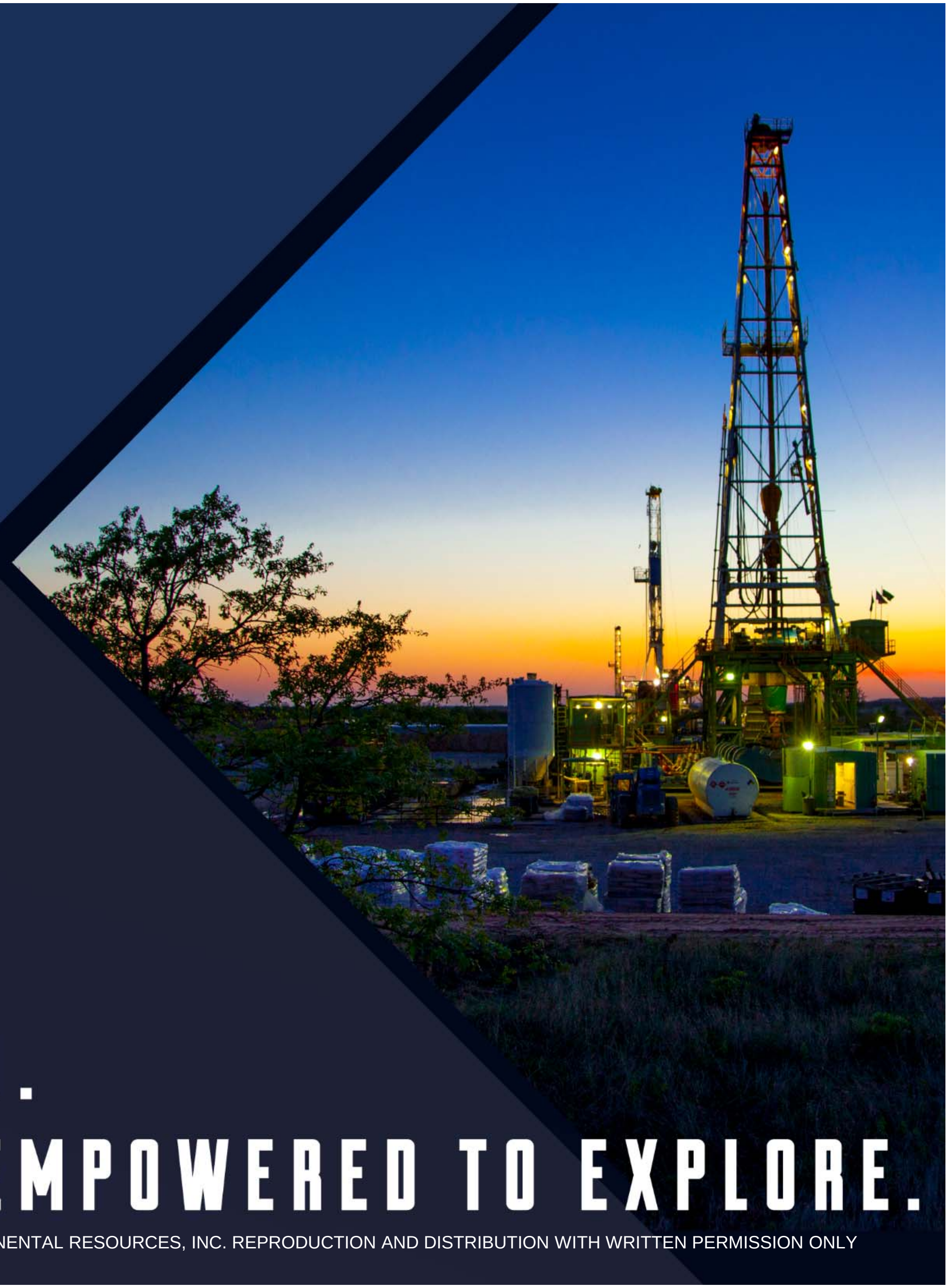
Investor Update

February 2019



Continental RESOURCES

DRIVEN TO LEAD.

EMPOWERED TO EXPLORE.

NYSE: CLR

Forward-Looking Information

Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

This presentation includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements included in this presentation other than statements of historical fact, including, but not limited to, forecasts or expectations regarding the Company's business and statements or information concerning the Company's future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows, are forward-looking statements. When used in this presentation, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget," "target," "plan," "continue," "potential," "guidance," "strategy," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements are based on the Company's current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control. No assurance can be given that such expectations will be correct or achieved or the assumptions are accurate. The risks and uncertainties include, but are not limited to, commodity price volatility; the geographic concentration of our operations; financial, market and economic volatility; the inability to access needed capital; the risks and potential liabilities inherent in crude oil and natural gas exploration, drilling and production and the availability of insurance to cover any losses resulting therefrom; difficulties in estimating proved reserves and other revenue-based measures; declines in the values of our crude oil and natural gas properties resulting in impairment charges; our ability to replace proved reserves and sustain production; the availability or cost of equipment and oilfield services; leasehold terms expiring on undeveloped acreage before production can be established; our ability to project future production, achieve targeted results in drilling and well operations and predict the amount and timing of development expenditures; the availability and cost of transportation, processing and refining facilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing; increased market and industry competition, including from alternative fuels and other energy sources; and the other risks described under Part I, Item 1A Risk Factors and elsewhere in the Company's Annual Report on Form 10-K for the year ended December 31, 2018, registration statements and other reports filed from time to time with the SEC, and other announcements the Company makes from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this presentation occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. Except as expressly stated above or otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this presentation, or otherwise.

Readers are cautioned that initial production rates are subject to decline over time and should not be regarded as reflective of sustained production levels. In particular, production from horizontal drilling in shale oil and natural gas resource plays and tight natural gas plays that are stimulated with extensive pressure fracturing are typically characterized by significant early declines in production rates.

We use the term "EUR" or "estimated ultimate recovery" to describe potentially recoverable oil and natural gas hydrocarbon quantities. We include these estimates to demonstrate what we believe to be the potential for future drilling and production on our properties. These estimates are by their nature much more speculative than estimates of proved reserves and require substantial capital spending to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from our properties will differ substantially. EUR data included herein remain subject to change as more well data is analyzed.

CLR's 2018 "Breakout Year"
Delivers Exceptional Results

2018 Full-Year Results

- $988 million net income
- ~14% annual ROCE[(1)]
- $824 million net debt reduction since Dec-17[(2)]
- Record low annual LOE: $3.59/Boe
- 14% increase in YE18 proved reserves over YE17

4Q18 Results

Bakken
- 52 wells average 2,800 Boepd IP per well[(3)] (CLR quarterly record)
- 60% of 2018 Bakken program paid out by end of 4Q18[(4)]

STACK
- 19 wells average 3,645 Boepd IP per well[(3)]
- Boden unit wells outperforming parent type curve by ~40%

SCOOP
- 4Q18 oil production up 47% over 4Q17
- SpringBoard on pace to add 10% to CLR net oil production (3Q18-3Q19)

Production	2018	YoY Change
Total	298,190 Boepd	**Up 23%**
Oil	168,177 Bopd	**Up 21%**
Bakken	167,800 Boepd	**Up 26%**
SCOOP/STACK	120,394 Boepd	**Up 24%**

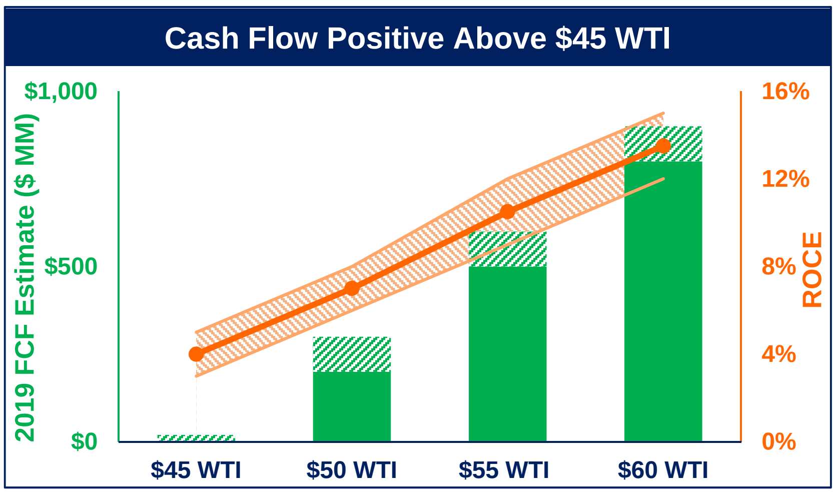
Production	4Q18	Change from 3Q18
Total	324,001 Boepd	**Up 9%**
Oil	186,934 Bopd	**Up 14%**
Bakken	183,836 Boepd	**Up 10%**
SCOOP/STACK	130,191 Boepd	**Up 9%**

1. See the calculation of ROCE on slide 27.
2. Net debt is a non-GAAP measure. See slide 21 for a definition and reconciliation of this measure to the most comparable U.S. GAAP financial measure.
3. Maximum average 24-hour IP rate from gross operated wells.
4. 2018 Bakken Program consists of 159 gross operated wells with first production in 2018.

