CALLON
PETROLEUM

INVESTOR PRESENTATION

APRIL 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. Words such as “estimate,” “project,” “will,” “may,” “anticipate,” “plan,” “intend,” “believe,” “expect,” “outlook,” “guidance,” “target,” “objective” 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 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”). 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.

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, exploration expense, (gains) losses on derivative instruments excluding net cash receipts (payments) on settled derivative instruments and premiums paid for put options that settled during the period, impairment of oil and natural gas properties, non-cash equity based compensation, asset retirement obligation accretion expense, other income, gains and losses from the sale of assets and other non-cash operating items. Adjusted EBITDA is not a measure of net income as determined by United States generally accepted accounting principles (‘‘GAAP’’).

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 below. Prior to being tax-effected and excluded, the amounts reflected in the determination of Adjusted income and Adjusted income per diluted share below were computed in accordance with GAAP.

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. 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.

For a reconciliation of non-GAAP measures to their most directly comparable GAAP measure, please see schedules included in the Appendix.

Important Disclosures

Reserve-Related Disclosures

Cautionary Note to U.S. Investors: The Securities and Exchange Commission ("SEC") prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than "reserves," as that term is defined by the SEC. This presentation discloses estimates of quantities of oil and gas using certain terms, such as "resource potential," "net recoverable resource potential," "resource base," "estimated ultimate recovery," "EUR" or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC's definitions of proved, probable and possible reserves, and which the SEC's guidelines strictly prohibit the Company from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by the Company. U.S. investors are urged to consider closely the disclosures in the Company's periodic filings with the SEC. Such filings are available from the Company at 1401 Enclave Pkwy, Ste 600, Houston, TX 77077, Attention: Investor Relations, and the Company's website at www.callon.com. These filings also can be obtained from the SEC by calling 1-800-SEC-0330.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms, and price and cost sensitivities for such reserves, and prohibits disclosure of resources that do not constitute such reserves. The Company uses the terms "estimated ultimate recovery" (or "EUR") that the SEC's rules may prohibit the Company from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves, and accordingly are subject to substantially greater risk of being realized by the Company.

EUR estimates and potential horizontal well locations have not been risked by the Company. Actual locations drilled and quantities that may be ultimately recovered from the Company's interest may differ substantially from the Company's estimates. There is no commitment by the Company to drill all of the potential horizontal drilling locations. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling and completion services and equipment, drilling results, commodity price levels, lease expirations, regulatory approval and actual drilling results, as well as geological and mechanical factors. Estimates of type/decline curves and per-well EURs may change significantly as development of the Company's oil and gas assets provides additional data.

Type/decline curves, estimated EURs, recovery factors and well costs represent Company estimates based on evaluation of petrophysical analysis, core data and well logs, well performance from existing drilling and recompletion results and seismic data, and have not been reviewed by independent engineers. These are presented as hypothetical recoveries if assumptions and estimates regarding recoverable hydrocarbons, recovery factors and costs prove correct. As a result, such estimates may change significantly as results from more wells are evaluated. Estimates of EURs do not constitute reserves, but constitute estimates of contingent resources that the SEC has determined are too speculative to include in SEC filings. Unless otherwise noted, Internal Rate of Return (or "IRR") and Net Present Value (or "NPV") estimates are before taxes and assume Company-generated EUR and decline curve estimates based on Company drilling and completion cost estimates that do not include land, seismic, G&A or other corporate level costs.

Investors are urged to consider closely the disclosure in our Form 10-K and other reports filed with the SEC, available on our website or by request by contacting Investor Relations: Callon Petroleum Company, 1401 Enclave Parkway, Suite 600, Houston, TX 77077. You may also email the Company at ir@callon.com.

You can also obtain our Form 10-K and other reports filed with the SEC by contacting the SEC directly at 1-800-SEC-0330 or by downloading it from the SEC's web site http://www.sec.gov.

Callon Petroleum

4Q17 RESULTS

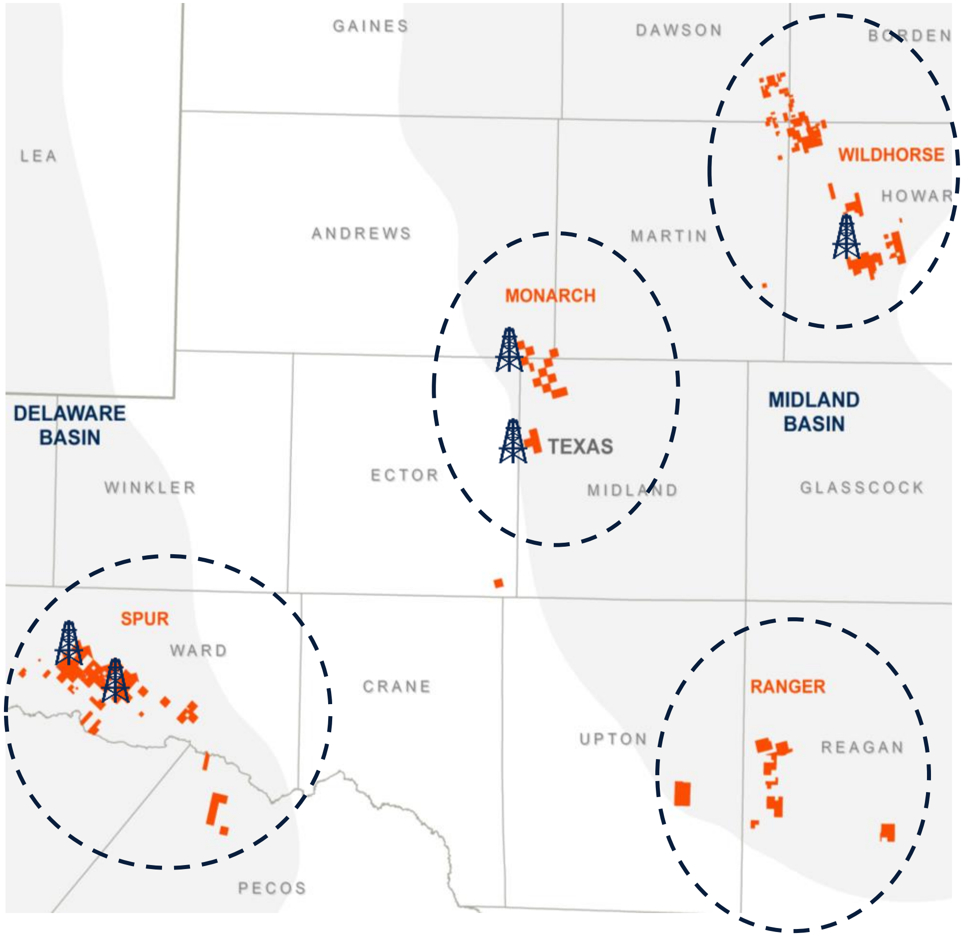
- 4Q17 production of 26.5 Mboe/d
  - Oil mix of 79%
  - Sequential oil growth of 22%
- Operating Margin of $40.51 per Boe (~80%)
- LOE per Boe $4.84 [1] ($5.41 including G&T)

YE17 HIGHLIGHTS

- 50% annual production growth
- 53% y/y oil production growth
- Total proved reserves of 137 MMBoe
  - 50% increase from 2016
  - 51% PDP / 78% oil
  - PD PV-10 [3] of $1.03 billion
- Drill-bit F&D [2] cost of $8.42 per Boe (2-stream)

Key Statistics [4]	
Shares Outstanding	201 MM
Market Capitalization	$2.5 B
Net Debt	$0.6 B
Enterprise Value	$3.1 B
YE 2017 PV-10 [3]	$1.6 B
Net Debt/4Q17 Annualized EBITDA	1.7x

CURRENT RIG ACTIVITY



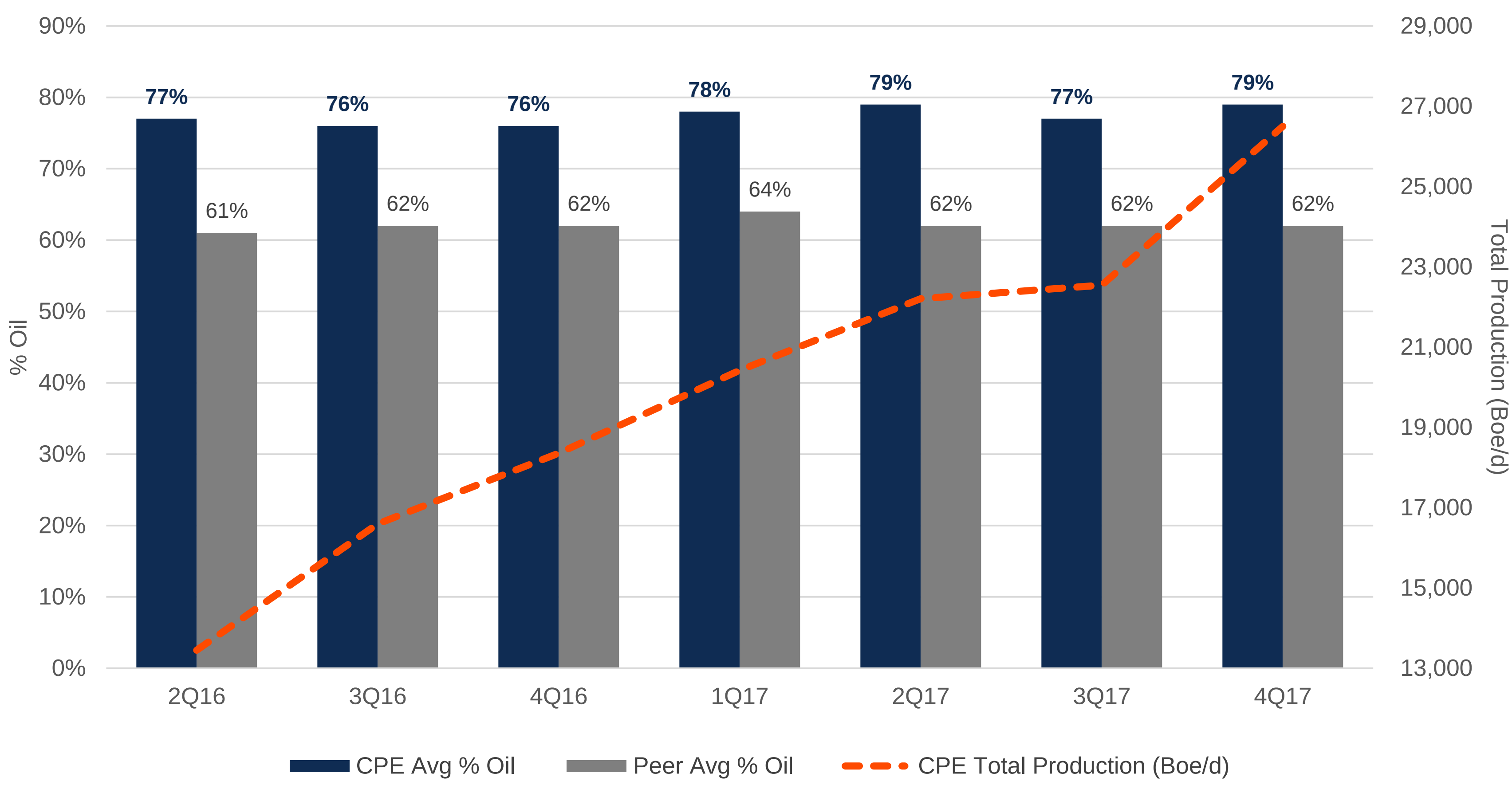
~ 60,000 NET ACRES

1,400 "DELINEATED & OPERATED" INVENTORY LOCATIONS

1. LOE figures do not include gathering and treating expense of $0.57 per Boe.
2. Drill Bit F&D calculated as cash costs incurred for exploration and development divided by sum of extensions and discoveries.
3. PV-10 is a non-GAAP measure. See Important Disclosures.
4. Statistical measures for Market Capitalization and Enterprise Value are as of market close on Apr 05, 2018.

