3Q17 Earnings Presentation

Callon Petroleum

November 06, 2017

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. 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, 2016 filed with the Securities and Exchange Commission (the "SEC").

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

3Q17 Highlights

FINANCIAL RESULTS

- Adj. EBITDA margin increase to ~74% [1]
- Continued focus on cost improvements, 20% reduction in LOE/Boe since 1Q17
  - $5.08 per Boe (excludes G&T, $0.52/Boe)
- 36% production growth versus 3Q16
  - Oil mix of ~77% (17,293 Bbl/d)

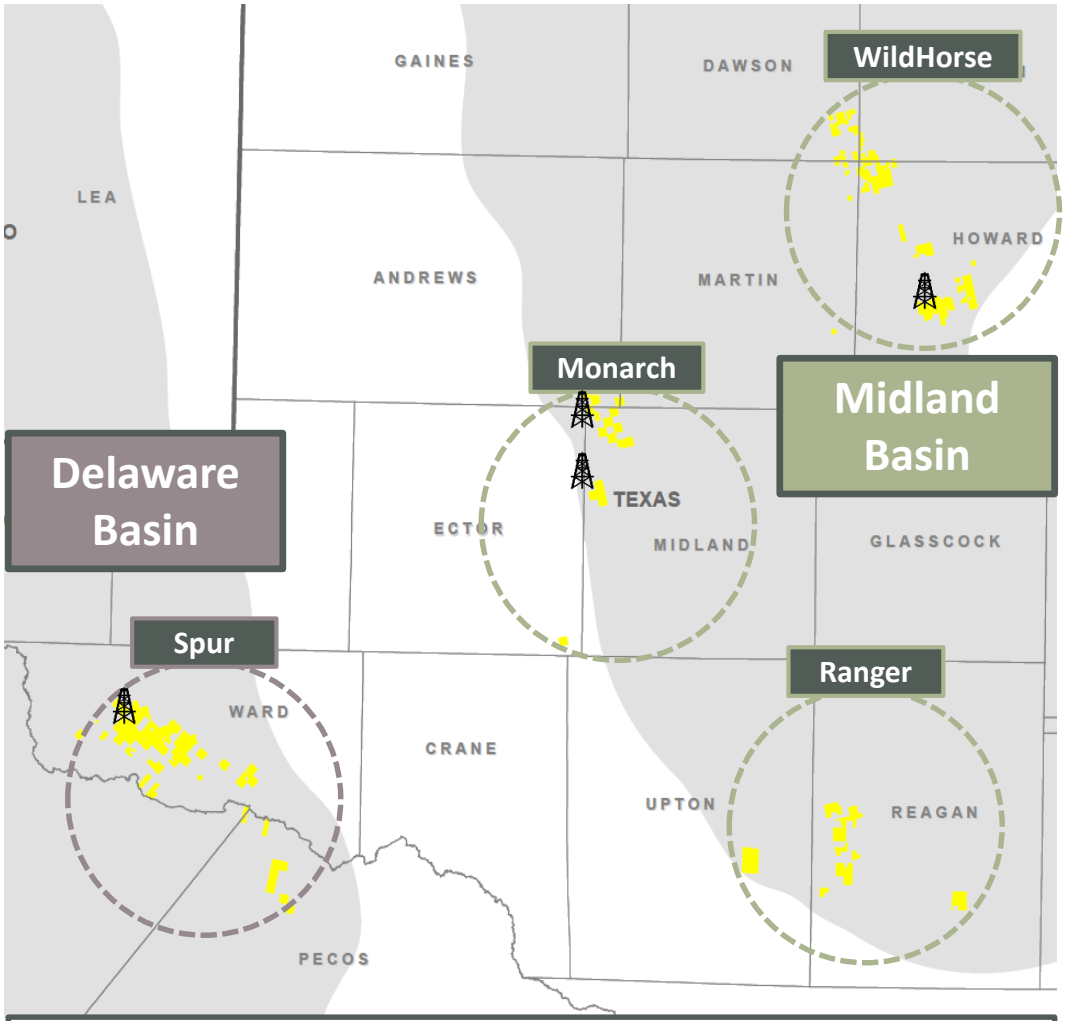
OPERATIONAL RESULTS

- **Spur:** Exceeding type curve on 1st operated WC A well by 60% in early time
- **WildHorse:** Continued strong performance from WC A wells across entire position
- **Ranger:** Recent WC B wells outperforming type curve by 23%; WC C test pending

FY18 OUTLOOK

- Expected delivery of 5th rig in mid-1Q18
- **Multiple catalysts pending for 2018**
  - Ranger: WC C delineation
  - Wildhorse: WC A 10 well per section test
  - Spur: Testing new zones and stacked/staggered development

Current Rig Activity



~60,000 net acres

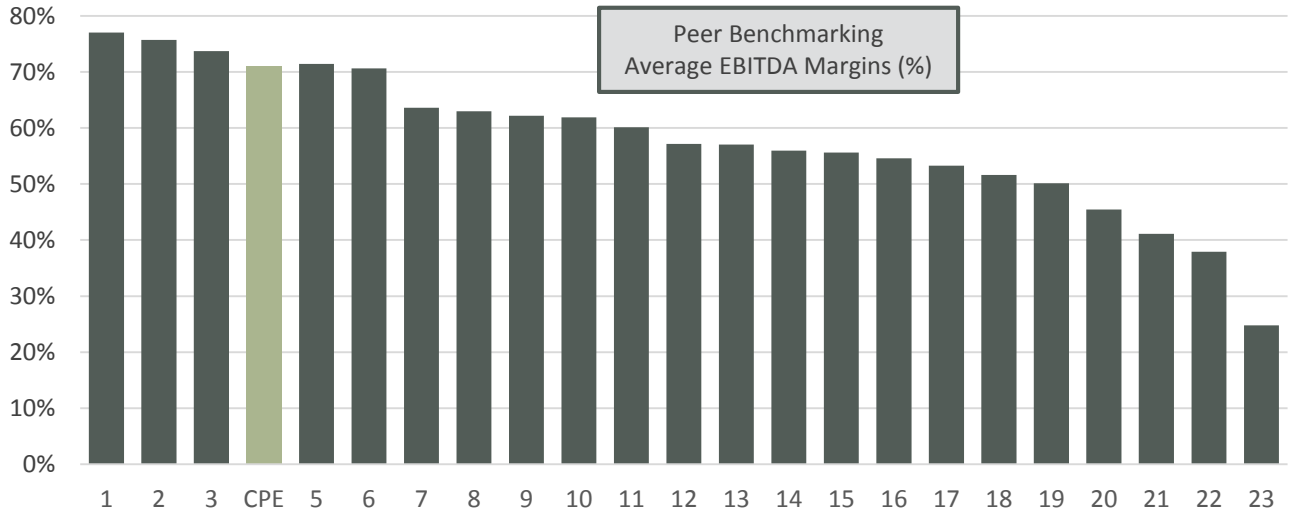
1) See the non-GAAP related disclosures in the Appendix.

