3rd QUARTER 2018 EARNINGS

November 6, 2018

IMPORTANT DISCLOSURES

FORWARD LOOKING STATEMENTS

This presentation contains projections and other 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 production; cash flow projections; the Company's 2018 guidance; capital, operations and G&A expenditure forecasts; estimated reserve quantities and the present value thereof; and the implementation of the Company's business plans and strategy, as well as statements including words such as "estimate," "project," "will," "may," "anticipate," "plan," "intend," "believe," "expect," "outlook," "guidance," "target," "objective," "forecast" or similar expressions that convey the prospective nature of events or outcomes generally indicate forward-looking statements. These projections and statements reflect the Company's current views with respect to future events, investment plans and financial performance as of this date. No assurances can be given, however, 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. For a summary of events that may affect the accuracy of these projections and forward-looking statements, see "Risk Factors" in our Form 10-K for the year ended December 31, 2017 filed with the Securities and Exchange Commission (the "SEC"), quarterly reports on Form 10-Q, and other filings with the SEC. Unless legally required, Callon does not undertake any obligation to update forward looking statements as a result of new information, future events or otherwise

SUPPLEMENTAL NON-GAAP FINANCIAL MEASURES

This presentation includes non-GAAP measures, such as Adjusted EBITDA, Adjusted Income, Adjusted Income per diluted share, Adjusted G&A and other measures identified as non-GAAP. Management also uses EBITDAX, which reflects EBITDA plus exploration and abandonment expense.

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.

We believe that the non-GAAP measure of Adjusted income available to common shareholders ("Adjusted Income") and Adjusted Income per diluted share are useful to investors because they provide readers with a meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. These measures exclude the net of tax effects of certain non-recurring items and non-cash valuation adjustments, which are detailed in the reconciliation provided in our appendix.

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. The Appendix table details all adjustments to G&A on a GAAP basis to arrive at Adjusted G&A.

We believes discretionary cash flow per share 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

We believe that the non-GAAP measure of Adjusted Total Revenue 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.

EXECUTION IS PRIORITY ONE

FOCUSED ON THE FUTURE, AND THE FUTURE IS NOW

PREPARATION

- Significant scale attained via ~87,000 net acres of best in class Permian footprint
- Robust infrastructure network resulting from thoughtful planning and investment
- Significant liquidity and healthy capital structure support development plans
- Investing in people with build-out of technical, operational, and analytical teams

PURPOSE

- Harvesting asset value from premier acreage position
- Increasing corporate-level returns to drive shareholder value creation
- “Life of field” development balancing capital efficiency and longer term reinvestment
- Thoughtful capital allocation post HBP activity to focus on value maximization

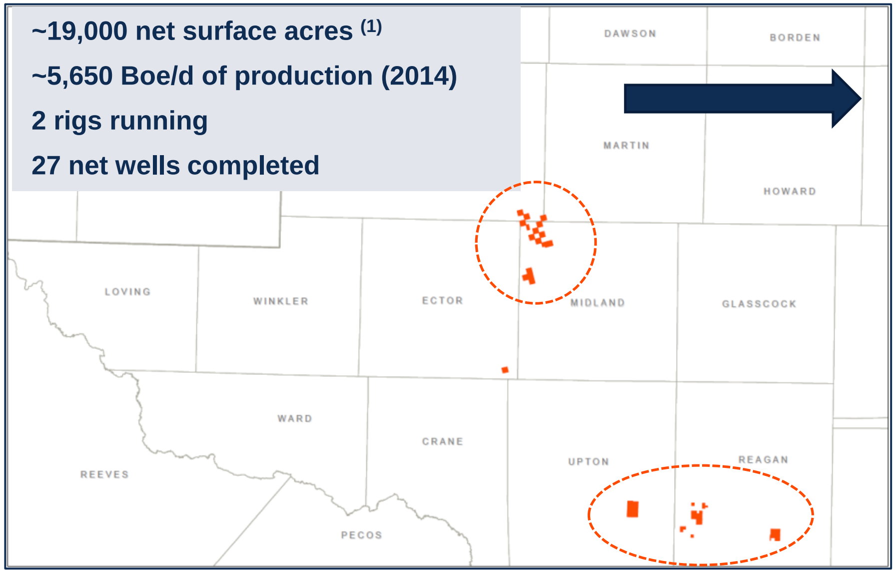
PRIORITIES

- Sustainable organic growth funded with internally generated cash flow
- Large pad development, benefiting resource optimization and capital efficiency
- Preservation of leading cash margins through cost management and leveraging of existing infrastructure
- Select asset monetization opportunities to enhance returns on capital

CALLON'S EVOLUTION IN THE PERMIAN

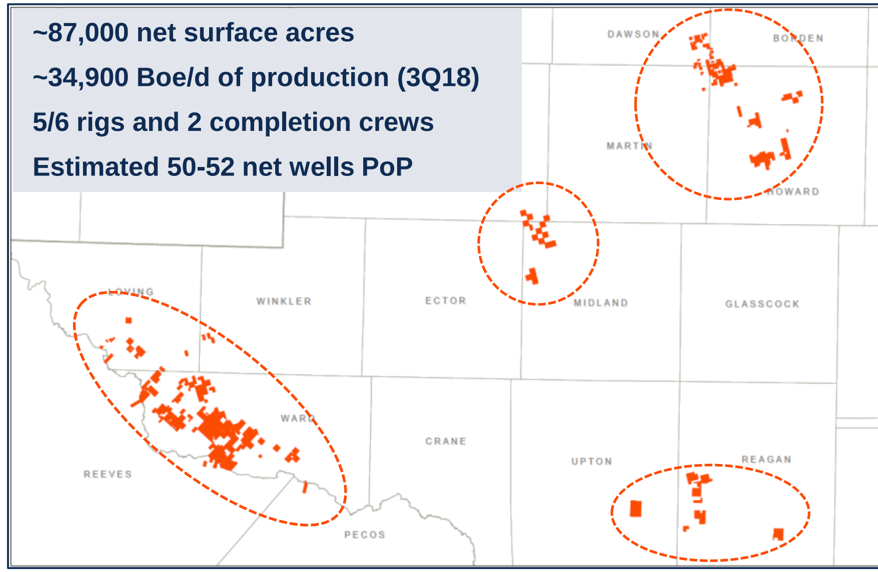
2014: INITIAL BUILDING PHASE

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

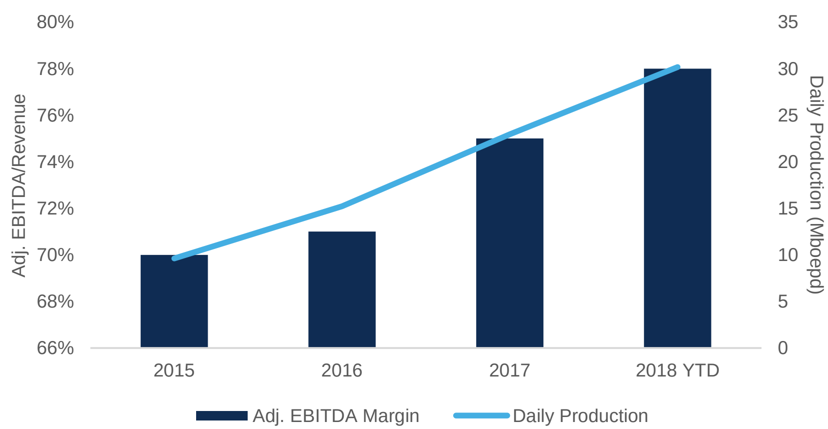


2018: TRANSITION TO FULL ASSET DEVELOPMENT

- ~87,000 net surface acres
- ~34,900 Boe/d of production (3Q18)
- 5/6 rigs and 2 completion crews
- Estimated 50-52 net wells PoP



CONTINUOUS ADJ. EBITDA MARGIN IMPROVEMENT [(2)]



MANAGEMENT COMPENSATION METRICS [(3)]

2014	2018
SAFETY	SAFETY
PRODUCTION GROWTH	CASH GROWTH PER DEBT-ADJUSTED SHARE
RESERVE GROWTH	PRODUCTION GROWTH
LIQUIDITY/WELL COSTS	PROVED DEVELOPED F&D
LOE + G&A	LEVERAGE
STRATEGIC INITIATIVES	LOE + G&A
	STRATEGIC INITIATIVES

1. Excluding Northern Midland Basin exploration properties.
2. Based on CPE calculated Adjusted EBITDA(X) and Adjusted Total Revenues, non-GAAP financial measures. Please see the Non-GAAP reconciliation disclosures in the Appendix.
3. Subject to Board discretion.