Quarterly Production

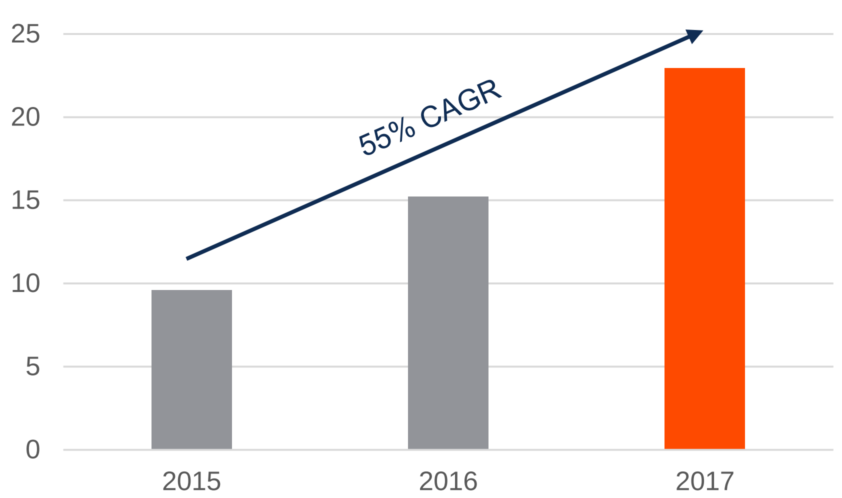
Callon has delivered sustained, sequential production growth while consistently outpacing peers on oil content



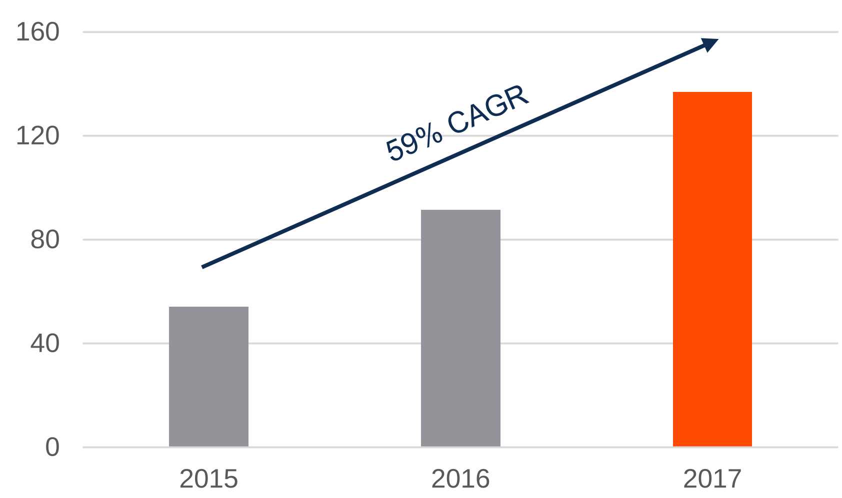
Note: Peers include CXO, EGN, FANG, LPI , MTDR, PE, and RSPP.

Consistent, Solid Execution

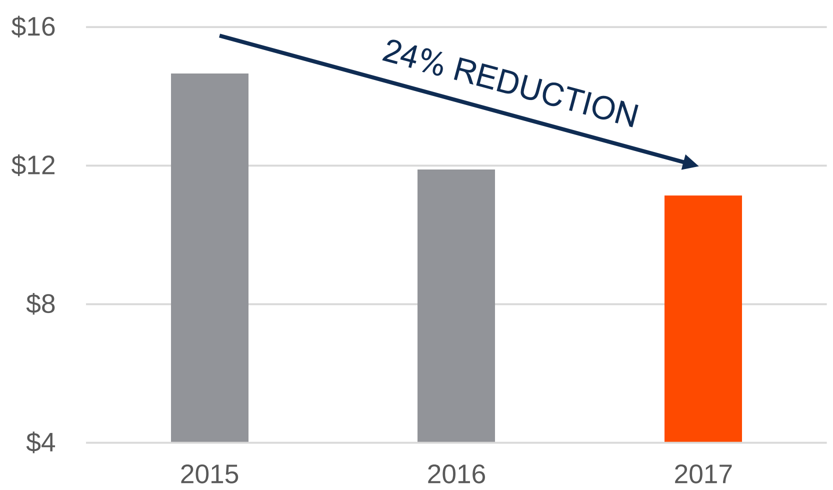
PRODUCTION GROWTH (MBOE)



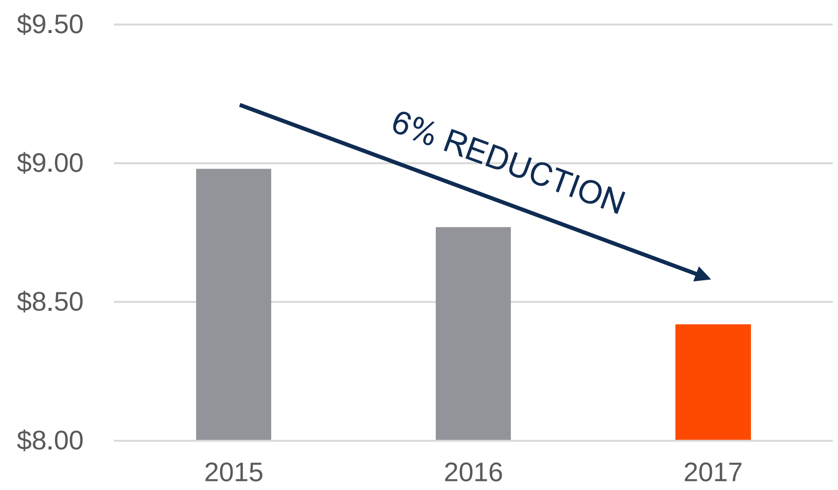
RESERVE GROWTH (MMBOE)



OPERATING CASH COST IMPROVEMENT [1]



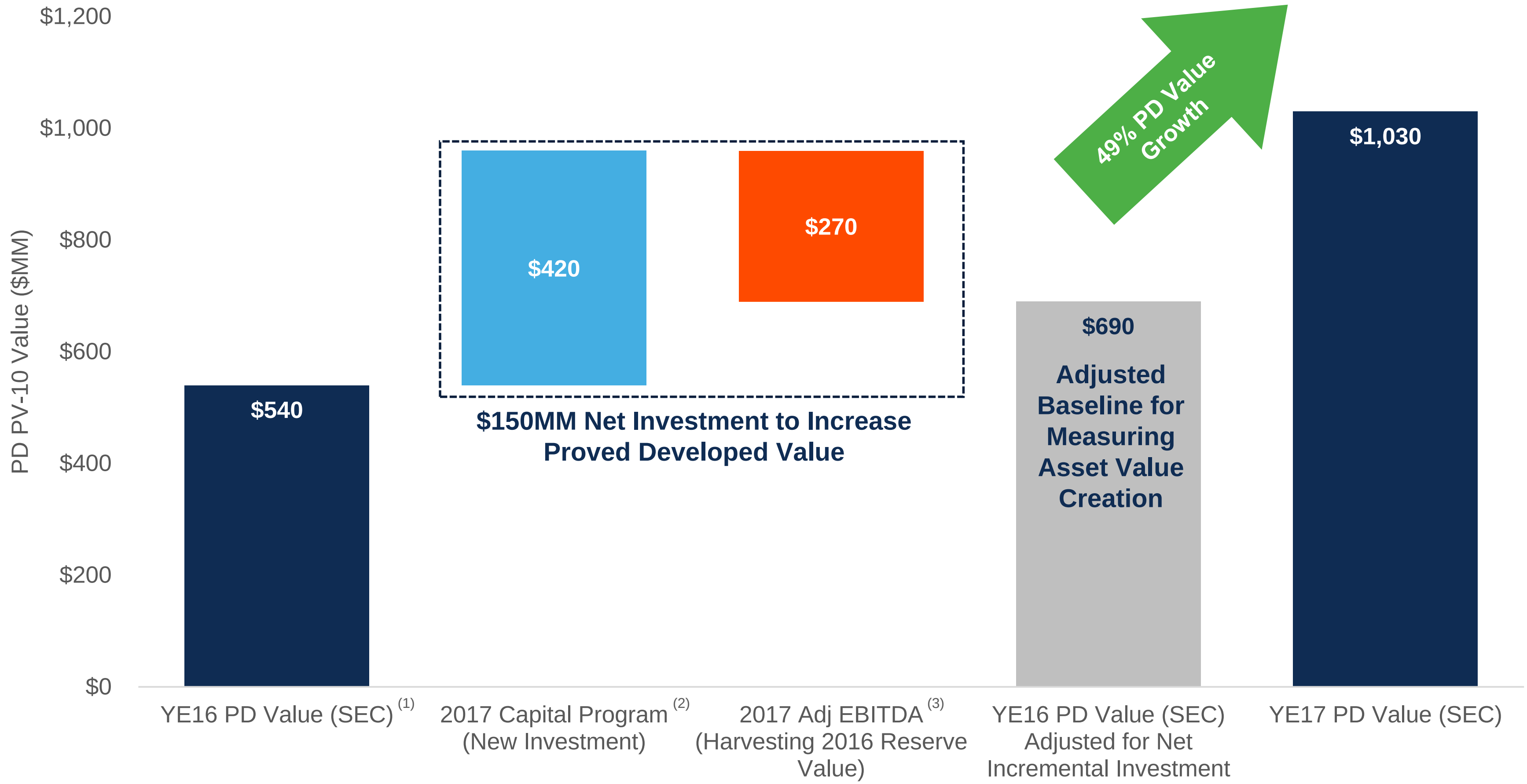
DRILL-BIT F&D IMPROVEMENT ($/BOE) [2]



1. Cash operating costs include LOE, production taxes, and cash G&A.
2. Drill Bit F&D calculated as cash costs incurred for exploration and development divided by sum of extensions and discoveries.

Organic Value Creation

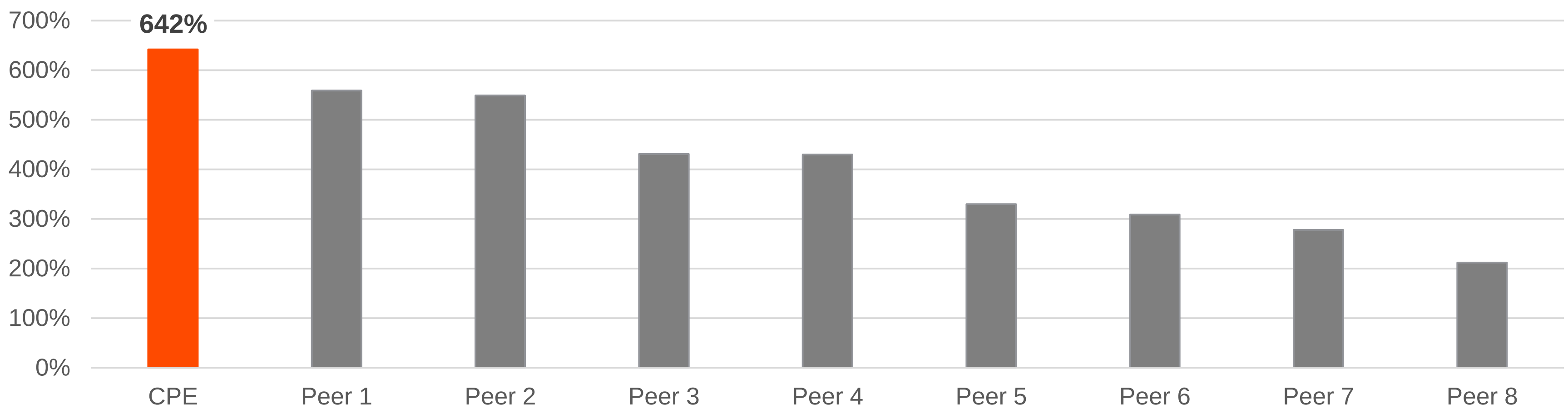
YE17 PD Value (SEC)	$1,030
Less: YE16 PD Value (SEC)	(540)
Total Value Increase	$490
Net Investment	$150
Total Value Increase / Net Investment	**3.3x**



