.32	6.70
Labor & Overhead	5.41	6.32	6.38	6.47	6.99	6.60	6.61	6.71
Repairs & Maintenance	0.84	0.84	0.80	0.91	1.09	0.85	0.91	1.00
Chemicals	1.02	1.04	1.00	1.05	1.17	1.03	1.06	1.08
Workovers	1.87	2.44	2.84	2.21	3.20	3.60	2.96	2.94
Other	0.97	1.06	1.01	1.59	1.11	1.54	1.31	1.20
Total Normalized LOE(1)	$17.56	$20.53	$21.80	$21.34	$22.50	$23.32	$22.24	$23.53
Special or Unusual Items(2)	0.15	(0.18)	—	—	—	—	—	—
Total LOE	$17.71	$20.35	$21.80	$21.34	$22.50	$23.32	$22.24	$23.53
Oil Pricing								
NYMEX Oil Price	$43.41	$50.96	$62.96	$67.85	$69.60	$58.81	$64.81	$54.87
Realized Oil Price(3)	$41.12	$50.64	$64.25	$68.24	$71.44	$60.50	$66.11	$56.50

1) Normalized LOE excludes special or unusual items and Thompson Field repair costs (see footnote 2 below).

2) Special or unusual items consist of (a) repair costs to return Thompson Field to production following weather-related flooding in 2016, and (b) cleanup and repair costs associated with Hurricane Harvey ($3MM) offset by an adjustment for pricing related to one of our industrial CO_2 sources ($7MM) in 2017.

3) Excludes derivative settlements.

CO_2 Cost & NYMEX Oil Price



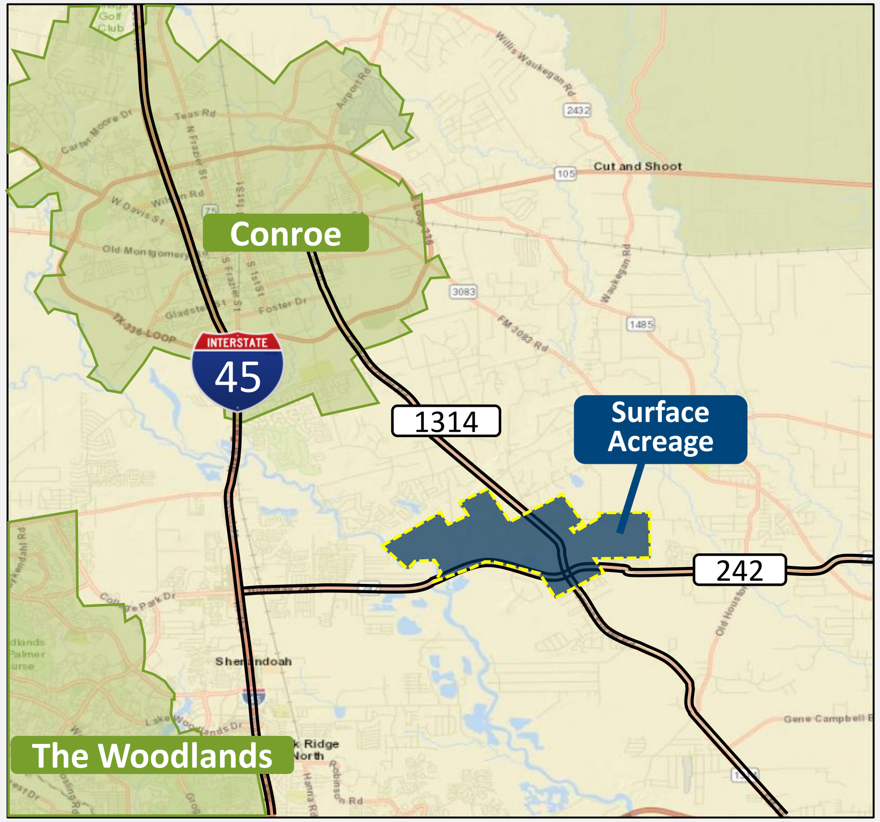
Industrial-Sourced CO_2 %	16%	16%	15%	15%	18%	22%	22%	23%	23%	25%	22%	22%	26%	24%	25%	28%	29%	34%	29%	28%	26%

