Approach Resources Inc.

Fourth Quarter & Full-Year 2014 Results

FEBRUARY 25, 2015

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, IRR estimates are before taxes and assume 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 G&A costs.

Company overview

AREX OVERVIEW

Enterprise value $740MM

High-quality reserve base

- 146 MMBoe proved reserves
- 66% Liquids, 38% oil
- $1.4 BN proved PV-10

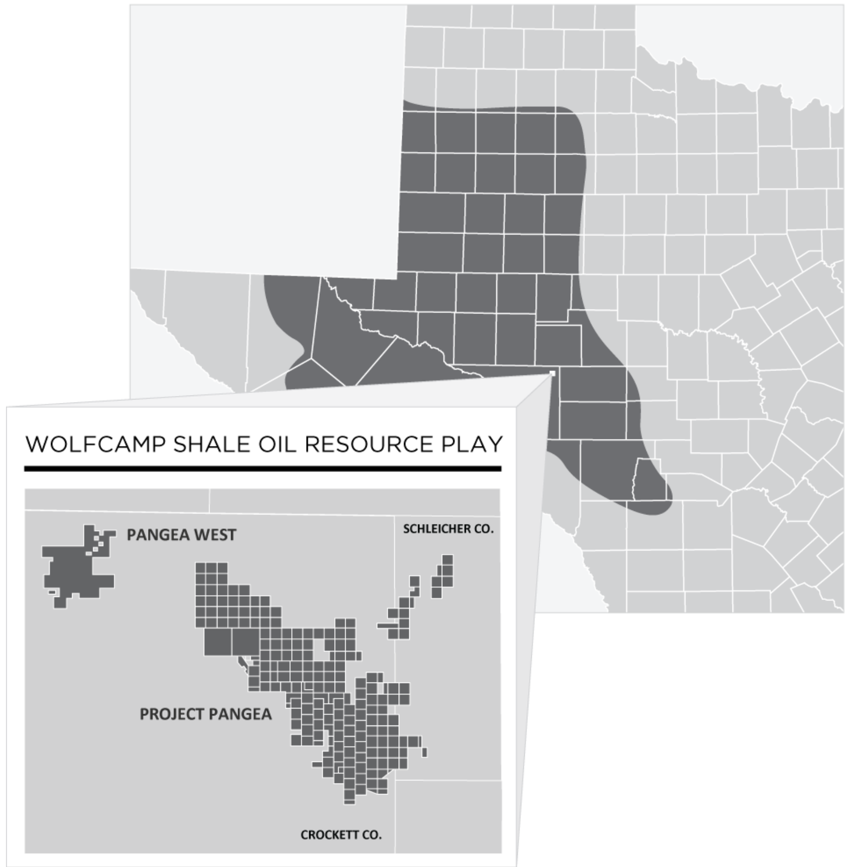
Permian core operating area

- 155,000 gross (136,000 net) acres
- ~1+ BnBoe gross, unrisked resource potential
- ~2,000 Identified HZ drilling locations targeting Wolfcamp A/B/C

2015 Capital program focused on flexibility and returns

- Running an average of 1 HZ rig in the Wolfcamp shale play with a capital budget of approximately $160 MM

ASSET OVERVIEW



Notes: Proved reserves and acreage as of 12/31/2014. All Boe and Mcfe calculations are based on a 6 to 1 conversion ratio. Enterprise value is equal to market capitalization using the closing share price of $8.64 per share on 2/17/2015, plus net debt as of 12/31/2014. See "PV-10 (unaudited)" slide.

Fourth quarter and full-year 2014 financial highlights

	FY 2014	Q4 2014
Record revenue and net income	• Revenues of \$258.5 MM (up 43% YoY) • Net income of \$56.2 MM, or \$1.42 per diluted share • Adjusted net income (non-GAAP) of \$29.2 MM, or \$0.74 per diluted share	• Revenues of \$55.1 MM (down 6% YoY despite 25% YoY drop in oil prices) • Net income of \$27.0 MM, or \$0.68 per diluted share • Adjusted net income (non-GAAP) of \$3.4 MM, or \$0.08 per diluted share
Significant cash flow and capex below budget	• EBITDAX (non-GAAP) of \$188.3 MM (up 47% YoY), or \$4.78 per diluted share (up 46% YoY) • Capital expenditures of \$393.5 MM, below \$400 MM capex guidance	• EBITDAX (non-GAAP) of \$44.3 MM (up 8% YoY), or \$1.12 per diluted share (up 7% YoY) • Capital expenditures of \$92.9 MM

Strong financial position

- Liquidity of \$300 MM at December 31st
- Borrowing base increased to \$600 MM during 4Q14, with elected commitments of \$450 MM
- 34% Debt-to-capital ratio

Note: See "Adjusted Net Income," "EBITDAX" and "Strong, Simple Balance Sheet" slides.

Strong, simple balance sheet

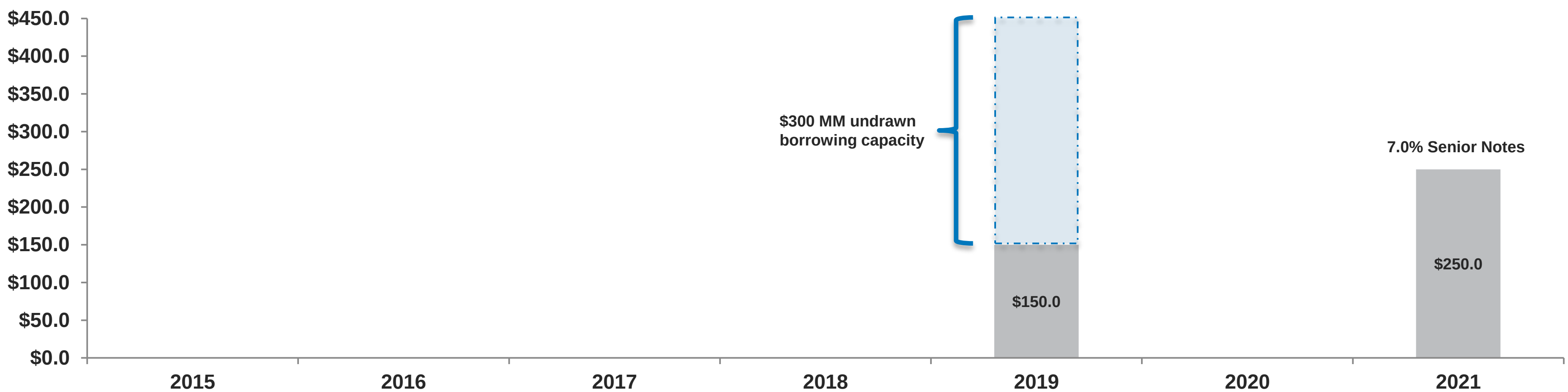
- Following the Fall 2014 redetermination, the borrowing base under our $1 billion revolving credit facility was increased to $600 million, with a company-elected commitment limit of $450 million
    - Provides a sizable cushion against more conservative bank lending framework
- Manageable Debt / LTM EBITDAX of 2.1x
- LTM EBITDAX / LTM Interest of 8.7x, well above minimum 2.5x covenant requirement
- Simple balance sheet with no near-term debt maturities

AREX Liquidity and Capitalization

AREX Capitalization as of 12/31/2014 ($ MM)	
Cash	**$0.4**
Credit Facility	150.0
7.0% Senior Notes due 2021	250.0
Total Long-Term Debt	**$400.0**
Shareholders' Equity	774.3
Total Book Capitalization	**$1,174.3**

AREX Liquidity as of 12/31/2014	
Borrowing Base	**$450.0**
Cash and Cash Equivalents	0.4
Borrowings under Credit Facility	(150.0)
Undrawn Letters of Credit	(0.3)
Liquidity	**$300.1**

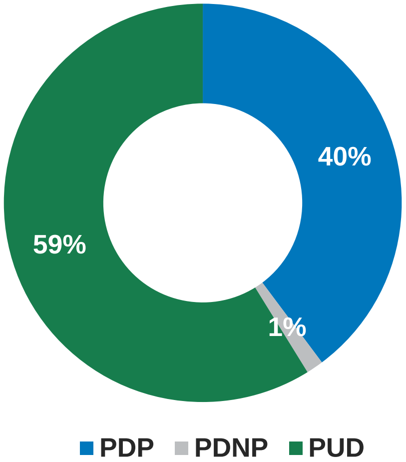
AREX Debt Maturity Schedule ($ MM)



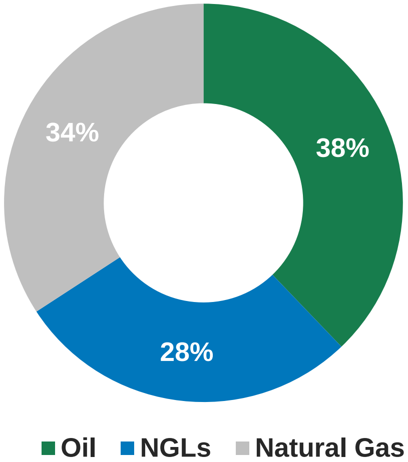
Valuation and leverage well supported by proved reserve base

- 12/31/2014 reserve summary prepared by DeGolyer and MacNaughton ("D&M")
- Replaced 819% of produced reserves at a drill-bit F&D cost of $8.94 per Boe[1]
- Total proved reserves up 27% YoY, proved oil reserves up 20% YoY
- PV-10 up 25% YoY to a record $1.4 billion

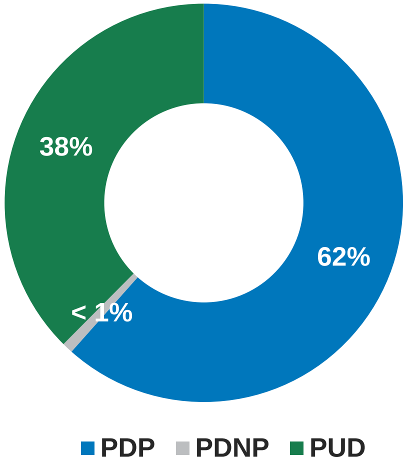
Total Proved Reserves



Reserves by Commodity



Proved PV-10



	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 ($ MM) [2]
PDP	17,599	18,319	133,583	58,181	$870.0
PDNP	379	763	5,378	2,039	$12.4
PUD	37,360	21,825	161,059	86,028	$530.6
Total Proved	55,338	40,907	300,020	146,248	$1,413.0

1. Drill-bit F&D costs are calculated by dividing the sum of exploration costs and development costs for the year by the total of reserve extensions and discoveries for the year.
2. PV-10 calculated based on the first-of-the-month, 12-month average prices for oil, NGLs and natural gas, of $94.56 per Bbl of oil, $31.50 per Bbl of NGLs and $4.55 per MMBtu of natural gas.