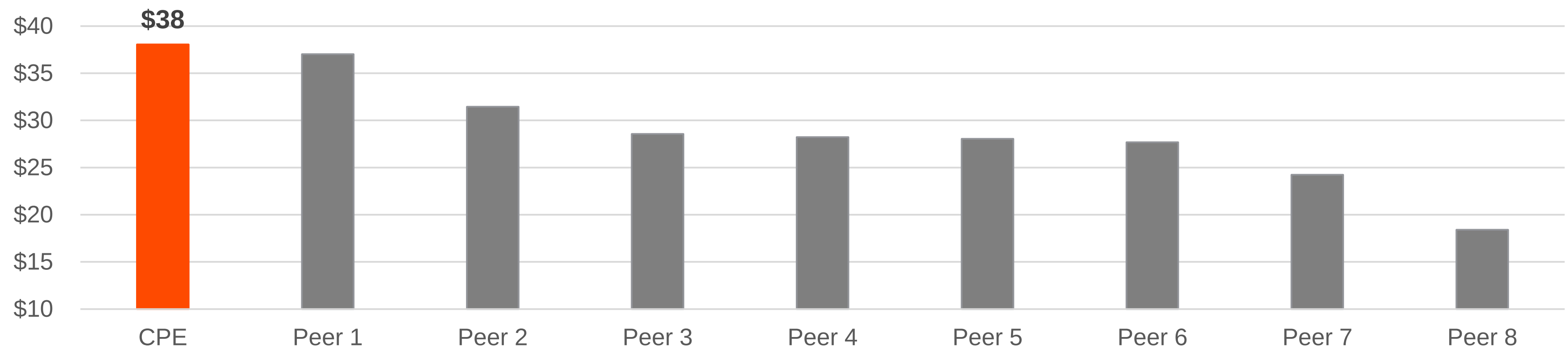
1. Pro forma for PD acquisitions.
2. Includes capitalized G&A.
3. See "Important Disclosures" slides for disclosures related to Supplemental non-GAAP Financial Measures.

Highly Efficient Drilling with Leading Cash Margins

RESERVE REPLACEMENT RATIO VERSUS PEERS [1]

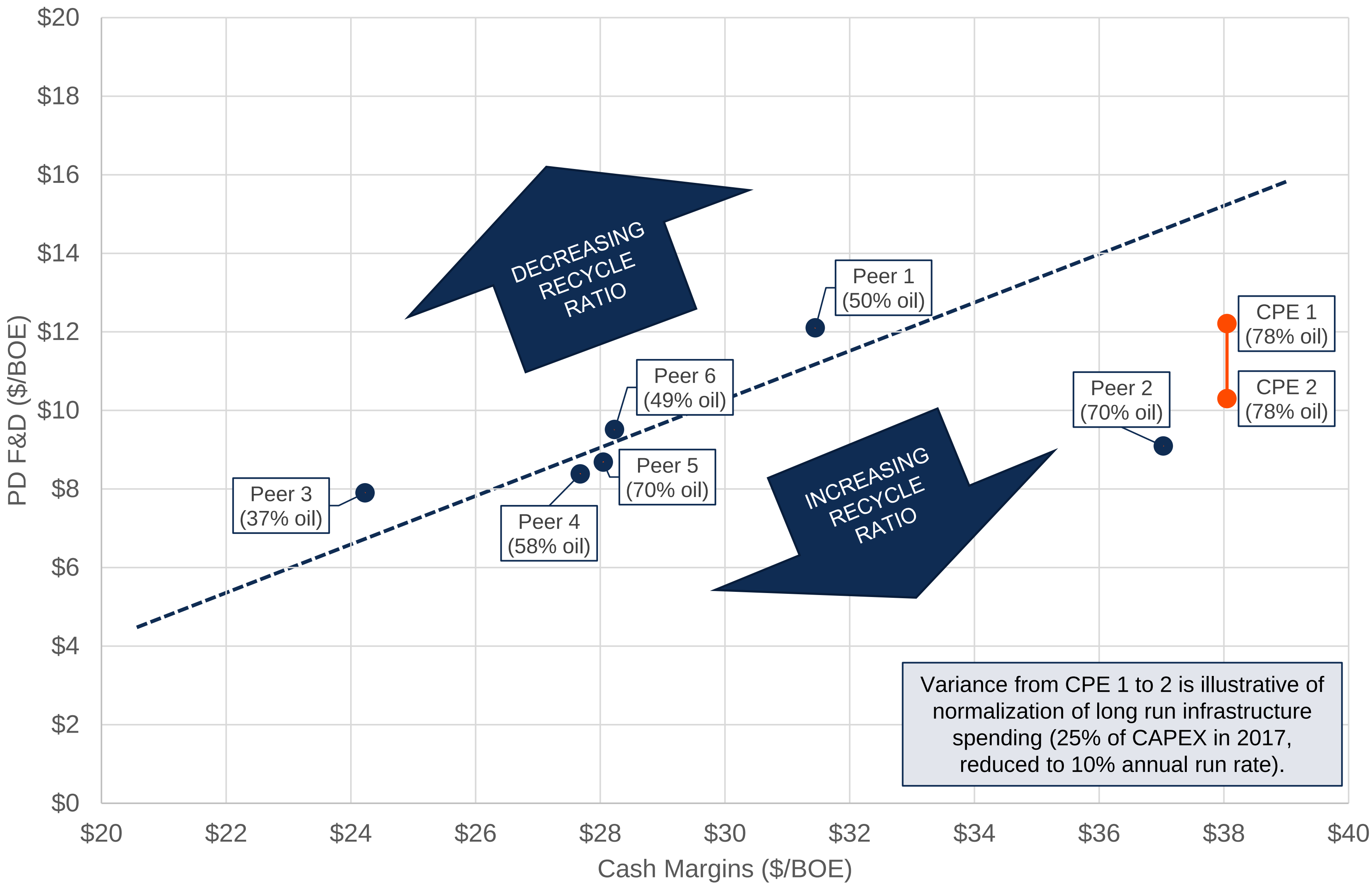


4Q17 CASH MARGINS VERSUS PEERS ($/BOE) [2]



1. Reserve Replacement calculated as total annual reserve additions, net of revisions (MBOE) divided by production (MBOE). Peer group data as of most recent quarterly filing. Peers include CXO, EGN, FANG, LPI, MTDR, PE, PXD, SM.
2. Cash margins calculated as realized price per BOE less LOE, gathering & transportation, production taxes and cash G&A expenses per BOE. Peer group data as of most recent quarterly filing. Peer Group includes CXO, EGN, FANG, LPI, MTDR, PE, PXD, SM.

PD F&D vs 4Q17 Cash Margins (1)(2)

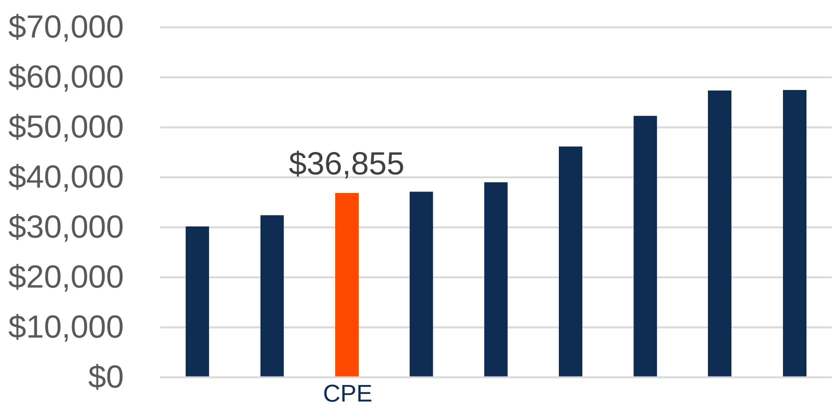


1. Cash margins calculated as realized price per BOE less LOE, G&T, production taxes and cash G&A expenses. Parenthetical references oil % of proved reserves.
2. PD F&D sourced from company investor presentations and press releases. Peers included: CXO, EGN, FANG, LPI, PE, PXD.

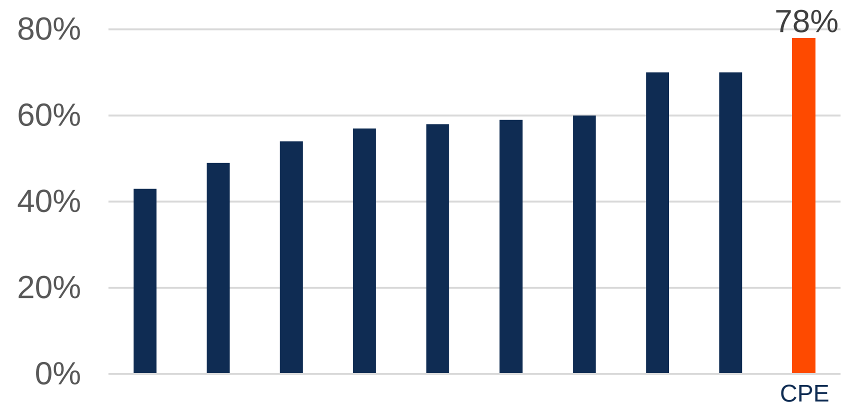
Compelling Valuation with Oil Exposure

After adjustment for proved developed value (2017 PDP PV-10), Callon trades at a discount, despite highest oil content and robust reserve life.

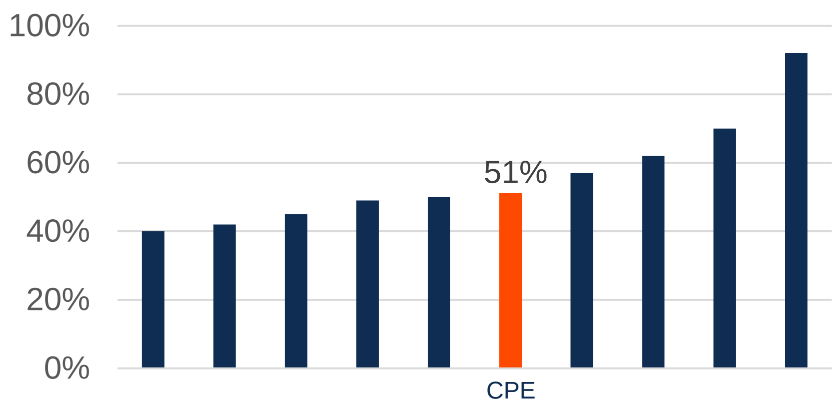
$/NET ACRE (EV LESS PDP PV-10 VALUE)



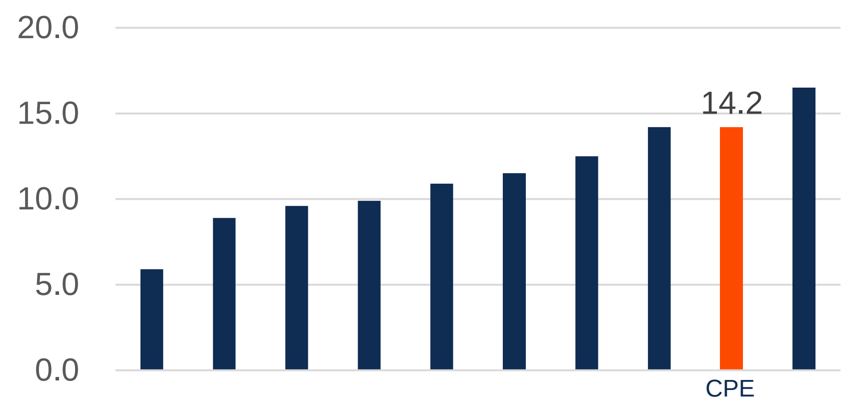
% OIL



% PROVED DEVELOPED



TOTAL 1P RESERVE / PRODUCTION (YEARS) AS OF 4Q17



Note: Peer set includes FANG, CDEV, REN, EGN, CXO, PE, MTDR and PXD.

