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February 8, 2017

PDC ENERGY

Forward Looking Statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding the company's business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are "forward-looking statements" within the meaning of the safe harbor provisions of the United States ("U.S.") Private Securities Litigation Reform Act of 1995. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein. These statements relate to, among other things: the effects of recent Delaware Basin acquisitions; estimated future production (including the components of such production), sales, expenses, cash flows, liquidity and balance sheet attributes (including debt to EBITDAX ratios); estimated crude oil, natural gas and natural gas liquids ("NGLs") reserves; the impact of prolonged depressed commodity prices, including potentially reduced production and associated cash flow; anticipated capital projects, expenditures and opportunities; expected capital budget allocations; operational flexibility and ability to revise development plans, either upward or downward; availability of sufficient funding and liquidity for the capital program and sources of that funding; expected net settlements on derivatives for 2017; future exploration, drilling and development activities, including non-operated activity, the number of drilling rigs expected to run and lateral lengths of wells, including the number of rigs expected to run in 2017 in the Delaware Basin; expected 2017 production and timing of turn-in-lines; the evaluation method of customers' and derivative counterparties' credit risk; effectiveness of the derivative program in providing a degree of price stability; potential for future impairments; expected expansion of gas processing systems and expected line pressure; compliance with debt covenants; impact of litigation on the results of operations and financial position; that the company does not expect to pay dividends in the foreseeable future; and future strategies, plans and objectives.

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements made in this presentation reflect PDC's good faith judgment, such statements can only be based on facts and factors currently known to PDC. Forward-looking statements are always subject to risks and uncertainties, and become subject to greater levels of risk and uncertainty as they address matters further into the future. Throughout this presentation, the Company uses the terms "outlook," "projection" or similar terms or expressions, to indicate that it has "modeled" certain future scenarios. PDC typically uses these terms to indicate its current thoughts on possible outcomes relating to its business or the industry in periods beyond the current fiscal year. In addition to being subject to additional levels of uncertainty generally, forward-looking statements regarding such prospective matters do not necessarily reflect the outcomes the Company views as the most likely to occur, but instead are shown to illustrate aspects of its business in the context of a variety of scenarios it believes to be plausible.

PDC urges you to carefully review and consider the cautionary statements and disclosures, specifically those under Item 1A, *Risk Factors*, made in the Company's Annual Report on Form 10-K for the year ended December 31, 2015, and PDC's other filings with the U.S. Securities and Exchange Commission ("SEC"), which are incorporated by this reference as though fully set forth herein, for further information on risks and uncertainties that could affect the Company's business, financial condition, results of operations and cash flows. The Company cautions you not to place undue reliance on forward-looking statements, which speak only as of the date hereof. **PDC undertakes no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this presentation or currently unknown facts or conditions or the occurrence of unanticipated events. All forward looking statements are qualified in their entirety by this cautionary statement.**

PDC Energy Asset History

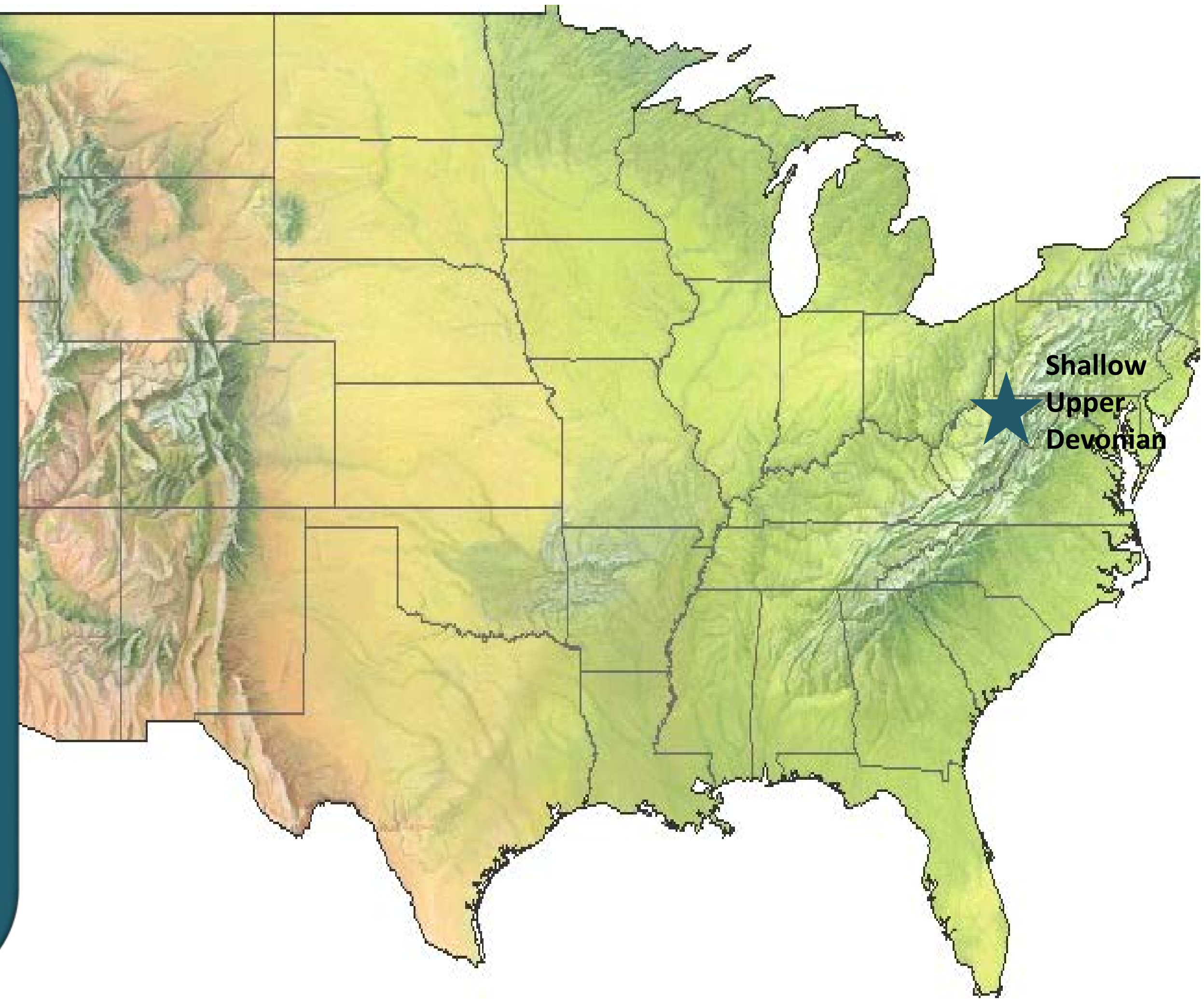
★ Assets 1969 – West Virginia

1969 - 1999

- Founded in Bridgeport, WV (1969)
- Shallow Upper Devonian drilling partnerships
- Natural gas focused

1977

- Began trading on NASDAQ as PETD
- Stock price: $1.75/share
- Market Cap: $9 MM
- Proved Reserves: 1.4 MMBoe (89% nat gas)



PDC Energy Asset History

★ Assets 1999-forward

1999 - 2014

- Moved headquarters to Denver, CO (2009)
- Asset acquisitions (Wattenberg, Piceance, etc.)

2010

- Began trading under new ticker: PDCE
- Shifted focus to liquid-rich drilling

2014

- Stock price: $50/share
- Market cap: ~$2 B

PDC Energy Asset History

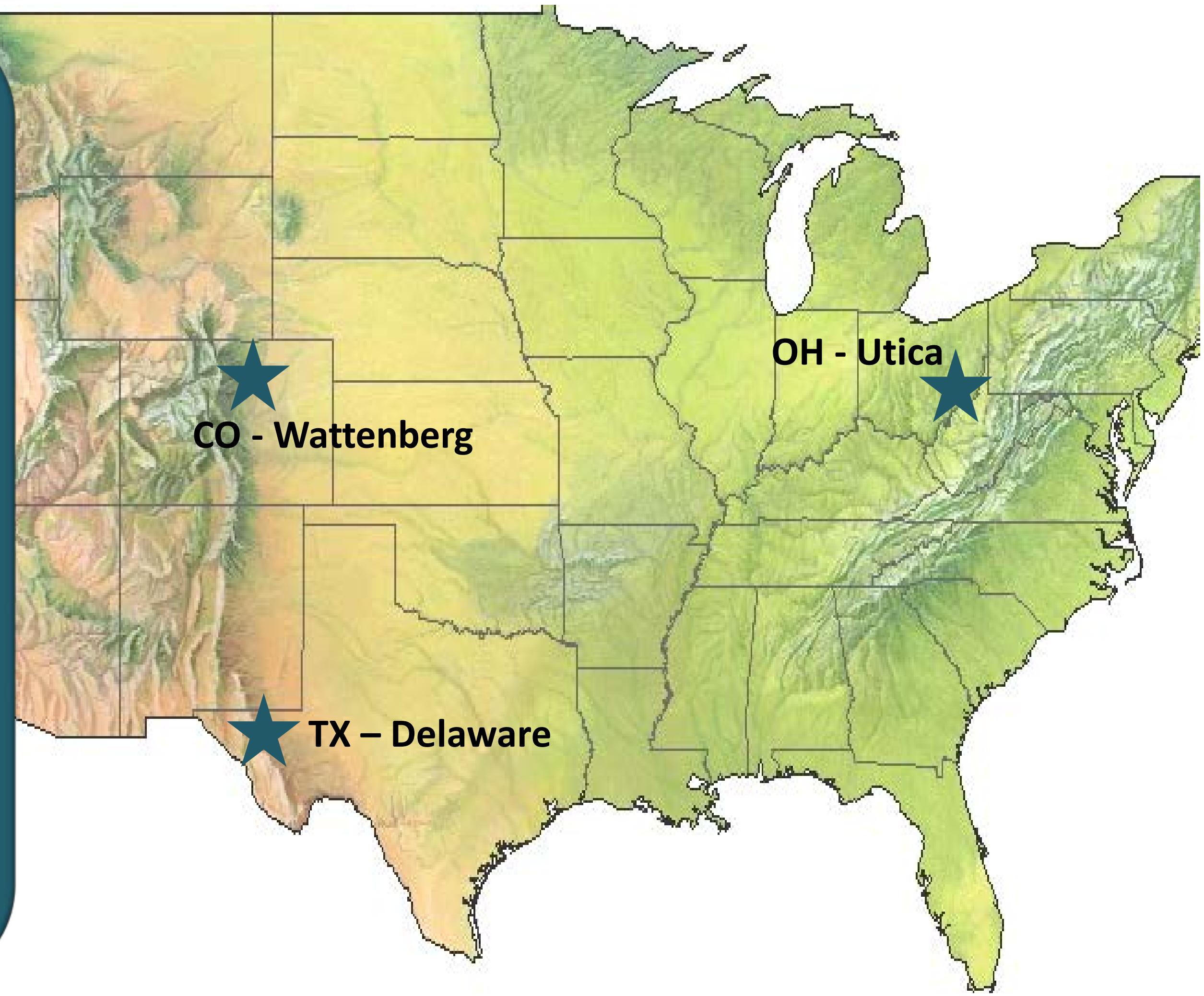
★ Assets 2017

<u>2015 - 2017</u>

- Drove efficiencies through downturn (2015)
- Consolidated acreage position in Wattenberg (NBL trade)
- $1.6 billion Delaware Basin acquisitions
  - 61,500 net acres

<u>2017 (Feb. 1st)</u>

- Stock price: $73/share
- Market Cap: ~$5 B
- Proved Reserves: 341 MMBoe (58% liquids)



PDC Energy – Company Overview

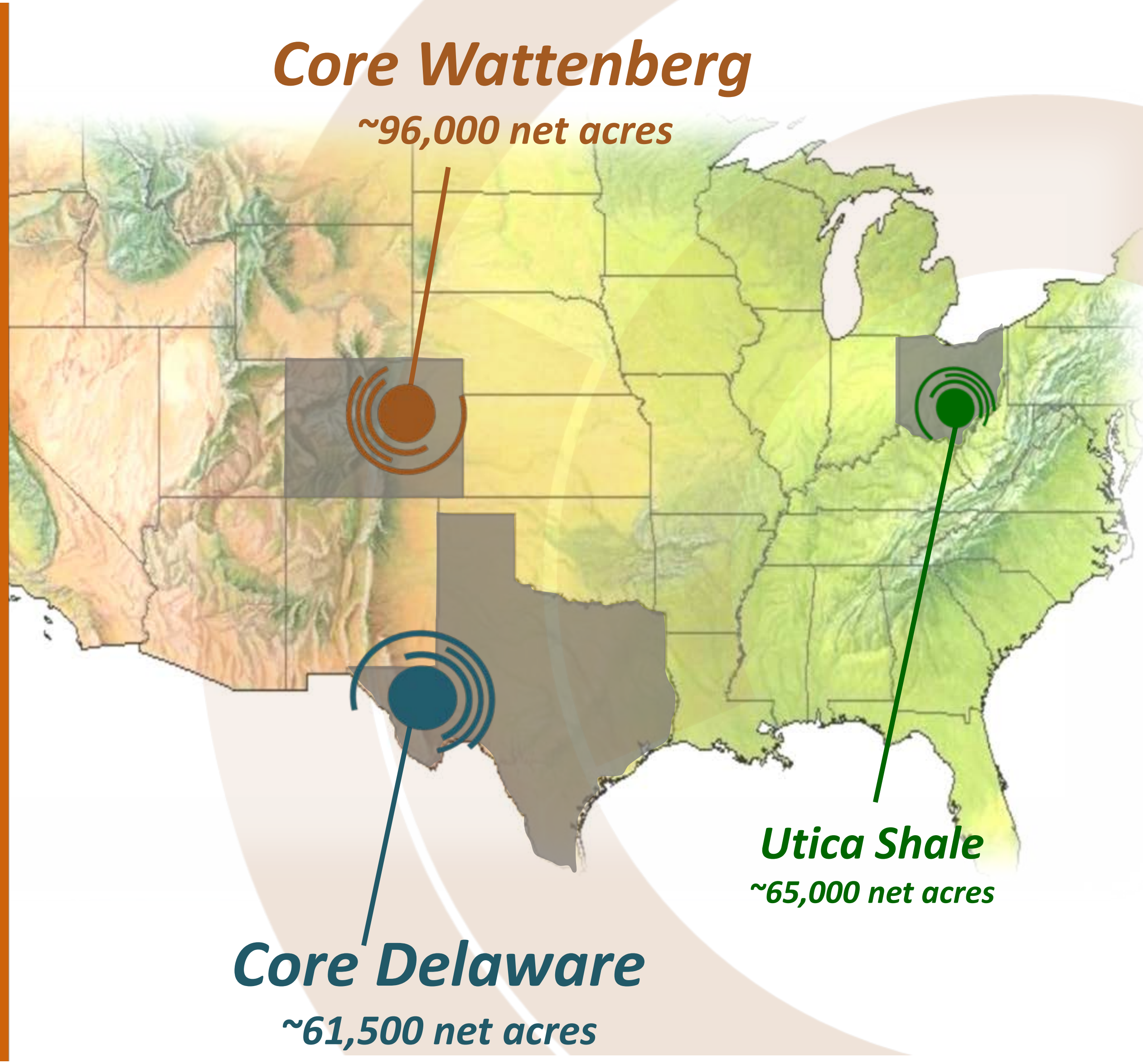
$6.0
Enterprise Value (Billions)(1)

~1.8x
YE17e Debt/EBITDAX(2)

30 - 33
2017e Production (MMBoe)

>40%
2017e Annual Production Growth (Midpoint)

341
YE16 Proved Reserves (MMBoe)



(1) As of 2/3/17; 65.7 million shares outstanding (2) EBITDAX is adj. EBITDA plus exploration expense, excludes gain/loss sale on assets.