Focused on Corporate Level Returns

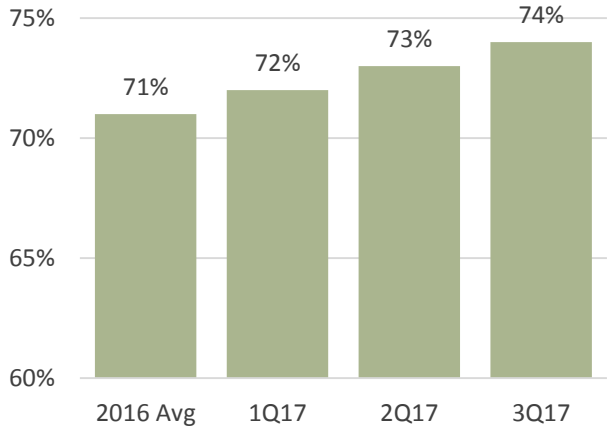
What Creates Value?

- Constant re-evaluation of best capital allocation decisions on a full-cycle basis
- Long-term view of priority projects to clear the development runway for capital efficient growth
- Redeployment of strong cash margins to pull forward well-level returns on a measured basis
- Visible path to near-term cash flow neutrality, balanced with operational flexibility to react to market conditions
- Consistent, manageable growth within conservative leverage and liquidity parameters

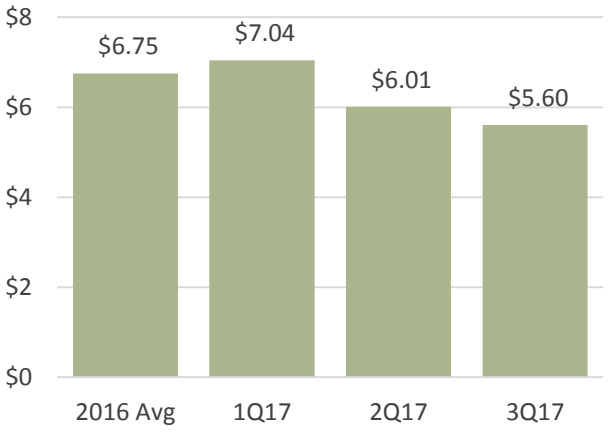
EBITDA Margins Drive Re-investment Value [1]



Adjusted EBITDA Margins [2]



Total LOE ($/Boe)



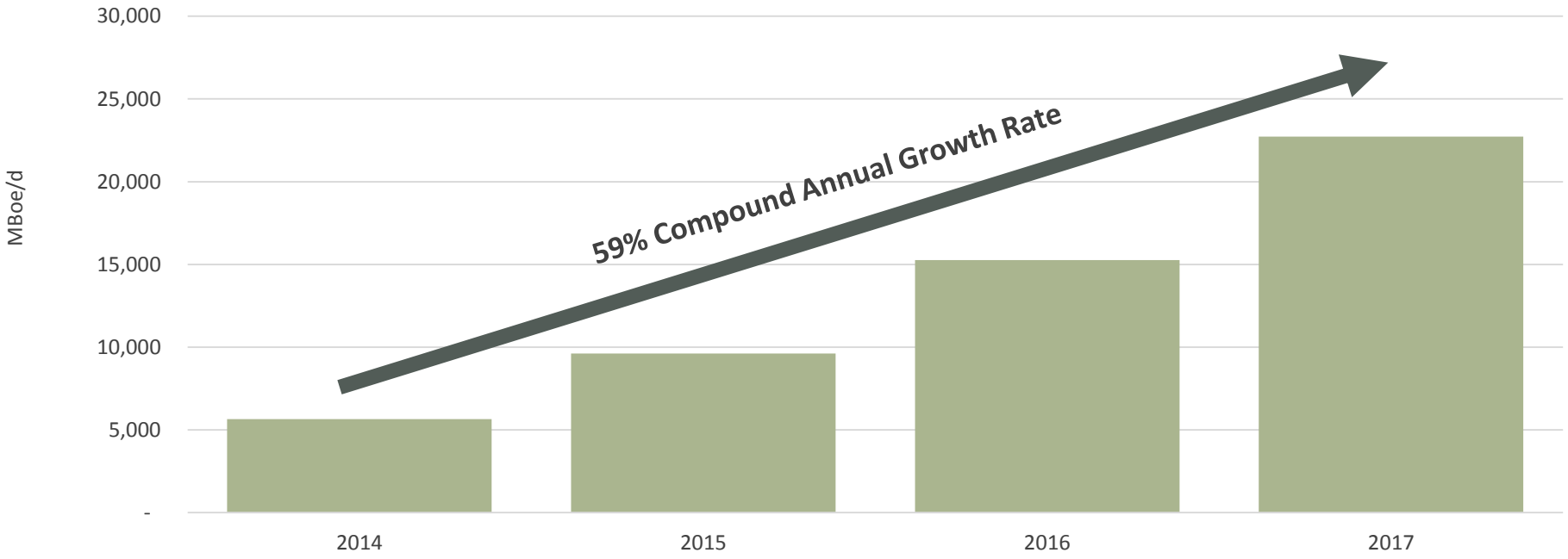
1) Average adjusted EBITDA margins 4Q16 to 2Q17. Peers include: APA, AREX, CDEV, CXO, DVN, EGN, EPE, FANG, JAG, LPI, MRO, MTDR, NFX, OAS, PE, PXD, QEP, REN, RSPP, SM, WPX, and XEC. Source: FactSet.
2) Adjusted EBITDA margins by quarter based on internal calculations. See Appendix for reconciliation.

Measured Growth Outlook

Increasing Production Through a Focus on Returns

- Production growth balanced with corporate-level returns to ensure sustained trajectory and alignment of cash flows
- 2017 infrastructure investment has provided a clear runway for measured increases in activity
- 2018 program will continue to focus on providing visibility for near-term cash flow neutrality while enhancing corporate returns on capital
- Operational flexibility maintained in order to capitalize on continuously expanding organic opportunity set

Average Daily Production [1]