Fourth quarter and full-year 2014 operating highlights

	FY 2014	Q4 2014
Solid execution	• Completed **64 HZ** wells • Total production 5,049 MBoe vs early guidance of 4,790 MBoe • **2014 oil production of 5,545 Bbl/d (up 40% YoY)**	• Completed **13 HZ** wells • Total production 1,390 MBoe • **4Q14 oil production of 5,902 Bbl/d (up 14% YoY and 7% QoQ)**
Low cost, on time, and on budget	• FY2014 capex of $394 MM ($364 MM D&C) vs $400 MM budget • Cash operating cost of $14.36/Boe (down 7% YoY)	• Q4 2014 capex of $93 MM ($87 MM D&C) • Cash operating cost of $13.47/Boe (down 21% YoY)
Higher well recoveries and advancing delineation	• Strong well results from the Baker and Elliott areas demonstrate upside potential of central and eastern acreage	• 4Q14 HZ Wolfcamp B/C average IP 795 Boe/d

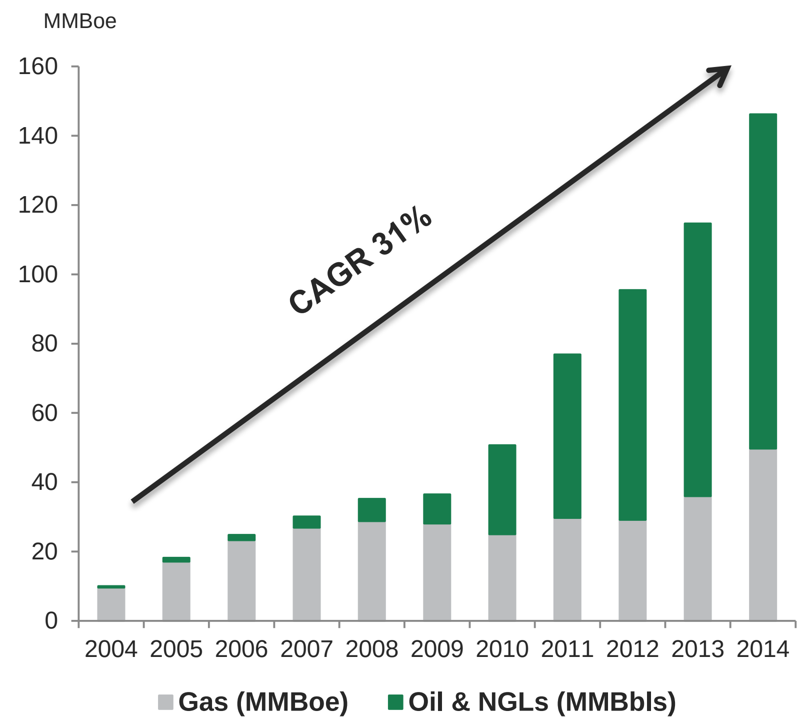
Well prepared for commodity price cycle

Key areas of focus in 2015

- Plan to stay nimble in 2015 with key focus on financial discipline and returns
- Capital budget of ~$160 MM is flexible
  - No significant drilling or service contract obligations – capital budget can be cut further
  - Plan to time and size the development budget based on magnitude of service cost reductions and direction of commodity prices
  - Delayed all completion and new well hook-ups in Q1 to March 2015 (no new wells hooked into sales since mid-December)
    - Ability to sell new production volumes at a meaningful premium vs January prices
- Operating team's top priority is service cost reduction
  - Expect reduction of 15% - 20% in D&C costs in second quarter 2015
  - Lower D&C costs significantly improves break-even price threshold
  - Water recycle center to be fully operational by end of Q1 2015
- Strong balance sheet ensures financial flexibility
  - Debt / LTM EBITDAX of 2.1x – top tier for SMID cap E&P universe
  - Liquidity of $300 MM at 12/31/2014
  - Borrowing base of $600 MM vs elected commitment of $450 MM provides further protection to liquidity
  - Solid hedge book in place for 2015

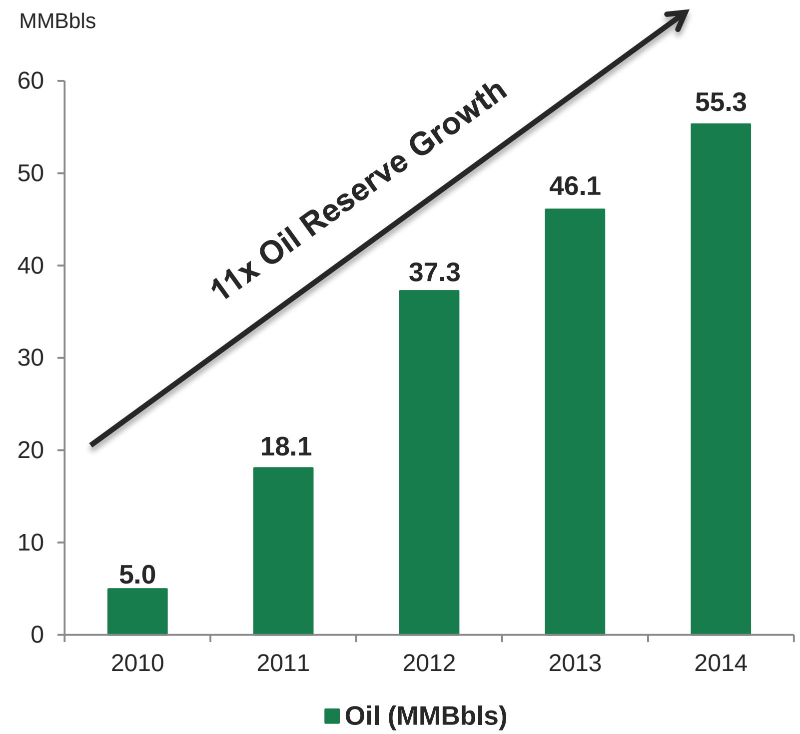
Strong track record of reserve growth

RESERVE GROWTH



- **YE14 reserves up 27% YoY**
- **Replaced 819% of produced reserves at a drill-bit F&D cost of $8.94/Boe**
- **124.8 MMBoe proved reserves booked to HZ Wolfcamp play**

OIL RESERVE GROWTH

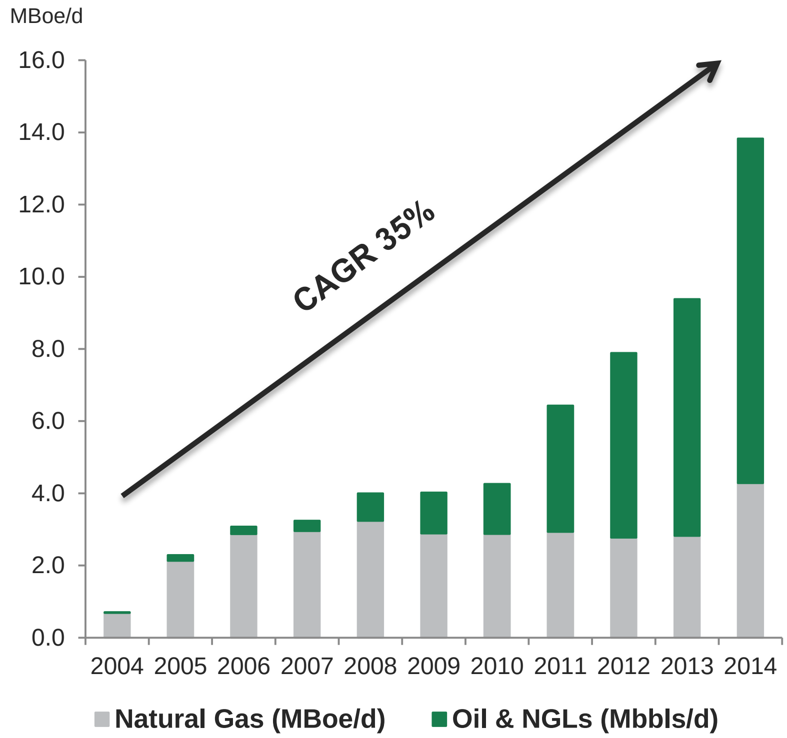


- **Strong, organic oil reserve growth driven by HZ Wolfcamp shale**
- **Oil reserves up 20% YoY**
- **Oil reserves up 11x since YE10**

Note: See “Drill-bit F&D cost (unaudited)” slide.