Capital Deployment Across The Entire Portfolio

2018 DEVELOPMENT PLAN

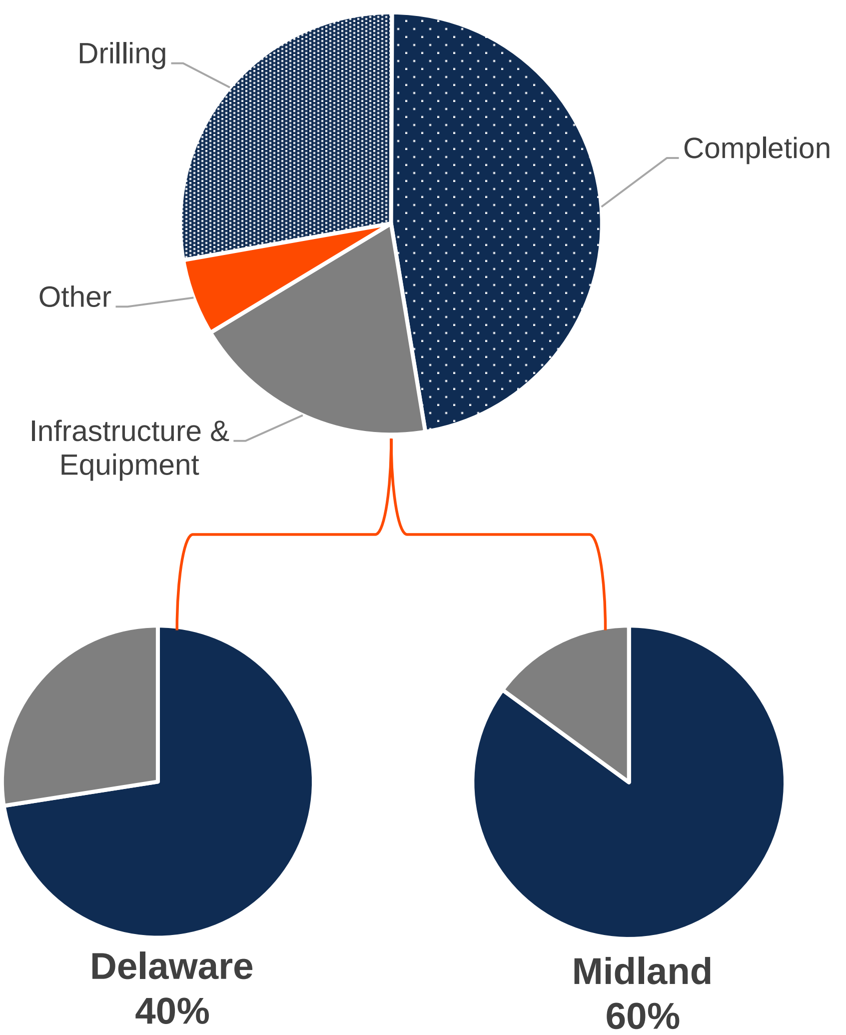
Operating plan is focused on increasing capital efficiency with a focus on development activity

- Increasing to 5 rigs with incremental Delaware activity / 2 dedicated completion crews
- Drilling focused on primary targets in each area
- Progression of larger pad development concepts
- Select delineation and down-spacing opportunities offer organic inventory growth without acquisition costs

Infrastructure and equipment investment continues to lower operating expenses and pave path for development

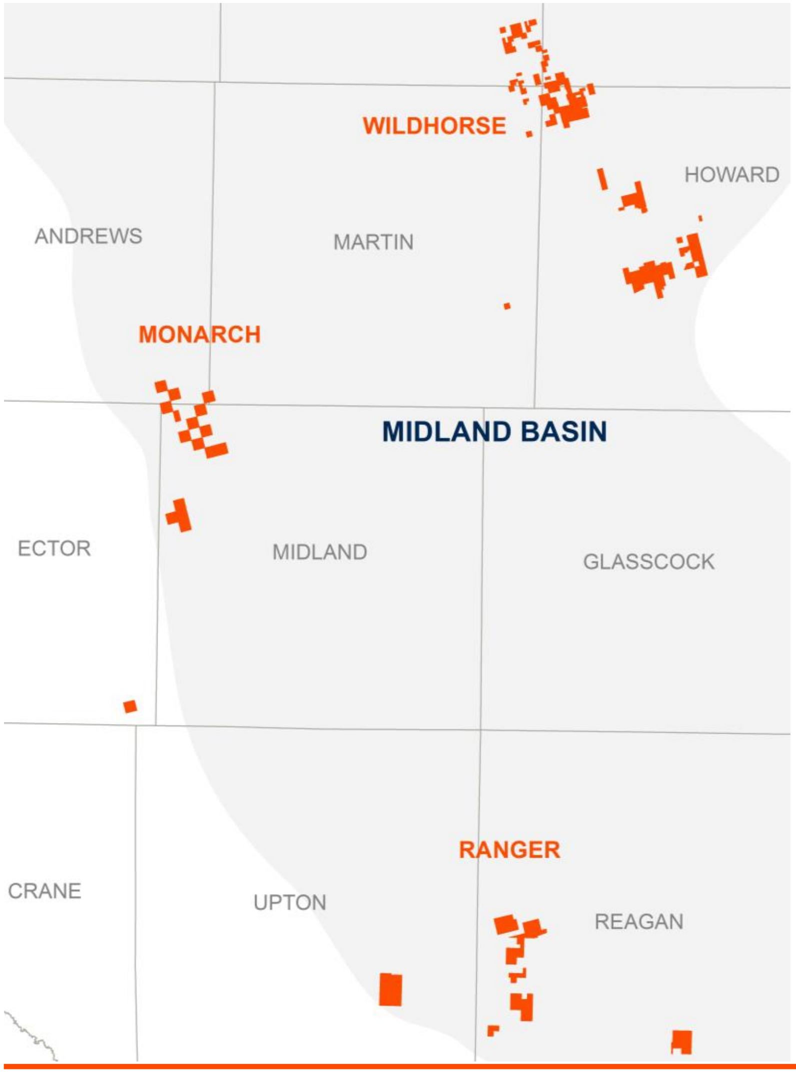
- Ahead of the curve on water sourcing and disposal issues
- Recycling program focus on Spur after Monarch success

OPERATIONAL CAPEX BUDGET OF $500-$540 MILLION



Midland Basin – Delineation and Development

MAJOR 2018 INITIATIVES IN THE MIDLAND



Focused on High Return/Potential Projects

- LSBY at Monarch
- WC A at WildHorse
- WC C at Ranger

WildHorse: Expanded drilling of WC A pads

- Testing down-spacing concept at roughly 460’ spacing (2 well pad), success could lead to 25% uplift in inventory
- Intra-basin sand testing during 1H18

Monarch: Continued focus on LSBY development

- Testing pad concept (6 wells, single zone) planned for 2018, with mid-year 1st production
- Established infrastructure allows recycling ramp in 2018, targeting capacity of 30k bwpd by year end

Ranger: Optimizing LWC B / Testing the Wolfcamp C

- Recent results by offset operators confirm broader productivity within WC C
- First Callon WC C on flowback along with 2 additional LWC B tests utilizing new generation completions
- Level of additional capital allocation dependent on well results

Delaware Basin – Increasing Activity

MAJOR 2018 INITIATIVES IN THE DELAWARE

2018 activity will focus primarily on WC A drilling with tests of WC C and 2nd BS Shale planned

- Activity level increase with entry of 2nd rig in mid-Q1
- Majority of production ramp in middle to 2nd half of year

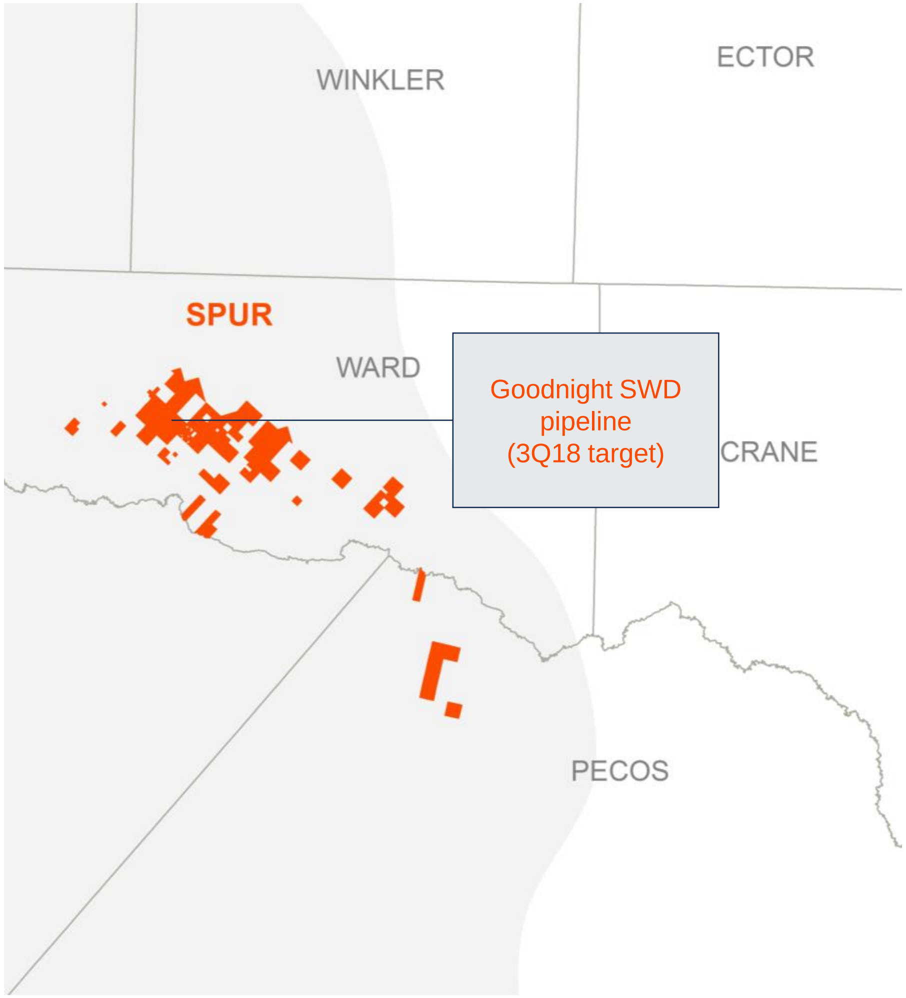
Majority of infrastructure investment to be completed by YE18

- Establish tank battery footprint
- Centralized water gathering system

Recent transactions (Brazos Midstream, Goodnight, Gravity) help to clear the path for efficient future development

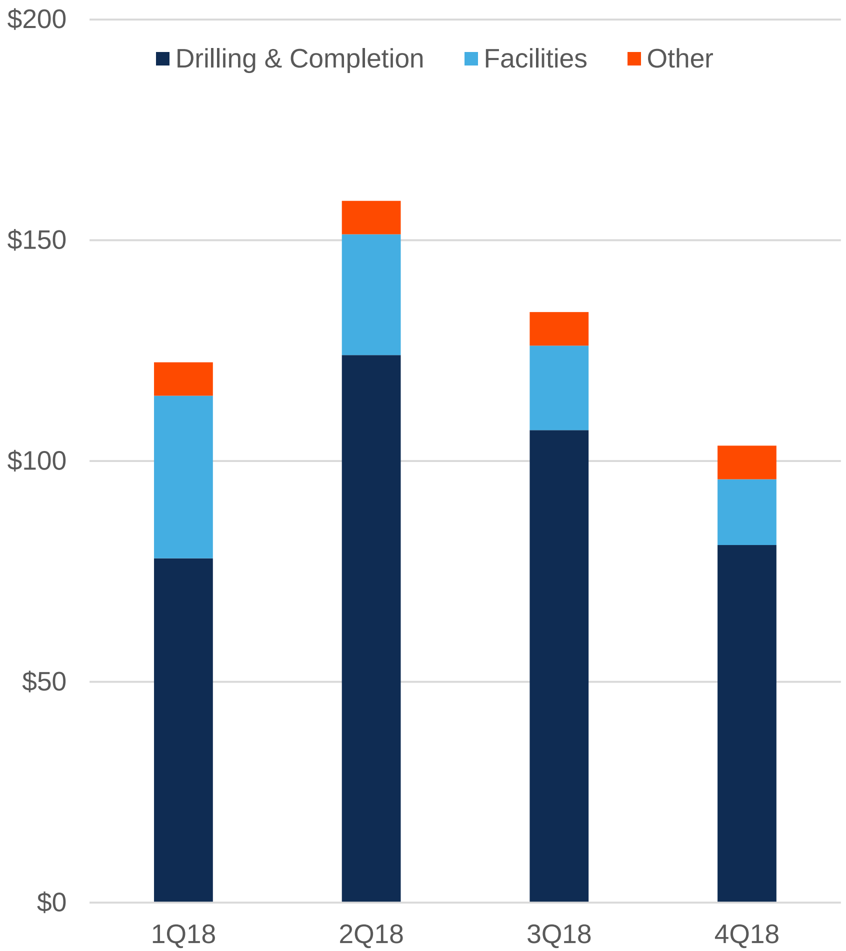
- Sourcing (Gravity) and disposal (Goodnight) deals ensure resource capacity for ramp in activity
- Water recycling program set to ramp during 2nd half of 2018 creating meaningful cost savings opportunities