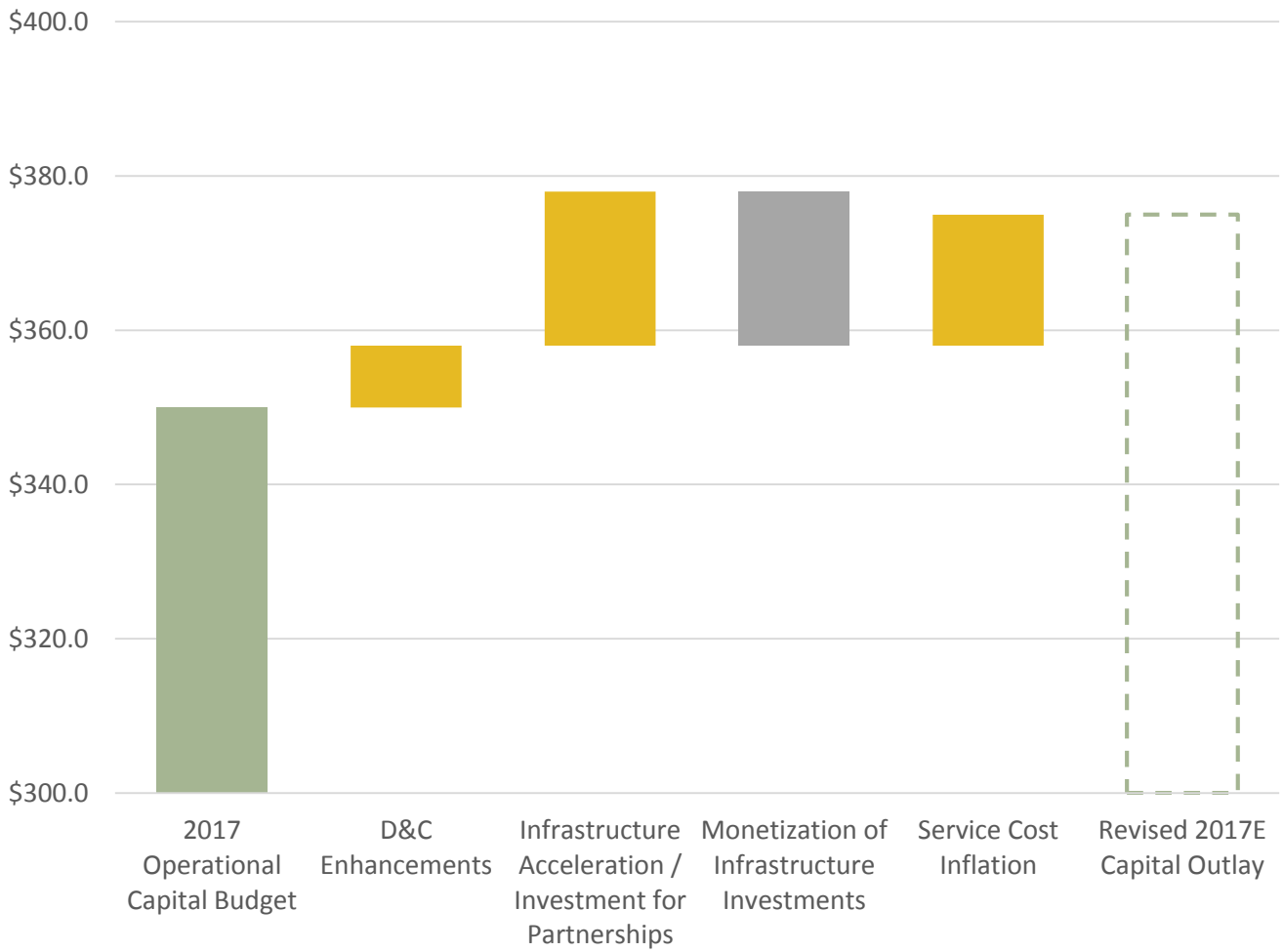
1) 2017 Average Daily Production figures reflect midpoint of full-year guidance as stated in 3Q17 earnings press release.

Capital Budget Update

Preparing for 2018

- 2017 capital activity has incorporated proactive infrastructure spending to prepare for full asset development
- Annual Operational Capex increases driven by:
  - D&C enhancements (rotary steerables, increased diverter usage)
  - Pull forward of 2018 infrastructure and critical projects for "partnerships"
  - Service cost inflation
- ***Opportunity to selectively monetize infrastructure assets for re-investment in wells***

Net Cash Outlay Expected to Increase Slightly ($MM)

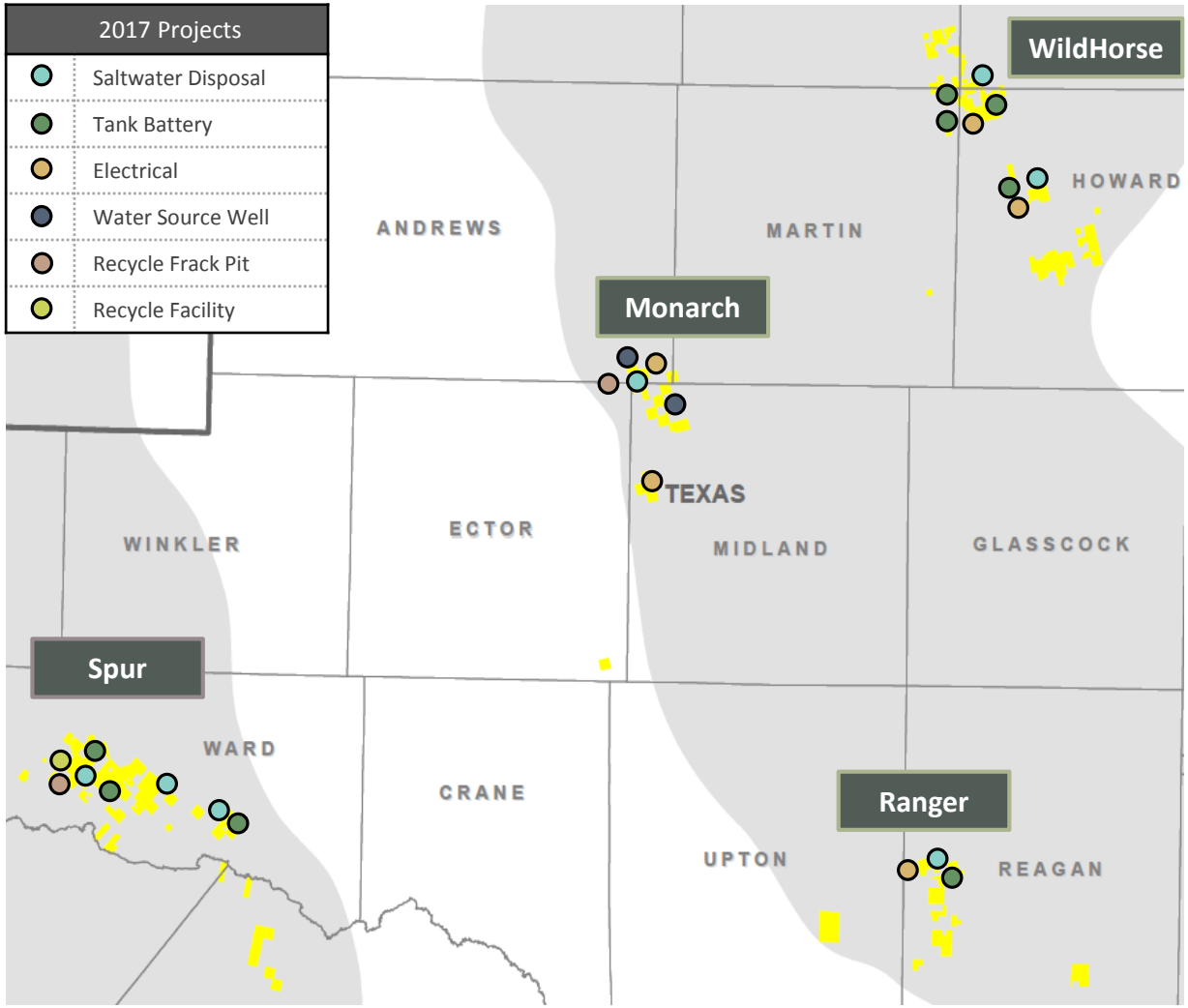


Building Out Infrastructure for 2018 and Beyond

Laying the Groundwork

- Significant strides for infrastructure build-out across the entire Callon footprint
  - Addition and upgrades to 7 SWD facilities increase throughput and support dewatering of new wells
  - Water recycling projects reduce both sourcing and disposal costs for multiple planned developments
  - Power installations, including substations, provides cost savings from generator removal as well as increase power reliability
  - All new pads connected to LACT units, reducing trucked barrel costs
  - Upgraded tank batteries accommodate larger volumes and pad development
- ***Investment in infrastructure in 2017 clears the path for development in 2018 and beyond in a cost effective and reliable manner***

