MARCH INVESTOR PRESENTATION

March 25, 2019

IMPORTANT DISCLOSURES

FORWARD LOOKING STATEMENTS

This presentation contains 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. Forward-looking statements include all statements regarding wells anticipated to be drilled and placed on production; future levels of drilling activity and associated production and cash flow expectations; the Company's 2019 production guidance and capital expenditure forecast; estimated reserve quantities and the present value thereof; anticipated returns and financial position; and the implementation of the Company's business plans and strategy, as well as statements including the words "believe," "expect," "may," "will," "forecast," "outlook," "plans" and words of similar meaning. These statements reflect the Company's current views with respect to future events and financial performance based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. No assurances can be given, however, as of this date that these events will occur or that these projections will be achieved, and actual results could differ materially from those projected as a result of certain factors. Any forward-looking statement speaks only as of the date of which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. Some of the factors which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include the volatility of oil and natural gas prices, ability to drill and complete wells, operational, regulatory and environment risks, cost and availability of equipment and labor, our ability to finance our activities and other risks more fully discussed in our filings with the Securities and Exchange Commission, including our Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q, available on our website or the SEC's website at www.sec.gov.

SUPPLEMENTAL NON-GAAP FINANCIAL MEASURES

This presentation includes non-GAAP measures, such as Adjusted EBITDA, Adjusted Total Revenue, Adjusted G&A, Discretionary Cash Flow, PV-10, Net Debt to LTM Adjusted EBITDA and other measures identified as non-GAAP. Management also uses EBITDAX, which reflects EBITDA plus exploration and abandonment expense. Reconciliations are available in the Appendix.

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, asset retirement obligation accretion expense, exploration expense, (gains) losses on derivative instruments excluding net settled derivative instruments, impairment of oil and natural gas properties, non-cash equity based compensation, other income, gains and losses from the sale of assets and other non-cash operating items. Management believes Adjusted EBITDA is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDA 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. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA 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 Adjusted EBITDA. Our presentation of Adjusted EBITDA should not be construed as an inference that our results will be unaffected by unusual or non-recurring items.

Adjusted Total Revenues is a supplemental non-GAAP financial measure. We define Adjusted Total Revenues as Total Operating Revenues inclusive of the impact of commodity derivative settlements. We believe Adjusted Total Revenues is useful to investors because it provides readers with a revenue value more comparable to other companies who engage in price risk management activities through the use of commodity derivative instruments and reflects the results of derivative settlements with expected cash flow impacts within total revenues.

Adjusted general and administrative expense ("Adjusted G&A") is a supplemental non-GAAP financial measure that excludes certain non-recurring expenses and non-cash valuation adjustments related to incentive compensation plans, as well as non-cash corporate depreciation and amortization expense. We believe that the non-GAAP measure of Adjusted G&A is useful to investors because it provides readers with a meaningful measure of our recurring G&A expense and provides for greater comparability period-over-period.

We believe discretionary cash flow is a comparable metric against other companies in the industry and is a widely accepted financial indicator of an oil and natural gas company's ability to generate cash for the use of internally funding their capital development program and to service or incur debt. Discretionary cash flow is defined by the Company as net cash provided by operating activities before changes in working capital and payments to settle asset retirement obligations and vested liability share-based awards. The Company has included this information because changes in operating assets and liabilities relate to the timing of cash receipts and disbursements, which the company may not control and the cashflow effect may not be reflected the period in which the operating activities occurred. Discretionary cash flow is not a measure of a company's financial performance under GAAP and should not be considered as an alternative to net cash provided by operating activities (as defined under GAAP), or as a measure of liquidity, or as an alternative to net income

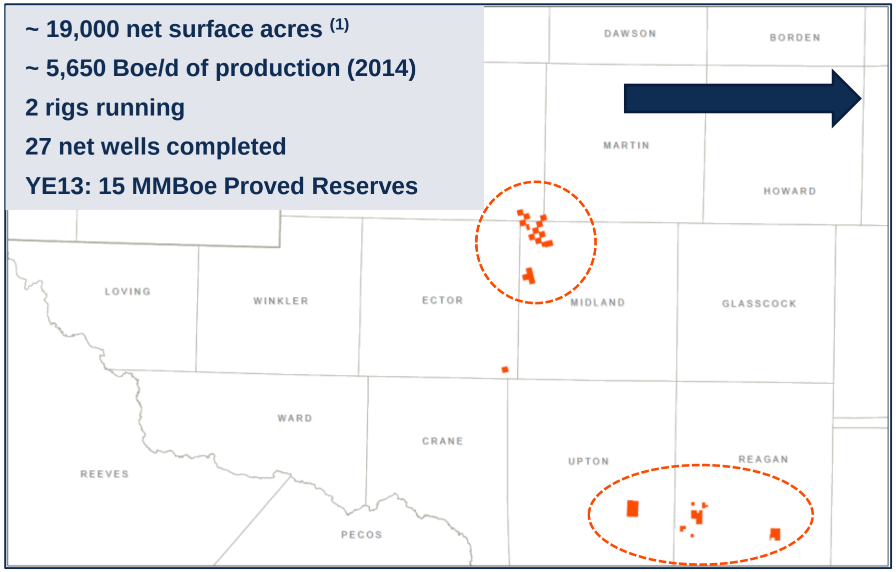
Year-end pre-tax PV-10 value is a non-GAAP financial measure as defined by the SEC. The Company believes that the presentation of pre-tax PV-10 value is relevant and useful to its investors because it presents the discounted future net cash flows attributable to reserves prior to taking into account future corporate income taxes and the Company's current tax structure. The Company further believes investors and creditors use pre-tax PV-10 values as a basis for comparison of the relative size and value of its reserves as compared with other companies. The GAAP financial measure most directly comparable to pre-tax PV-10 is the standardized measure of discounted future net cash flows ("Standardized Measure"). Pre-tax PV-10 is calculated using the Standardized Measure before deducting future income taxes, discounted at 10 percent.

Net Debt to Last Twelve Months ("LTM)" Adjusted EBITDA is a non-GAAP measure. The Company defines Net Debt to LTM Adjusted EBITDA as the sum of total long-term debt less unrestricted cash and cash equivalents (as determined under U.S. GAAP), divided by the Company's Adjusted EBITDA inclusive of annualized pro-forma results from its acquisitions completed over the last twelve month period. The Company presents this metric to help evaluate its capital structure, financial leverage, and forward-looking cash profile. The Company believes that Net Debt to LTM Adjusted EBITDA is widely used by industry professionals, research and credit analysts, and lending and rating agencies in the evaluation of total leverage.

CALLON'S PERMIAN EVOLUTION

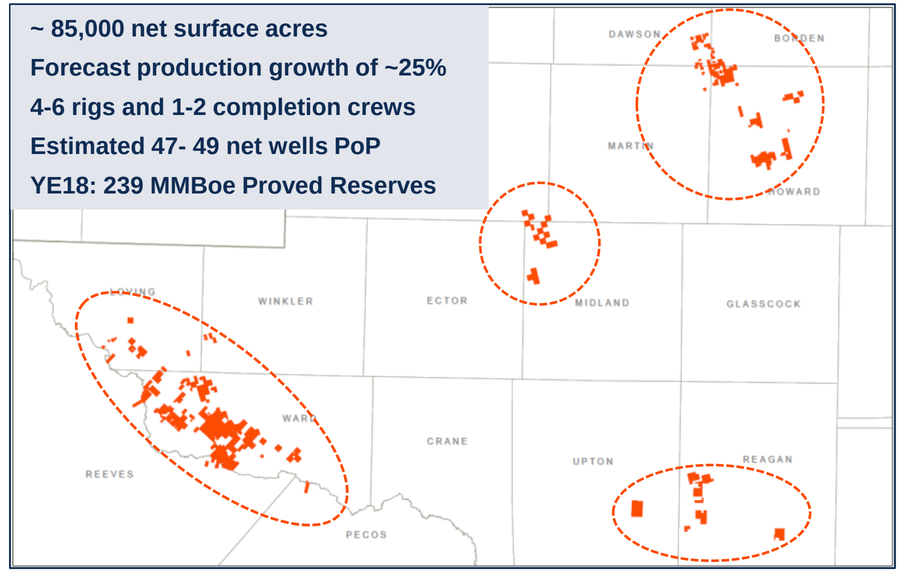
2014: INITIAL BUILDING PHASE

- ~ 19,000 net surface acres [(1)]
- ~ 5,650 Boe/d of production (2014)
- 2 rigs running
- 27 net wells completed
- YE13: 15 MMBoe Proved Reserves

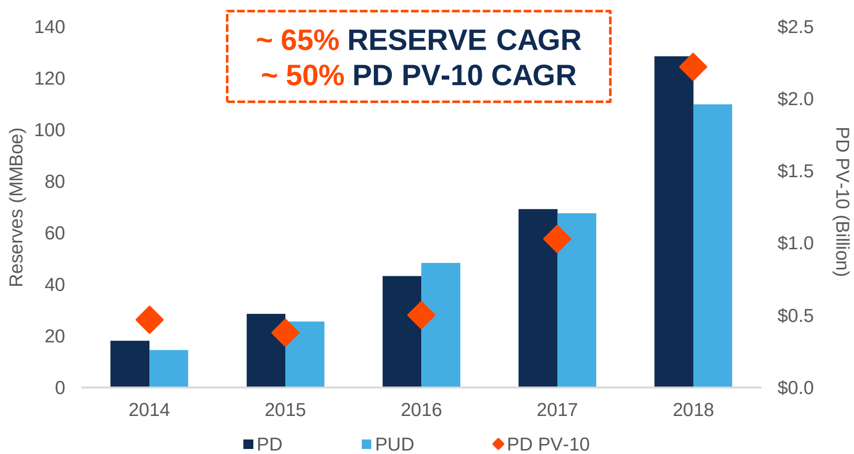


2019: TRANSITION TO FULL ASSET DEVELOPMENT

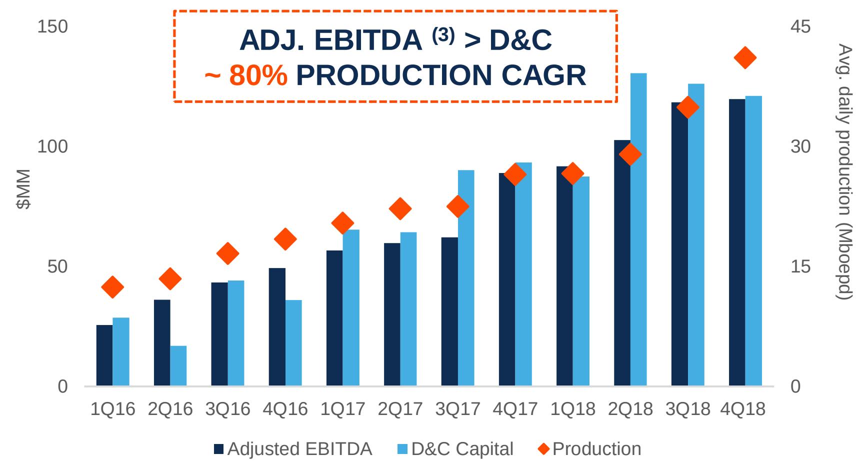
- ~ 85,000 net surface acres
- Forecast production growth of ~25%
- 4-6 rigs and 1-2 completion crews
- Estimated 47- 49 net wells PoP
- YE18: 239 MMBoe Proved Reserves