PDC Energy – 2017 Production and Capital Budget

$750mm
2017e Capex Midpoint
($725 - $775mm)

$50-100mm
YE17e Cash Balance(1)

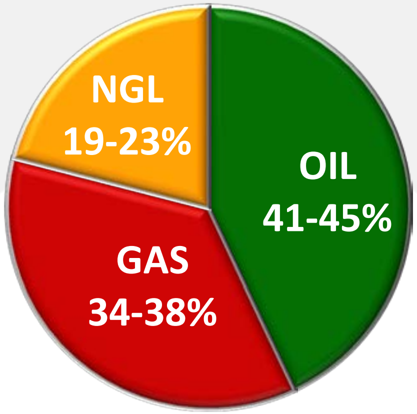
1.8x
YE17e Debt to EBITDAX(1)

37%
2017e Increase
in Lateral Feet Drilled

2017e PRODUCTION GUIDANCE

- 30.0 – 33.0 MMBoe
  - 82,200 – 90,400 Boe/d
  - ~97,000 Boe/d Dec. 2017 exit rate
  - 40% production growth over 2016
  - 50% oil production growth

2017e Production Mix
(~66% Liquids)



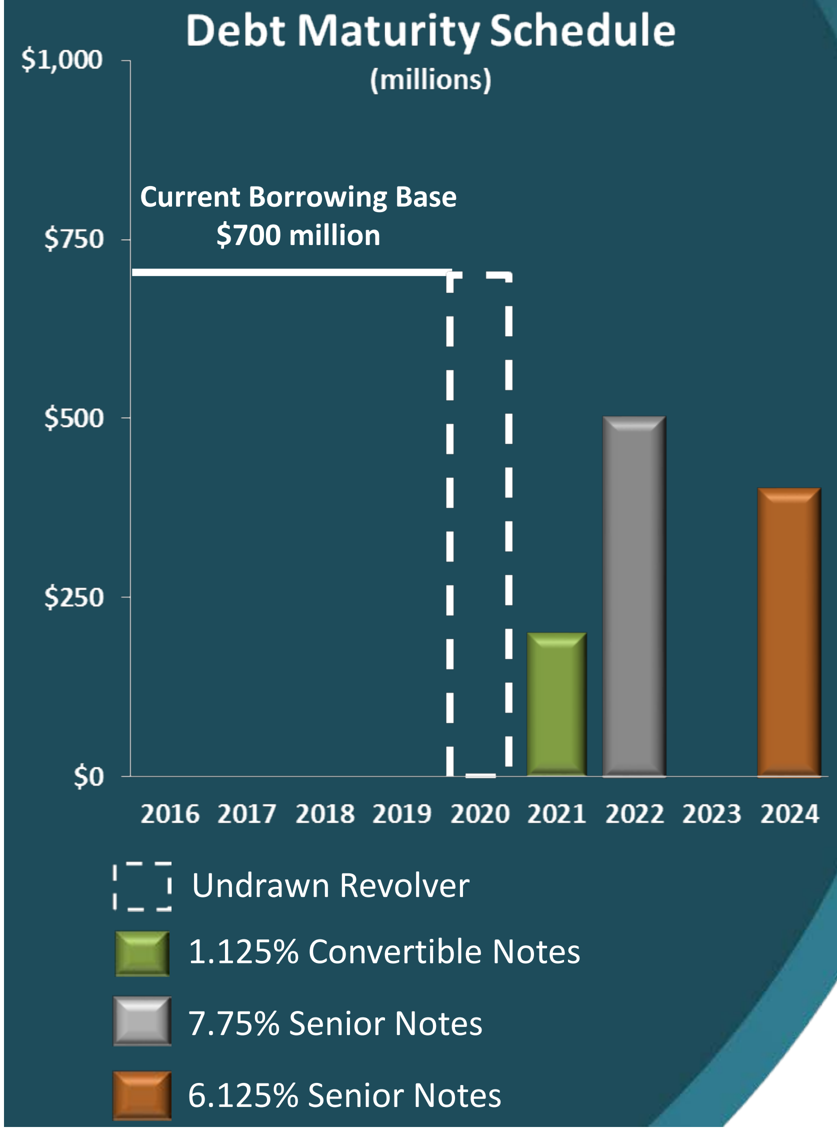
2017e Drilling Program

All numbers approximate	Wattenberg	Delaware	Utica
Capital Expenditures (millions)	$490	$235(2)	$18
Operated Spuds	145	28	2
Operated TILs	150	19	2
Avg. TIL Lateral Length (feet)	6,900	8,600	12,000
Avg. Working Interest	85%	92%	80%

(1) Guidance based on internal NYMEX price assumptions: ~$51/Bbl oil, $3.30/Mcf Natural Gas, NGL realizations at 25% of NYMEX.
(2) Includes ~$35 million for leasing, seismic and technical studies and ~$15 million in midstream related capital investment.

PDC Energy – Strong Financial Positioning

As of 9/30/16, Pro Forma Delaware Basin Acquisitions



Leverage and Liquidity

- YE16e Debt/ EBITDAX(1) of ~2.2x
- ~$200 million cash balance
- ~$890 million liquidity

Debt Maturities

- $700 million credit facility due May 2020
- $200 million 1.125% convertible notes due September 2021
- $500 million 7.75% senior notes due October 2022
- $400 million 6.125% senior notes due September 2024

(1) EBITDAX is adjusted EBITDA plus exploration expense, includes gain/loss on sale of assets & pre-tax provision for uncollectible notes receivable of $44.0 million.

Asset Overview – Scalability in Two Top-Tier Basins

Core Wattenberg & Core Delaware Portfolio

- Multiple years of highly economic drilling in Core Wattenberg and Core Delaware
  - Internal rates of return extremely competitive
- Estimated combined net reserve potential in excess of 1 Billion Boe
  - Downspacing and delineation efforts are ongoing
- Approximately $9 billion of combined future investment capital currently identified

GROSS INVENTORY LIFE(1)

Core Wattenberg – 10-12 Years	Core Delaware – 15-20 Years

ESTIMATED POTENTIAL NET RESERVES

Core Wattenberg – 550-600 MMBoe	Core Delaware – 550-600 MMBoe

NET INVESTMENT CAPITAL

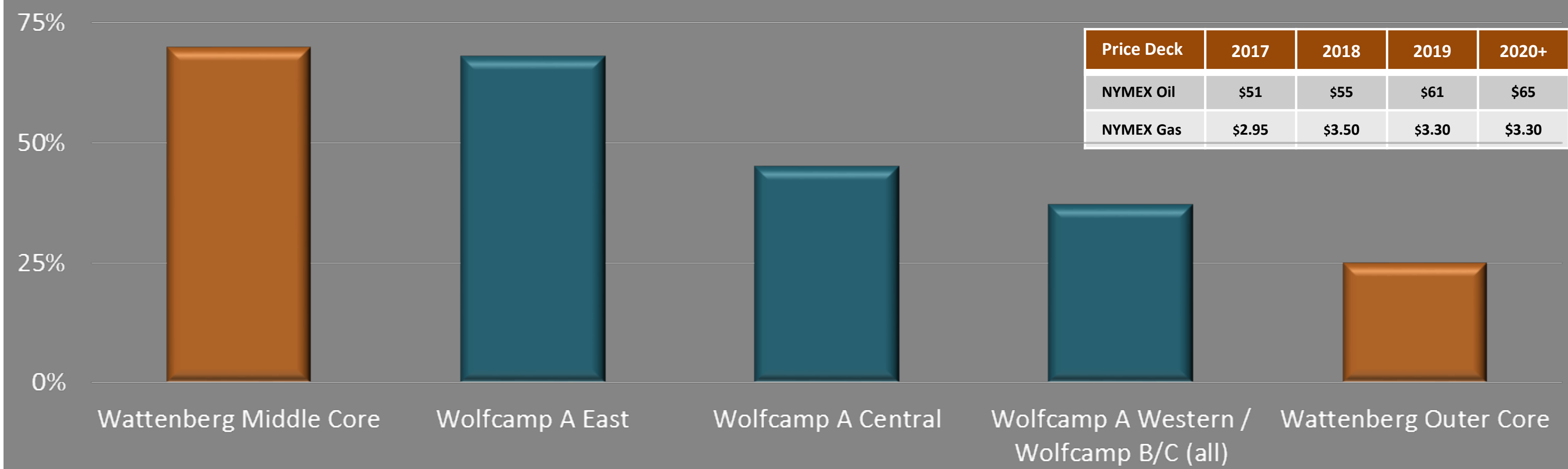
Core Wattenberg – ~$5 Billion	Core Delaware – ~$4 Billion

(1) Assumes current development plan and spacing assumptions.

Asset Overview – High-Return Portfolio Optionality

- Untapped upside present in both Wattenberg and Delaware assets
- Competition for capital drives innovation and enhanced results
- Allocation of capital split between two top-tier basins, provides portfolio optionality

PDC Portfolio Type Well IRRs(1)



Price Deck	2017	2018	2019	2020+
NYMEX Oil	$51	$55	$61	$65
NYMEX Gas	$2.95	$3.50	$3.30	$3.30

(1) Completed well cost ("CWC") $2.5MM (SRL Watt.); $6.5MM (5,000' lateral; East & Central Del.) & $9.5MM (10,000' lateral; Western); Reflects long-term differentials. Excludes lease acquisition and corporate level costs

WATTENBERG OVERVIEW

Core Wattenberg – Asset Summary

96,000

~ Net Acres

100%

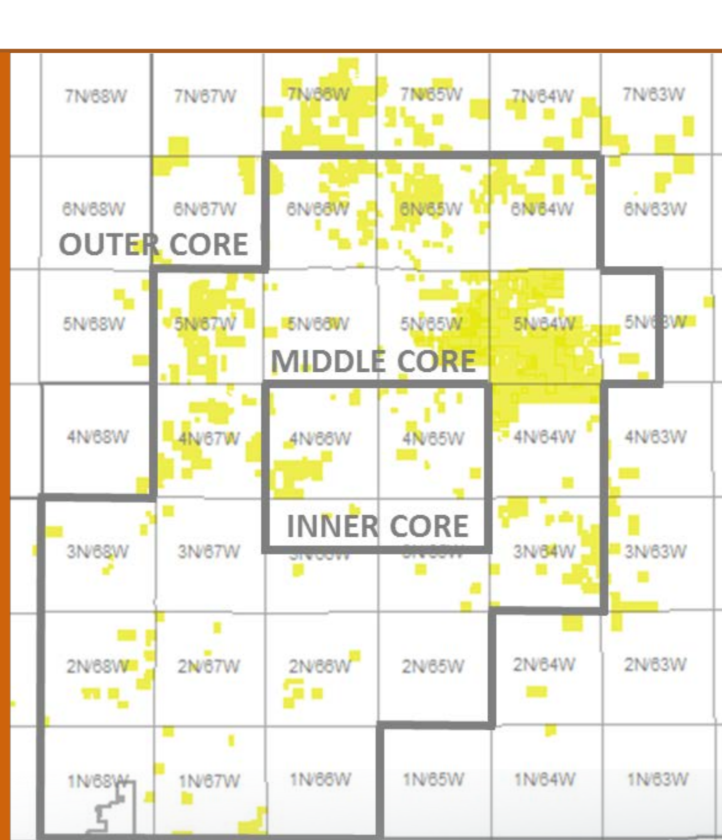
~ Acreage HBP

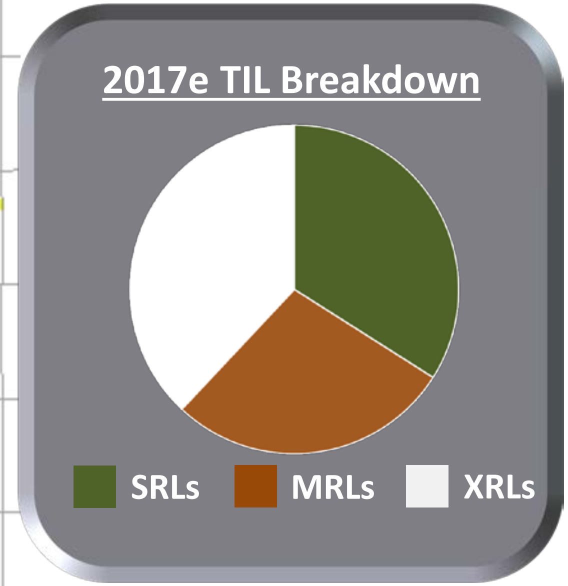
145/150

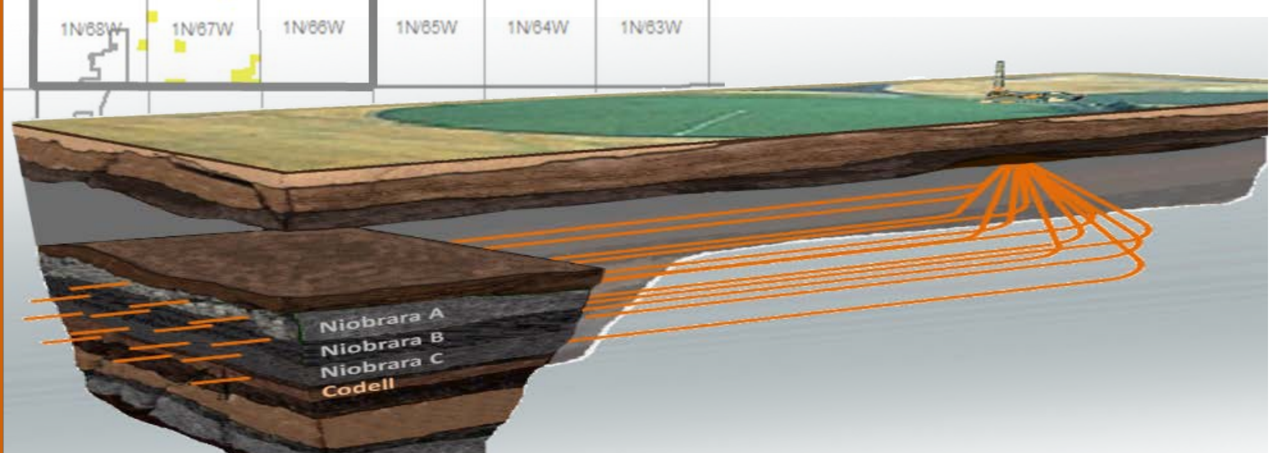
2017e Spuds & TILs

7,300’