1) Excludes DD&A on CO_2 wells and facilities; includes Gulf Coast & Rocky Mountain industrial-source CO_2 costs.
2) CO_2 costs include workovers carried out at Jackson Dome in 3Q17 and 4Q15 of $3 million ($0.08 per Mcf) and $3 million ($0.05 per Mcf), respectively, and a downward adjustment in 4Q17 for pricing related to one of our industrial CO_2 sources of $7 million ($0.12 per Mcf)

Houston Area Land Sales

Conroe

- ~3,400 surface acres consisting of 7 parcels for commercial and residential development



Webster

- ~800 surface acres consisting of 11 commercial parcels
- Multiple parcels along I-45 frontage road

Non-GAAP Measures

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

	2018						2019	
In millions	Q1	TTM	Q2	Q3	Q4	FY	Q1	TTM
Net income (loss) (GAAP measure)	$40	$181	$30	$78	$174	$323	$(26)	$256
Adjustments to reconcile to Adjusted EBITDAX								
Interest expense	17	89	16	19	18	70	17	70
Income tax expense (benefit)	14	(124)	9	16	48	87	(11)	62
Depletion, depreciation, and amortization	52	208	53	51	60	216	57	221
Noncash fair value losses (gains) on commodity derivatives	15	96	41	(17)	(236)	(196)	92	(120)
Stock-based compensation	3	14	3	4	3	12	3	13
Litigation accrual and loan receivable impairment	—	—	—	—	67	67	0	67
Noncash, non-recurring and other[1]	1	23	1	(3)	7	5	6	11
Adjusted EBITDAX (non-GAAP measure)	$142	$487	$153	$148	$141	$584	$138	$580

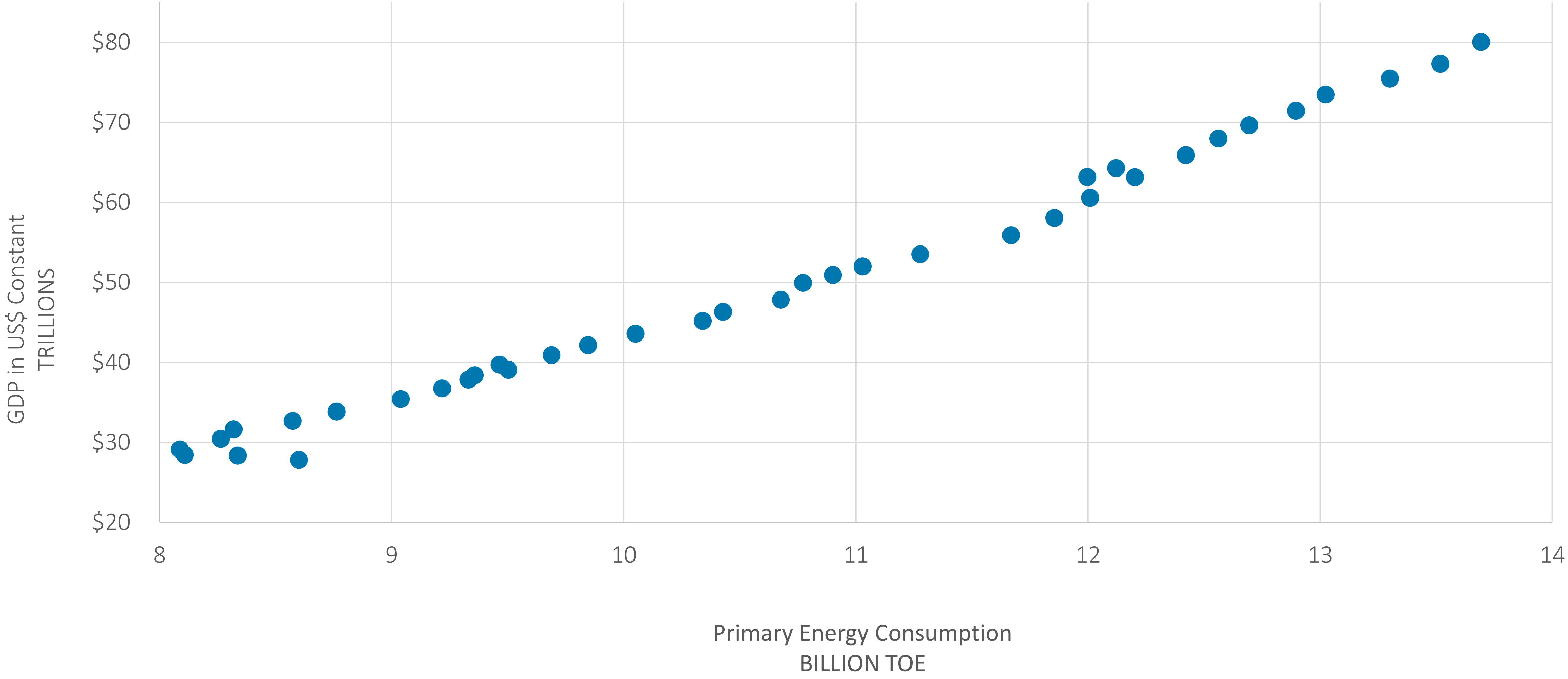
1) Excludes proforma adjustments related to qualified acquisitions or dispositions under the Company's senior secured bank credit facility.