PROVED DEVELOPED GROWTH DRIVES VALUE [(2)]



DEVELOPMENT CAPITAL ALIGNED WITH CASH FLOW [(3) (4)]



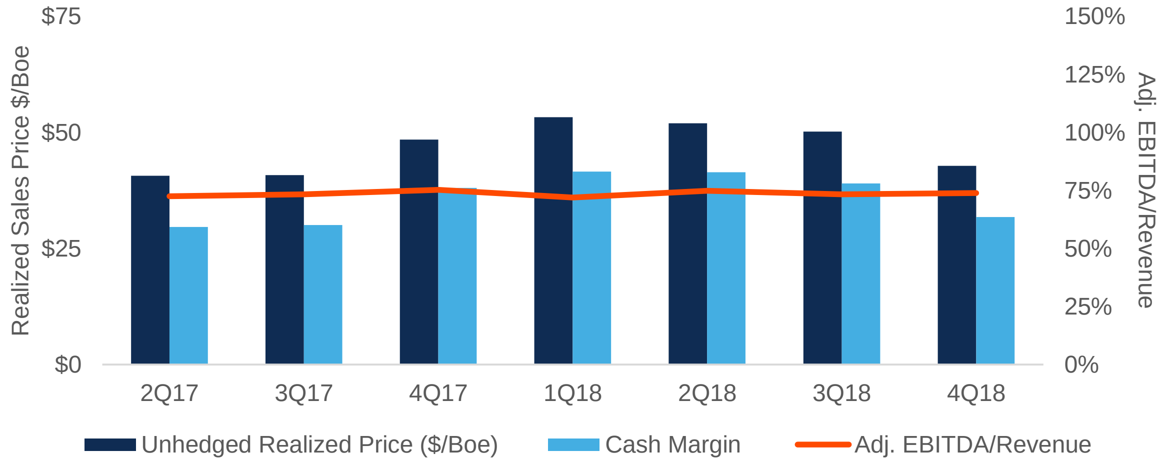
1. Excluding Northern Midland Basin exploration properties.
2. PD PV-10 is a non-GAAP financial measure: The 12-month average benchmark pricing used to estimate proved reserves in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission ("SEC") and pre-tax PV-10 value for crude oil and natural gas was $65.56 per Bbl of WTI crude oil and $3.10 per MMBtu of natural gas at Henry Hub before differential adjustments. After differential adjustments, the Company's SEC pricing realizations for year-end 2018 were $58.40 per Bbl of oil and $3.64 per Mcf of natural gas. Please refer to the Non-GAAP Disclosure at the beginning of this release for information regarding pre-tax PV-10.
3. Based on CPE calculated Adjusted EBITDA and Adjusted Total Revenues, non-GAAP financial measures. Please see the Non-GAAP reconciliation disclosures in the Appendix.
4. D&C capital excludes facilities spend.

PRESERVATION OF INDUSTRY LEADING MARGINS

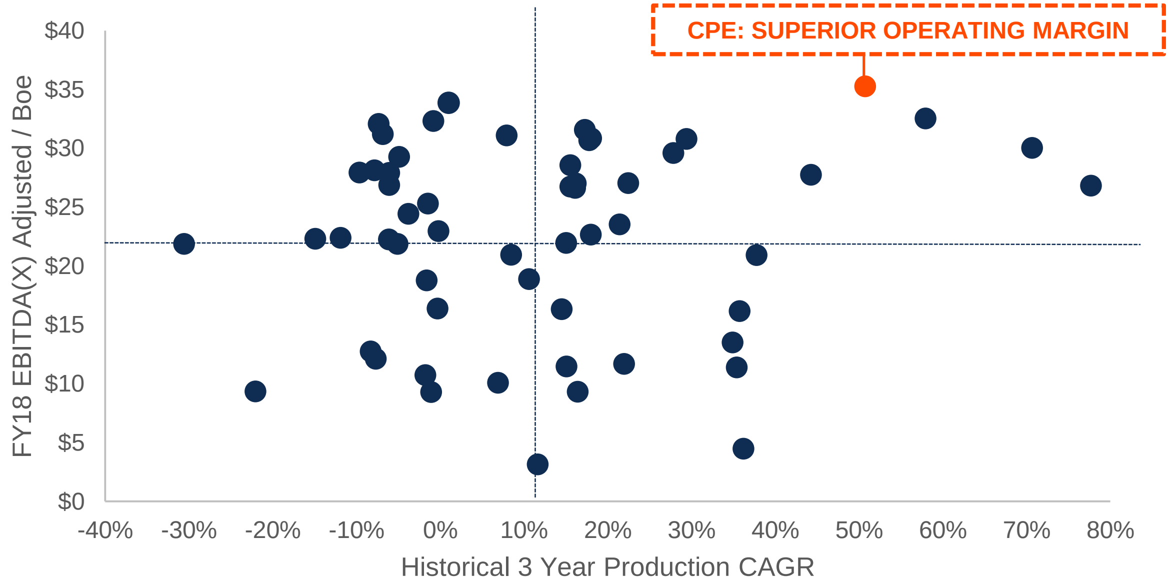
MARGIN EXPANSION

- Industry leading operating margins
  - Cash margin of $31.82/Boe represents an 8% CAGR over the last two years
  - Cash G&A of $2.03/Boe declined ~ 6% sequentially
  - Adj. EBITDA[2] of $119.7MM representing +1% sequential margin improvement as the unhedged realized sales price declined 15% Q/Q
- Acreage quality and operational excellence
  - 4Q'18 Adj. EBITDA/Revenue expanded to 74% [2]
  - In 2018, CPE achieved the highest Bloomberg standardized Adj. EBITDA(X)/Boe operating margin across publicly traded E&Ps [3][4]
- Future cost improvements
  - Reduced drilling days, increased local sand usage, and more stages per day
  - Adaptive completion designs
  - Increased water recycling
  - Optimization of acquired properties
  - Preferred vendor concession consolidation

MARGIN PRESERVATION ACROSS COMMODITY CYCLES [1][2]



CAPITAL EFFICIENT PRODUCTION GROWTH WITH SUPERIOR MARGINS [3]



1. Cash margin is defined as operating revenue minus cash operating costs including Lease Operating Expenses, Production Taxes, and Cash G&A.
2. Based on CPE calculated Adjusted EBITDA, a non-GAAP financial measure. Please see the Non-GAAP reconciliation disclosures in the Appendix.
3. Based on standardized Bloomberg calculations for Adjusted EBITDA(X) for over 55 publicly traded E&Ps. Adjusted EBITDA(X) is a non-GAAP financial measure. Please see the Non-GAAP reconciliation disclosures in the Appendix.
4. As of 3/21/19.

BROAD "SCALE" INITIATIVES ACROSS THE BASIN

SECURING LONG-TERM VALUE CREATION

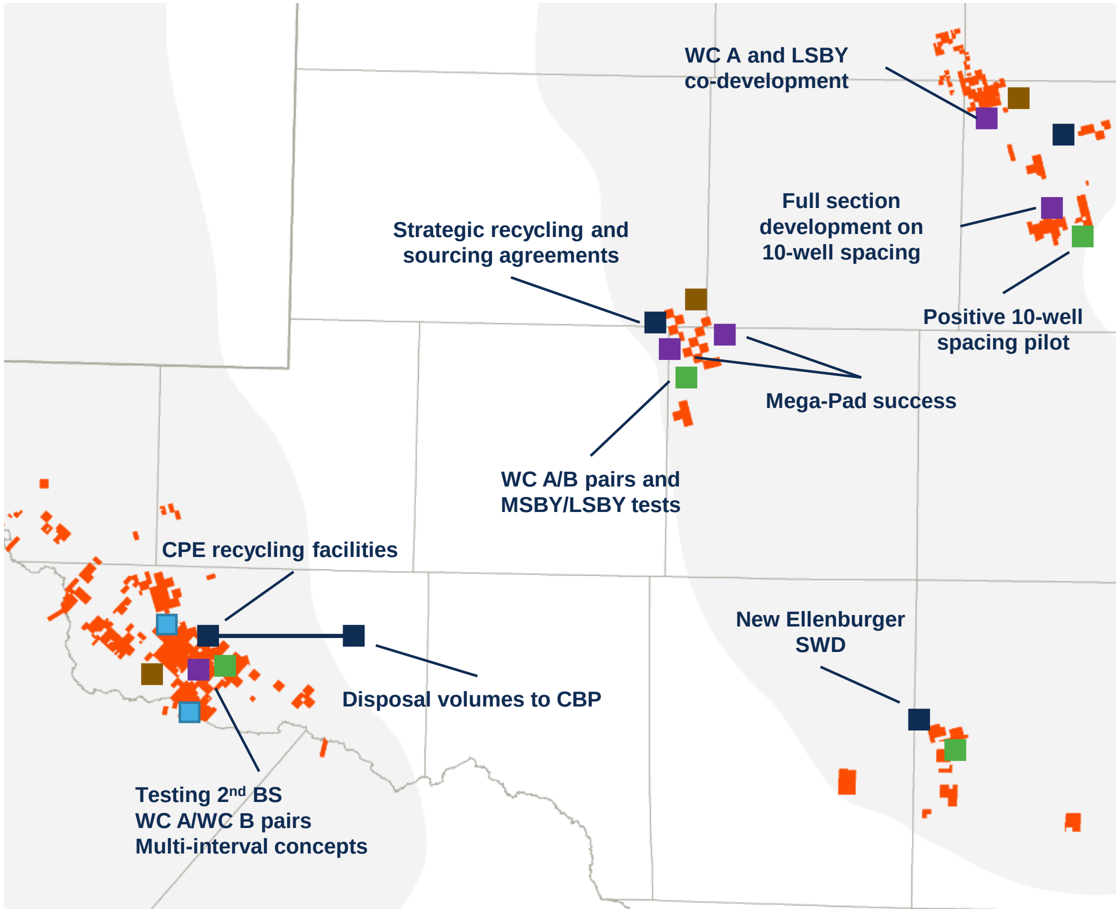
Field optimization and infrastructure investments are driving down operating costs and increasing productivity