2017e Avg. Lateral Length (Spud)





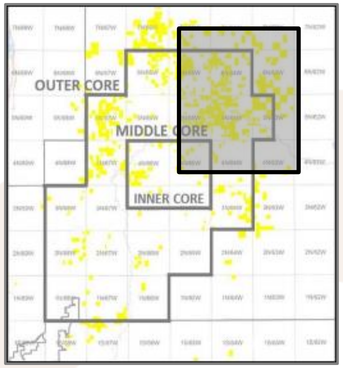


Core Wattenberg – Strategic Acreage Trade

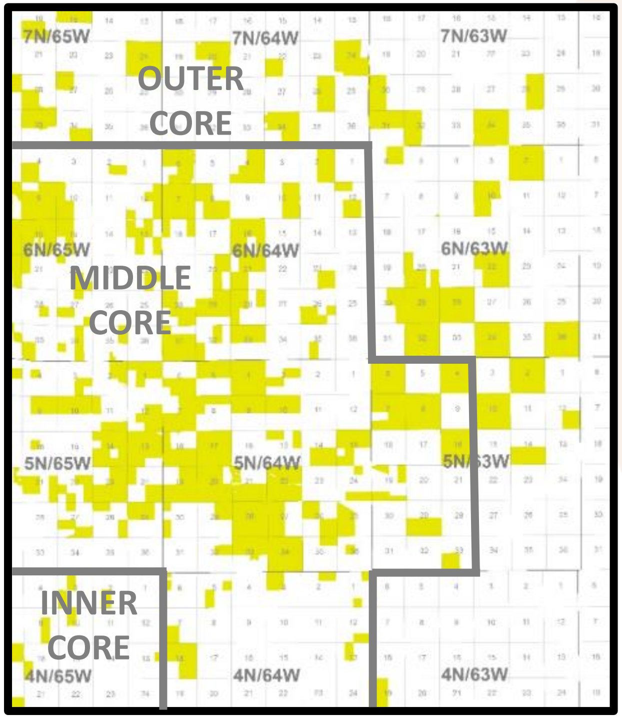
Trade with Noble Energy Closed September 2016

PDC Acreage

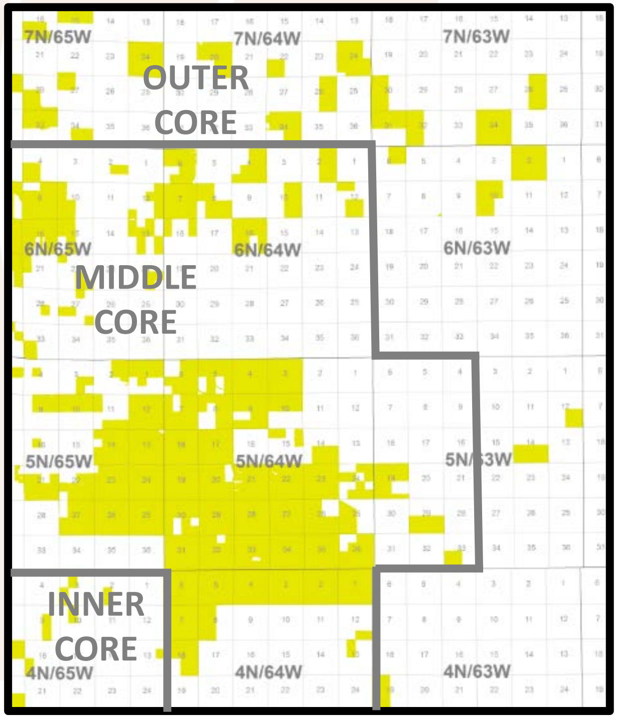
- Middle Core net acreage increased to ~70,300 from ~60,000
- Adds incremental value through increased working interests, improved synergies and enhanced long-term planning capabilities
- ‘Blocky’ acreage more conducive to long-lateral development
  - Reduced surface impact/footprint
  - Allows for consolidation of production facilities



PRE-TRADE

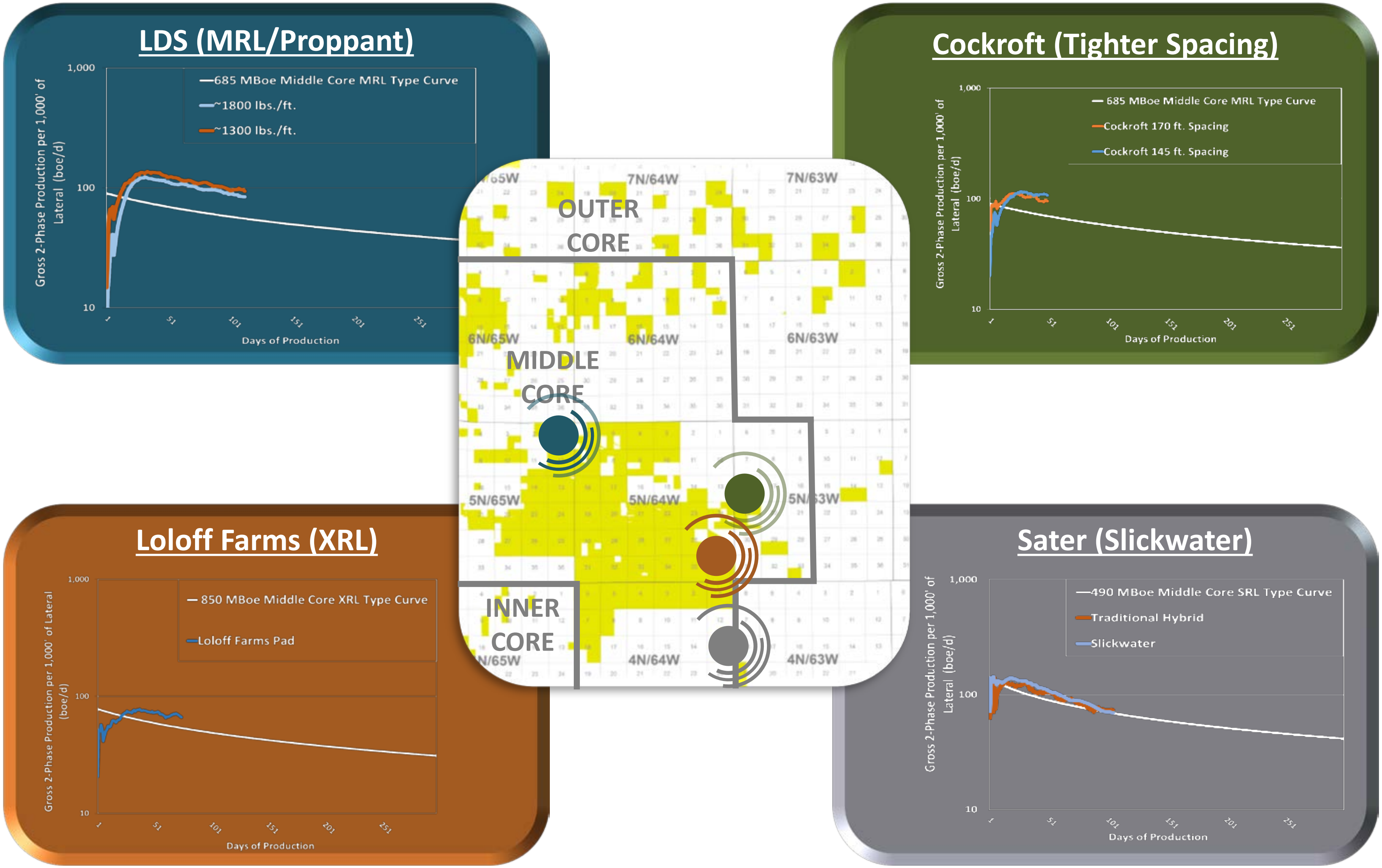


POST-TRADE

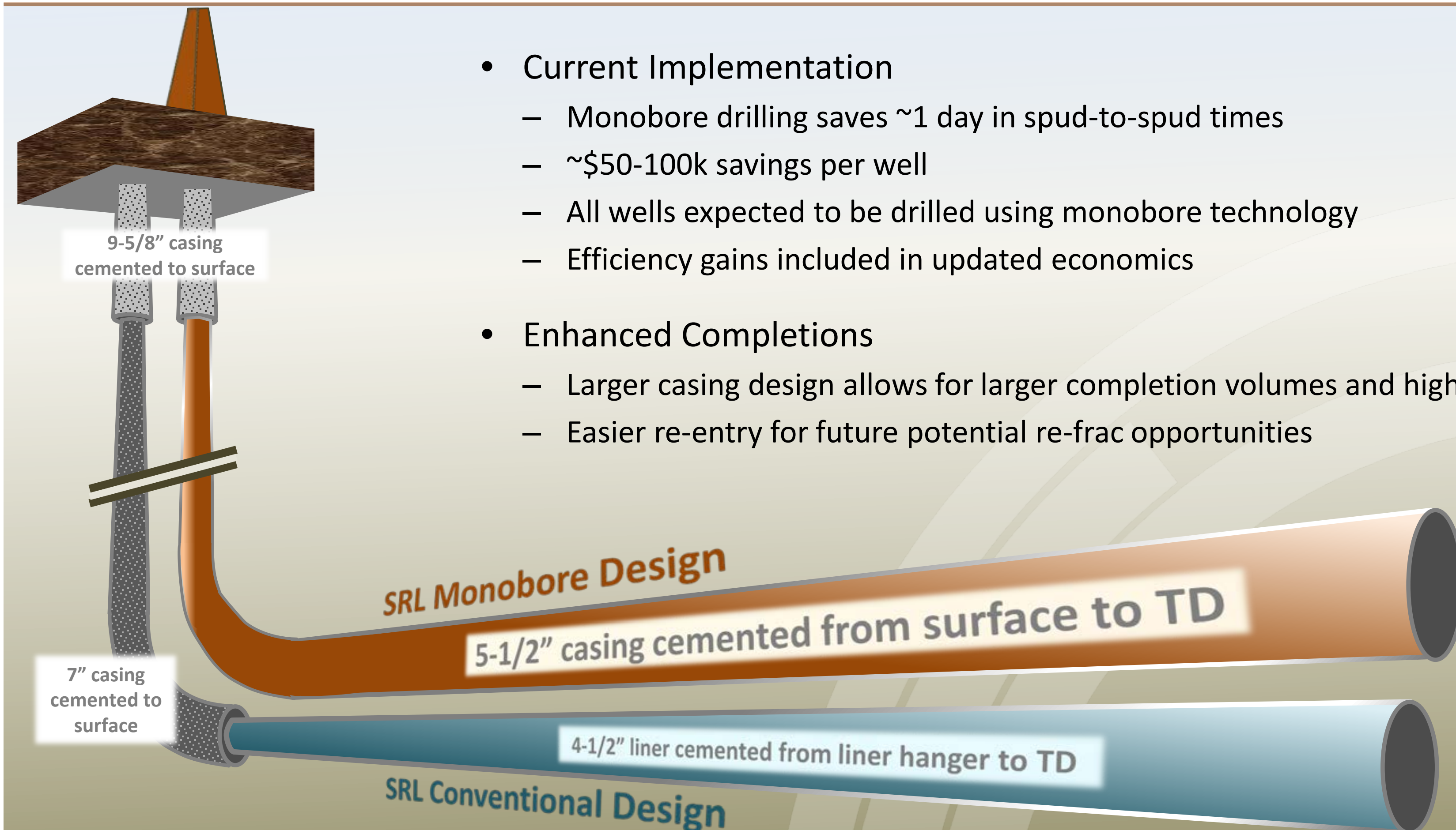


Core Wattenberg – Ongoing Enhancement Tests

PDC Acreage



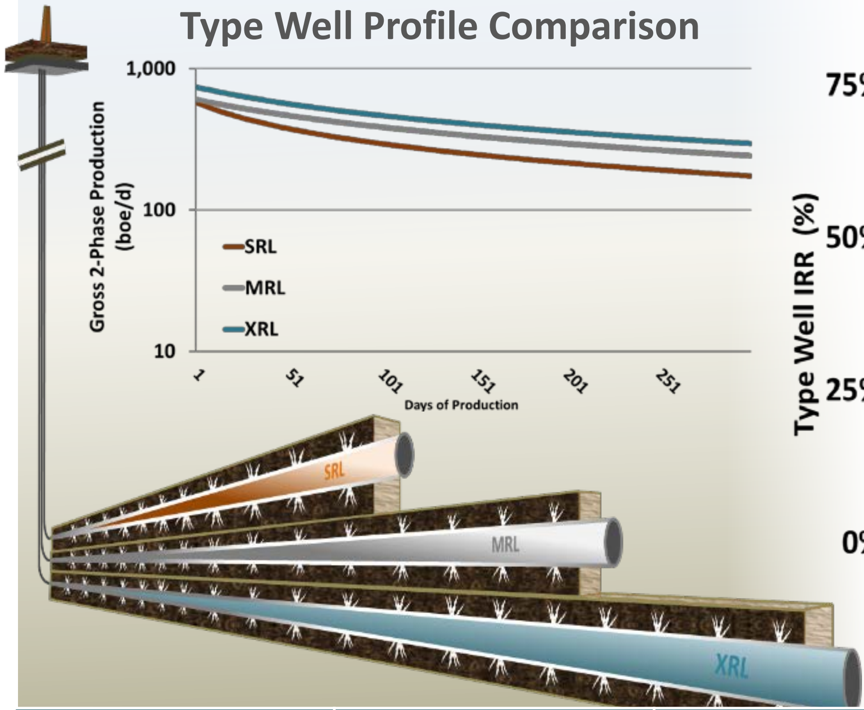
Core Wattenberg – Monobore Drilling Gains