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.

Three Questions About the Future of the Oil Industry

1. Are we approaching peak oil demand?
2. Can tight oil production growth meet expected demand?
3. Is there any future for conventional oil production?

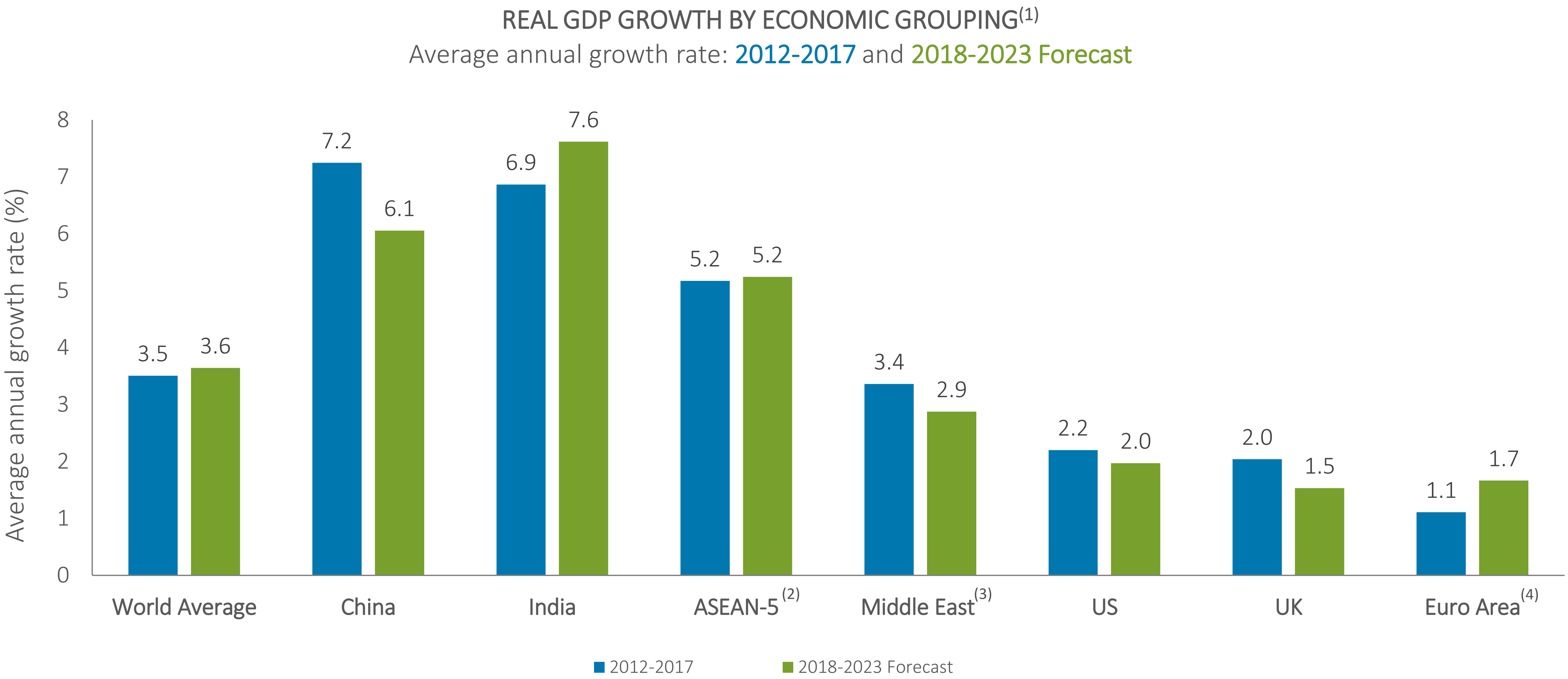
Linear Correlation between Economic Growth and Energy



