Third Quarter 2017 Results

Approach Resources Inc.

NOVEMBER 2, 2017

Forward-looking statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of management regarding plans, strategies, objectives, anticipated financial and operating results of the Company, including as to the Company's Wolfcamp shale resource play, estimated resource potential and recoverability of the oil and gas, estimated reserves and drilling locations, capital expenditures, typical well results and well profiles, type curve, and production and operating expenses guidance included in the presentation. These statements are based on certain assumptions made by the Company based on management's experience and technical analyses, current conditions, anticipated future developments and other factors believed to be appropriate and believed to be reasonable by management. When used in this presentation, the words "will," "potential," "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project," "target," "profile," "model" or their negatives, other similar expressions or the statements that include those words, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. In particular, careful consideration should be given to the cautionary statements and risk factors described in the Company's most recent Annual Report on Form 10-K and Quarterly Reports on Form 10-Q. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Cautionary statements regarding oil & gas quantities

The Securities and Exchange Commission ("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"), reserve or resource "potential," and other descriptions of volumes of reserves potentially recoverable through additional drilling or recovery techniques 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 actually realized by the Company.

EUR estimates, identified drilling locations and resource potential estimates 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 drilling locations that have been attributed these quantities. Factors affecting ultimate recovery include the scope of the Company's drilling project, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling and completion services and equipment, drilling results, lease expirations, regulatory approval and actual drilling results, as well as geological and mechanical factors. Estimates of unproved reserves, type/decline curves, per well EUR and resource potential may change significantly as development of the Company's oil and gas assets provides additional data.

Type/decline curves, estimated EURs, resource potential, recovery factors and well costs represent Company estimates based on evaluation of petrophysical analysis, core data and well logs, well performance from limited 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. The Company has limited production experience with this project, and accordingly, such estimates may change significantly as results from more wells are evaluated. Estimates of resource potential and EURs do not constitute reserves, but constitute estimates of contingent resources which the SEC has determined are too speculative to include in SEC filings. Unless otherwise noted, internal rate of return ("IRR") estimates are before taxes and assume New York Mercantile Exchange ("NYMEX") forward-curve oil and gas pricing and Company-generated EUR and decline curve estimates based on Company drilling and completion cost estimates that do not include land, seismic or general and administrative ("G&A") costs.

Solid foundation for long-term value

APPROACH RESOURCES OVERVIEW

Enterprise value 600 MM[1]

High-quality reserve base[2]

- 165.5 MMBoe proved reserves
- 62% liquids, 31% oil

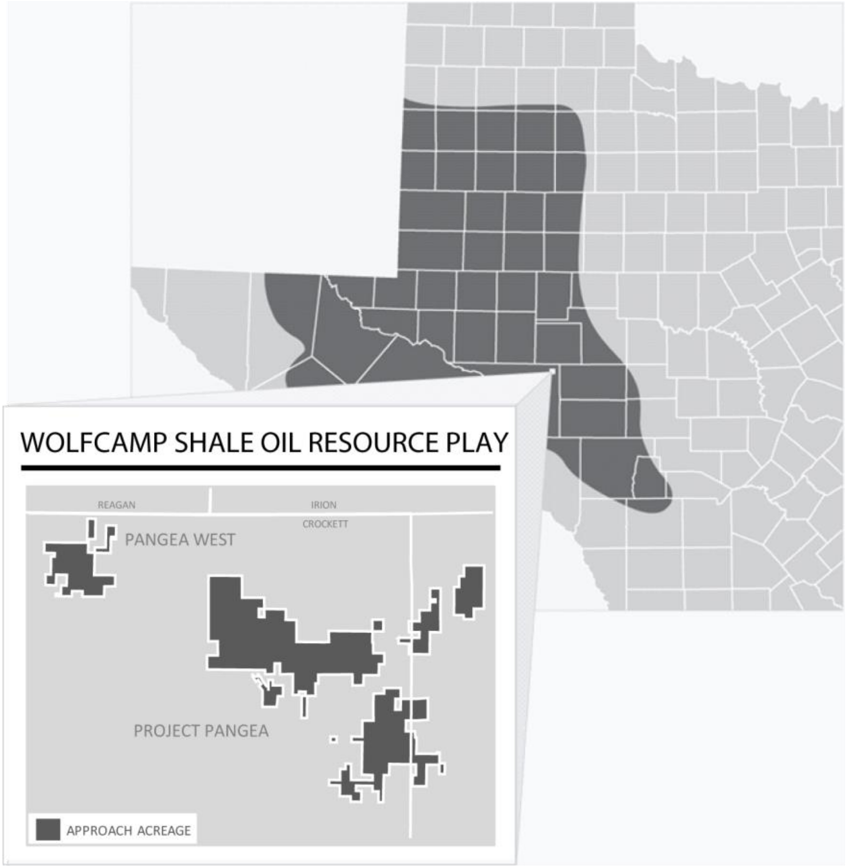
Permian Basin core operating area

- 124,000 gross (111,000 net) acres
- ~1+ BnBoe gross, unrisked resource potential
- ~1,500 identified HZ drilling locations
- ~100% working interest
- Large contiguous acreage position with multiple benches
- Prolific Wolfcamp shale is the largest estimate of unconventional oil ever assessed by USGS[3]

Capital program focused on aligning capex with cash flow

- Stable leasehold that is largely HBP provides for flexible budget
- Improving commodity prices would allow us to seamlessly increase capital budget, funded with operating cash flow
- Drilled 12 horizontal wells and completed 9 through 3Q17, ended 3Q17 with 9 DUCS
- DUC inventory provides agility in oil price recovery

ASSET OVERVIEW



1. Enterprise value is equal to market capitalization using net debt as of 9/30/17, the closing share price of $2.57 per share and the share count each as of 10/2/17.
2. Proved reserves as of 6/30/17 and acreage as of 9/30/2017. All Boe and Mcfe calculations are based on a 6 to 1 conversion ratio. Reserves were estimated using SEC pricing at June 30, 2017 and were calculated based on the first-of-the-month, twelve month average prices for oil, NGLs and natural gas of $49.00 per BBL, $15.57 per Bbl and $3.02 per MMBtu, respectively, adjusted for basis differentials, grade and quality
3. Per USGS estimates - https://www.usgs.gov/news/usgs-estimates-20-billion-barrels-oil-texas-wolfcamp-shale-formation.

Bolt-on acquisition highlights

Transaction Overview

- Current production of approximately 550 Boe/d (48% oil) with existing field infrastructure and facilities
- Estimated PDP reserves of approximately 1.8 MMBoe (42% oil)
- Funded 100% with Approach stock
- Valuation in line with PDP value at NYMEX strip
- ~ 3,200 net producing acres, held by production

Strategic Benefits

Enhances credit metrics
Reduces leverage by a half turn .

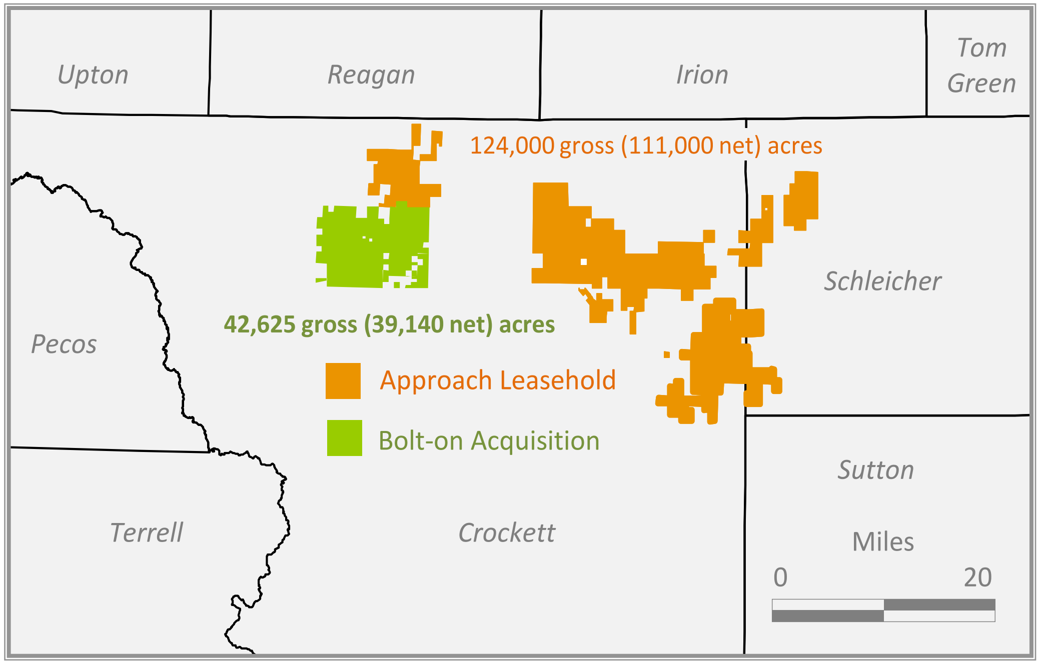
Accretive to earnings and cash flow

Improves margins and best-in-class cost structure
Seamless integration of operations and production

