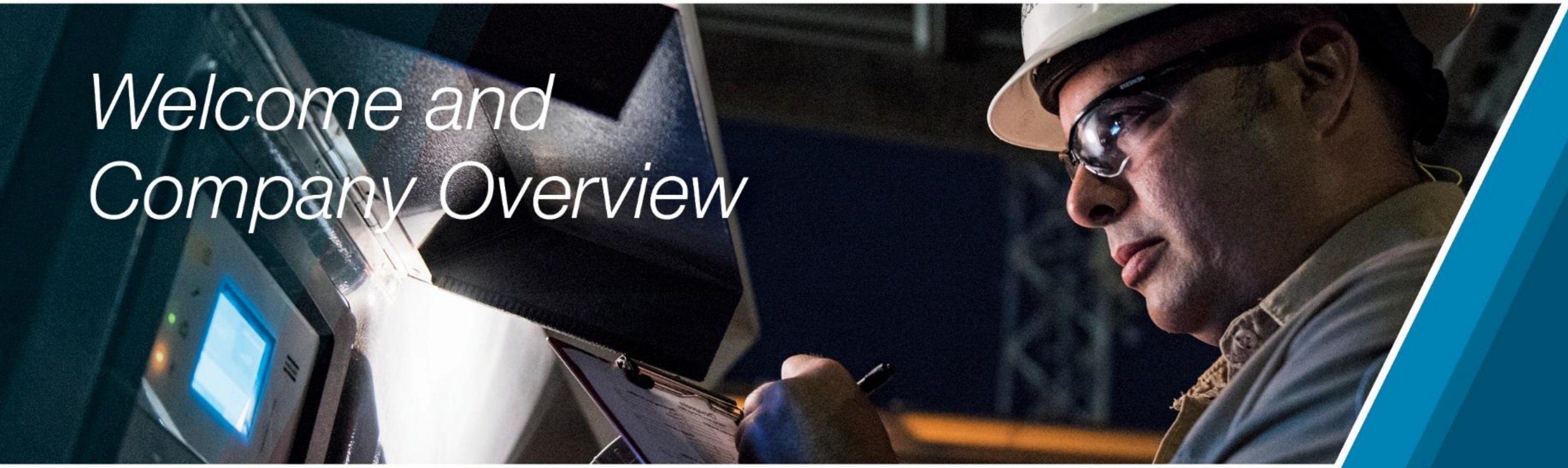
Welcome and Company Overview



DOUG LAWLER

CAUTIONARY STATEMENTS

This presentation includes “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. Forward-looking statements are statements other than statements of historical fact. They include statements that give our current expectations or forecasts of future events, production and well connection forecasts, estimates of operating costs, anticipated capital and operational efficiencies, planned development drilling and expected drilling cost reductions, general and administrative expenses, capital expenditures, the timing of anticipated noncore asset sales and proceeds to be received therefrom, projected cash flow and liquidity, our ability to enhance our cash flow and financial flexibility, plans and objectives for future operations (including our ability to optimize base production and execute gas gathering agreements), the ability of our employees, portfolio strength and operational leadership to create long-term value, and the assumptions on which such statements are based. Although we believe the expectations and forecasts reflected in the forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate or changed assumptions or by known or unknown risks and uncertainties.

Factors that could cause actual results to differ materially from expected results include those described under “Risk Factors” in Item 1A of our annual report on Form 10-K and any updates to those factors set forth in Chesapeake’s subsequent quarterly reports on Form 10-Q or current reports on Form 8-K (available at http://www.chk.com/investors/sec-filings). These risk factors include the volatility of oil, natural gas and NGL prices; the limitations our level of indebtedness may have on our financial flexibility; our inability to access the capital markets on favorable terms or at all; the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations; a further downgrade in our credit rating requiring us to post more collateral under certain commercial arrangements; write-downs of our oil and natural gas asset carrying values due low commodity prices; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures; our ability to generate profits or achieve targeted results in drilling and well operations; leasehold terms expiring before production can be established; commodity derivative activities resulting in lower prices realized on oil, natural gas and NGL sales; the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations; adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims; charges incurred in response to market conditions and in connection with our ongoing actions to reduce financial leverage and complexity; drilling and operating risks and resulting liabilities; effects of environmental protection laws and regulation on our business; legislative and regulatory initiatives further regulating hydraulic fracturing; our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used; impacts of potential legislative and regulatory actions addressing climate change; federal and state tax proposals affecting our industry; potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations; competition in the oil and gas exploration and production industry; a deterioration in general economic, business or industry conditions; negative public perceptions of our industry; limited control over properties we do not operate; pipeline and gathering system capacity constraints and transportation interruptions; terrorist activities and cyber-attacks adversely impacting our operations; potential challenges of our spin-off of Seventy Seven Energy Inc. (SSE) in connection with SSE’s recently completed bankruptcy under Chapter 11 of the U.S. Bankruptcy Code; an interruption in operations at our headquarters due to a catastrophic event; the continuation of suspended dividend payments on our common stock and preferred stock; certain anti-takeover provisions that affect shareholder rights; and our inability to increase or maintain our liquidity through debt repurchases, capital exchanges, asset sales, joint ventures, farmouts or other means.

CAUTIONARY STATEMENTS (CONT.)

In addition, disclosures concerning the estimated contribution of derivative contracts to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility. Our production forecasts are also dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Expected asset sales may not be completed in the time frame anticipated or at all. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this presentation, and we undertake no obligation to update any of the information provided in this presentation, except as required by applicable law.

PV10 is a non-GAAP measurement used by the industry, investors and analysts to estimate present value, discounted at 10% per annum, of estimated future cash flows of our estimated proved reserves before income tax and asset retirement obligations. The most directly comparable GAAP measure is the standard measure of discounted future net cash flows. Management believes that PV10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural 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 our company. PV10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP. With respect to PV10 calculated as of an interim date, it is not practical to calculate taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms in this presentation, such as “estimated ultimate recovery” (EUR), “oil in place” (OIP), “gross recoverable resource,” “resource potential,” “type curve” and similar phrases. 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. The SEC guidelines strictly prohibit us from including these estimates in filings with the SEC. Investors are urged to consider closely the disclosures and risk factors in our most recent Form 10-K and in other reports on file with the SEC.

Agenda

7:00 a.m.	**Registration and Breakfast – Poster Sessions**
9:00 a.m.	**Doug Lawler** *Welcome and Company Overview*
9:15 a.m.	**Frank Patterson** *Powder River Basin, Appalachia, Exploration, Mid-Continent*
10:30 a.m.	**Break**
10:45 a.m.	**Jason Pigott** *Operations and Technical Services, South Texas, Gulf Coast*
11:45 a.m.	**Break – Boxed Lunches**
12:15 p.m.	**Nick Dell'Osso** *Capital Structure and Outlook*
12:45 p.m.	**Doug Lawler** *Summary and Path Forward*
1:00 p.m.	**Q&A/Closing Remarks**
2:00 p.m.	**Dismiss, Poster Sessions and Tours**

Rediscovering Chesapeake Energy…

FINANCIAL DISCIPLINE

BUSINESS DEVELOPMENT

EXPLORATION

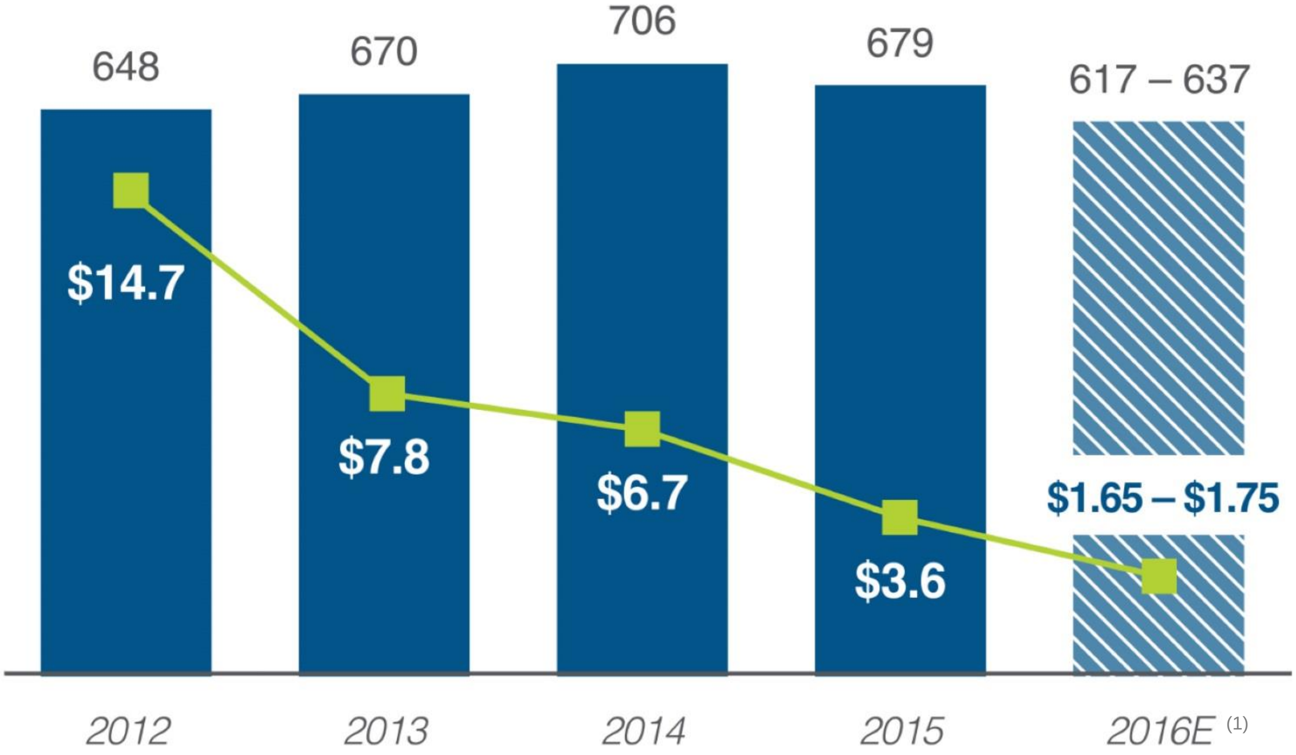
PROFITABLE AND EFFICIENT GROWTH

~50% REDUCTION

IN TOTAL LEVERAGE

=$10.9 BILLION

CAPITAL EFFICIENCY DEFINED



(1) 2016E represents 10/20 Outlook ranges

BUSINESS DEVELOPMENT

FINANCIAL DISCIPLINE

EXPLORATION

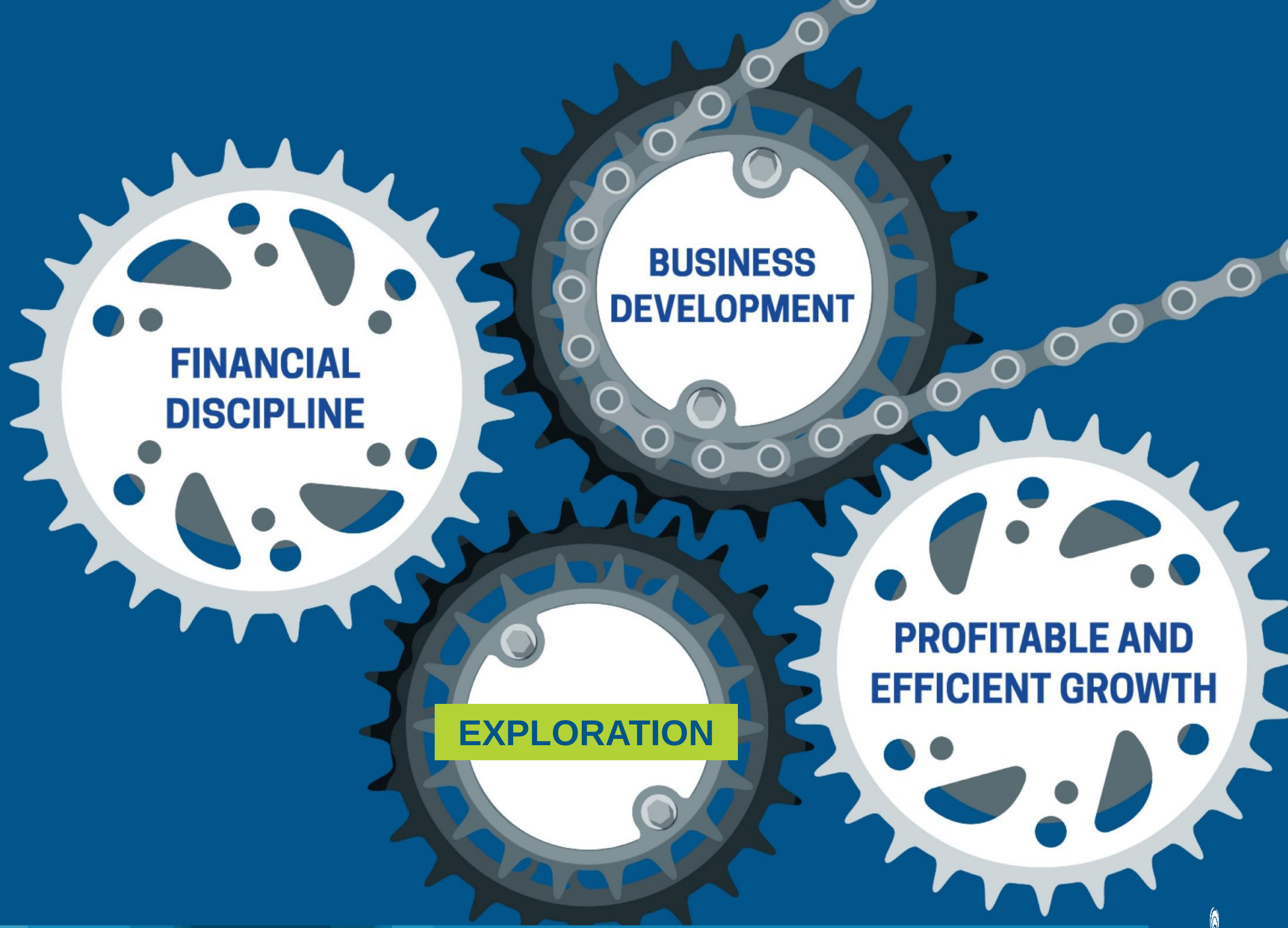
PROFITABLE AND EFFICIENT GROWTH

$1.3B asset sales

closed or pending

2016 total expected > $2B

*Represents gross proceeds from asset sales



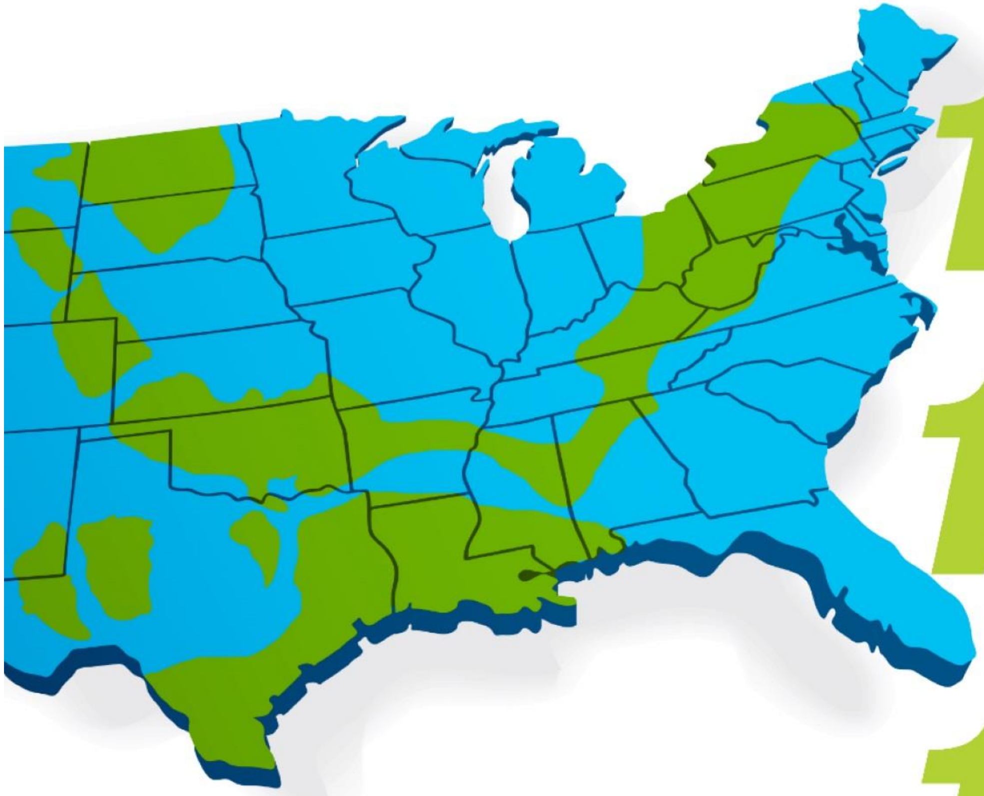
FINANCIAL DISCIPLINE

BUSINESS DEVELOPMENT

EXPLORATION

PROFITABLE AND EFFICIENT GROWTH

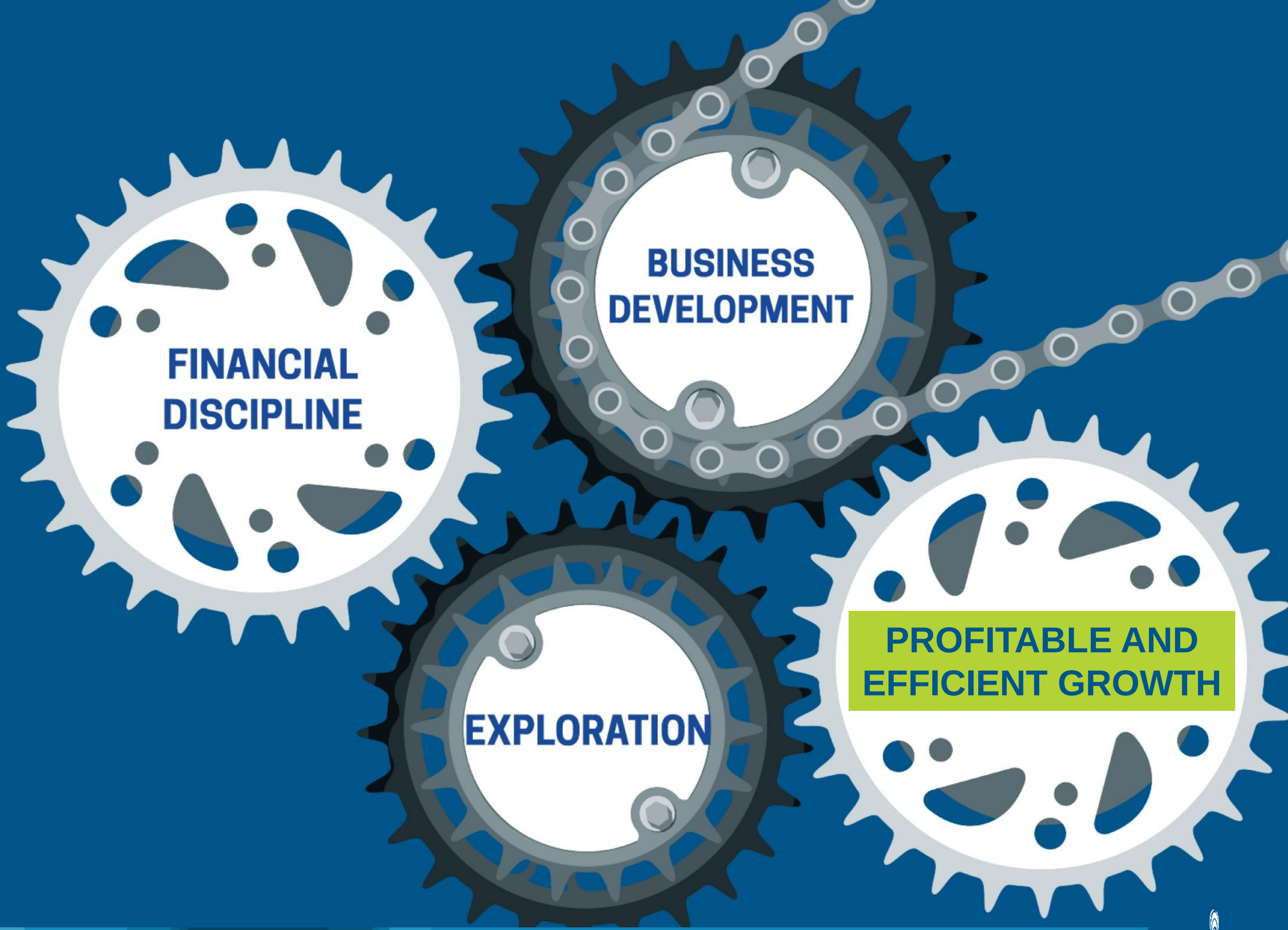
Exploration Opportunities



17 Prospects adding value to current HBP position

15 Growth opportunities in CHK-operated basins

11 New basin-entry plays

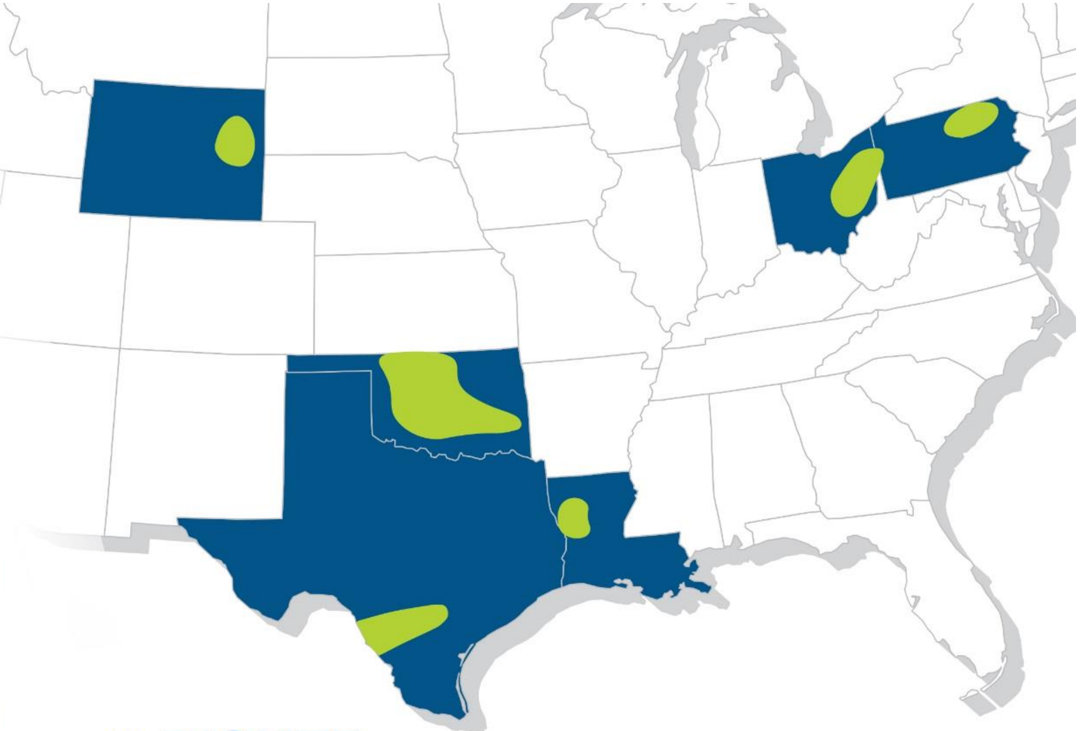


BUSINESS DEVELOPMENT

FINANCIAL DISCIPLINE

EXPLORATION

PROFITABLE AND EFFICIENT GROWTH



~17,600 LOCATIONS

Remain to be drilled

~10,500 LOCATIONS

Above 20% ROR (1)