Successful integration of new core assets overlaying legacy Spur footprint with increased development pace

Advancing multi-interval development program to enhance long-term recovery and overall resource management

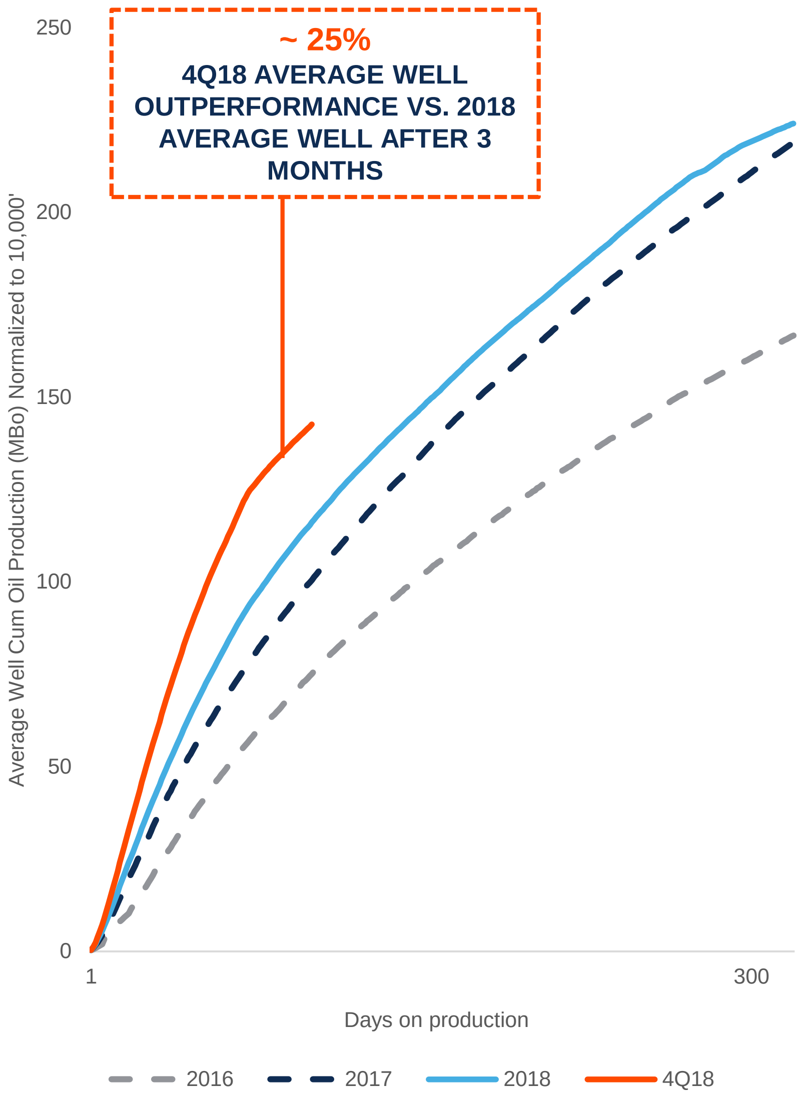
New strategic water management agreements combined with growing recycling program increase reliability, reduce capital needs, and mitigate environmental impact

Testing of new intervals and enhanced completion concepts unlocking additional value and organic inventory upside

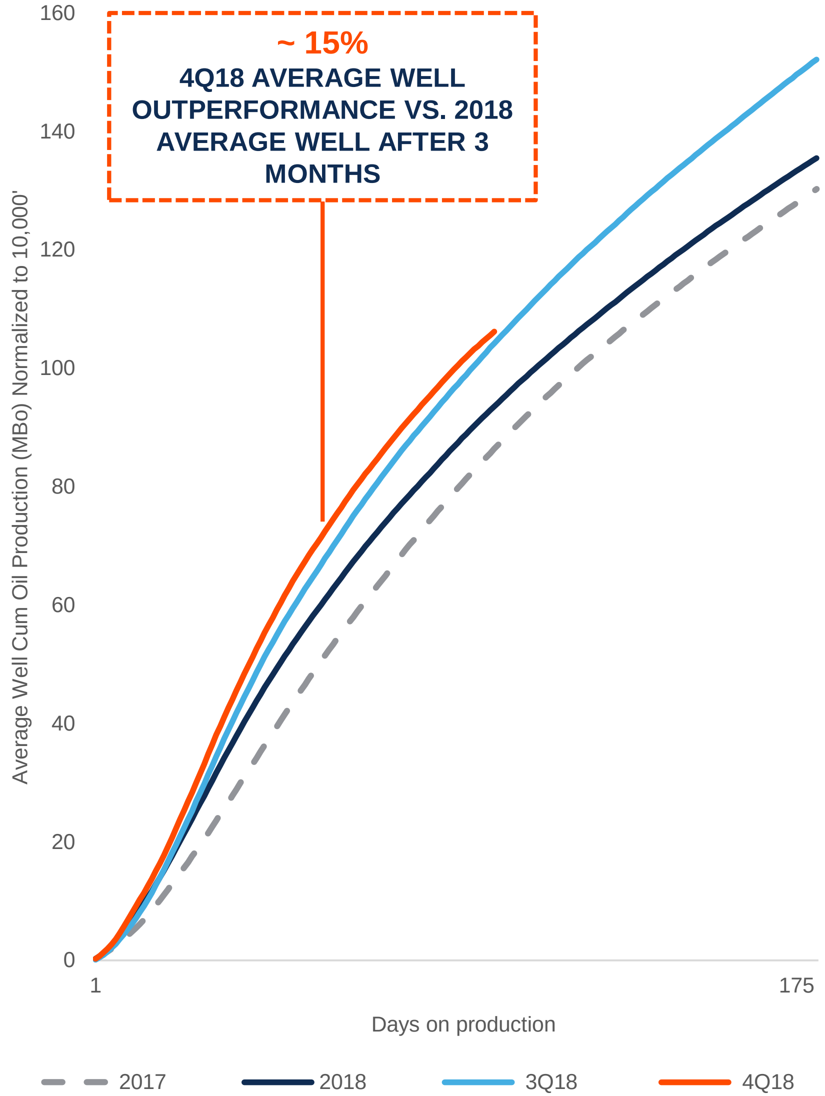


CONSISTENTLY IMPROVING WELL PERFORMANCE

DELAWARE WELLS PoP AVG. CUM OIL PRODUCTION [1]



MIDLAND WELLS PoP AVG. CUM OIL PRODUCTION [1]



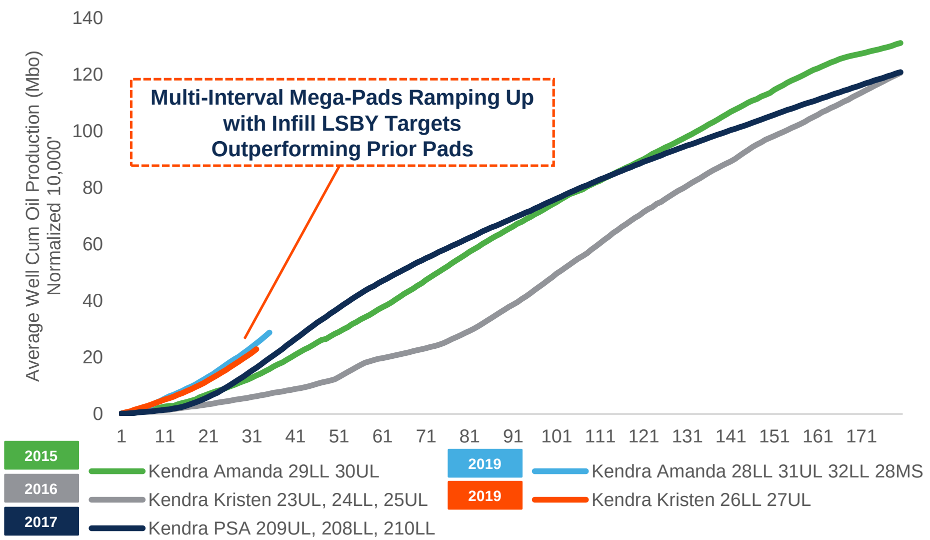
1. 2018 inclusive of production data from all wells PoP.

CO-DEVELOPMENT EXCEEDING PRIOR VINTAGES

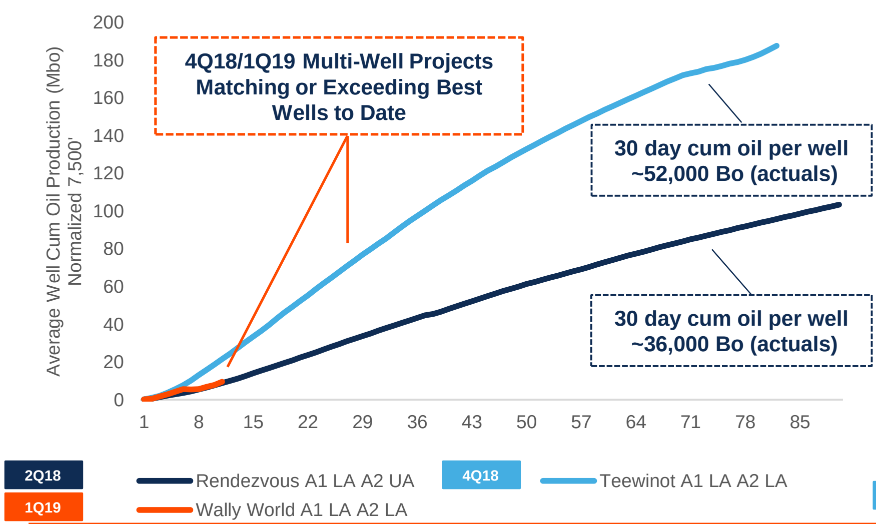
CAPITAL DEPLOYMENT FOR ASSET OPTIMIZATION

- Average well performance per pad exceeding risked expectations as increase co-development
    - Middle Spraberry interval de-risking as part of recent Mega-Pad test
    - New interval testing with larger pads (ex: Middle Spraberry and 2nd Bone Shale)
    - Repeatable multi-interval A/B program in Monarch
- D&C cost savings for multi-well development driving efficient capital allocation