RECENT COMPANY HIGHLIGHTS

3Q18 HIGHLIGHTS

Quarterly Production: 34.9 Mboed (78% oil)

- 55% growth yoy
- Targeting 40 Mboe/d for 4Q18
- September production of 40 Mboe/d achieved including the impact of partial month of gas plant interruption

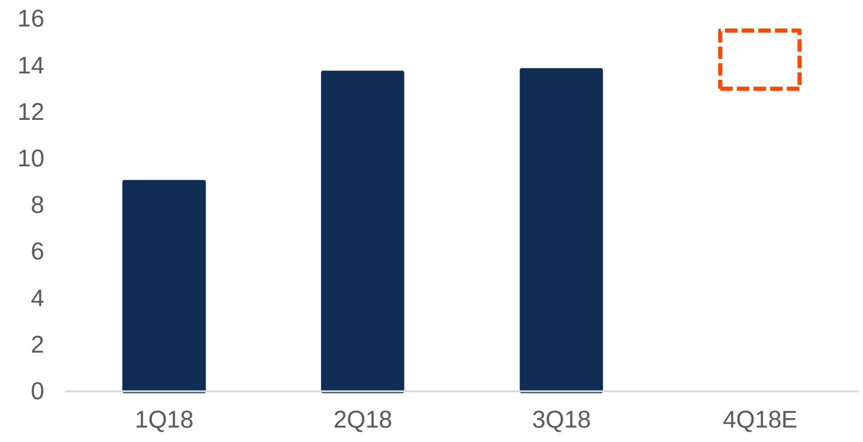
Cash Margin (1): $39.05/Boe improved 30% yoy

Adj. EBITDA (2): $118.4MM up 15% sequentially

DCFPS (3): $0.51 (up 65% yoy)

Cash G&A (4): $2.17/Boe declined ~20% Q/Q

NET WELLS PoP PER QUARTER



OPERATIONAL UPDATES

Extended preferred vendor agreement for completion services providing price certainty for the next five quarters

Strong performance from Monarch Mega-Pads

Wildhorse 4-well pad testing WCA/LSB stacked horizontal development concept exceeding type curves

Delaware wells outperforming type curves while achieving 12.5% YTD improvement in cycle time

ACCELERATING DISCRETIONARY CASH FLOW (3)

1. Cash operating costs include Lease Operating Expenses, Production Taxes, and Cash G&A.
2. Based on CPE calculated Adjusted EBITDA(X), a non-GAAP financial measure. Please see the Non-GAAP reconciliation disclosures in the Appendix.
3. Based on CPE calculated Discretionary Cash Flow per Diluted Share, a non-GAAP financial measure. Please see the Non-GAAP reconciliation disclosures in the Appendix.
4. 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.

CAPITAL EFFICIENCY DRIVING CASH FLOW ALIGNMENT

MATURING MODEL DRIVING IMPROVED RETURNS

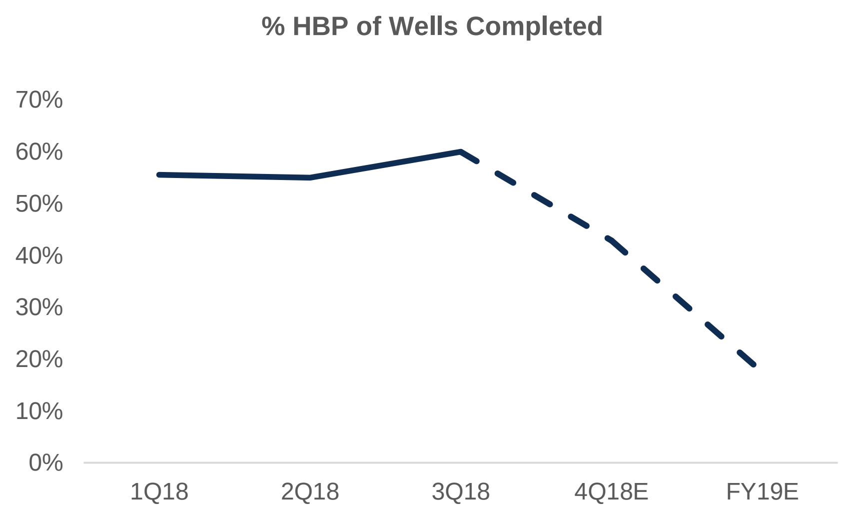
Optionality provides breadth of opportunity

- Pad development and contiguous acreage improves capital efficiency as illustrated by field level FCF trajectory
- Reduced leasehold obligations provide greater flexibility to maximize shareholder value
- Leveraging infrastructure portfolio enhances reliability and cost controls

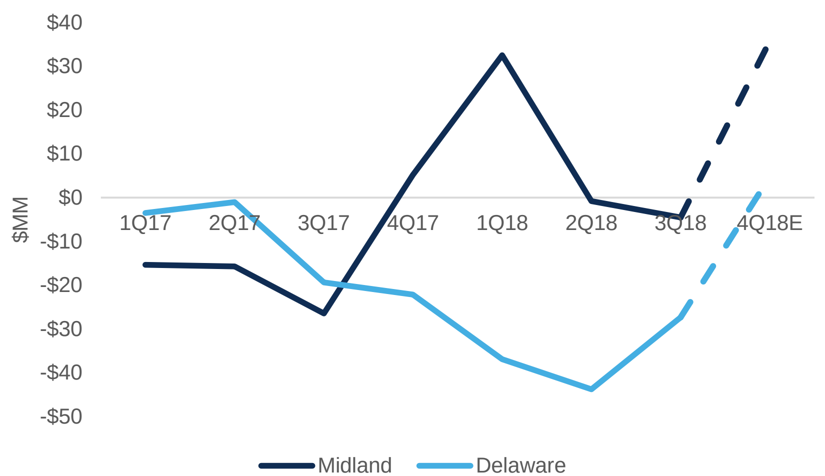
Returns-driven capital allocation

- New pad development concepts optimize resource value
- Highest and best use of capital with asset rationalization where needed
- Decisions driven by shareholder value creation and FCF goals, not arbitrary growth targets

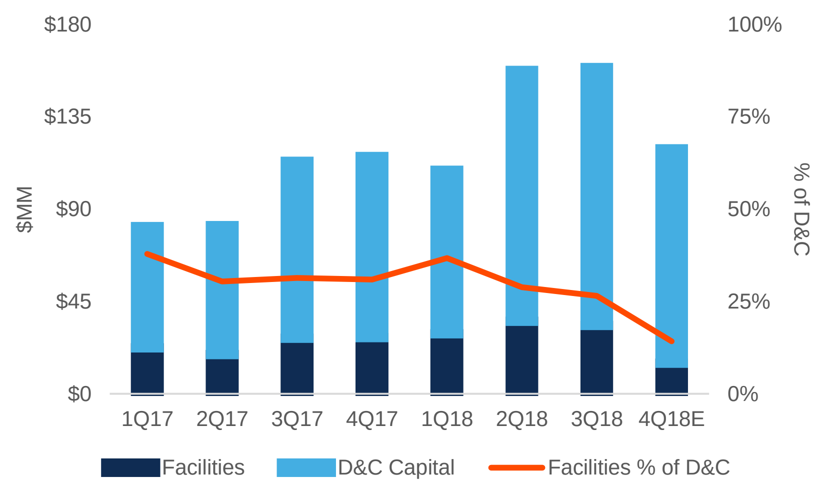
REDUCED HBP WELLS PROMOTES SCALABLE GROWTH