Complementary bolt-on asset
Shared lease line with Approach's Pangea West acreage

Undeveloped acreage optionality
Optionality/potential upside from ~35,000 net undeveloped acres

Total acreage post acquisition 166,625 gross (150,140 net)(1)



(1) Approximately 35,000 net acres subject to short term expiration and continuous drilling obligation in December 2017

Execution focused on value creation

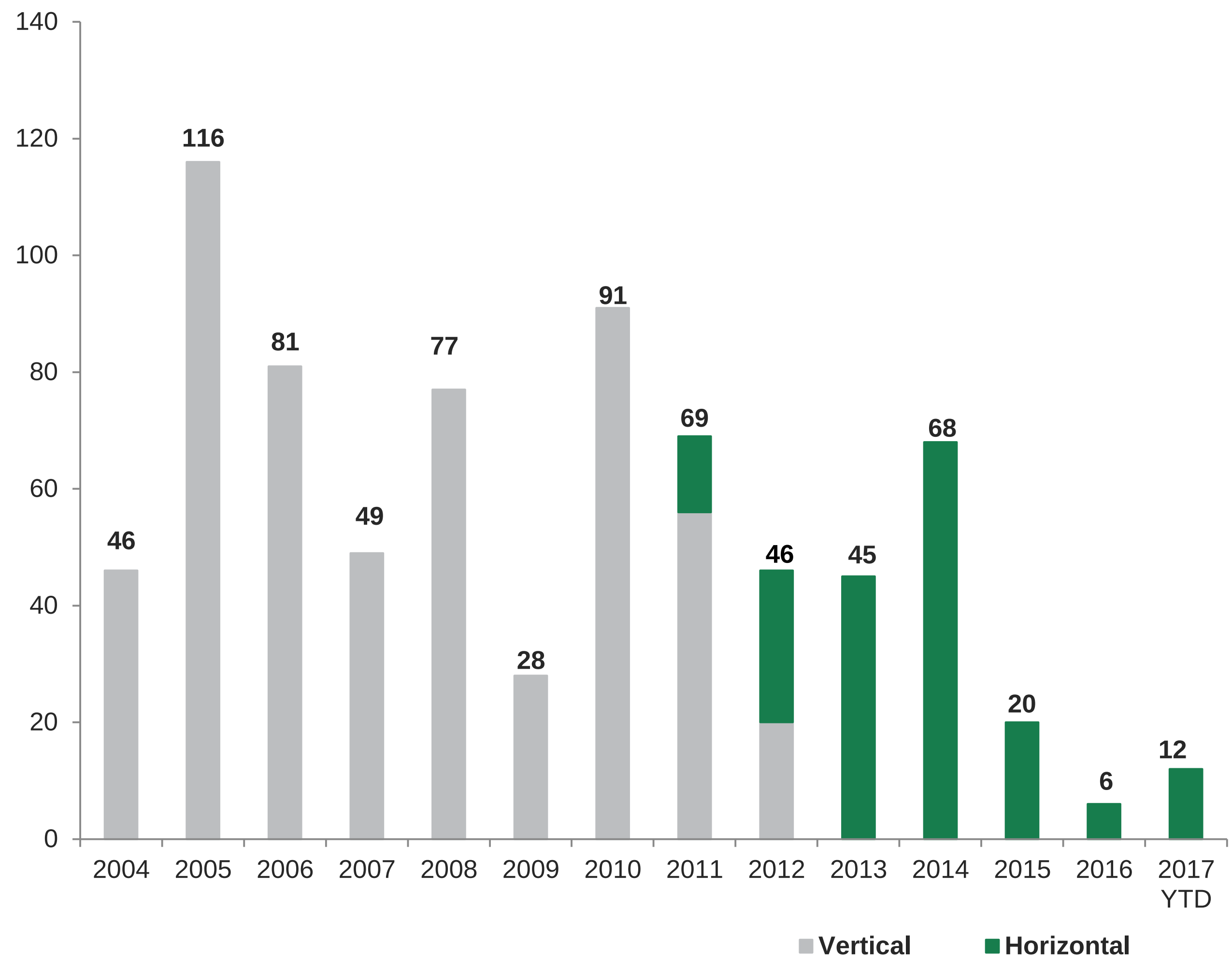
- Wells outperforming type curve
- Full cycle return development plan focused on value enhancing production
- Negotiated contracts mitigating OFS escalation
- Shallow PDP decline and low operating cost generate meaningful cash flow for operations
- Disciplined hedging program, capitalizing on balanced commodity profile
- Majority of acreage HBP, enabling focused development near infrastructure

Water Treatment System

Long history of operating in Midland Basin

WELLS DRILLED TO DATE

- Drilled more than 750 wells in Midland Basin since 2004 564 Vertical gas wells & 187 Horizontal oil wells
- One of the first-movers in the HZ Wolfcamp play with longest production history and track record of full-scale development
- Well data, core data, 3-D seismic and micro-seismic reduces future development risk
- Focused execution through commodity cycles



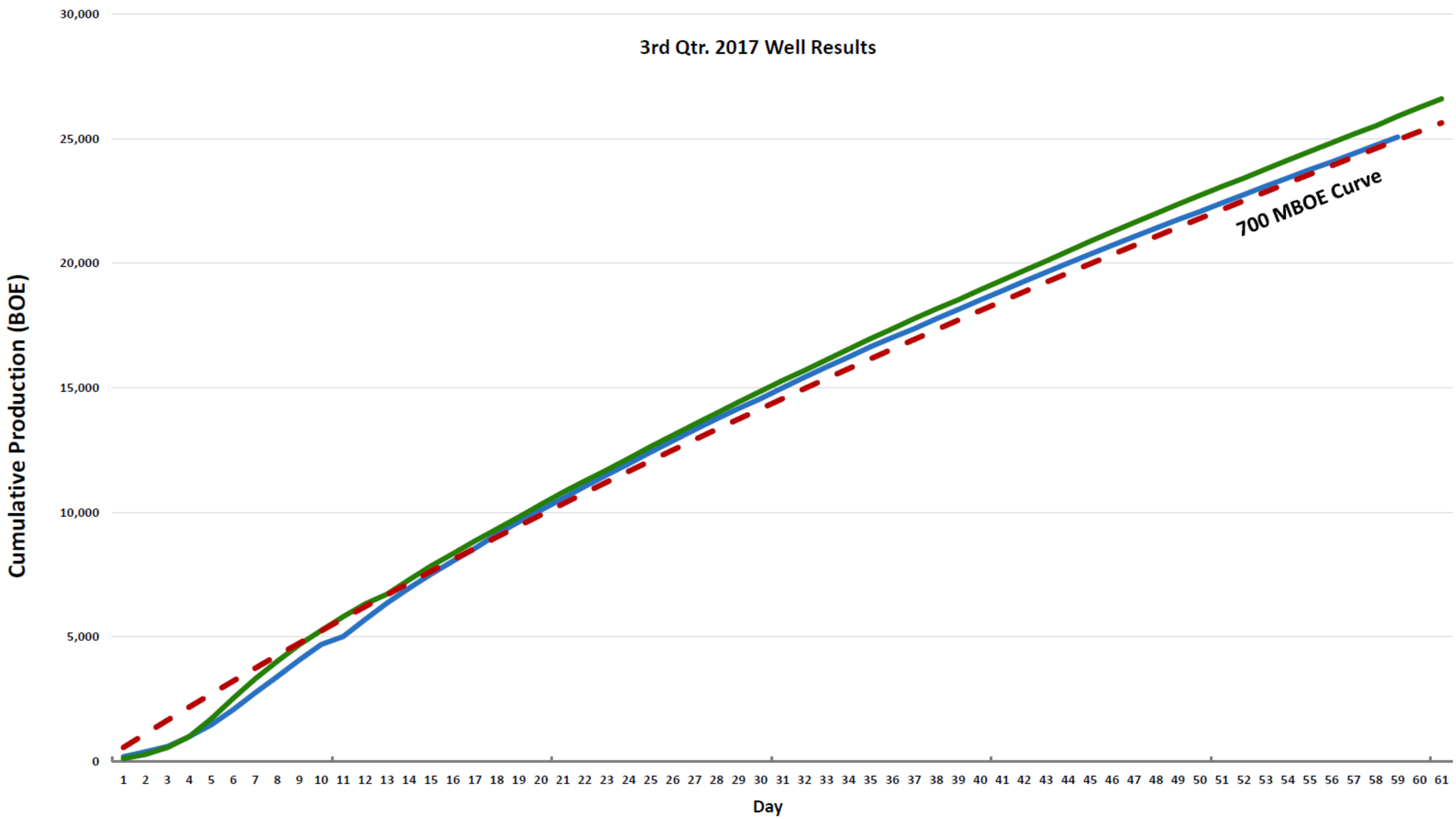
History of discipline and proactive management