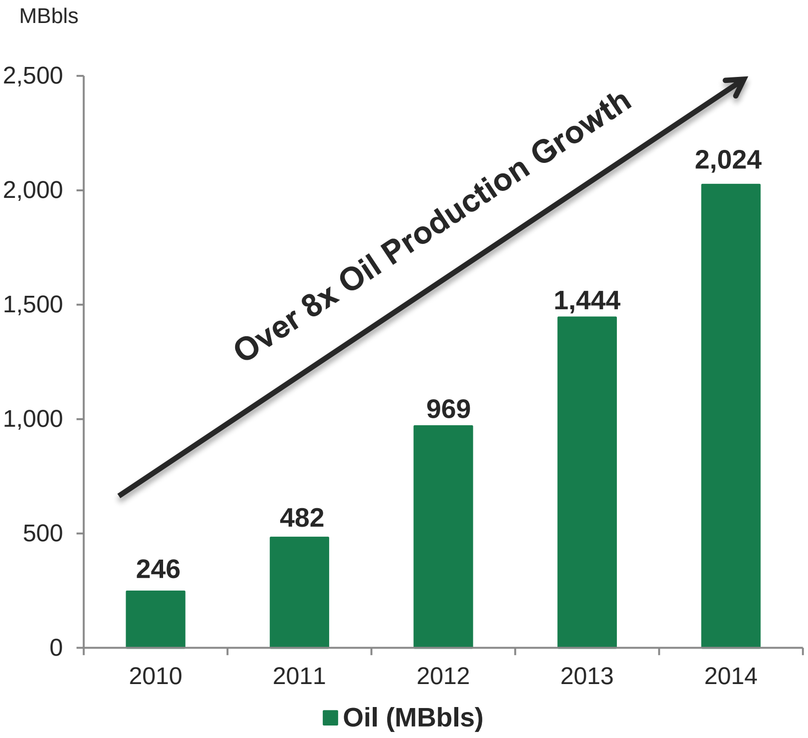
Strong track record of production growth

PRODUCTION GROWTH



- **2014 Production increased 47% YoY**
- **Targeting 10-14% production growth in 2015**

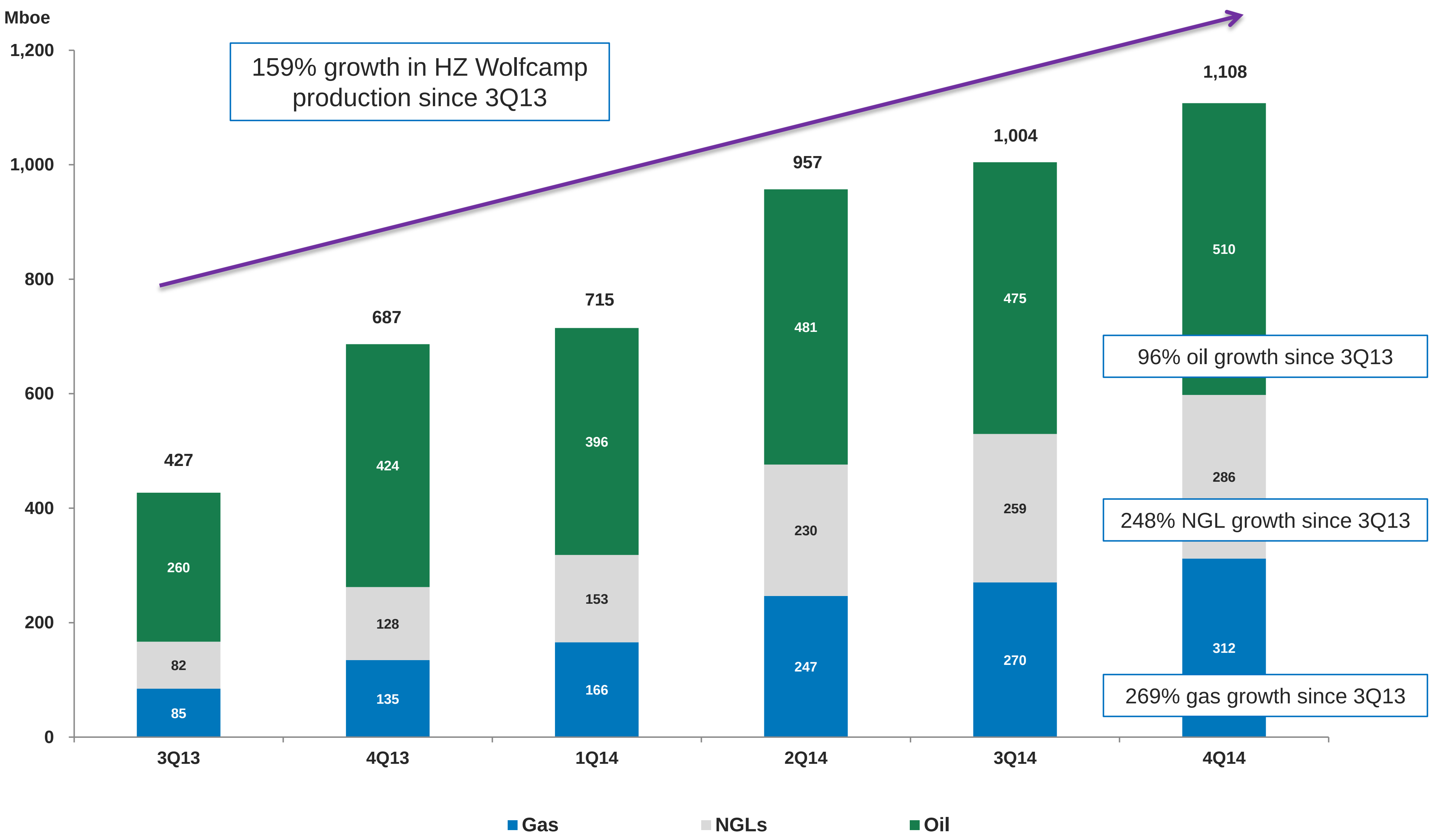
OIL PRODUCTION GROWTH



- **Strong, organic oil production growth driven by HZ Wolfcamp shale**
- **Oil production up 40% YoY**
- **Oil production up over 8x since FY10**

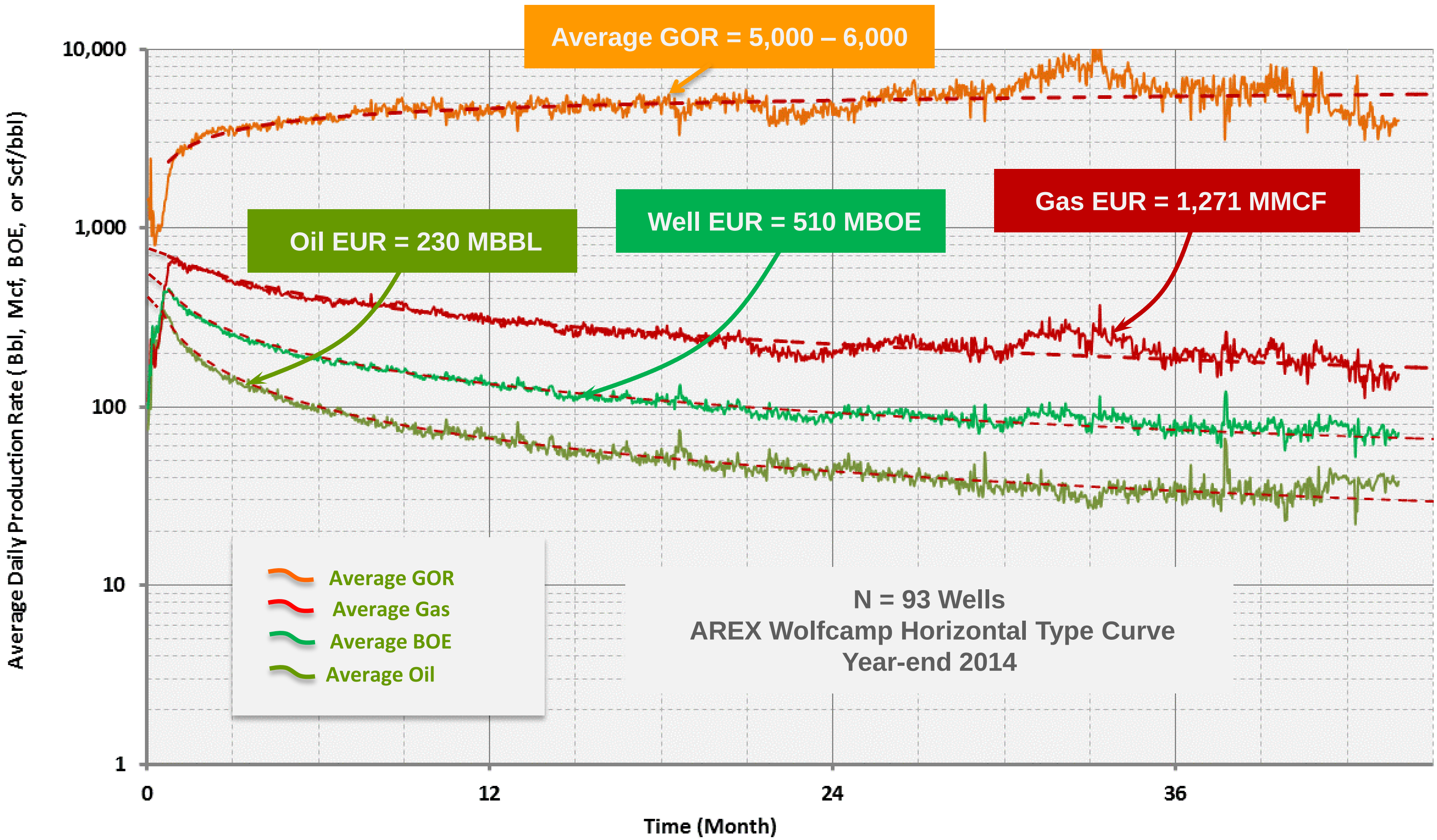
Outperformance in gas/NGL volumes achieves higher reserve recovery and drives production growth