~5,600 LOCATIONS

Above 40% ROR (1)

- RISKED LOCATIONS
- DOWNSPACING UPSIDE
- PROVEN RESERVOIRS
- TREMENDOUS EXPLORATION *AND* TECHNOLOGY UPSIDE

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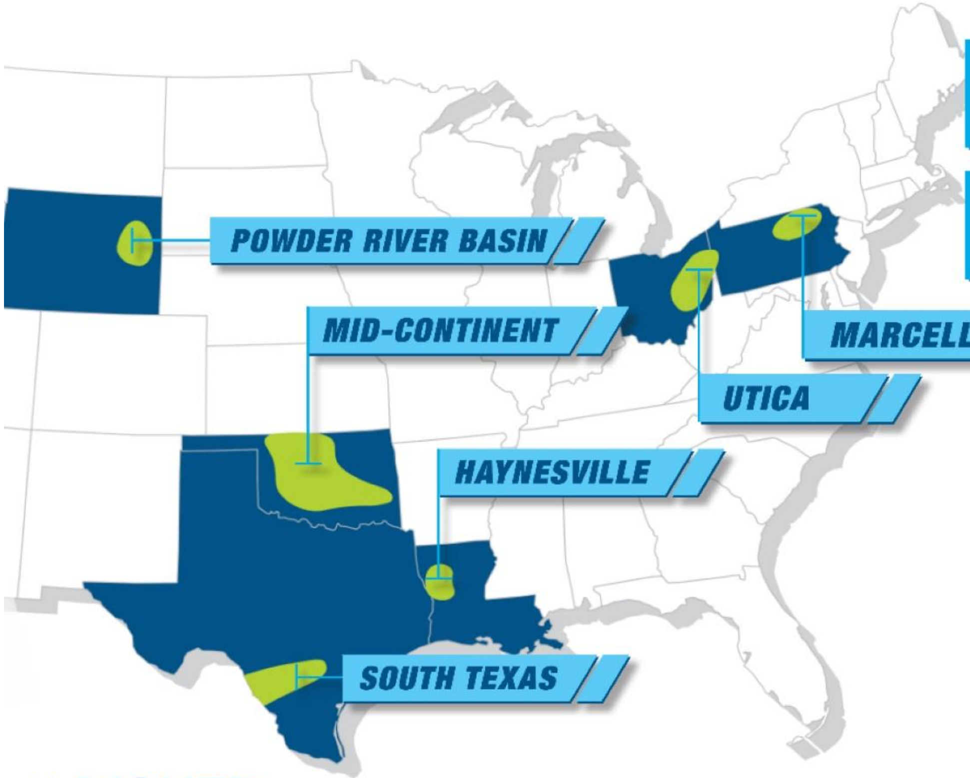
(1) Economics assume $3/mcf and $60/bbl flat

POWER OF THE PORTFOLIO



11.3 BBOE TOTAL NET recoverable resources

- » RISKED LOCATIONS
- » DOWNSPACING UPSIDE
- » PROVEN RESERVOIRS
- » TREMENDOUS EXPLORATION *AND* TECHNOLOGY UPSIDE

SOUTH TEXAS

75%
undeveloped

5,260
LOCATIONS
remain to be drilled (1)

2.0
BBOE
net recoverable resources

$39/bbl
breakeven (PV10) (2)

(1) Includes Upper Eagle Ford and Austin Chalk locations; operated gross risked locations
(2) PV10 positive breakeven price assuming $3 gas price

HAYNESVILLE

75%
undeveloped

10X MORE
PRODUCTIVE

18.9
TCF
net recoverable resources

$2.35/mcf
breakeven (PV10)

2,070
LOCATIONS
remain to be drilled (1)

(1) Includes all Gulf Coast locations; operated gross risked locations

MID-CONTINENT

1.5 mm

acres under lease after $1 billion in 2016 divestitures

170% ROR

Oswego economics (1)

>1.0 BBOE

net recoverable resources

<$40/bbl

breakeven (PV10) (2)

15

targeted horizons

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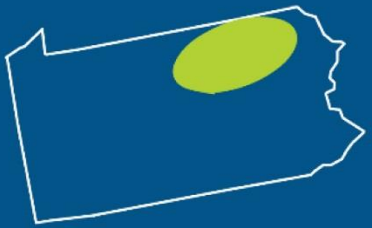
(1) Price deck at $3 and $60 flat
(2) PV10 positive breakeven price assuming $3 gas price

MARCELLUS



1.8
BCF/D
flat gross production with minimal capital spend

$2.00/mcf
breakeven (PV10)

2,900
LOCATIONS
remain to be drilled (1)

11.2
TCF
net recoverable resources

(1) Operated gross risked locations

UTICA

90%
OF GAS
flows out of basin

1,575
LOCATIONS
remain to be drilled (1)

1.6
BBOE
net recoverable resources

$2.15/mcf
Utica dry breakeven (PV10)

$37/bbl
Utica wet breakeven (PV10) (2)

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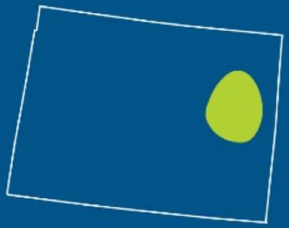
(1) Operated gross risked locations
(2) PV10 positive breakeven price assuming $3 gas price

POWDER RIVER BASIN



1.7
BBOE
net recoverable resources

2,600
LOCATIONS
remain to be drilled (1)

730K
ACRES
equivalent stacked acreage

$35-$45 /bbl
breakeven (PV10) (2)

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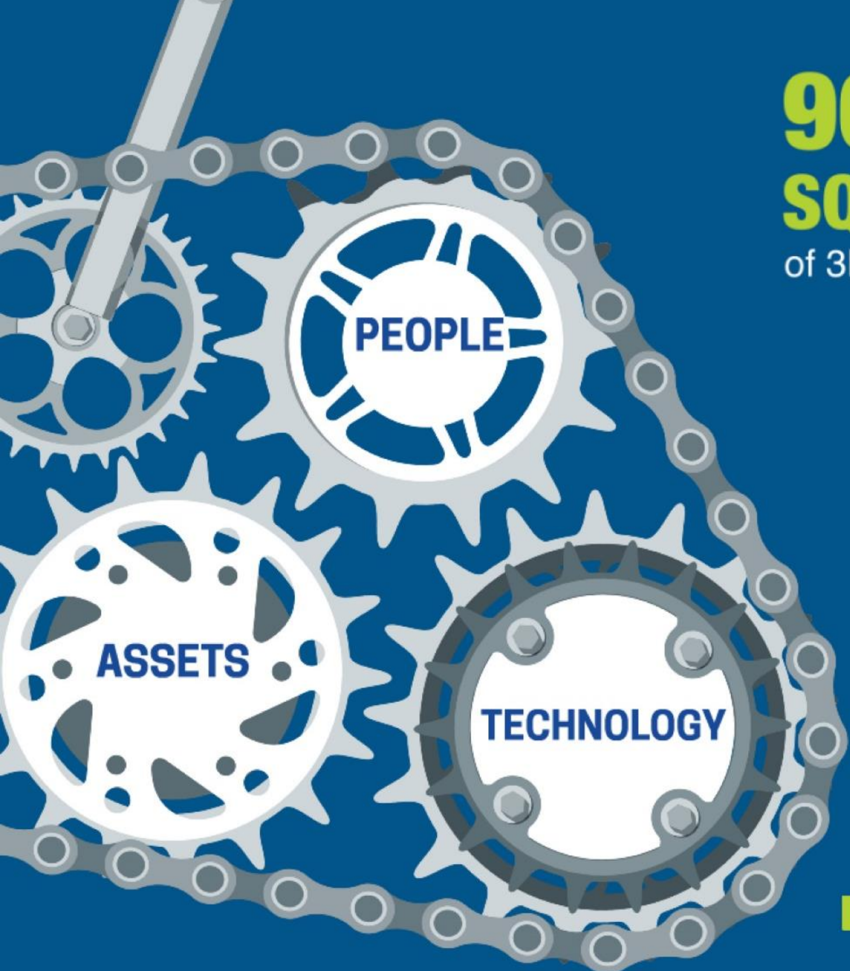
(1) Operated gross risked locations
(2) PV10 positive breakeven price assuming $3 gas price

70%

improvement in employee and contractor total recordable incident rate



96,000 SQ. MILES
of 3D seismic data

26,000
PRODUCING
WELLS

2.5 MILLION
well logs

>11,000
horizontal wells drilled

23,000 MILES
DRILLED IN LAST
10 YEARS

#1
driller of
horizontal wells

7 MM ACRES(1)

17,600 LOCATIONS
remaining to be drilled

11.3 BBOE
TOTAL NET
recoverable
resources

Done more, doing more, more to do.

---

(1) ~7.0mm net acres

WHAT YOU NEED TO KNOW…

- *Large acreage position that is largely held, so no longer drilling just to hold acreage, but drilling to deliver value*
- *We are expanding the economic core in several plays and have more remaining locations to drill than we have drilled in our history*
- *Stacked potential in almost every play*
- *Leading drilling and completion technology in several plays – technological advances rapidly being deployed throughout the portfolio*
- *Multiple oil growth opportunities in portfolio*

Our program today will build on this foundation and more…

POWDER RIVER BASIN:

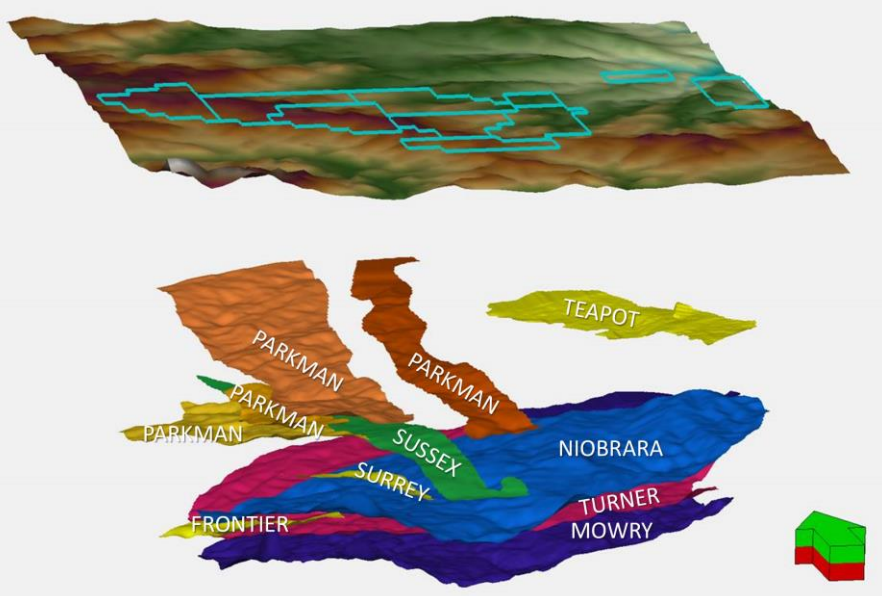
Emerging Oil Growth Giant

FRANK PATTERSON

Chesapeake
ENERGY

POWDER RIVER BASIN – WHAT HAS CHANGED?

- Renegotiated midstream agreement unlocks a material development opportunity
- Leveraged learnings throughout CHK to optimize performance
- Petroleum systems-based analysis provides new stacked-play opportunities

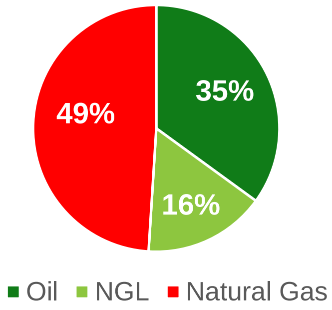


Development program commences November 2016

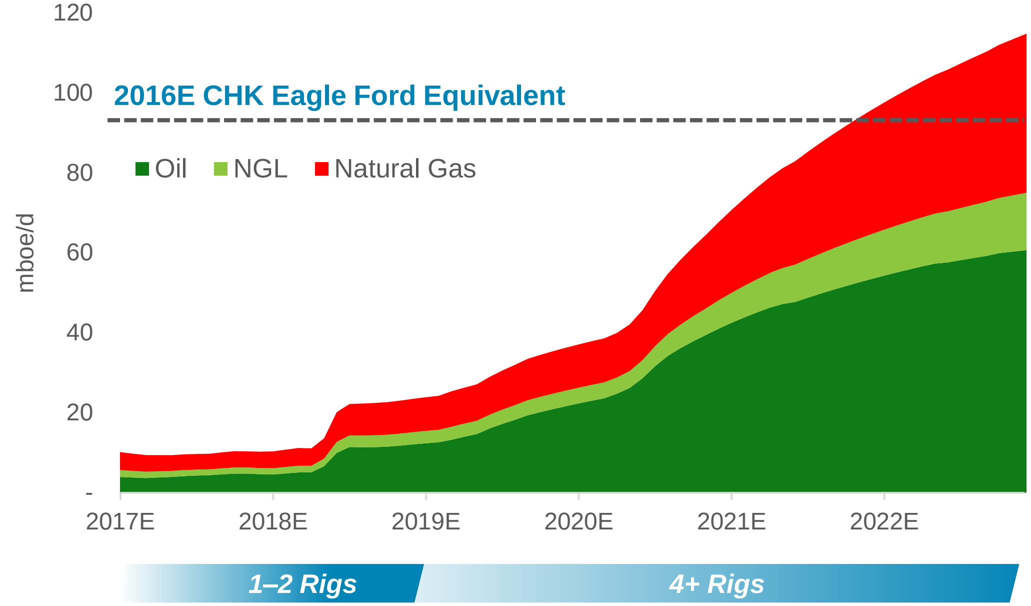
~2.7 BBOE RESOURCE POTENTIAL

- One vertical mile of opportunity
  - > 8+ stacked formations
- ~2,600 risked locations
- The next oil growth asset

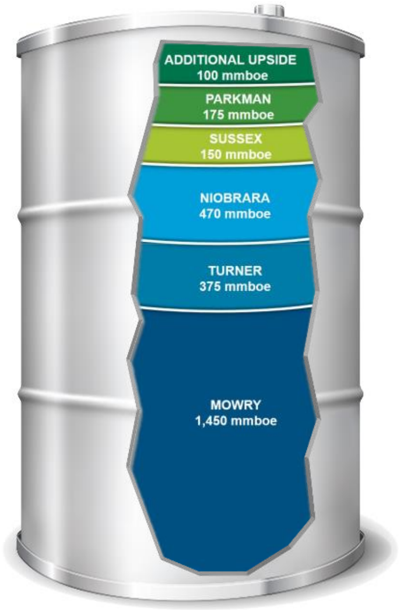
Resource Mix



Net Production Potential

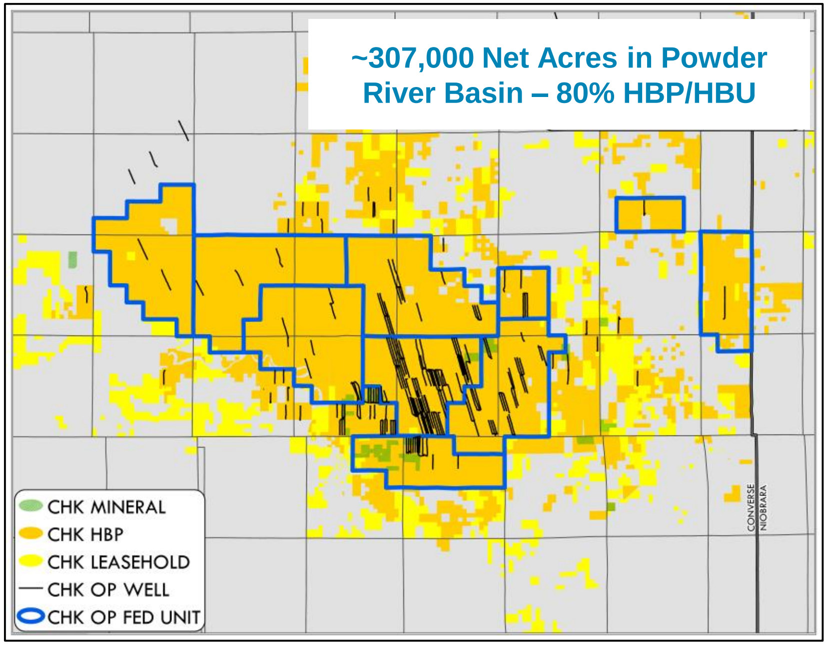


Gross Recoverable Resource Potential



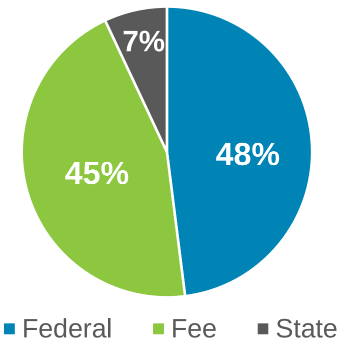
307,000 ACRES OF GROWTH POTENTIAL

- ~90% undeveloped locations
- 98% of leases cover all depths
- 10 operated federal units
  - > Single-operator control
  - > Minimal drilling obligations
  - > Long-lateral development

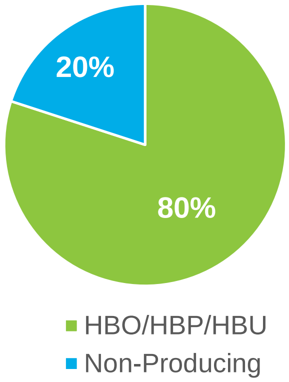


~307,000 Net Acres in Powder River Basin – 80% HBP/HBU

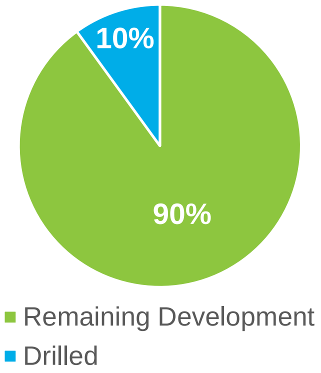
Acreage Type



Acreage Status

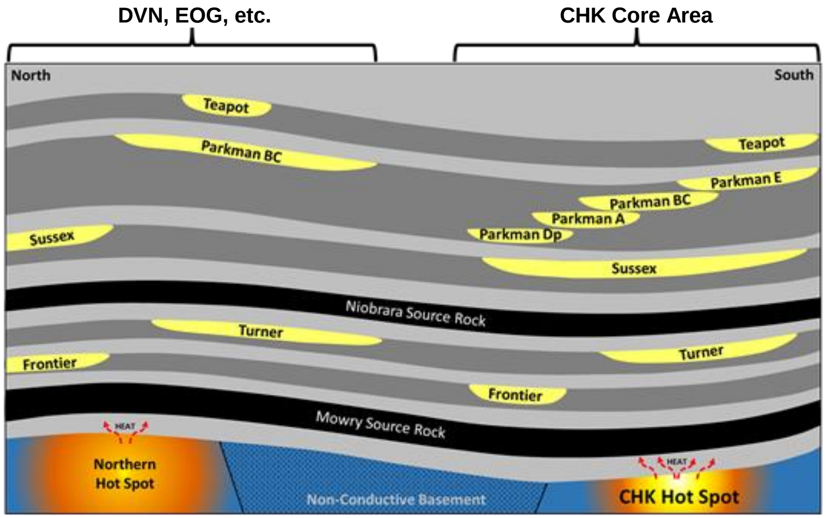


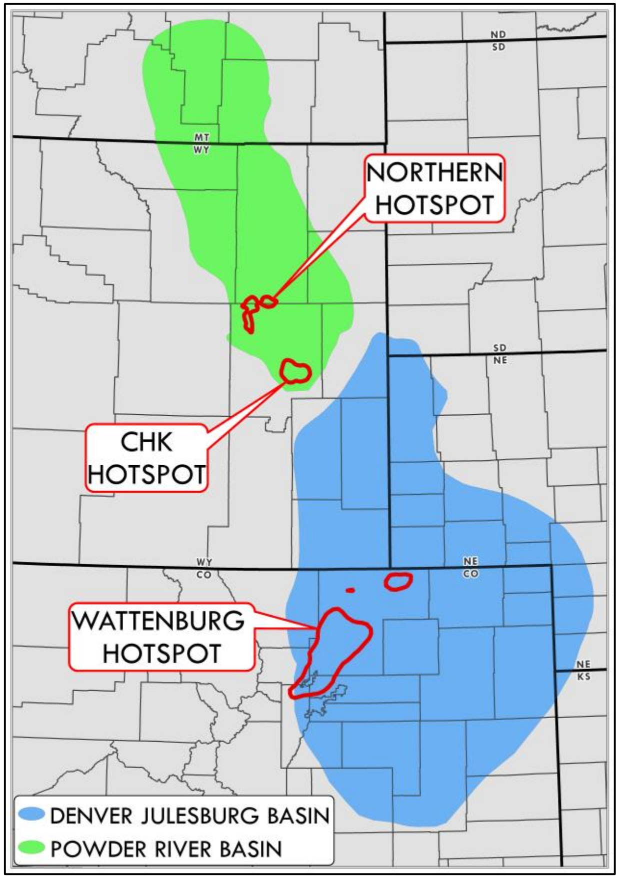
Locations



HOTSPOT ADVANTAGE

- CHK owns Southern PRB hotspot
- DJ Basin and Northern PRB analog
- Advantages of CHK hotspot position
  - > Higher pressure
  - > Greater hydrocarbon generation (maturity)
  - > Exposed to all three hydrocarbon phases