CLR's 2019 Plan:
Sustained Returns, FCF, Low-Cost Oil-Weighted Growth

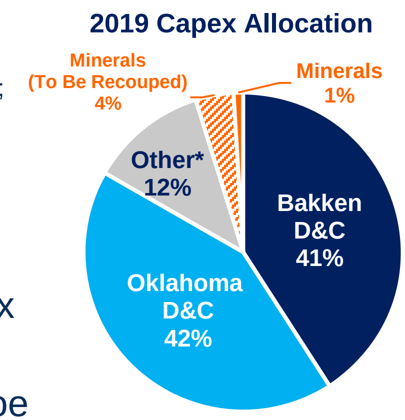
2019: Delivering Strong FCF[1] & Returns

- 9% to 12% annual ROCE
- $500MM to $600MM FCF[1] at $55 WTI
  - Cash neutral in mid-$40's WTI
  - $5 WTI change = $325MM change in FCF[1]
- Reduce net debt to $5B target by YE 2019[2]



2019 Capital-Efficient, Oil-Weighted Growth

- $2.6B Capex
  - ~$2.2 billion D&C (~½ Bakken, ~½ OK)
  - $125 million mineral royalty acquisitions; of which $100 million will be recouped
- $3.75 to $4.25 LOE/Boe
- 8.0% to 8.3% Production Tax
- $1.70 to $2.00 Total G&A/Boe
- $15.00 to $17.00 DD&A/Boe



Oil-Weighted Growth		
2019 Production Guidance		YoY Growth
Oil	190,000 to 200,000 Bopd	13% to 19%
Nat Gas	790,000 to 810,000 Mcfpd	1% to 4%

1. Free cash flow (FCF) is a non-GAAP measure. With respect to this projected amount, please see slide 20 for an explanation of the factors that make a quantitative reconciliation of this forward-looking estimate to U.S. GAAP not possible.
2. Net debt is a non-GAAP measure. With respect to this projected amount, please see slide 21 for an explanation of the factors that make a quantitative reconciliation of this forward-looking estimate to U.S. GAAP not possible.

* Other Capex is planned to be primarily focused on leasehold, workovers and facilities.

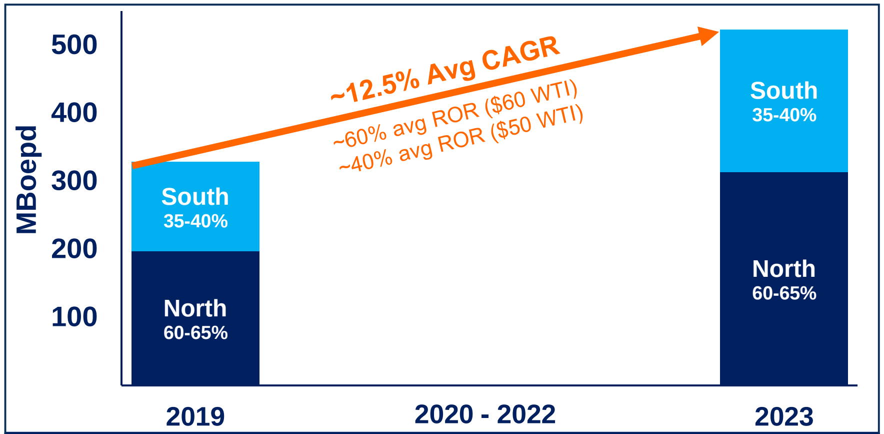
CLR's 5-Year Vision:
Sustainable, Cash Flow Positive Growth from Current Inventory

5-Year Vision Delivers Value & Growth

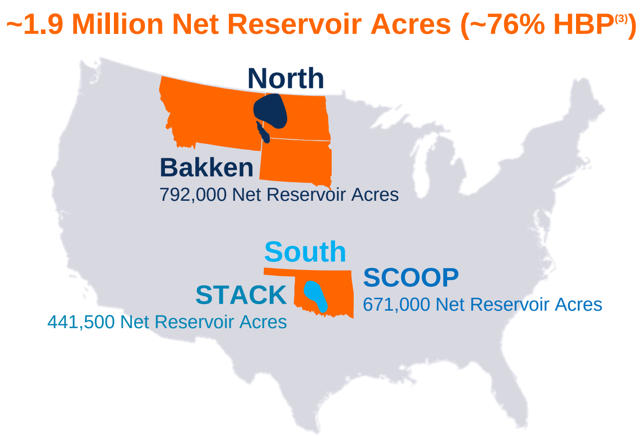
- Avg. annual FCF[1] of $700-$800 million/year at $60 WTI
  - o Projected range of $500 million to over $1 billion/year
- Avg. ~14.5% annual ROCE/year at $60 WTI
- Avg. ~12.5% production CAGR[2]

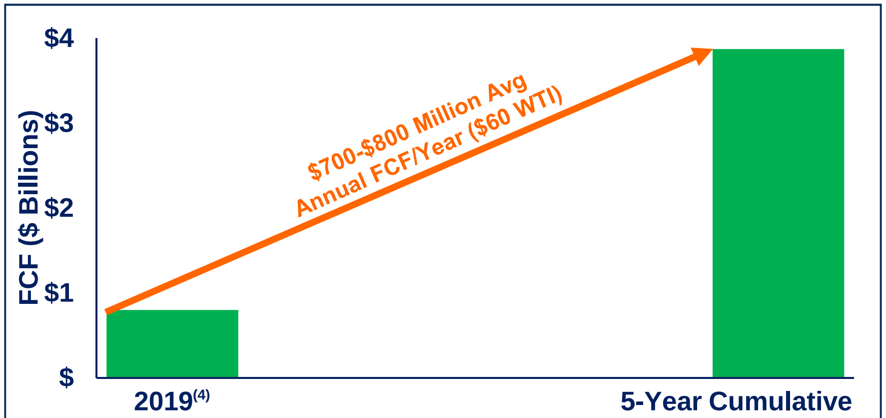
Built on Depth & Quality of Current Inventory

- Less than 30% of current inventory to be developed during period
- Delivers blended average of 60% ROR at $60 WTI



Projected Production

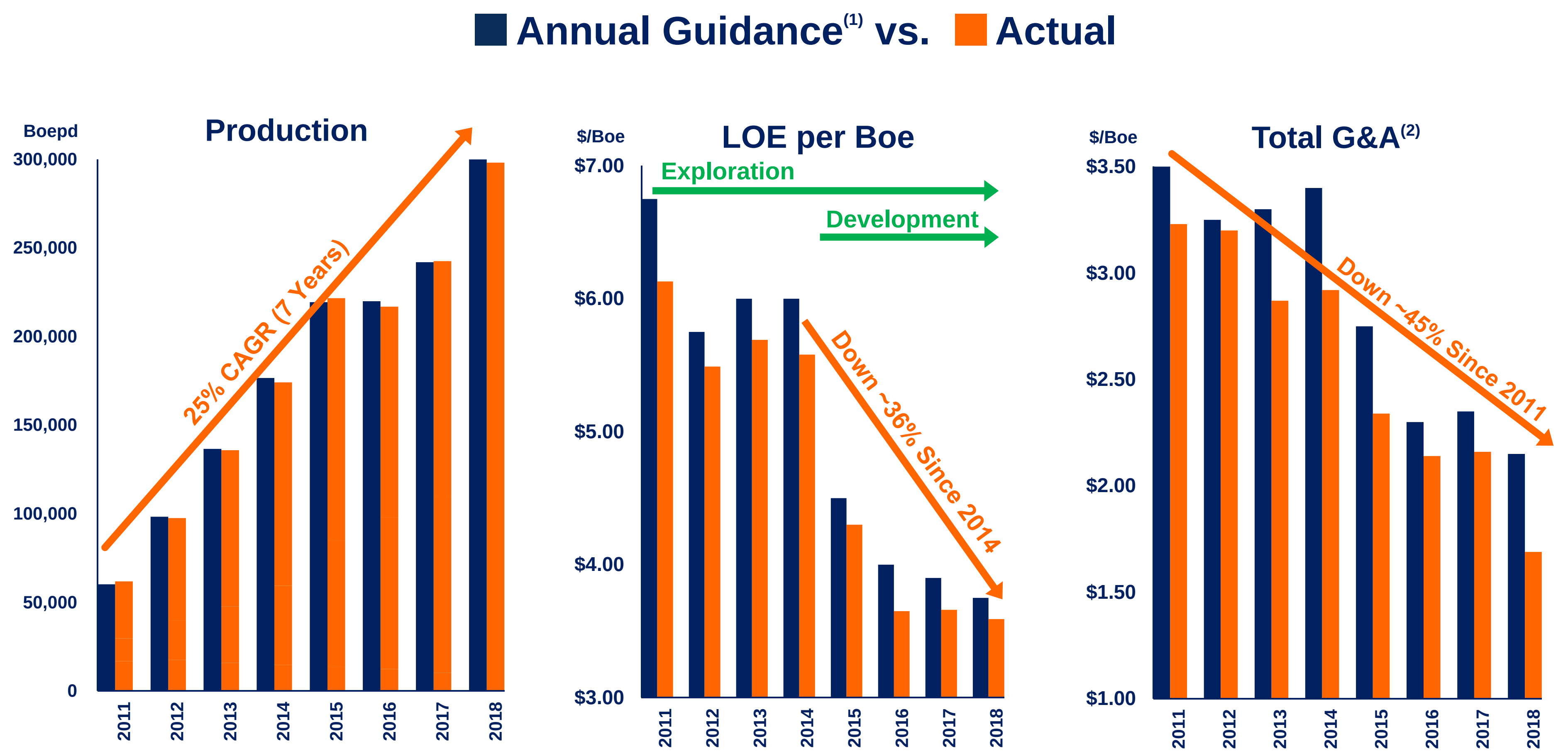




Projected Free Cash Flow[1]

1. Free cash flow (FCF) is a non-GAAP measure. With respect to this projected amount, please see slide 20 for an explanation of the factors that make a quantitative reconciliation of this forward-looking estimate to U.S. GAAP not possible.
2. Total annual production growth expected to range between 10% and 15% each year.
3. Acreage numbers and HBP numbers are approximate as of 4Q18.
4. The 2019 capital budget is projected to generate an estimated $500 to $600 million of free cash flow for full-year 2019 at $55 WTI and $3 HH. A $5 change per barrel WTI is estimated to impact annual cash flow by $300 million to $325 million.