- Through the industry turmoil, Approach has consistently delivered on our operational targets, financial projections and deleveraging plan

- Substantial progress made toward improved balance sheet for current commodity prices
  - Focus remains on aligning capital spending at or near cash flow
  - Best-in-class cost structure enhances margins and maximizes reinvestment cash flow
  - Shallow PDP decline rate reduces maintenance capital requirement, making more capital available for growth investment

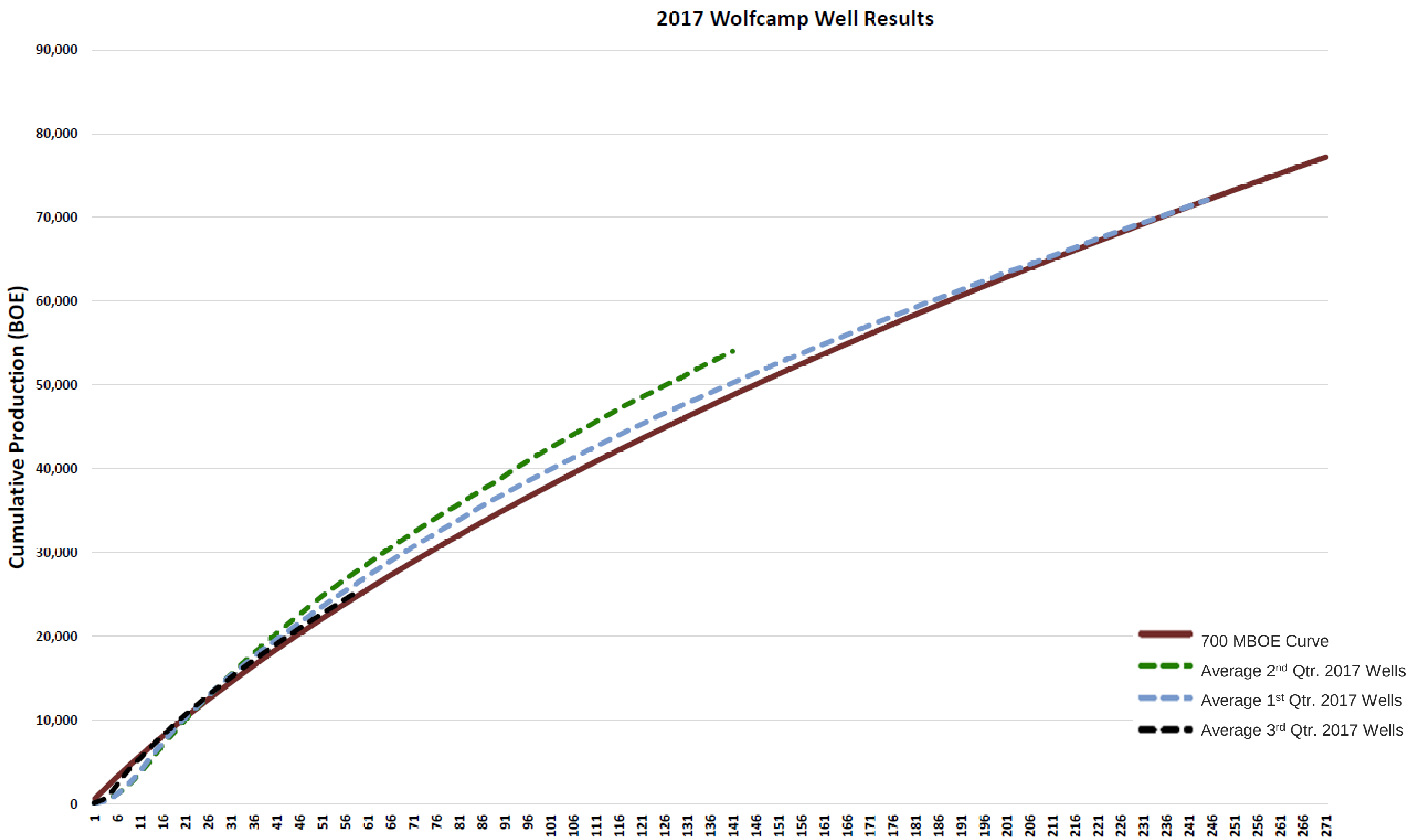
- Financial health translates to financial flexibility
  - One-of-a-kind comprehensive recapitalization transaction strengthened balance sheet
  - Simple balance sheet provides flexibility

Enhanced completion design drives outperformance



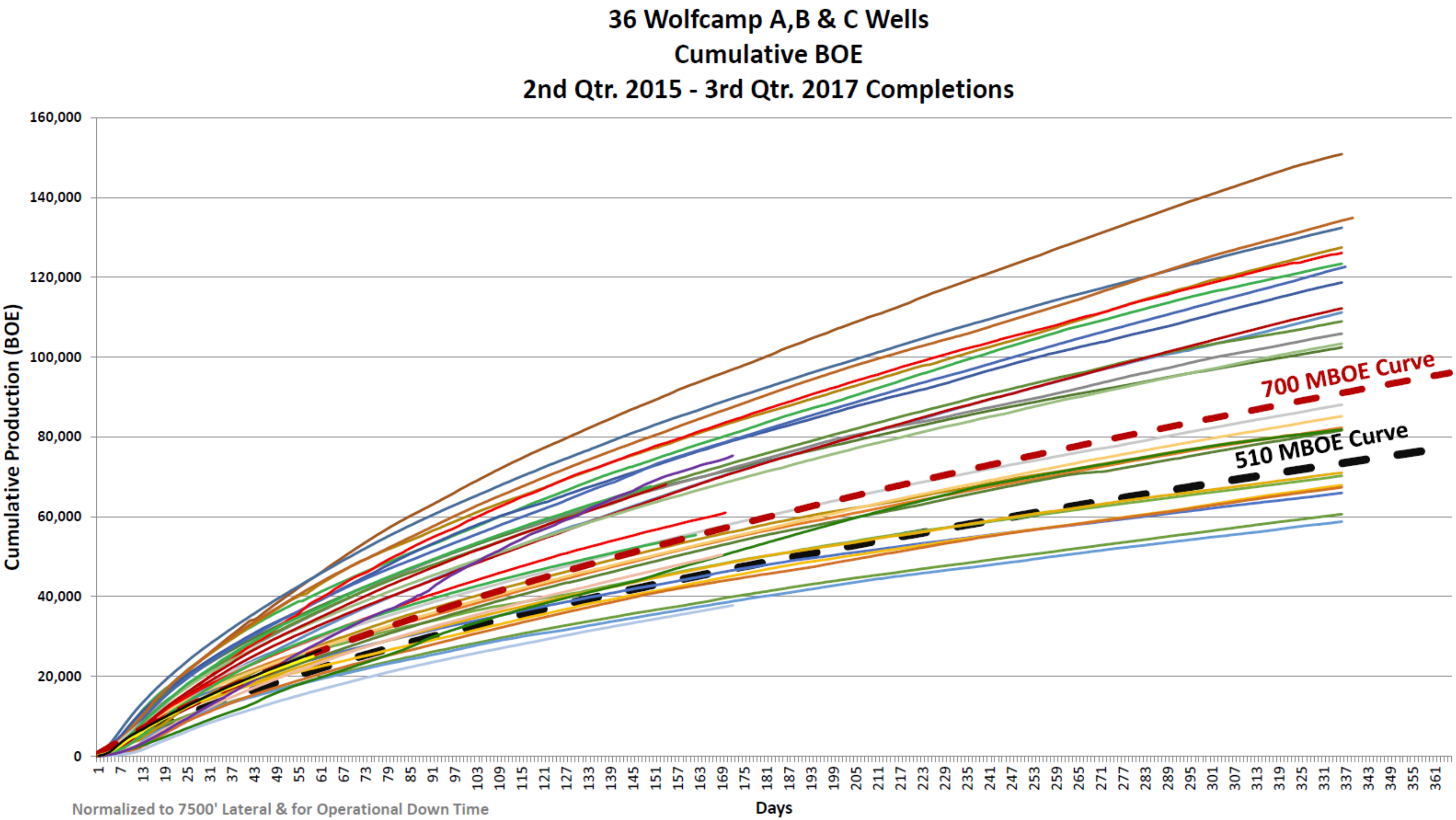
All Wells Normalized to 7500' lateral & for Operational Downtime