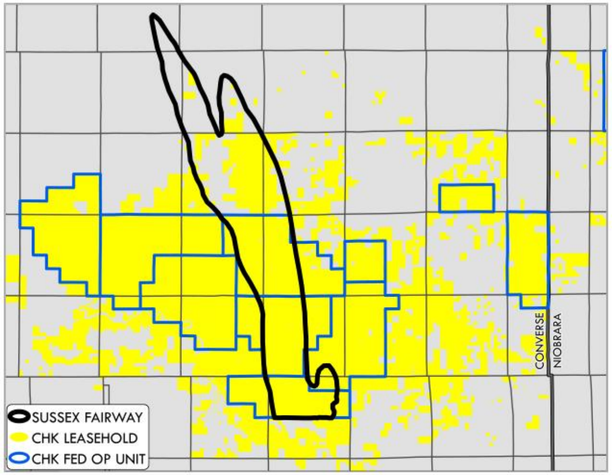


SUSSEX SANDSTONE
HIGHLY ECONOMIC OIL PLAY

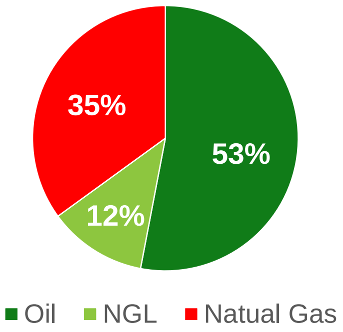
- Moving to development
- Dominant position in the play
- ~200 undrilled locations
  - > Assumes 1,320' spacing
  - > Overpressured – high deliverability
- Targeted development
  - > EUR: 825 – 1,350 mboe
  - > ROR: 50 – 70% (1)
  - > 2017 focused drilling program

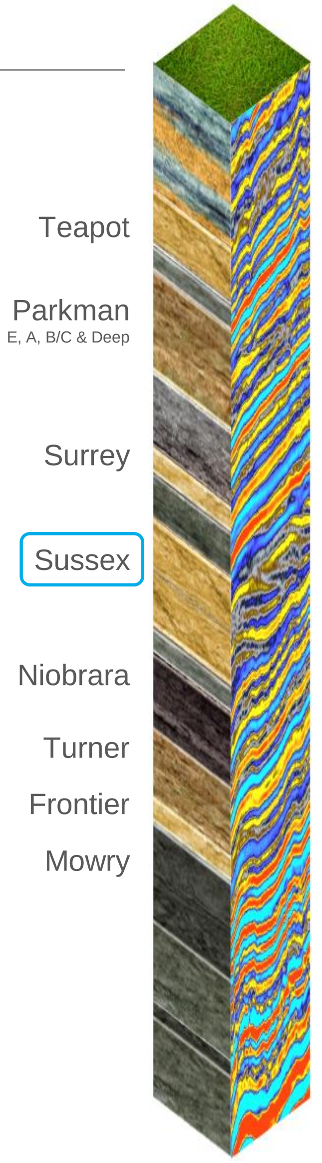
Oil breakeven price (2)

<$40



Production Mix





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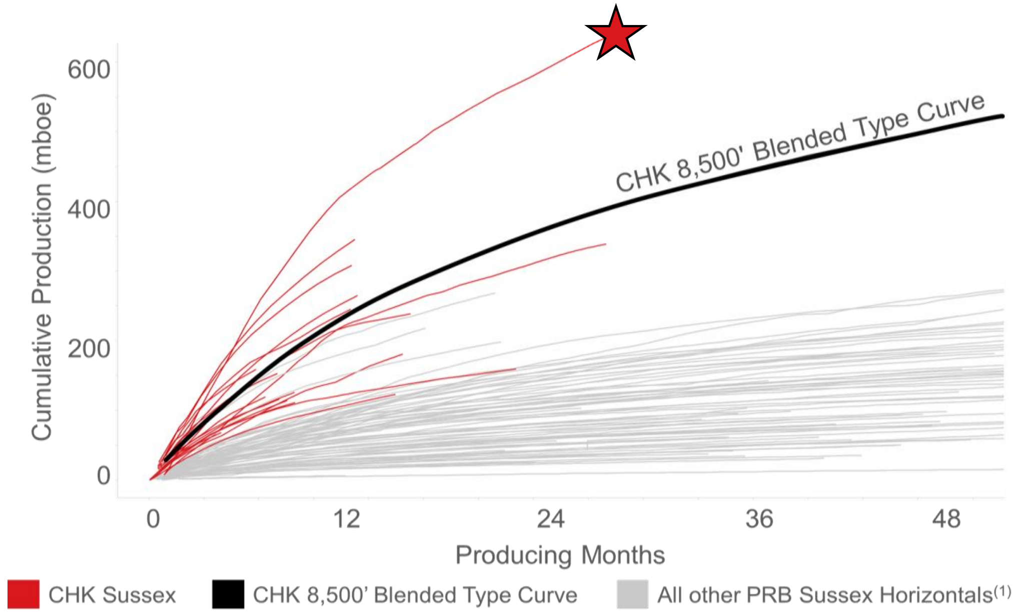
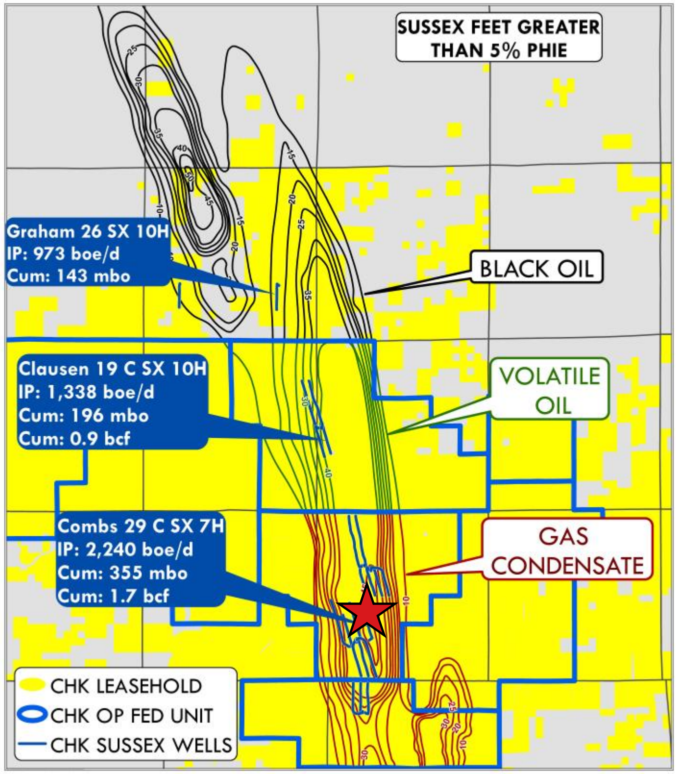
(1) Assumes $3 gas and $60 oil prices flat
(2) PV10 positive breakeven price assuming $3 gas price

SUSSEX SANDSTONE
BEST IN BASIN

- Best Sussex performance in the Powder River Basin
- Development plan optimized
  - Spacing
  - Drilling and completion design
- Competitive economics in current environment

Best Sussex in the PRB





#1 PRB Sussex well

640 mboe cumulative production

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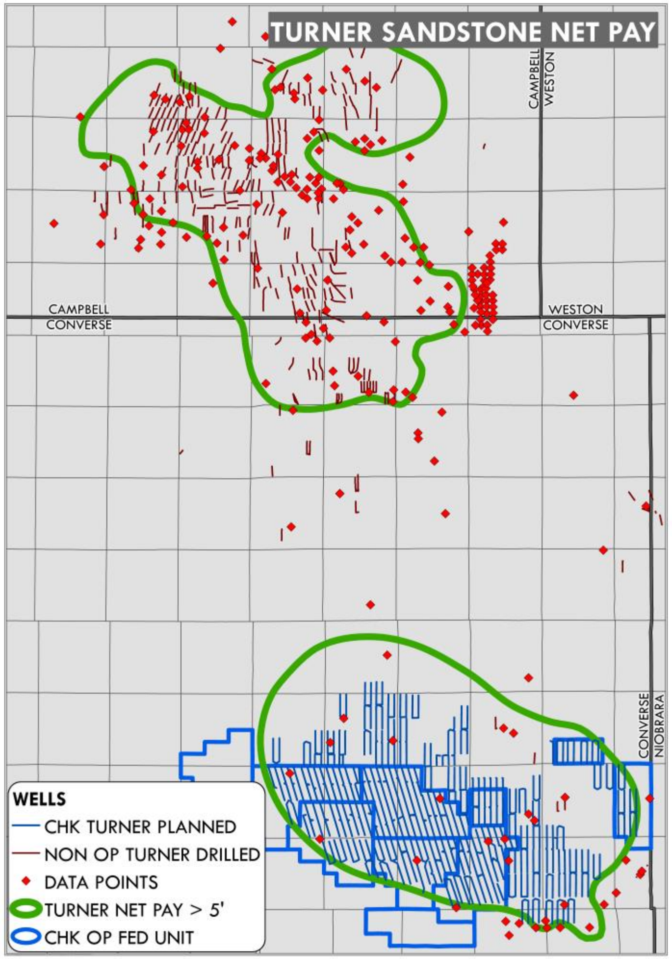
(1) IHS data

TURNER SANDSTONE

PROVEN RESERVOIR – UNREALIZED VALUE

- Same play as northern hotspot with similar rock properties and anticipated higher pressure
- >300 industry wells drilled to date
- One of the most actively permitted sandstones in the Powder River Basin
- Offset activity proves potential, but not optimized for drilling and completion

	Turner North	CHK Turner
Depth	~10,000'	~11,000'
Reservoir Pressure (Est.)	**~4,800 psi**	**~6,800 psi**
Avg. Porosity	7%	7%
Avg. Water Saturation	45 – 60%	35 – 60%



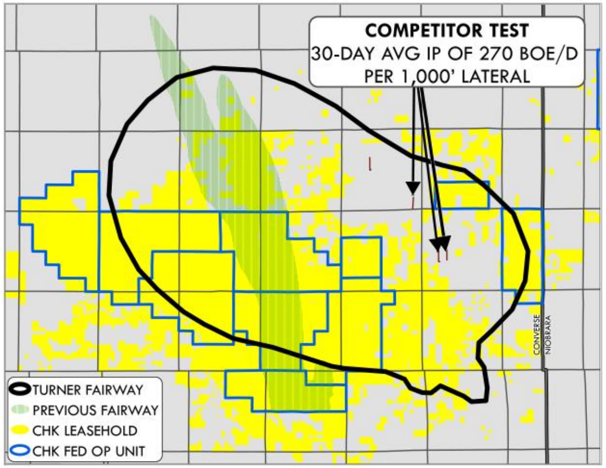
TURNER SANDSTONE

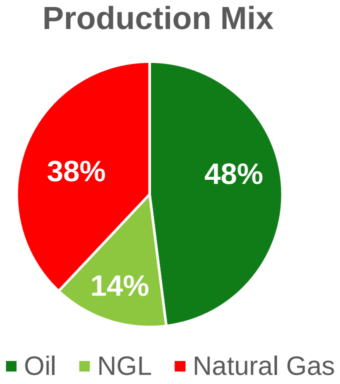
PROVEN RESERVOIR – UNREALIZED VALUE

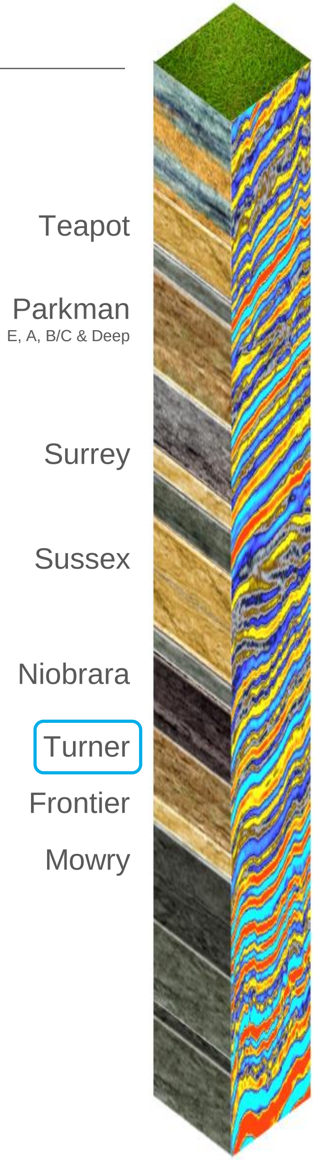
- CHK controls 65% of southern high-grade
  - CHK position overlies thickest net pay
- ~340 undrilled locations
  - Assumes 2,640' spacing
- Targeted development through 2020
  - EUR: ~1,300 mboe
  - ROR: ~45% (1)

Oil breakeven price (2)

~$40







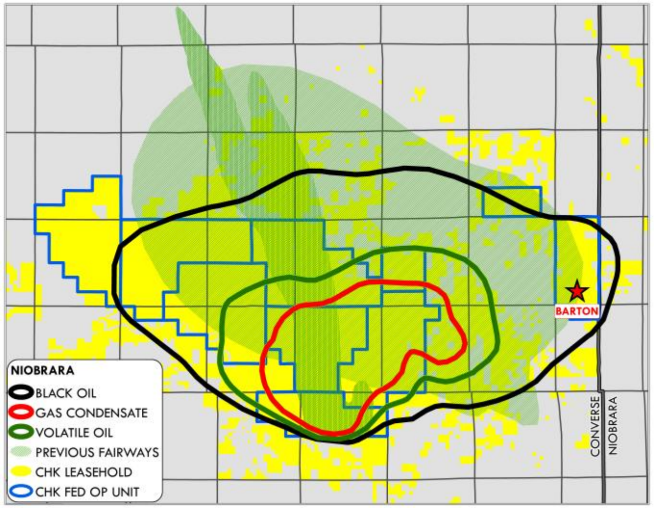
(1) Assumes $3 gas and $60 oil

(2) PV10 positive breakeven price assuming $3 gas price

NIOBRARA

POSITIONED FOR SUCCESS

- Premier Niobrara position in the PRB
- Oil, gas and condensate – provides flexibility
- ~580 undrilled locations
  - > Assumes 1,100' – 1,320' spacing
- Targeted development through 2020
  - > EUR: ~880 mboe
  - > ROR: ~45% (1)

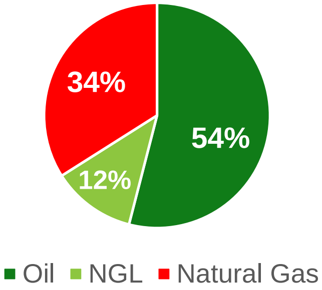


Outperforming all U.S. Niobrara horizontal wells to date

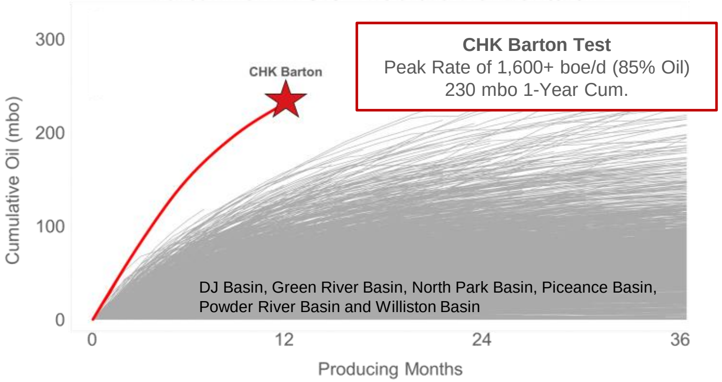
Oil breakeven price (2)

~$40

Production Mix

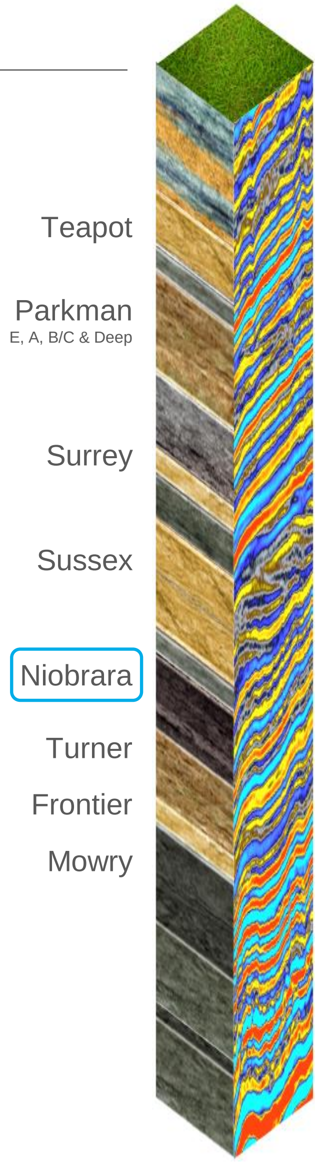


Barton vs. All U.S. Niobrara Horizontals (3)



CHK Barton Test
Peak Rate of 1,600+ boe/d (85% Oil)
230 mbo 1-Year Cum.