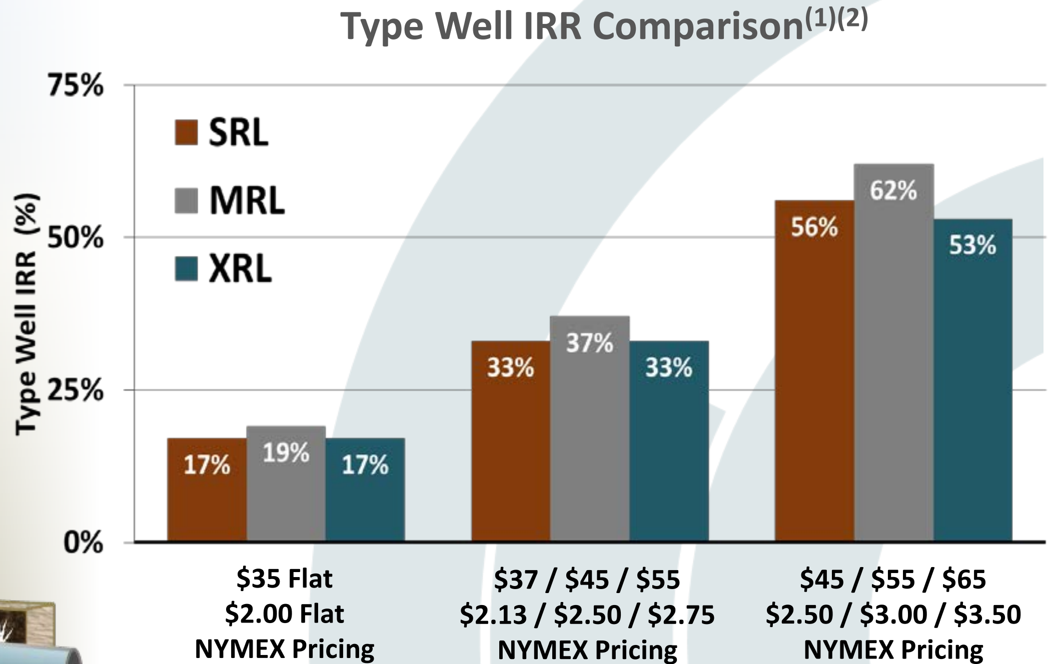


- Current Implementation
  - Monobore drilling saves ~1 day in spud-to-spud times
  - ~$50-100k savings per well
  - All wells expected to be drilled using monobore technology
  - Efficiency gains included in updated economics
- Enhanced Completions
  - Larger casing design allows for larger completion volumes and higher rates
  - Easier re-entry for future potential re-frac opportunities

Design Comparison	Conventional	Monobore
Avg. Drill Times	7 – 9 days	6 – 8 days

Core Wattenberg – Resilient Returns



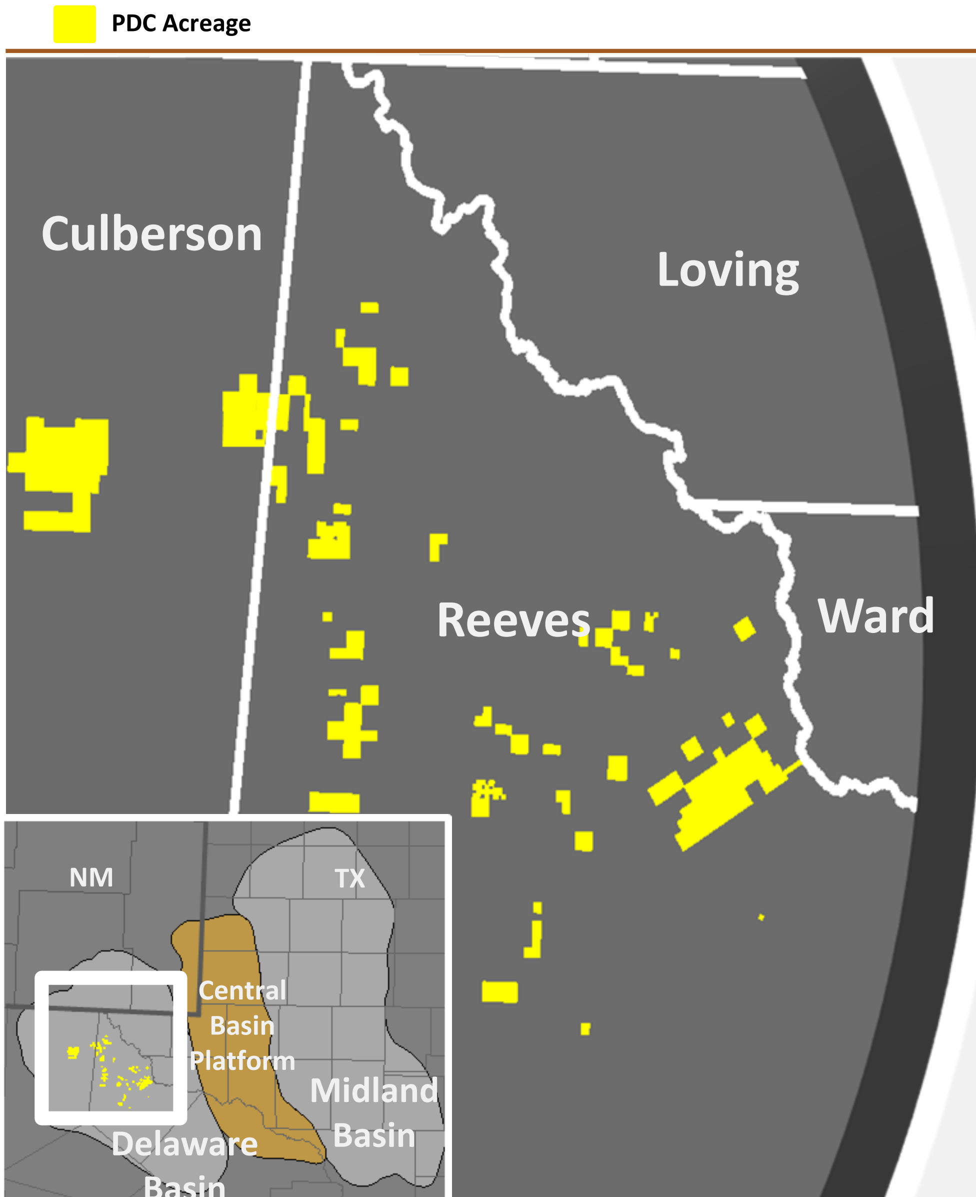


Lateral Type	Lateral Length (feet)	EUR (MBoe)	Capital Cost (MM)	F&D Cost (per Boe)	IRR[2]	PV10[2] (MM)
SRL	4,200	490	$2.5	$6.37	33%	$1.4
MRL	6,900	685	$3.5	$6.39	37%	$2.4
XRL	9,500	850	$4.5	$6.61	33%	$2.8

(1) 2016, 2017, 2018 pricing scenarios; third year pricing held flat in out years. Reflects long-term differentials. Excludes lease acquisition and corporate-level costs.
(2) Esc. pricing: $37, $45, $55 flat annual NYMEX Oil, $2.13, $2.50, $2.75 flat annual NYMEX Gas. Reflects long-term differentials. Excludes lease acquisition and corporate-level costs.

DELAWARE OVERVIEW

Delaware Basin – Asset Overview



- 61,500 net acres in Reeves (42,050) and Culberson (19,450) Counties, TX
- 32.5 MMBoe proved reserves at YE16; ~68% liquids
  - ~580 MMBoe of estimated net reserves potential (65% liquids) across all acreage
- 785 currently identified locations in Wolfcamp A, B and C zones
  - Primarily 5,000’ laterals
  - Assumes only 4-12 wells per section
  - Industry testing significantly tighter spacing and additional zones
- 93% average working interest
  - ~100% operated; ~30% currently HBP

Delaware Basin – Acreage Overview

PDC Acreage

93%

Average WI

100%

Approximate Operated Position

785

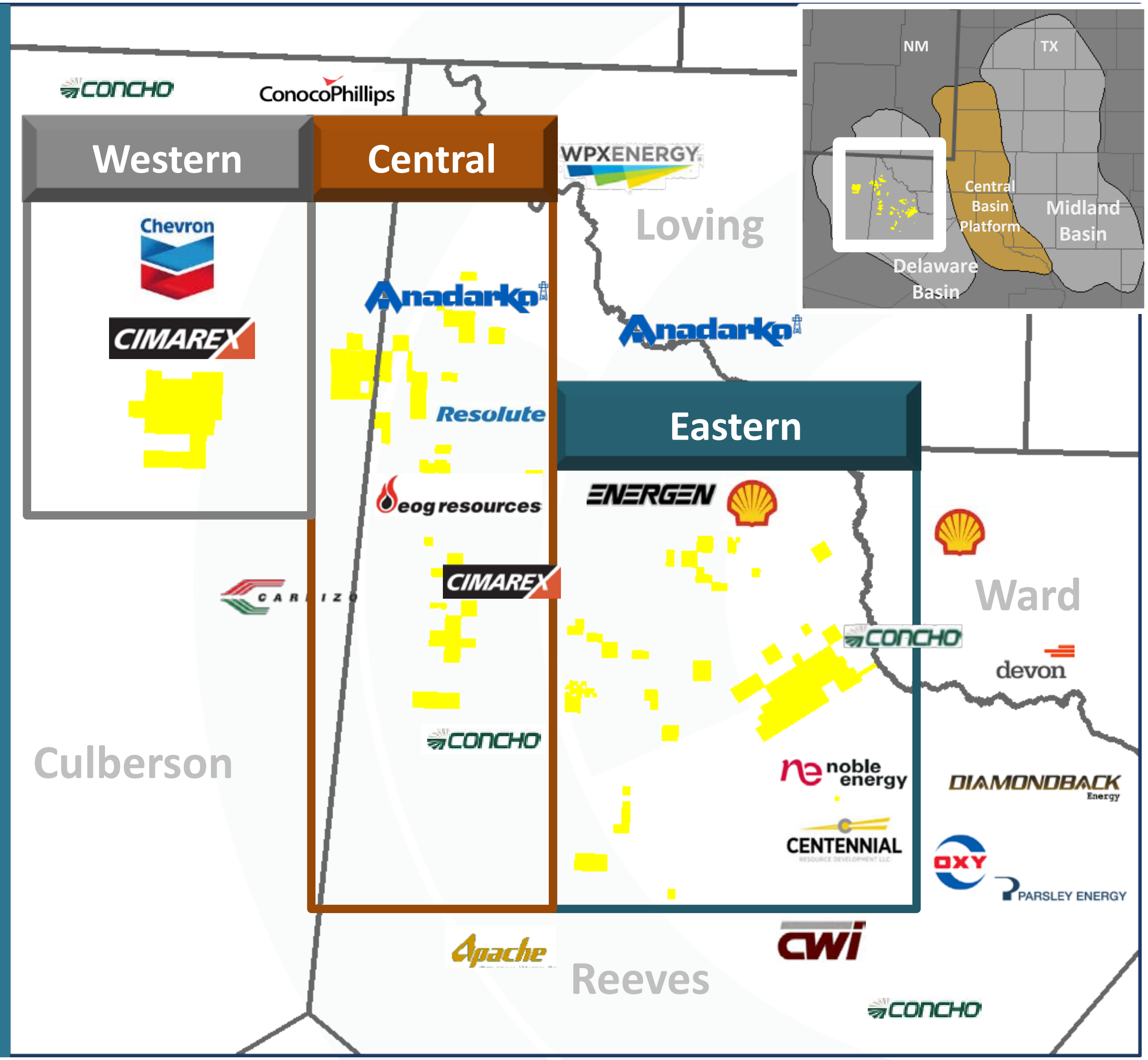
Currently Identified Locations
(Based on only 4-12 total wells per section targeting Wolfcamp A/B/C)

15-20

Years of Drilling Inventory

~1 MM

Average Boe EURs/Well



Off-set operator positions estimated

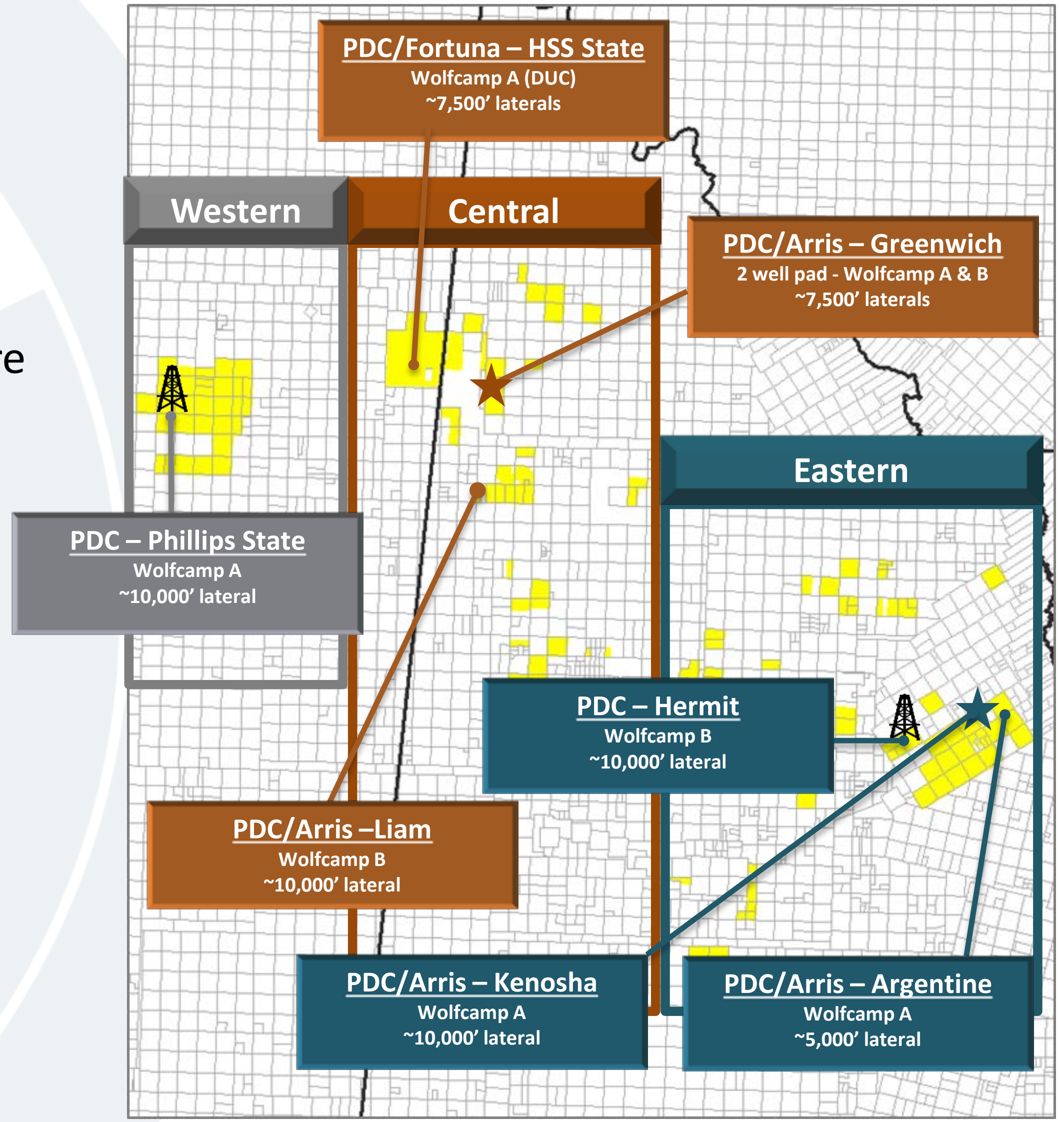
Delaware Basin – 2017 Initiatives and Capital Budget