Enhanced completion design drives outperformance



Normalized to 7500' Lateral & for Operational Down Time

Results outperform type curve



Next generation completion design

Utilized during the 2nd and 3rd quarter science wells

✓ **Increase sand concentration**

- 1,800 – 2,000 lbs./ft. of completed lateral
- >60% 100 mesh sand

✓ **Decrease stage spacing <180'**

- Improves cluster efficiencies

• **Increase % of recycled / produced water**

- >70% of the completion fluid

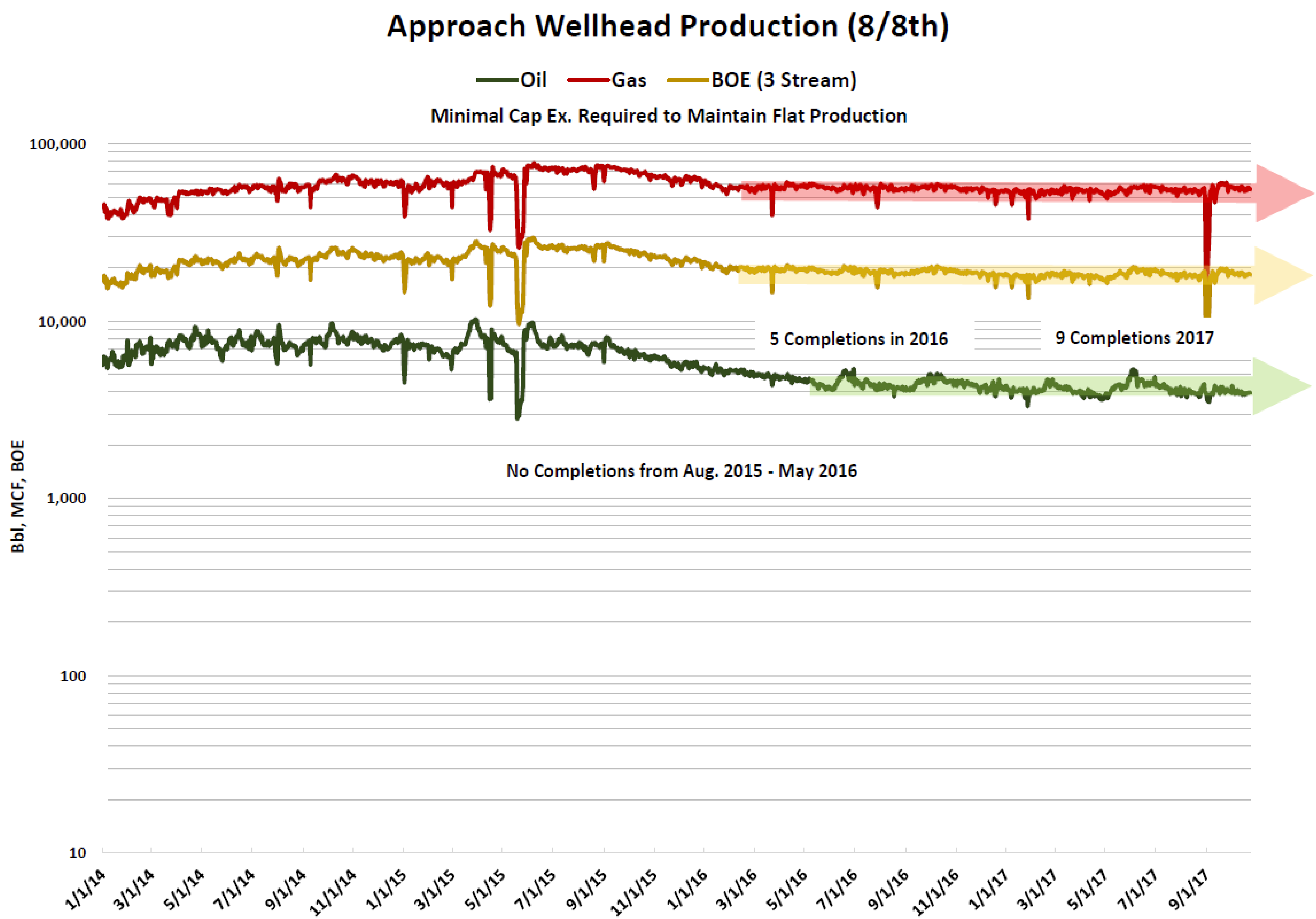
✓ **Complex nano-fluids (new class of engineered surfactants)**

- Sub-nanometer fluids
- Reduced breakdown pressure requires less hydraulic horse power
- Reduced surface tension within the micro fractures
- Reduced formation damage created by relative permeability impairment/phase trapping

• **Chemical diverters (enhancing complexity of created micro fractures)**

- Improves perforation cluster effectiveness
- Enhances far-field diversion inside the created fracture network which induces additional branch fracturing

Approach asset base is unique due to low capital intensity



Third quarter 2017 highlights

OPERATION HIGHLIGHTS

- Produced **11.5** Mboe, despite impact of approximately 500 Boe/d from Hurricane Harvey
- Drilled **1 HZ** well and completed **2 HZ** wells during the quarter
- DUC inventory of **9 HZ** wells at September 30, 2017
- Average producing rate of the third quarter wells[1], outperforming a 700 MBoe curve
- $4.16 per Boe lease operating expense