Horizontal Wolfcamp Production by Commodity



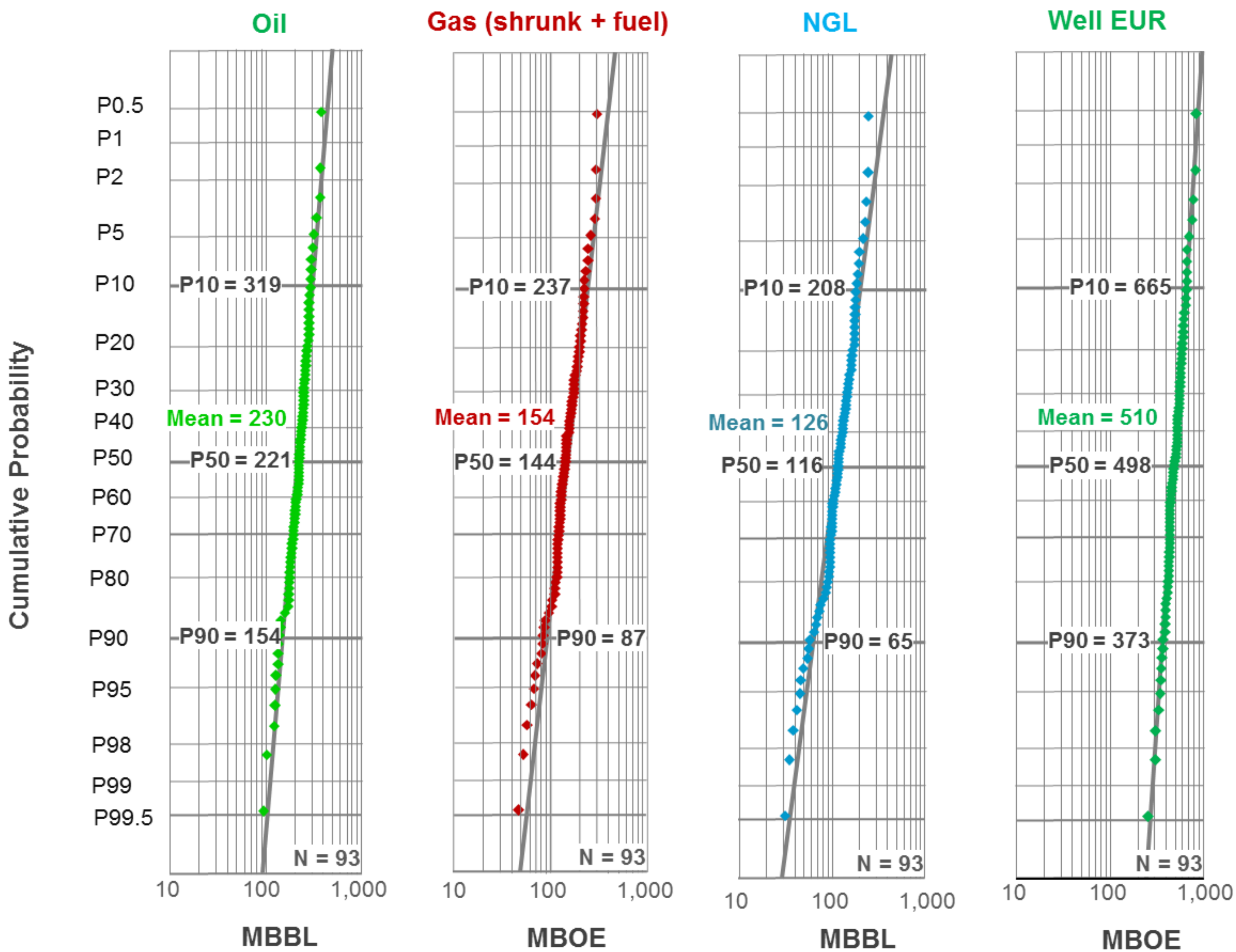
AREX HZ Wolfcamp Well Performance

AREX HZ WOLFCAMP (BOE/D)

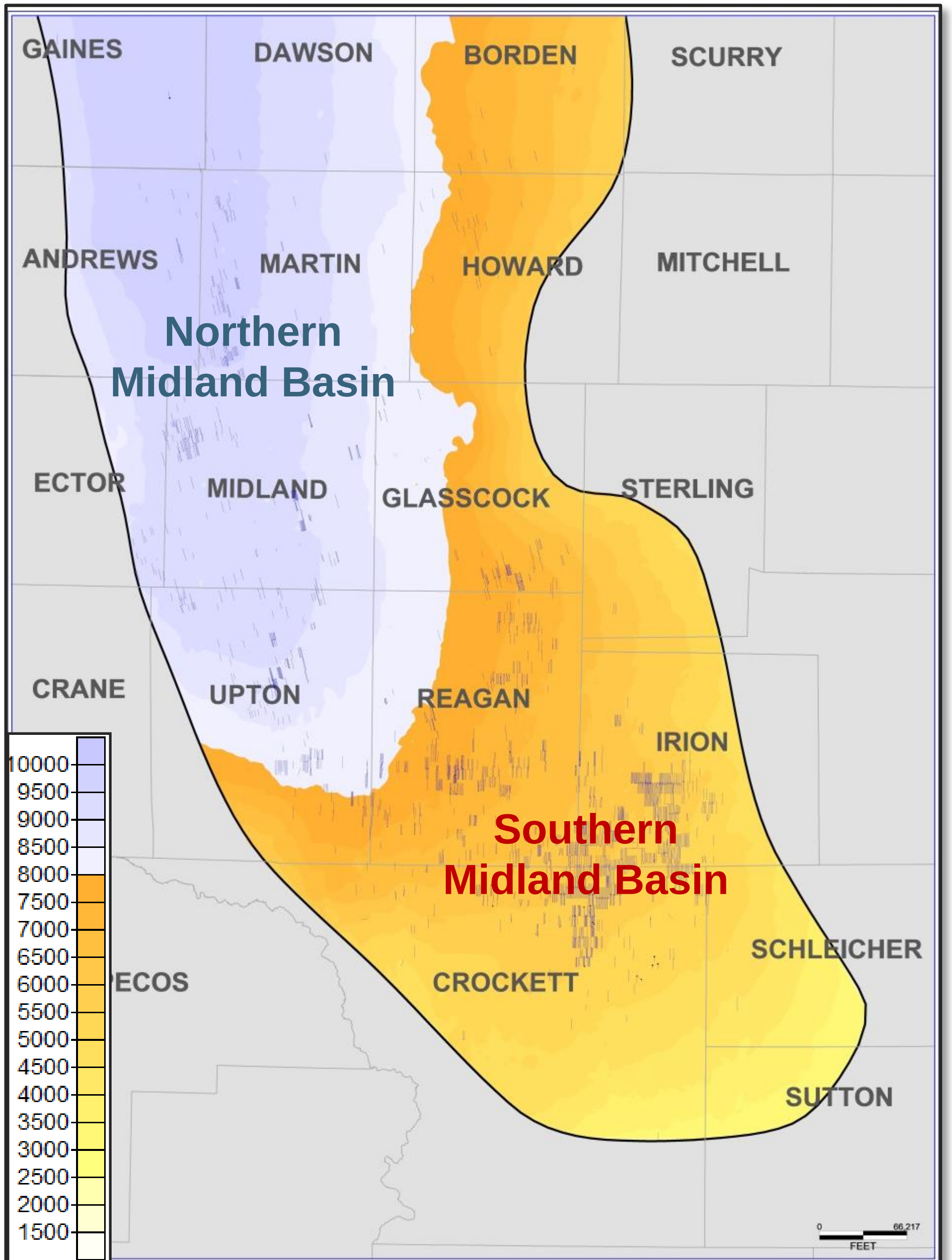


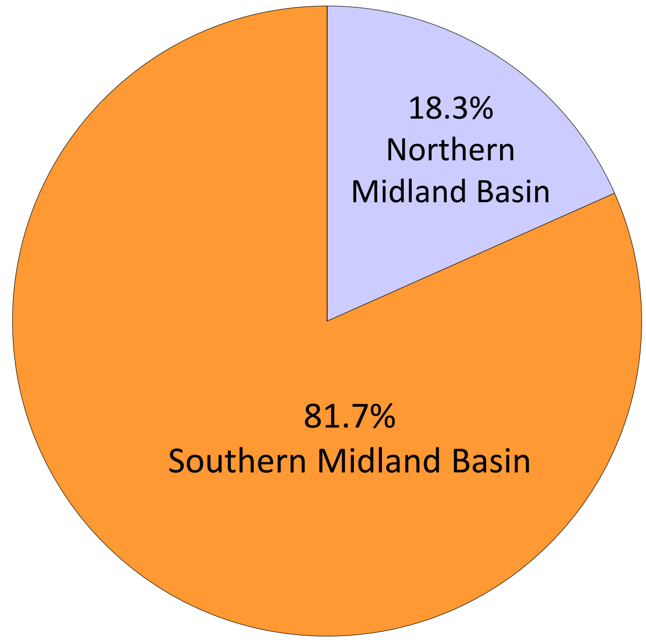
Note: Daily production normalized for operational downtime. Gas EUR is unprocessed wellhead volume.

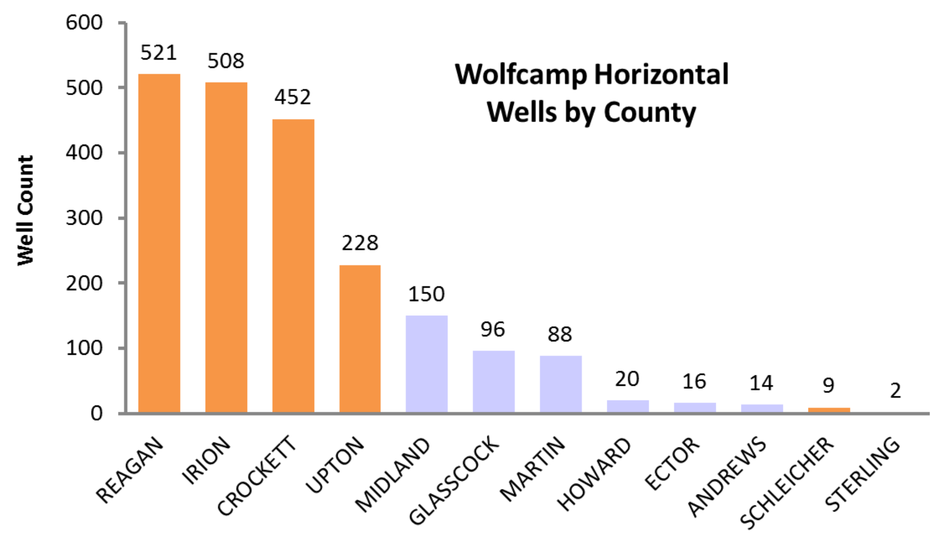
Probability Distribution of AREX 93 Type Curve Wells at Year-end 2014