Rig Location | Waiting-on-Completion | PDC Acreage

- $185 million D&C budget
  - Spud 28 wells
    - 12 spuds in Eastern
    - 14 spuds in Central
    - 2 spuds in Western
  - TIL 19 wells including 13 XRLs
- $15 million midstream infrastructure
  - Install gas gathering lines
  - Drill water supply well and construct frac pits
  - Add SWD wells and capacity
- $35 million leasing, seismic & tech studies

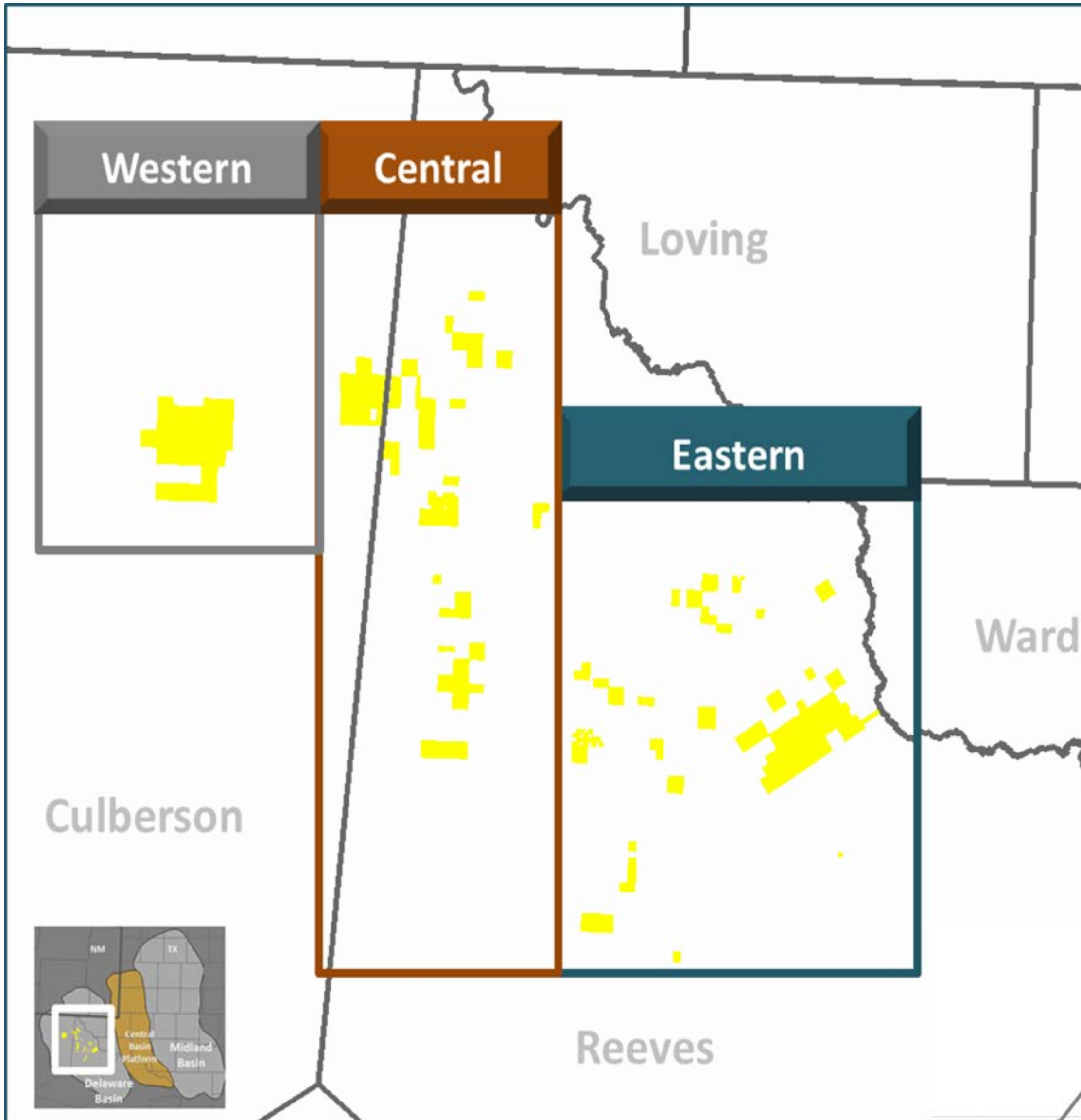
Budgeted Well Costs (millions)

Lateral Length	1-Well Pad	4-Well Pad
1 mile (SRL)	$6.5	$5.8
1.5 miles (MRL)	$8.0	$7.6
2 miles (XRL)	$9.5	$9.1



Delaware Basin – Highly Productive Acreage Blocks

PDC Acreage



EASTERN

17,600 net acres 91% WI

Wolfcamp EURs
- A: 1,000 MBoe
- B: 750 MBoe

Oil: 50 – 70%
Gas: 20 – 30%
NGLs: 10 – 20%

- Inventory: 410 locations

CENTRAL

27,900 net acres 87% WI

Wolfcamp EURs
- A/B: 1,050 MBoe
- C: 1,400 MBoe

Oil: 30 – 50%
Gas: 30 – 40%
NGLs: 20 – 30%

- Inventory: 335 locations

WESTERN

16,000 net acres 100% WI

Wolfcamp EURs
- A: 1,200 MBoe

Oil: 20 – 50%
Gas: 30 – 50%
NGLs: 20 – 30%

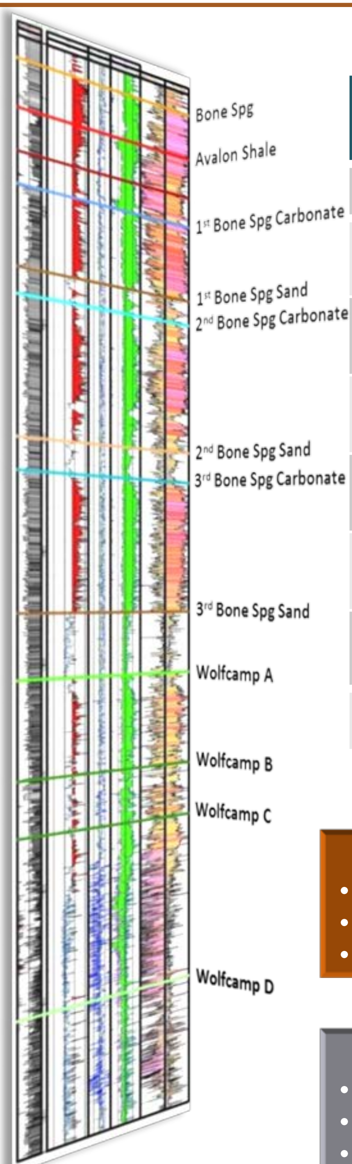
- Inventory: 40 locations

* All EURs and locations based on 5,000' laterals except Western which are based on 10,000' laterals

Delaware Basin – Expansive Inventory Upside

Acquisition Model Assumes Maximum Density of Only 12 Wells per Section

Over 3,000' of Stacked Pay Potential



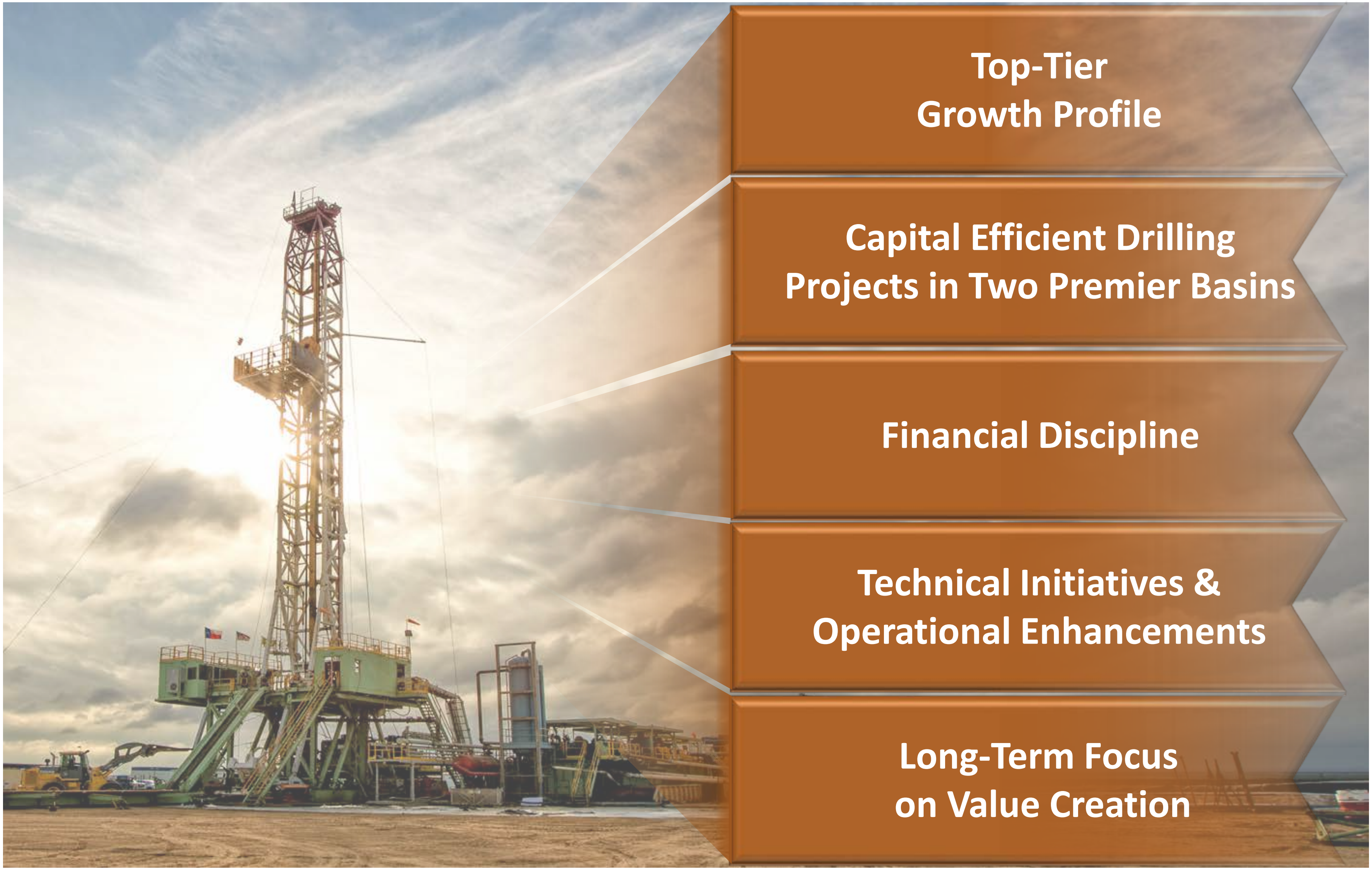
Well Spacing & Inventory Summary

Bench	Max ACQ Spacing	Peer Tests	Eastern Inventory (17,600 net acres)		Central Inventory (27,900 net acres)		Western Inventory (17,600 net acres)	
	Wells/Sec	Wells/Sec	ACQ	Upside	ACQ	Upside	ACQ	Upside
1st Bone Spg/Avalon	-	4 - 12 (XEC, CXO)	-	200	-	315	-	150
2nd Bone Spg	-	4 - 6 (CXO)	-	125	-	220	-	125
3rd Bone Spg	-	4 - 8 (NBL, CXO)	-	150	-	250	-	150
Wolfcamp A	8	8 - 12 (XEC, APC)	260	350	125	380	40	100
Wolfcamp B	4	6 - 8 (NBL, EGN)	150	250	105	155	-	150
Wolfcamp C	4	6 (EGN)	-	150	105	155	-	150
Total	4 - 12	32 - 52	410	1,225	335	1,475	40	825

Acquisition Model
- 785 currently identified gross locations
- 3 main horizons
- Estimated 580 MMBoe of potential net reserves

Potential Unrisked Upside Inventory
- Over 3,500 total potential gross locations
- 6+ potential zones across acreage
- Over 1 Billion Boe of potential net resource