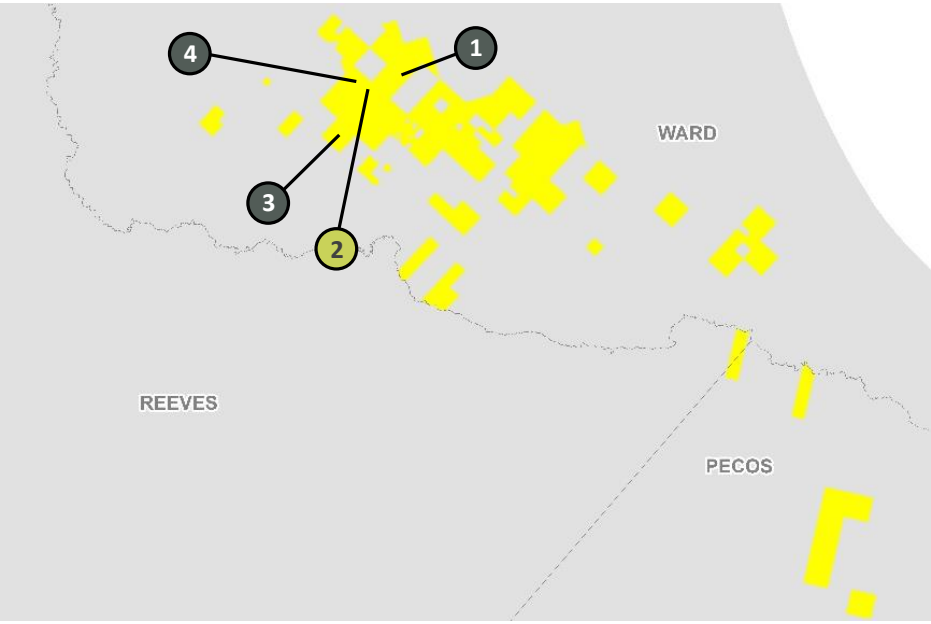
Major Infrastructure Projects



Spur: Strong Initial Operated Well Results

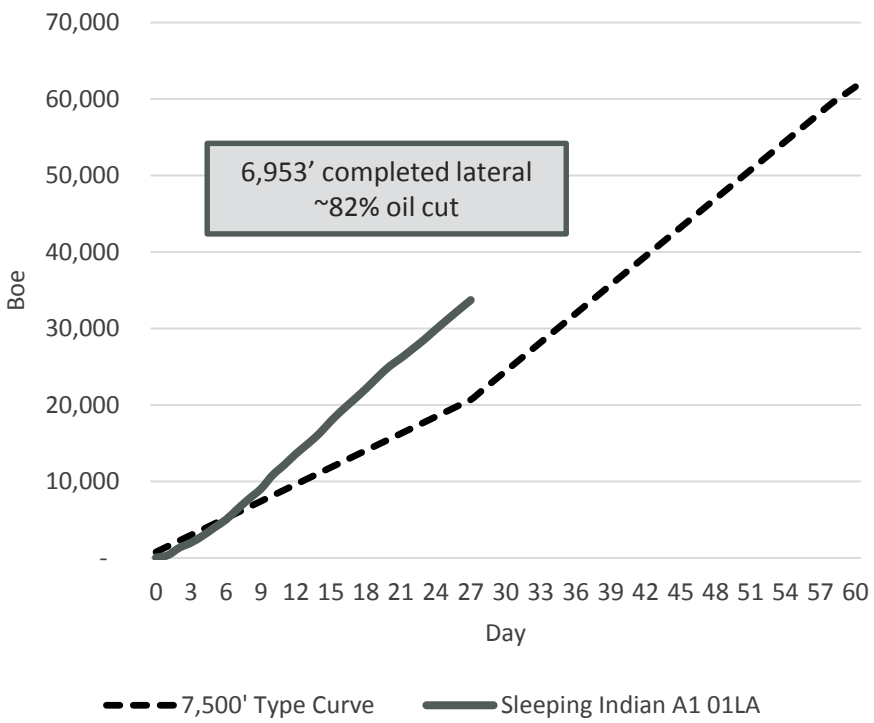
- Early time results from the Sleeping Indian A1 tracking 60% above Lower WC A type curve
  - Peak 24 hr rate to date: 1,640 Boe/d (82% oil) or ~238 Boepd/1,000' (has not reached peak 30 day average)
- Saratoga A1 well recently completed and placed on flowback
- Recent transactions (Brazos Midstream and Goodnight) help to clear the path for efficient future development
- Multi-well pad development kicks off in December with staggered upper and lower WC A laterals

Spur Asset Area



1	Corbets 34-149 2WA [1]	3	Sleeping Indian A1 1LA [2]
2	Saratoga 34-161 1WB [1]	4	Saratoga A1 7LA [2]

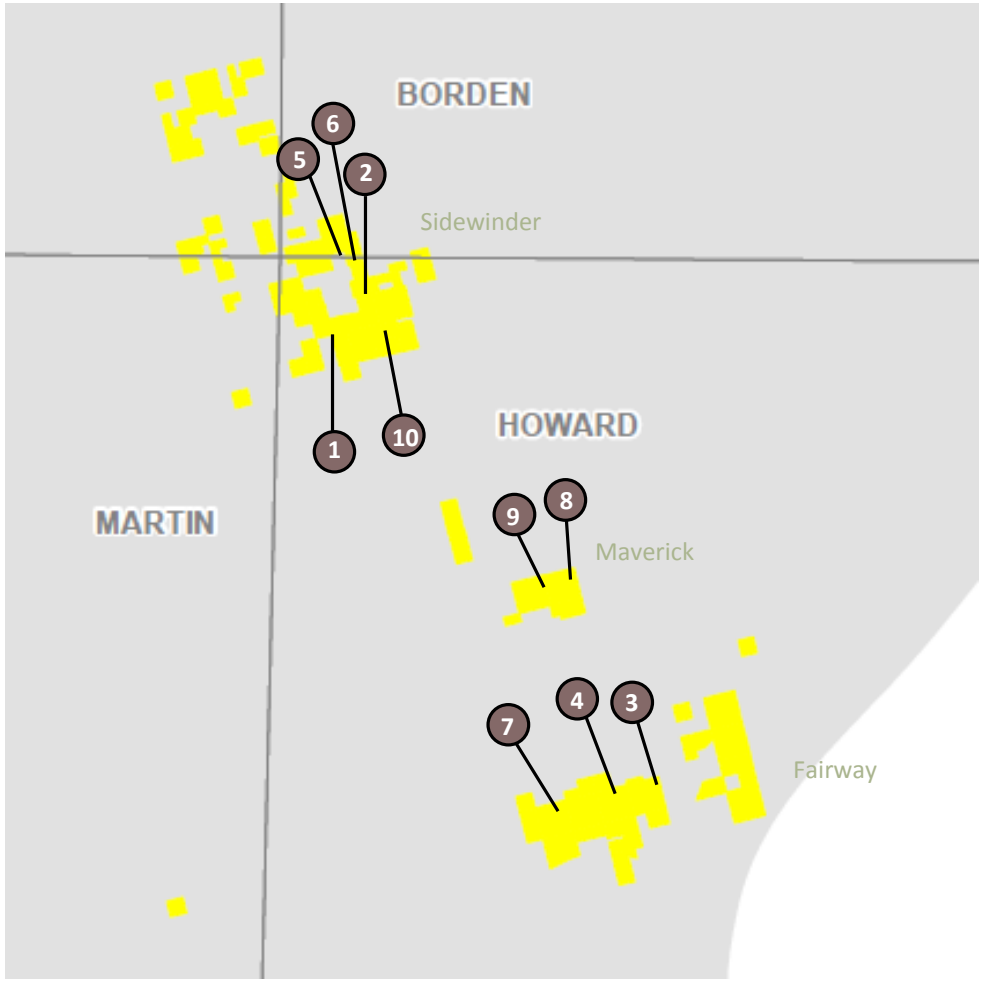
Early-time Production from Sleeping Indian Well



1) Wells drilled by previous operator.
2) Callon designed and operated wells.