DJ Basin, Green River Basin, North Park Basin, Piceance Basin, Powder River Basin and Williston Basin



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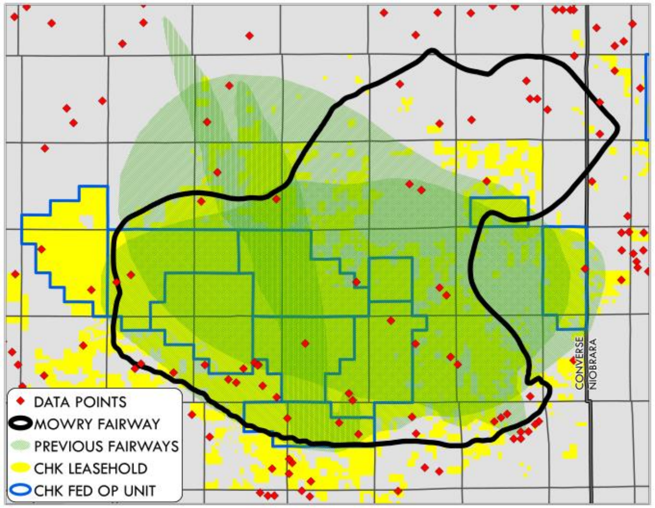
(1) Assumes $3 gas and $60 oil
(2) PV10 positive breakeven price assuming $3 gas price
(3) IHS data

MOWRY SHALE
HIDDEN RESOURCE GIANT

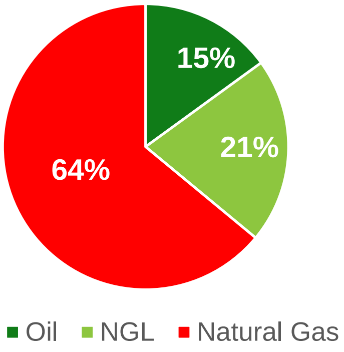
- World-class source rock
  - Overpressured
  - Three phases present
- Multiple penetrations and core data available
- ~25 horizontal wells drilled by industry since 2005

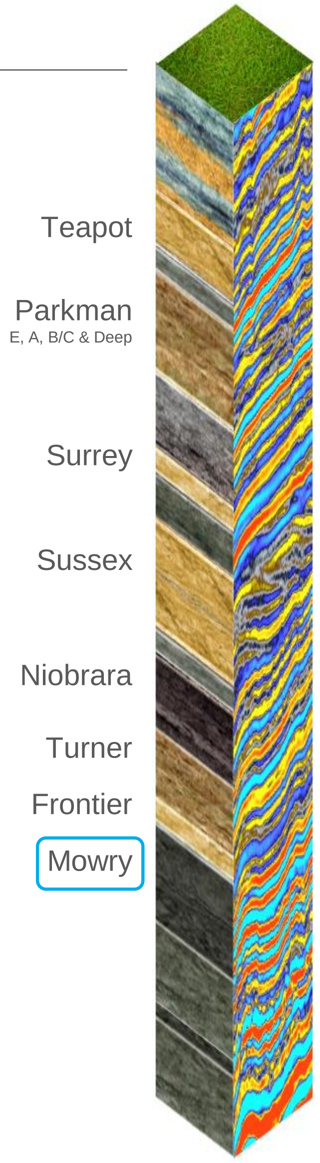


1.45 bboe

Gross recoverable resource potential

Production Mix



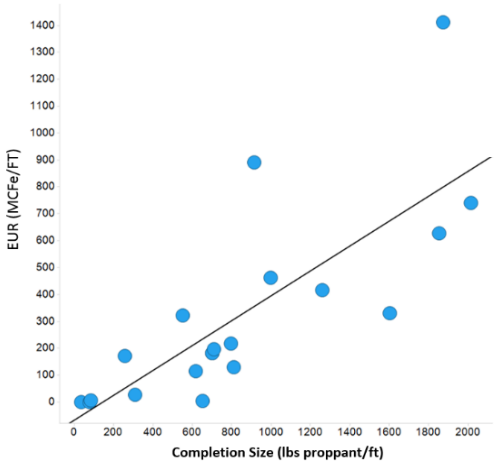


MOWRY SHALE

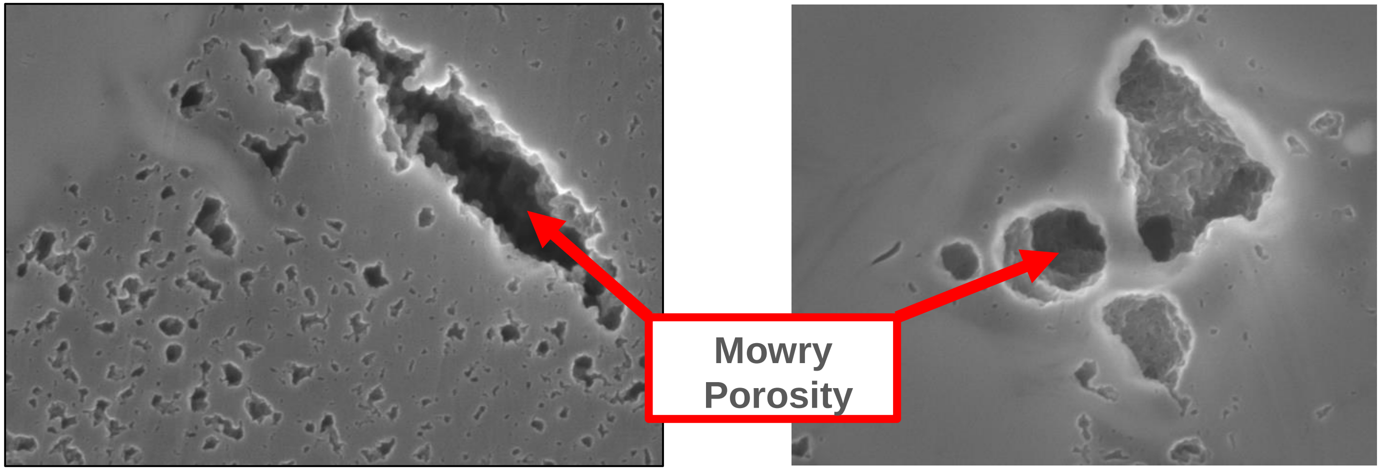
HIDDEN RESOURCE GIANT

- Mowry compares favorably to other prolific source rocks
- Strong relationship between competitor frac size and EUR
    - > Large upside with Chesapeake-style frac
- Anticipate significantly greater reservoir pressure than northern Mowry wells

Positive Correlation of Proppant vs. EUR/ft. (1)



	Pressure	Thickness	Porosity	TOC	Mineralogy
Mowry is similar to…	Utica	Haynesville	Woodford	Eagle Ford	Woodford

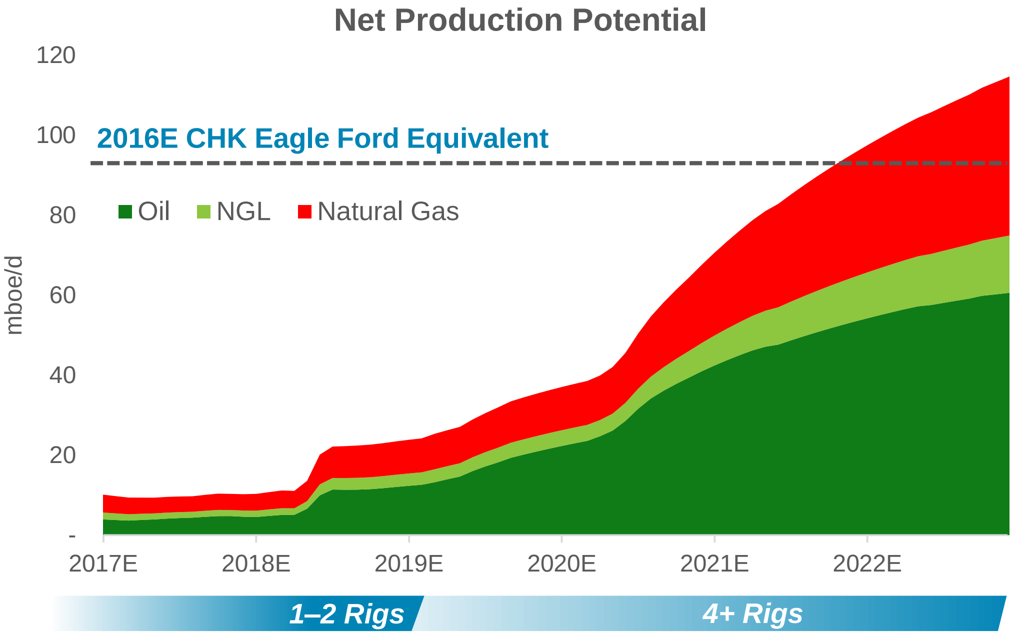


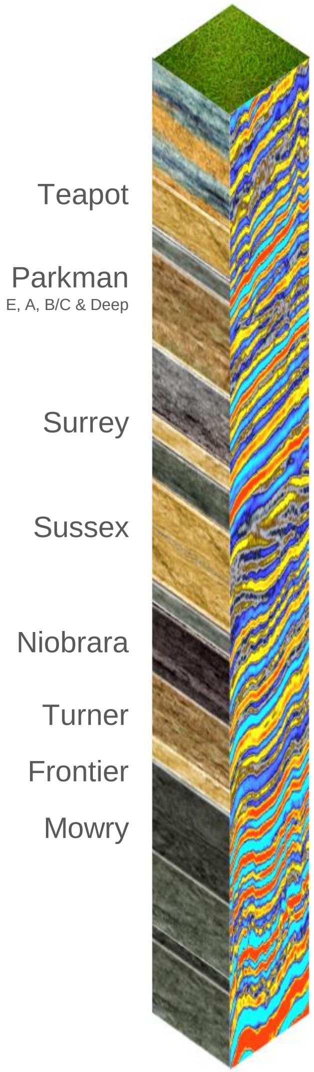
(1) IHS data

WHY POWDER RIVER BASIN?

ONE MILE OF OPPORTUNITY

- ~2.7 bboe gross recoverable resource potential
- ~2,600 risked locations
- Stacked potential – equivalent to 730,000 acres
- Renegotiated midstream unlocks value
- Significant exposure to Mowry upside
- The next oil growth asset

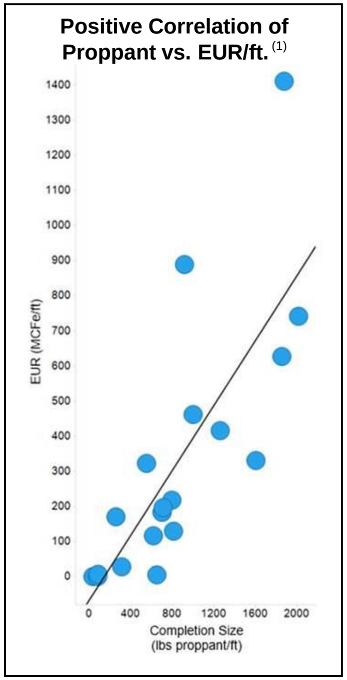


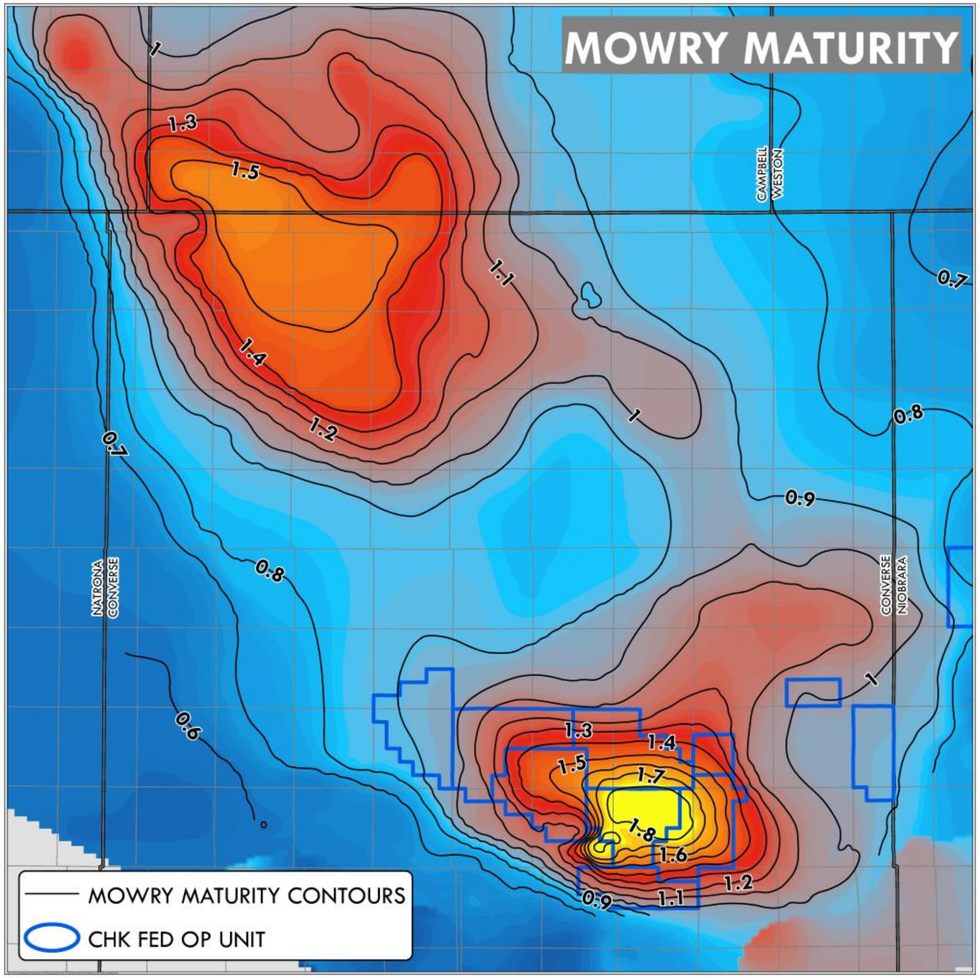


APPENDIX

MOWRY SHALE
HIDDEN RESOURCE GIANT

- CHK Mowry maturity 20% – 30% higher than northern Mowry
- Strong correlation with completion size and performance


Positive Correlation of Proppant vs. EUR/ft. (1)



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(1) IHS data

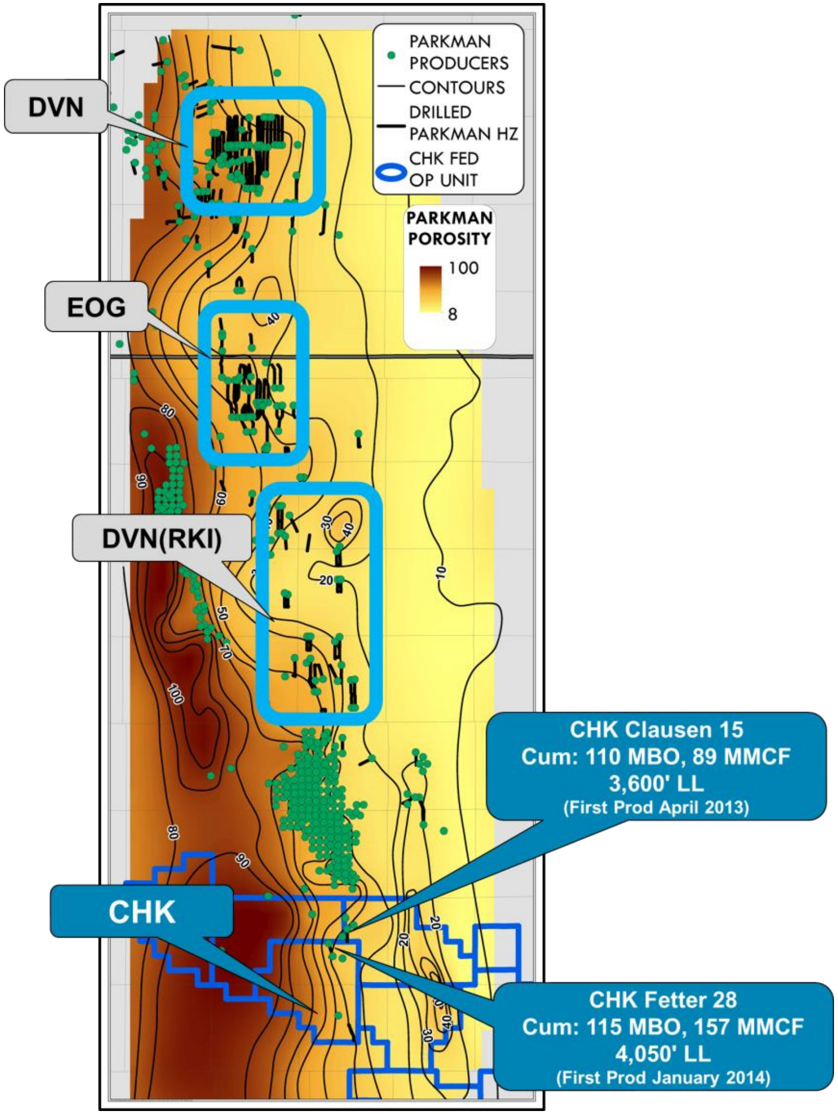
PARKMAN SANDSTONES

HIGH VOLUME OIL PLAYS

- Extensive play development to north
  - BC sand produced by DVN and EOG
- CHK controls the southern extension of the Parkman BC trend
  - Similar rock quality and thickness to that in the northern area
- CHK Parkman area contains three additional, discrete sands
- EUR: 860 mboe
- ROR: ~45%(1)

Four Parkman sands

Within CHK's position



CHK Clausen 15
Cum: 110 MBO, 89 MMCF
3,600' LL
(First Prod April 2013)

CHK Fetter 28
Cum: 115 MBO, 157 MMCF
4,050' LL
(First Prod January 2014)

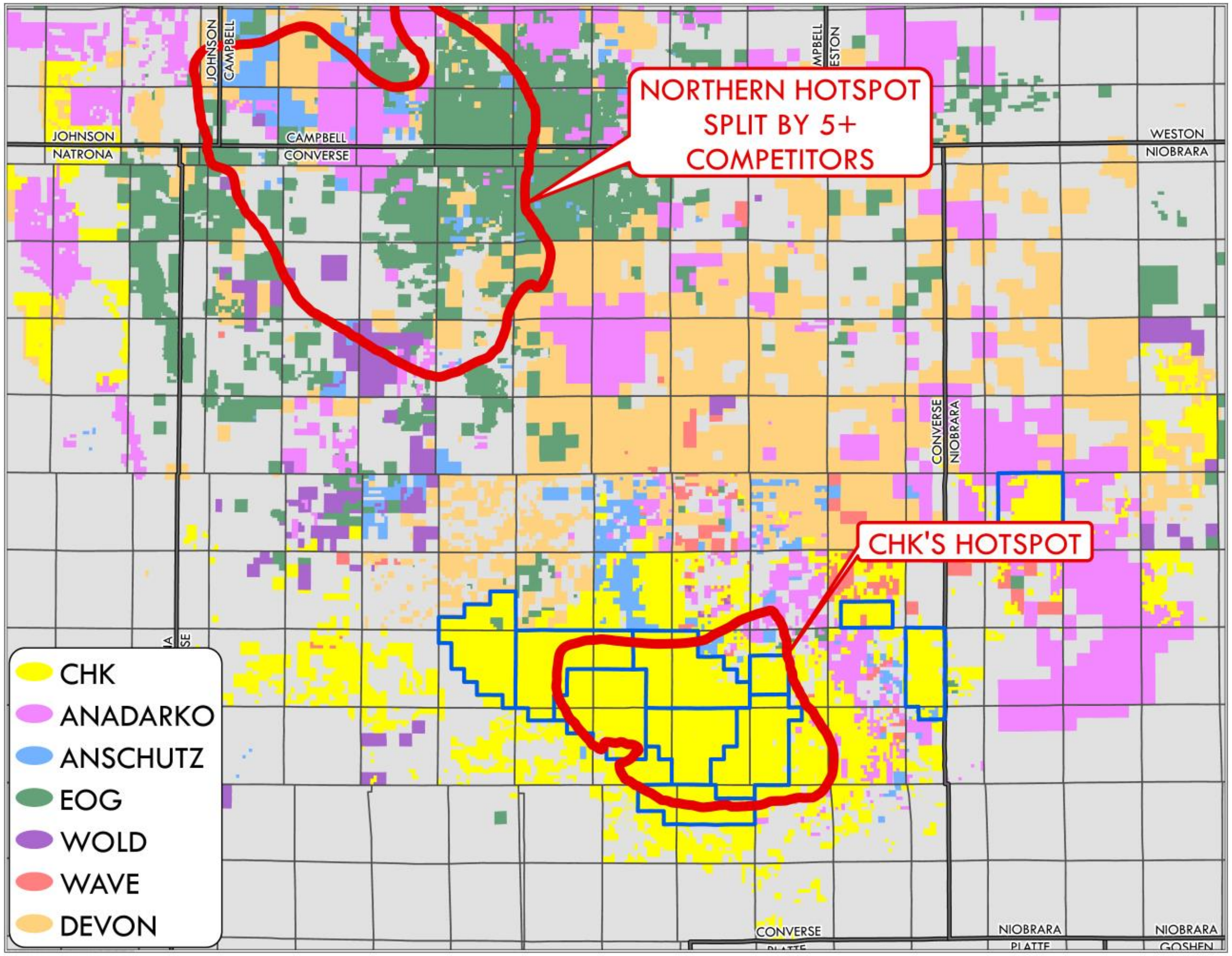
---

(1) Assumes $3 gas and $60 oil flat

CHK LAND POSITION

A STRATEGIC ADVANTAGE

- CHK dominates southern Powder hotspot
- Northern hotspot shared by multiple competitors (1)



NORTHERN HOTSPOT SPLIT BY 5+ COMPETITORS

CHK'S HOTSPOT

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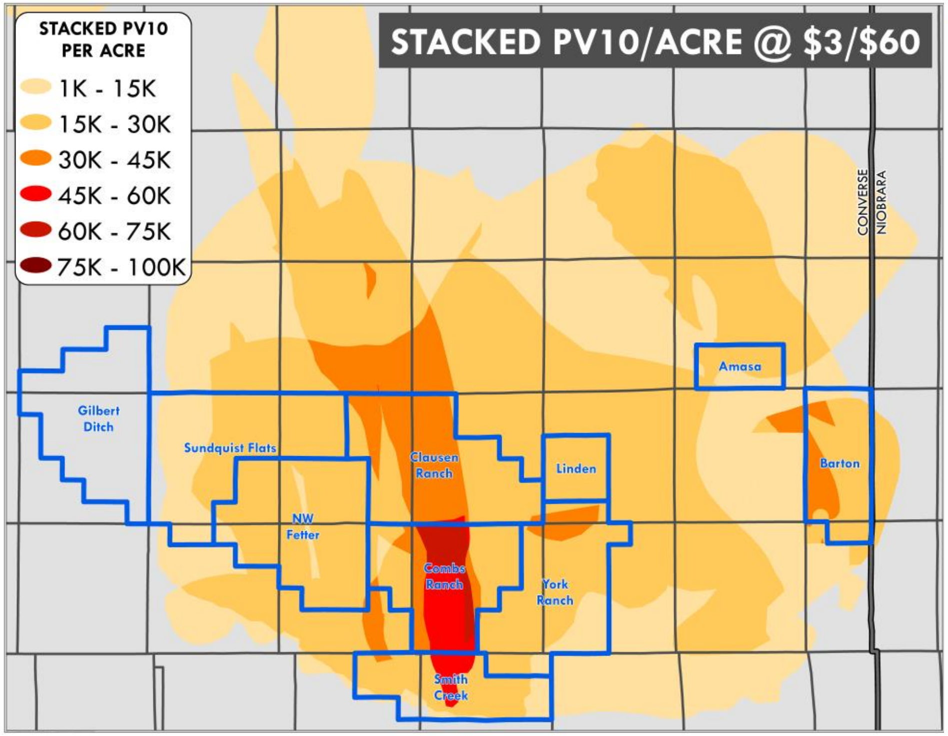
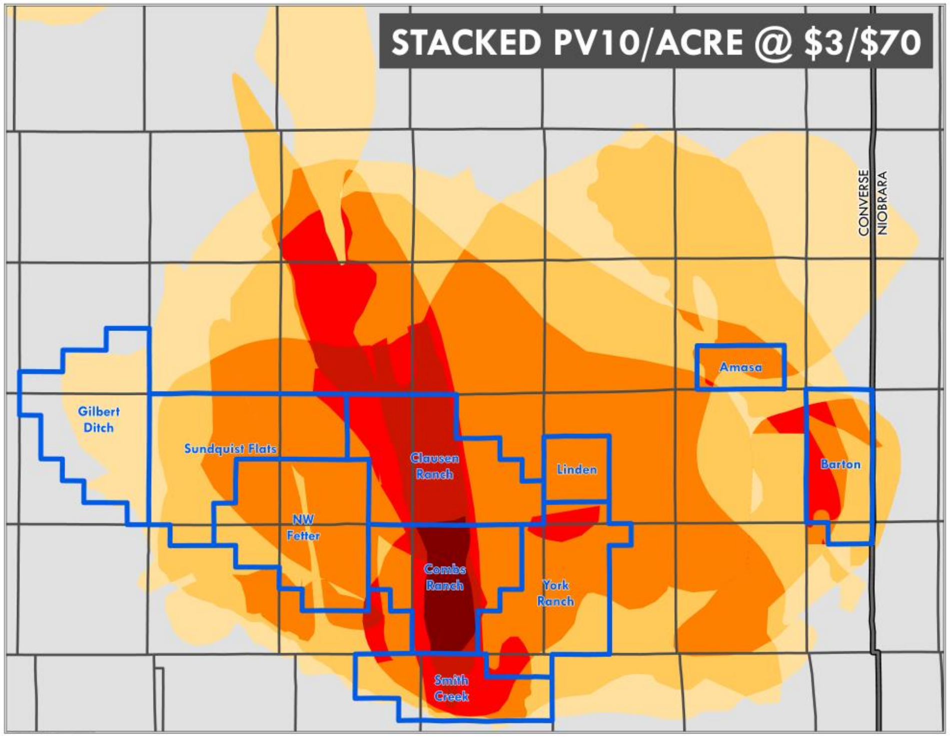
(1) Competitor leasehold sourced from Drilling Info and company press releases