FIELD LEVEL CASH FLOW TRAJECTORY IMPROVED [1]



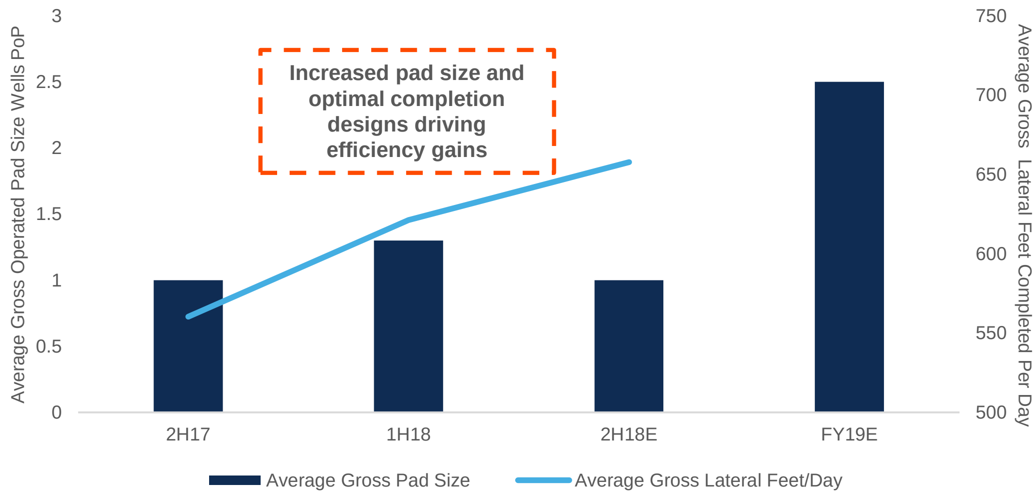
CAPITAL SPENDING INCREASINGLY FOCUSED ON D&C



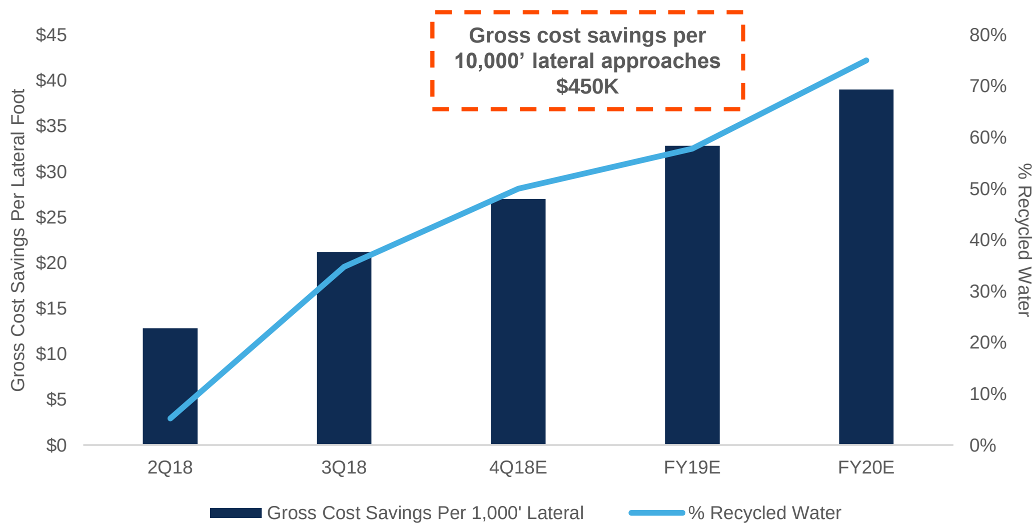
1. Pricing is forward strip for all commodities (including Waha and Midland basis differentials) as of 10/19/2018.

DELAWARE: INFLECTION POINT OF EFFICIENCY GAINS

INCREASED PAD DEVELOPMENT REDUCES COMPLETION TIMES



WATER RISK MANAGEMENT FLOWS INTO COST SAVINGS



SUSTAINABLE INVESTMENTS

2019 program development

- Transition from single-well, HBP-driven activity to multi-well pad and Mega-pad (SIMOPs) designs
- Mega-pads will test UWCA/LWCA and stacked development of 2BS/UWCA/LWCA/WCB
- Improvement in cycle time (10,000' lateral) trajectory expected to continue to sub-35 days following reduction from ~ 40 days at YE'17

Technical analysis

- Subsurface team implementing optimal frac designs following review of 2016-2018 results
- Defining well spacing assumptions early in asset development

Water management investments materialize in efficiency gains

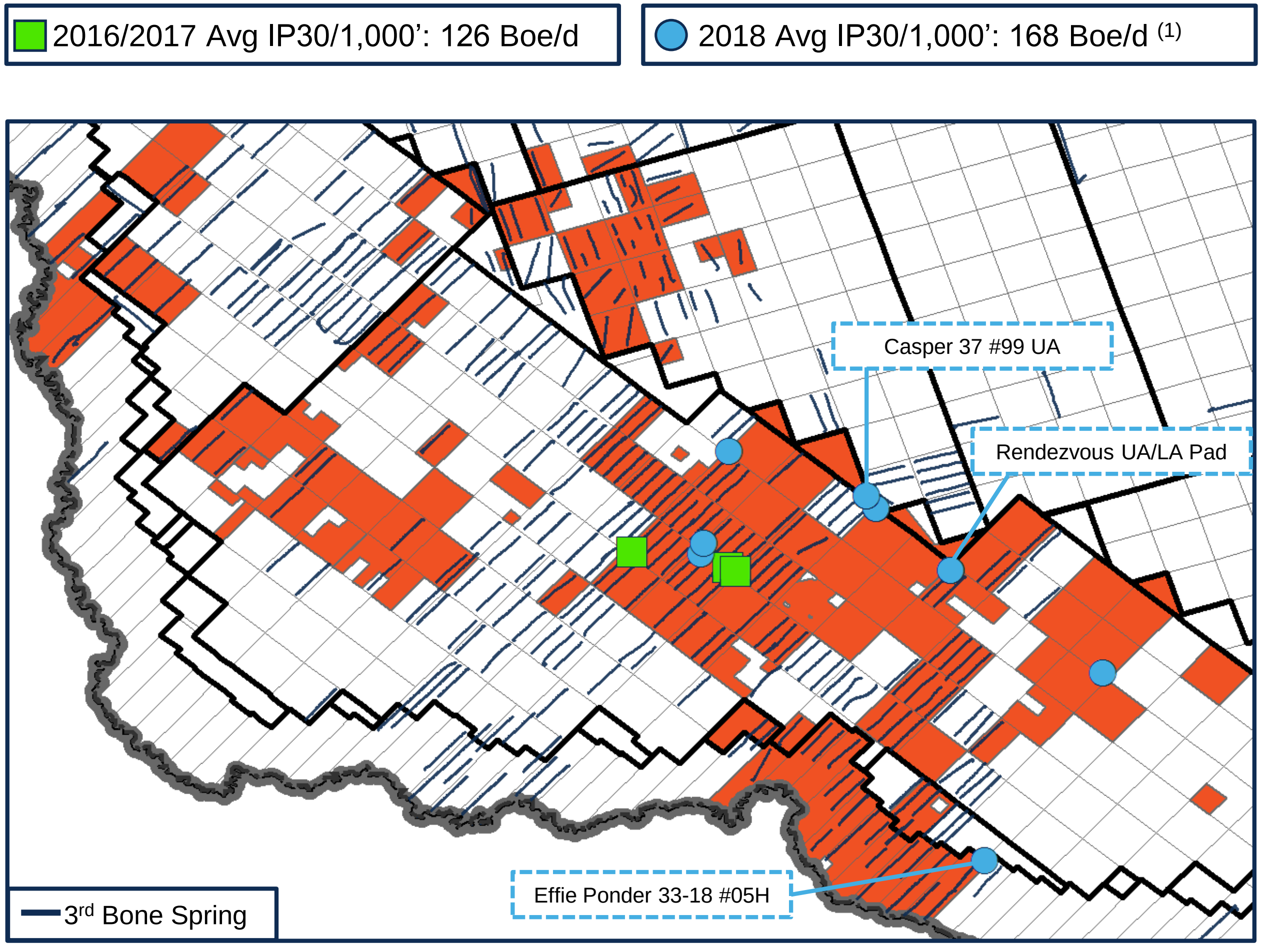
- Goodnight Midstream's water disposal pipeline to the CBP started operating in October, improving operational flexibility while protecting long-term development across acreage
- Gross cost savings per 10,000' lateral vs. current market rates expected to approach $450K per well over time
- % cost savings from recycling vs. 3rd party contracts to increase from 0% in 1Q'18 to > 50% in FY'19