WildHorse: Consistent Performance and Oil Growth

Continued Delineation Across Focus Area



Exceptional WC A Performance

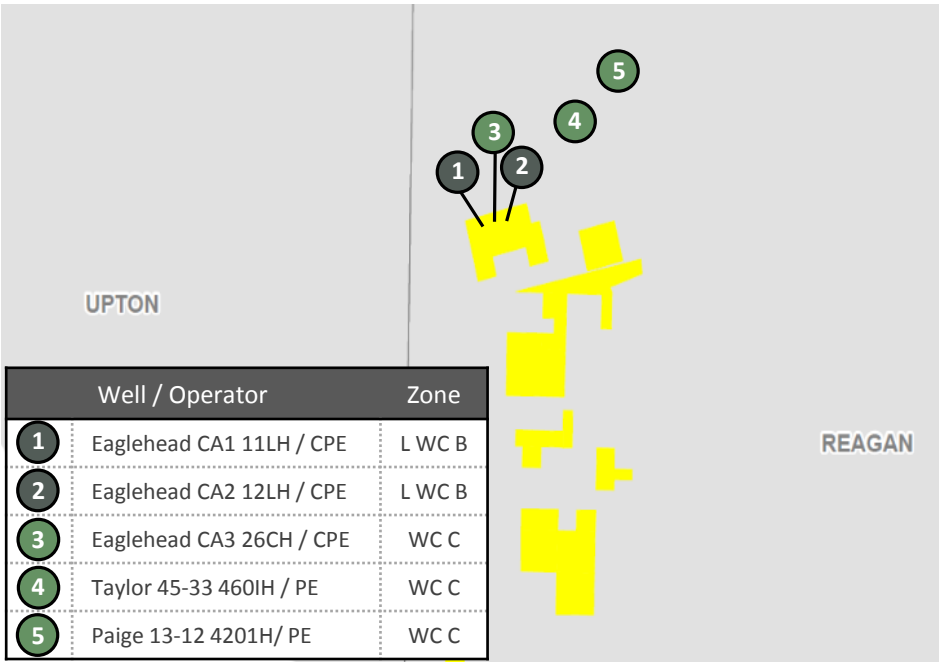
	Well / Pad	IP30 (Boe/d)
1	Wright-Adams Unit 31-42 05AH	1,976
2	Cheek Unit 28-21 01AH	1,901
3	Colonial Pad	1,553
4	Wyndham Pad	1,396
5	Wright Unit 29-20 02AH	1,649
6	Wright Unit 29-20 01AH	1,616
7	Players Pad	Cleaning up
8	Garrett-Reed Unit 37-48 01AH	Cleaning up
9	Garrett Unit 37-48 05AH	Cleaning up
10	Wright Unit B 41-32 07AH	Cleaning up

- Current infrastructure build-out allows for full program development going into 2018; Three target zones (WC A, WC B and LSBY)
- Continued exceptional performance in WC A; Tracking above 1 MMBoe type curve, on average, across the entire position
- Planning 10 well spacing test in 2018 which could lead to ~25% organic inventory growth (WC A)
- Recent LSBY wells with refined completion concepts have resulted in reduced time to first oil

Ranger: Potential for Increased Returns and Inventory

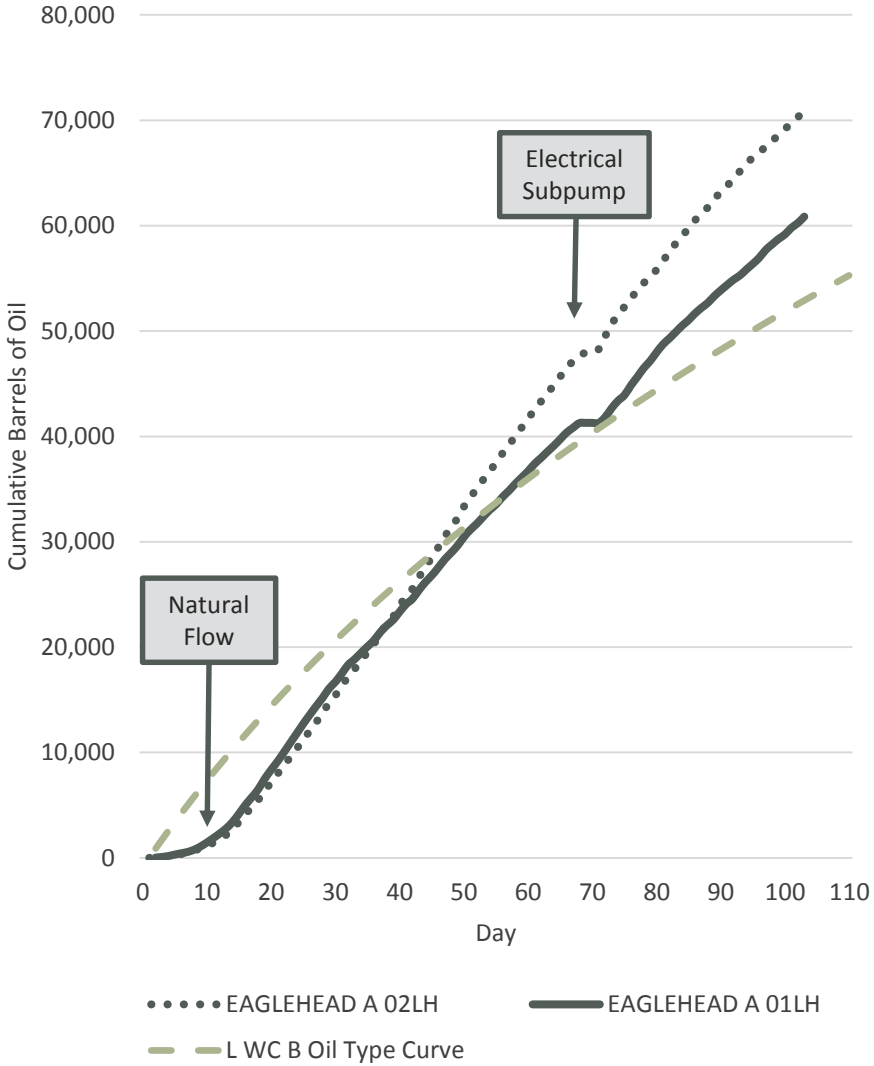
- Eaglehead Lower WC B wells have crossed over type curve and continue to climb
  - On average, the new wells are outperforming oil type curve by over 23% through first 100 days
- Two additional Lower WC B results and a test of WC C, projected to be completed during 4Q17
- Positive WC C results could add ~50 gross locations to inventory in Reagan County

Strong Performance from Recent Area Wells



	Well / Operator	Zone
1	Eaglehead CA1 11LH / CPE	L WC B
2	Eaglehead CA2 12LH / CPE	L WC B
3	Eaglehead CA3 26CH / CPE	WC C
4	Taylor 45-33 460IH / PE	WC C
5	Paige 13-12 4201H/ PE	WC C