NOTE: 1 tonne of oil equivalent (TOE) = ~7.33 barrels of oil equivalent (BOE)

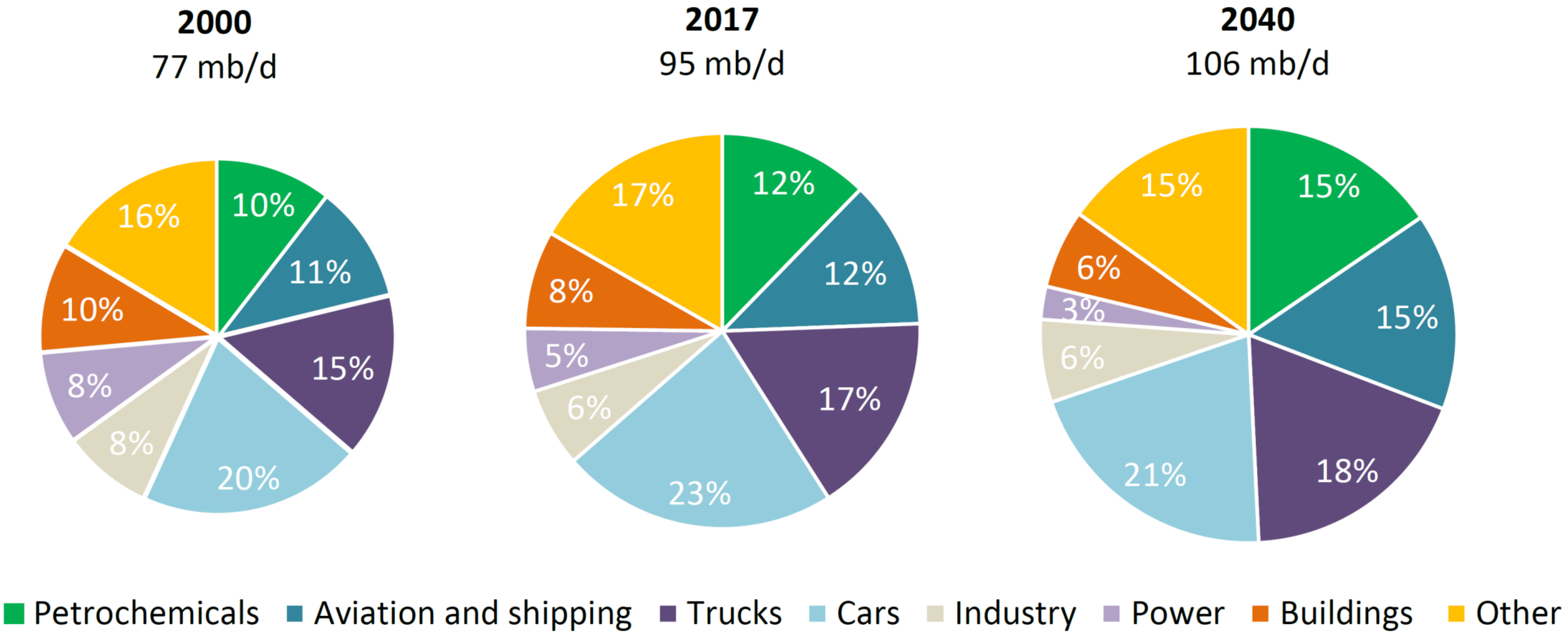
Source: GDP Data from IMF World Economic Outlook Database, October 2018; Primary Energy Consumption Data from US Energy Information Administration