In-basin sand offers incremental cost savings

- Tested 100% in-basin sand in LWCA well
- Optionality for 100% in-basin sand at YE'18; an increase from ~30% currently

DELAWARE: STRONG WOLFCAMP A RESULTS

3BS INDUSTRY LATERAL MAP WITH CPE ACREAGE AND WCA WELLS



DELAWARE HIGHLIGHTS

CPE operated wells continue to outperform

- 2018 YTD IP30/1,000' performance is 33% above earlier vintage development
- **Casper 37 #99 UA:** 1,800 Boe/d IP24 rate with daily production of 1,500 Boe/d on day 62 of oil flow back

Bolt-on acquisition integrated seamlessly

- **Effie Ponder 33-18 05H:** 1,400 Boe/d IP24 rate
- This river tract well was completed in the top 100' of the WCA (offsetting legacy 3BS development) by the previous operator

2019: transition to co-development of U/L WCA

- **Rendezvous Pad** outperforming type curve by ~17% at day 200 (cumulative production of 425 Mboe / 369 Mbo)
- Multiple opportunities for 2019 stacked U/L WCA development

1. Includes CPE operated wells only.

LARGE PAD CONCEPTS ACROSS PORTFOLIO

TESTING OPTIMAL DEVELOPMENT CONCEPTS

Monarch U/L LS mega-pad outperforming

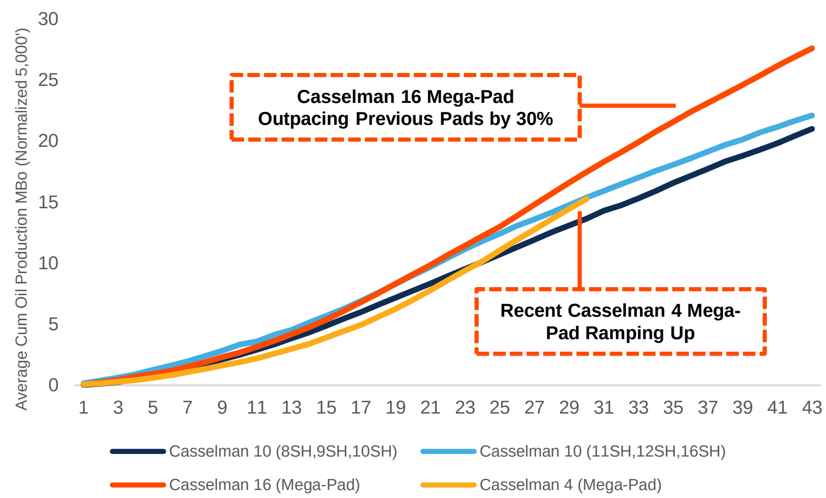
- First Mega-Pad (Casselman 16) outperforming Casselman 10 pads average by > 30% on day 110
- Second Mega-Pad (Casselman 4) early time results validating U/L LS chevron development

Rendezvous UA/LA test promotes co-development of zones in Delaware

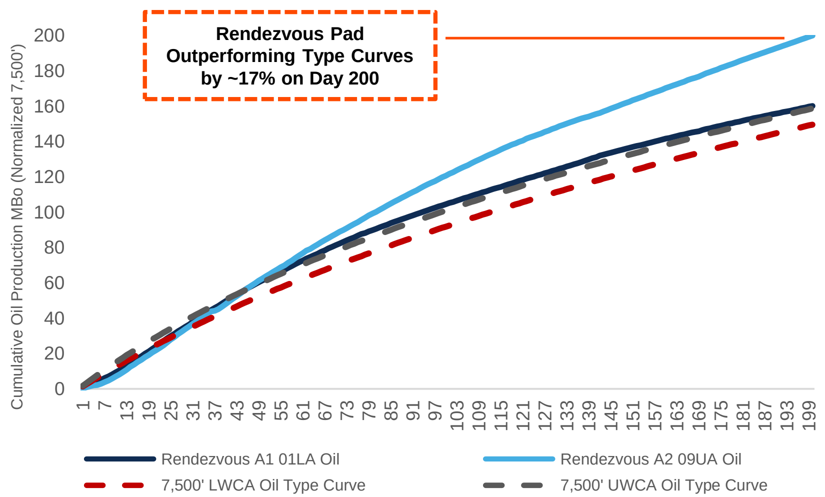
- 2019 multi-pad developments will test co-development of UA/LA
- 2019 Mega-Pad concept will test stacked development of 2BS/UWCA/LWCA/WCB

Wright WCA/LSB four well pad at sidewinder provides encouraging stacked horizontal development tests in Howard County

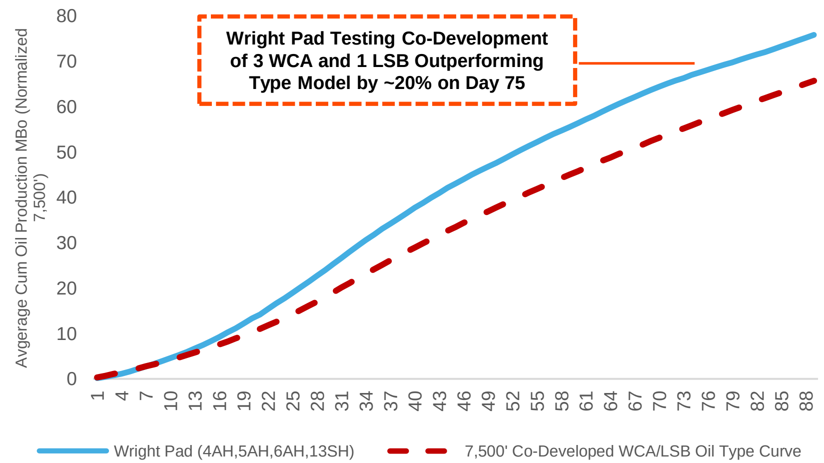
SINGLE INTERVAL DEVELOPMENT: MIDLAND MEGA-PADS



MULTI-INTERVAL DEVELOPMENT: DELAWARE UA/LA PAD



MULTI-INTERVAL DEVELOPMENT: MIDLAND WCA/LSB PAD



MIDLAND: PILOTS EXCEEDING EXPECTATIONS

RECENT MIDLAND HIGHLIGHTS

Optimized frac loadings achieving 3% - 5% cost savings

- Gibson Unit 28-21 wells (9,400' laterals) significantly outpacing type curve with 1,800lbs/ft of sand
- Wright Unit C 41-32 A1 04AH WCA well (6,945' lateral) was a reduced water completion, testing NPV acceleration and reduced water handling cost

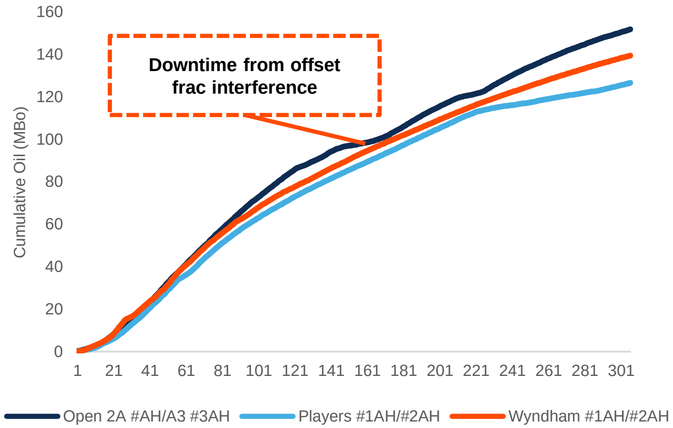
Casselman mega-pads

- Casselman 4 results tracking Casselman 16
- Utilizing ~40% recycled water for incremental cost savings