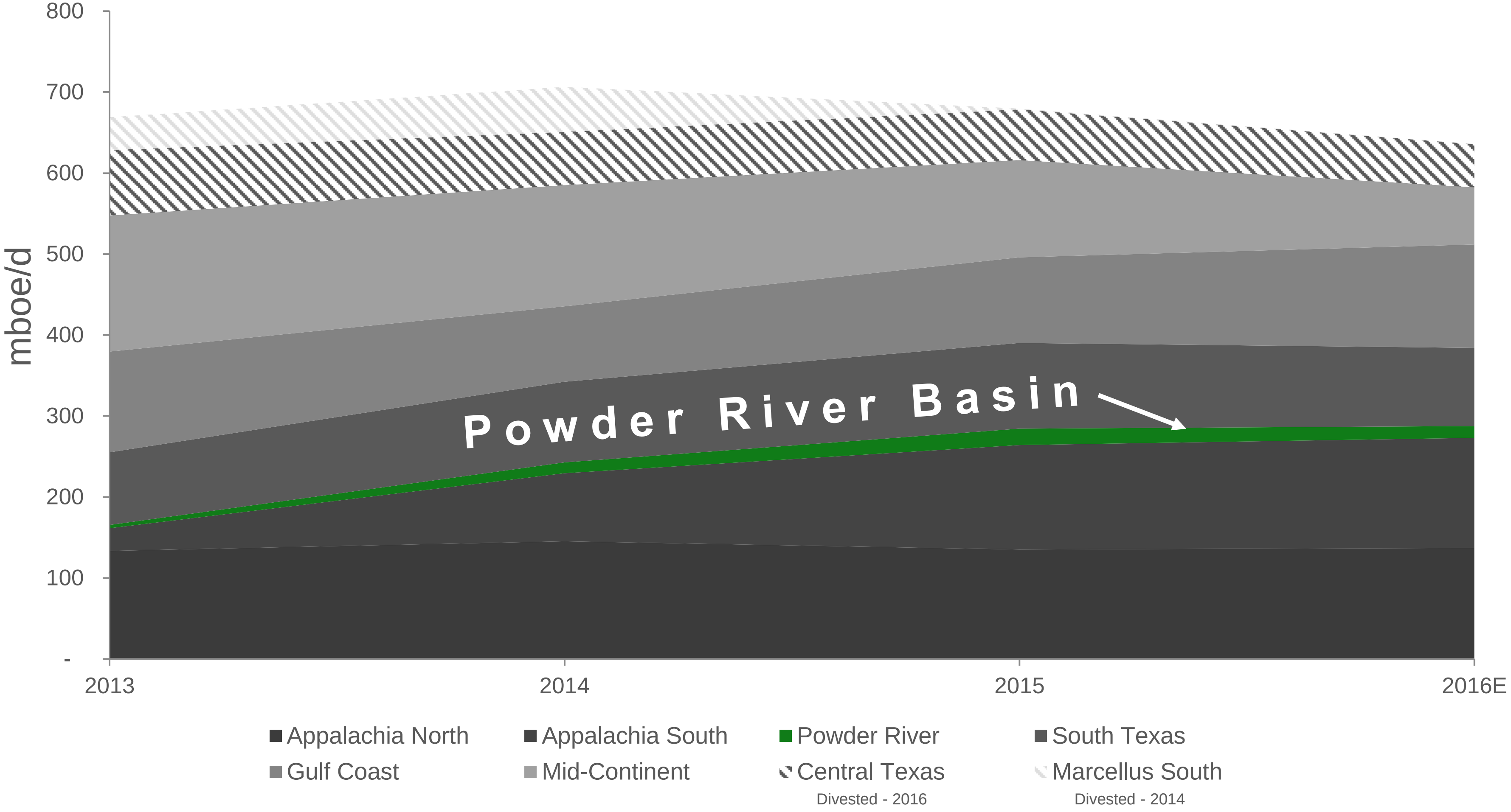
PV10 DEVELOPMENT MONEY MAPS





NET EQUIVALENT PRODUCTION

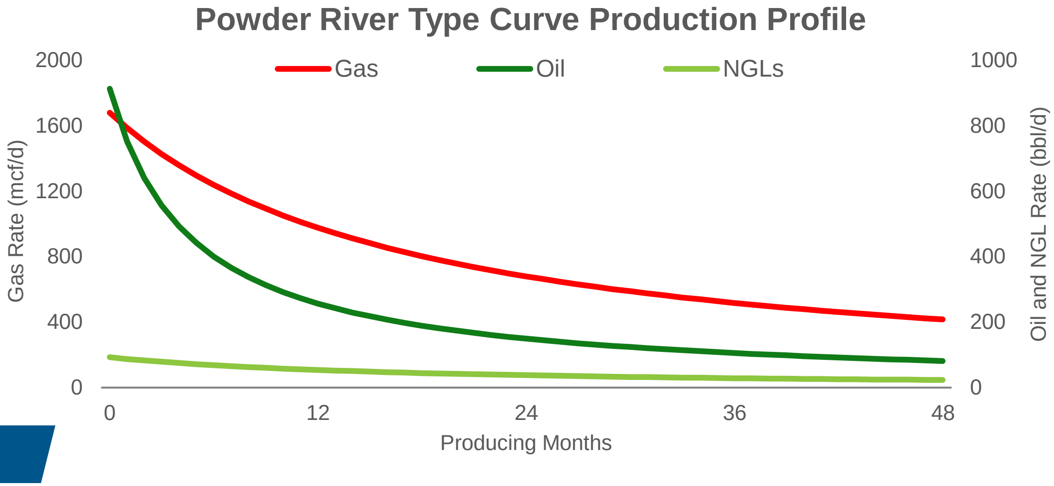
POWDER RIVER BASIN: ~2% TOTAL PRODUCTION 2016E



POWDER RIVER MODELING INPUTS

Base Production[1]	
3Q'16E Net Production	14 mboe/d
4 Yr. Average Annual Decline[2]	24%

2017 Expenses & Differential Estimates[1]	
Production Expense[3] ($/boe)	$4.95 – $5.35
2017 GP&T[4] ($/boe)	$13.25 – $13.45
Future Dev. GP&T[4] ($/boe)	$4.75 – $6.75

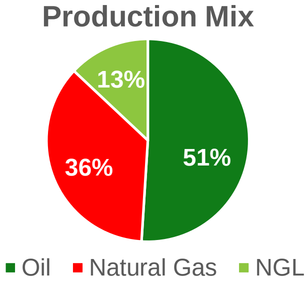

Powder River Type Curve Production Profile

2017 – 2020 Blended Development Program

Curve Parameters	
IP[5] (Oil / Gas)	990 bbl/d / 1.7 mmcf/d
Decline (Oil / Gas)	74%/42.5%
B-factor (Oil / Gas)	1.0/0.9
Shrink	92%
NGL Yield	55 bbl/mmcf
EUR	1.2 mmboe
Lateral Length	8,400 ft.

Gross Capex	
Drilling[6] (136 days to TIL)	$4.3mm
Completion (62 days to TIL)	$3.2mm
TIL	$1.0mm
TOTAL	***$8.5mm***

Interest / Gross Locations	
WI / NRI[7]	80%/65%
Producing	185
DUCs	15
Undrilled[8]	2,600
Rig Count	1 – 10


Production Mix

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 27 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020

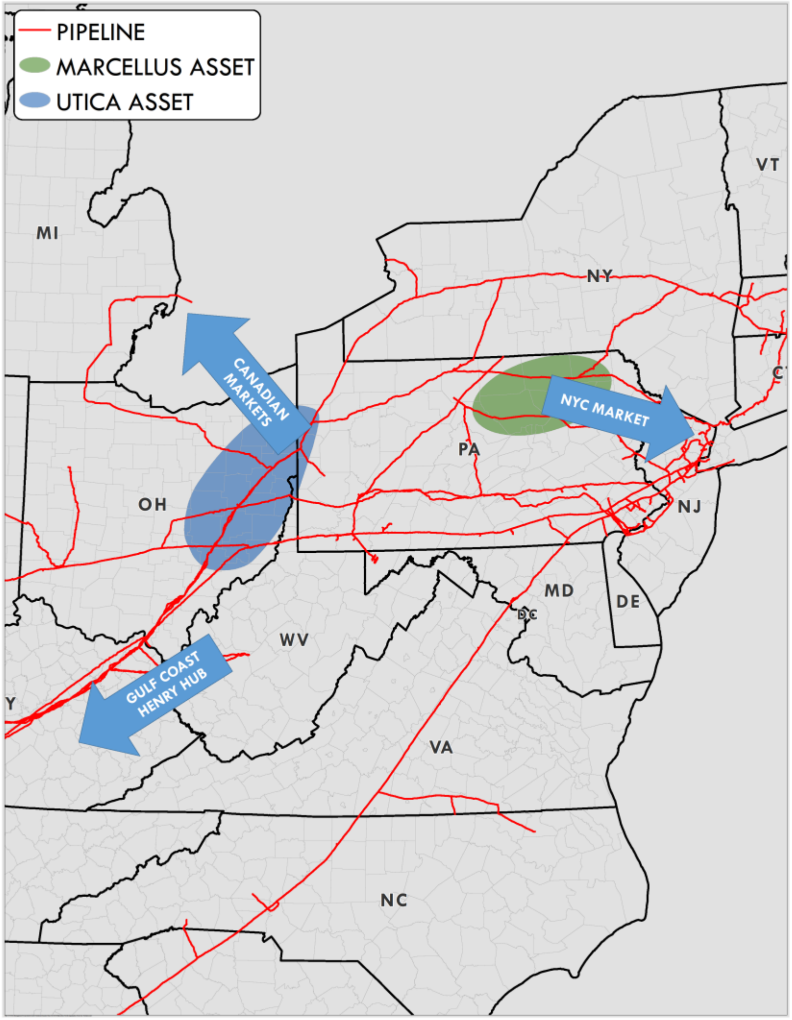
APPALACHIA:
Northeast Gas Powerhouse

FRANK PATTERSON

NORTHEAST GAS POWERHOUSE

- Free cash flow generator
- High-quality and diverse position
- Growth potential and portfolio flexibility
- Operational excellence

4% of domestic gas production



Access to premium markets

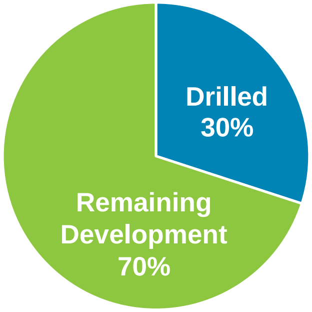
UTICA SHALE

THREE PHASE PETROLEUM SYSTEM

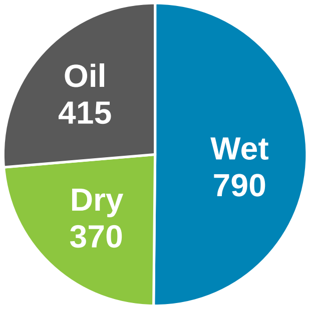
Abundant opportunities

Significant resource optionality

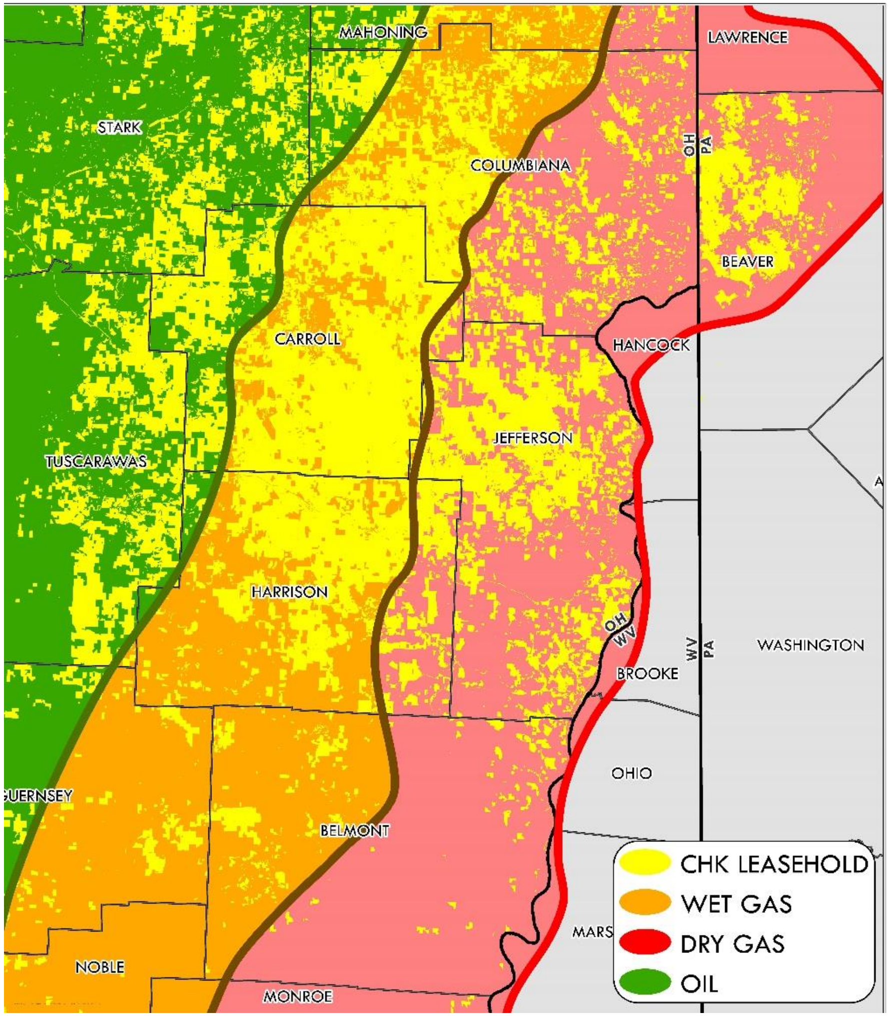
Location Count



Undrilled Locations

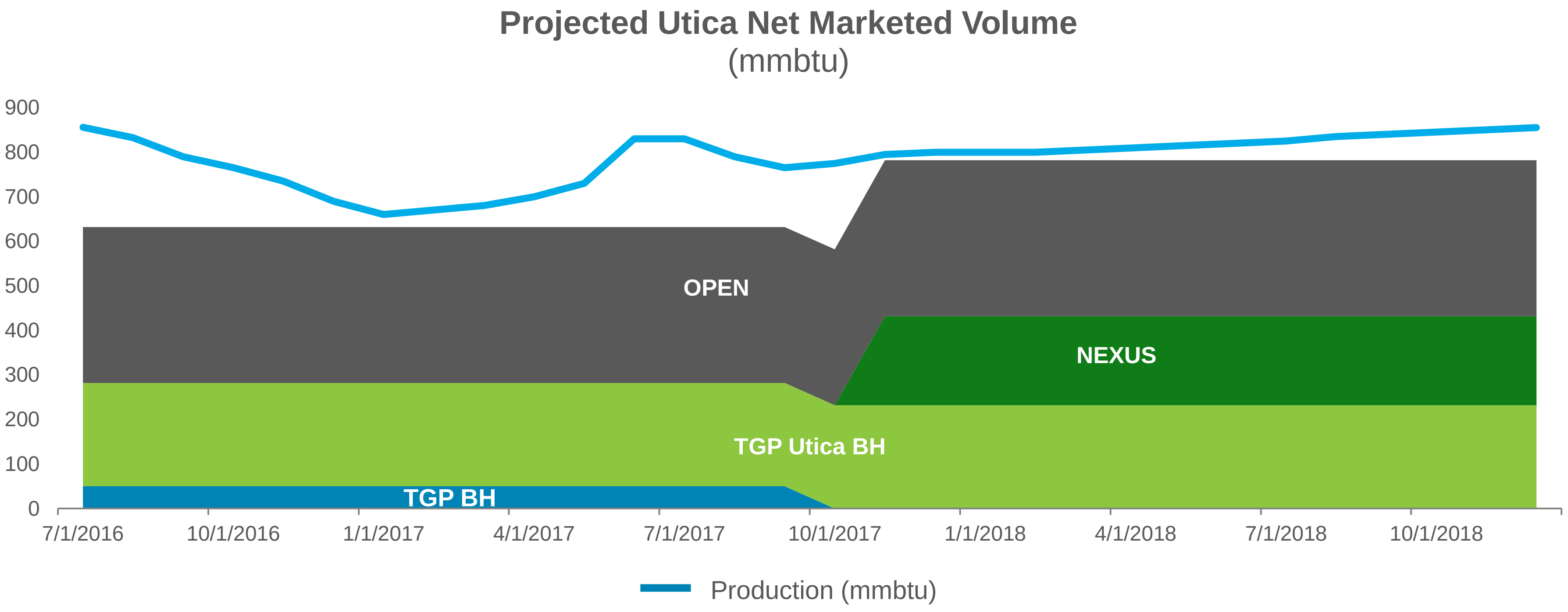


~1,100,000 Net Acres in Utica



CHESAPEAKE'S MARKETING ADVANTAGES

UTICA



Increasing basin takeaway

- *Opportunity to acquire available capacity*

No projected shortfalls

- *Requires less than four rigs per year*

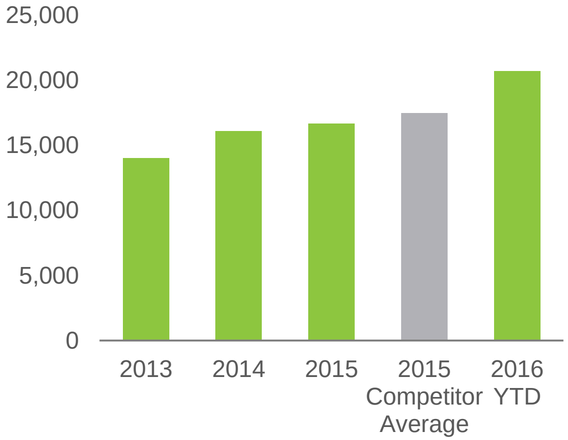
Significant access to premium markets

- *>90% of gas flows out of basin*

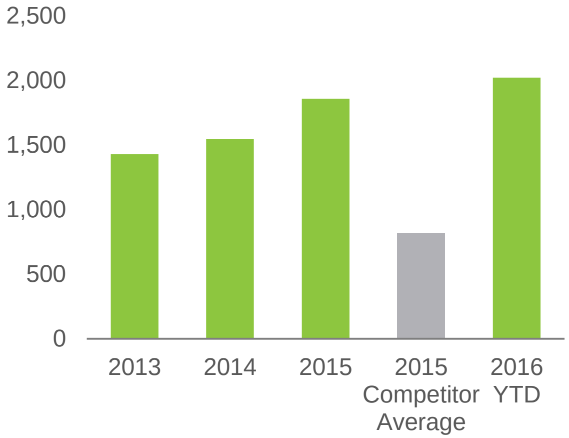
BASIN-LEADING OPERATIONAL PERFORMANCE

UTICA

Measured Depth
(ft.)