Offset results surrounding Spur footprint have pointed to incremental opportunities in additional zones

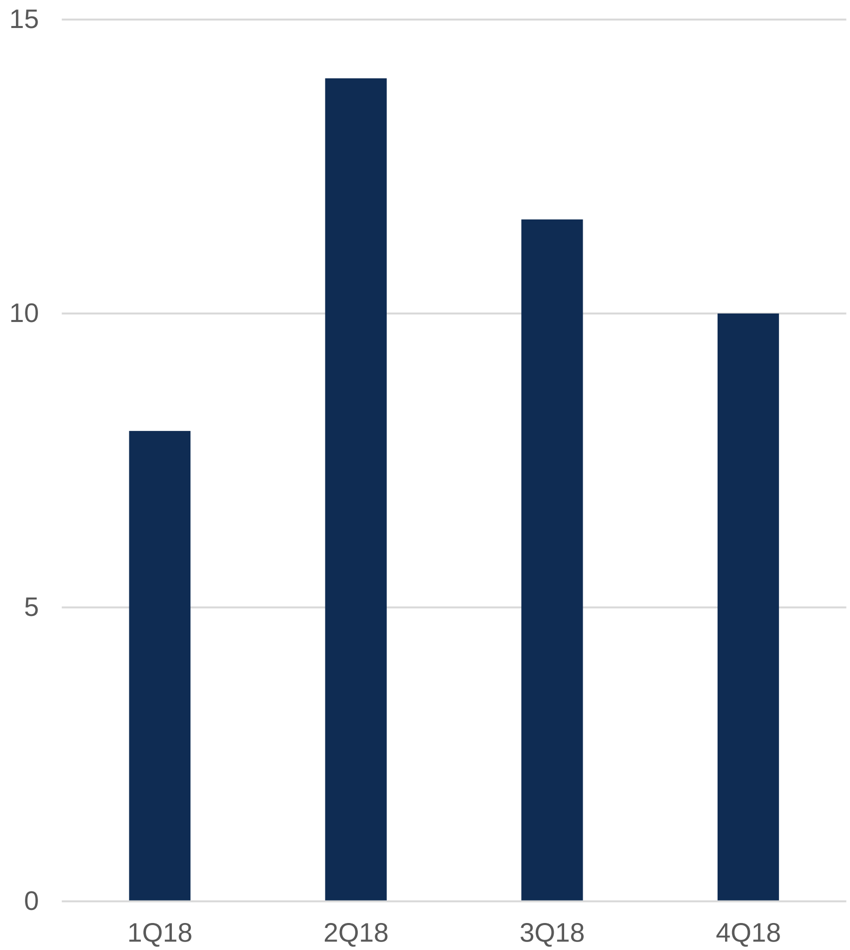


2018 Operational Activity

PROJECTED CAPITAL SPENDING ($MM) (1)



2018E NET WELLS PLACED ON PRODUCTION (2)



1. Charted figures for 2018 projected capital spending represent the midpoint of guidance for operational capital and other, excluding capitalized expenses.
2. Net wells placed on production represents timing expectations for net wells placed on production according to the mid-point of annual guidance.

2018 Infrastructure Projects

2018 DEVELOPMENT

2018 infrastructure focus primarily at Spur with increasing activity

- Tank batteries in new drilling units
- Water system connectivity

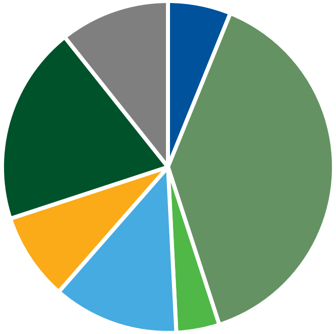
Leverage partnership structures to reduce capital investment

Past Midland Basin investment provides control of development pace

- Significant water infrastructure
- Nearly 100% of oil on pipe
- Larger tank batteries accommodate pad development

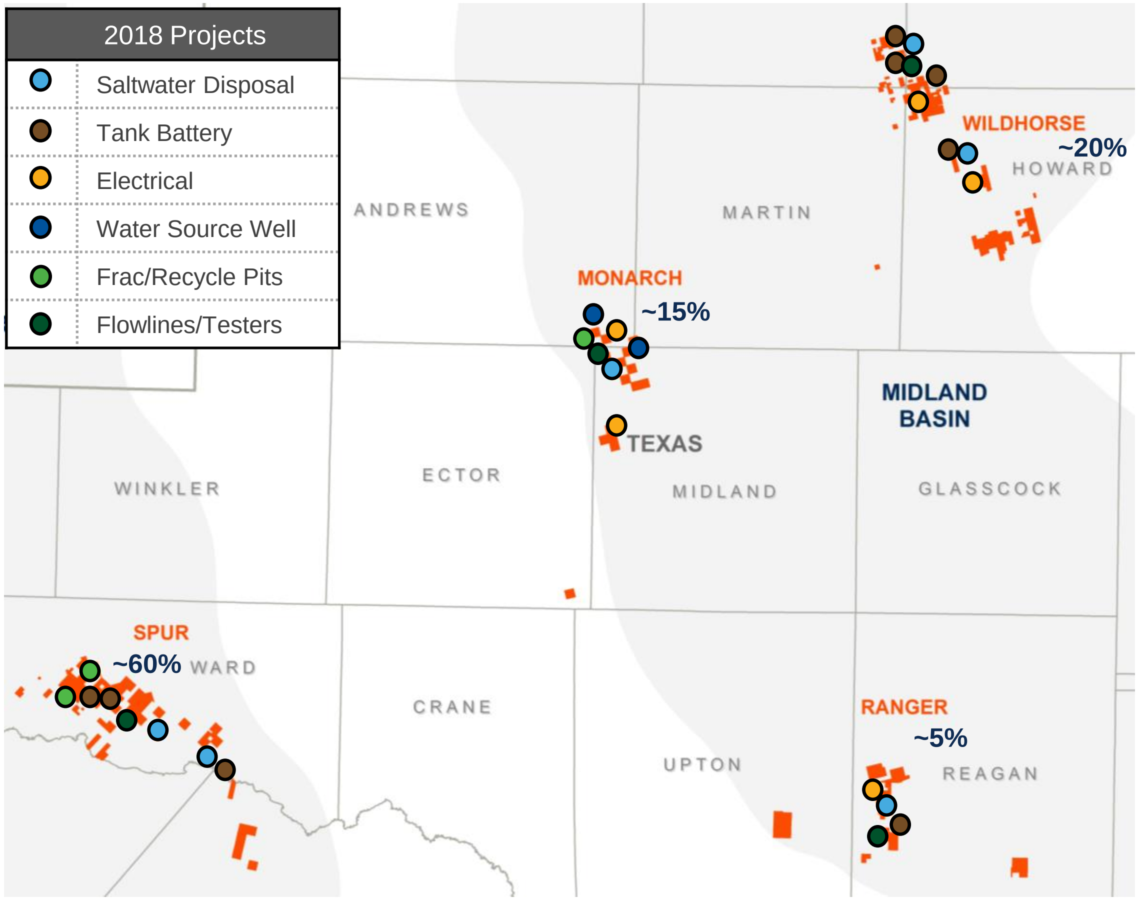
LOE benefits being realized

INFRASTRUCTURE BY CATEGORY [1]



MAJOR INFRASTRUCTURE PROJECTS

2018 Projects	
	Saltwater Disposal
	Tank Battery
	Electrical
	Water Source Well
	Frac/Recycle Pits
	Flowlines/Testers



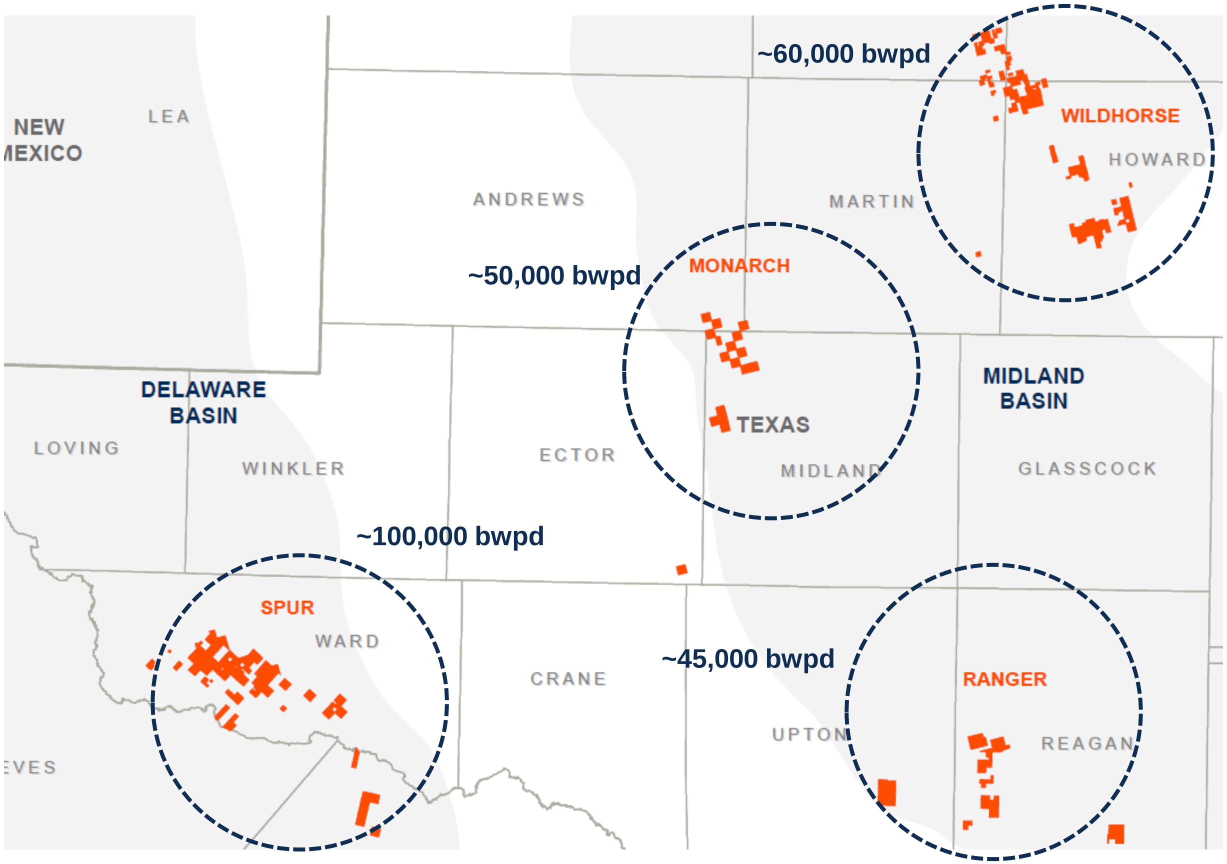
Note: "Other" includes Land, ESP, rod pump installation, and plug and abandonment.