1. Normalized to 7500' lateral

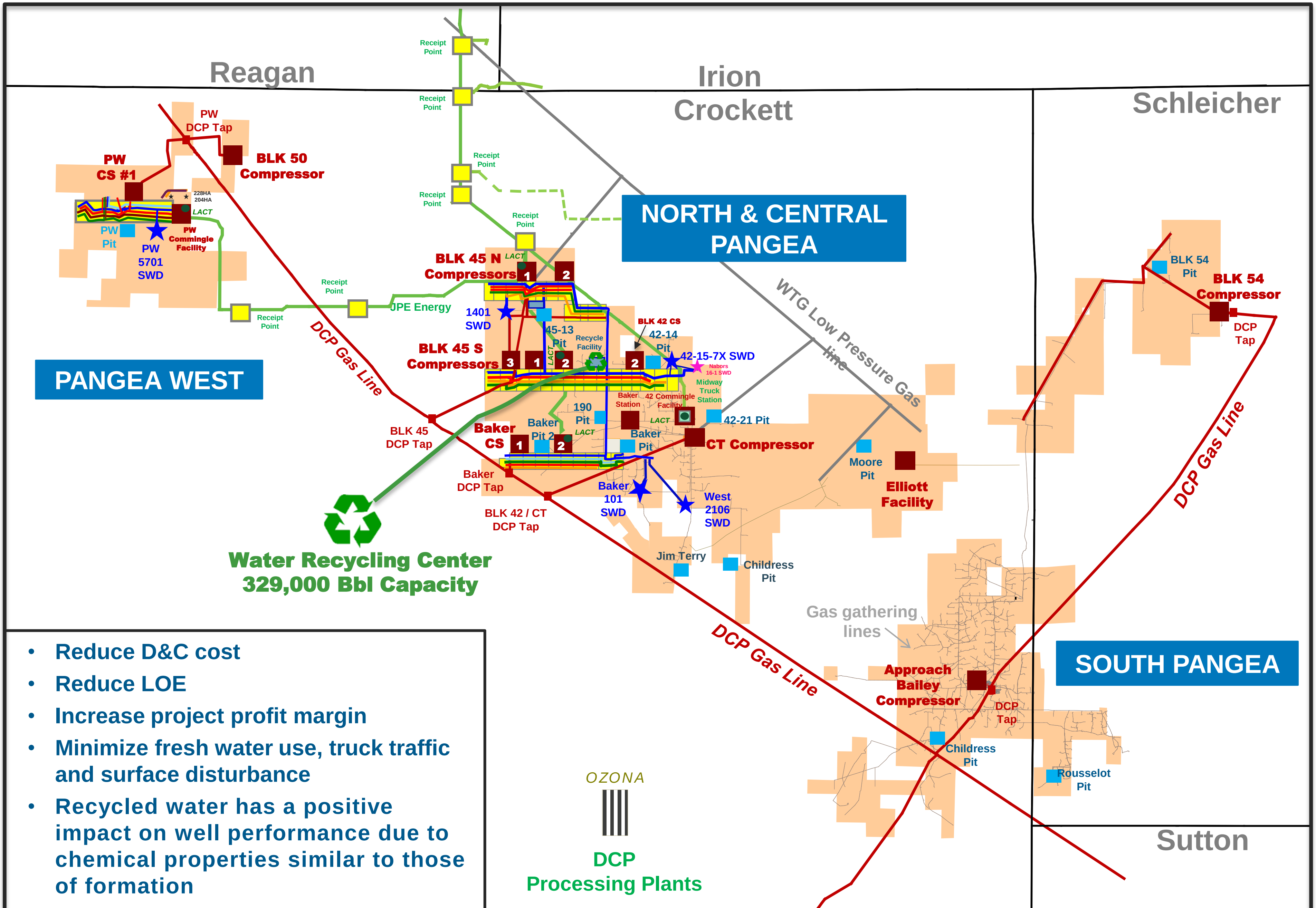
A track record of doing what we say we will do

FINANCIAL HIGHLIGHTS

- Revenue of $25.6 million, an increase of 8% over prior year quarter
- 25% reduction in interest expense over prior year, redeployed to the development of our asset
- EBITDAX (Non-GAAP) totaled $13.8 million[2], a 7% increase over prior quarter
- 13% improvement in unhedged cash margin per Boe (Non-GAAP) over prior quarter and prior period last year[2]
- Generated $13.3 million in operating cash flows

2. See "EBITDAX (unaudited)" and "Unhedged cash margin (unaudited)" slide for reconciliation to GAAP measures.

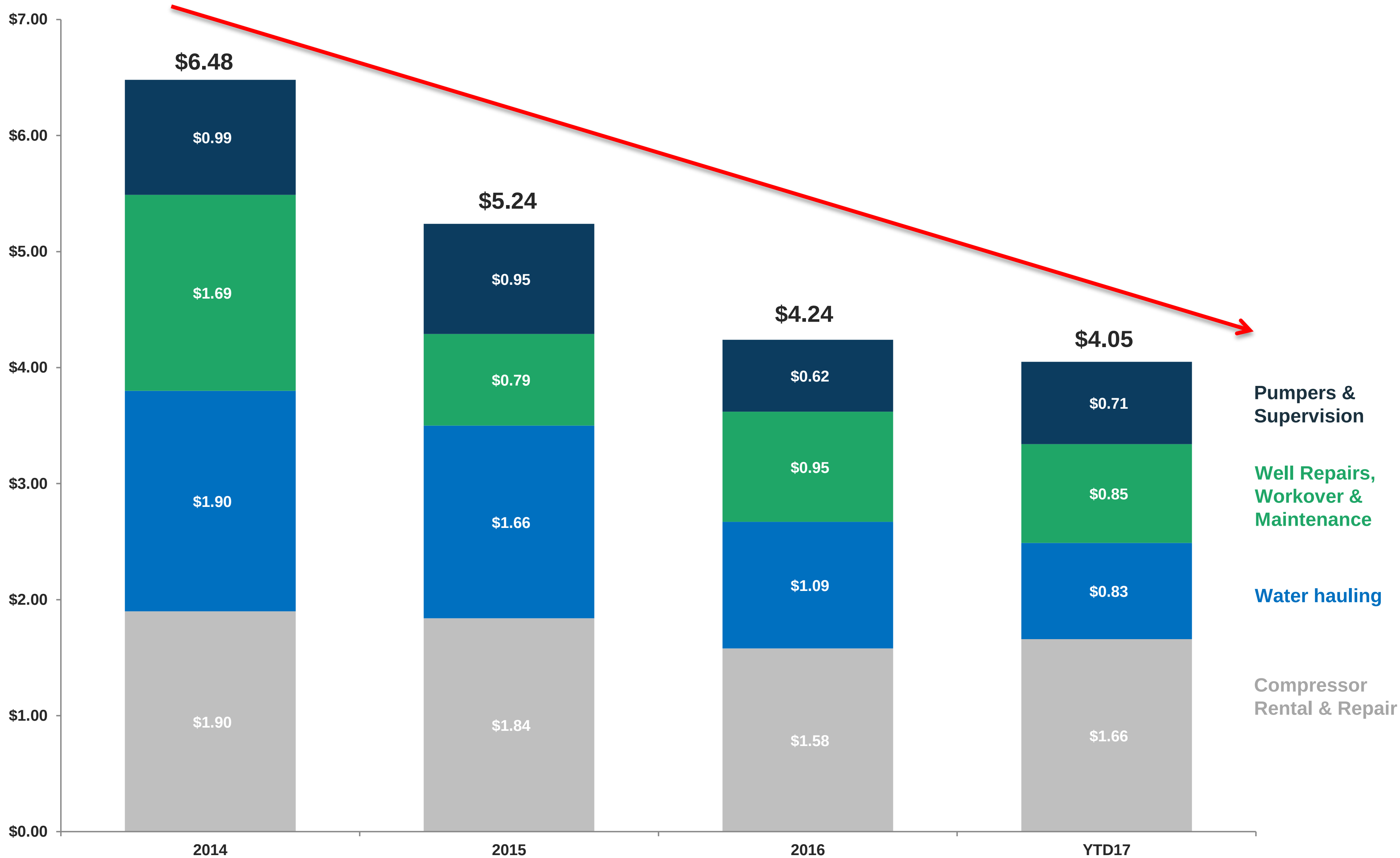
Strategic midstream asset



- Reduce D&C cost
- Reduce LOE
- Increase project profit margin
- Minimize fresh water use, truck traffic and surface disturbance
- Recycled water has a positive impact on well performance due to chemical properties similar to those of formation