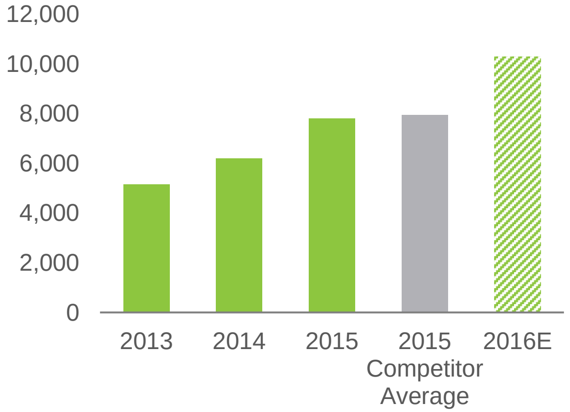


Drilling Efficiency
(ft./d)

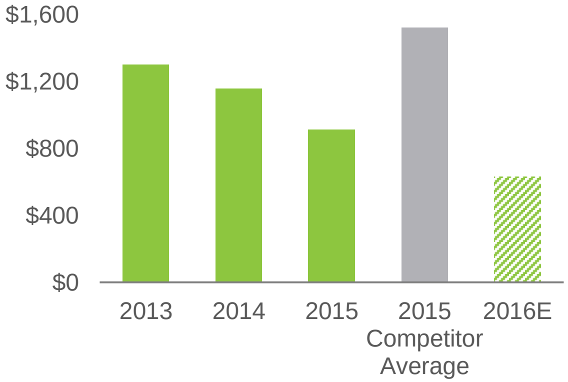


~40% increase in drilling efficiency

Completed Lateral Length
(ft.)



Gross Well Capex
($/ft. of Completed Lateral)

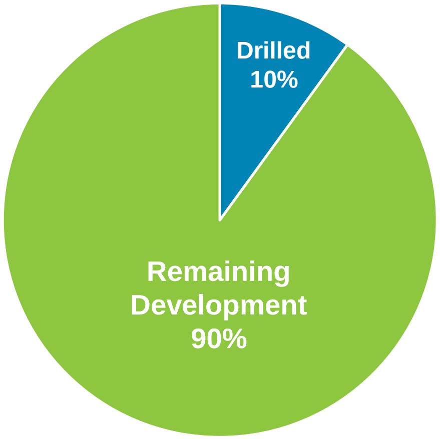


~50% increase in capital efficiency

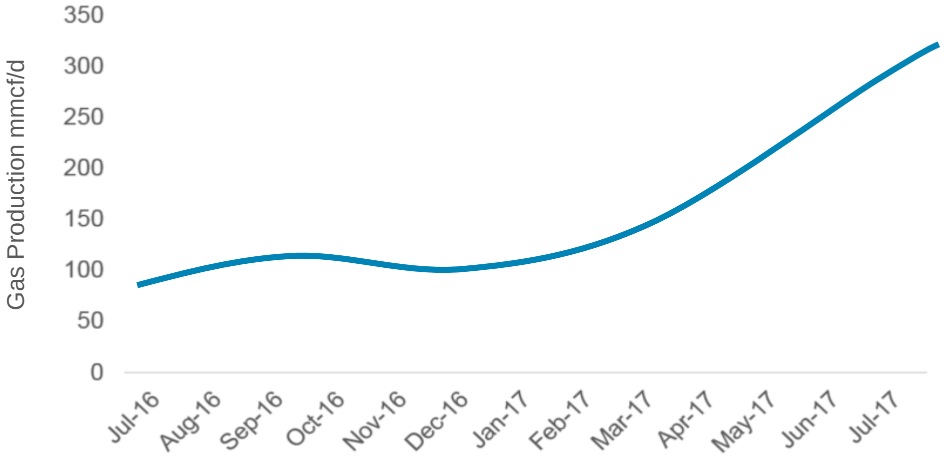
Competitor data from IHS, public data and company disclosures, competitors include AR, ARU, ECR and GPOR (ARU excluded from gross well capex)

DRY GAS GROWTH
UTICA

Utica Dry Locations



Utica Dry Production
(mmcf/d)



>40% ROR

Average CHK WI ~ 90% (1)

$2.14

Per mcf Utica Dry PV10 breakeven

>350%

Production growth

~93% of dry gas is sent to Gulf market

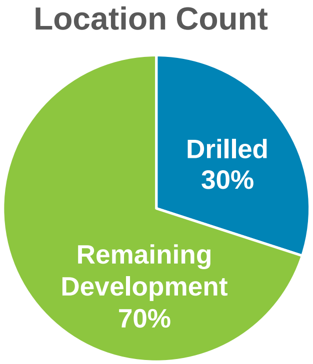
---

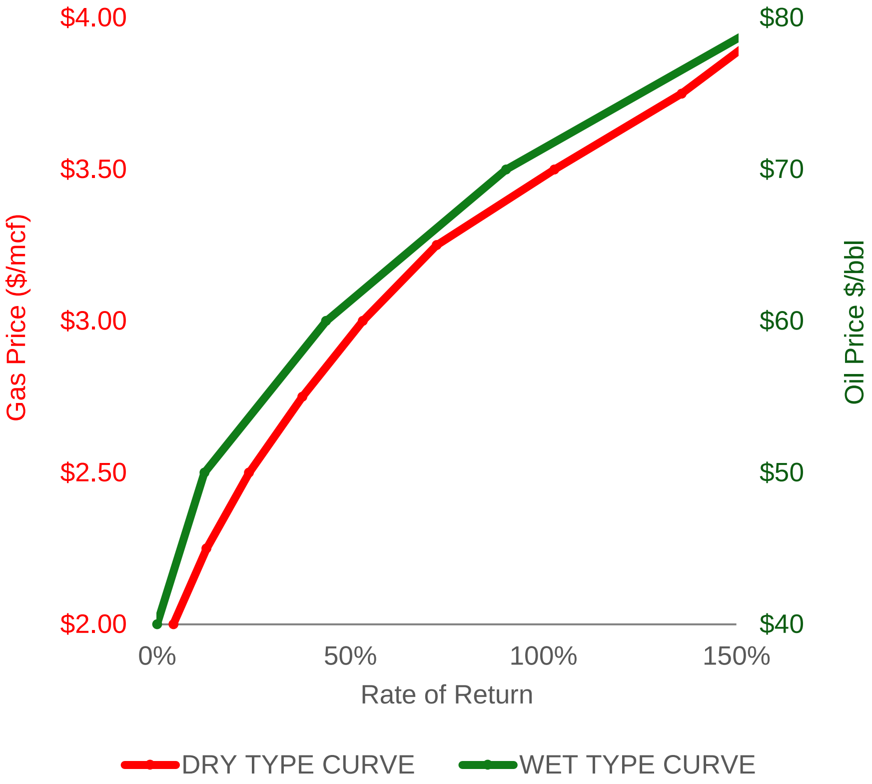
(1) Assumes $3/mcf gas flat

FLEXIBLE INVESTMENT OPPORTUNITIES

STRENGTH IN OPTIONALITY – UTICA

- High-quality and diverse position
- Operational excellence
- Market advantages
- Large inventory





~$200mm

Projected free cash flow through 2018 (1)

---

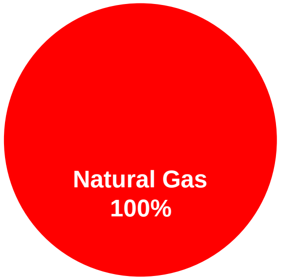
(1) Assumes $3 / $48 for 2017 and $3 / $60 in 2018, excluding hedges

MARCELLUS SHALE

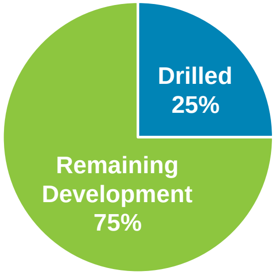
THE PREMIER DOMESTIC GAS

- Growth potential in a remarkable reservoir
- Operational excellence
- Stable free cash flow

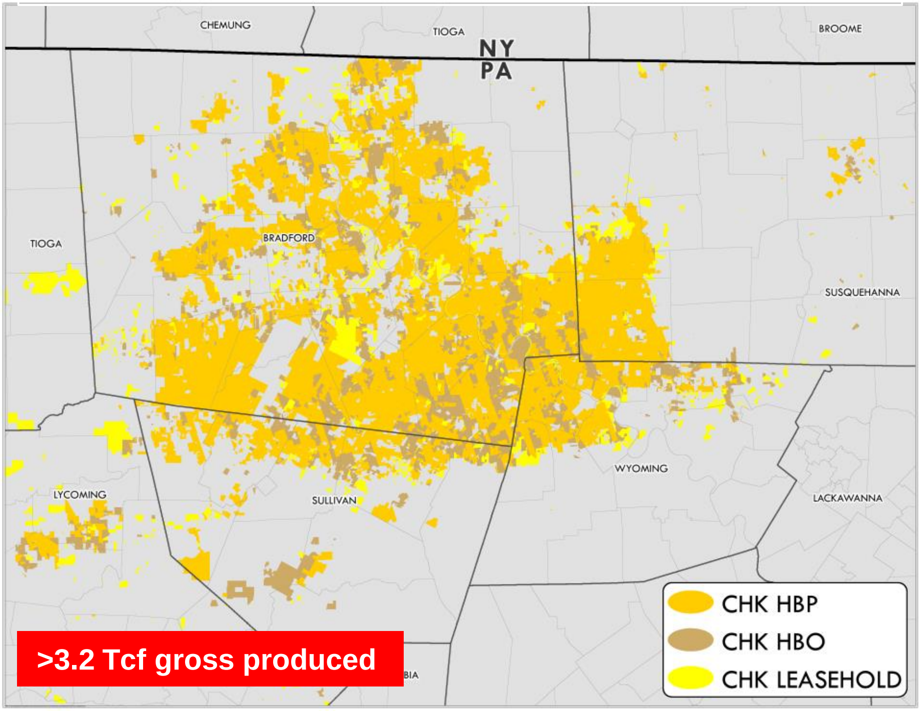
Production Mix



Marcellus Locations



~795,000 Net Acres in North Appalachia



>3.2 Tcf gross produced

Well Status	Marcellus Locations
Producing	686
DUC(1) Inventory	85
Undrilled Inventory	2,900

(1) DUC: “Drilled uncompleted” wells

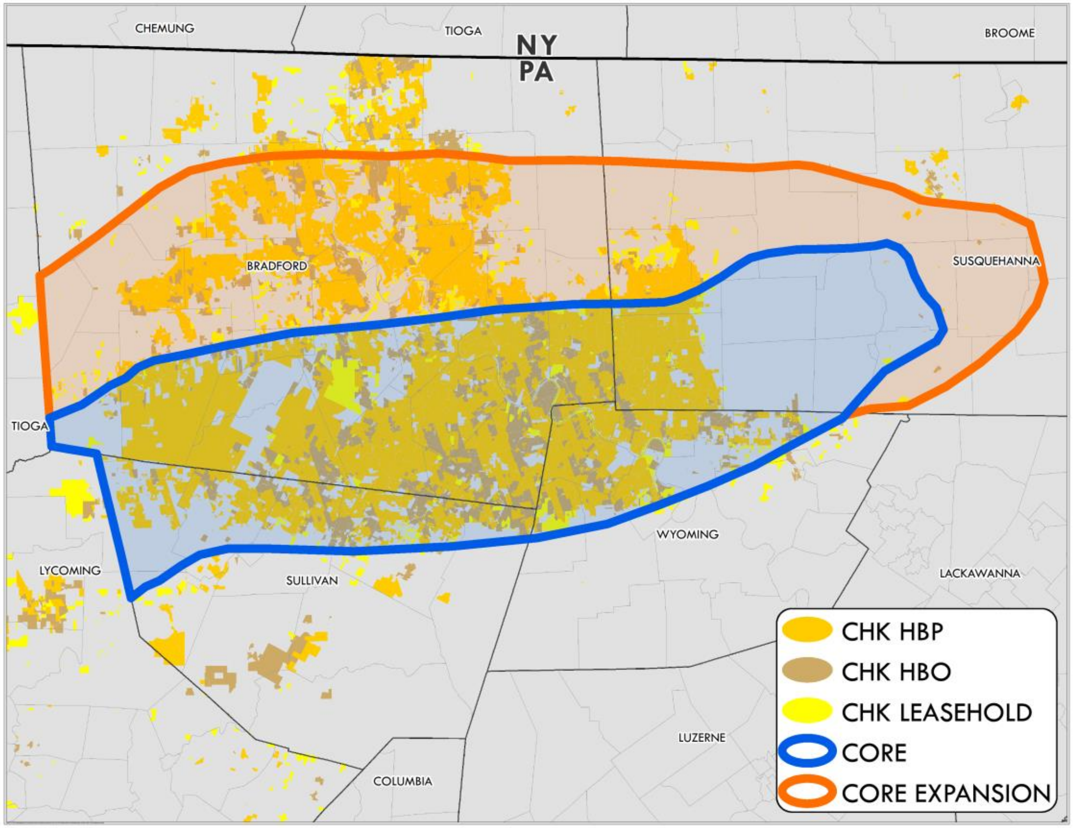
CONTROL THE CORE

MARCELLUS

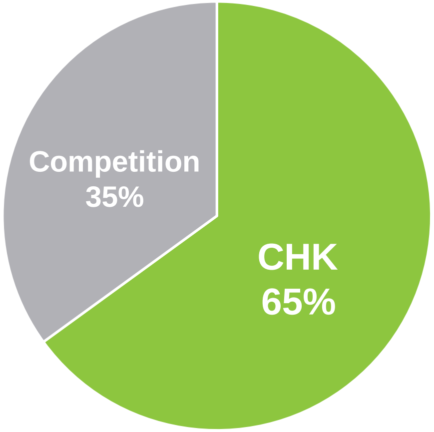
Dominant position

92% CHK acreage HBP (1)

CHK	Core(2)	Core Expansion(2)
HBP	93%	88%
Gross	429,400	240,900
Net	277,400	148,000



CHK Core Operated Position



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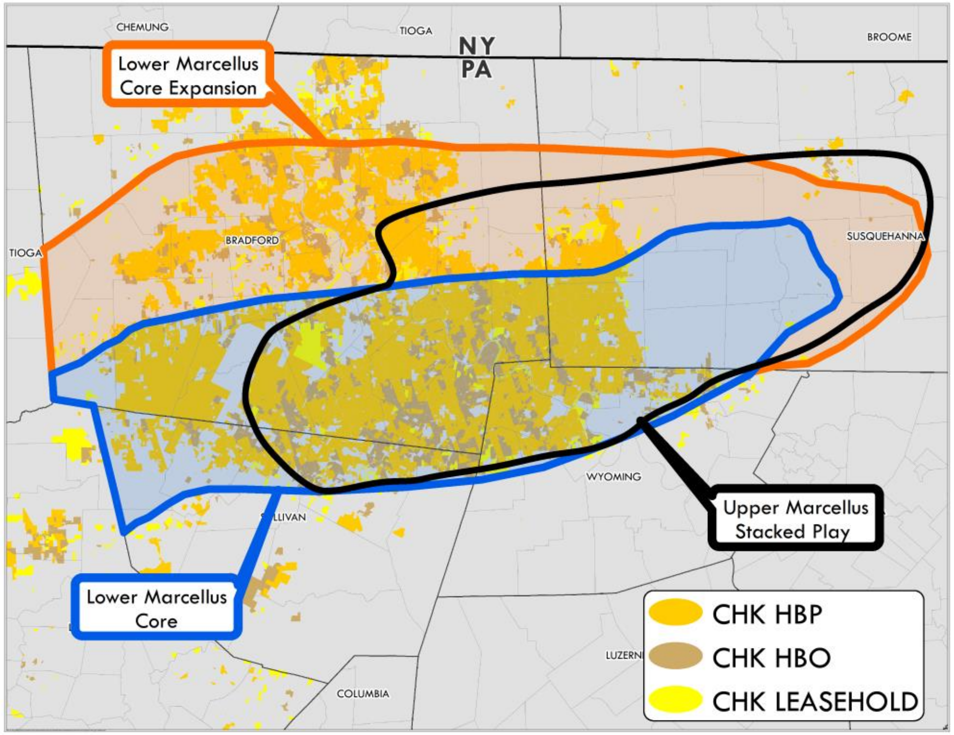
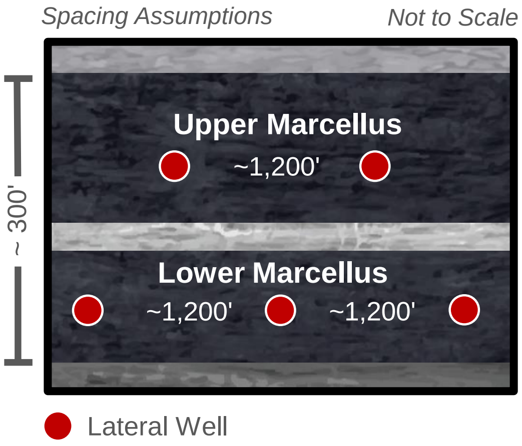
(1) Bradford, Susquehanna, Sullivan, and Wyoming Counties PA

(2) Core and Core Expansion delineated using water saturation, porosity, permeability, pressure and thickness

GROWTH POTENTIAL AND FUTURE DEVELOPMENT

- Longer laterals
- Optimal completion designs
- Substantial Upper Marcellus fairway
- Additional upside in Utica development



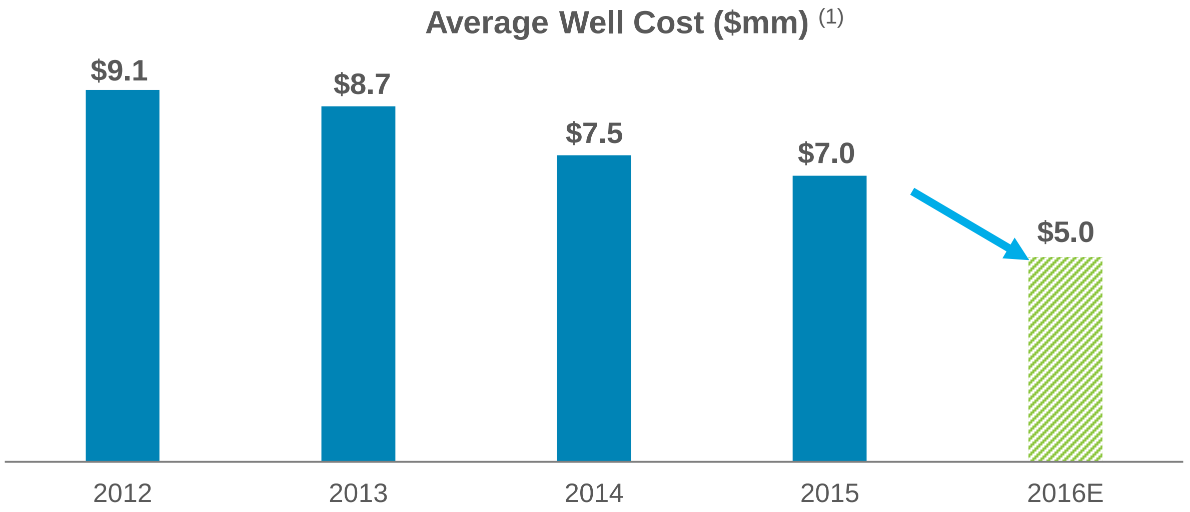


	Lateral Length	Locations Remaining
Lower Marcellus Core (1)	6,000'	780
Lower Marcellus Core Expansion (1)	6,000'	620
Upper Marcellus	5,000'	1,500
Upper Marcellus Optimized (1)	**10,000'**	**~750**

(1) Optimizing future Marcellus locations to >10,000' lateral length where possible

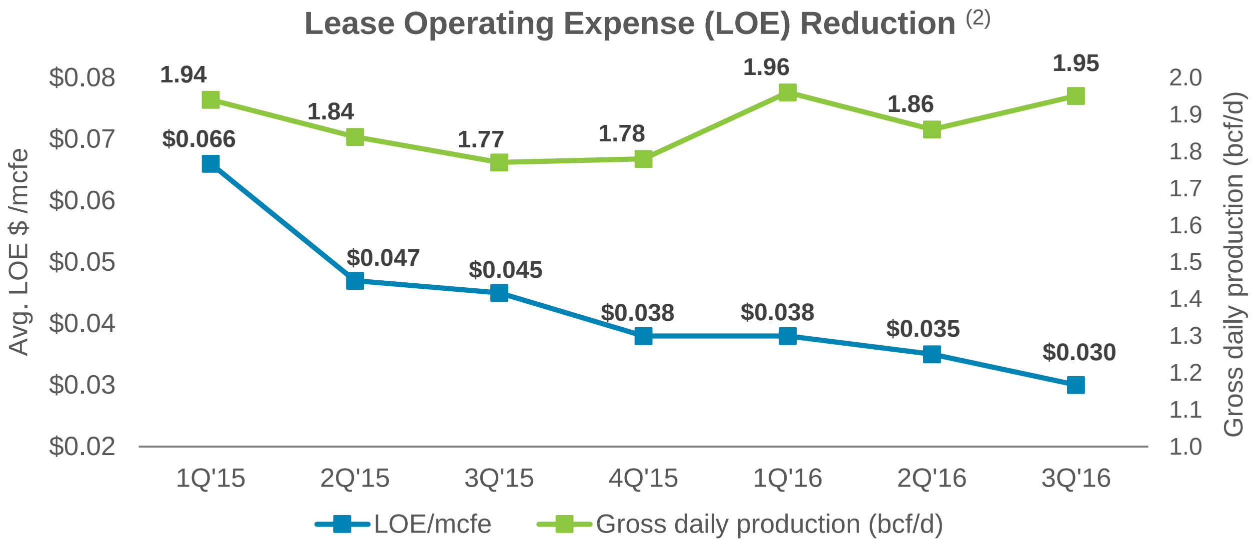
CONTINUOUS IMPROVEMENT

MARCELLUS



Capex:

Reduced 29% YTD



LOE:

Reduced 33% YTD

(1) Normalized to 6,000-ft. LL

(2) Gross core operated controllable LOE (excluding Ad Val taxes and overhead)

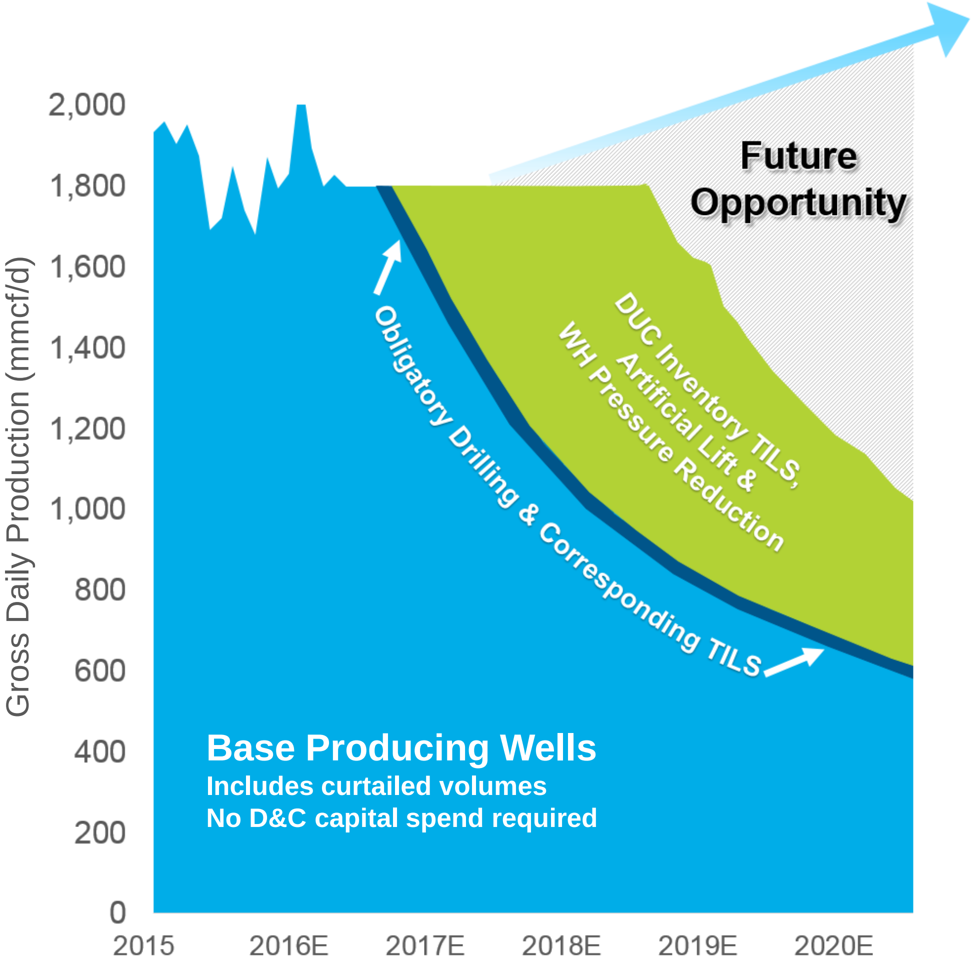
MARCELLUS PRODUCTION STRENGTH

SUSTAINABLE PRODUCTION WITH MINIMAL CAPITAL

- 300 mmcf/d shut-in
  - > Produce into favorable market
- > 300 mmcf/d curtailed
  - > Available with planned wellhead pressure reductions
- DUC focus in 2017 and 2018
  - > Exceptional point forward economics
- Minimal obligations
  - > 11 obligatory spuds through 2018

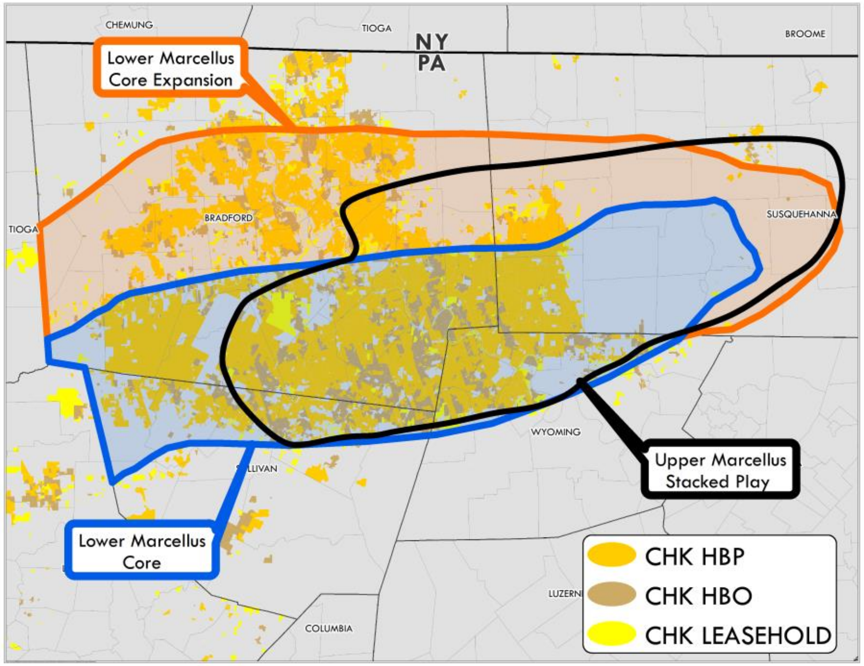
Remarkable productivity

Minimal capital required



MARCELLUS SHALE

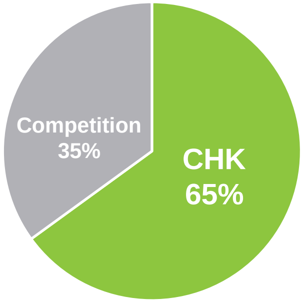
- Stable free cash flow
  - > Flat production generates significant free cash flow
- Operational excellence
  - > Basin-leading performance
- Remarkable reservoir quality
  - > Massive Marcellus upside and significant base strength



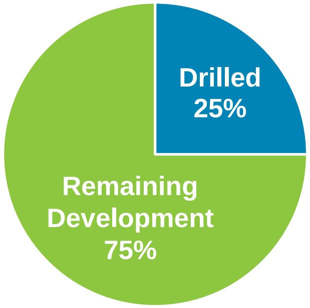
The premier domestic basin

CHK = The Core Operator

CHK Core Operated Position



Marcellus Locations

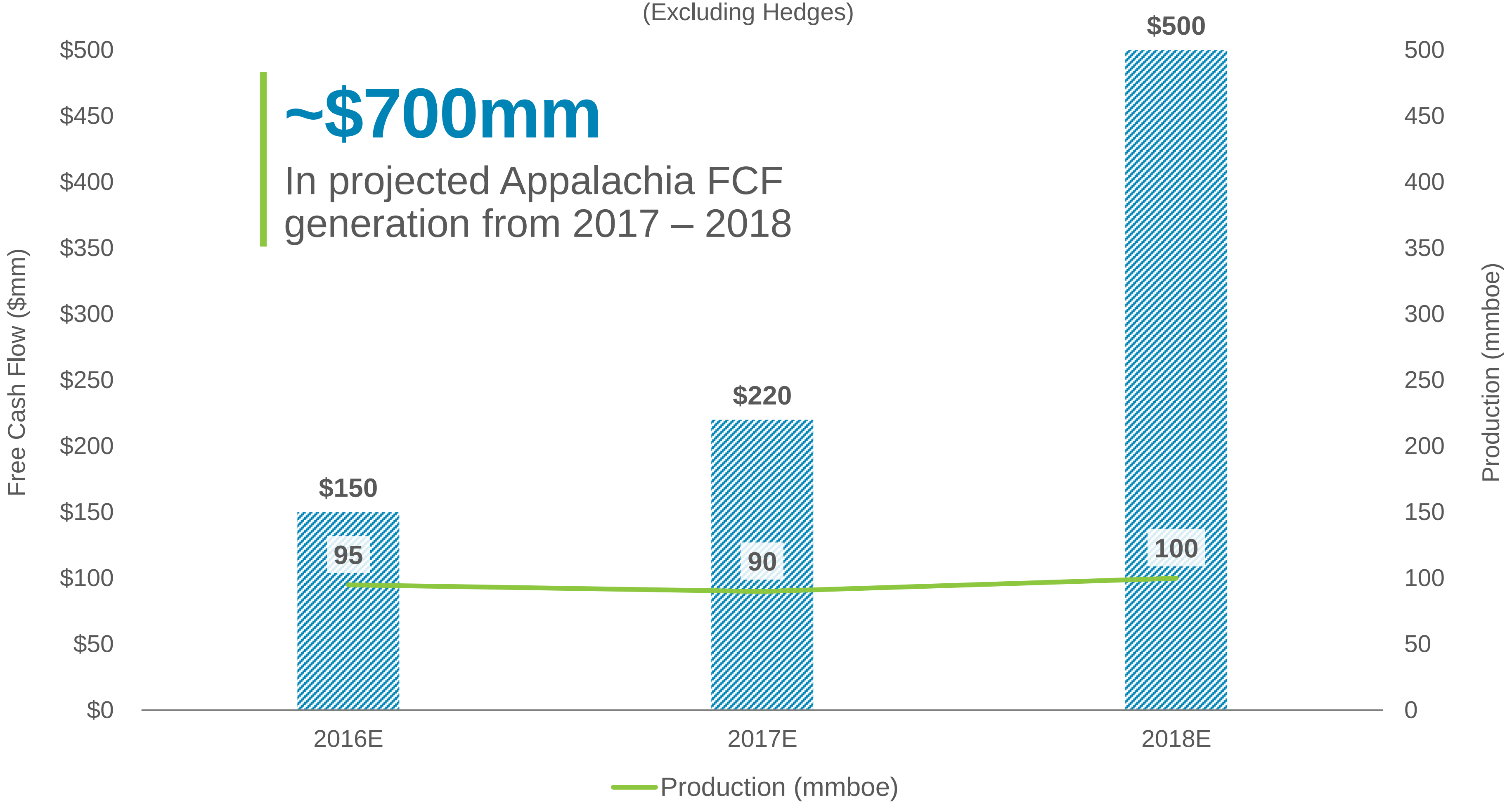


APPALACHIA – ADVANTAGE CHESAPEAKE

ONE BASIN, TWO ASSETS = OUTSTANDING VALUE

2016 – 2018 Projected Free Cash Flow(1,2) and Production

(Excluding Hedges)



~$700mm

In projected Appalachia FCF generation from 2017 – 2018

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(1) Assumes $3 / $48 for 2017 and $3 / $60 in 2018

(2) Free cash flow defined as net revenue less all operating, marketing and capital expenditures

APPENDIX

WORLD-CLASS RESERVOIR QUALITY
MARCELLUS SHALE

A prolific resource
With near-term and long-term growth opportunity

Lower Marcellus (Core)

EUR/ft. (mcf) (1)	3,000 – 4,300
Thickness (ft.)	125 – 145
Depth (ft.)	5,200 – 6,900
Porosity (%)	6.0 – 8.5
Pressure Gradient (psi/ft.)	0.60 – 0.70
Breakeven ($) (2)	2.02

Upper Marcellus

EUR/ft. (mcf) (1)	2,200 – 3,250
Thickness (ft.)	125 – 250
Depth (ft.)	4,800 – 6,700
Porosity (%)	5.5 – 8.0
Pressure Gradient (psi/ft.)	0.55 – 0.70
Breakeven ($) (2)	2.43

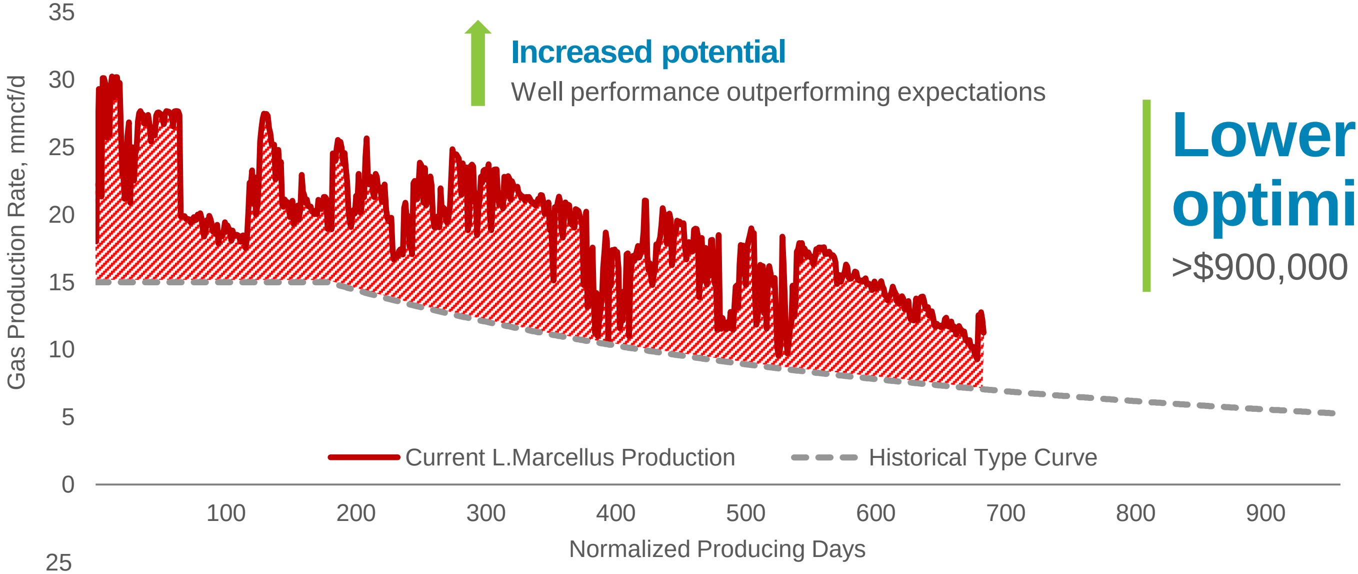
Utica

Future Potential

(1) Assumes 50 psi wellhead pressure
(2) PV10 based on $4.5mm capex

TREMENDOUS WELL PERFORMANCE

CONTINUAL IMPROVEMENT THROUGH TECHNOLOGY

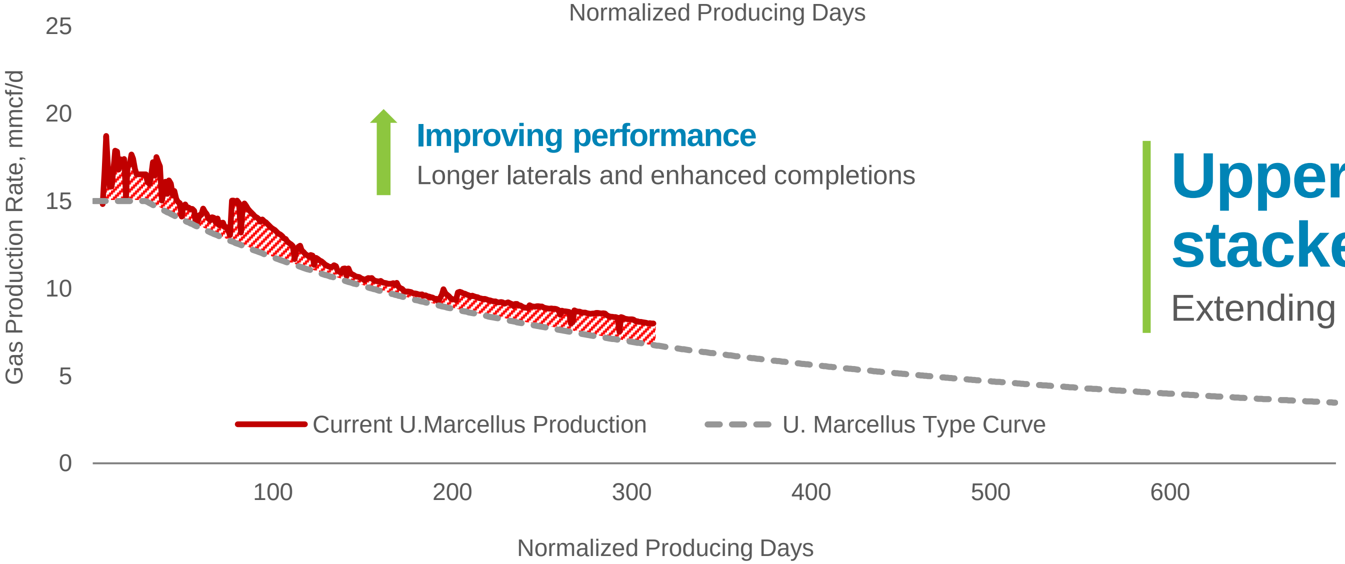


Increased potential

Well performance outperforming expectations

Lower Marcellus optimization

>$900,000 value acceleration/well



Improving performance

Longer laterals and enhanced completions

Upper Marcellus stacked pay

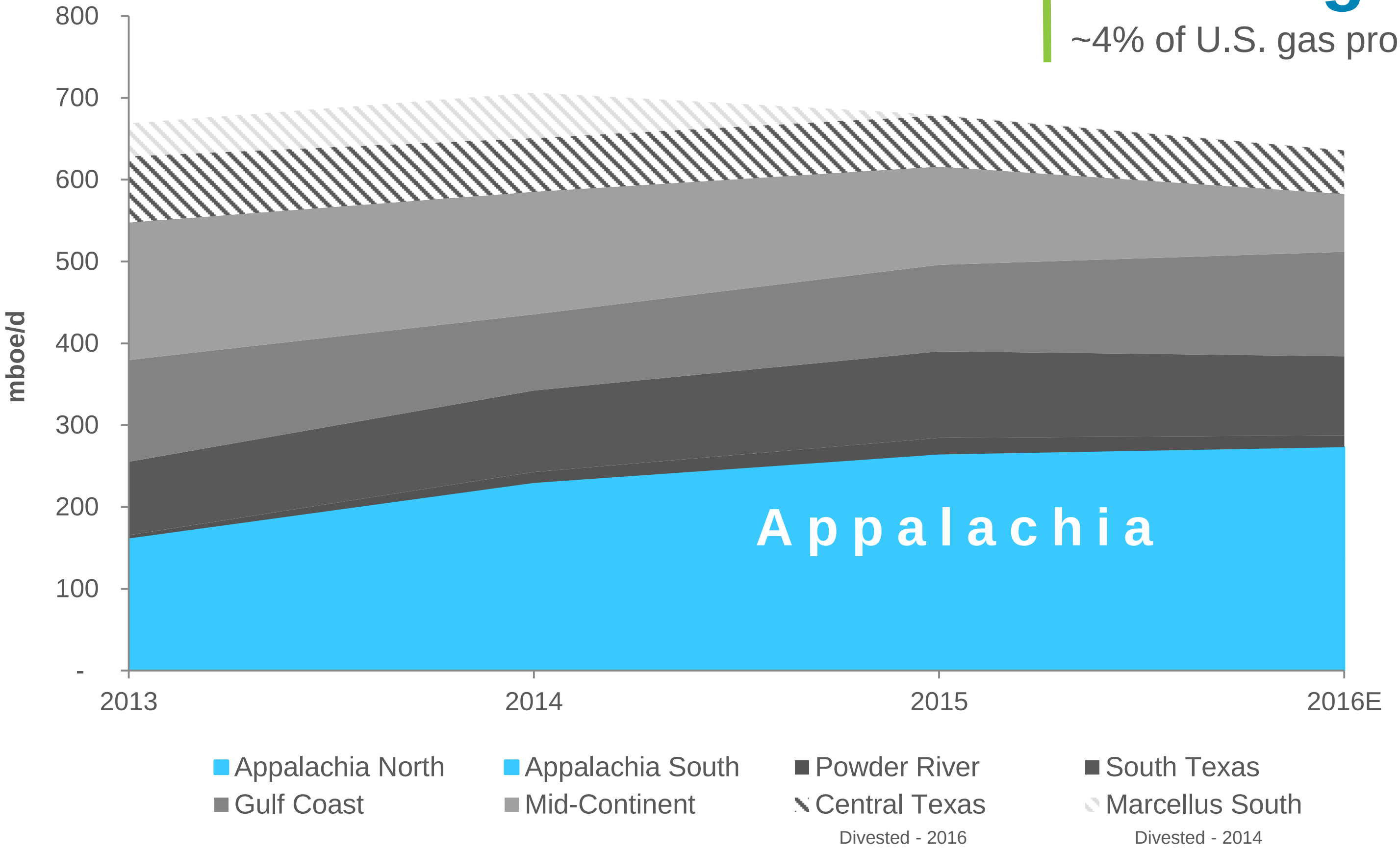
Extending asset life

NET EQUIVALENT PRODUCTION

APPALACHIA: ~43% TOTAL PRODUCTION 2016E

3 bcf/d gross

~4% of U.S. gas production (1)

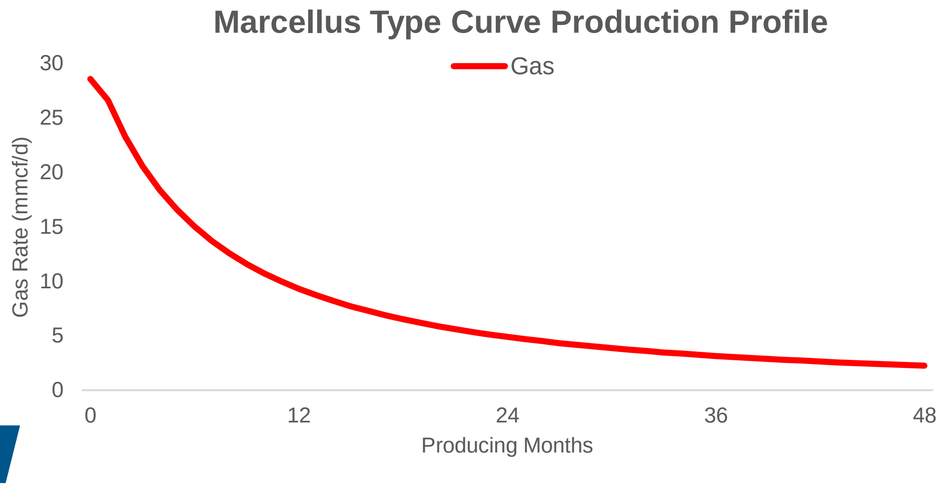


(1) Source EIA Jul 2016 US Dry Gas Production Monthly volumes released 9/30/16 (https://www.eia.gov/dnav/ng/hist/n9070us1m.htm)

MARCELLUS MODELING INPUTS

Base Production[1]	
3Q'16E Net Production	805 mmcf/d
4 Yr. Average Annual Decline[2]	24%

2017 Expenses & Differential Estimates[1]	
Production Expense[3] ($/mcf)	$0.08 – $0.11
GP&T[4] ($/mcf)	$0.93 – $0.97

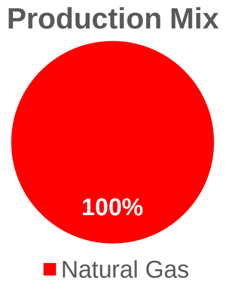


2017 – 2020 Blended Development Program

Curve Parameters	
IP[5]	28.5 mmcf/d
Decline	68.5%
B-factor	0.70
EUR[6]	17.1 bcf
Lateral Length	6,200 ft.