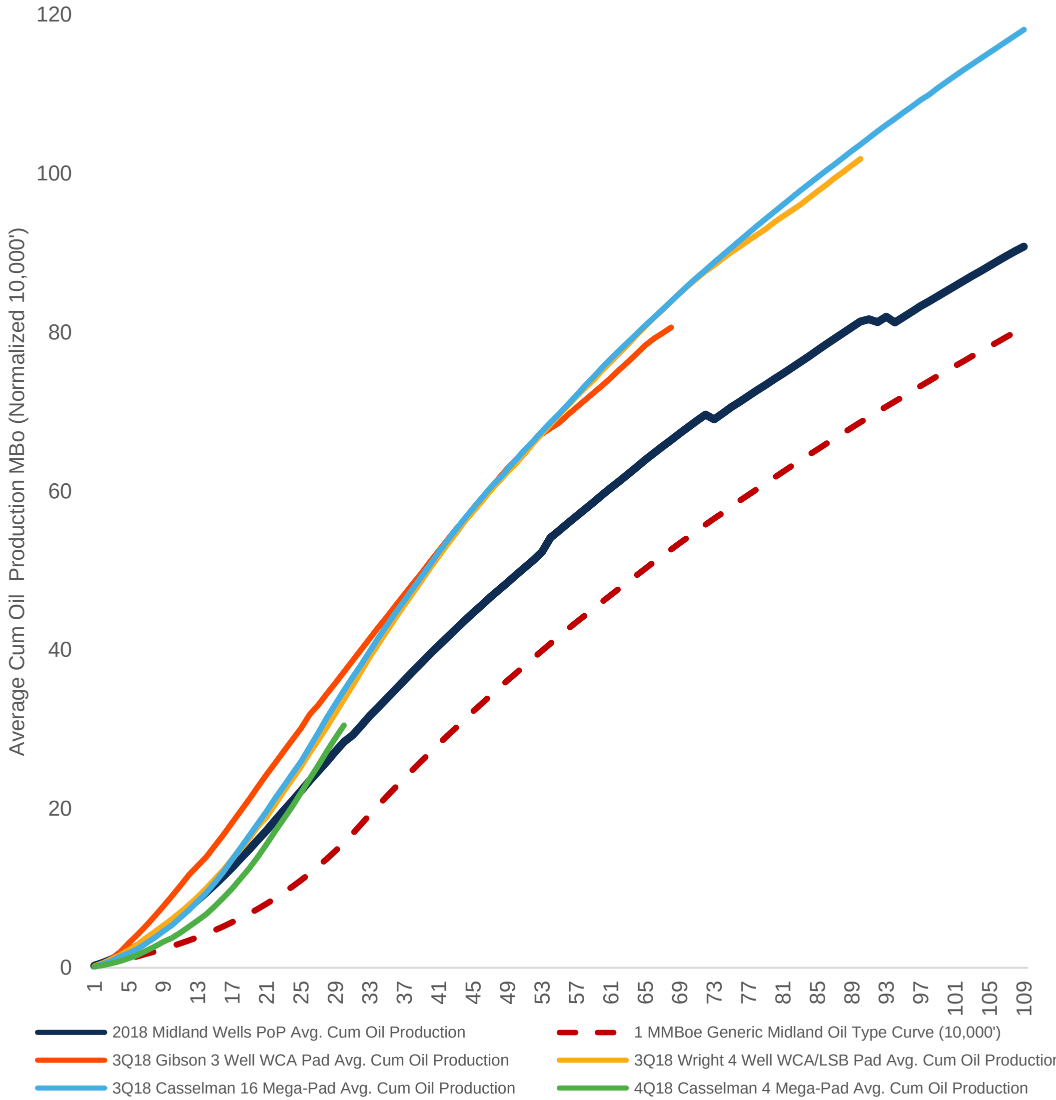
Ten well downspacing test continues to exceed offset results

- Drilling 5-well pad in Fairway to further test downspacing concept

WILDHORSE 10-WELL DOWNSPACING TEST



2018 CPE MIDLAND WELLS VS. 1 MMBOE EUR MIDLAND TYPE CURVE



FINANCIAL POSITIONING [1]

HIGHLIGHTS

Liquidity improved through +30% increase in elected commitment of $850MM under $1.1 BN borrowing base

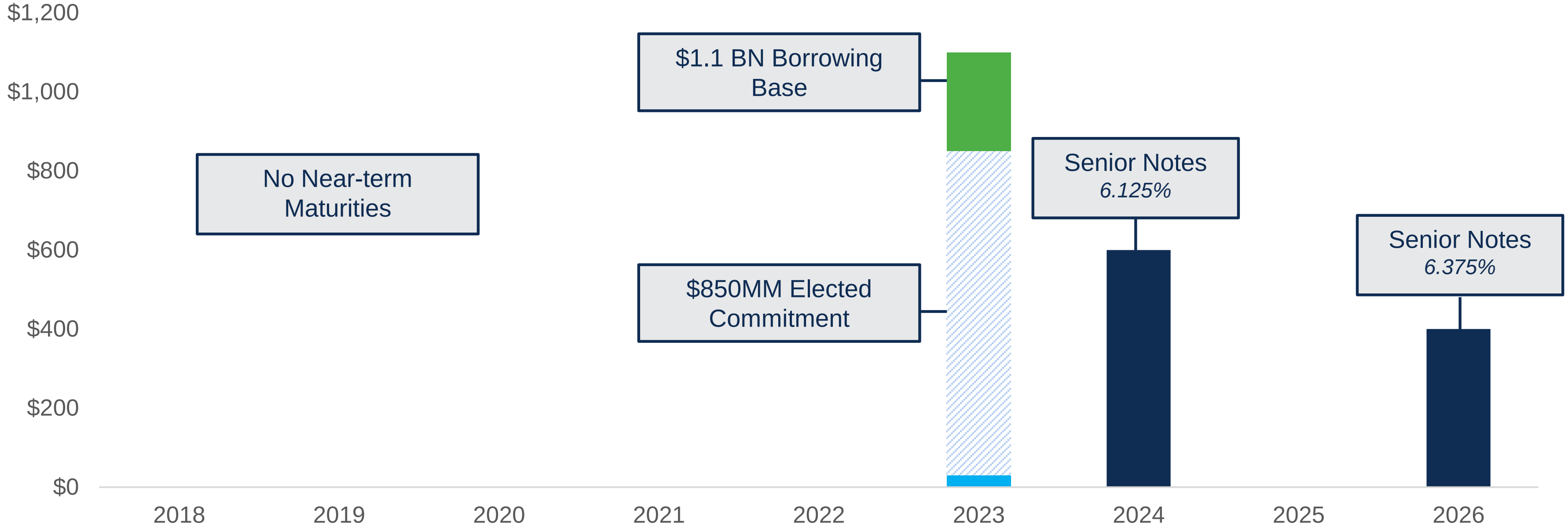
$65MM drawn on revolver with $12MM cash in hand

Pro-forma 3Q18 net debt / LQA adj. EBITDA of 2.0x [2]

Progressing free cash flow generation at field level to corporate-level

Disciplined financial benchmark and basis hedging program recently enhanced with diversification of physical pricing points

DEBT MATURITY SUMMARY ($MM)



1. As of 9/30/18.
2. LQA Adjusted EBITDA(X) is calculated using Adjusted EBITDA(X) inclusive of pro forma adjustments related to the Cimarex Asset Acquisition, reflecting historical results of operations provided by the seller. Based on CPE calculated Adjusted EBITDA(X), a non-GAAP financial measure. Please see the Non-GAAP reconciliation disclosures in the Appendix.