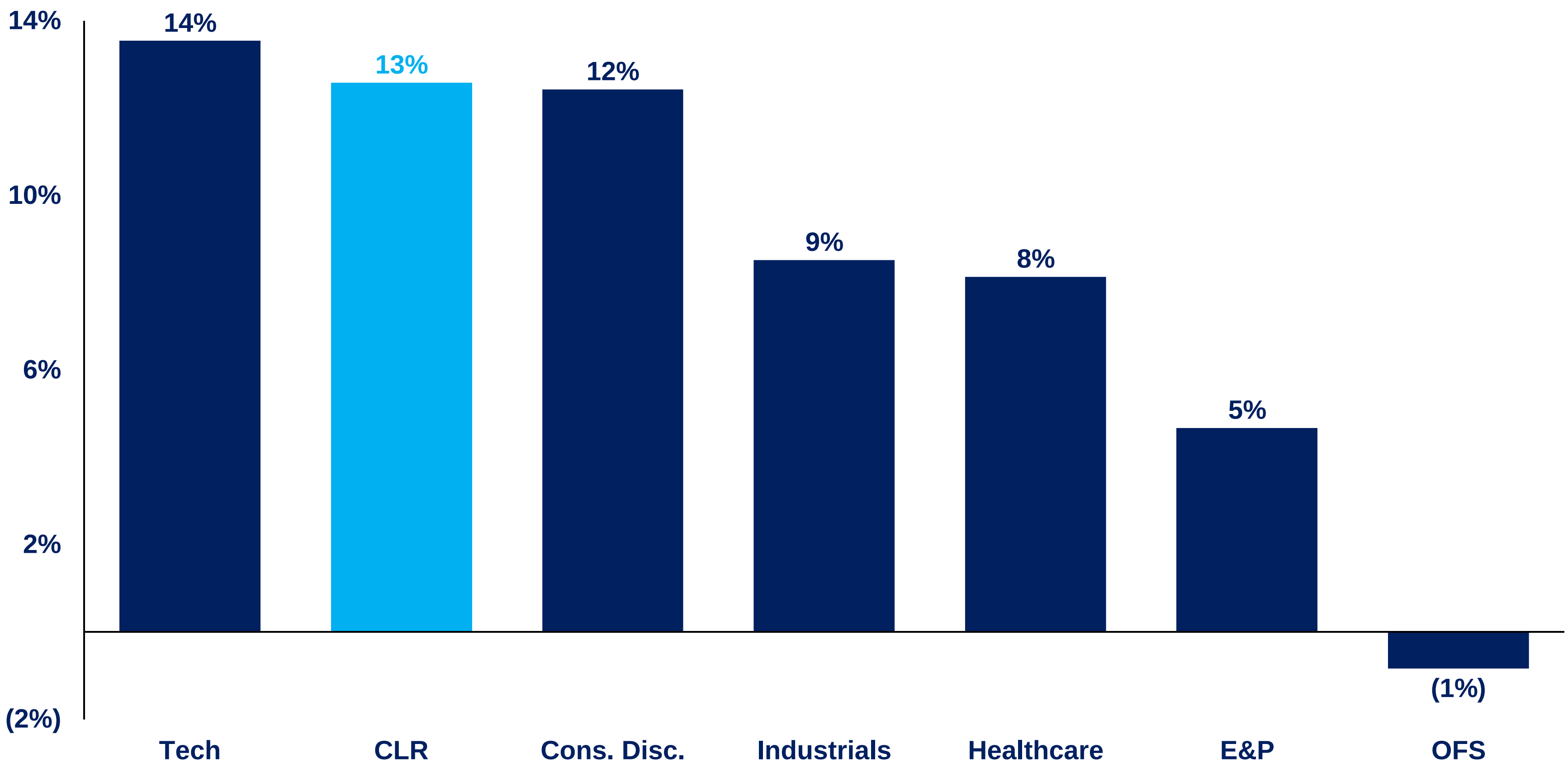
CLR: Consistently Delivers On Guidance!



1. Annual guidance calculated at the upper end of the most current guidance provided for each year.
2. Total G&A includes cash G&A expense per Boe and non-cash equity compensation per Boe. Excludes corporate relocation costs for 2011 to 2013.

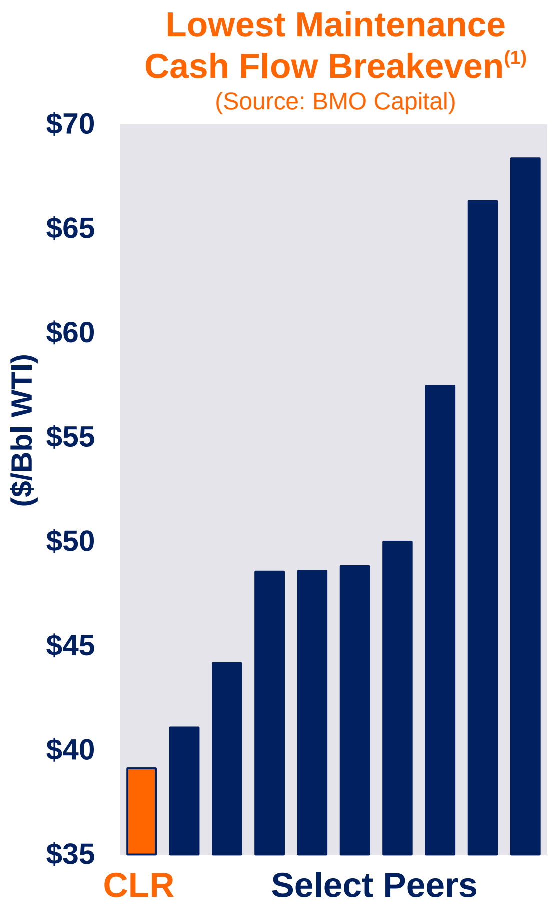
CLR's Corporate Returns Compete Across The Broader Market

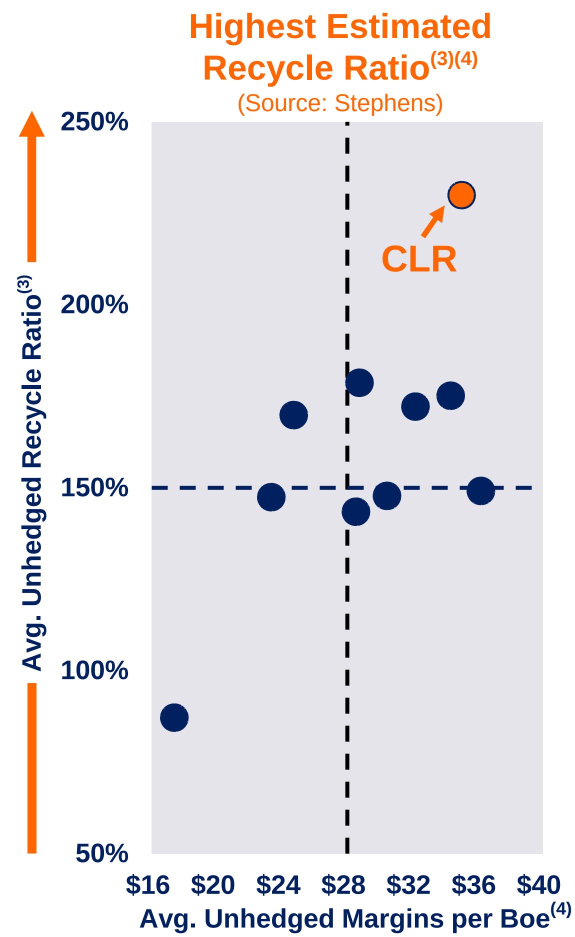
TTM 3Q18 CLR Corporate Returns Compete Across the Market[1]



1. Source: Bloomberg as of 01/14/19. Data is calculated as net income plus minority interest plus after-tax interest expense divided by the average of current and prior capital employed. Data represents an average of quarterly return over the trailing 4 quarters as of 3Q18. E&P: S&P 500 Exploration & Production Index; OFS: S&P 500 Oil Field Services Index; Tech: S&P 500 Info Tech Index; Industrials: S&P 500 Industrials Index; Cons. Disc.: S&P 500 Consumer Discretionary Index; Healthcare: S&P 500 Health Care Index.