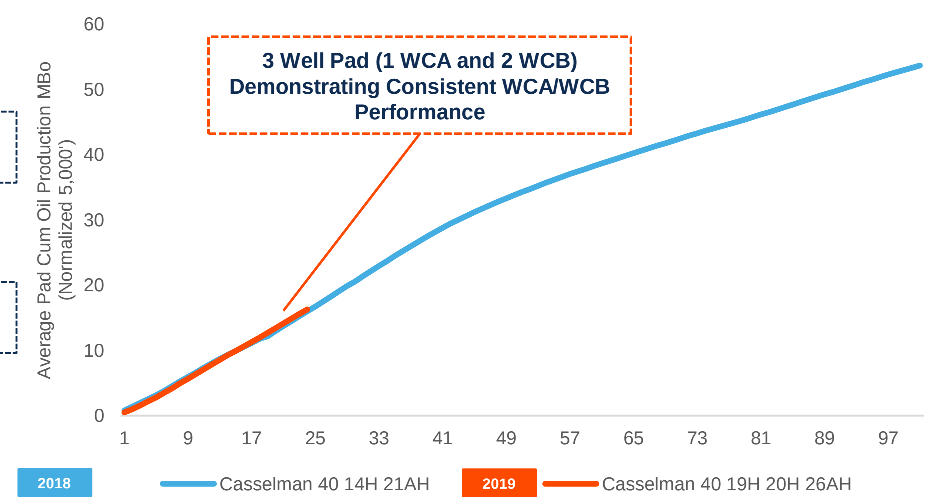
MULTI-INTERVAL: MIDLAND CO-DEVELOP MSB/ULSB/LLSB



MULTI-WELL: DELAWARE WCA TESTS

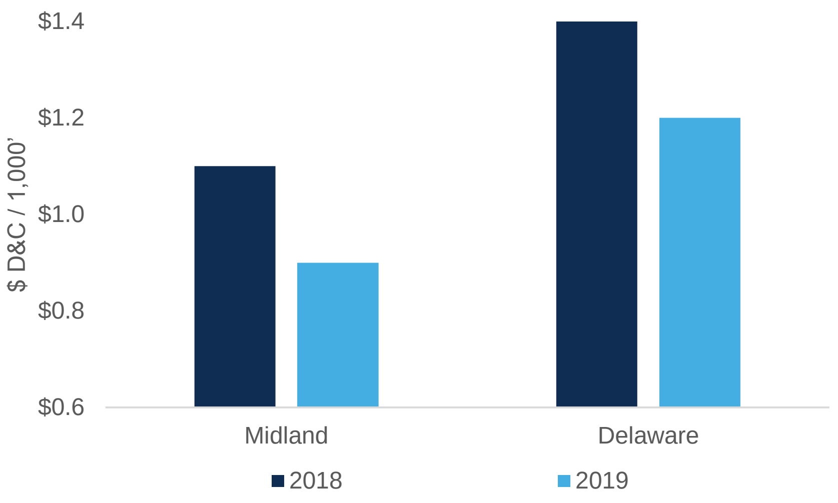


MULTI-INTERVAL: MIDLAND CO-DEVELOP WCA/WCB

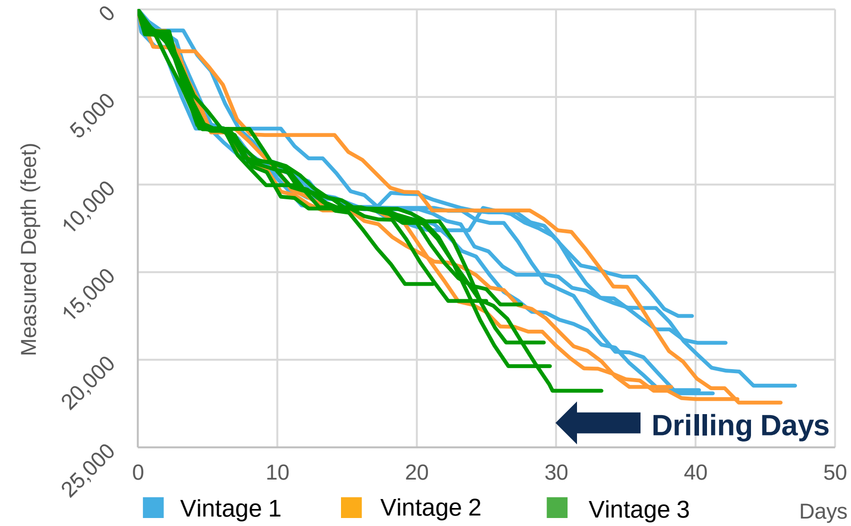


2019 INFLECTION POINT OF DEVELOPMENT PROGRAM

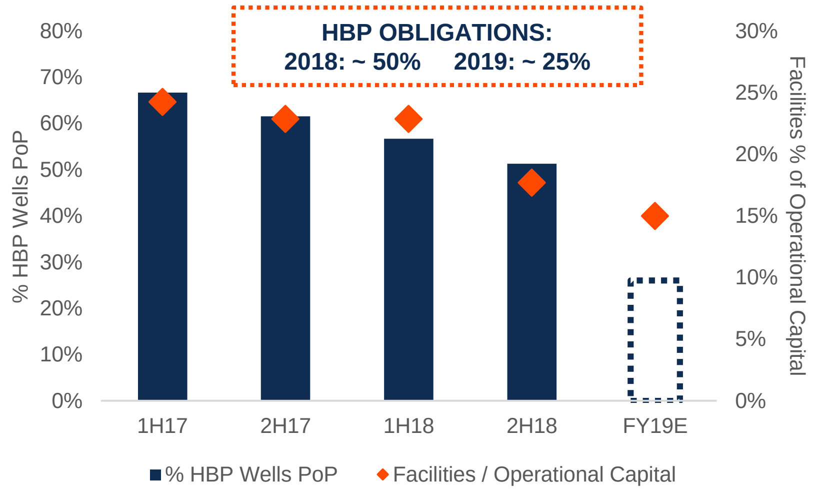
COST REDUCTIONS ACCELERATE EFFICIENCY GAINS