RISK MANAGEMENT

DOWNSIDE RISK PROTECTION [1]

Locking in WTI protection to support cash flow

- **4Q18:** ~65% hedged
- **2019:** ~50% hedged

Midland-Cushing basis differential assurance

- **4Q18:** ~55% hedged at an average swap price of ($5.30)
- **2019:** ~38% hedged at an average swap price of ($4.72)
- **2020:** ~25% hedged at an average swap price of ($1.51)

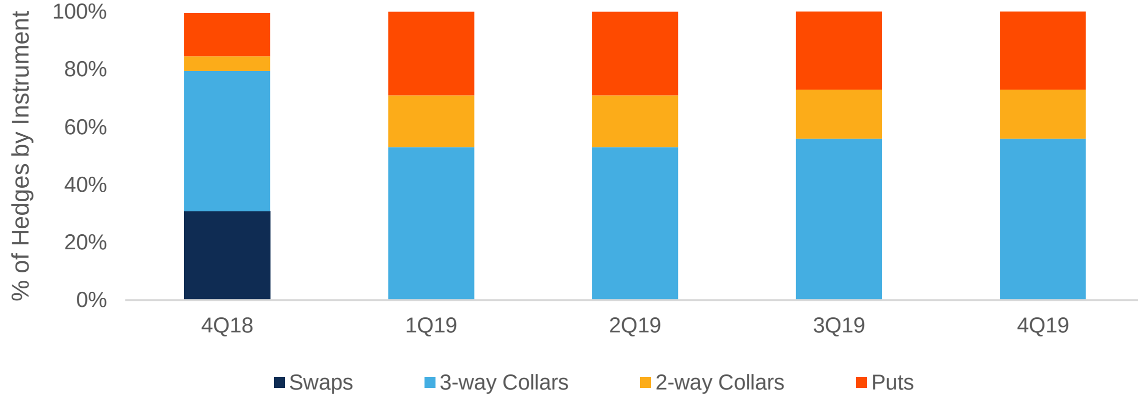
WAHA basis differential assurance

- **4Q18:** ~10% hedged at an average swap price of ($1.14)
- **2019:** ~40% hedged at an average swap price of ($1.25)
- **2020:** ~7% hedged at an average swap price of ($1.14)

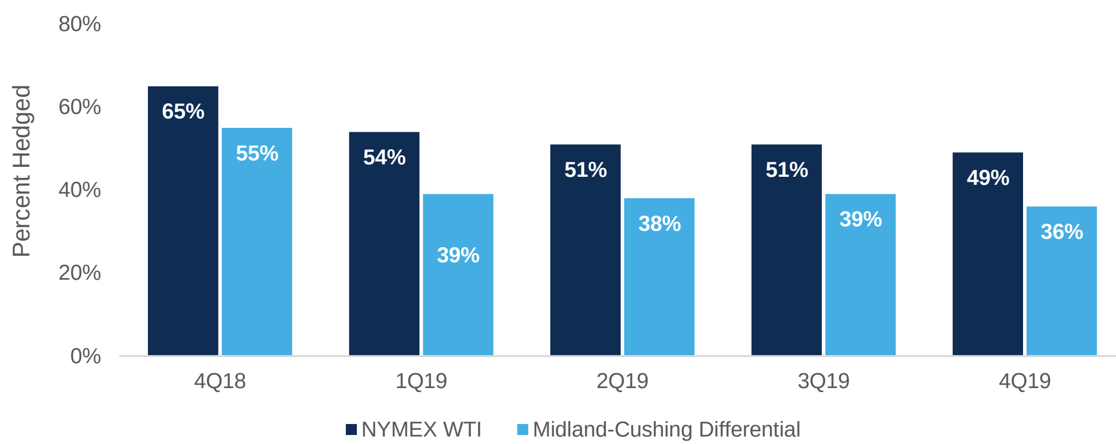
Executed 15 mb/d firm transportation on Grey Oak for diversified pricing

(combination of MEH and Brent)

WTI INSTRUMENT BREAKOUT



CRUDE OIL HEDGE POSITION BY QUARTER [1]



1. Hedge contracts as of 10/31/18. Volumes hedged as a percentage of Consensus estimates sourced from FactSet 10/31/18.

2018 GUIDANCE UPDATE

GUIDANCE TAKEAWAYS

Operational outperformance

- Raised mid-point FY'18 production guidance despite expected 4Q loss of ~1,500 Boe/d from recent gas plant interruption
- Raised mid-point FY'18 oil production guidance by 3% despite weather related downtime in October

Capital efficiency: doing more with less

- Increased mid-point FY'18 guidance for net operated horizontal wells PoP by 5% with total capex increase of 2%
- Extended preferred vendor agreement with new completions pricing
- Increased local sand usage and water recycling
- Lower trend of infrastructure spending

Maximizing returns and margin control

- Reiterated FY'18 LOE guidance following the integration of older acquired wells with higher operating costs per unit
- 4Q18E field-level FCF forecast reaffirmed and accelerated [5]

	YTD 2018 ACTUALS	PRIOR FY'18 GUIDANCE	UPDATED FY'18 GUIDANCE
Total production (MBoepd)	30.2	31.5 – 33.0	**32.0 – 33.0**
Oil production	77%	76%	**77% - 78%**
Income statement expenses (per BOE)			
LOE, including workovers	$5.43	$5.00 - $6.00	**$5.00 - $6.00**
Production taxes, including ad valorem (% of unhedged revenues)	6%	7%	**7%**
Adjusted G&A: cash component [1]	$2.50	$1.75 - $2.50	**$1.75 - $2.50**
Adjusted G&A: non-cash component [2]	$0.58	$0.50 - $1.00	**$0.50 - $1.00**
Cash interest expense [3]	$0.00	$0.00	**$0.00**
Statutory income tax rate	22%	22%	**22%**
Capital expenditures ($MM, accrual basis)			
Total operational capital excluding capitalized expenses [4]	$442	$530 - $560	**$560**
Capitalized expenses	$59	$75 - $85	**$75 - $85**
Net operated horizontal wells placed on production	37	47 - 50	**50-52**

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.
4. Includes drilling, completions, facilities, seismic, land and other items. Excludes capitalized expenses.
5. See slide 7 for updated chart and disclosure.

2019 AND BEYOND

GOALS AND OBJECTIVES

Long-term strategic focus

- Subsurface technology: balancing long-term IRR and NPV objectives from 2018 learnings
  - Larger development concepts
  - Tailored co-development across multiple zones
- Strategic partnerships: integrated model pricing power
  - Extension of completions contract (2 dedicated frac crews)
  - Secured improved 2019 pricing

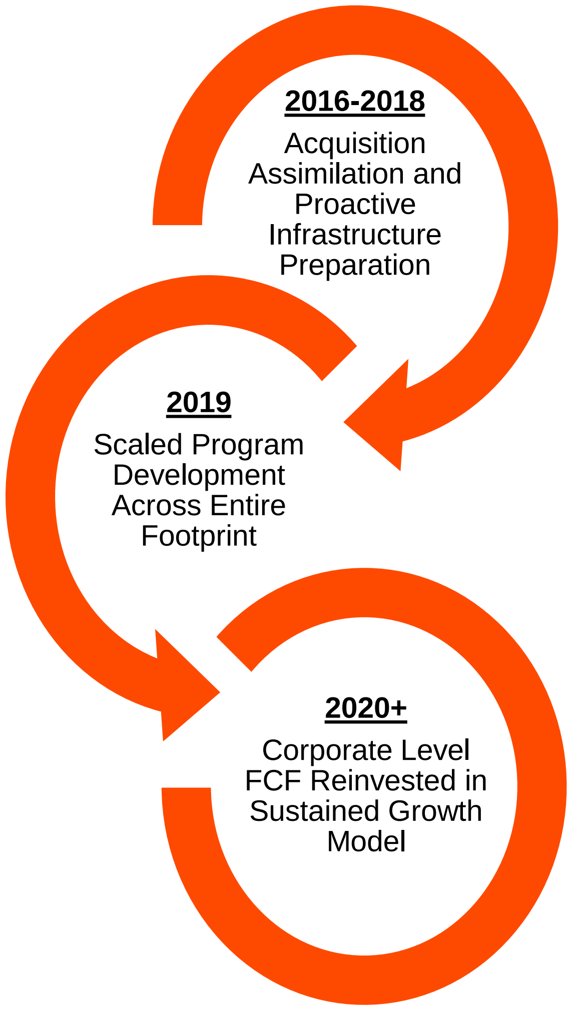
Asset value optimization

- Large-scale development
  - 1,500 gross operated locations in inventory
  - IRR threshold > 25% for delineated inventory
- Rationalize and extract value from water/facilities investments and tail-end inventory
  - Accelerate NPV and improve corporate-level returns
  - Leverage non-operated acreage as currency