PDC Energy – Strategic Overview



Top-Tier
Growth Profile

Capital Efficient Drilling
Projects in Two Premier Basins

Financial Discipline

Technical Initiatives &
Operational Enhancements

Long-Term Focus
on Value Creation

Investor Relations

Mike Edwards, Senior Director Investor Relations

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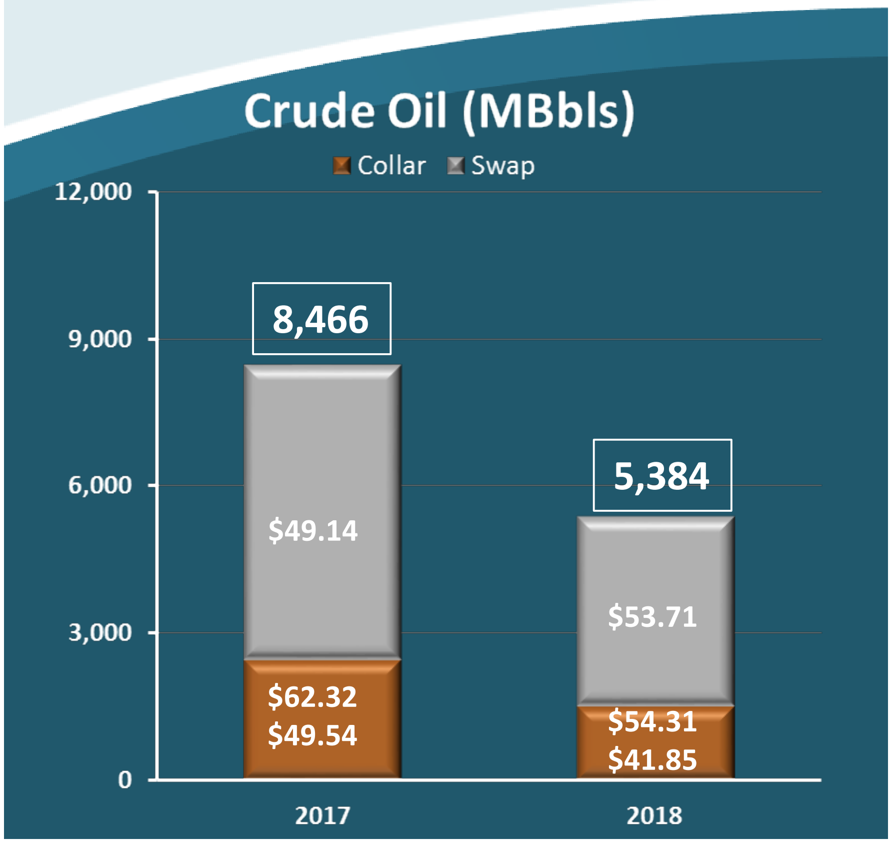
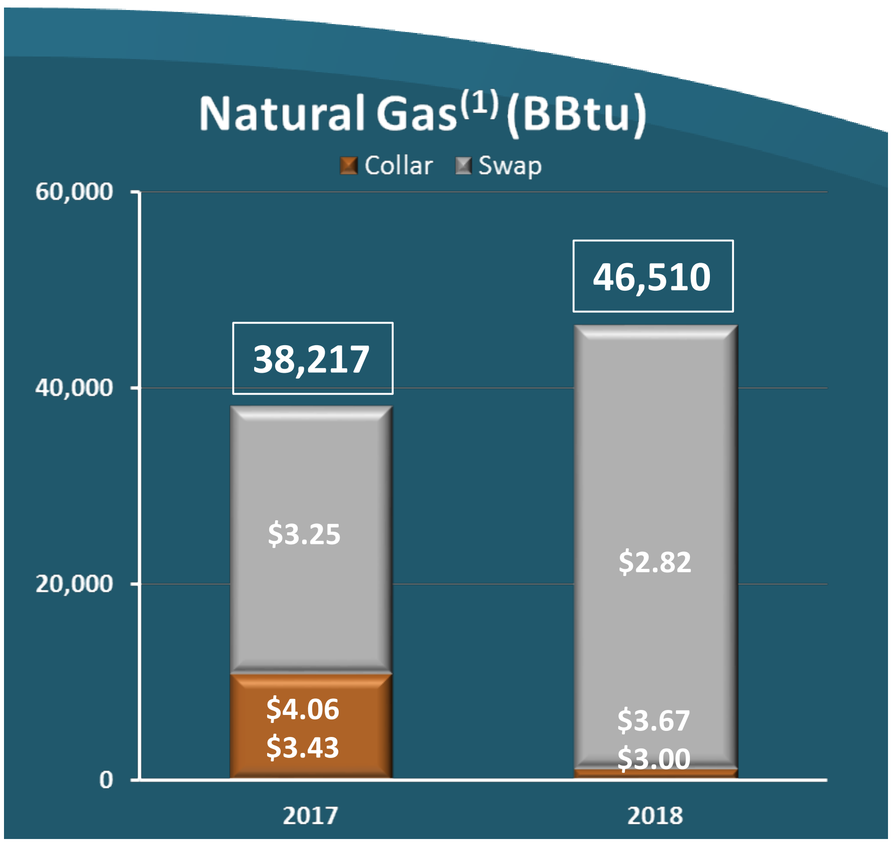
APPENDIX

PDC Energy – Hedge Position Summary

Hedges in place as of December 31, 2016 plus hedges entered prior to January 31, 2017

2017	~8.5 MMBbls crude oil volumes at weighted average floor price of $49.25/Bbl
	38,217 BBtu natural gas volumes at weighted average floor price of $3.30/MMBtu
2018	~5.2 MMBbls crude oil volumes at weighted average floor price of $50.38/Bbl
	46,510 BBtu natural gas volumes at weighted average floor price of $2.83/MMBtu





(1) Natural gas hedged price is at NYMEX and includes any CIG basis swaps.

Core Wattenberg – Midstream Overview

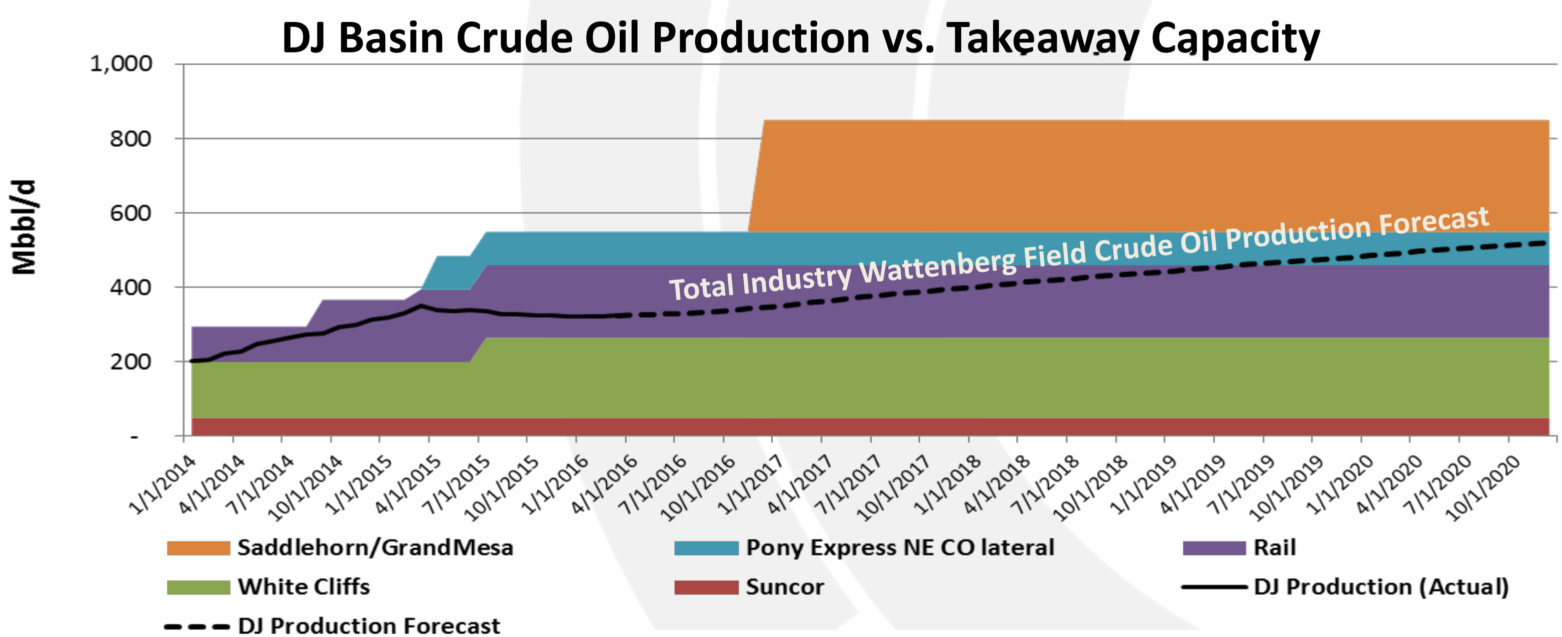
OIL	NATURAL GAS

OIL

- Multiple takeaway options (refinery, pipeline, trucking and rail)
- Excess takeaway capacity projected for several years
- 2017 oil differential of ~$4.50/Bbl(1)

NATURAL GAS

- Diversified gas takeaway (DCP/Aka-APC)
- DCP current capacity ~800 MMcf/d(2)
  - + 40 MMcf/d bypass (summer 2017)
  - + 200 MMcf/d plant (year-end 2018)
  - + 200 MMcf/d plant (mid-year 2019)



(1) Budget average, includes firm commitment on White Cliffs pipeline; (2) Source: DCP Midstream press release, 1/4/17

Core Wattenberg – Updated 2016 EUR Analysis

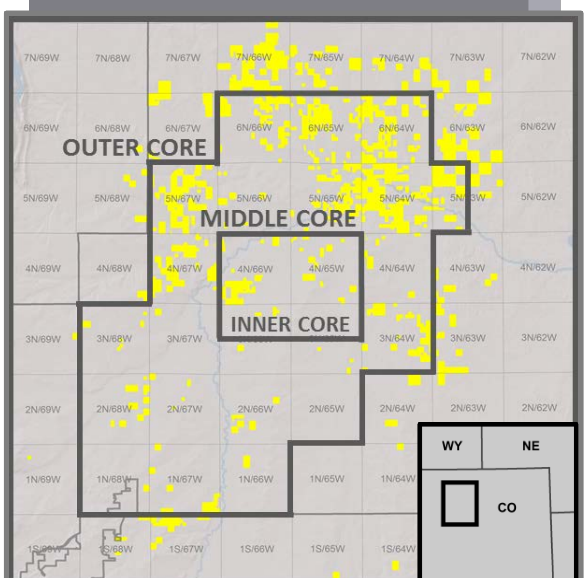
Based on Evaluation of Public Production Data

PDC Acreage

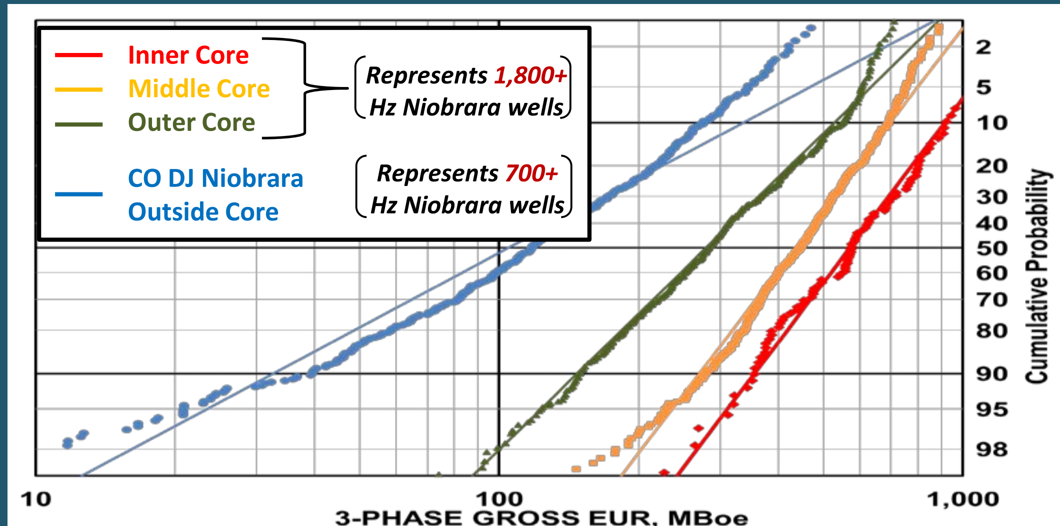
2,500
Wells Included in Study

2.6-3.6
EUR Variability Ratio Range for Core Wattenberg

4,200'
Normalized Lateral Length



2016 EUR ANALYSIS



Area	Industry Average 3-Phase EUR	EUR Variability (P10/P90) Ratio
Inner Core	600 MBoe	2.6
Middle Core	460 MBoe	2.6
Outer Core	311 MBoe	3.6
Non-Core DJ Basin	149 MBoe	10.3

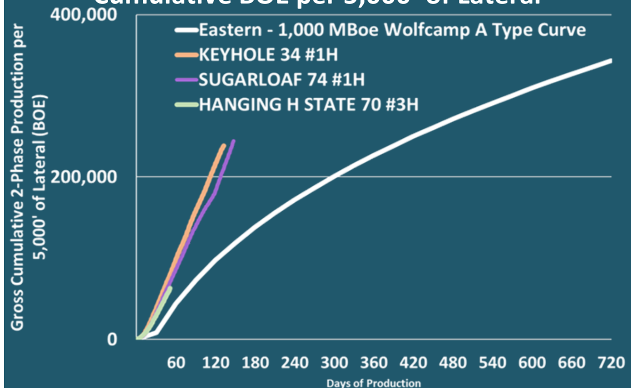
(1) Based upon publicly available data as of December 31, 2015 for wells in Colorado with 4+ months of production. Assumes an NGL yield of 90 Bbls/MMcf and a 20% gas shrink factor for all wells.