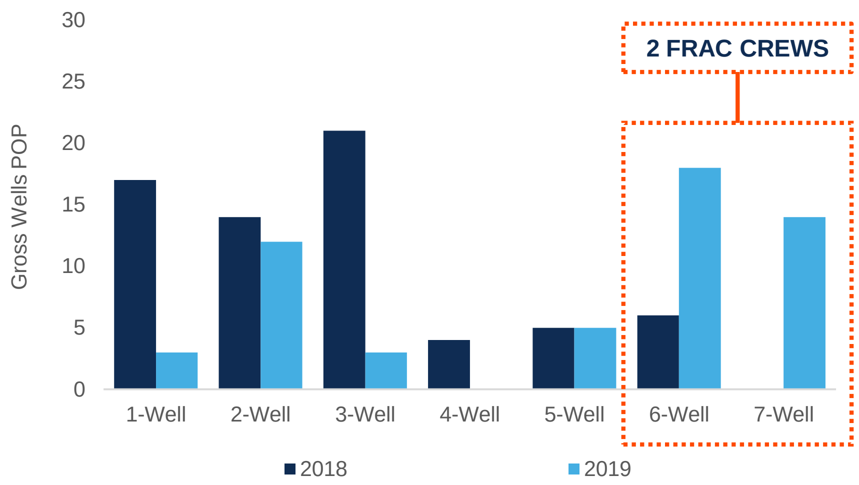
IMPROVEMENTS CONSISTENT AND MEASURABLE



OPERATIONAL FLEXIBILITY OPTIMIZES CAPITAL SPEND



PROJECT SIZE INCREASE MAXIMIZES ASSET RECOVERY

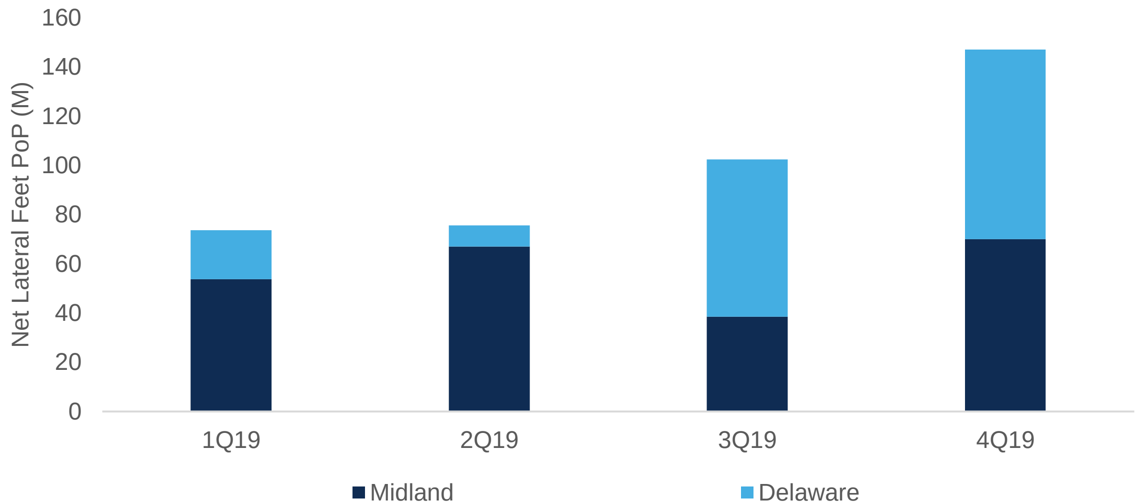


2019 OPERATIONAL PROGRAM

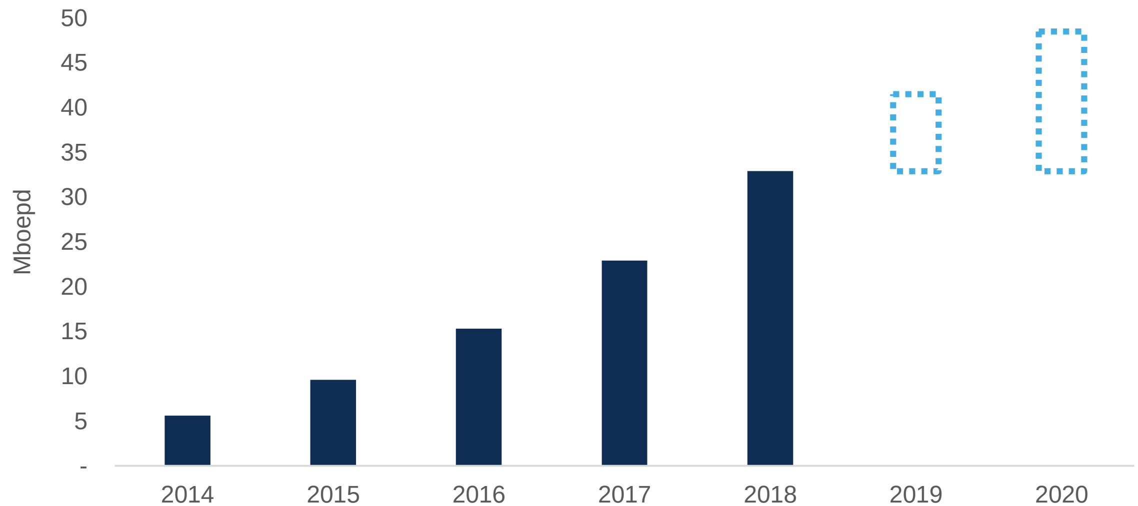
2019 DEVELOPMENT PROGRAM

- 2019 current efficiency objectives
  - ~ 25% production growth on reduced capex (YoY)
  - 15% decline in D&C/1,000’ (YoY)
  - Operating cost reductions with larger scale development
- 2019 future valuation creation objectives
  - Increase capital allocation in the Delaware to maximize resource capture
  - Mitigate parent-child impact in Midland co-development program
  - Apply appropriate risking parameters throughout planning process
- Foundation of maturing PDP
  - 2019 PDP decline rate upper 30% [(1)]
  - Projected 2020 decline rate lower by ~5%
- Transition to 2020
  - FCF generation and 15%+ growth at \$52.50/Bbl WTI (\$62.50 Brent) and \$2.75/mmbtu
  - Maintain operational capex below 2018 levels
  - Determine cash return priorities

LARGE DELAWARE PROJECTS SET UP STRONG ENTRY INTO 2020



CONSISTENT PROFILE OF GROWTH FOR THE FORESEEABLE FUTURE [(2)]



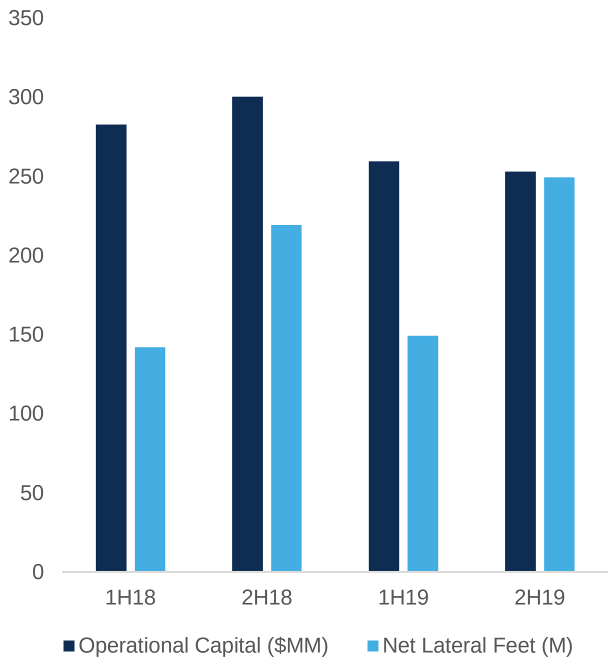
1) On a percentage basis. Based upon January 2019 production rate to projected January 2020 rate.
2) Production range estimate for 2019 represents incremental growth including the top end of current guidance for estimated daily production rates. 2020 figures assume 15% growth from the range provided for 2019.

2019 OUTLOOK

GUIDANCE TAKEAWAYS

- Program designed to maximize efficiency in continued shift to large pad development
- Emergence of large pad Delaware impact in 2H19 drives strong transition in 1Q20
- Appropriately risking for start-up of multi-interval and co-development projects

LONGER LATERALS WITH LESS CAPITAL



	FY'19 GUIDANCE
Total production (MBoepd)	**39.5 – 41.5**
Oil production	**77% - 78%**
Income statement expenses (per BOE)	
LOE, including workovers	**$5.50 - $6.50**
Production taxes, including ad valorem (% of unhedged revenues)	**7%**
Adjusted G&A: cash component (1)	**$2.00 - $2.50**
Adjusted G&A: non-cash component (2)	**$0.50 - $1.00**
Cash interest expense (3)	**$0.00**
Statutory income tax rate	**22%**
Capital expenditures ($MM, accrual basis)	
Total operational capital (4)	**$500 - $525**
Total capitalized expenses (including interest) (3)	**$100 - $105**
Net operated horizontal wells placed on production	**47 - 49**

1. Excludes stock-based compensation and corporate depreciation and amortization. Based on CPE calculated Adjusted G&A, a non-GAAP financial measure – please see reconciliation disclosures in the Appendix.
2. Excludes certain non-recurring expenses and non-cash valuation adjustments. Based on CPE calculated Adjusted G&A, a non-GAAP financial measure – please see reconciliation disclosures in the Appendix.
3. All cash interest expense anticipated to be capitalized at estimated weighted average of 6%.
4. Includes drilling, completions, facilities, seismic, land and other items. Excludes capitalized expenses.

FINANCIAL POSITIONING [1]

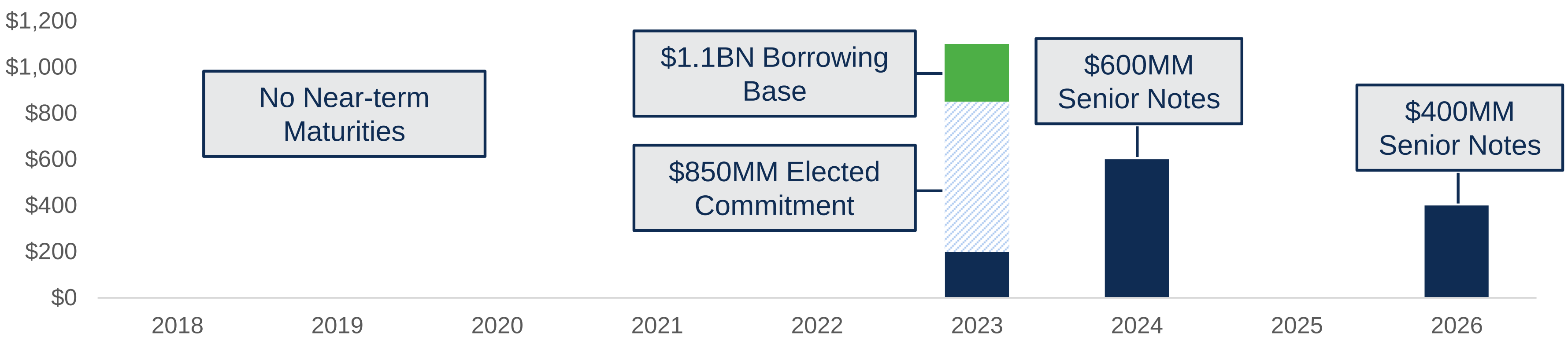
HIGHLIGHTS

- Progressing toward free cash flow generation from field level to corporate-level with 4Q19 target at $50/Bbl [2]
- Focused on reducing leverage to meet long-term targets, < 2.0x Net Debt [3] / Adjusted EBITDA(X)
- Strong liquidity position that is supported by a Revolving Credit Facility that has an elected commitment amount of $850MM under a $1.1Bn borrowing base
- Flexible capital structure given no near-term debt maturities

CAPITALIZATION ($MM)

	4Q18
Cash	$16
Credit Facility	$200
Senior Notes due 2024	600
Senior Notes due 2026	400
Total Debt	$1,200
Stockholders' Equity	2,445
Total Capitalization	$3,645
Total Liquidity [1]	**$648**
Net Debt to FY2018 Adjusted EBITDA [3][4]	**2.4x**

DEBT MATURITY SUMMARY ($MM)



1. Based on current elected commitment amount. All figures are as of 12/31/18 and reflect certain items, such as letters of credit, not specifically shown in the capitalization table.
2. WTI benchmark pricing. Assumes Henry Hub benchmark pricing of $2.75/mmbtu.
3. Net debt is a non-GAAP financial measure. Please refer to the Appendix for reconciliation.
4. Net Debt to LTM Adjusted EBITDA is a non-GAAP measure and is calculated as the sum of total long-term debt less unrestricted cash and cash equivalents, divided by the Company's Adjusted EBITDA inclusive of annualized pro-forma results from its acquisitions completed over the last twelve month period.

OUTLOOK

RESPONSIBILITY: EXECUTION AND SAFETY

OPTIMIZE HIGH-QUALITY PERMIAN INVENTORY

DRIVE CORPORATE LEVEL RETURNS WITH PEER LEADING CASH MARGINS

EFFICIENT CAPITAL CONVERSION WITHIN CASH FLOWS GENERATES DOUBLE DIGIT PRODUCTION GROWTH

DELINEATE AND RATIONALIZE RESOURCE BASE

INTEGRATE SUSTAINABLE INVESTMENTS TO DRIVE FUTURE COST SAVINGS AND LONG-TERM EFFICIENCY GAINS

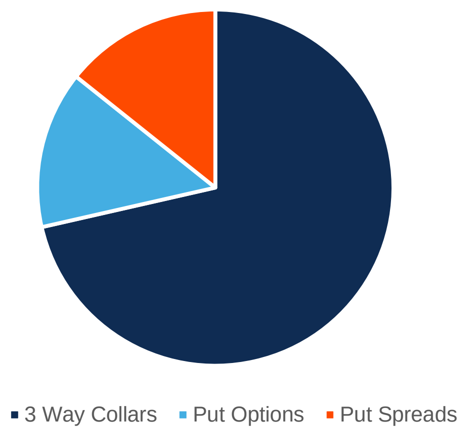
APPENDIX

MARKETING AND RISK MANAGEMENT (1)

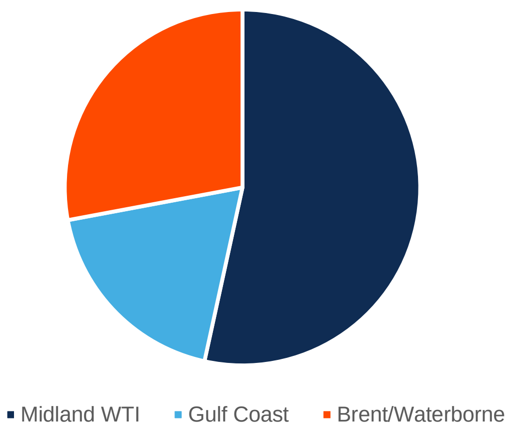
PROTECTING CASH FLOW

- Total realized price focus covering both benchmark and basis
- Midland oil basis differentials have narrowed as expected, with Mid-Cush trading at a premium to WTI recently
- Will strategically align the hedge portfolio to match additional pricing points
- Beginning to layer into 2020 positions