Recent L WC B Performance Outpacing Type Curve

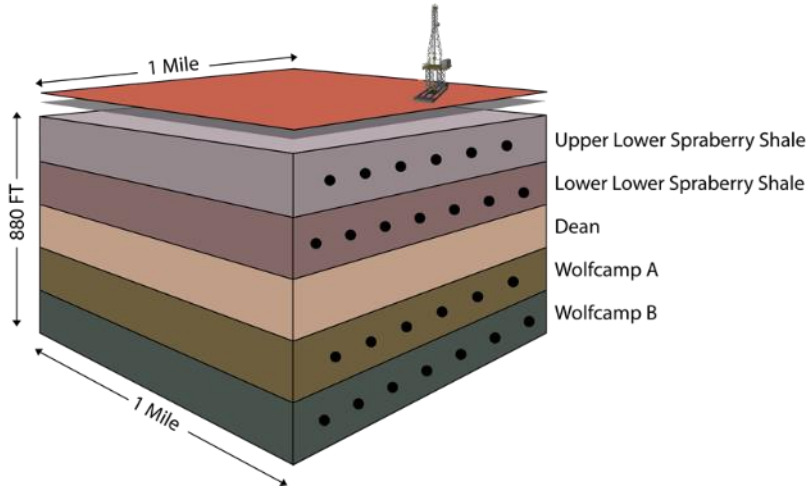


Monarch: Track Record of Solid Results

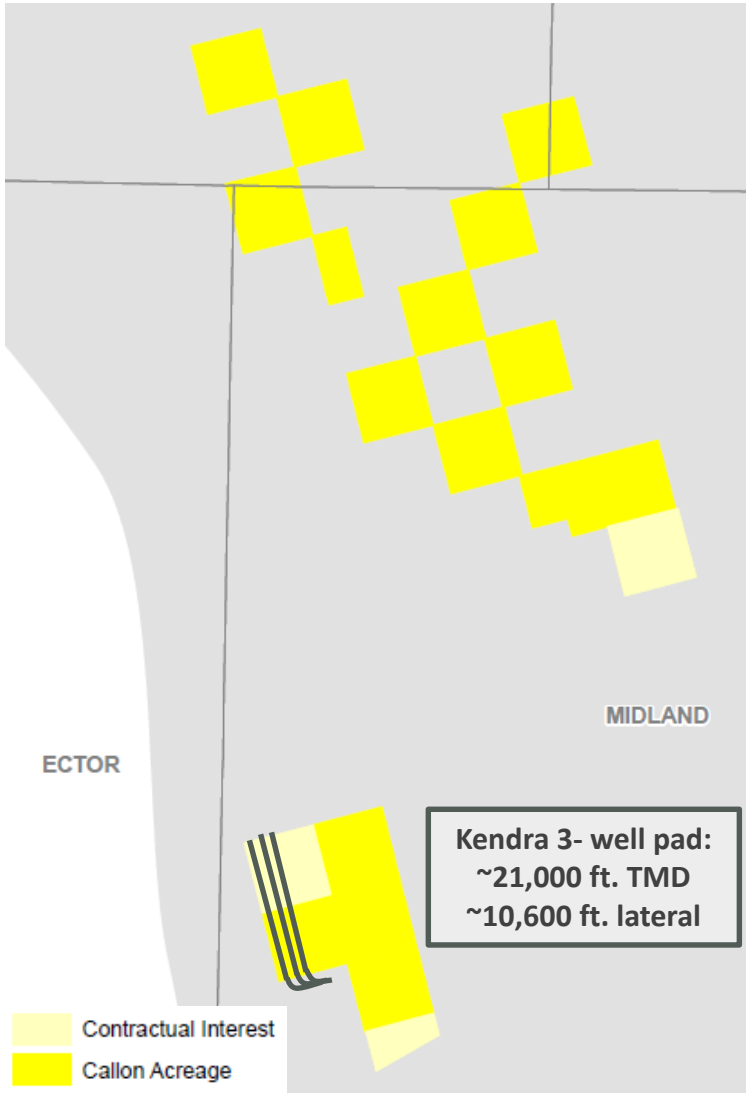
Pilot Programs Prove 13-Well Spacing in LSBY

- Continued strong results from the Kendra pad, longest laterals drilled to-date, reaffirm LSBY potential
- Established infrastructure requires minimal investment to support multi-pad development
- Environmentally and mechanically responsible disposal water recycling at Casselman 40
  - Recycling 10,000 bwpd with plans to increase to 30,000 bwpd
- Efficient development initiative: drilling two 3-well pads simultaneously on a ½ section for full ½ section development

Current 13 WPS Upper/Lower LSBY Spacing



Longest Laterals Drilled To-date



Financial Positioning

Highlights

- Ample liquidity supported by a largely unfunded revolving credit facility
  - Current borrowing base of $650MM with an elected commitment of $500MM [6]
  - $562MM [3] of liquidity as of September 30th
- Target a long-term leverage ratio of <2.5x Net Debt / Adjusted EBITDA
- Continued to strategically enter into additional 2018 hedges (benchmark and basis) [5]
  - Approximately 14,500 Bbl/d
  - Cash flow protection as progress to cash flow neutrality

Capitalization ($MM) [1]

	September 30, 2017
Cash	$62
Credit Facility [2]	$1
Senior Notes due 2024	$600
Total Debt	$601
Stockholders' Equity	$1,833
Total Capitalization	$2,434
Total Liquidity [3]	**$562**
Net Debt to LQA Adj EBITDA [1]	**2.2x**

Debt Maturity Summary ($MM)

1) See the non-GAAP related disclosures in the Appendix.
2) $1.25 MM Letters of Credit outstanding.
3) Assumes elected commitment amount of $500 MM.
4) At issuance as of May 19, 2017.
5) See Appendix.
6) Currently working through the semi-annual fall borrowing base review. Our administrative agent on the facility has recommended a borrowing base of $700 MM.

Guidance Summary

Highlights

PRODUCTION

- Forecasting 10% sequential growth for 4Q17
- Steady oil mix at the top of peer group

COST STRUCTURE

- Delivered LOE reduction of more than 20% YTD
- Total cash costs approaching $10/Boe (2-stream basis)

CAPITAL

- Addition of drilling enhancements supporting strong well results
- Monetization activity offsets acceleration of 2018 projects

	3Q17 Guidance	3Q17 Actual	4Q17 Guidance
Total production (MBoepd)	22.5 – 22.6	22.5	24.0 – 25.5
Oil production	77%	77%	77%
Income Statement Expenses (per BOE)			
LOE, including workovers	$6.00 - $6.50	$5.08	$5.75 - $6.25
Gathering and treating	$0.40 - $0.50	$0.52	$0.55 - $0.65
Production taxes, including ad valorem (% of unhedged revenues)	7%	6%	7%
Adjusted G&A: cash component [1]	$2.25 - $2.50	$2.50	$2.25 - $2.50
Adjusted G&A: non-cash component [2]	$0.50 - $0.75	$0.65	$0.55 - $0.65
Cash interest expense [3]	$0.00	$0.00	$0.00
Capital expenditures ($MM, accrual basis)			
Total operational/Net of monetization [4]	$110 - $130	$117	$108 - $112/ $88 - $92
Capitalized expenses (cash component)	$12 - $17	$15	$13 - $17
Net operated horizontal completions:			
Midland Basin	~10	9	~12
Delaware Basin	~1	1	~1

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.