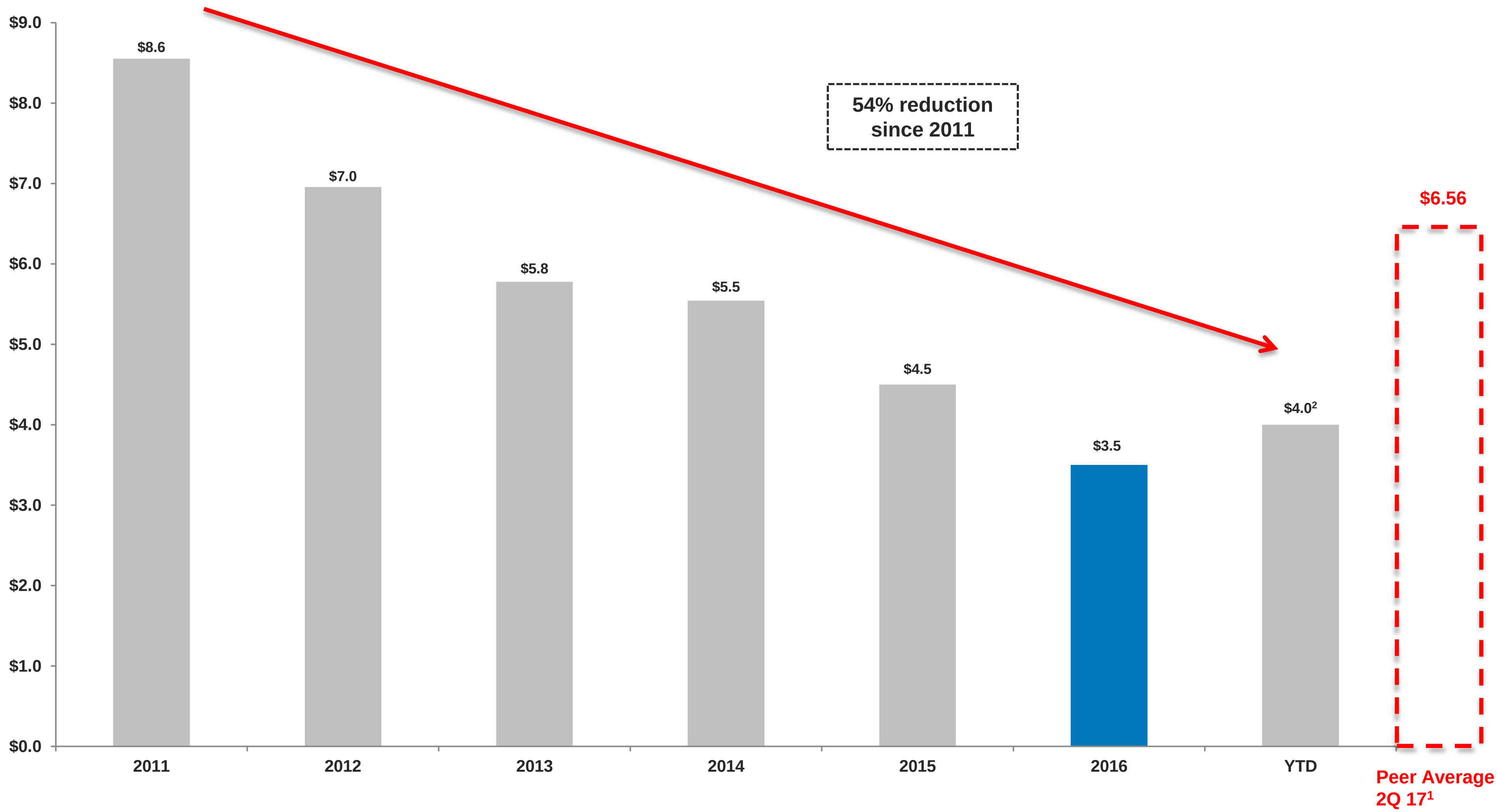
LOE cost reductions driven by water handling infrastructure and field-level operating efficiencies

AREX LOE Historical Track Record ($/Boe)



Approach continues to achieve one of the lowest cost structures in the Permian Basin

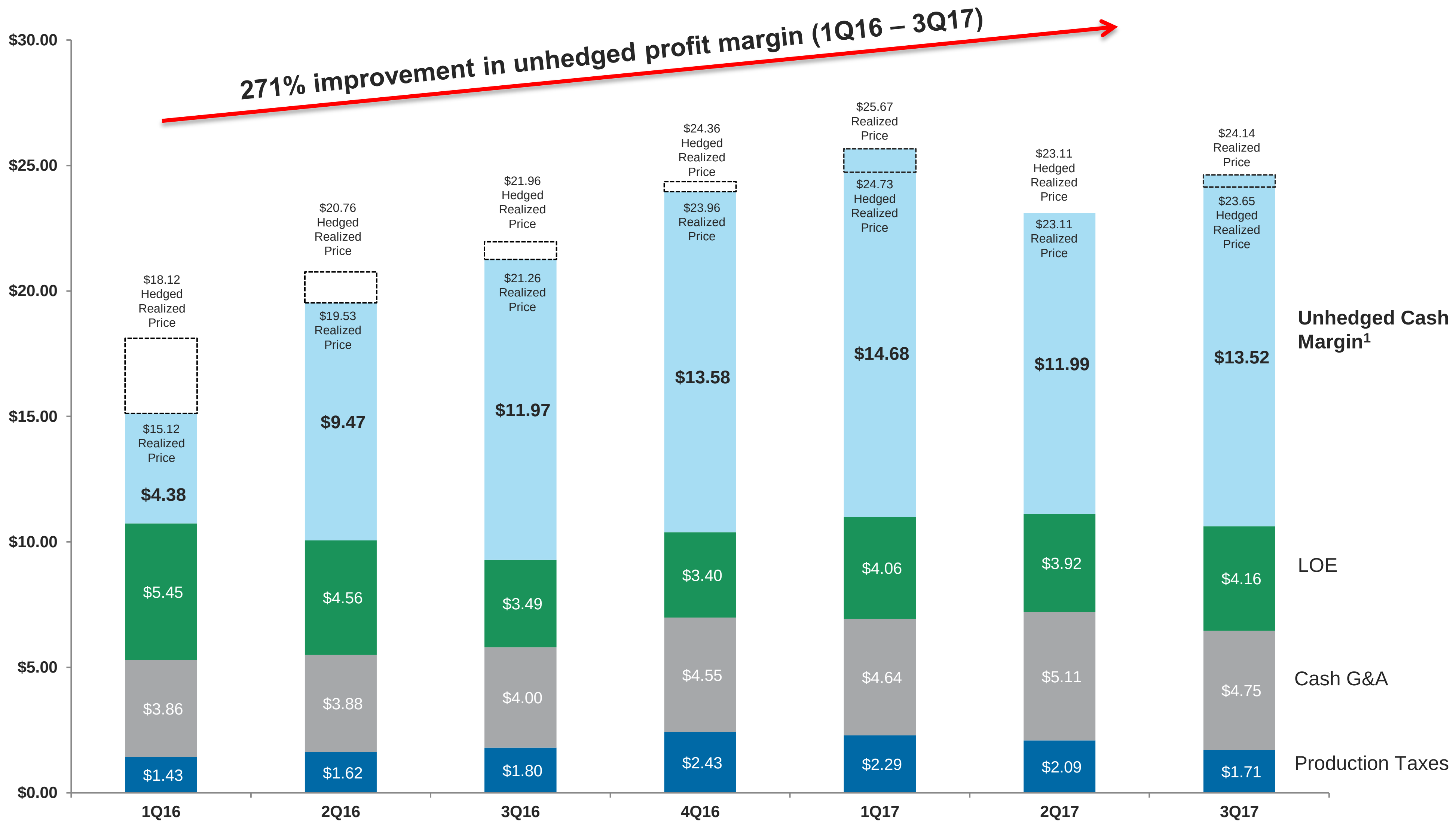
AREX D&C Historical Track Record ($ MM)



1. Source: Latest available company presentations and public filings. Peers include CPE, CXO, EGN, EPE, FANG, LPI, MTDR, PE, PXD, and RSPP.
2. For standard 7500' lateral well

Cost reductions and improvement in commodity prices are translating into expanding profit margins

Profit margin per Boe



1. Defined as unhedged revenue per Boe less LOE, production taxes, and cash G&A per Boe.

Current hedge summary

- Approximately 80% of Q4 production has been hedged (based on midpoint of guidance)
- Adding 2018 hedges

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
October 2017 – December 2017	Swap	2,500 Bbls/day	$50.23/Bbl
January 2018 – December 2018	Swap	300 Bbls/day	$50.00/Bbl
January 2018 – March 2018	Collar	1,000 Bbls/day	$50.00/Bbl - $55.05/Bbl
Natural Gas			
October 2017 – December 2017	Collar	100,000 MMBtu/month	$3.00/MMBtu - $3.65/MMBtu
October 2017 – December 2017	Collar	200,000 MMBtu/month	$2.30/MMBtu - $2.60/MMBtu
October 2017 – December 2017	Collar	200,000 MMBtu/month	$3.00/MMBtu - $3.44/MMBtu
October 2017 – December 2017	Collar	200,000 MMBtu/month	$3.00/MMBtu - $3.50/MMBtu
January 2018 – December 2018	Swap	450,000 MMBtu/month	$3.0844/MMBtu
NGLs (C2 - Ethane)			
October 2017 – December 2017	Swap	1,050 Bbls/day	$11.34/Bbl
NGLs (C3 - Propane)			
October 2017 – December 2017	Swap	750 Bbls/day	$27.916/Bbl
October 2017 – March 2018	Swap	450 Bbls/day	$30.24/Bbl
NGLs (IC4 - Isobutane)			
October 2017 – December 2017	Swap	75 Bbls/day	$36.7325/Bbl
October 2017 – March 2018	Swap	50 Bbls/day	$36.12/Bbl
NGLs (NC4 - Butane)			
October 2017 – December 2017	Swap	250 Bbls/day	$35.9205/Bbl
October 2017 – March 2018	Swap	150 Bbls/day	$35.70/Bbl
NGLs (C5 - Pentane)			
November 2017 – December 2017	Swap	250 Bbls/day	$50.61/Bbl