CLR Continues To Be The Low Cost Leader Among Peers





Select peers for all charts include: APA, CXO, DVN, HES, NBL, OAS, PXD, WLL and WPX.

1. Source: BMO Capital Markets as of January 2019. Estimated maintenance cash flow breakeven price is the estimated oil price calculated to hold production flat within cash flow. This price is calculated on a cumulative basis over 2019-21. U.S. rig activity levels are adjusted so that each company's 2019-21 total production is held flat with estimated 4Q18 levels.
2. Source: Public company filings as of 3Q18.
3. Source: Stephens. Estimated 2018 recycle ratio is calculated as margins divided by F&D per Boe. F&D consists of fully loaded well costs divided by 5-year cumulative volumes based on type curve estimates by operator by asset area.
4. Source: Stephens. Estimated 2018 margins are calculated as E&P revenue less LOE, TT&O and cash G&A per Boe. Estimated margin is calculated in a different manner than CLR's calculation of margin on page 19.

CLR: #1 Bakken Producer

Bakken Delivering Outstanding Capital-Efficient Growth

Production and Reserves up 26% YoY

- 183,836 Boepd avg. 4Q18 production

52 gross operated wells completed in 4Q18

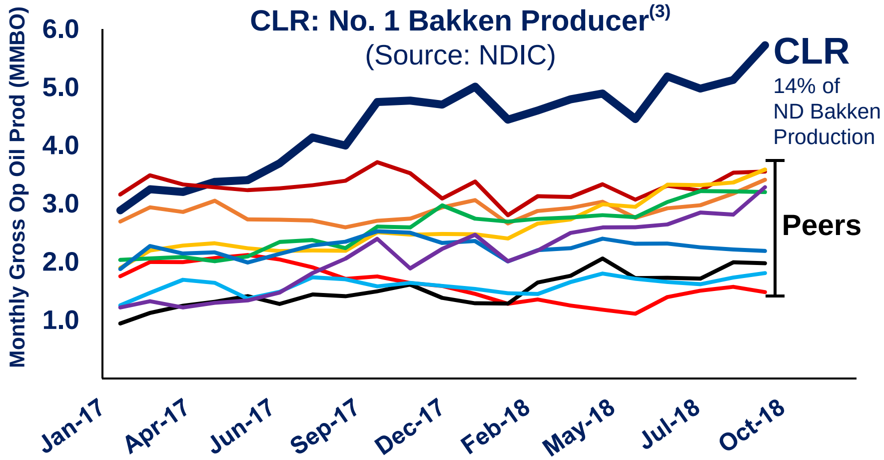
- 2,800 Boepd/well avg. IP[1]

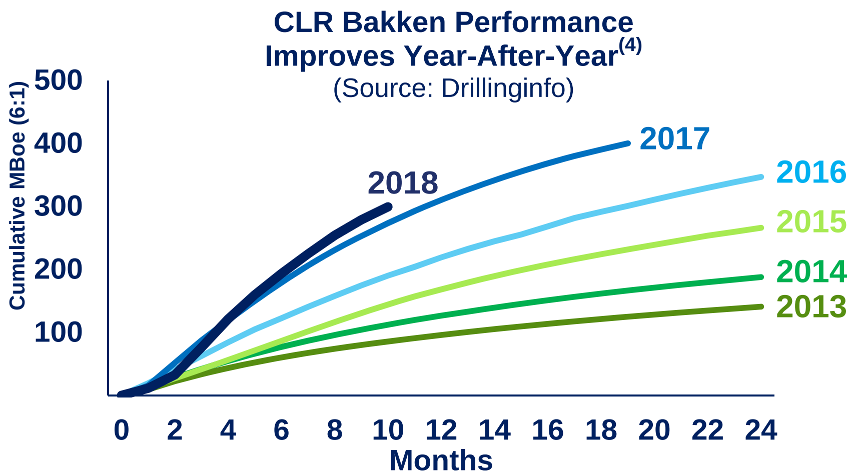
Outstanding Capital-Efficient Growth

- 2017 drilling program: Paid out in 2018
- 2018 drilling program: 60% paid out at YE18[2]

Efficiencies Keep On Coming

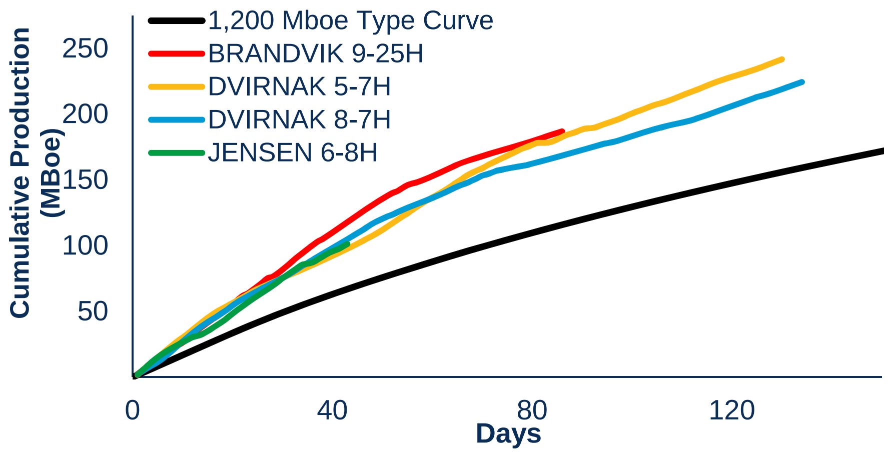
- Increased stage spacing; decreases CWC $200K
  - 45-stage limited entry vs. 60-stage completions delivering similar results
  - CWC reduced $200K to $8.2MM/well





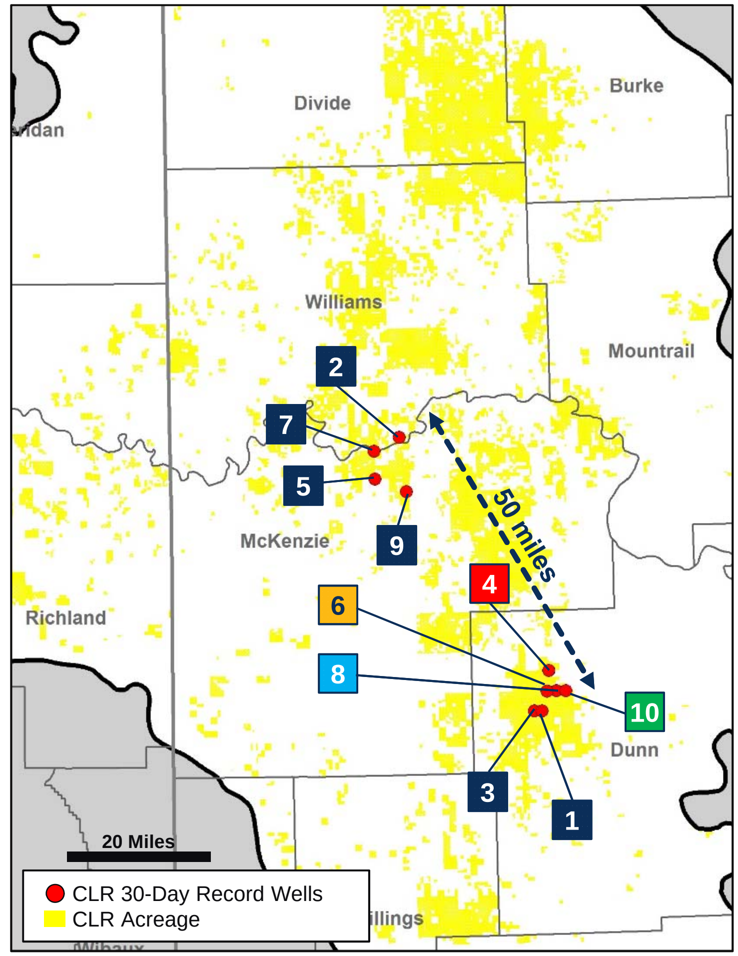
1. Maximum average 24-hour IP rate.
2. 2018 Bakken Program consists of 159 gross operated wells with first production in 2018.
3. Source: NDIC Monthly Petroleum Report. Select peers include COP, EOG, EQNR, HES, MRO, OAS, WLL, WPX, XOM.
4. Source: Drillinginfo as of February 2019. All years include peak months.