Eastern Acreage Block: ~17,600 Net Acres

PDC Acreage | Existing Well | Acquired Well

Wolfcamp A

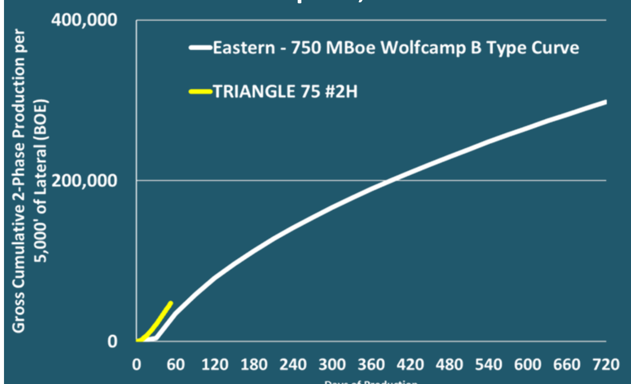
Cumulative BOE per 5,000' of Lateral



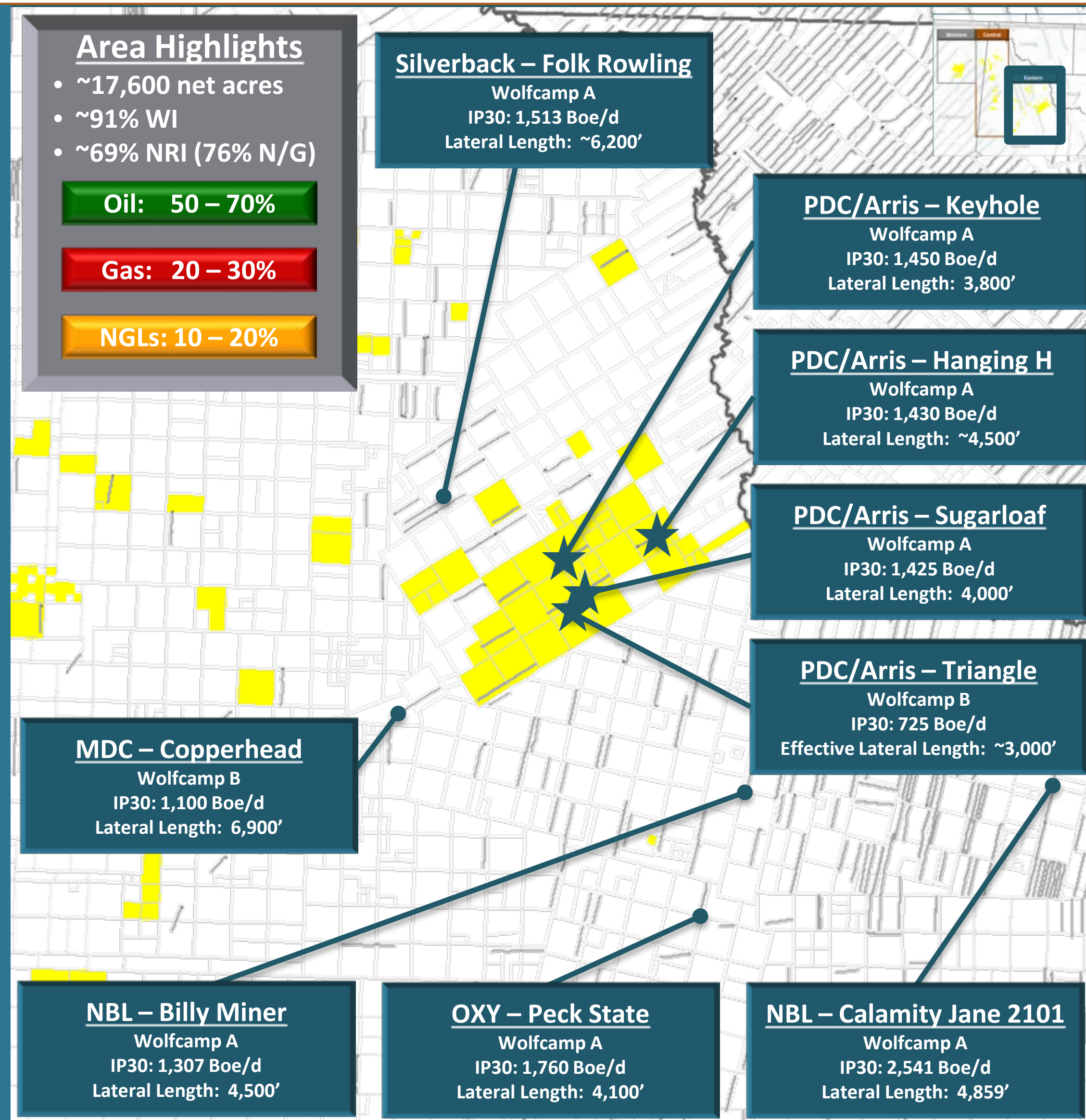
Est. 1-Mile EUR: 1,000 MBoe

Wolfcamp B

Cumulative BOE per 5,000' of Lateral



Est. 1-Mile EUR: 750 MBoe



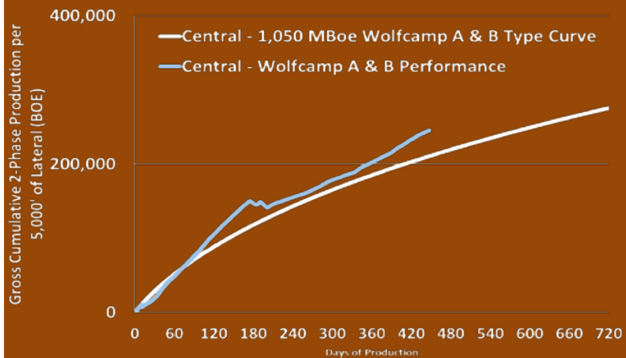
Type curve estimates based on industry wells completed since 2014.

Central Acreage Block: ~27,900 Net Acres

PDC Acreage | Existing Well | Acquired Well

Wolfcamp A / Wolfcamp B

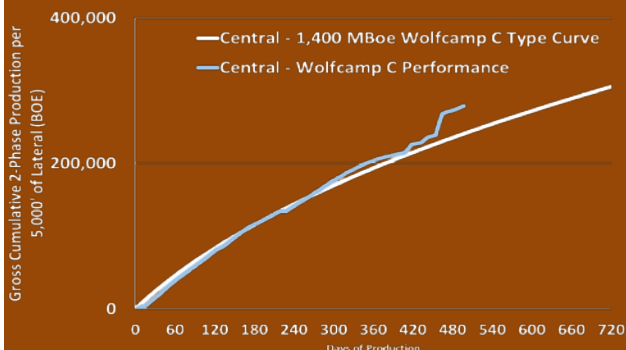
Cumulative BOE per 5,000' of Lateral



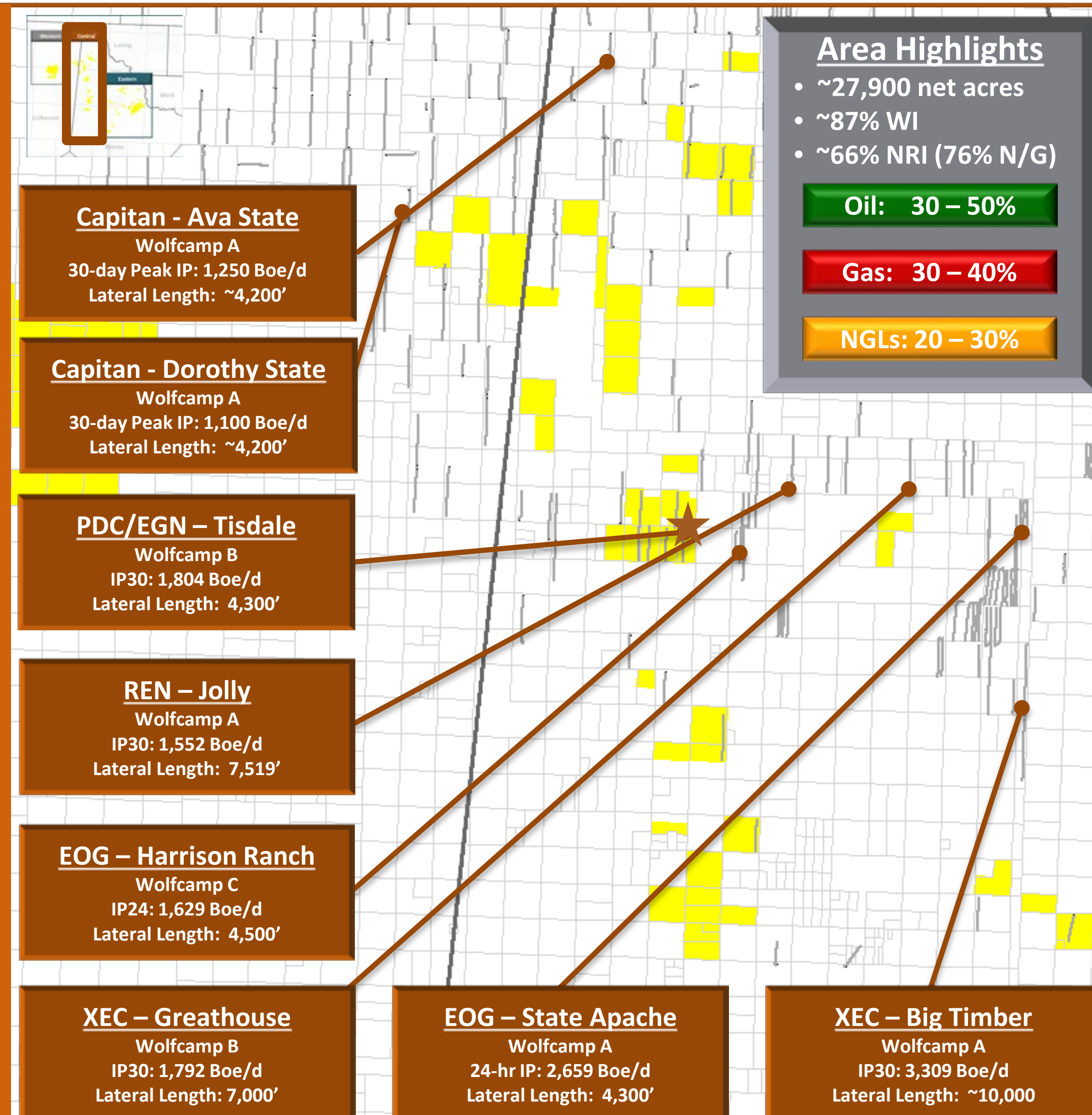
Est. 1-Mile EUR: 1,050 MBoe

Wolfcamp C

Cumulative BOE per 5,000' of Lateral



Est. 1-Mile EUR: 1,400 MBoe



Area Highlights

- ~27,900 net acres
- ~87% WI
- ~66% NRI (76% N/G)

Oil: 30 – 50%

Gas: 30 – 40%

NGLs: 20 – 30%

Capitan - Ava State
Wolfcamp A
30-day Peak IP: 1,250 Boe/d
Lateral Length: ~4,200'

Capitan - Dorothy State
Wolfcamp A
30-day Peak IP: 1,100 Boe/d
Lateral Length: ~4,200'

PDC/EGN – Tisdale
Wolfcamp B
IP30: 1,804 Boe/d
Lateral Length: 4,300'

REN – Jolly
Wolfcamp A
IP30: 1,552 Boe/d
Lateral Length: 7,519'

EOG – Harrison Ranch
Wolfcamp C
IP24: 1,629 Boe/d
Lateral Length: 4,500'

XEC – Greathouse
Wolfcamp B
IP30: 1,792 Boe/d
Lateral Length: 7,000'

EOG – State Apache
Wolfcamp A
24-hr IP: 2,659 Boe/d
Lateral Length: 4,300'

XEC – Big Timber
Wolfcamp A
IP30: 3,309 Boe/d
Lateral Length: ~10,000

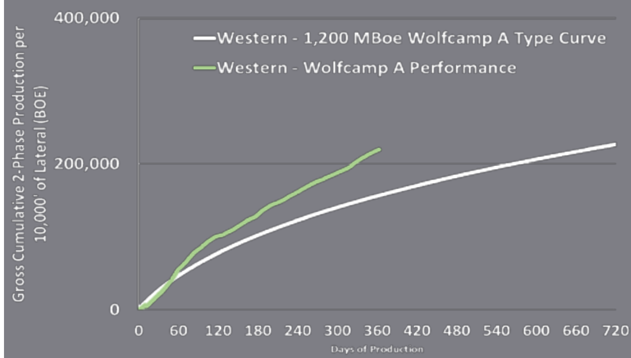
Type curve estimates based on industry wells completed since 2014.

Western Acreage Block: ~16,000 Net Acres

PDC Acreage | Existing Well | Acquired Well

Wolfcamp A

Cumulative BOE per 10,000' of Lateral



Est. 2-Mile EUR: 1,200 MBoe

Additional Upside Potential

- Lower Wolfcamp zones not included in current inventory/reserves
- Strong results from nearby industry test of lower Wolfcamp zones
- Significant upside potential in Wolfcamp A based on offset industry downspacing tests

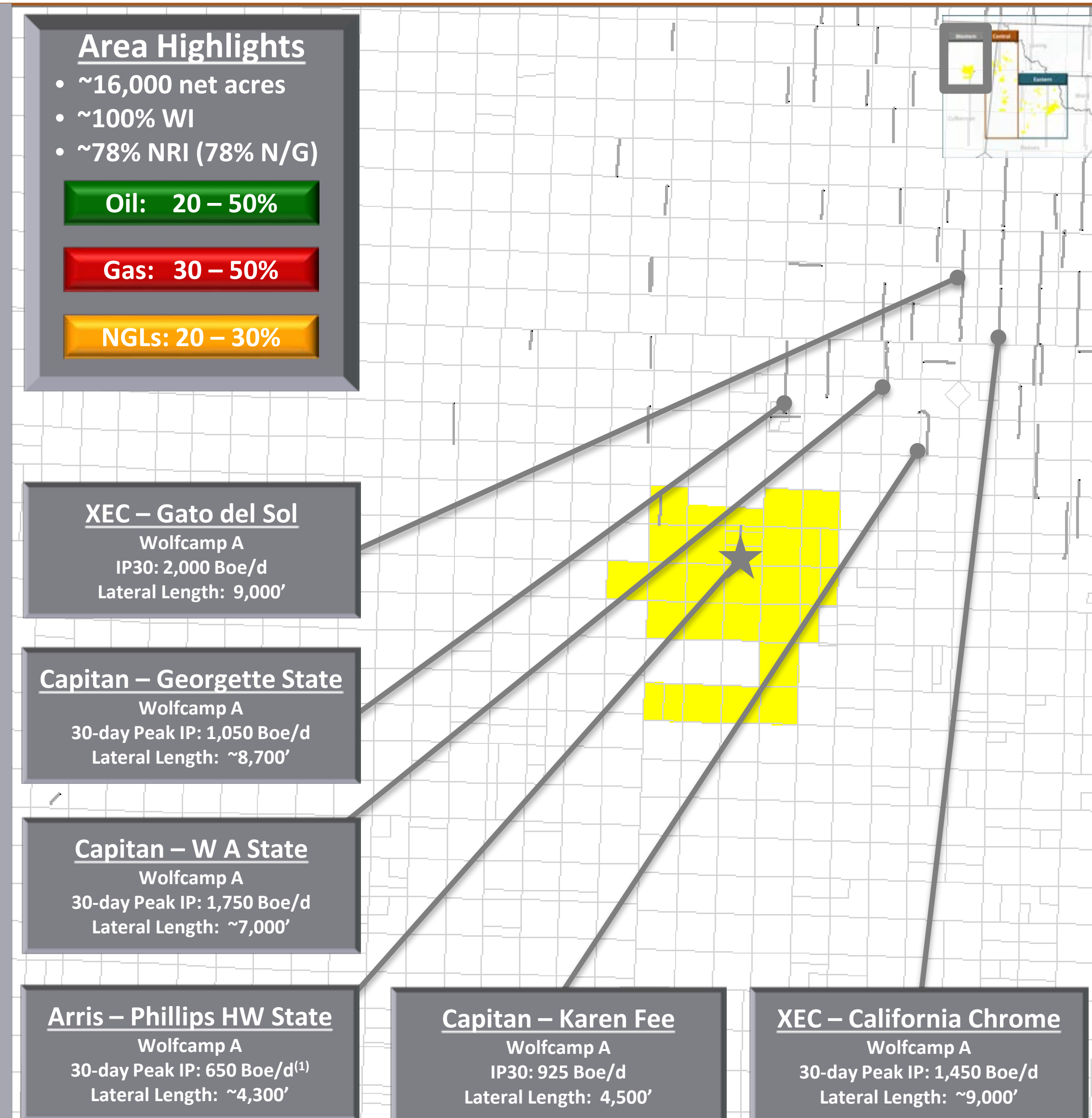
Area Highlights

- ~16,000 net acres
- ~100% WI
- ~78% NRI (78% N/G)

Oil: 20 – 50%

Gas: 30 – 50%

NGLs: 20 – 30%



XEC – Gato del Sol
Wolfcamp A
IP30: 2,000 Boe/d
Lateral Length: 9,000'

Capitan – Georgette State
Wolfcamp A
30-day Peak IP: 1,050 Boe/d
Lateral Length: ~8,700'

Capitan – W A State
Wolfcamp A
30-day Peak IP: 1,750 Boe/d
Lateral Length: ~7,000'

Arris – Phillips HW State
Wolfcamp A
30-day Peak IP: 650 Boe/d(1)
Lateral Length: ~4,300'

Capitan – Karen Fee
Wolfcamp A
IP30: 925 Boe/d
Lateral Length: 4,500'

XEC – California Chrome
Wolfcamp A
30-day Peak IP: 1,450 Boe/d
Lateral Length: ~9,000'

(1) Excludes midstream related downtime; type curve estimates based on industry wells completed since 2014.