Water Disposal as a Competitive Advantage

Between company owned and third party committed volumes, Callon has in excess of 400,000 bbl/d of water disposal capacity (excluding pending Goodnight project of 80,000 bbl/d)

Average CPE water disposal during February was ~90K Bwpd across the entire Permian footprint (25% of controlled capacity)

COMPANY OWNED AND OPERATED DISPOSAL CAPACITY BY AREA



WATER MANAGEMENT INITIATIVES

Strategic Water Handling Agreements

- Gravity – water sourcing (Wildhorse and Spur areas)
- Goodnight Midstream – Spur disposal pipeline to the CBP

Recycling Efforts

- Underway at Monarch, utilized on recently fracked wells **+40%** of sourced volumes
- Spur build-out progressing, goal of sourcing 50% of frac water volumes from recycling by year end

Incremental Capacity in Key Areas

- New Deep Ellenburger wells projected online at Ranger and Wildhorse during Q2 supplying significant incremental capacity

Commodity Flow Assurance Basin Wide

Multiple Deliverable Points Available

Delaware Gas Volumes

- Enters El Paso line past Waha (firm sales agreement) with back haul options to hub
- Second connection pending (mid-year) with FT to Waha via Whitewater
- February sales of less than 3 mmcf/d

Delaware Oil Volumes

- Gathered by Enterprise with additional connection to Medallion expected in May
- Reserved capacity on Medallion with ability to move to all primary delivery points (Crane, Midland, Colorado City, local refineries)

Midland Gas Volumes

- WTG, Enlink primarily (expansive delivery networks, multiple markets and plants)
- All sales are well head with NGL uplift add-back

Midland Oil Volumes

- Medallion primary gatherer with Plains, Enterprise, and Reliance as well
- Callon holds the capacity on Medallion system
- Sales are still at the wellhead

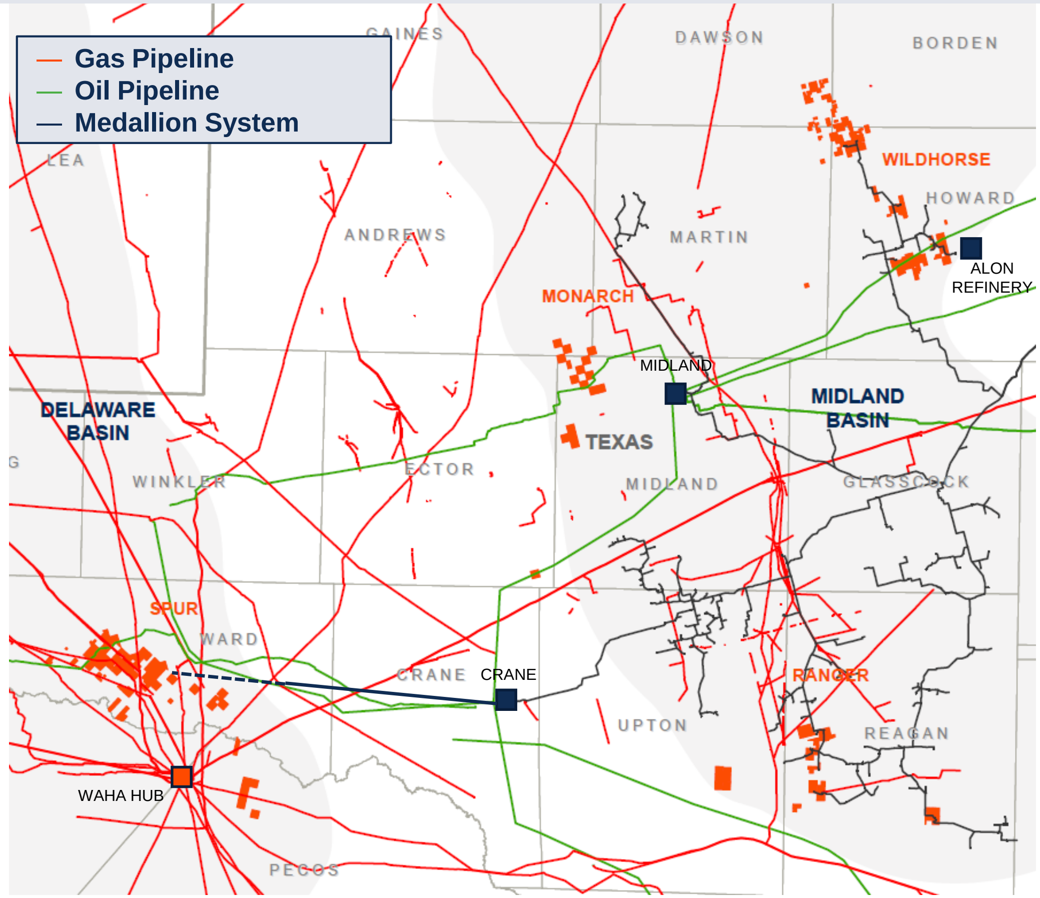
~40K bopd gathering commitments from 3 primary providers (multi-year term agreements)

7 primary oil purchasers (Plains, Enterprise, Shell, BP, etc.) with ~90% of volumes currently under term sales agreements

- Remaining volumes expected to be under term agreements within weeks

More than 90% of oil on pipe with additional tie-ins pending

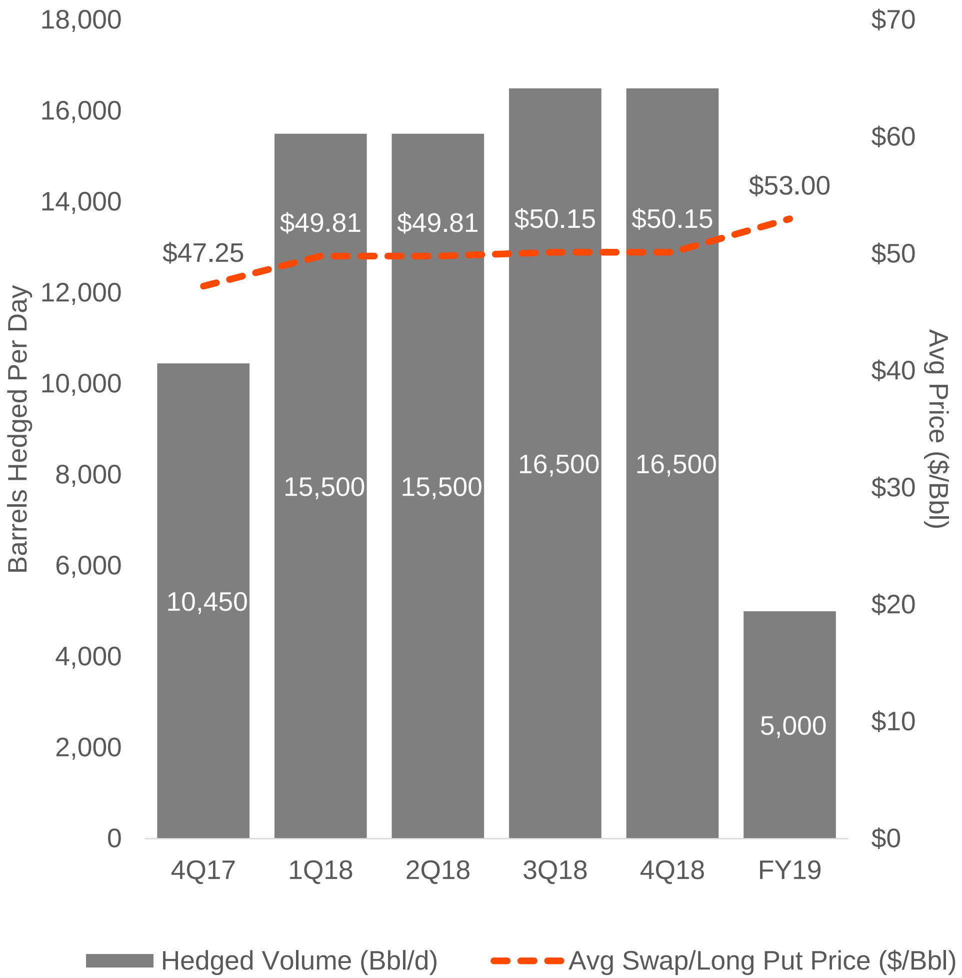
Commodity Flow Options for Callon Production



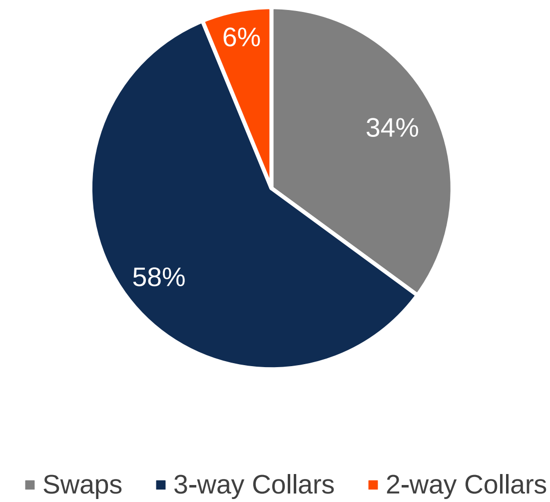
Oil	▪ ~40,000 bopd of term gathering contracts on 3 major networks provide access to all primary delivery points ▪ Sales to seven purchasers, including in-basin refineries
Gas	▪ Firm transport to Waha and downstream point in Delaware ▪ Well established, diversified network in Midland

Crude Oil Hedge Contracts [1]

PRICE PROTECTION OF ~$50/BBL FOR 2018



2018 STRUCTURE BREAKDOWN



~65% of 2018 Consensus oil volumes hedged [2]

~15% of 2019 Consensus oil volumes hedged [2]

~65% of 2018 oil hedges are Collars, allowing for meaningful participation in recent price increases

Mid/Cush basis hedges protect pricing for ~2/3 of annual oil production

1. Hedge contracts as of February 26, 2018.
2. FactSet as of February 27, 2018.

Financial Positioning

HIGHLIGHTS

Significant liquidity enhanced by recent increase to credit facility

- Raised borrowing base to $825MM with an elected commitment of $650MM
- Facility maturity moved out to 2023
- Pricing grid reduced by 50 to 75 basis points

Target a long-term leverage ratio of <2.5x Net Debt / Adjusted EBITDA

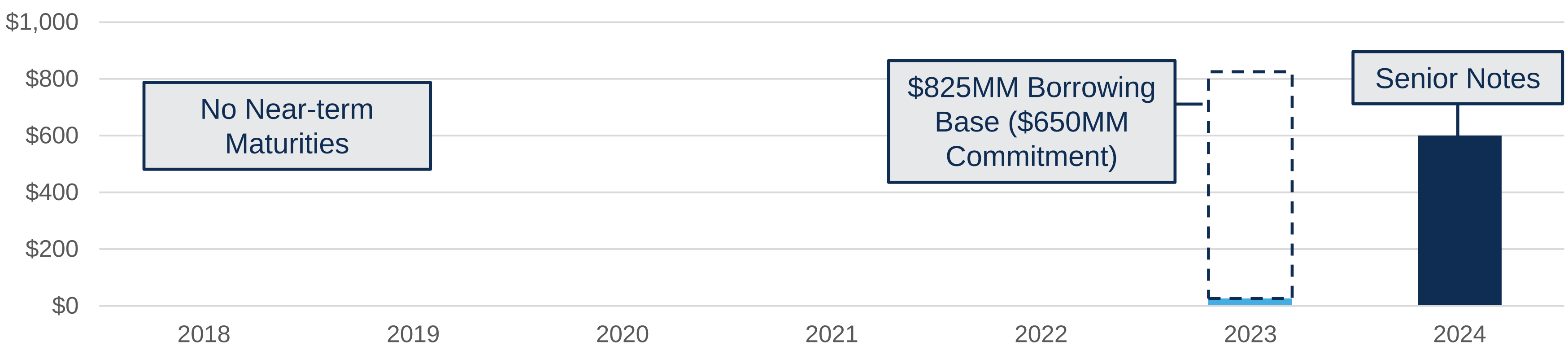
Continued to strategically enter into additional 2018 hedges (benchmark and basis) [(3)]

- Approximately 16,000 Bbl/d, including oil basis hedges
- Cash flow protection as progress to cash flow neutrality

CAPITALIZATION ($MM) [(1)]

	December 31, 2017
Cash	$28
Credit Facility [(1)]	$26
Senior Notes due 2024	$600
Total Debt	$626
Stockholders' Equity	$1,856
Total Capitalization	$2,482
Total Liquidity [(2)]	**$502**
Net Debt to LQA Adj EBITDA [(3)]	**1.7x**

DEBT MATURITY SUMMARY ($MM)



1. Assumes elected commitment amount of $500 MM.
2. Includes drawn balance plus $1.25 MM Letters of Credit outstanding.
3. See Appendix.