4 New Top 10 CLR All-Time 30-Day Rate Bakken Wells



	Top 10 CLR-Operated Bakken Wells	30-Day Avg Daily Oil	30-Day Avg Daily Gas	30-Day Avg Daily Boe	Quarter
1	MOUNTAIN GAP 7-10H	2,603	3,001	3,104	2Q18
2	MONROE 6-2H	2,203	3,408	2,771	4Q17
3	MOUNTAIN GAP 8-10H1	2,264	2,798	2,730	2Q18
4	**BRANDVIK 9-25H**	**2,259**	**2,415**	**2,661**	**4Q18**
5	LANSING 6-25H	1,995	3,725	2,616	1Q18
6	**DVIRNAK 5-7H[(1)]**	**2,078**	**2,304**	**2,462**	**3Q18**
7	UHLMAN FEDERAL 3-7H	1,989	2,835	2,461	2Q18
8	**DVIRNAK 8-7H[(1)]**	**2,044**	**2,438**	**2,450**	**3Q18**
9	PITTSBURGH 3-7H	1,951	2,615	2,387	2Q18
10	**JENSEN 6-8H**	**2,106**	**1,499**	**2,356**	**4Q18**

Top 10 CLR-Operated Bakken Wells



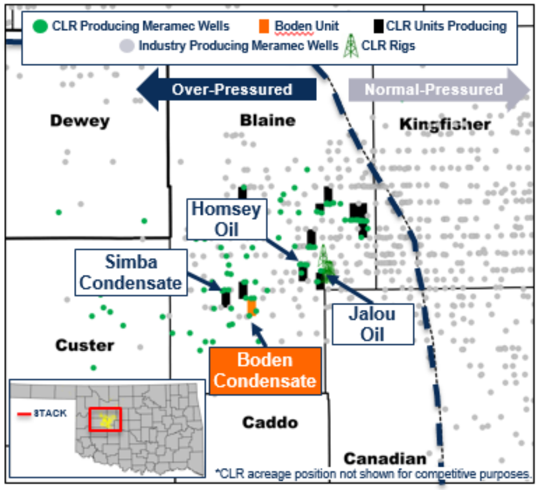
1. 3Q18 well that was added to the top ten list in 4Q18 due to lack of 30 days of production at the end of 3Q18.

Another STACK Over-Pressured Condensate Unit Outperforms Parent Type Curve

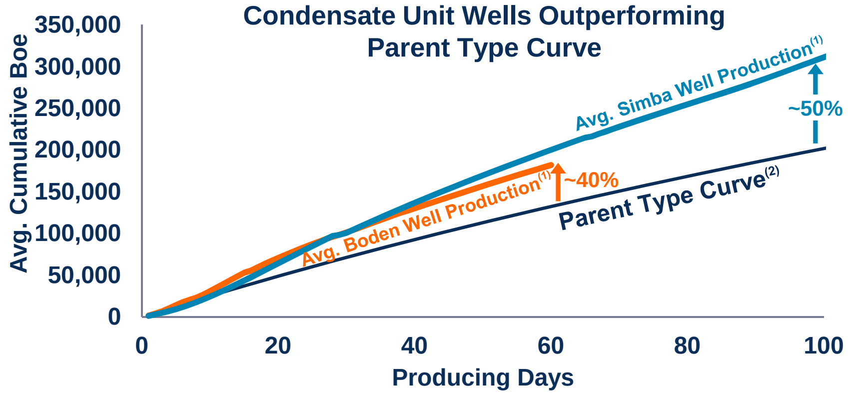
Recent STACK Results Underscore Repeatability

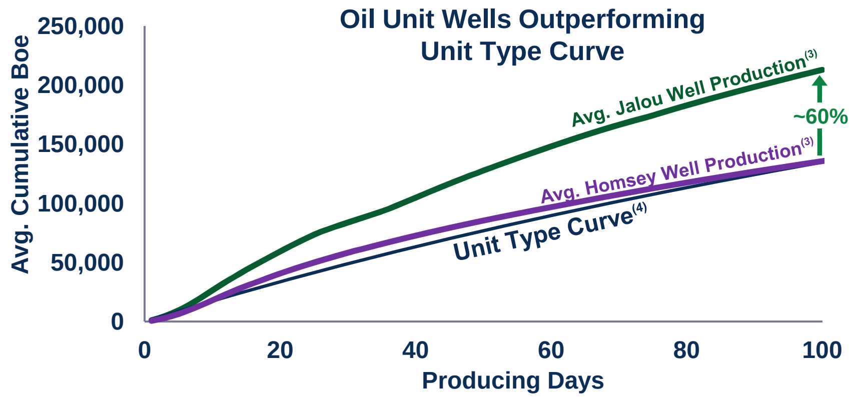
Unit	2-Mi Equiv. Wells/Unit	Bopd/ Unit	Mcfpd/ Unit	Boepd/ Unit	24-Hour IP/ Well (Boepd)
Jalou	6	14,820	63,522	25,404	4,234
Homsey	6	12,425	52,207	21,127	3,521
Simba	6	3,728	144,004	27,729	4,622
Boden	**3**	**3,590**	**62,884**	**14,071**	**4,690**

All CLR STACK Units In Over-Pressured Window



- Up to 65 operated units to be developed in over-pressured oil & condensate windows
- ~5 rigs focusing on unit development

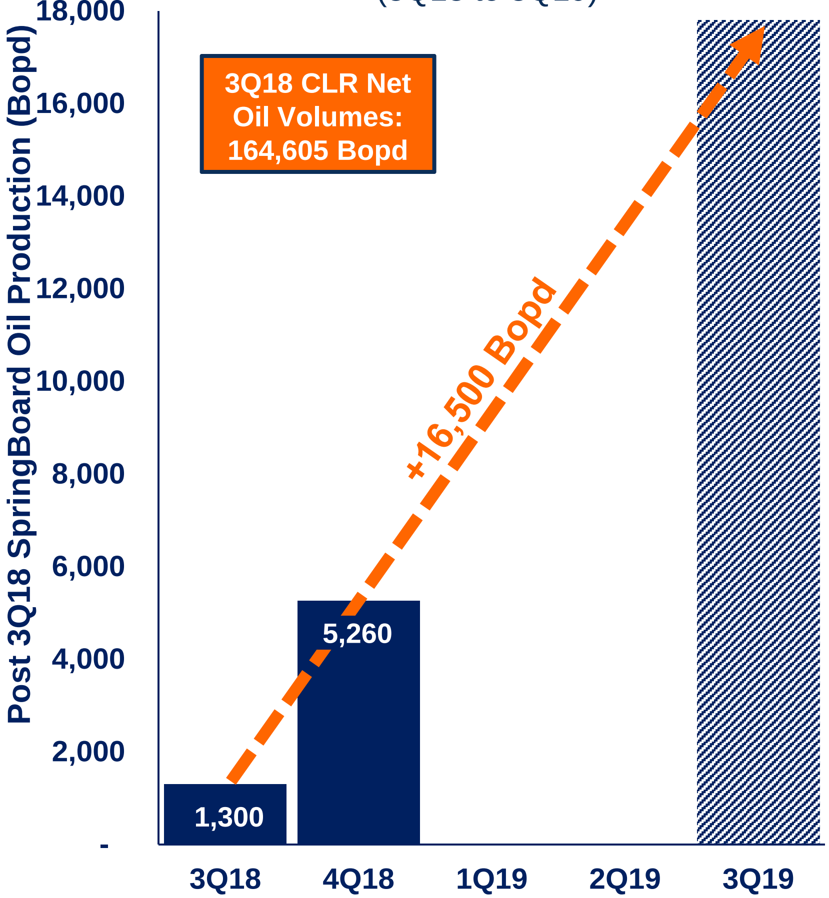




1. Average production of unit normalized to 9,800' LL.
2. 2,400 MBoe condensate parent type curve.
3. Average production of 6 unit wells.
4. 1,200 MBoe oil unit type curve.

SCOOP Project SpringBoard
2019 High Impact Oil Development On Track

SpringBoard on Pace to Add 10% to CLR Net Oil Production
(3Q18 to 3Q19)



22 Springer Wells Producing (as of 02/19):

- ~2.3 million cumulative gross Boe (81% oil)
- ~13,300 gross Boe per day

2019 Development On Track

- 45 wells currently waiting on completion
  - 18 Springer
  - 27 Woodford/Sycamore
- Averaging ~12 rigs in 2019
  - ~7 targeting Springer
  - ~5 targeting Woodford/Sycamore

SCOOP & STACK Mineral Royalties Ownership
Enhancing Returns & Increasing CLR Value In 2019 & Beyond

CLR Benefits from Mineral Royalties Ownership

- Capitalizes on proprietary asset/operations knowledge
- Enhances revenue by aligning with CLR drill schedule
- CLR can earn up to 50% of revenue for 20% of cost, based on predetermined targets