Midland Basin - Wolfcamp Horizontal Well Activity

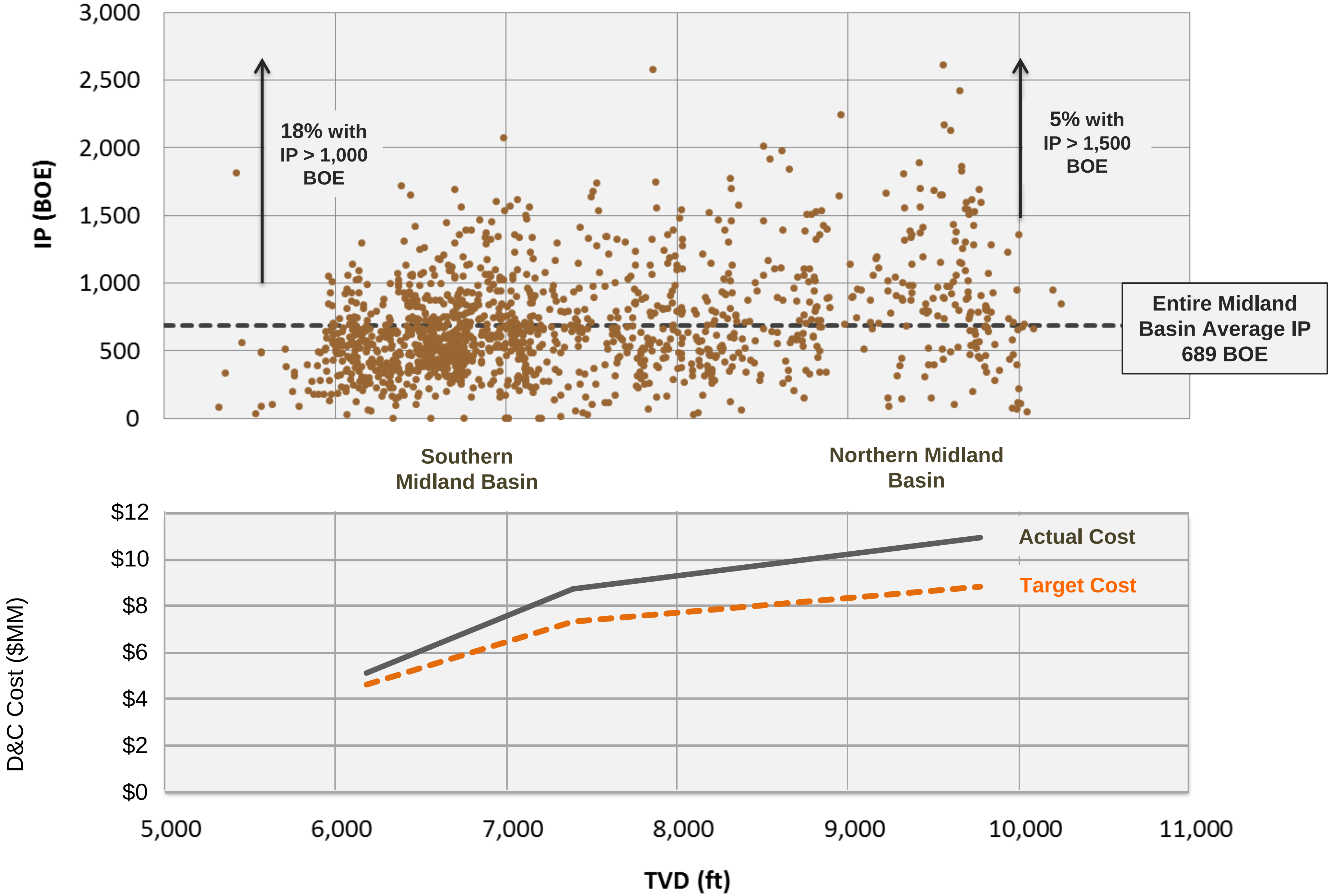






Source: DrillingInfo and IHS

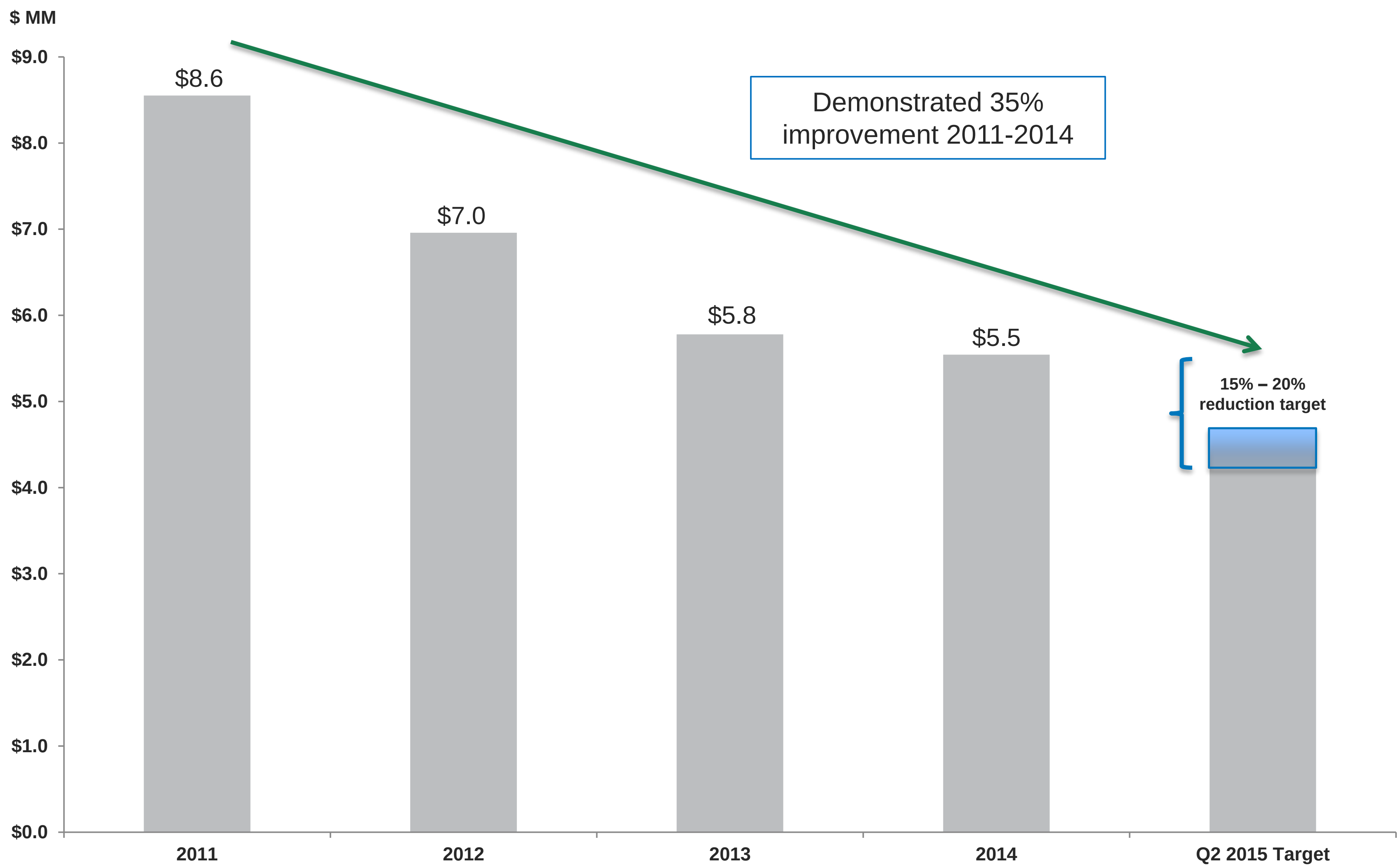
Midland Basin - IP and Drilling & Completion Cost



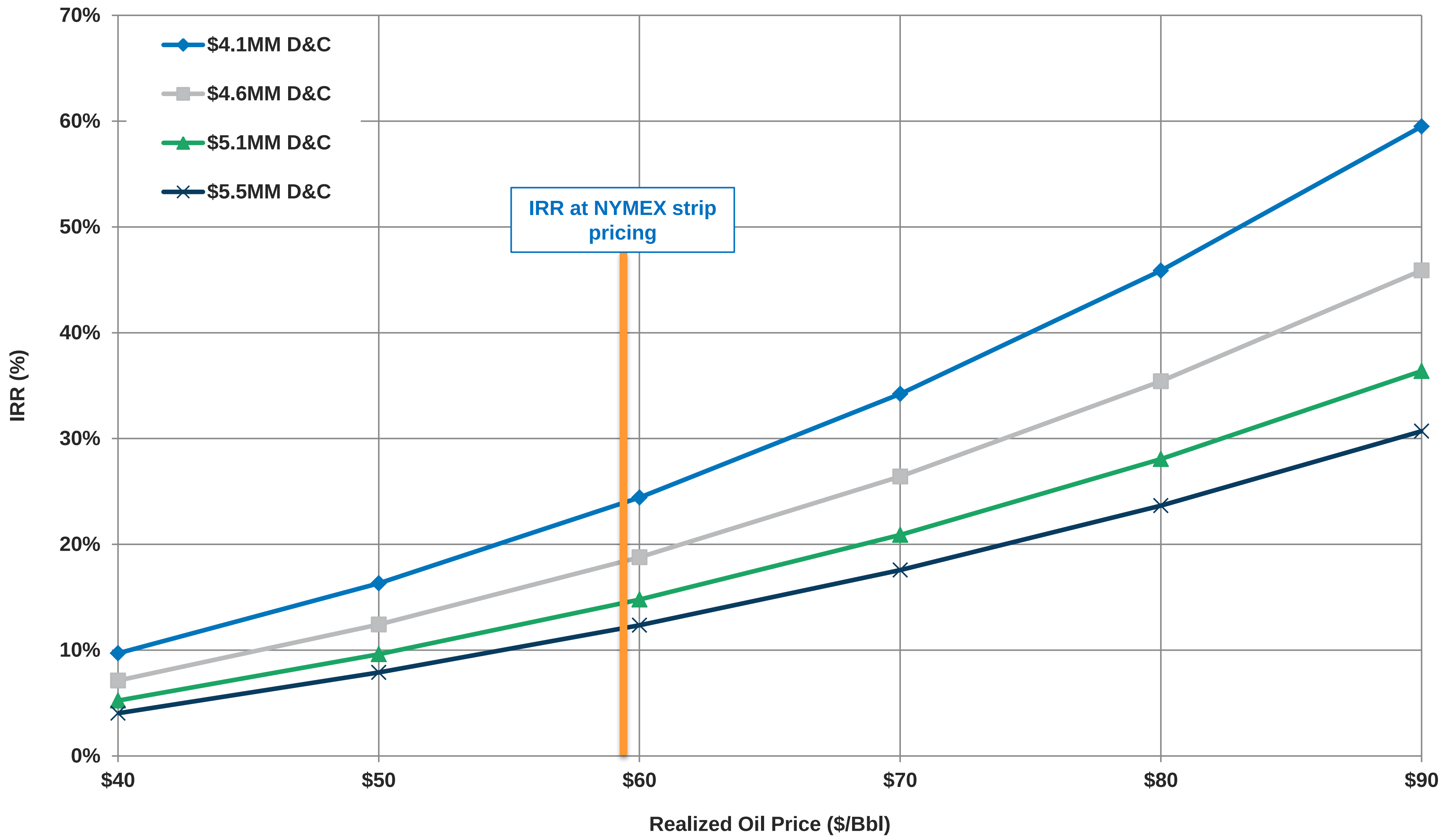
Source: Company releases/presentations, DrillingInfo, IHS, public databases, and internal studies.
Note: Three-stream IP estimated using 0.1539 Bbl per Mcf and 25% shrinkage factor.