2019 WTI INSTRUMENT OVERVIEW



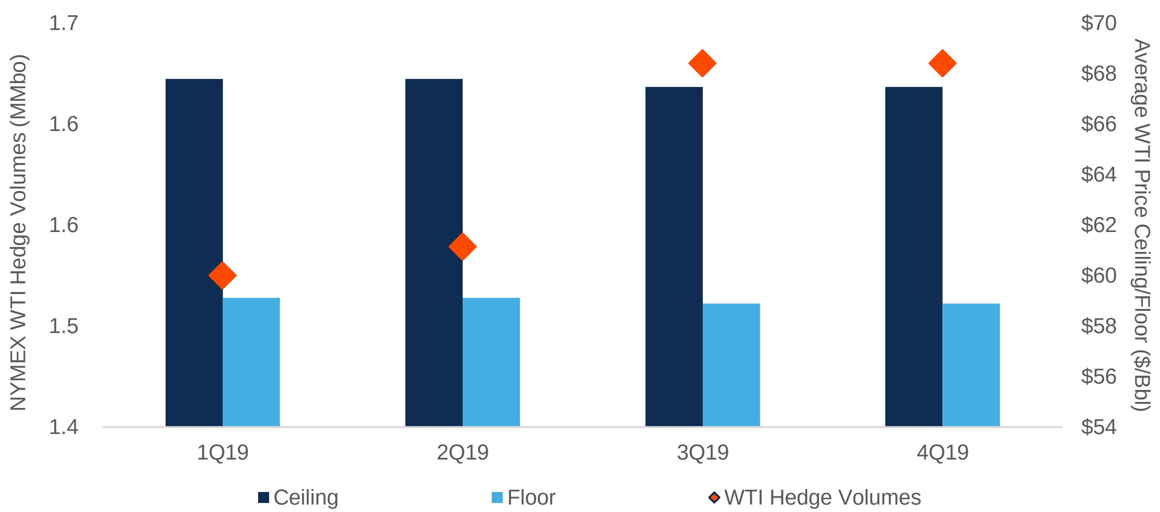
CURRENT 2020E PRICING POINTS



ENHANCING RETURNS

- New marketing agreements will increase exposure to MEH, Brent, and waterborne pricing starting 4Q19
  - 4Q19 Gray Oak: 15 Mb/d gross FT matched with a combination of MEH and Brent contracts
  - Incremental 10 Mb/d gross sales at waterborne pricing starting 1/1/20
- Evaluating additional physical marketing and FT contracts to diversify price exposure

WTI HEDGE VOLUME WITH WEIGHTED AVERAGE CEILING AND FLOOR PRICE (2)

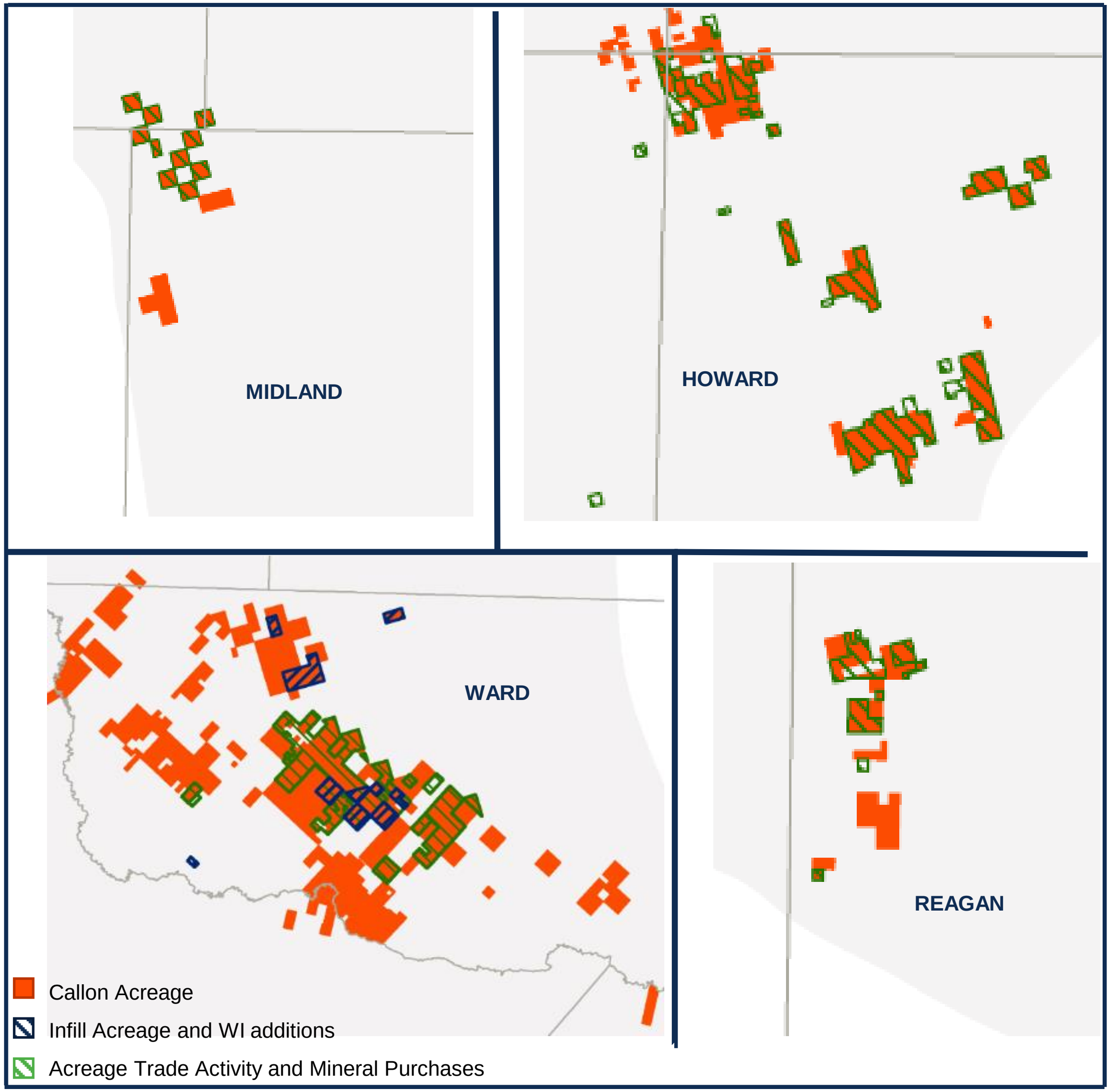


1. Hedge contracts as of 2/22/19.
2. Ceiling prices reflected are only applicable to 3-way collars. Puts and put spreads are uncapped with upside potential for rising prices.

OPTIMIZING THE FOOTPRINT

ACTIVELY IMPROVING OUR NET ACRE VALUE

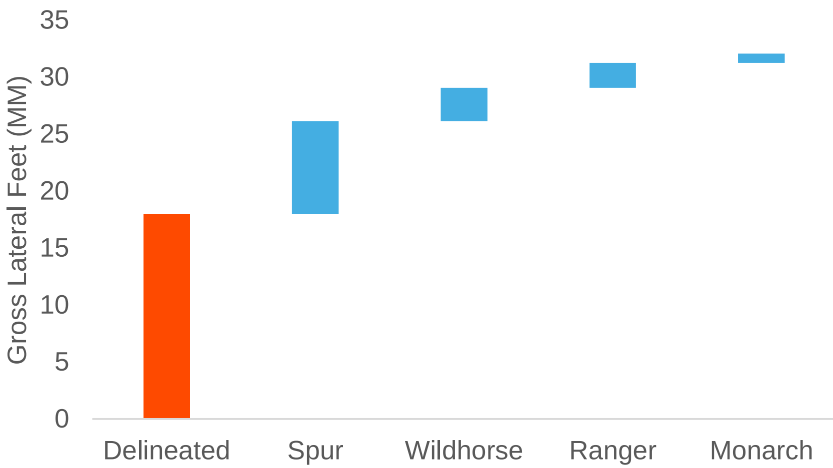
- Infill acreage additions
  - Acquired 3,158 net acres within/contiguous to Spur footprint in 2H18
  - 100% HBP; ~77% NRI
  - Enhance scaled program development
- Leasehold activity
  - Trades: ~ 4,325 net acres
  - Leasing and additions: ~ 3,100 net acres
- Mineral rights
  - Acquired over 1,600 net mineral acres across core development areas
  - Highly accretive with near-term planned development
- Increasing asset rationalization
  - Non-core asset sales and continued trade activity expected through 2019
  - 3,540 net acres divested in 2018