Delaware Basin Netback Summary

CRUDE OIL

Key Highlights

- Currently trucked at competitive rates
- Sufficient long-term takeaway from Permian basin
  - Approx. 400 MBbls/d of excess pipeline capacity

Est. Average Netback

NYMEX Oil Price:	$50/Bbl
PDC Netback:	$46/Bbl
Oil Deduct:	$4.00/Bbl

NGLs

Key Highlights

- NGLs piped via multiple pipelines to Gulf Coast
- NGL yields vary based on C2 rejection/recovery

Est. Average Netback

NYMEX Oil Price:	$50/Bbl
PDC Netback:	$15/Bbl
% of NYMEX Oil:	30%

NATURAL GAS

Key Highlights

- Strong relative basis pricing
- Limited term acreage dedication
  - Provides future upside
- No volume commitments

Est. Average Netback

NYMEX Gas Price:	$3.00/MMbtu
PDC Netback:	$2.04/MMbtu
% of NYMEX Gas:	68%

Pro Forma 3-Year Outlook

Organic Base Case | Range | Pro Forma Acquisition | Range

>100

Est. Combined 2018 Daily Production (Mboe/d)

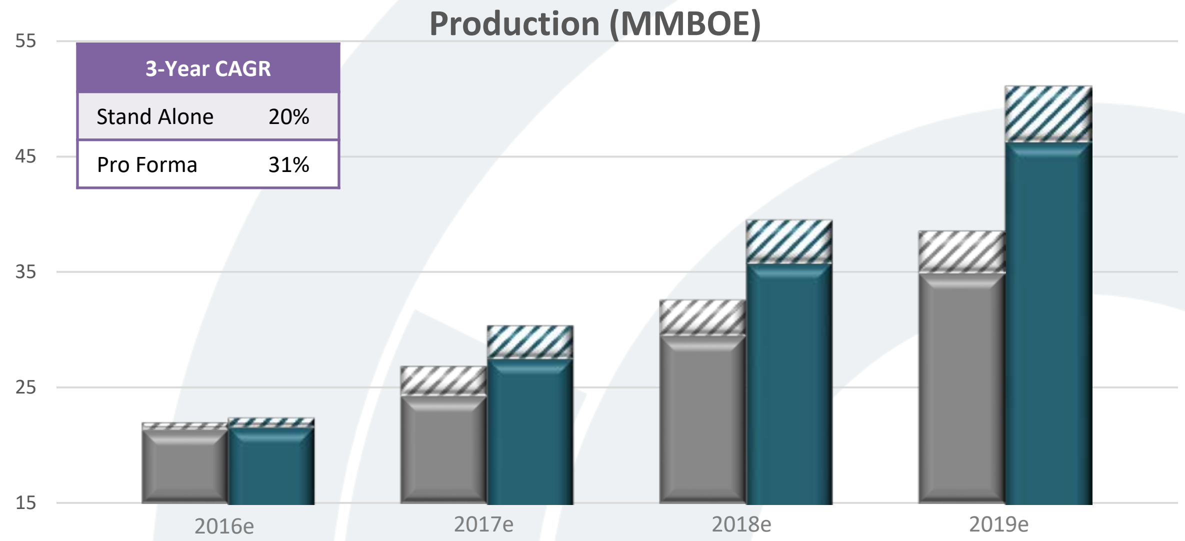
40%

Est. Pro Forma Oil Production Mix

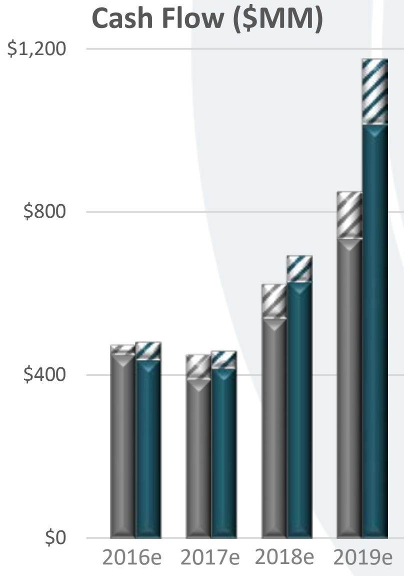
<2.5x

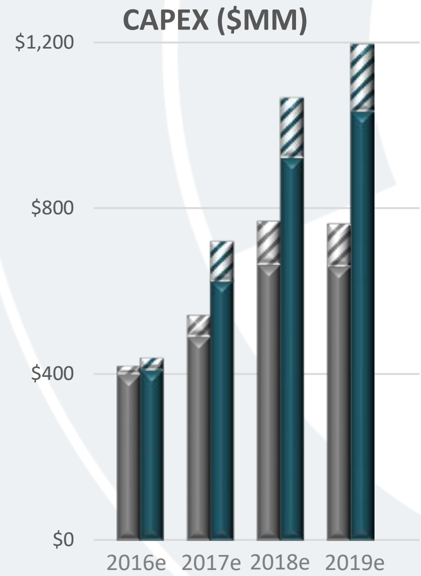
Target Debt/EBITDAX[(1)]

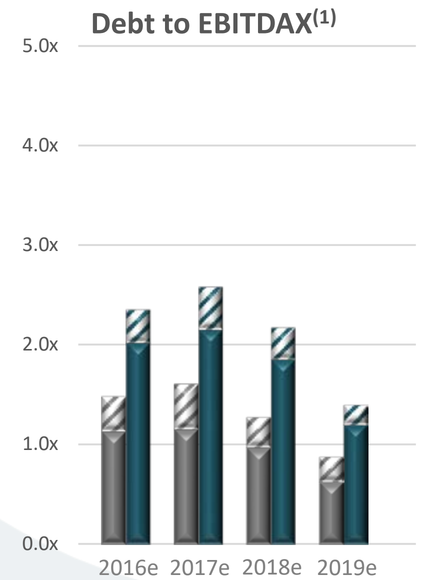
	2016	2017	2018	2019
NYMEX Oil	$42	$51	$55	$61
NYMEX Gas	$2.37	$2.95	$3.50	$3.30



3-Year CAGR	
Stand Alone	20%
Pro Forma	31%



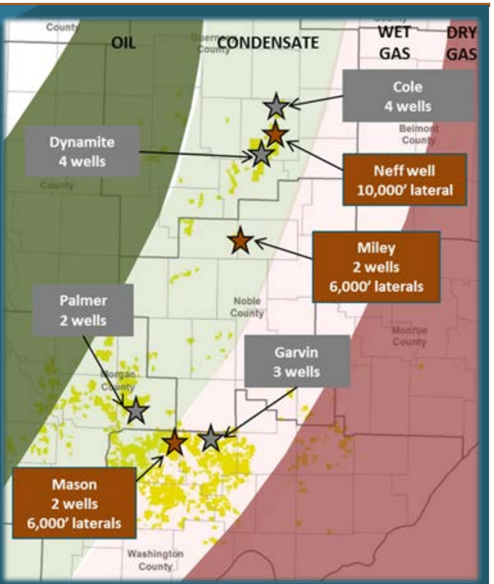


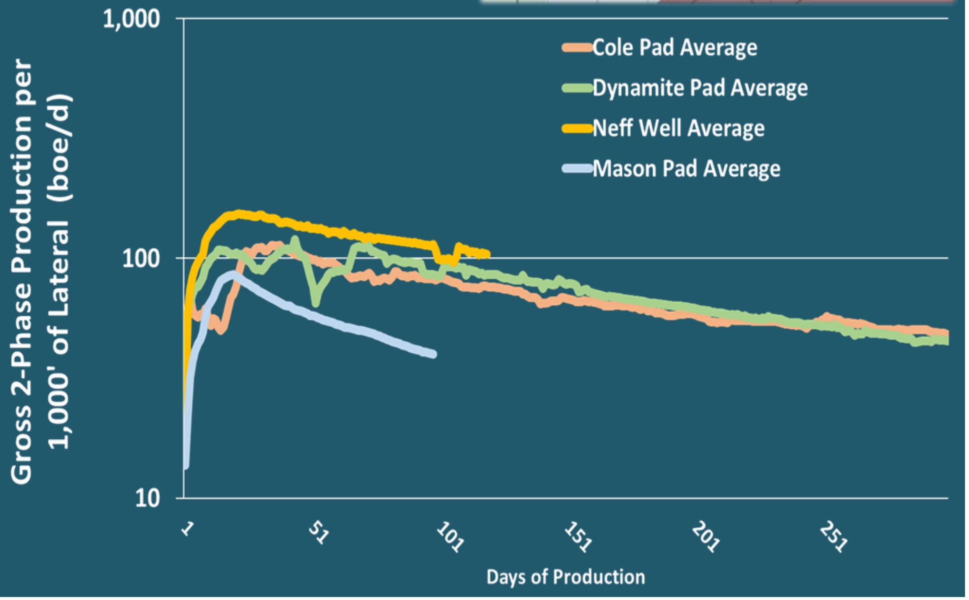


(1) Debt to EBITDAX reflects corporate target and permanent acquisition financing of both debt and equity.

Utica Update

- ~65,000 net acres; ~50% HBP
- ~$27MM capital plan in 2016
  - Neff well: May TIL
    - 10,000' lateral testing efficiency improvements
    - Best PDC Utica results per lateral foot to-date
  - Mason pad: June TIL
    - 6,000' lateral testing completion designs from Cole & Dynamite pads
    - Continue to monitor well performance
  - Miley pad: November TIL
    - Well-orientation testing
- Completed well costs of ~$5.5 million for a 6,000' lateral well





Reconciliation of Non-US GAAP Financial Measures

In millions, except per share data

Adjusted EBITDA from net income (loss):	**Three Months Ended Sept 30,**		**Nine Months Ended Sept 30,**	
	2016	**2015**	**2016**	**2015**
Net loss	($23.3)	($41.5)	($190.3)	($71.3)
(Gain) loss on commodity derivative instruments	($19.4)	($123.5)	$62.3	($141.2)
Net settlements on commodity derivative instruments	$47.7	$68.0	$167.9	$162.5
Interest expense, net	$20.1	$10.7	$40.9	$31.8
Income tax provision	($12.0)	($21.2)	($112.2)	($40.6)
Impairment of properties and equipment	$0.9	$154.0	$6.1	$161.2
Depreciation, depletion, and amortization	$112.9	$81.0	$317.3	$206.9
Accretion of asset retirement obligations	$1.8	$1.6	$5.4	$4.7
Adjusted EBITDA	**$128.7**	**$129.1**	**$297.4**	**$314.0**
Weighted-average diluted shares outstanding	48.8	40.1	45.7	38.8
Adjusted EBITDA per diluted share	$2.64	$3.22	$6.50	$8.09

Adjusted EBITDA from net cash from operations activities:	**Three Months Ended Sept 30,**		**Nine Months Ended Sept 30,**	
	2016	**2015**	**2016**	**2015**
Net cash from operating activities	$163.0	$136.5	$360.8	$283.0
Interest expense, net	$20.1	$10.7	$40.9	$31.8
Stock-based compensation	($4.1)	($4.8)	($15.2)	($14.3)
Amortization of debt discount and issuance costs	($9.9)	($1.8)	($12.9)	($5.3)
Gain on sale of properties and equipment	$0.2	$0.1	-	$0.3
Other	($0.2)	$2.2	($41.6)	$7.9
Changes in assets and liabilities	($40.4)	($13.8)	($34.6)	$10.6
Adjusted EBITDA	**$128.7**	**$129.1**	**$297.4**	**$314.0**
Weighted-average diluted shares outstanding	48.8	40.1	45.7	38.8
Adjusted EBITDA per diluted share	$2.64	$3.22	$6.50	$8.09

Reconciliation of Non-US GAAP Financial Measures

In millions, except per share data

Adjusted net income (loss) from net income (loss):	**Three Months Ended Sept 30,**		**Nine Months Ended Sept 30,**	
	2016	**2015**	**2016**	**2015**
Net loss	($23.3)	($41.5)	($190.3)	($71.3)
(Gain) loss on commodity derivative instruments	($19.4)	($123.5)	$62.3	($141.2)
Net settlements on commodity derivative instruments	$47.7	$68.0	$167.9	$162.5
Tax effect of above adjustments	($10.8)	$21.1	($87.6)	($8.1)
Adjusted net loss	**($5.8)**	**($75.9)**	**($47.7)**	**($58.1)**
Weighted-average diluted shares outstanding	48.8	40.1	45.7	38.8
Adjusted net loss per diluted share	($0.12)	($1.89)	($1.04)	($1.50)

Adjusted cash flows from operations from net cash from operating activities:	**Three Months Ended Sept 30,**		**Nine Months Ended Sept 30,**	
	2016	**2015**	**2016**	**2015**
Net cash from operating activities	$163.0	$136.5	$360.8	$283.0
Changes in assets and liabilities	($40.4)	($13.8)	($34.6)	$10.6
Adjusted cash flows from operations	**$122.6**	**$122.7**	**$326.2**	**$293.6**
Weighted-average diluted shares outstanding	48.8	40.1	45.7	38.8
Adjusted cash flows per diluted share	$2.51	$3.06	$7.14	$7.56