Proven track record of delivering lowest D&C cost in the Midland Basin

Approach's annual average horizontal well D&C cost

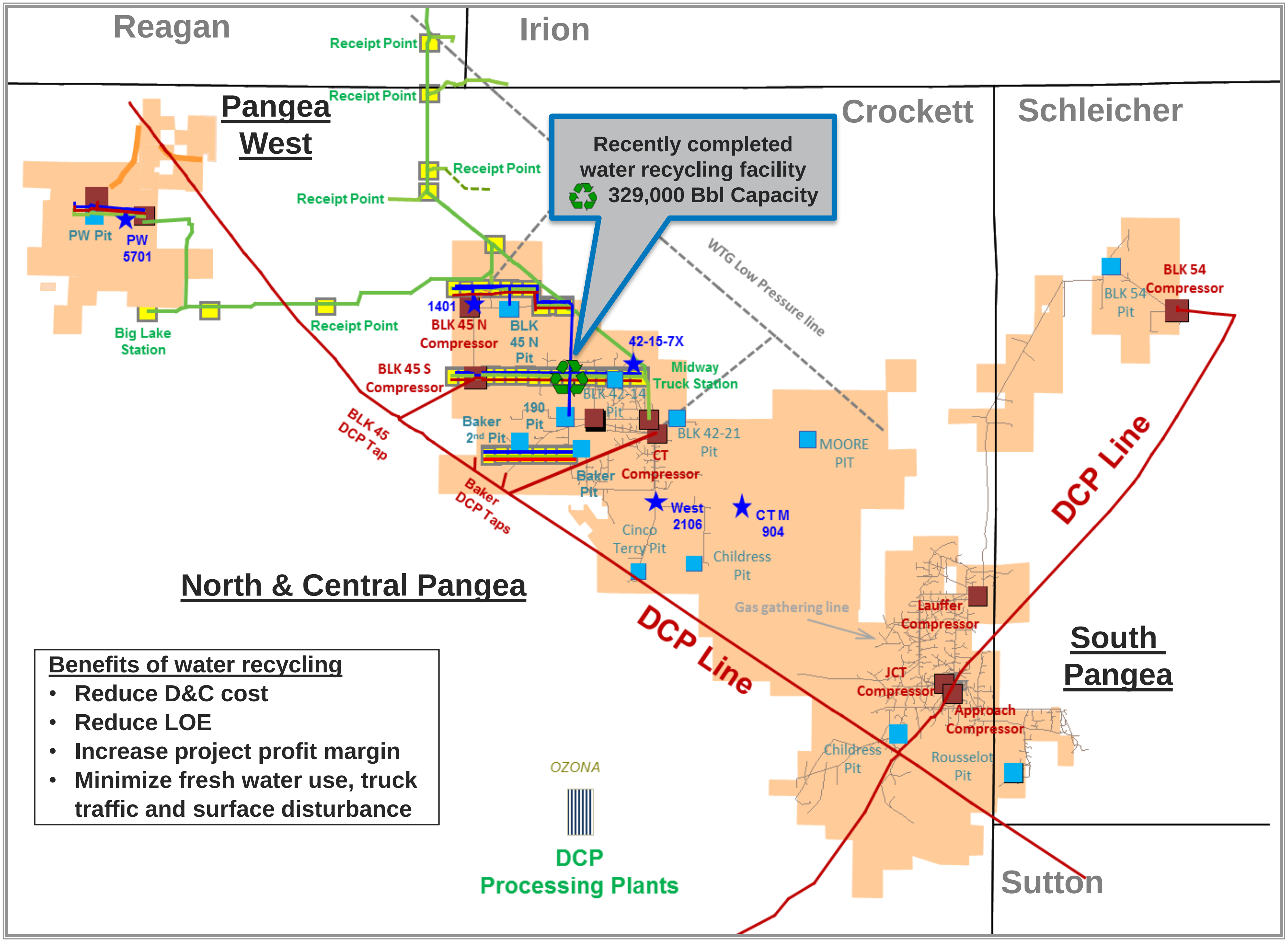


D&C Cost reductions will significantly improve profitability



Note: HZ Wolfcamp economics assume $4.00/Mcf realized natural gas price and NGL price based on 40% of realized oil price.

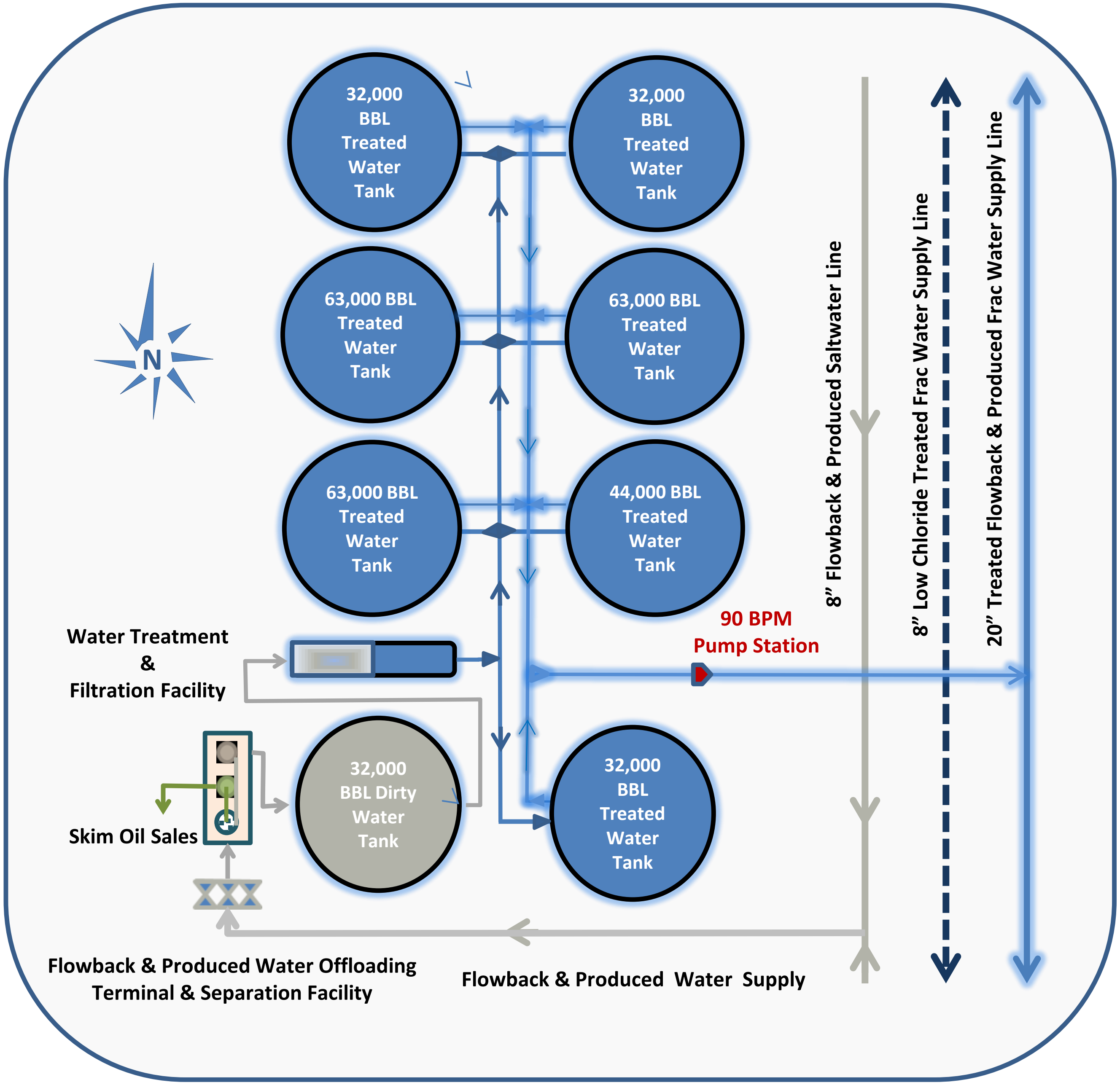
Established infrastructure in place is critical to low cost structure



Benefits of water recycling

- Reduce D&C cost
- Reduce LOE
- Increase project profit margin
- Minimize fresh water use, truck traffic and surface disturbance