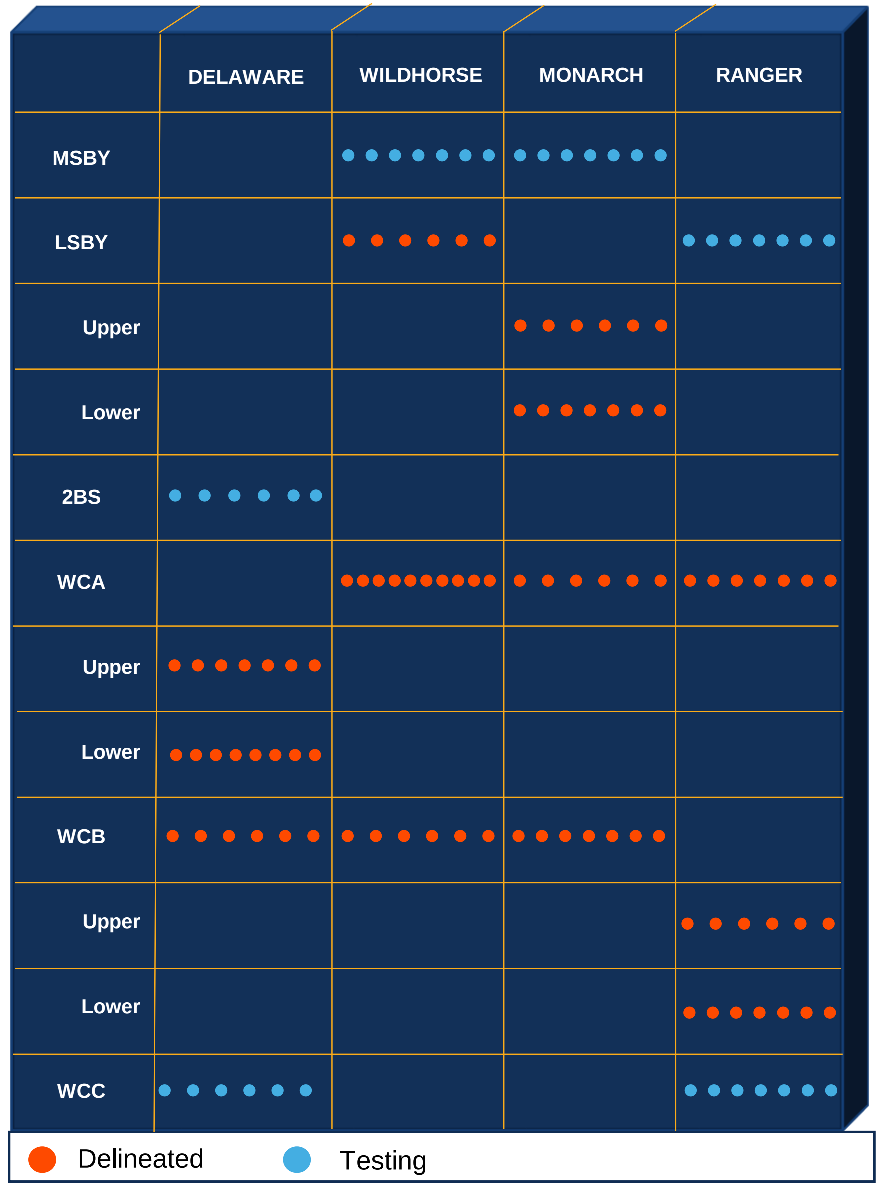


QUALITY INVENTORY SCALABLE FOR LARGER PADS

	MIDLAND	DELAWARE
Net Acres	~ 39,500	~ 45,200
Producing Flow Units	7	4
Gross Delineated Locations	940	1,210
Operated	820	580
Non-Operated	120	630
Wtd. Avg. Lateral Length	8,100’	8,600’
Operated	7,800’	8,900’
Non-Operated	9,600’	8,400’
Delineated Lateral Feet (Gross Operated)	~ 18 Million	

32 MM GROSS LATERAL FEET OF POTENTIAL RESOURCE



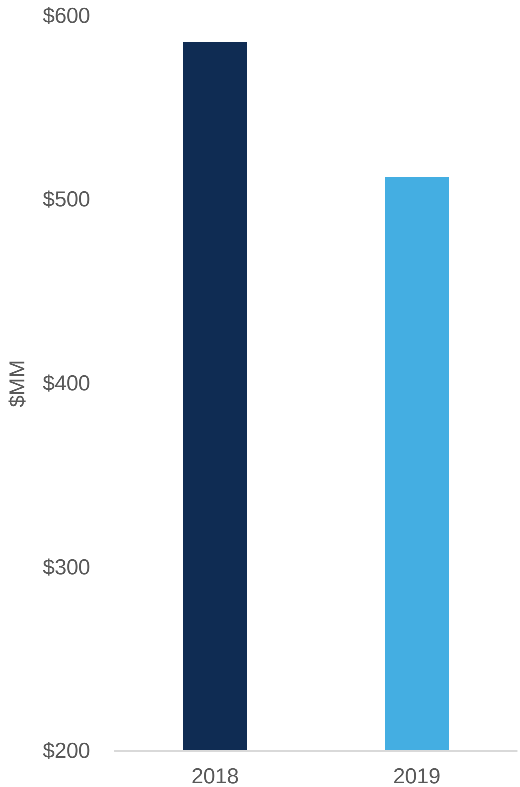


DEVELOPMENT PROGRAM EFFICIENCY GAINS

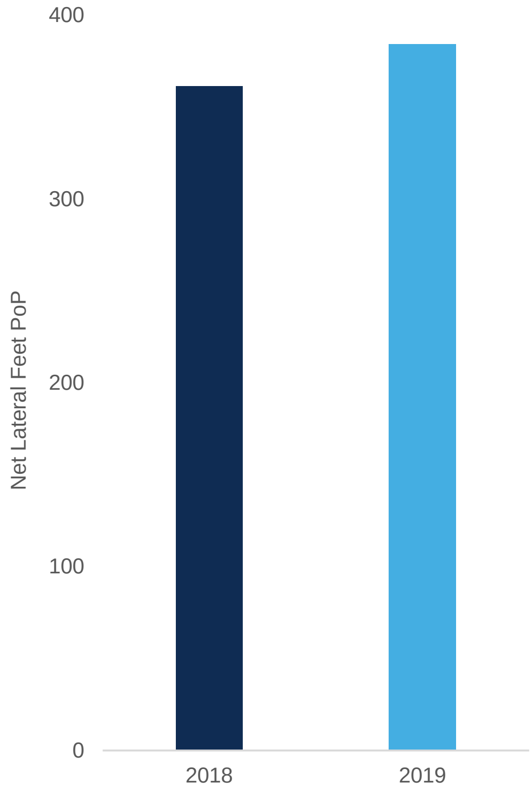
LARGER PAD DEVELOPMENT DRIVING CAPITAL EFFICIENCY

- Increased opportunity for longer laterals as a result of blocking up acreage and executing quality trades
- Improvements to operational efficiency drive cost reductions on a lateral foot basis
- Consistently lower development costs across the portfolio without assumed service cost deflation

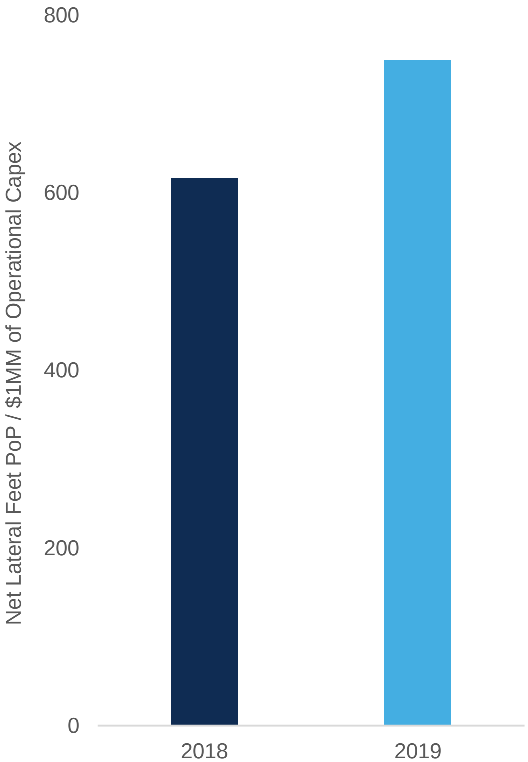
13% ↓ OPERATIONAL CAPITAL



6% ↑ NET LATERAL FEET



22% ↑ NET LATERAL FOOTAGE PER $1 MM OF OPERATIONAL CAPEX



OIL HEDGE PORTFOLIO (1)

	1Q19	2Q19	3Q19	4Q19	1H19	2H19	2019	1Q20	2Q20	3Q20	4Q20	1H20	2H20	2020
NYMEX WTI (Bbl, $/Bbl)														
Three-way Collars														
Total Volumes	1,080,000	1,092,000	1,196,000	1,196,000	2,172,000	2,392,000	4,564,000	-	-	-	-	-	-	-
Total Daily Volumes	12,000	12,000	13,000	13,000	12,000	13,000	12,504	-	-	-	-	-	-	-
Avg. Short Call Price	$67.78	$67.78	$67.46	$67.46	$67.78	$67.46	$67.62	-	-	-	-	-	-	-
Avg. Long Put Price	$56.67	$56.67	$56.54	$56.54	$56.67	$56.54	$56.60	-	-	-	-	-	-	-
Avg. Short Put Price	$43.54	$43.54	$43.65	$43.65	$43.54	$43.65	$43.60	-	-	-	-	-	-	-
Avg. Premium Price	($0.10)	($0.10)	($0.09)	($0.09)	($0.10)	($0.09)	($0.09)	-	-	-	-	-	-	-
Two-way Collars														
Total Volumes	-	-	-	-	-	-	-	182,000	182,000	184,000	184,000	364,000	368,000	732,000
Total Daily Volumes	-	-	-	-	-	-	-	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Avg. Short Call	-	-	-	-	-	-	-	$64.63	$64.63	$64.63	$64.63	$64.63	$64.63	$64.63
Avg. Put	-	-	-	-	-	-	-	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00
Avg. Premium Price	-	-	-	-	-	-	-	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
Put Options														
Total Volumes	225,000	227,500	230,000	230,000	452,500	460,000	912,500	-	-	-	-	-	-	-
Total Daily Volumes	2,500	2,500	2,500	2,500	2,500	2,500	2,500	-	-	-	-	-	-	-
Avg. Long Put Price	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	-	-	-	-	-	-	-
Avg. Premium Price	$6.44	$6.44	$6.44	$6.44	$6.44	$6.44	$6.44	-	-	-	-	-	-	-
Put Spreads														
Total Volumes	225,000	227,500	230,000	230,000	452,500	460,000	912,500	-	-	-	-	-	-	-
Total Daily Volumes	2,500	2,500	2,500	2,500	2,500	2,500	2,500	-	-	-	-	-	-	-
Avg. Long Put Price	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	-	-	-	-	-	-	-
Avg. Short Put Price	$42.50	$42.50	$42.50	$42.50	$42.50	$42.50	$42.50	-	-	-	-	-	-	-
Avg. Premium Price	$4.39	$4.39	$4.39	$4.39	$4.39	$4.39	$4.39	-	-	-	-	-	-	-
Total Volume Hedged (Bbl)	1,530,000	1,547,000	1,656,000	1,656,000	3,077,000	3,312,000	6,389,000	182,000	182,000	184,000	184,000	364,000	368,000	732,000
Average Ceiling Price ($/Bbl)	$67.78	$67.78	$67.46	$67.46	$67.78	$67.46	$67.62	$64.63	$64.63	$64.63	$64.63	$64.63	$64.63	$64.63
Average Floor Price ($/Bbl)	$59.12	$59.12	$58.89	$58.89	$59.12	$58.89	$59.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00
MIDLAND-CUSHING DIFFERENTIAL (Bbls/$/Bbl)														
Swaps														
Total Volumes	1,634,000	1,683,500	1,748,000	1,670,500	3,317,500	3,418,500	6,736,000	1,092,000	1,092,000	1,196,000	1,196,000	2,184,000	2,392,000	4,576,000
Total Daily Volumes	18,156	18,500	19,000	18,158	18,329	18,579	18,455	12,000	12,000	13,000	13,000	12,000	13,000	12,503
Avg. Swap Price	($5.59)	($5.51)	($3.13)	($3.22)	($5.55)	($3.18)	($4.34)	($1.73)	($1.73)	($0.89)	($0.89)	($1.73)	($0.89)	($1.29)