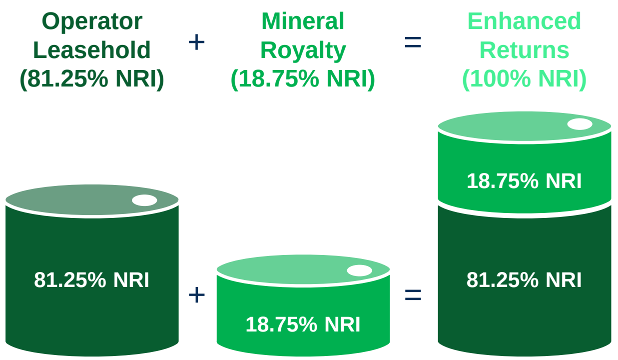
Near Term Benefit

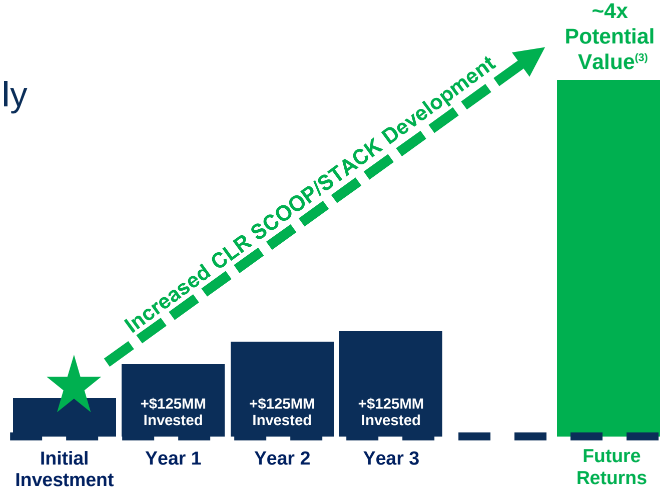
- CLR expects to earn 50% of total revenue in 2019
- CLR to recoup $100MM of $125MM from FNV in 2019
- ~14 rigs currently focused on royalty position; volumes growing rapidly

Long Term Benefit

- Multi-$ billion IPO potential
- Most comparable structure to date[2] has generated ~4x ROI[3]

Owning Royalties Enhances Returns By Increasing NRI[1]





1. Example for illustration purposes only and assumes a 100% working interest and acquisition of full unit royalty.
2. Based on Viper Energy Partners, a mineral company owned and operated by an E&P company.
3. Statement is made based on the historic performance of Viper Energy Partners. While CLR's mineral assets and structure are different, CLR believes similar performance is possible.

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Reference Materials

2019 Guidance

Production & Capital	2018 Results	2019 Guidance
Capital expenditures budget	$2.8 billion	$2.6 billion
Production (Boe per day)	298,190	
Oil Production (Bo per day)	168,177	190,000 - 200,000
Natural Gas Production (Mcf per day)	780,083	790,000 - 810,000
Operating Expenses		
Production expense ($ per Boe)	$3.59	$3.75 - $4.25
Production tax (% of net oil & gas revenue)	7.9%	8.0% - 8.3%
Cash G&A expense(1) ($ per Boe)	$1.25	$1.25 - $1.45
Non-cash equity compensation ($ per Boe)	$0.44	$0.45 - $0.55
DD&A ($ per Boe)	$17.09	$15.00 - $17.00
Average Price Differentials		
NYMEX WTI crude oil ($ per barrel of oil)	($5.27)	($4.50) - ($5.50)
Henry Hub natural gas(2) ($ per Mcf)	($0.09)	$0.00 - ($0.50)

2019 Operating Detail	2018 Total	2019 Bakken	2019 OK	2019 Total
Total Capex	$2.8B			$2.6B
D&C Capex	$2.4B	$1.1B	$1.1B	$2.2B
Rigs	31 @ YE	6	19	25
Gross Op Wells	292	166	141	307
Net Op Wells	185	107	100	207
Stim Crews	10	4	5	9

1. Cash G&A is a non-GAAP measure and excludes the range of values shown for non-cash equity compensation per Boe in the item appearing immediately below. Guidance for 2019 total G&A (cash and non-cash) is an expected range of $1.70 - $2.00 per Boe. See "Cash G&A Reconciliation to GAAP" on slide 26 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe.
2. Includes natural gas liquids production in differential range.

Continental RESOURCES

YE 2018 CLR Proved Reserves Up 14% Over YE 2017

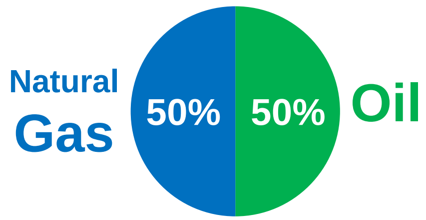
Year-End 2018

- Proved reserves: 1,522 MMBoe
  - Up 14% over YE17 (1,331 MMBoe)
- PV-10: $18.7 billion(1)
  - Up 58% over YE17 ($11.8 billion)
- 44% PDP
- 85% operated

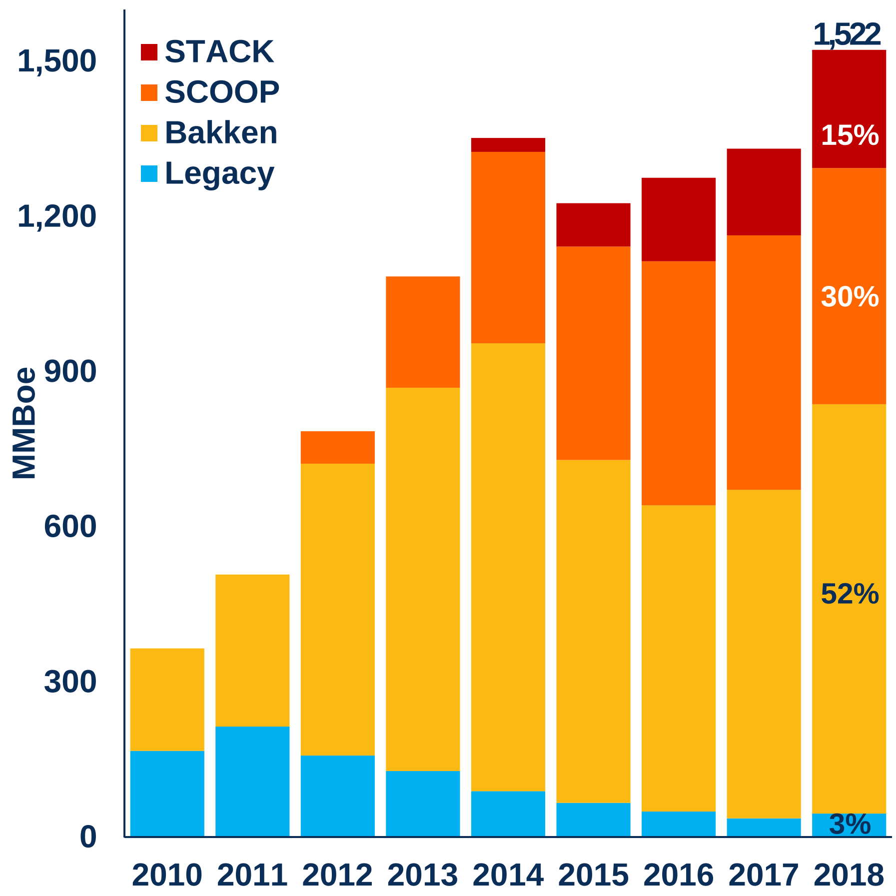
SEC Price Deck

- $65.56 per Bo
- $3.10 per MMbtu gas

YE18



CLR Total Proved Reserves



1. At December 31, 2018, Continental had a Standardized Measure of discounted future net cash flows of $15.7 billion. PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues of approximately $3.0 billion.

Continued Focus On Net Debt Reduction

Financial Metrics

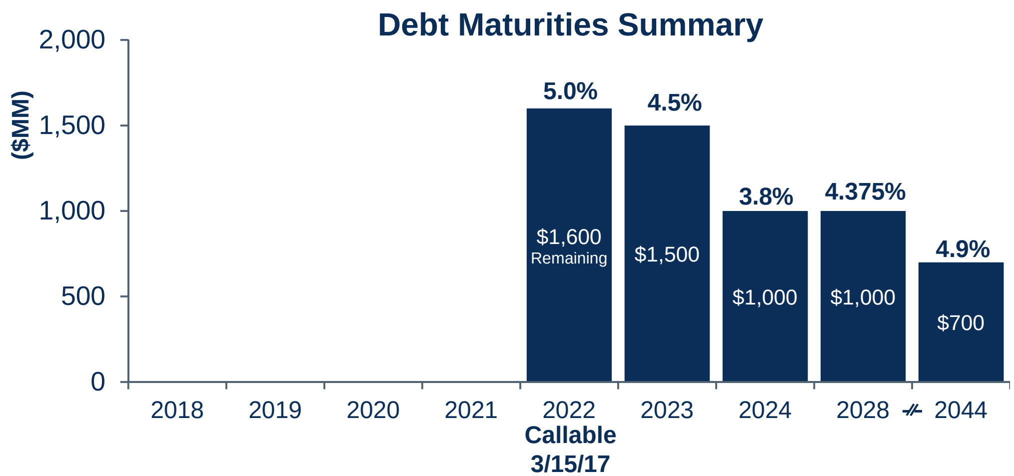
- **1.61x:** Net debt[(1)] / 4Q18 Annualized EBITDAX[(1)]
- **1.51x:** Net debt[(1)] / TTM EBITDAX[(1)]