Balance sheet detail

AREX Liquidity and Capitalization

AREX Capitalization as of 9/30/2017 ($ MM)

Cash	$0.0
Credit Facility	291.1
7.0% Senior Notes due 2021	84.1
Total Long-Term Debt [1]	**$375.2**
Shareholders' Equity	543.1
Total Book Capitalization	**$918.3**

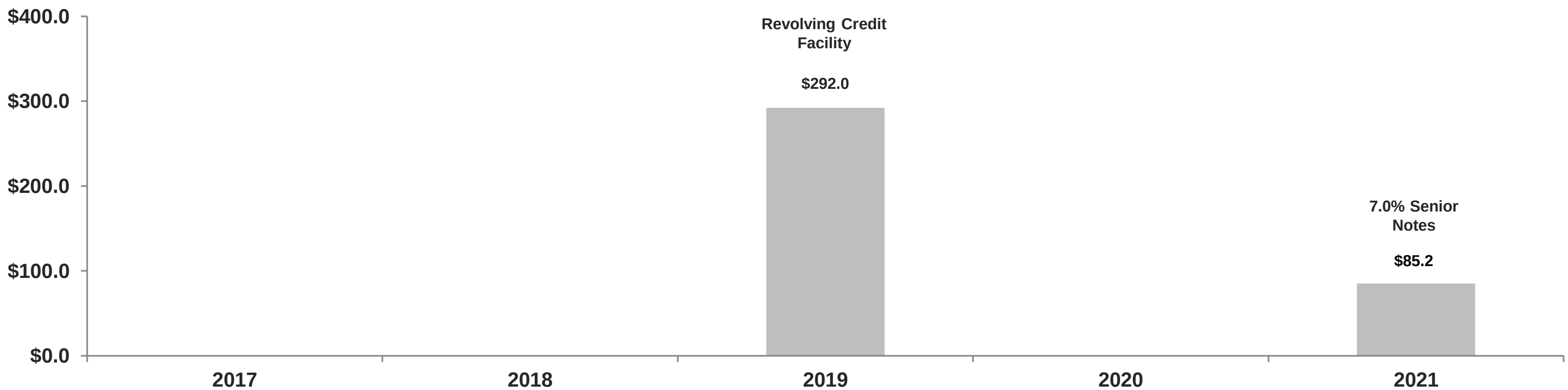
1. Long-term debt is net of debt issuance costs of $2.0 million as of September 30, 2017.

AREX Liquidity as of 9/30/2017 ($MM)

Borrowing Base	**$325.0**
Cash and Cash Equivalents	0
Borrowings under Credit Facility	(292.0)
Undrawn Letters of Credit	(0.3)
Liquidity	**$32.7**

- Interest coverage ratio of 2.6x, above minimum 1.25x covenant requirement
- Current ratio of 1.7x, above minimum 1.0x covenant requirement
- No near-term debt maturities

AREX Debt Maturity Schedule ($ MM)

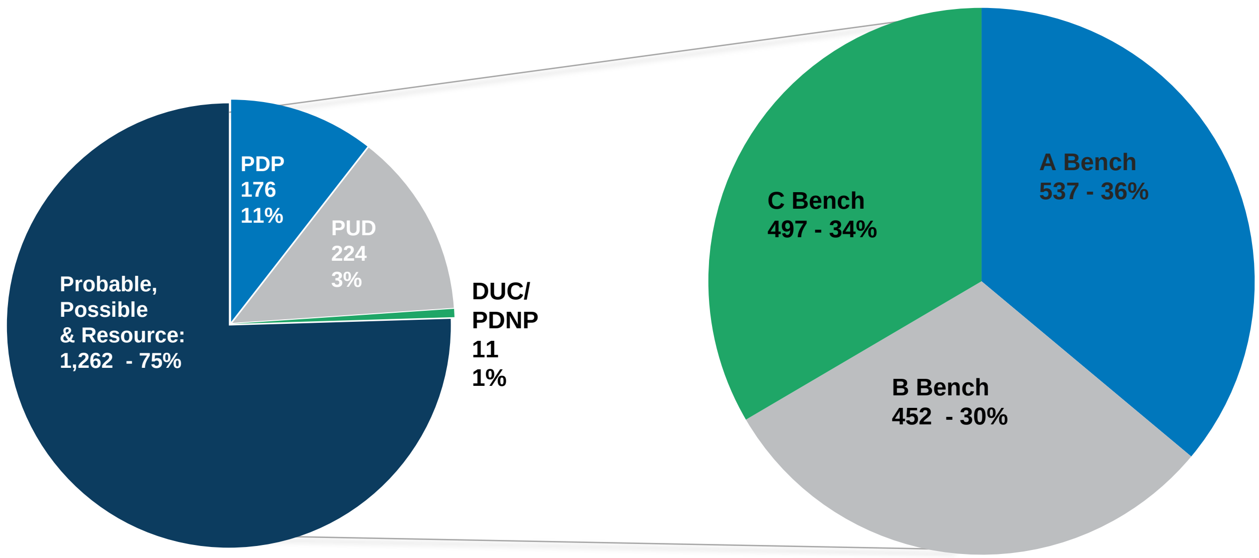


APPROACH RESOURCES

Appendix

Multi-Year Drilling Inventory Drives Upside Potential

AREX Horizontal Wells / Locations
Total identified undrilled locations
~ 1,500

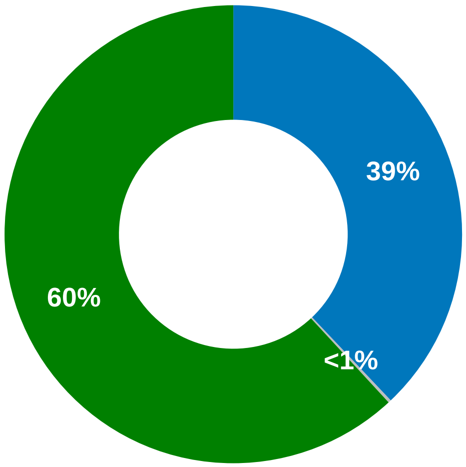


Drilled			Undrilled- Mid-Year 2017		
Bench	PDP	DUC/ PDNP	PUD	Prob, Poss & Resource	Total - % of undrilled locations
A	18	3	39	498	537 – 36%
B	109	4	75	377	452 – 30%
C	49	4	110	387	497 – 34%
Total	176	11	224	1262	1486

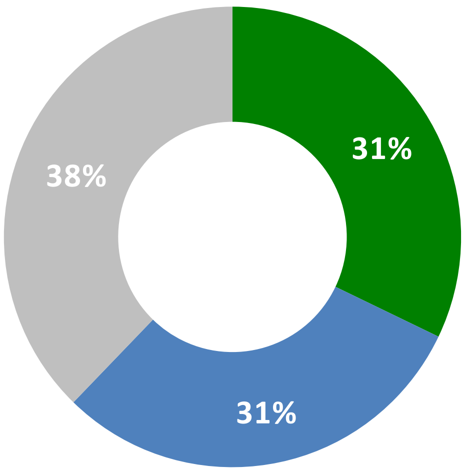
The business is anchored by long-lived, low-cost proved reserve base

- Internal reserves estimate using SEC pricing at June 30, 2017[1]
- Balanced reserves can take advantage of price recovery in any of the 3 commodities