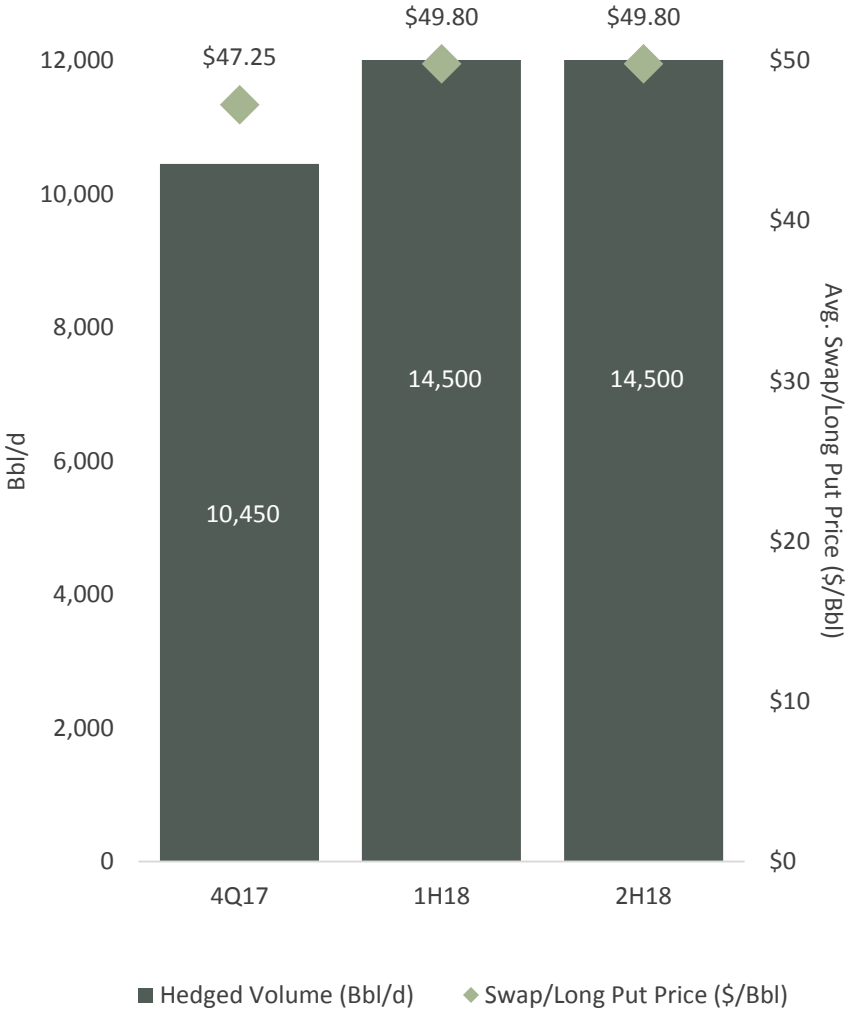
Appendix

Oil Hedge Contracts [1]

~55% of 2018 Consensus Volumes Hedged [2]

Crude Oil (Bbl, $/Bbl)	4Q17	1H18	2H18
Swaps	184,000	905,000	920,000
Strike Price	$45.74	$51.42	$51.42
Swaps combined with Short Puts	184,000		
Swap Price	$44.50	-	-
Short Put	$30.00		
Deferred Premium Put Spreads	253,000		
Premium	$2.45	-	-
Long Put	$50.00		
Short Put	$40.00		
Costless Collars	340,400		
Ceiling	$58.19	-	-
Floor	$47.50		
Three-way Collars		1,719,500	1,748,000
Ceiling	-	$60.86	$60.86
Floor		$48.95	$48.95
Short Put		$39.21	$39.21
Midland Basin Oil Differential	552,000	2,624,500	2,484,000
Swap Price	($0.52)	($0.87)	($0.93)
Total NYMEX WTI Hedge Volume	961,400	2,624,500	2,668,000
Weighted Average Floor Price	$47.25	$49.80	$49.80

Price Protection of ~$50/Bbl for 2018



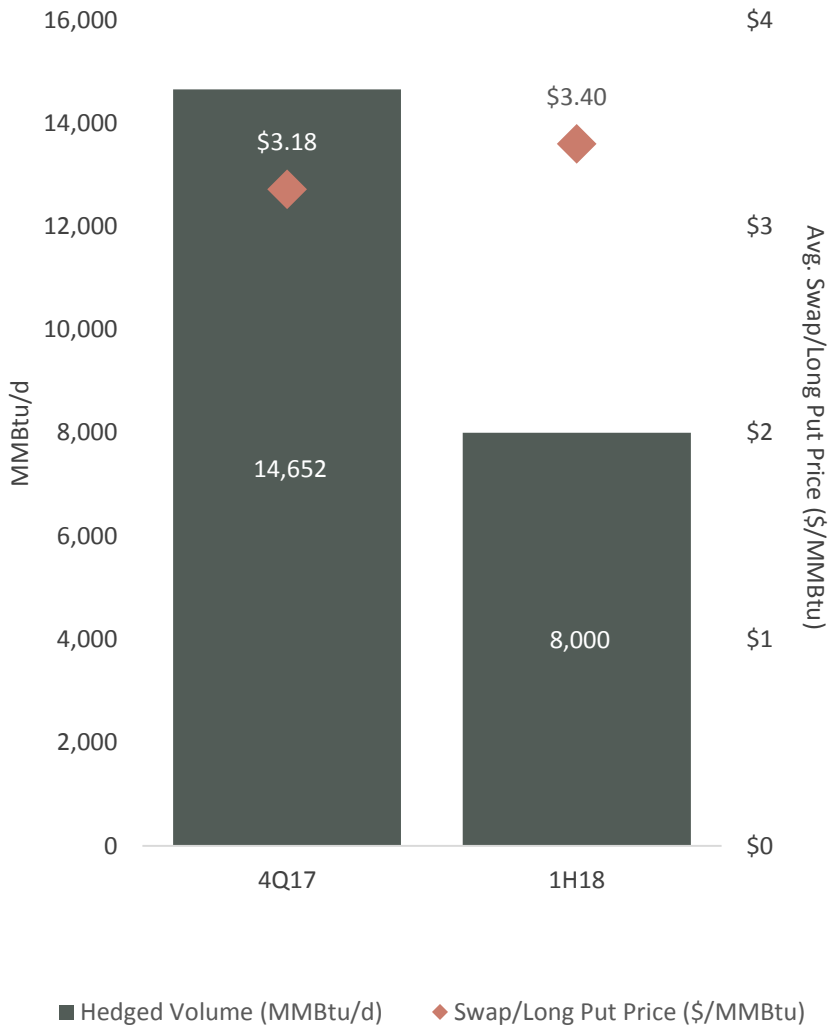
1) Hedge contracts as of October 27, 2017.
2) Source: FactSet as of November 06, 2017.

Natural Gas Hedge Contracts [1]

~15% of 2018 Consensus Volumes Hedged [2]

Natural Gas (MMBtu, $/MMBtu)	4Q17	1H18	2H18
Swaps	124,000	-	-
Strike Price	$3.39		
Costless Collars	856,000	720,000	-
Ceiling	$3.78	$3.84	
Floor	$3.27	$3.40	
Three-way Collars	368,000	-	-
Ceiling	$3.71		
Floor	$3.00		
Short Put	$2.50		
Total Hedge Volume	1,348,000	720,000	-
Weighted Average Floor Price	$3.18	$3.40	

Price Protection Over $3 through 1Q18



1) Hedge contracts as of October 27, 2017.
2) Source: FactSet as of November 06, 2017.