FCF and sustainable value creation

- Convert field level free cash flow into corporate level free cash flow
  - Margin improvement and increase D&C as % overall CAPEX
  - Benefits of larger scale pads
  - Corporate-level FCF targeted for 2H19
- FCF deployment
  - Aligned to long-term shareholder value creation
  - Commitment to improving leverage metrics

LONGER-TERM OUTLOOK



APPENDIX

INDUSTRY LEADING MARGINS CONTINUE TO IMPROVE

MARGIN EXPANSION

Industry leading operating margins

- Per unit cash margins of $39.05 improved 30% YoY (1)
- Cash G&A of $2.17/Boe declined ~20% sequentially
- Adj. EBITDA(2) of $118.4MM represented 15%+ Q/Q growth despite 8% Q/Q decline in unhedged realized oil prices

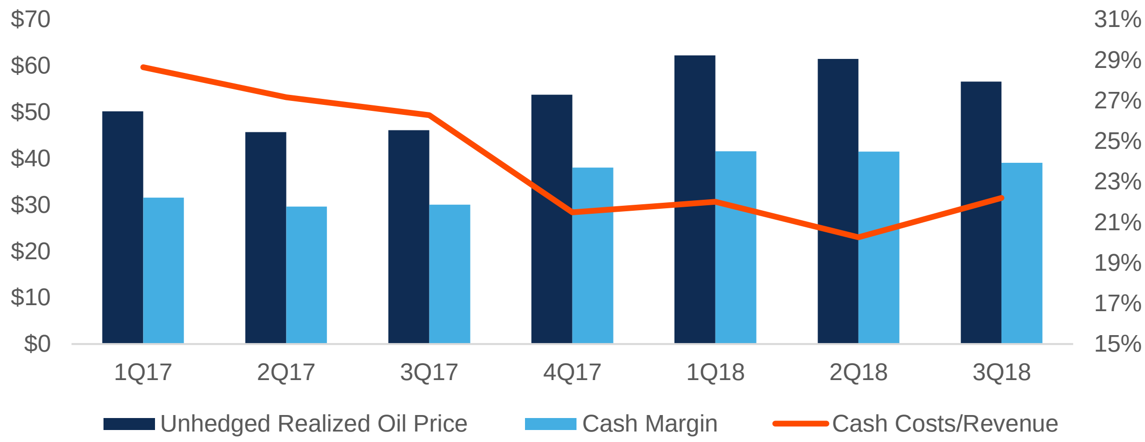
Acreage quality and operational excellence

- 3Q'18 Adj. EBITDA(X)/Boe expanded to $36.86/Boe(2), representing 23% margin growth YoY
- During 1H'18, CPE achieved the highest Bloomberg standardized Adj. EBITDAX/Boe operating margin across publicly traded E&Ps (2)(3)

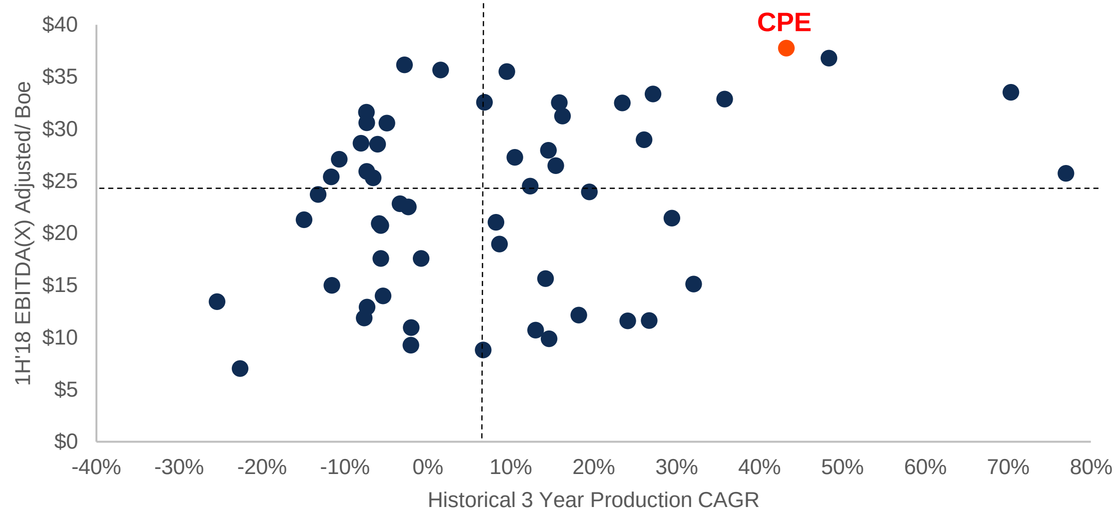
Strengthened strategic partnerships with focus on capital efficiency

- Renegotiated terms for meaningful price improvement
- Extended term for 2 fleets, receiving price certainty for the next five quarters
- Optionality to move from 30% to 100% in-basin sand for the Delaware at YE'18

COST IMPROVEMENTS DRIVING OPERATING RETURNS



CAPITAL EFFICIENT PRODUCTION GROWTH WITH SUPERIOR MARGINS (3)



1. Cash operating costs include Lease Operating Expenses, Production Taxes, and Cash G&A.
2. Based on CPE calculated Adjusted EBITDA(X), 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.

OIL HEDGE PORTFOLIO [1]

	4Q18	1Q19	2Q19	3Q19	4Q19	2020
NYMEX WTI (Bbls, $/Bbl)						
Swaps						
Total Volumes	552,000	-	-	-	-	-
Daily Volumes	6,000	-	-	-	-	-
Avg. Swap	$52.07	-	-	-	-	-
Three-way Collars						
Total Volumes	874,000	810,000	819,000	920,000	920,000	-
Daily Volumes	9,500	9,000	9,000	10,000	10,000	-
Avg. Short Call	$60.86	$63.71	$63.71	$63.70	$63.70	-
Avg. Long Put	$48.95	$53.89	$53.89	$54.00	$54.00	-
Avg. Short Put	$39.21	$43.89	$43.89	$44.00	$44.00	-
Two-way Collars						
Total Volumes	92,000	270,000	273,000	276,000	276,000	-
Daily Volumes	1,000	3,000	3,000	3,000	3,000	-
Avg. Short Call	$60.50	$80.00	$80.00	$80.00	$80.00	-
Avg. Put	$50.00	$65.00	$65.00	$65.00	$65.00	-
Deferred Premium Put Options						
Total Volumes	276,000	450,000	455,000	460,000	460,000	-
Daily Volumes	3,000	5,000	5,000	5,000	5,000	-
Avg. Long Put	$65.00	$65.00	$65.00	$65.00	$65.00	-
Avg. Premium	$2.26	$6.45	$6.45	$6.45	$6.45	-
Total Volume Hedged	1,794,000	1,530,000	1,547,000	1,656,000	1,656,000	-
Average Ceiling Price	$57.64	$67.78	$67.78	$67.46	$67.46	-
Average Floor Price	$52.43	$59.12	$59.12	$58.89	$58.89	-
MIDLAND-CUSHING DIFFERENTIAL (Bbls/$/Bbl)						
Swaps						
Total Volumes	1,518,000	1,125,000	1,137,500	1,242,000	1,242,000	4,024,000
Daily Volumes	16,500	12,500	12,500	13,500	13,500	10,995
Avg. Swap	($5.30)	($5.74)	($5.74)	($3.78)	($3.78)	($1.51)