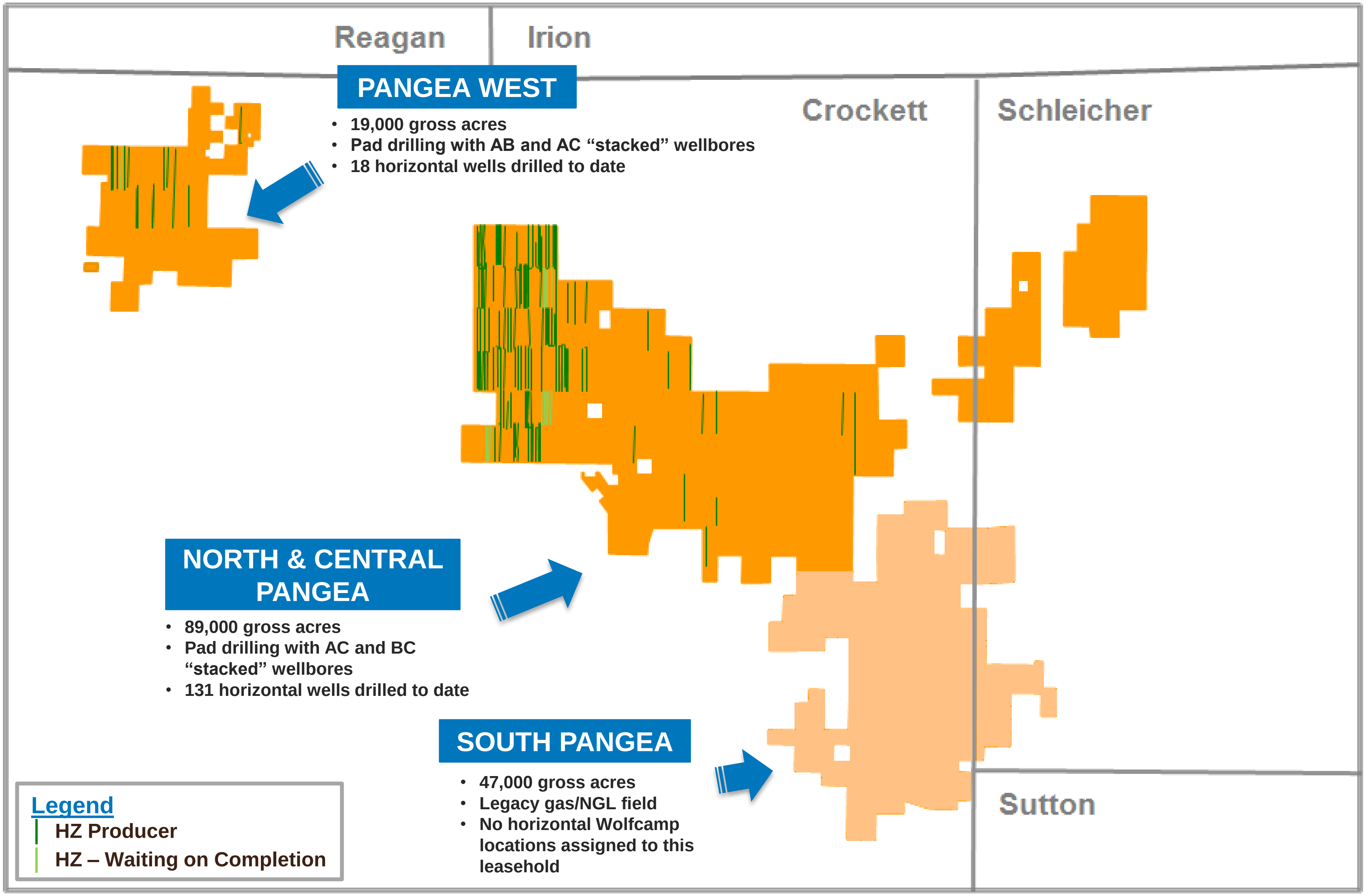
AREX Flowback and Produced Water Recycle Facility



329,000 Bbl Capacity Facility

- Reduce drilling and completion cost by $450K per well
- Reduce LOE by up to $1.00 per BOE
- Eliminate usage of potable fresh water for completion
- Minimize surface disturbance
- Skim oil sale up to 200 Bbls per day - more than sufficient to pay for facility operating expense

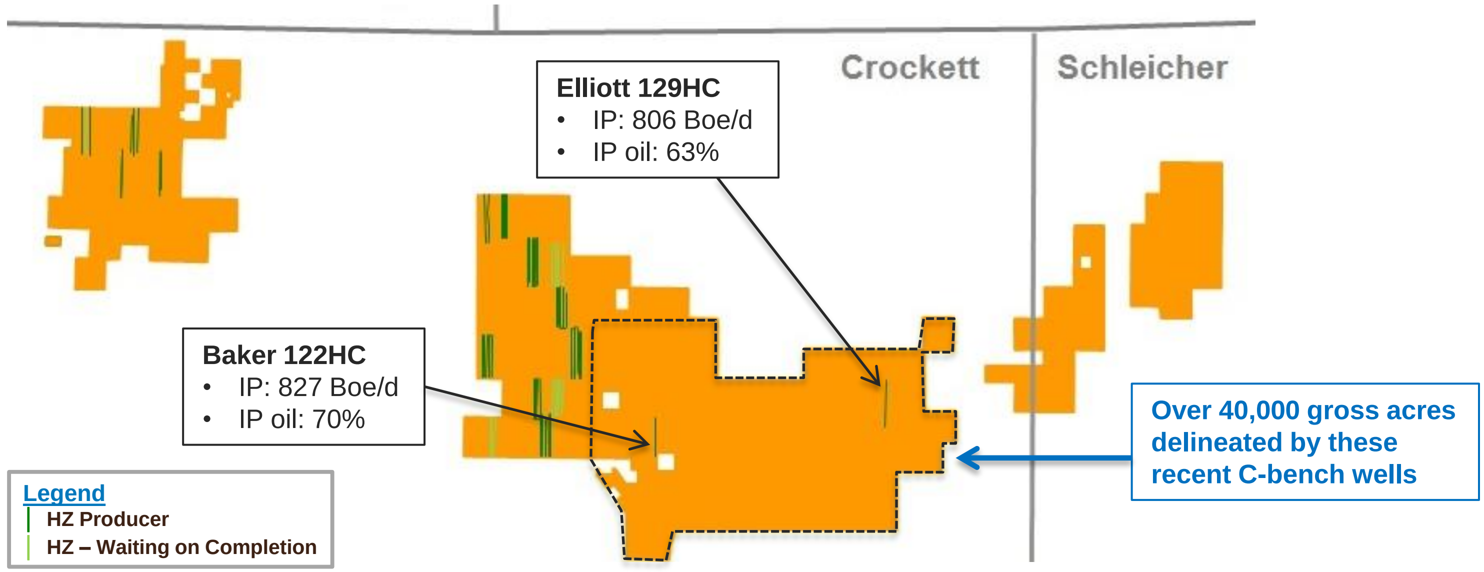
AREX Horizontal Wolfcamp activity



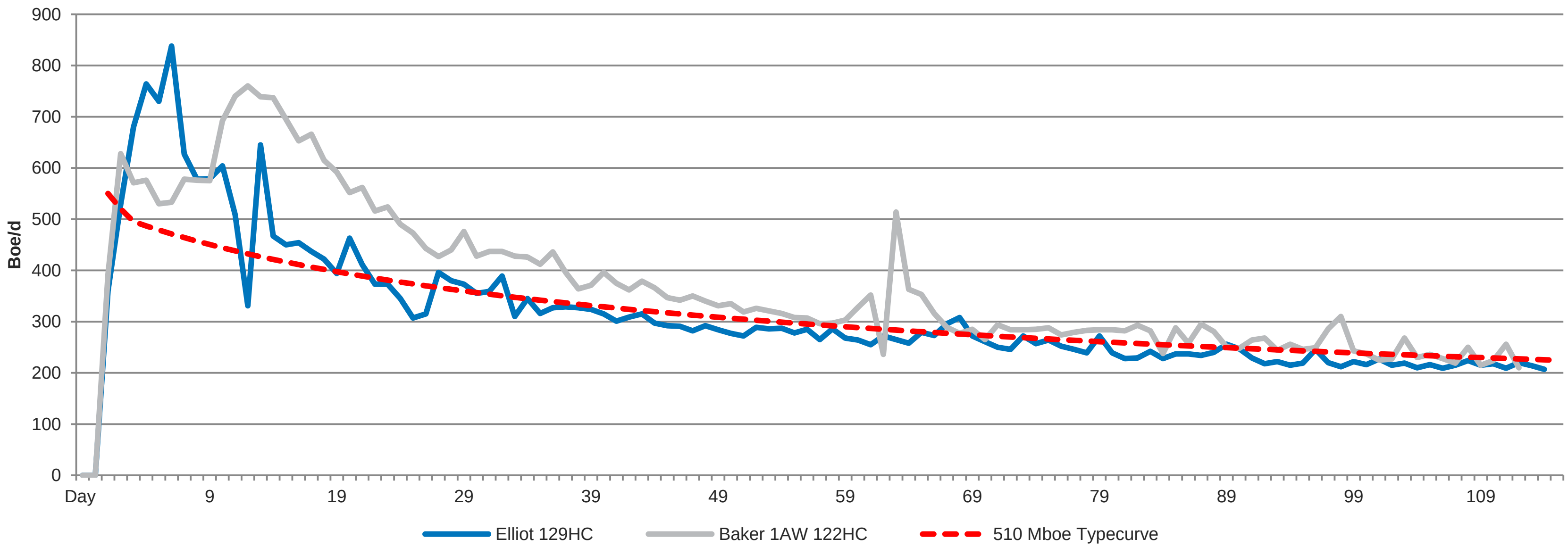
Note: Acreage as of 12/31/2014.

Baker 122HC and Elliott 129HC drilled in 2014 have validated significant upside potential of AREX's portfolio

2014 HZ Wolfcamp activity



Well performance



Current hedge position

- Based on the midpoint of current 2015 guidance, approximately 64% of forecasted oil production and 44% of forecasted natural gas production are hedged at weighted average floor prices of $80.59/Bbl and $4.05/MMBtu, respectively.