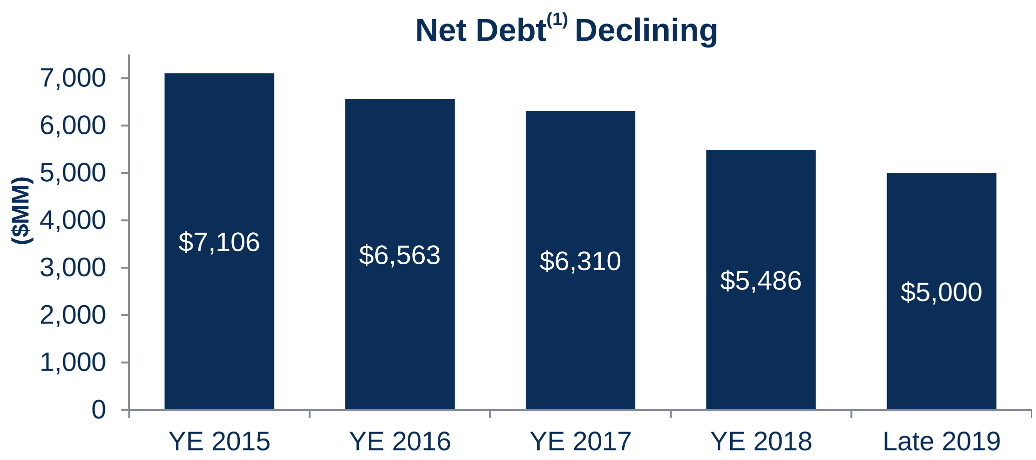
Financial Strength

- **Earliest debt maturity** is 2022 bonds (callable)
- 4.4% average interest rate in 4Q18

Unsecured Credit Facility

- **Ample liquidity** with $1.5B revolver; fully undrawn at 1/31/19





1. Net debt and EBITDAX are non-GAAP measures. See slides 21-23 for definitions and reconciliations of these measures to the most comparable U.S. GAAP financial measures.

Continuing To Deliver Strong Margins[1]

	2015	2016	2017	4Q 2018	2018
Crude oil net sales price ($/Bbl)[2]	$40.50	$35.51	$45.70	$50.06	$59.19
Natural gas net sales price ($/Mcf)[2]	$2.31	$1.87	$2.93	$3.26	$3.01
Oil production (Bopd)	146,622	128,005	138,455	186,934	168,177
Natural gas production (Mcfpd)	450,558	533,442	625,093	822,402	780,083
Total production (Boepd)	221,715	216,912	242,637	324,001	298,190
EBITDAX ($000's)[3]	$1,978,896	$1,881,889	$2,363,617	$850,640	$3,623,373
Key Operational Statistics (per Boe)[4]					
Oil equivalent net sales price (excludes derivatives) ($/Boe)[2]	$31.48	$25.55	$33.65	$37.13	$41.25
Production expenses	$4.30	$3.65	$3.66	$3.50	$3.59
Production taxes	$2.47	$1.79	$2.35	$3.04	$3.25
Cash G&A[5]	$1.70	$1.53	$1.64	$1.18	$1.25
Interest expense	$3.86	$4.04	$3.32	$2.33	$2.69
Total of selected costs	**$12.33**	**$11.01**	**$10.97**	**$10.05**	**$10.78**
Margin[1]	**$19.15**	**$14.54**	**$22.68**	**$27.08**	**$30.47**
Margin %	**61%**	**57%**	**67%**	**73%**	**74%**

1. Margin represents the Company's average net sales price for a period expressed in barrels of oil equivalent (Boe) less production expenses, production taxes, G&A expenses (exclusive of non-cash equity compensation expenses), and interest expense, all expressed on a per-Boe basis. Margin does not reflect all activities of the Company that give rise to cash inflows and outflows and specifically excludes income and costs associated with derivative settlements, service operations, exploration activities, asset dispositions, litigation settlement and various non-operating activities. These items are excluded from the computation of Margin because they can vary significantly from period to period in a manner that does not correlate with changes in the Company's production and sales volumes. Therefore, these items are not typically utilized by management on a per-Boe basis in assessing the performance of the Company's E&P operations from period to period.
2. See slide 25 for a discussion and calculation of net sales prices, which are non-GAAP measures for 2018.
3. See "EBITDAX reconciliation to GAAP" on slides 22-23 for a reconciliation of GAAP net income/loss and net cash provided by operating activities to EBITDAX, which is a non-GAAP measure.
4. Average costs per Boe have been computed using sales volumes and exclude any effect of derivative transactions.
5. See "Cash G&A Reconciliation to GAAP" on slide 26 for a reconciliation of GAAP Total G&A per Boe to Cash G&A per Boe, which is a non-GAAP measure.

Free Cash Flow

Our presentation of projected free cash flow is a non-GAAP measure. We define projected free cash flow as cash flows from operations before changes in working capital items, less capital expenditures, plus noncontrolling interest capital contributions, less distributions to noncontrolling interests. Noncontrolling interest capital contributions and distributions primarily relate to our new relationship formed with Franco-Nevada in 2018 to fund a portion of certain mineral acquisitions which are included in our capital expenditures and operating results. Free cash flow is not a measure of net income or operating cash flows as determined by U.S. GAAP and should not be considered an alternative to, or more meaningful than, the comparable GAAP measure, and free cash flow does not represent residual cash flows available for discretionary expenditures. Management believes that this measure is useful to management and investors as a measure of a company's ability to internally fund its capital expenditures and to service or incur additional debt. From time to time the Company provides forward-looking free cash flow estimates or targets; however, the Company is unable to provide a quantitative reconciliation of the forward-looking non-GAAP measure to its most directly comparable forward-looking GAAP measure because management cannot reliably quantify certain of the necessary components of such forward-looking GAAP measure. The reconciling items in future periods could be significant.

Net Debt Reconciliation To GAAP

Net debt is a non-GAAP measure. We define net debt as total debt less cash and cash equivalents as determined under U.S. GAAP. Net debt should not be considered an alternative to, or more meaningful than, total debt, the most directly comparable GAAP measure. Management uses net debt to determine the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand. We believe this metric is useful to analysts and investors in determining the Company's leverage position since the Company has the ability to, and may decide to, use a portion of its cash and cash equivalents to reduce debt. This metric is sometimes presented as a ratio with EBITDAX in order to provide investors with another means of evaluating the Company's ability to service its existing debt obligations as well as any future increase in the amount of such obligations. At December 31, 2018, the Company's net debt amounted to $5.49 billion, representing total debt of $5.77 billion less cash and cash equivalents of $282.7 million. From time to time the Company provides forward-looking net debt forecasts; however, the Company is unable to provide a quantitative reconciliation of the forward-looking non-GAAP measure to the most directly comparable forward-looking GAAP measure of total debt because management cannot reliably quantify certain of the necessary components of such forward-looking GAAP measure. The reconciling items in future periods could be significant.

The following table reconciles total debt as determined under U.S. GAAP to net debt for the periods presented.

In thousands	2015	2016	2017	2018
Total debt (GAAP)	$7,117,788	$6,579,916	$6,353,691	$5,768,349
Less: Cash and cash equivalents	(11,463)	(16,643)	(43,902)	(282,749)
Net debt (non-GAAP)	$7,106,325	$6,563,273	$6,309,789	$5,485,600

EBITDAX Reconciliation To GAAP

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX, a non-GAAP measure. We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, non-cash equity compensation expense, and losses on extinguishment of debt as applicable. EBITDAX is not a measure of net income or net cash provided by operating activities as determined by U.S. GAAP.

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. Further, we believe EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. We exclude the items listed above from net income/loss and net cash provided by operating activities in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired.

EBITDAX should not be considered as an alternative to, or more meaningful than, net income/loss or net cash provided by operating activities as determined in accordance with U.S. GAAP or as an indicator of a company's operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table provides a reconciliation of our net income to EBITDAX for the periods presented.

EBITDAX Reconciliation To GAAP

The following tables provide reconciliations of our net income (loss) and net cash provided by operating activities to EBITDAX for the periods presented:

In thousands	**2015**	**2016**	**2017**	**4Q 2018**	**2018**
Net income (loss)	($353,668)	($399,679)	$789,447	$199,121	$989,700
Interest expense	313,079	320,562	294,495	69,441	293,032
Provision (benefit) for income taxes	(181,417)	(232,775)	(633,380)	62,868	307,102
Depreciation, depletion, amortization and accretion	1,749,056	1,708,744	1,674,901	488,416	1,859,327
Property impairments	402,131	237,292	237,370	38,494	125,210
Exploration expenses	19,413	16,972	12,393	3,295	7,642
Impact from derivative instruments:					
Total (gain) loss on derivatives, net	(91,085)	67,099	(90,432)	19,394	23,930
Total cash (paid) received on derivatives, net	69,553	89,522	32,401	(44,416)	(36,939)
Non-cash (gain) loss on derivatives, net	(21,532)	156,621	(58,031)	(25,022)	(13,009)
Non-cash equity compensation	51,834	48,097	45,868	14,027	47,236
Loss on extinguishment of debt	--	26,055	554	--	7,133
EBITDAX (non-GAAP)	$1,978,896	$1,881,889	$2,363,617	$850,640	$3,623,373