Sustained Strong Global Economic Growth



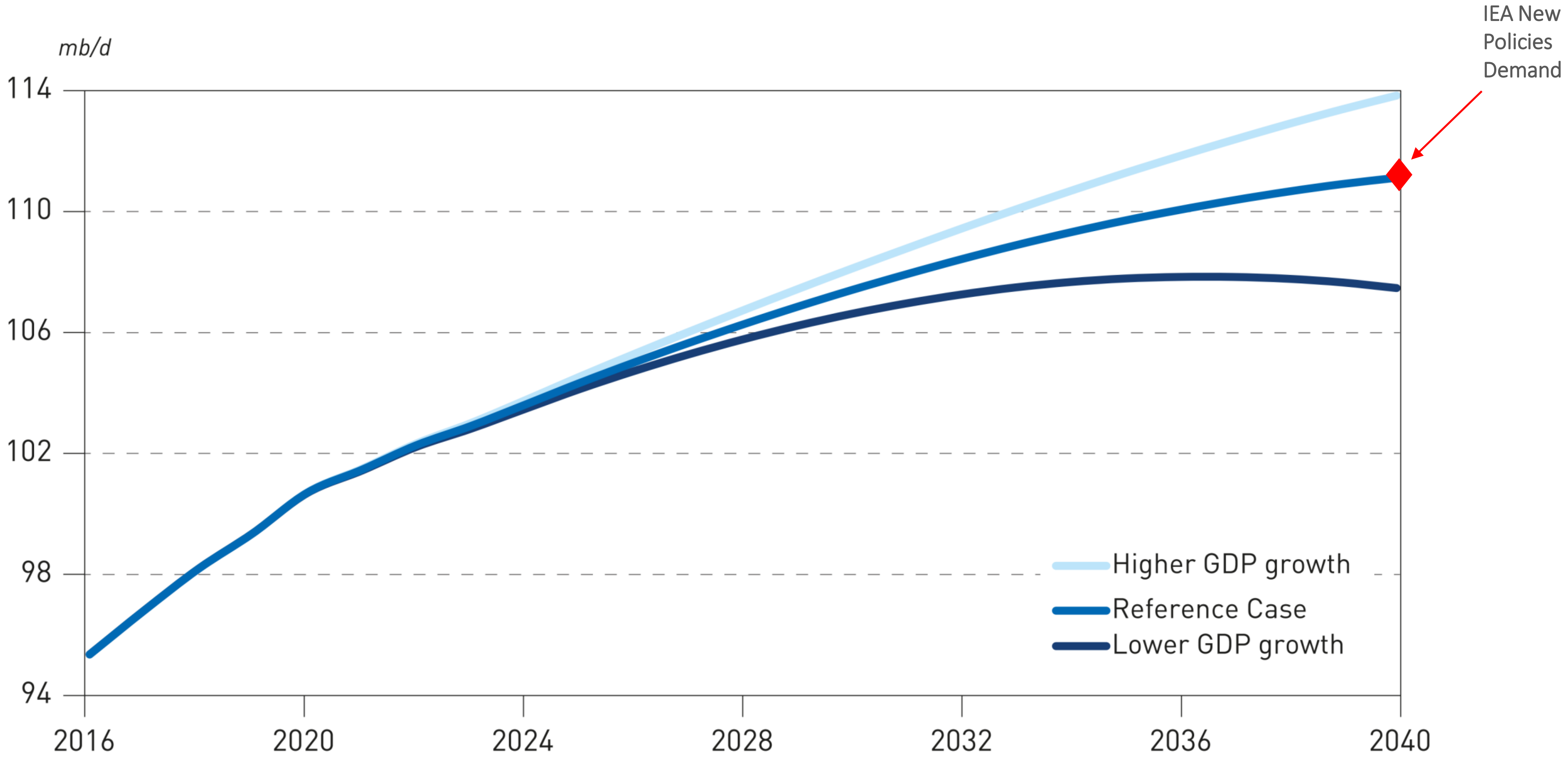
1) Source: World Economic Outlook Database, October 2018
2) ASEAN-5 = Indonesia, Malaysia, Philippines, Thailand and Vietnam.
3) Includes 21 countries in the Middle East and North Africa, Afghanistan and Pakistan
4) Composed of 19 economies in Europe: Austria, Belgium, Cyprus, Estonia, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Portugal, Slovak Republic, Slovenia and Spain