1. Hedge contracts as of 11/06/2018.

CAP

GAS HEDGE PORTFOLIO (1)

	4Q18	1Q19	2Q19	3Q19	4Q19	2020
NYMEX Henry Hub (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	1,380,000	-	-	-	-	-
Daily Volumes	15,000	-	-	-	-	-
Avg. Swap	$2.91	-	-	-	-	-
Two-way Collars						
Total Volumes	552,000	1,485,000	1,046,500	598,000	598,000	-
Daily Volumes	6,000	16,500	11,500	6,500	6,500	-
Avg. Short Call	$3.19	$3.28	$3.13	$2.95	$2.95	-
Avg. Put	$2.75	$2.79	$2.69	$2.65	$2.65	-
Total Volume Hedged	1,932,000	1,485,000	1,046,500	598,000	598,000	-
Average Ceiling Price	$2.99	$3.28	$3.13	$2.95	$2.95	-
Average Floor Price	$2.86	$2.79	$2.69	$2.65	$2.65	-

	4Q18	1Q19	2Q19	3Q19	4Q19	2020
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	552,000	2,340,000	2,366,000	2,392,000	2,392,000	2,196,000
Daily Volumes	6,000	26,000	26,000	26,000	26,000	6,000
Avg. Swap	($1.14)	($1.25)	($1.25)	($1.25)	($1.25)	($1.14)

1. Hedge contracts as of 11/06/2018.

QUARTERLY CASH FLOW STATEMENT

	3Q17	4Q17	1Q18	2Q18	3Q18
Cash flows from operating activities:					
Net income	$ 17,081	$ 22,824	$ 55,761	$ 50,474	$ 37,931
Adjustments to reconcile net income to cash provided by operating activities:					
Depreciation, depletion and amortization	29,132	37,222	36,066	39,387	48,977
Accretion expense	131	154	218	206	202
Amortization of non-cash debt related items	441	455	453	588	708
Deferred income tax expense	237	247	495	481	1,487
(Gain) loss on derivatives, net of settlements	12,947	26,037	(3,978)	8,572	25,100
Loss on sale of other property and equipment	—	—	—	22	(102)
Non-cash expense related to equity share-based awards	1,219	1,240	1,131	1,627	1,708
Change in the fair value of liability share-based awards	732	865	1,012	(463)	879
Payments to settle asset retirement obligations	(250)	(216)	(366)	(207)	(507)
Changes in current assets and liabilities:					
Accounts receivable	(4,338)	(32,347)	(8,067)	10,447	(56,764)
Other current assets	(38)	444	61	(5,611)	3,885
Current liabilities	1,854	23,413	12,938	4,123	47,741
Other long-term liabilities	1	—	87	200	5,500
Long-term prepaid	(4,650)	—	—	—	—
Other assets, net	(606)	(152)	(507)	(181)	(709)
Payments to settle vested liability share-based awards	—	—	(3,089)	(1,901)	—
Net cash provided by operating activities	53,893	80,186	92,215	107,764	116,036
Cash flows from investing activities:					
Capital expenditures	(121,128)	(152,621)	(111,330)	(187,040)	(156,982)
Acquisitions	(8,015)	(3,952)	(38,923)	(6,469)	(550,592)
Acquisition deposit	—	(900)	900	(28,500)	27,600
Proceeds from sales of mineral interests and equipment	—	20,525	—	3,077	5,249
Net cash used in investing activities	(129,143)	(136,948)	(149,353)	(218,932)	(674,725)
Cash flows from financing activities:					
Borrowings on senior secured revolving credit facility	—	25,000	80,000	85,000	105,000
Payments on senior secured revolving credit facility	—	—	(30,000)	(160,000)	(40,000)
Issuance of 6.375% senior unsecured notes due 2026	—	—	—	400,000	—
Issuance of common stock	—	—	—	288,357	7
Payment of preferred stock dividends	(1,824)	(1,824)	(1,824)	(1,824)	(1,823)
Payment of deferred financing costs	(401)	(28)	—	(8,664)	(1,296)
Tax withholdings related to restricted stock units	(65)	—	(560)	(1,028)	(216)
Net cash provided by (used in) financing activities	(2,290)	23,148	47,616	601,841	61,672
Net change in cash and cash equivalents	(77,540)	(33,614)	(9,522)	490,673	(497,017)
Balance, beginning of period	139,149	61,609	27,995	18,473	509,146
Balance, end of period	$ 61,609	$ 27,995	$ 18,473	$ 509,146	$ 12,129

NON-GAAP RECONCILIATION [1]

	3Q17	4Q17	1Q18	2Q18	3Q18
Adjusted Income Reconciliation					
Income available to common stockholders	$ 15,257	$ 21,001	$ 53,937	$ 48,650	$ 36,108
Adjustments:					
Net (gain) loss on derivatives, net of settlements	12,947	26,037	(3,978)	8,572	25,100
Change in the fair value of share-based awards	732	865	1,012	(463)	879
Tax effect on adjustments above	(4,788)	(9,416)	622	(1,703)	(5,456)
Change in valuation allowance	(6,064)	(8,285)	(11,753)	(10,562)	(8,323)
Adjusted Income	$ 18,084	$ 30,202	$ 39,840	$ 44,494	$ 48,308
Adjusted Income per fully diluted common share	$ 0.09	$ 0.15	$ 0.20	$ 0.21	$ 0.21
Adjusted EBITDA Reconciliation					
Net income	$ 17,081	$ 22,824	$ 55,761	$ 50,474	$ 37,931
Adjustments:					
Net (gain) loss on derivatives, net of settlements	12,947	26,037	(3,978)	8,572	25,100
Non-cash stock-based compensation expense	1,952	2,101	2,143	1,164	2,587
Acquisition expense	205	(112)	548	1,767	1,435
Income tax expense	237	248	495	481	1,487
Interest expense	444	461	460	594	711
Depreciation, depletion and amortization	29,132	37,222	36,066	39,387	48,977
Accretion expense	131	154	218	206	202
Adjusted EBITDA	$ 62,129	$ 88,935	$ 91,713	$ 102,645	$ 118,430

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

NON-GAAP RECONCILIATION (1)

	3Q17	4Q17	1Q18	2Q18	3Q18
Adjusted G&A Reconciliation					
Total G&A expense	$ 7,259	$ 8,173	$ 8,769	$ 8,289	$ 9,721
Adjustments:					
Less: Change in the fair value of liability share-based awards (non-cash)	(731)	(844)	(991)	484	(921)
Adjusted G&A – total	6,528	7,329	7,778	8,773	8,800
Less: Restricted stock share-based compensation (non-cash)	(1,198)	(1,202)	(1,105)	(1,587)	(1,730)
Less: Corporate depreciation & amortization (non-cash)	(146)	(125)	(124)	(109)	(102)
Adjusted G&A – cash component	$ 5,184	$ 6,002	$ 6,549	$ 7,077	$ 6,968
Adjusted Total Revenue Reconciliation					
Oil revenue	$ 73,349	$ 104,132	$ 115,286	$ 122,613	$ 142,601
Natural gas revenue	11,265	14,081	12,154	14,462	18,613
Total revenue	84,614	118,213	127,440	137,075	161,214
Impact of settled derivatives	(1,214)	(4,501)	(8,459)	(7,980)	(9,239)
Adjusted Total Revenue	$ 83,400	$ 113,712	$ 118,981	$ 129,095	$ 151,975
Total Production (Mboe)	2,074	2,439	2,391	2,635	3,212
Adjusted Total Revenue per Boe	$ 40.21	$ 46.62	$ 49.76	$ 48.99	$ 47.31
Discretionary Cash Flow Reconciliation					
Net cash provided by operating activities	$ 53,893	$ 80,186	$ 92,215	$ 107,764	$ 116,036
Changes in working capital	7,777	8,642	(4,512)	(8,978)	347
Payments to settle asset retirement obligations	250	216	366	207	507
Payments to settle vested liability share-based awards	—	—	3,089	1,901	—
Discretionary cash flow	$ 61,920	$ 89,044	$ 91,158	$ 100,894	$ 116,890

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