Reserves by Commodity



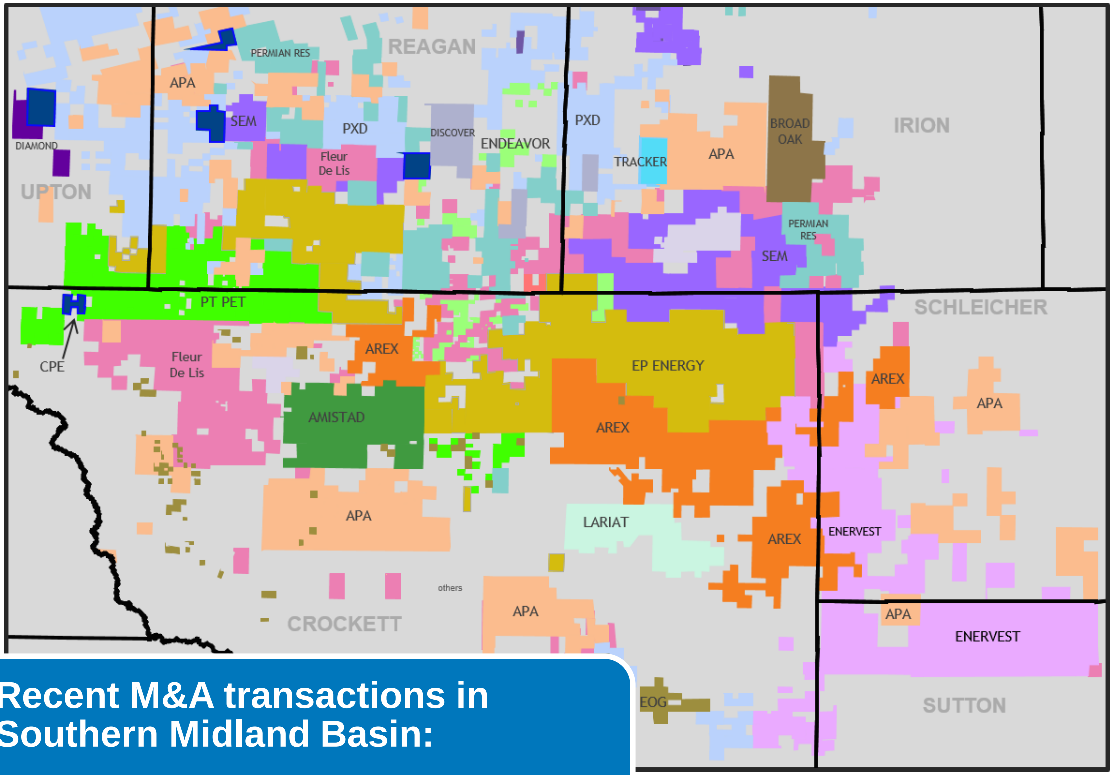
Total Proved Reserves



	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
PDP	14,030	23,009	169,373	65,268
PDNP	192	53	458	321
PUD	37,517	27,902	206,819	99,889
Total Proved	51,739	50,964	376,650	165,478

1. Reserves were estimated using SEC pricing at June 30, 2017 and were calculated based on the first-of-the-month, twelve month average prices for oil, NGLs and natural gas of $49.00 per BBL, $15.57 per Bbl and $3.02 per MMBtu, respectively, adjusted for basis differentials, grade and quality

AREX Wolfcamp assets offer significant upside



Recent M&A transactions in Southern Midland Basin:

- Amistad Energy Partners purchased EOG Crockett Co acreage
- Sequitur Energy purchased EOG Reagan, Irion, Schleicher and Crockett Co acreage
- Fleur de Lis purchased Devon Irion and Crockett Co acreage
- EP Energy / Apollo Drilling JV

Approach assets deliver:

- Balanced production profile
- Shallow natural decline rate
- Meaningful cash flow generated from operations
- Stacked-pay zone - Wolfcamp A, B and C offering ~1,500 undrilled locations
- Low cost to drill & complete due to shallow depth, efficiency, and existing water system
- Contiguous acreage position allowing large-scale infrastructure that lowers lease operating cost for the life of the property
- Proximity to the under-supplied Mexican natural gas and natural gas liquid market
- Recent acquisitions by PE-backed entrants offsetting AREX acreage attest to asset quality and upside potential when commodity prices recover

Production and expense guidance

2017 Guidance	
Annual Production Guidance:	
Oil Production (MBbls)	1,090 – 1,155
NGLs (MBbls)	1,440 – 1,480
Natural Gas (MMcf)	9,720 – 9,990
Total	4,150 – 4,300
Cash operating costs (per Boe):	
Lease operating	$4.00 - $4.50
Production and ad valorem taxes	8.5% of oil and gas revenues
Cash general and administrative (per Boe)	$4.50 - $5.00
Non-cash operating costs (per Boe):	
Exploration	$0.75 – $1.00
Total general and administrative (per Boe)	$5.50 - $6.25
Depletion, depreciation and amortization (per Boe)	$17.00 - $18.00
Capital expenditures ($MM)	~$47.0 - $49.0

Adjusted net loss (unaudited)

The amounts included in the calculation of **adjusted net loss** and **adjusted net loss per diluted share** below were computed in accordance with GAAP. We believe adjusted net loss and adjusted net loss per diluted share are useful to investors because they provide readers with a more meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website.

The following table provides a reconciliation of adjusted net loss to net loss for the three months ended September 30, 2017 and 2016.

(in thousands, except per-share amounts)	Three Months Ended September 30,	
	2017	**2016**
Net loss	$ (8,512)	$ (9,073)
Adjustments for certain items:		
Unrealized loss (gain) loss commodity derivatives	3,037	(760)
Tax effect	(1,063)	266
Adjusted net loss	$ (6,538)	$ (9,567)
Adjusted net loss per diluted share	$ (0.08)	$ (0.23)

EBITDAX (unaudited)

We define **EBITDAX** as net loss, plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized loss (gain) on commodity derivatives, (6) interest expense, net, and (7) income tax benefit. EBITDAX is not a measure of net income or cash flow as determined by GAAP. The amounts included in the calculation of EBITDAX were computed in accordance with GAAP. EBITDAX is presented herein and reconciled to the GAAP measure of net loss because of its wide acceptance by the investment community as a financial indicator of a company's ability to internally fund development and exploration activities. This measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website.

The table below provides a reconciliation of EBITDAX to net loss for the three months ended September 30, 2017 and 2016.

(in thousands)	Three Months Ended September 30,	
	2017	2016
Net loss	$ (8,512)	$ (9,073)
Exploration	100	1,047
Depletion, depreciation and amortization	16,843	19,422
Share-based compensation	1,330	1,357
Unrealized loss (gain) on commodity derivatives	3,037	(760)
Interest expense, net	5,304	7,067
Income tax benefit	(4,258)	(4,915)
EBITDAX	$ 13,844	$ 14,145

Unhedged cash margin (unaudited)

We define **unhedged cash margin** as revenue, less cash operating expenses. We define cash operating expenses as operating expenses, excluding (1) exploration expense, (2) depletion, depreciation and amortization expense, and (3) share-based compensation expense. Unhedged cash margin and cash operating expenses are not measures of operating income or cash flows as determined by GAAP. The amounts included in the calculations of unhedged cash margin and cash operating expenses were computed in accordance with GAAP. Unhedged cash margin and cash operating expenses are presented herein and reconciled to the GAAP measures of revenue and operating expenses. We use unhedged cash margin and cash operating expenses as an indicator of the Company's profitability and ability to manage its operating income and cash flows. This measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website.

The following table provides a reconciliation of unhedged cash margin and cash operating expenses to revenues and operating expenses for the three months ended September 30, 2017 and 2016.

(in thousands, except per Boe amounts)		Three Months Ended September 30,		
		2017		2016
Revenues	$	25,608	$	23,749
Production (Mboe)		1,061		1,117
Average realized price (per Boe)	$	24.14	$	21.26
Operating expenses	$	29,543	$	32,201
Exploration		(100)		(1,047)
Depletion, depreciation and amortization		(16,843)		(19,422)
Share-based compensation		(1,330)		(1,357)
Cash operating expenses	$	11,270	$	10,375
Cash operating expenses (per Boe)	$	10.62	$	9.29
Unhedged cash margin	$	14,338	$	13,374
Unhedged cash margin (per Boe)	$	13.52	$	11.97

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