Commodity & Period	Contract Type	Volume	Contract Price
Crude Oil			
January 2015 – March 2015	Collar	1,500 Bbls/d	$85.00/Bbl - $95.30/Bbl
January 2015 – December 2015	Collar	1,600 Bbls/d	$84.00/Bbl - $91.00/Bbl
January 2015 – December 2015	Collar	1,000 Bbls/d	$90.00/Bbl - $102.50/Bbl
January 2015 – December 2015	3-way Collar	500 Bbls/d	$75.00/Bbl - $84.00/Bbl - $94.00/Bbl
January 2015 – December 2015	3-way Collar	500 Bbls/d	$75.00/Bbl - $84.00/Bbl - $95.00/Bbl
Natural Gas			
January 2015 – June 2015	Collar	80,000 MMBtu/month	$4.00/MMBtu - $4.74/MMBtu
January 2015 – December 2015	Swap	200,000 MMBtu/month	$4.10/MMBtu
January 2015 – December 2015	Collar	130,000 MMBtu/month	$4.00/MMBtu - $4.25/MMBtu

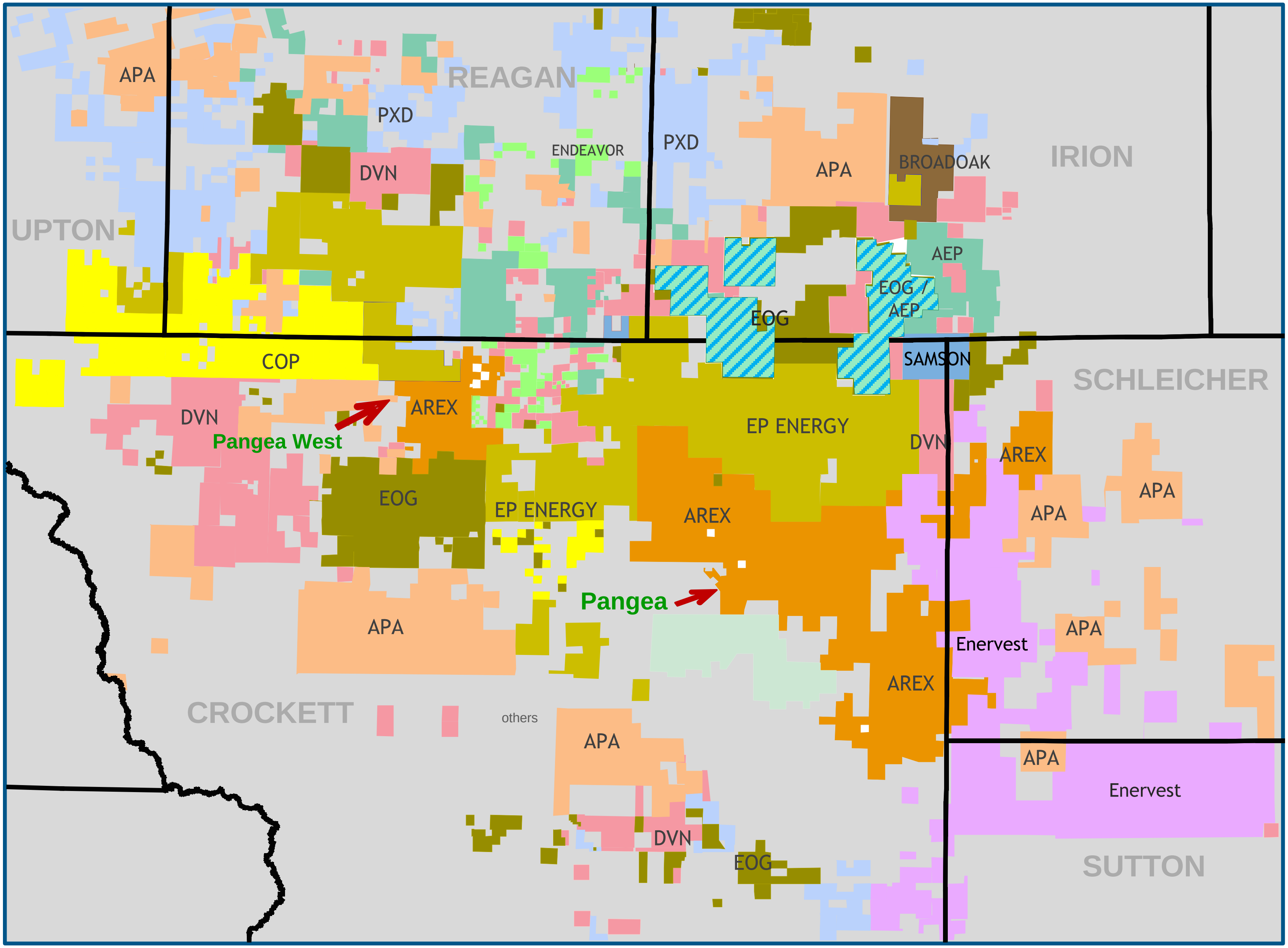
Production and expense guidance

	2015 Guidance
Production	
Oil (MBbls)	2,200 – 2,325
NGLs (MBbls)	1,575 – 1,625
Natural Gas (MMcf)	10,050 – 10,200
Total (MBoe)	5,450 – 5,650
Operating costs and expenses (per Boe)	
Lease operating	$6.00 - $7.00
Production and ad valorem taxes	7.25% of oil & gas revenues
Cash general and administrative	$3.75 - $4.25
Exploration (non-cash)	$0.50 - $1.00
Depletion, depreciation and amortization	$20.00 - $22.00
Capital expenditures (in millions)	~$160

APPROACH RESOURCES

Appendix

AREX Wolfcamp acreage is offset by large operators



Adjusted net income (unaudited)

The amounts included in the calculation of **adjusted net income** and **adjusted net income per diluted share** below were computed in accordance with GAAP. We believe adjusted net income and adjusted net income 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 income to net income (loss) for the three months ended December 31, 2014 and 2013.

(in thousands, except per-share amounts)	Three Months Ended December 31,	
	2014	**2013**
Net income	$ 26,987	$ 64,321
Adjustments for certain items:		
Unrealized (gain) loss on commodity derivatives	(36,907)	1,348
Gain on sale of equity method investment	-	(90,743)
Related income tax effect	13,287	33,076
Adjusted net income	$ 3,367	$ 8,002
Adjusted net income per diluted share	$ 0.08	$ 0.20

EBITDAX (unaudited)

We define **EBITDAX** as net income (loss), plus (1) exploration expense, (2) gain on the sale of our equity method investment, (3) depletion, depreciation and amortization expense, (4) share-based compensation expense, (5) unrealized loss (gain) on commodity derivatives, (6) interest expense and (7) income taxes. 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 income 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 following table provides a reconciliation of EBITDAX to net income (loss) for the three and twelve months ended December 31, 2014 and 2013.

(in thousands, except per-share amounts)	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2014	2013	2014	2013
Net income	$ 26,987	$ 64,321	$ 56,172	$ 72,256
Exploration	236	228	3,831	2,238
Gain on sale of equity method investment	-	(90,743)	-	(90,743)
Depletion, depreciation and amortization	28,664	22,005	106,802	76,956
Share-based compensation	2,521	512	8,247	5,901
Unrealized (gain) loss on commodity derivatives	(36,907)	1,348	(42,113)	4,596
Interest expense, net	5,715	5,225	21,651	14,084
Income tax provision	17,102	38,207	33,692	42,507
EBITDAX	$ 44,318	$ 41,103	$ 188,282	$ 127,795
EBITDAX per diluted share	$ 1.12	$ 1.05	$ 4.78	$ 3.28

F&D costs (unaudited)

All-in finding and development ("F&D") costs are calculated by dividing the sum of property acquisition costs, exploration costs and development costs for the year by the sum of reserve extensions and discoveries, purchases of minerals in place and total revisions for the year.

Drill-bit F&D costs are calculated by dividing the sum of exploration costs and development costs for the year by the total of reserve extensions and discoveries for the year.

We believe that providing F&D cost is useful to assist in an evaluation of how much it costs the Company, on a per Boe basis, to add proved reserves. 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 previous SEC filings and to be included in our annual report on Form 10-K to be filed with the SEC on February 26, 2015. Due to various factors, including timing differences, F&D costs do not necessarily reflect precisely the costs associated with particular reserves. For example, exploration costs may be recorded in periods before the periods in which related increases in reserves are recorded, and development costs may be recorded in periods after the periods in which related increases in reserves are recorded. In addition, changes in commodity prices can affect the magnitude of recorded increases (or decreases) in reserves independent of the related costs of such increases.

As a result of the above factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in our filings with the SEC, we cannot assure you that the Company's future F&D costs will not differ materially from those set forth above. Further, the methods used by us to calculate F&D costs may differ significantly from methods used by other companies to compute similar measures. As a result, our F&D costs may not be comparable to similar measures provided by other companies.

The following table reconciles our estimated F&D costs for 2014 to the information required by paragraphs 11 and 21 of ASC 932-235.

F&D Cost reconciliation		
Cost summary (in thousands)		
Property acquisition costs		
Unproved properties	$	4,578
Proved properties		-
Exploration costs		3,831
Development costs		382,995
Total costs incurred	$	391,404
Reserves summary (MBoe)		
Balance – 12/31/2013		114,661
Extensions & discoveries		43,247
Production (1)		(5,281)
Revisions to previous estimates		(6,379)
Balance – 12/31/2014		146,248
F&D cost ($/Boe)		
All-in F&D cost	$	10.62
Drill-bit F&D cost		8.94
Reserve replacement ratio		
Drill-bit		819%

(1) Production includes 1,390 MMcf related to field fuel.

PV-10 (unaudited)

The present value of our proved reserves, discounted at 10% ("PV-10"), was estimated at $1.4 billion at December 31, 2014, and was calculated based on the first-of-the-month, twelve-month average prices for oil, NGLs and gas, of $94.56 per Bbl of oil, $31.50 per Bbl of NGLs and $4.55 per MMBtu of natural gas.

PV-10 is our estimate of the present value of future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value." We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating the Company. We believe that PV-10 is a financial measure routinely used and calculated similarly by other companies in the oil and gas industry.

The following table reconciles PV-10 to our standardized measure of discounted future net cash flows, the most directly comparable measure calculated and presented in accordance with GAAP. PV-10 should not be considered as an alternative to the standardized measure as computed under GAAP.

(in millions)		December 31,
		2014
PV-10	$	1,413
Less income taxes:		
Undiscounted future income taxes		(1,267)
10% discount factor		910
Future discounted income taxes		(357)
Standardized measure of discounted future net cash flows	$	1,056

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