Quarterly Cash Flow Statement

	3Q16	4Q16	1Q17	2Q17	3Q17
Cash flows from operating activities:					
Net income (loss)	$ 21,139	$ (1,746)	$ 47,129	$ 33,390	$ 17,081
Adjustments to reconcile net income (loss) to cash provided by operating activities:					
Depreciation, depletion and amortization	17,733	22,512	24,932	26,765	29,132
Accretion expense	187	196	184	208	131
Amortization of non-cash debt related items	810	744	665	589	441
Deferred income tax (benefit) expense	(62)	48	466	323	237
Net (gain) loss on derivatives, net of settlements	(1,044)	11,030	(17,794)	(10,761)	12,947
Loss on sale of other property and equipment	—	—	—	62	—
Non-cash gain for early debt extinguishment	—	9,883	—	—	—
Non-cash expense related to equity share-based awards	778	811	930	4,865	1,219
Change in the fair value of liability share-based awards	3,371	908	(291)	1,982	732
Payments to settle asset retirement obligations	(576)	(576)	(765)	(816)	(250)
Changes in current assets and liabilities:					
Accounts receivable	(11,608)	(13,611)	(4,066)	(3,744)	(4,338)
Other current assets	54	(535)	576	(874)	(38)
Current liabilities	15,702	5,473	9,903	(4,223)	1,854
Change in other long-term liabilities	—	10	—	120	1
Change in long-term prepaid	—	—	—	—	(4,650)
Change in other assets, net	(1,221)	831	(523)	(247)	(606)
Payments to settle vested liability share-based awards	—	—	(8,662)	(4,511)	—
Net cash provided by operating activities	45,263	35,978	52,684	43,128	53,893
Cash flows from investing activities:					
Capital expenditures	(47,418)	(67,334)	(66,154)	(79,936)	(121,128)
Acquisitions	(18,033)	(352,622)	(648,485)	(58,004)	(8,015)
Acquisition deposit	(32,700)	(13,438)	46,138	—	—
Proceeds from sales of mineral interests and equipment	(708)	1,639	—	—	—
Net cash used in investing activities	(98,859)	(431,755)	(668,501)	(137,940)	(129,143)
Cash flows from financing activities:					
Borrowings on senior secured revolving credit facility	74,000	—	—	—	—
Payments on senior secured revolving credit facility	(114,000)	—	—	—	—
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 due 2024	—	—	—	8,250	—
Issuance of common stock	421,908	634,862	—	—	—
Payment of preferred stock dividends	(1,824)	(1,824)	(1,824)	(1,823)	(1,824)
Payment of deferred financing costs	(640)	(10,153)	—	(6,765)	(401)
Tax withholdings related to restricted stock units	(170)	—	(79)	(974)	(65)
Net cash provided by financing activities	379,274	722,885	(1,903)	198,688	(2,290)
Net change in cash and cash equivalents	325,678	327,108	(617,720)	103,876	(77,540)
Balance, beginning of period	207	325,885	652,993	35,273	139,149
Balance, end of period	$ 325,885	$ 652,993	$ 35,273	$ 139,149	$ 61,609

Non-GAAP Reconciliation [1]

	3Q16	4Q16	1Q17	2Q17	3Q17
Adjusted Income Reconciliation					
Income (loss) available to common stockholders	$ 19,315	$ (3,570)	$ 45,305	$ 31,566	$ 15,257
Adjustments:					
Change in valuation allowance	(7,907)	559	(13,119)	(11,194)	(6,064)
Net (gain) loss on derivatives, net of settlements	(679)	7,170	(11,566)	(6,995)	8,416
Change in the fair value of share-based awards	2,192	590	(189)	(315)	475
Settled share-based awards	—	—	—	4,128	—
Loss on early redemption of debt	—	8,374	—	—	—
Adjusted Income	$ 12,921	$ 13,123	$ 20,431	$ 17,190	$ 18,084
Adjusted Income per fully diluted common share	$ 0.09	$ 0.08	$ 0.10	$ 0.09	$ 0.09
Adjusted EBITDA Reconciliation					
Net income (loss)	$ 21,139	$ (1,746)	$ 47,129	$ 33,390	$ 17,081
Adjustments:					
Net (gain) loss on derivatives, net of settlements	(1,044)	11,030	(17,794)	(10,761)	12,947
Non-cash stock-based compensation expense	4,150	1,718	639	499	1,952
Settled share-based awards	—	—	—	6,351	—
Loss on early redemption of debt	—	12,883	—	—	—
Acquisition expense	456	1,263	450	2,373	205
Income tax (benefit) expense	(62)	48	466	322	237
Interest expense	831	1,369	665	589	444
Depreciation, depletion and amortization	17,733	22,512	24,932	26,765	29,132
Accretion expense	187	196	184	208	131
Adjusted EBITDA	$ 43,390	$ 49,273	$ 56,671	$ 59,736	$ 62,129
Adjusted EBITDA inclusive of Pro forma Adjustments [2]	$ 52,876	$ 54,030	$ 59,329	$ 59,736	$ 62,129

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]

	3Q16	4Q16	1Q17	2Q17	3Q17
Adjusted G&A Reconciliation					
Total G&A expense	$ 7,891	$ 6,562	$ 5,206	$ 6,430	$ 7,259
Adjustments:					
Less: Early retirement expenses	—	—	—	(444)	—
Less: Early retirement expenses related to share-based compensation	—	—	—	(81)	—
Less: Change in the fair value of liability share-based awards (non-cash)	(3,372)	(857)	(307)	567	(731)
Adjusted G&A – total	4,519	5,705	5,513	6,472	6,528
Less: Restricted stock share-based compensation (non-cash)	(768)	(801)	(921)	(966)	(1,198)
Less: Corporate depreciation & amortization (non-cash)	(114)	(104)	(121)	(114)	(146)
Adjusted G&A – cash component	$ 3,637	$ 4,800	$ 4,471	$ 5,392	$ 5,184
Adjusted Total Revenue Reconciliation					
Oil revenue	$ 49,095	$ 60,559	$ 72,008	$ 72,885	$ 73,349
Natural gas revenue	6,832	8,522	9,355	9,398	11,265
Total revenue	55,927	69,081	81,363	82,283	84,614
Impact of cash-settled derivatives	4,091	2,079	(2,491)	(267)	(1,214)
Adjusted Total Revenue	$ 60,018	$ 71,160	$ 78,872	$ 82,016	$ 83,400
Total Production (Mboe)	1,527	1,689	1,838	2,021	2,074
Adjusted Total Revenue per Boe	$ 39.30	$ 42.13	$ 42.91	$ 40.58	$ 40.21
Discretionary Cash Flow Reconciliation					
Net cash provided by operating activities	$ 45,263	$ 35,978	$ 52,684	$ 43,128	$ 53,893
Changes in working capital	(2,927)	7,832	(5,890)	8,968	7,777
Payments to settle asset retirement obligations	576	576	765	816	250
Payments to settle vested liability share-based awards	—	—	8,662	4,511	—
Discretionary cash flow	$ 42,912	$ 44,386	$ 56,221	$ 57,423	$ 61,920
Discretionary cash flow per diluted share	$ 0.31	$ 0.27	$ 0.28	$ 0.28	$ 0.31

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