APPENDIX

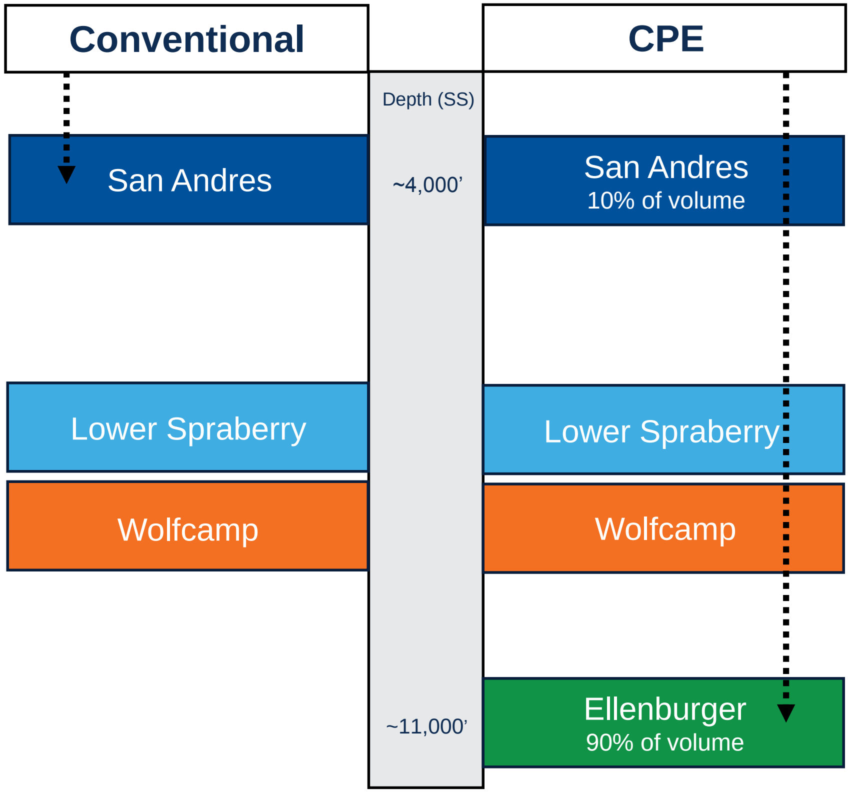
Guidance Summary

	FY18 Guidance
Total production (MBoepd)	29.5 – 32.0
Oil production	77%
Income statement expenses (per BOE)	
LOE, including workovers	$5.25 - $6.25
Production taxes, including ad valorem (% of unhedged revenues)	6%
Adjusted G&A: cash component [1]	$1.75 - $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 - $540
Capitalized expenses	$60 - $70
Net operated horizontal wells placed on production	43 – 46

1. Excludes stock-based compensation and corporate depreciation and amortization. See the Non-GAAP related disclosures in the Appendix.
2. Excludes certain non-recurring expenses and non-cash valuation adjustments. See the non-GAAP related 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. Net of infrastructure monetizations of $20 million.

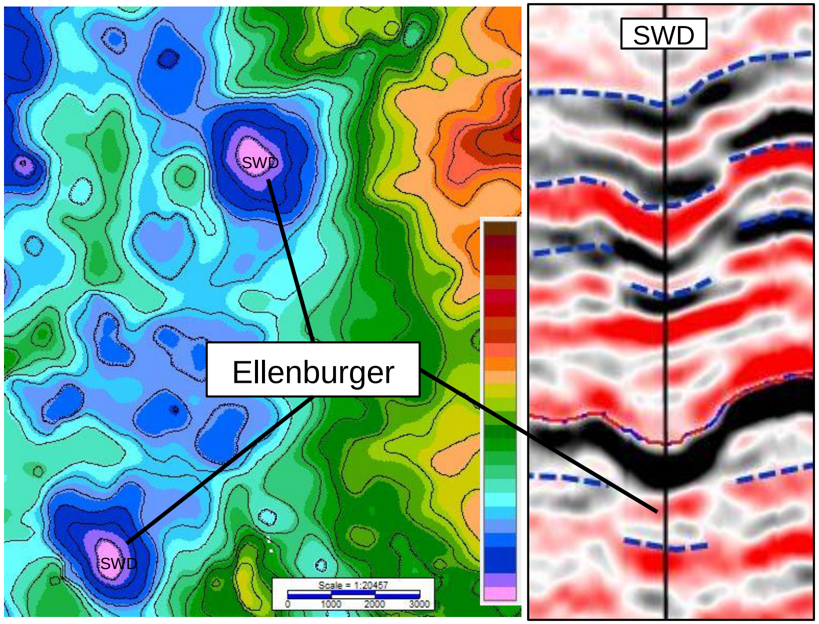
Continued Focus on Responsible Water Management

DISPOSAL DEPTH COMPARISON [1]



Conventional San Andres SWD		CPE Ellenburger SWD
~$2.4 MM	Absolute Cost	~$3.5 MM
~15 MBwpd	Avg. Capacity	~30 MBwpd
~$160/Bwpd	Per Unit Cost	~$117/Bwpd

IDENTIFYING SWD LOCATIONS WITH SEISMIC [2]



- Utilizing seismic technology to improve deep SWD well location success
- Investing in long-term water disposal solution that doesn’t over pressure development formations
- Long-term planning: partnering with 3rd party SWD providers moves entire industry to a better water management solution
- Recycle/reuse reduces disposal requirements

1. Zone thickness not to scale.
2. Seismic cross-section source: CGG.

Salt Water Disposal – Leading the Way in the Delaware

KEY PARTNERSHIP DETAILS

New agreement with 3rd party operator (Goodnight) to dispose up to 80% of produced volumes at Spur

Disposal volumes piped to CBP, 15+ miles away from current Spur footprint

In-service date of 3Q18

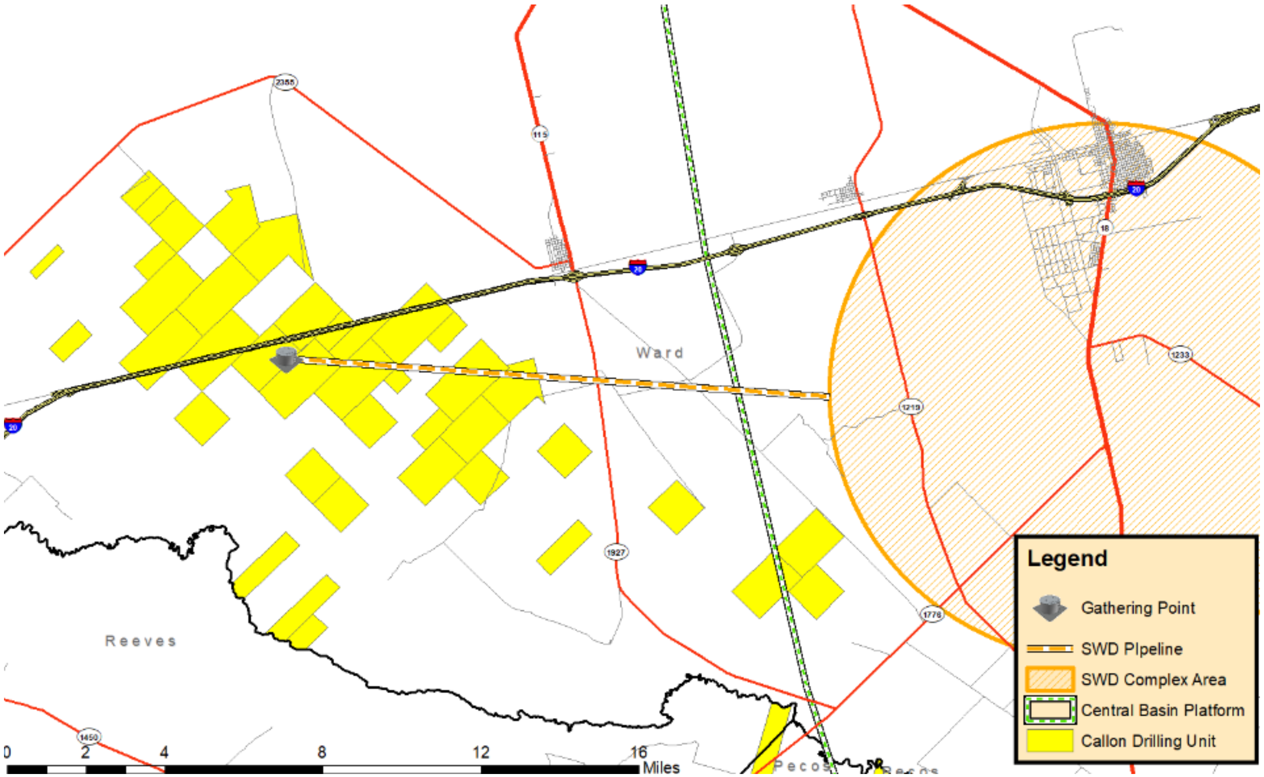
Positive NPV impact versus Callon-standalone SWD infrastructure

- Substantial capital reduction for Callon beginning in 2H18
- Disposal rates roughly inline with royalty-burdened, operated SWD wells

Optionality to divert disposal volumes for recycle and re-use in fracs with no penalty

Accelerating remaining planned operated SWD wells to 2H17 to bridge activity ramp for 2nd rig until Goodnight system online

SOUTH CENTRAL BASIN DISPOSAL SYSTEM (“SCBDS”)



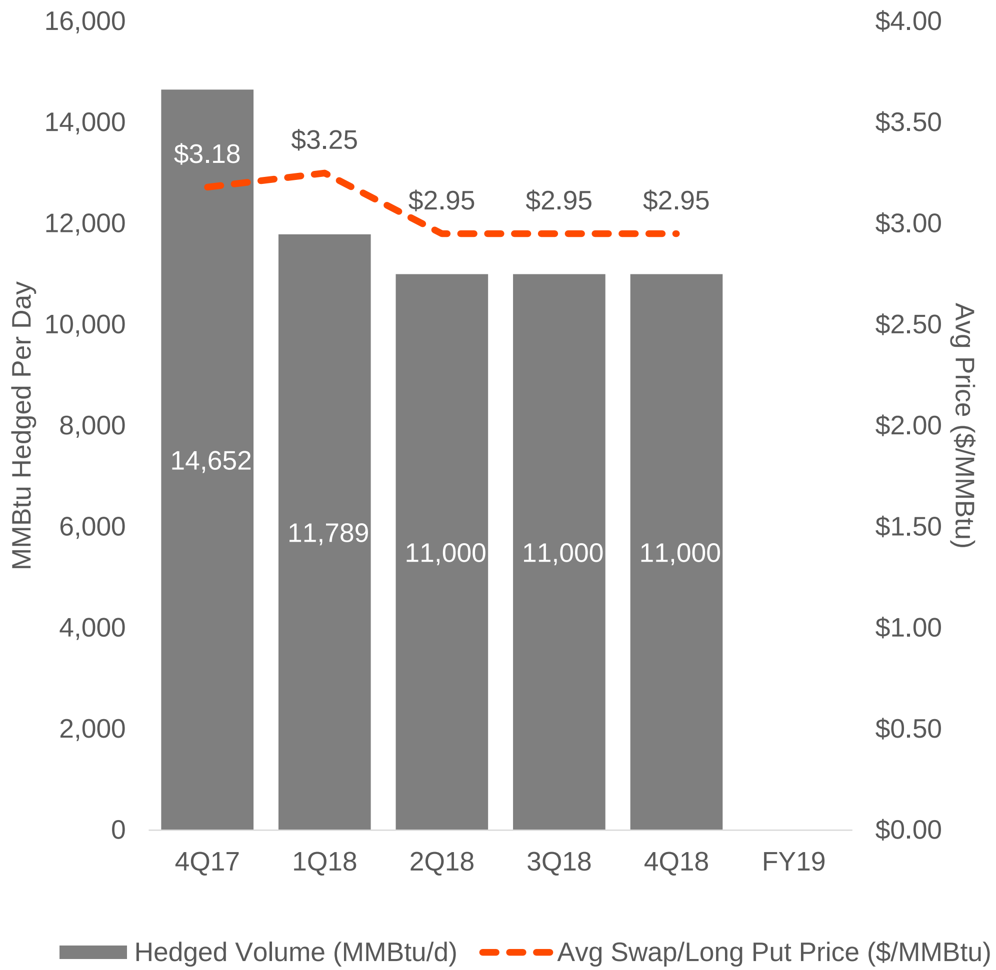
Crude Oil Hedge Contracts [1]