Oil Demand by Sector



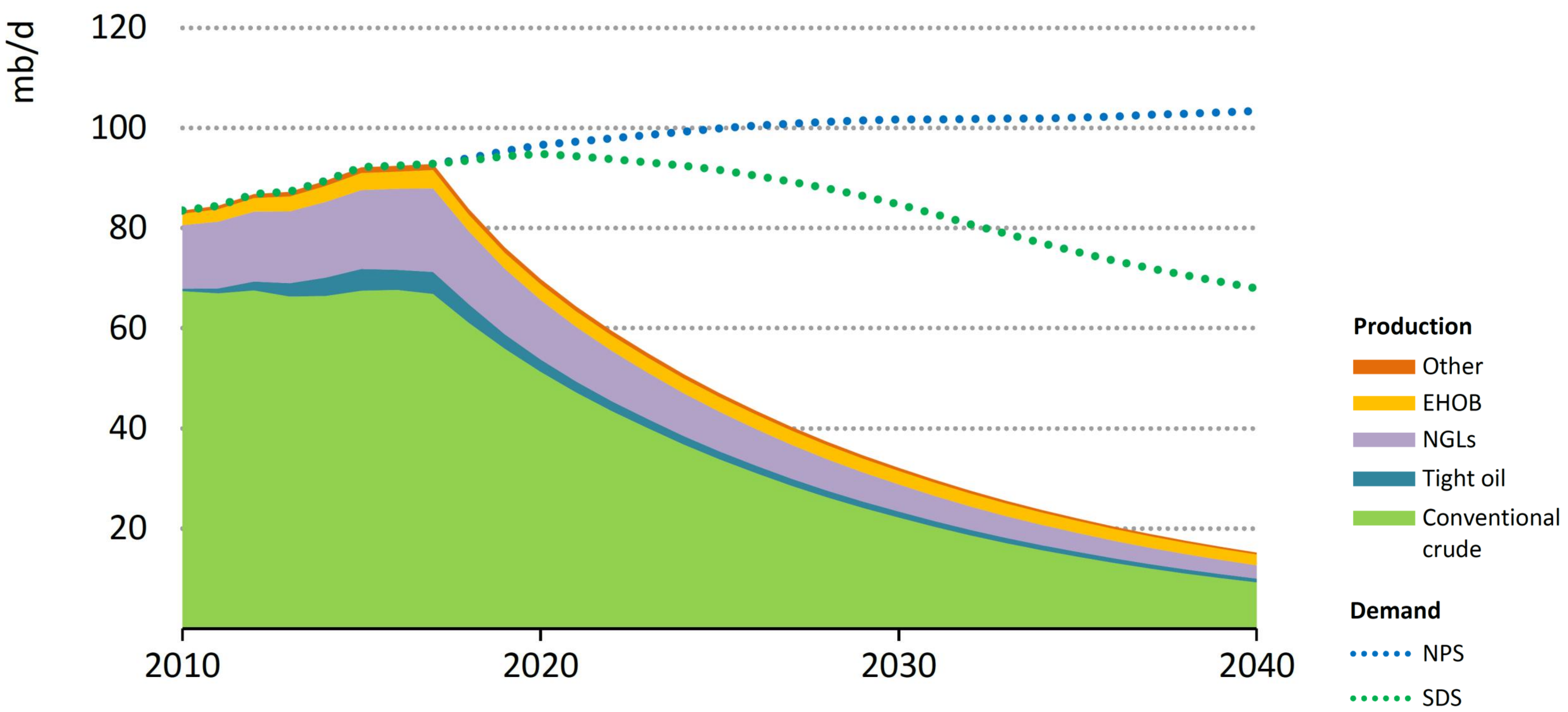
Source: IEA World Energy Outlook 2018

Oil Demand Forecast



Sources: OPEC World Oil Outlook 2017, IEA World Energy Outlook 2018

World Oil Production with no New Investment



Source: IEA World Energy Outlook 2018

What Will the Future Bring in the Oil Industry?

1. Oil demand is likely to increase over the next 20 years
2. Production from tight oil is expected to peak around the middle of the next decade and will not meet future supply needs
3. Significant investments in conventional production are needed to meet this future demand

While tight oil production will remain important for many years, a return of focus on conventional production is coming, and the need for traditional, conventional technical skill sets will <u>increase</u> in the coming years, rather than decrease