In thousands	**2015**	**2016**	**2017**	**4Q 2018**	**2018**
Net cash provided by operating activities	$1,857,101	$1,125,919	$2,079,106	$955,267	$3,456,008
Current income tax provision (benefit)	24	(22,939)	(7,781)	2	(7,776)
Interest expense	313,079	320,562	294,495	69,441	293,032
Exploration expenses, excluding dry hole costs	11,032	12,106	12,217	3,149	7,495
Litigation Settlement	--	--	(59,600)	--	--
Gain on sale of assets, net	23,149	304,489	55,124	8,410	16,671
Tax benefit (deficiency) from stock-based compensation	13,177	(9,828)	--	--	--
Other, net	(10,044)	(10,636)	(8,529)	(5,516)	(16,349)
Changes in assets and liabilities	(228,622)	162,216	(1,415)	(180,113)	(125,708)
EBITDAX (non-GAAP)	$1,978,896	$1,881,889	$2,363,617	$850,640	$3,623,373

ADJUSTED Earnings Reconciliation To GAAP

Our presentation of adjusted earnings and adjusted earnings per share that exclude the effect of certain items are non-GAAP financial measures. Adjusted earnings and adjusted earnings per share represent earnings and diluted earnings per share determined under U.S. GAAP without regard to non-cash gains and losses on derivative instruments, property impairments, losses on certain litigation settlements, gains and losses on asset sales, losses on extinguishment of debt and the impact of U.S. tax reform legislation as applicable. Management believes these measures provide useful information to analysts and investors for analysis of our operating results. In addition, management believes these measures are used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis without regard to an entity's specific derivative portfolio, impairment methodologies, and property dispositions. Adjusted earnings and adjusted earnings per share should not be considered in isolation or as an alternative to, or more meaningful than, earnings or diluted earnings per share as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies. The following table reconciles earnings and diluted earnings per share as determined under U.S. GAAP to adjusted earnings and adjusted diluted earnings per share for the periods presented.

	Three months ended December 31,			
	2018		2017	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net income attributable to Continental Resources (GAAP)	$197,738	$0.53	$841,914	$2.25
Adjustments:				
Non-cash (gain) loss on derivatives	(25,022)		7,450	
Property impairments	38,494		27,552	
Litigation settlement	--		59,600	
Gain on sale of assets	(8,410)		(54,420)	
Loss on extinguishment of debt	--		554	
Total tax effect of adjustments (1)	(1,114)		(15,335)	
Tax benefit from US tax reform legislation	--		(713,655)	
Total adjustments, net of tax	3,948	0.01	(688,254)	(1.84)
Adjusted net income (non-GAAP)	$201,686	$0.54	$153,660	$0.41
Weighted average diluted shares outstanding	374,525		373,764	
Adjusted diluted net income per share (non-GAAP)	$0.54		$0.41	

	Year ended December 31,			
	2018		2017	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net income attributable to Continental Resources (GAAP)	$988,317	$2.64	$789,447	$2.11
Adjustments:				
Non-cash gain on derivatives	(13,009)		(58,031)	
Property impairments	125,210		237,370	
Litigation settlement	--		59,600	
Gain on sale of assets	(16,671)		(55,124)	
Loss on extinguishment of debt	7,133		554	
Total tax effect of adjustments (1)	(24,743)		(69,358)	
Tax benefit from US tax reform legislation	--		(713,655)	
Total adjustments, net of tax	77,920	0.20	(598,644)	(1.60)
Adjusted net income (non-GAAP)	$1,066,237	$2.84	$190,803	$0.51
Weighted average diluted shares outstanding	374,838		373,768	
Adjusted diluted net income per share (non-GAAP)	$2.84		$0.51	

1. Computed by applying a combined federal and state statutory tax rate of 24.5% in effect for 2018 and 38% in effect for 2017 to the pre-tax amount of adjustments associated with our operations in the United States other than the 2017 tax benefit adjustment related to U.S. tax reform legislation.

Net Sales Prices Reconciliation To GAAP

On January 1, 2018, we adopted Accounting Standards Update 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), which impacted the presentation of our crude oil and natural gas revenues. We adopted the new rules using a modified retrospective transition approach whereby changes have been applied only to the most current period presented and prior period results have not been adjusted to conform to current presentation.

Under the new rules, revenues and transportation expenses associated with production from our operated properties are now reported on a gross basis compared to net presentation in the prior year. For non-operated properties, we receive a net payment from the operator for our share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds received, consistent with our historical practice. As a result, beginning January 1, 2018 the gross presentation of revenues from our operated properties differs from the net presentation of revenues from non-operated properties. This impacts the comparability of certain operating metrics, such as per-unit sales prices, when such metrics are prepared in accordance with U.S. GAAP using gross presentation for some revenues and net presentation for others.

In order to provide metrics prepared in a manner consistent with how management assesses the Company's operating results, to achieve comparability between operated and non-operated revenues, and to achieve comparability with prior period metrics for analysis purposes, we may present crude oil and natural gas sales net of transportation expenses, which we refer to as "net crude oil and natural gas sales," a non-GAAP measure. Average sales prices calculated using net crude oil and natural gas sales are referred to as "net sales prices," a non-GAAP measure, and are calculated by taking revenues less transportation expenses divided by sales volumes, whether for crude oil or natural gas, as applicable. Management believes presenting our revenues and sales prices net of transportation expenses is useful because it normalizes the presentation differences between operated and non-operated revenues and allows for a useful comparison of net realized prices to NYMEX benchmark prices on a Company-wide basis.

The following table presents a reconciliation of crude oil and natural gas sales (GAAP) to net crude oil and natural gas sales and related net sales prices (non-GAAP) for the three and twelve months ended December 31, 2018. Information is also presented for the three and twelve months ended December 31, 2017 for comparative purposes.

	Three months ended December 31, 2018			Three months ended December 31, 2017		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$900,872	$253,232	$1,154,104	$800,871	$216,879	$1,017,750
Less: Transportation expenses	(42,373)	(6,655)	(49,028)	—	—	—
Net crude oil and natural gas sales (non-GAAP for 2018)	$858,499	$246,577	$1,105,076	$800,871	$216,879	$1,017,750
Sales volumes (MBbl/MMcf/MBoe)	17,149	75,661	29,759	15,653	65,644	26,594
Net sales price (non-GAAP for 2018)	50.06	3.26	37.13	51.16	3.30	38.27

	Year ended December 31, 2018			Year ended December 31, 2017		
In thousands	Crude oil	Natural gas	Total	Crude oil	Natural gas	Total
Crude oil and natural gas sales (GAAP)	$3,792,594	$886,128	$4,678,722	$2,313,862	$669,104	$2,982,966
Less: Transportation expenses	(162,312)	(29,275)	(191,587)	—	—	—
Net crude oil and natural gas sales (non-GAAP for 2018)	$3,630,282	$856,853	$4,487,135	$2,313,862	$669,104	$2,982,966
Sales volumes (MBbl/MMcf/MBoe)	61,332	284,730	108,787	50,628	228,159	88,655
Net sales price (non-GAAP for 2018)	59.19	3.01	41.25	45.70	2.93	33.65

Cash G&A Reconciliation To GAAP

Our presentation of cash general and administrative ("G&A") expenses per Boe is a non-GAAP measure. We define cash G&A per Boe as total G&A determined in accordance with U.S. GAAP less non-cash equity compensation expenses, expressed on a per-Boe basis. We report and provide guidance on cash G&A per Boe because we believe this measure is commonly used by management, analysts and investors as an indicator of cost management and operating efficiency on a comparable basis from period to period. In addition, management believes cash G&A per Boe is used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis of G&A spend without regard to stock-based compensation programs which can vary substantially from company to company. Cash G&A per Boe should not be considered as an alternative to, or more meaningful than, total G&A per Boe as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies.

The following table reconciles total G&A per Boe as determined under U.S. GAAP to cash G&A per Boe for the periods presented.

	2015	2016	2017	4Q 2018	2018	2019 Guidance
Total G&A per Boe (GAAP)	$2.34	$2.14	$2.16	$1.65	$1.69	$1.70 - $2.00
Less: Non-cash equity compensation per Boe	($0.64)	($0.61)	($0.52)	($0.47)	($0.44)	($0.45) - ($0.55)
Cash G&A per Boe (non-GAAP)	$1.70	$1.53	$1.64	$1.18	$1.25	$1.25 - $1.45

Calculation Of Return On Capital Employed (ROCE)

The following table shows the calculation of ROCE for 2018.

In thousands, except per share data	**2018**
Net income (loss) attributable to Continental Resources	$988,317
Impact from derivative instruments:	
Total (gain) loss on derivatives, net	23,930
Total cash received (paid), net	(36,939)
Non-cash (gain) loss on derivatives, net	(13,009)
Provision (benefit) for income taxes	307,102
Non-cash equity compensation	47,236
Interest expense	293,032
Loss on extinguishment of debt	7,133
Adjusted EBIT	$1,629,811
Equity attributable to Continental Resources - beginning of period	$5,131,203
Total debt - beginning of period	6,353,691
Capital employed - beginning of period	$11,484,894
Equity attributable to Continental Resources - end of period	$6,145,133
Total debt - end of period	5,768,349
Capital employed - end of period	$11,913,482
Average capital employed	$11,699,188
ROCE	13.9%