Crude Oil (Bbl, $/Bbl)	4Q17	1Q18	2Q18	3Q18	4Q18	FY18	FY19
Swaps Strike Price	184,000 $45.74	450,000 $51.42	455,000 $51.42	552,000 $52.07	552,000 $52.07	2,009,000 $51.78	-
Costless Collars Short Call Price Put Price	340,400 $58.19 $47.50	90,000 $60.25 $50.00	91,000 $60.25 $50.00	92,000 $60.25 $50.00	92,000 $60.25 $50.00	365,000 $60.25 $50.00	-
Three-way Collars Short Call Price Put Price Short Put Price	-	855,000 $60.86 $48.95 $39.21	864,500 $60.86 $48.95 $39.21	874,000 $60.86 $48.95 $39.21	874,000 $60.86 $48.95 $39.21	3,467,500 $60.86 $48.95 $39.21	1,825,000 $62.40 $53.00 $43.00
Swaps combined with Short Puts Swap Price Short Put Price	184,000 $44.50 $30.00	-	-	-	-	-	-
Deferred Premium Put Spreads Premium Put Price Short Put Price	253,000 $2.45 $50.00 $40.00	-	-	-	-	-	-
Midland-Cushing Basis Differential Swap Price	552,000 ($0.52)	1,395,000 ($0.80)	1,410,500 ($0.80)	1,242,000 ($0.93)	1,242,000 ($0.93)	5,289,500 ($0.86)	-
Total NYMEX WTI Hedge Volume Weighted Average Floor Price	961,400 $47.25	1,395,000 $49.81	1,410,500 $49.81	1,518,000 $50.15	1,518,000 $50.15	5,841,500 $49.99	1,825,000 $53.00

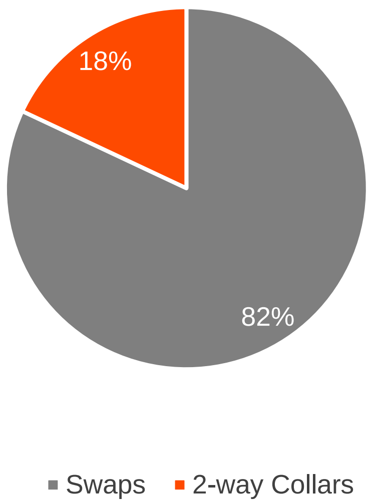
1. Hedge contracts as of February 26, 2018.

Natural Gas Hedge Contracts (1)

PRICE PROTECTION OF ~$3/MMBTU FOR 2018



2018 STRUCTURE BREAKDOWN



~20% of 2018 consensus volumes hedged (2)

Weighted average ceiling price of $3.84 for 1Q18

Continuing to monitor Henry Hub and Waha pricing

1. Hedge contracts as of February 26, 2018.
2. FactSet as of February 27, 2018.

Natural Gas Hedge Contracts (1)

Natural Gas (MMBtu, $/MMBtu)	4Q17	1Q18	2Q18	3Q18	4Q18	FY18	FY19
Swaps Strike Price	124,000 $3.39	341,000 $2.95	1,001,000 $2.95	1,012,000 $2.95	1,012,000 $2.95	3,366,000 $2.95	-
Costless Collars Short Call Price Put Price	856,000 $3.77 $3.23	720,000 $3.84 $3.40	-	-	-	720,000 $3.84 $3.40	-
Three-way Collars Short Call Price Put Price Short Put Price	368,000 $3.71 $3.00 $2.50	-	-	-	-	-	-
Waha Basis Differential Swap Price	-	-	-	-	-	-	-
Total NYMEX Henry Hub Hedge Volume Weighted Average Floor Price	1,348,000 $3.18	1,061,000 $3.25	1,001,000 $2.95	1,012,000 $2.95	1,012,000 $2.95	4,086,000 $3.03	-

1. Hedge contracts as of February 26, 2018.

Quarterly Cash Flow Statement

	4Q16	1Q17	2Q17	3Q17	4Q17
Cash flows from operating activities:					
Net income (loss)	$ (1,746)	$ 47,129	$ 33,390	$ 17,081	$ 22,824
Adjustments to reconcile net income to cash provided by					
Depreciation, depletion and amortization	22,512	24,932	26,765	29,132	37,222
Accretion expense	196	184	208	131	154
Amortization of non-cash debt related items	744	665	589	441	455
Deferred income tax expense	48	466	323	237	247
(Gain) loss on derivatives, net of settlements	11,030	(17,794)	(10,761)	12,947	26,037
Loss on sale of other property and equipment	—	—	62	—	—
Non-cash loss on early extinguishment of debt	9,883	—	—	—	—
Non-cash expense related to equity share-based awards	811	930	4,865	1,219	1,240
Change in the fair value of liability share-based awards	908	(291)	1,982	732	865
Payments to settle asset retirement obligations	(576)	(765)	(816)	(250)	(216)
Changes in current assets and liabilities:					
Accounts receivable	(13,611)	(4,066)	(3,744)	(4,338)	(32,347)
Other current assets	(535)	576	(874)	(38)	444
Current liabilities	5,473	9,903	(4,223)	1,854	23,413
Other long-term liabilities	10	—	120	1	—
Long-term prepaid	—	—	—	(4,650)	—
Other assets, net	831	(523)	(247)	(606)	(152)
Payments for cash-settled restricted stock unit awards	—	(8,662)	(4,511)	—	—
Net cash provided by operating activities	35,978	52,684	43,128	53,893	80,186
Cash flows from investing activities:					
Capital expenditures	(67,334)	(66,154)	(79,936)	(121,128)	(152,621)
Acquisitions	(352,622)	(648,485)	(58,004)	(8,015)	(3,952)
Acquisition deposit	(13,438)	46,138	—	—	(900)
Proceeds from sales of mineral interests and equipment	1,639	—	—	—	20,525
Net cash used in investing activities	(431,755)	(668,501)	(137,940)	(129,143)	(136,948)
Cash flows from financing activities:					
Borrowings on senior secured revolving credit facility	—	—	—	—	25,000
Payments on term loan	(300,000)	—	—	—	—
Issuance of 6.125% senior unsecured notes due 2024	400,000	—	200,000	—	—
Premium on the issuance of 6.125% senior unsecured notes	—	—	8,250	—	—
Issuance of common stock	634,862	—	—	—	—
Payment of preferred stock dividends	(1,824)	(1,824)	(1,823)	(1,824)	(1,824)
Payment of deferred financing costs	(10,153)	—	(6,765)	(401)	(28)
Tax withholdings related to restricted stock units	—	(79)	(974)	(65)	—
Net cash provided by financing activities	722,885	(1,903)	198,688	(2,290)	23,148
Net change in cash and cash equivalents	327,108	(617,720)	103,876	(77,540)	(33,614)
Balance, beginning of period	325,885	652,993	35,273	139,149	61,609
Balance, end of period	$ 652,993	$ 35,273	$ 139,149	$ 61,609	$ 27,995

Non-GAAP Reconciliation (1)

	4Q16	1Q17	2Q17	3Q17	4Q17
Adjusted Income Reconciliation					
Income (loss) available to common stockholders	$ (3,570)	$ 45,305	$ 31,566	15,257	21,001
Adjustments:					
Change in valuation allowance	559	(13,119)	(11,194)	(6,064)	(8,285)
Net (gain) loss on derivatives, net of settlements	7,170	(11,566)	(6,995)	8,416	16,924
Change in the fair value of share-based awards	590	(189)	(315)	475	562
Settled share-based awards	—	—	4,128	—	—
Loss on early redemption of debt	8,374	—	—	—	—
Adjusted Income	$ 13,123	$ 20,431	$ 17,190	18,084	30,202
Adjusted Income per fully diluted common share	$ 0.08	$ 0.10	$ 0.09	$ 0.09	$ 0.15
Adjusted EBITDA Reconciliation					
Net income (loss)	$ (1,746)	$ 47,129	$ 33,390	$ 17,081	$ 22,824
Adjustments:					
Net (gain) loss on derivatives, net of settlements	11,030	(17,794)	(10,761)	12,947	26,037
Non-cash stock-based compensation expense	1,718	639	499	1,952	2,101
Settled share-based awards	—	—	6,351	—	—
Loss on early redemption of debt	12,883	—	—	—	—
Acquisition expense	1,263	450	2,373	205	(112)
Income tax expense	48	466	322	237	248
Interest expense	1,369	665	589	444	461
Depreciation, depletion and amortization	22,512	24,932	26,765	29,132	37,222
Accretion expense	196	184	208	131	154
Adjusted EBITDA	$ 49,273	$ 56,671	$ 59,736	$ 62,129	$ 88,935
Adjusted EBITDA inclusive of Pro forma (2)	$ 54,030	$ 59,329	$ 59,736	$ 62,129	$ 88,935

1. See "Important Disclosure" slides for disclosures related to Supplemental Non-GAAP Financial Measures.
2. Adjusted EBITDA inclusive of Pro forma Adjustments is used primarily for the purpose of calculating compliance with covenants, such as Debt/EBITDA calculations, and includes the impact of acquisitions closed during prior periods as if they were completed at the beginning of the reporting period.

Non-GAAP Reconciliation [1]

	4Q16	1Q17	2Q17	3Q17	4Q17
Adjusted G&A Reconciliation					
Total G&A expense	$ 6,562	$ 5,206	$ 6,430	$ 7,259	$ 8,173
Adjustments:					
Less: Early retirement expenses	—	—	(444)	—	—
Less: Early retirement expenses related to share-	—	—	(81)	—	—
Less: Change in the fair value of liability share-based	(857)	(307)	567	(731)	(844)
Adjusted G&A – total	5,705	5,513	6,472	6,528	7,329
Less: Restricted stock share-based compensation	(801)	(921)	(966)	(1,198)	(1,202)
Less: Corporate depreciation & amortization (non-	(104)	(121)	(114)	(146)	(125)
Adjusted G&A – cash component	$ 4,800	$ 4,471	$ 5,392	$ 5,184	$ 6,002
Adjusted Total Revenue Reconciliation					
Oil revenue	$ 60,559	$ 72,008	$ 72,885	$ 73,349	$ 104,132
Natural gas revenue	8,522	9,355	9,398	11,265	14,081
Total revenue	69,081	81,363	82,283	84,614	118,213
Impact of cash-settled derivatives	2,079	(2,491)	(267)	(1,214)	(4,501)
Adjusted Total Revenue	$ 71,160	$ 78,872	$ 82,016	$ 83,400	$ 113,712
Total Production (Mboe)	1,689	1,838	2,021	2,074	2,439
Adjusted Total Revenue per Boe	$ 42.13	$ 42.91	$ 40.58	$ 40.21	$ 46.62
Discretionary Cash Flow Reconciliation					
Net cash provided by operating activities	$ 35,978	$ 52,684	$ 43,128	$ 53,893	$ 80,186
Changes in working capital	7,832	(5,890)	8,968	7,777	8,642
Payments to settle asset retirement obligations	576	765	816	250	216
Payments to settle vested liability share-based	—	8,662	4,511	—	—
Discretionary cash flow	$ 44,386	$ 56,221	$ 57,423	$ 61,920	$ 89,044
Discretionary cash flow per diluted share	$ 0.27	$ 0.28	$ 0.28	$ 0.31	$ 0.44

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