1. Hedge contracts as of 2/22/19.

GAS HEDGE PORTFOLIO (1)

	1Q19	2Q19	3Q19	4Q19	1H19	2H19	2019	1Q20	2Q20	3Q20	4Q20	1H20	2H20	2020
NYMEX Henry Hub (MMBtu, $/MMBtu)														
Swaps														
Total Volumes	-	455,000	1,242,000	155,000	455,000	1,397,000	1,852,000	-	-	-	-	-	-	-
Total Daily Volumes	-	5,000	13,500	1,685	2,514	7,592	5,074	-	-	-	-	-	-	-
Avg. Swap Price	-	$2.87	$2.89	$2.87	$2.87	$2.89	$2.88	-	-	-	-	-	-	-
Two-way Collars														
Total Volumes	2,525,000	1,501,500	598,000	598,000	4,026,500	1,196,000	5,222,500	-	-	-	-	-	-	-
Total Daily Volumes	28,056	16,500	6,500	6,500	22,246	6,500	14,308	-	-	-	-	-	-	-
Avg. Short Call Price	$3.63	$3.82	$3.50	$3.50	$3.70	$3.50	$3.65	-	-	-	-	-	-	-
Avg. Put Price	$2.97	$3.06	$3.13	$3.13	$3.00	$3.13	$3.03	-	-	-	-	-	-	-
Total Volume Hedged (MMBtu)	2,525,000	1,956,500	1,840,000	753,000	4,481,500	2,593,000	7,074,500	-	-	-	-	-	-	-
Average Ceiling Price ($/MMBtu)	$3.63	$3.60	$3.09	$3.37	$3.62	$3.17	$3.45	-	-	-	-	-	-	-
Average Floor Price ($/MMBtu)	$2.97	$3.02	$2.97	$3.07	$2.99	$3.00	$2.99	-	-	-	-	-	-	-
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)														
Swaps														
Total Volumes	2,300,000	1,729,000	2,116,000	2,116,000	4,029,000	4,232,000	8,261,000	1,183,000	1,183,000	1,196,000	1,196,000	2,366,000	2,392,000	4,758,000
Total Daily Volumes	25,556	19,000	23,000	23,000	22,260	23,000	22,633	13,000	13,000	13,000	13,000	13,000	13,000	13,000
Avg. Swap Price	($1.24)	($1.22)	($1.18)	($1.18)	($1.24)	($1.18)	($1.21)	($1.12)	($1.12)	($1.12)	($1.12)	($1.12)	($1.12)	($1.12)

1. Hedge contracts as of 2/22/19.

QUARTERLY CASH FLOW STATEMENT

	4Q17	1Q18	2Q18	3Q18	4Q18
Cash flows from operating activities:					
Net income (loss)	$ 22,824	$ 55,761	$ 50,474	$ 37,931	$ 156,194
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation, depletion and amortization	37,222	36,066	39,387	48,977	60,301
Accretion expense	154	218	206	202	248
Amortization of non-cash debt related items	455	453	588	708	734
Deferred income tax (benefit) expense	247	495	481	1,487	5,647
(Gain) loss on derivatives, net of settlements	26,037	(3,978)	8,572	25,100	(105,512)
(Gain) loss on sale of other property and equipment	—	—	22	(102)	(64)
Non-cash expense related to equity share-based awards	1,240	1,131	1,627	1,708	1,823
Change in the fair value of liability share-based awards	865	1,012	(463)	879	(1,053)
Payments to settle asset retirement obligations	(216)	(366)	(207)	(507)	(389)
Payments for cash-settled restricted stock unit awards	—	(3,089)	(1,901)	—	—
Changes in current assets and liabilities:					
Accounts receivable	(32,347)	(8,067)	10,447	(56,764)	37,033
Other current assets	444	61	(5,611)	3,885	(5,936)
Current liabilities	23,413	12,938	4,123	47,741	9,510
Other long-term liabilities	—	87	200	5,500	(6,065)
Other assets, net	(152)	(507)	(181)	(709)	(832)
Net cash provided by operating activities	80,186	92,215	107,764	116,036	151,639
Cash flows from investing activities:					
Capital expenditures	(152,621)	(111,330)	(187,040)	(156,982)	(155,821)
Acquisitions	(3,952)	(38,923)	(6,469)	(550,592)	(122,809)
Acquisition deposit	(900)	900	(28,500)	27,600	—
Proceeds from sales of assets	20,525	—	3,077	5,249	683
Additions to other assets	—	—	—	—	(3,100)
Net cash used in investing activities	(136,948)	(149,353)	(218,932)	(674,725)	(281,047)
Cash flows from financing activities:					
Borrowings on senior secured revolving credit facility	25,000	80,000	85,000	105,000	230,000
Payments on senior secured revolving credit facility	—	(30,000)	(160,000)	(40,000)	(95,000)
Issuance of 6.375% senior unsecured notes due 2026	—	—	400,000	—	—
Payment of deferred financing costs	(28)	—	(8,664)	(1,296)	530
Issuance of common stock	—	—	288,357	7	(376)
Payment of preferred stock dividends	(1,824)	(1,824)	(1,824)	(1,823)	(1,824)
Tax withholdings related to restricted stock units	—	(560)	(1,028)	(216)	—
Net cash provided by financing activities	23,148	47,616	601,841	61,672	133,330
Net change in cash and cash equivalents	(33,614)	(9,522)	490,673	(497,017)	3,922
Balance, beginning of period	61,609	27,995	18,473	509,146	12,129
Balance, end of period	$ 27,995	$ 18,473	$ 509,146	$ 12,129	$ 16,051

NON-GAAP RECONCILIATION (1)

Adjusted EBITDA Reconciliation	4Q17	1Q18	2Q18	3Q18	4Q18
Net income	$ 22,824	$ 55,761	$ 50,474	$ 37,931	$ 156,194
Adjustments:					
Net (gain) loss on derivatives, net of settlements	26,037	(3,978)	8,572	25,100	(105,512)
Non-cash stock-based compensation expense	2,101	2,143	1,164	2,587	770
Acquisition expense	(112)	548	1,767	1,435	1,333
Income tax expense	248	495	481	1,487	5,647
Interest expense	461	460	594	711	735
Depreciation, depletion and amortization	37,222	36,066	39,387	48,977	60,301
Accretion expense	154	218	206	202	248
Adjusted EBITDA	$ 88,935	$ 91,713	$ 102,645	$ 118,430	$ 119,716

Net Debt to LTM Adjusted EBITDA	2018
Senior secured revolving credit facility	$ 200,000
6.125% senior unsecured notes due 2024	600,000
6.375% senior unsecured notes due 2026	400,000
Total principal outstanding	1,200,000
LESS: Unrestricted cash	(16,100)
Net Debt	1,183,900
Adjusted EBITDA	432,504
Acquisitions - pro forma adjustments	54,325
LTM Adjusted EBITDA	$ 486,829
LTM Net debt to Adjusted EBITDA	2.4

Adjusted G&A Reconciliation	4Q17	1Q18	2Q18	3Q18	4Q18
Total G&A expense	$ 8,173	$ 8,769	$ 8,289	$ 9,721	$ 8,514
Less: Change in the fair value of liability share-based awards (non-cash)	(844)	(991)	484	(921)	1,069
Adjusted G&A – total	7,329	7,778	8,773	8,800	9,583
Less: Restricted stock share-based compensation (non-cash)	(1,202)	(1,105)	(1,587)	(1,730)	(1,802)
Less: Corporate depreciation & amortization (non-cash)	(125)	(124)	(109)	(102)	(94)
Adjusted G&A – cash component	$ 6,002	$ 6,549	$ 7,077	$ 6,968	$ 7,687

1. See "Important Disclosure" slides for disclosures related to Supplemental Non-GAAP Financial Measures.

NON-GAAP RECONCILIATION (1)

Adjusted Total Revenue Reconciliation	4Q17	1Q18	2Q18	3Q18	4Q18
Oil revenue	$ 104,132	$ 115,286	$ 122,613	$ 142,601	$ 150,398
Natural gas revenue	14,081	12,154	14,462	18,613	11,497
Total revenue	118,213	127,440	137,075	161,214	161,895
Impact of cash-settled derivatives	(4,501)	(8,459)	(7,980)	(9,239)	(1,594)
Adjusted Total Revenue	$ 113,712	$ 118,981	$ 129,095	$ 151,975	$ 160,301
Total Production (Mboe)	2,439	2,391	2,635	3,212	3,780
Adjusted Total Revenue per Boe	$ 46.62	$ 49.76	$ 48.99	$ 47.31	$ 42.41

Discretionary Cash Flow Reconciliation	4Q17	1Q18	2Q18	3Q18	4Q18
Net cash provided by operating activities	$ 80,186	$ 92,215	$ 107,764	$ 116,036	$ 151,639
Changes in working capital	8,642	(4,512)	(8,978)	347	(33,710)
Payments to settle asset retirement obligations	216	366	207	507	389
Payments for cash-settled restricted stock unit awards	—	3,089	1,901	—	—
Discretionary cash flow	$ 89,044	$ 91,158	$ 100,894	$ 116,890	$ 118,318

PV-10 Reconciliation	2014	2015	2016	2017	2018
Standardized measure of discounted future net cash flows	$ 579,542	$ 570,890	$ 809,832	$ 1,556,682	$ 2,941,293
Add: 10 percent annual discount, net of income taxes	586,596	589,918	1,009,787	1,822,842	3,716,571
Add: future undiscounted income taxes	164,490	—	1,602	166,985	782,470
Undiscounted future net cash flows	1,330,628	1,160,808	1,821,221	3,546,509	7,440,334
Less: 10 percent annual discount without tax effect	(700,948)	(589,902)	(1,011,389)	(1,969,754)	(4,291,127)
Total Proved Reserves - Pre-tax PV-10	629,680	570,906	809,832	1,576,755	3,149,207
Total Proved Developed Reserves - Pre-tax PV-10	469,485	378,752	501,098	1,030,329	2,222,049
Total Proved Undeveloped Reserves - Pre-tax PV-10	$ 160,195	$ 192,154	$ 308,734	$ 546,426	$ 927,158

1. See "Important Disclosure" slides for disclosures related to Supplemental Non-GAAP Financial Measures.