Gross Capex	
Drilling[7] (109 days to TIL)	$2.2mm
Completion (57 days to TIL)	$1.9mm
TIL	$0.4mm
TOTAL	***$4.5mm***

Interest / Gross Locations	
WI / NRI[8]	48%/41%
Producing	686
DUCs	85
Undrilled[9]	2,900
Rig Count	0 – 2



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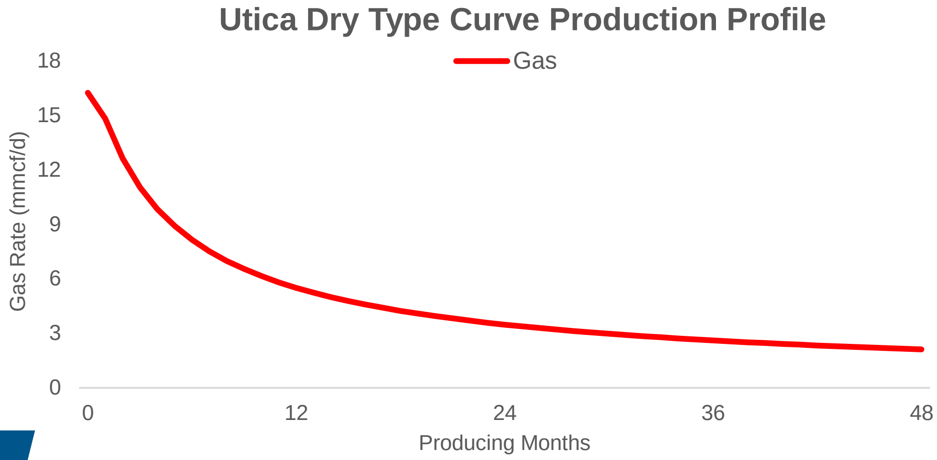
(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) Assumes 600psi
(7) 13 days spud to spud
(8) Assumed until well proposed
(9) All potential locations, not necessarily all drilled by 2020

UTICA DRY MODELING INPUTS

Base Production[1]	
3Q'16E Net Production	85 mmcf/d
4 Yr. Average Annual Decline[2]	26%

2017 Expenses & Differential Estimates[1]	
Production Expense[3] ($/mcf)	$0.16 – $0.20
GP&T[4] ($/mcf)	$1.00 – $1.10



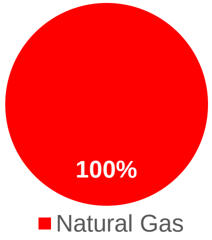
2017 – 2020 Blended Development Program

Curve Parameters	
IP[5]	16.2 mmcf/d
Decline	67%
B-factor	1.25
EUR	16.9 bcf
Lateral Length	10,500 ft.

Gross Capex	
Drilling[6] (93 days to TIL)	$3.1mm
Completion (39 days to TIL)	$2.4mm
TIL	$0.5mm
TOTAL	***$6.0mm***

Interest / Gross Locations	
WI / NRI[7]	89%/73%
Producing	40
DUCs	25
Undrilled[8]	370
Rig Count	0 – 1

Production Mix

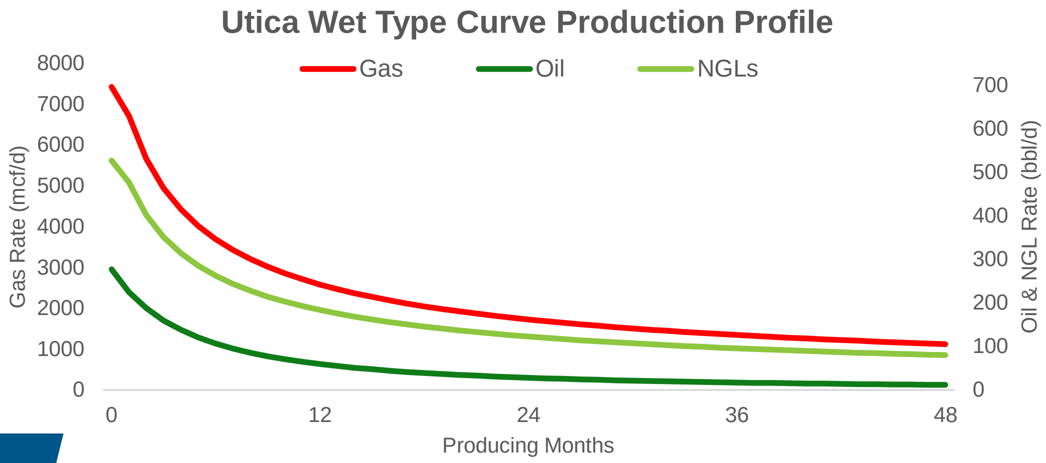


(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 15 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020

UTICA WET MODELING INPUTS

Base Production[1]	
3Q'16E Net Production	110 mboe/d
4 Yr. Average Annual Decline[2]	25%

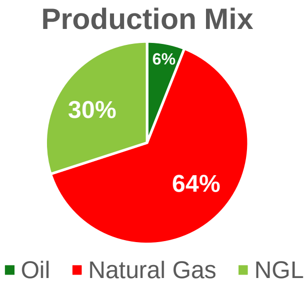
2017 Expenses & Differential Estimates[1]	
Production Expense[3] ($/boe)	$1.02 – $1.12
GP&T[4] ($/boe)	$8.50 – $9.50


Utica Wet Type Curve Production Profile

2017 – 2020 Blended Development Program

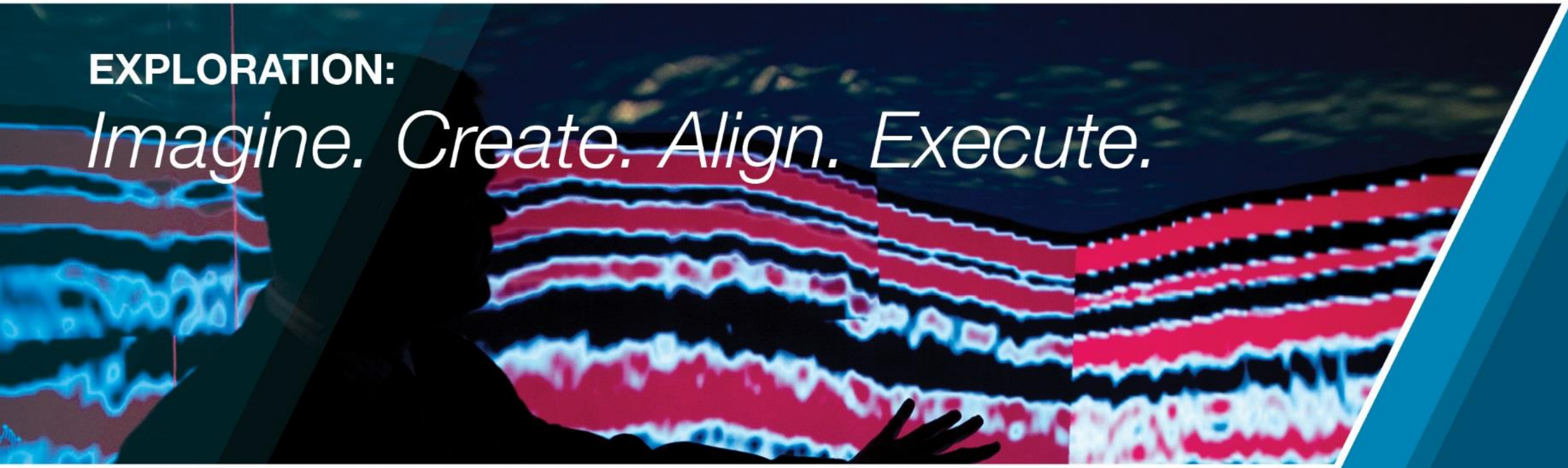
Curve Parameters	
IP[5] (Oil / Gas)	275 bbl/d / 7.4 mmcf/d
Decline (Oil / Gas)	80%/66%
B-factor (Oil / Gas)	0.64/1.50
Shrink	90%
NGL Yield	71 bbl/mmcf
EUR	2.0 mmboe
Lateral Length	9,000 ft.

Gross Capex	
Drilling[6] (105 days to TIL)	$2.4mm
Completion (51 days to TIL)	$2.5mm
TIL	$0.6mm
TOTAL	***$5.5mm***


Production Mix

Interest / Gross Locations	
WI / NRI[7]	67%/54%
Producing	600
DUCs	30
Undrilled[8]	790
Rig Count	1 – 4

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 12 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020



EXPLORATION:

Imagine. Create. Align. Execute.

FRANK PATTERSON

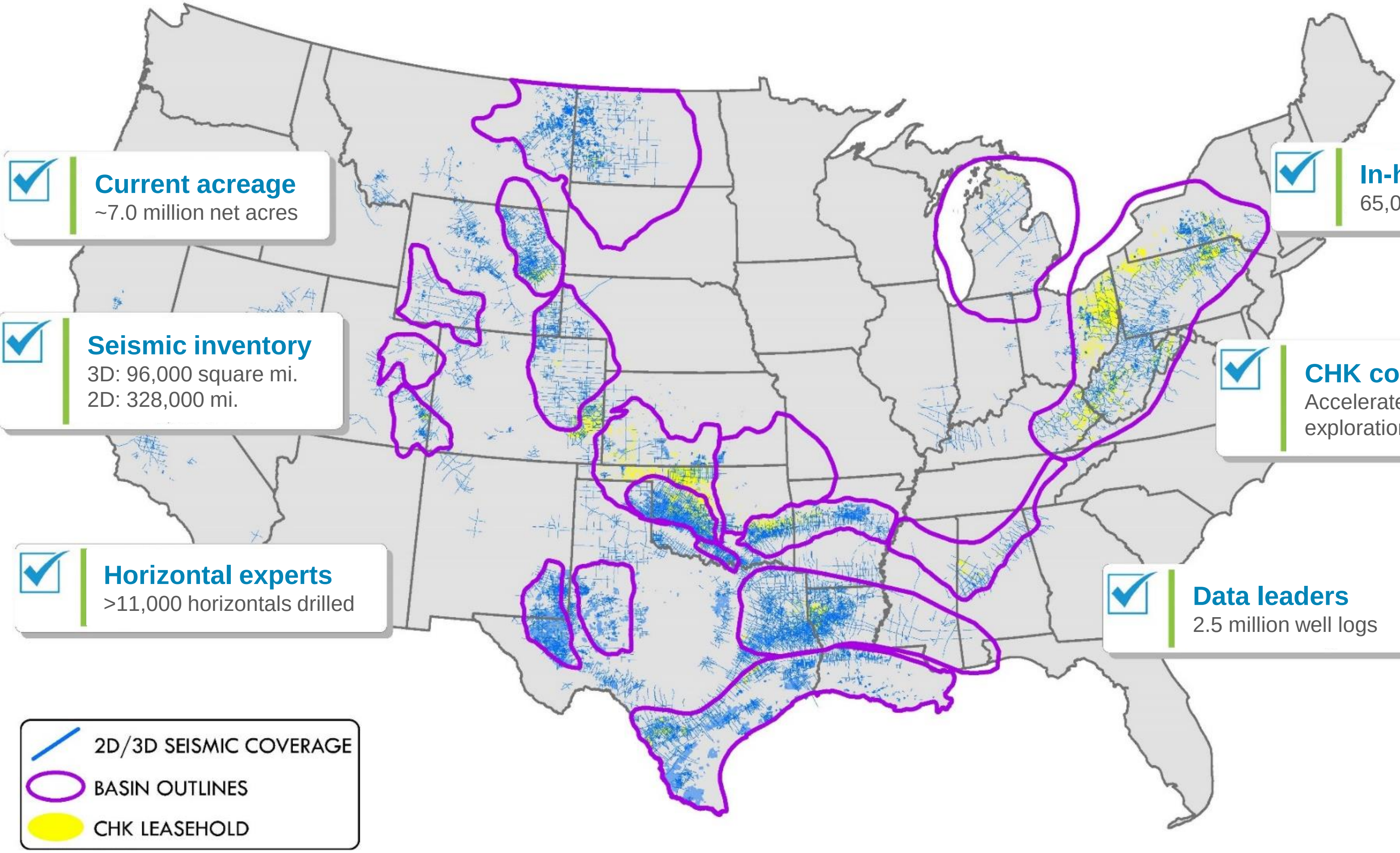
EXPLORING FOR THE FUTURE

Current Exploration Opportunities

- **11** new basin-entry plays
- **15** growth opportunities in CHK-operated basins
- **17** prospects adding value to current HBP position

- Unmatched subsurface data with in-house expertise
- Petroleum systems approach generating innovative play concepts
- Building inventory of stacked play opportunities

WE ARE UNCONVENTIONAL EXPERTS



☑ **Current acreage**
~7.0 million net acres

☑ **Seismic inventory**
3D: 96,000 square mi.
2D: 328,000 mi.

☑ **Horizontal experts**
>11,000 horizontals drilled

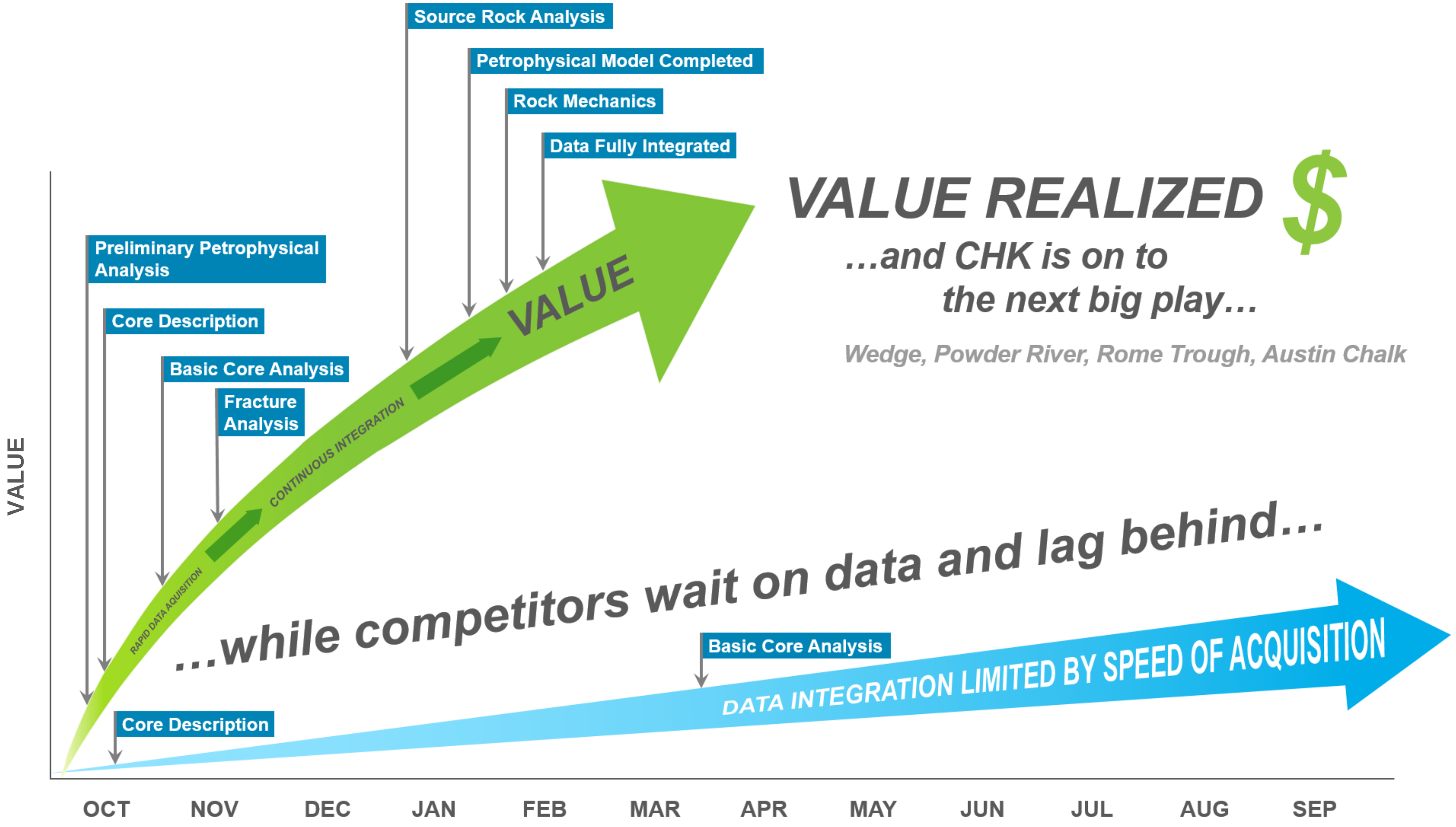
☑ **In-house core**
65,000 ft. analyzed

☑ **CHK core lab**
Accelerates exploration value

☑ **Data leaders**
2.5 million well logs

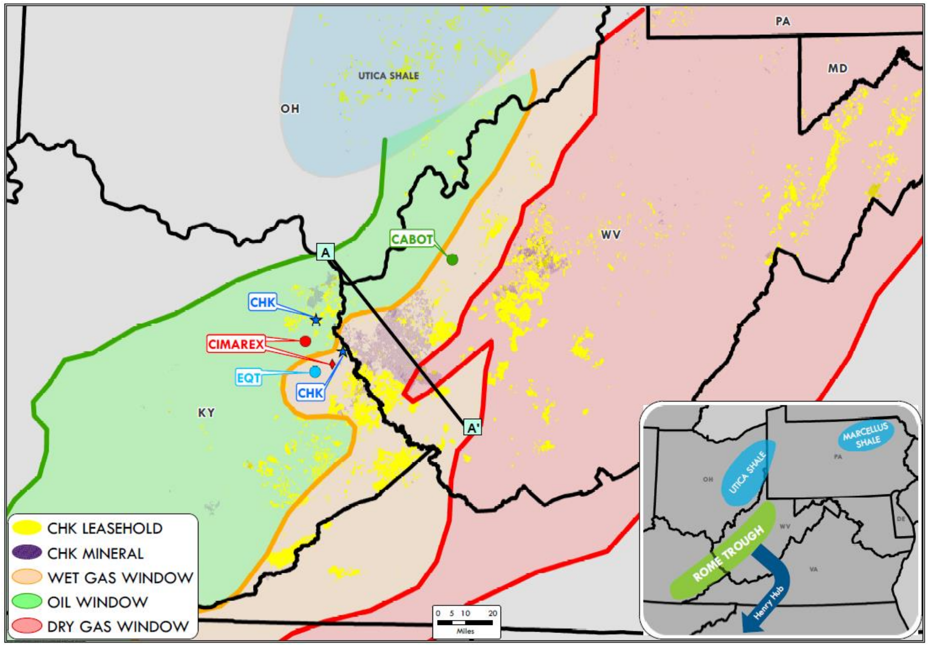
CHK VALUE REALIZATION

ANALYSIS TO IMPLEMENTATION IN MONTHS NOT YEARS



1,600,000 ACRES – CHK ADVANTAGE

ROME TROUGH



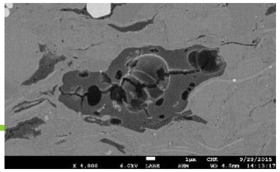
- Multi-zone stacked potential
  - ~1 to 4.5 bboe recoverable in single zone
- 1.4mm acres HBP/minerals
  - Two vertical core wells drilled
- Competitors de-risking around CHK HBP position
- Access to Gulf Coast markets

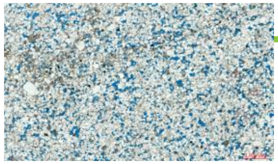
65% of acreage

In liquids window

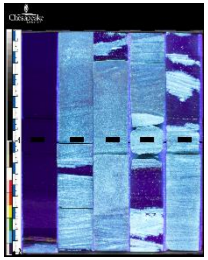
Oil-prone source rock and stacked reservoirs

Target A



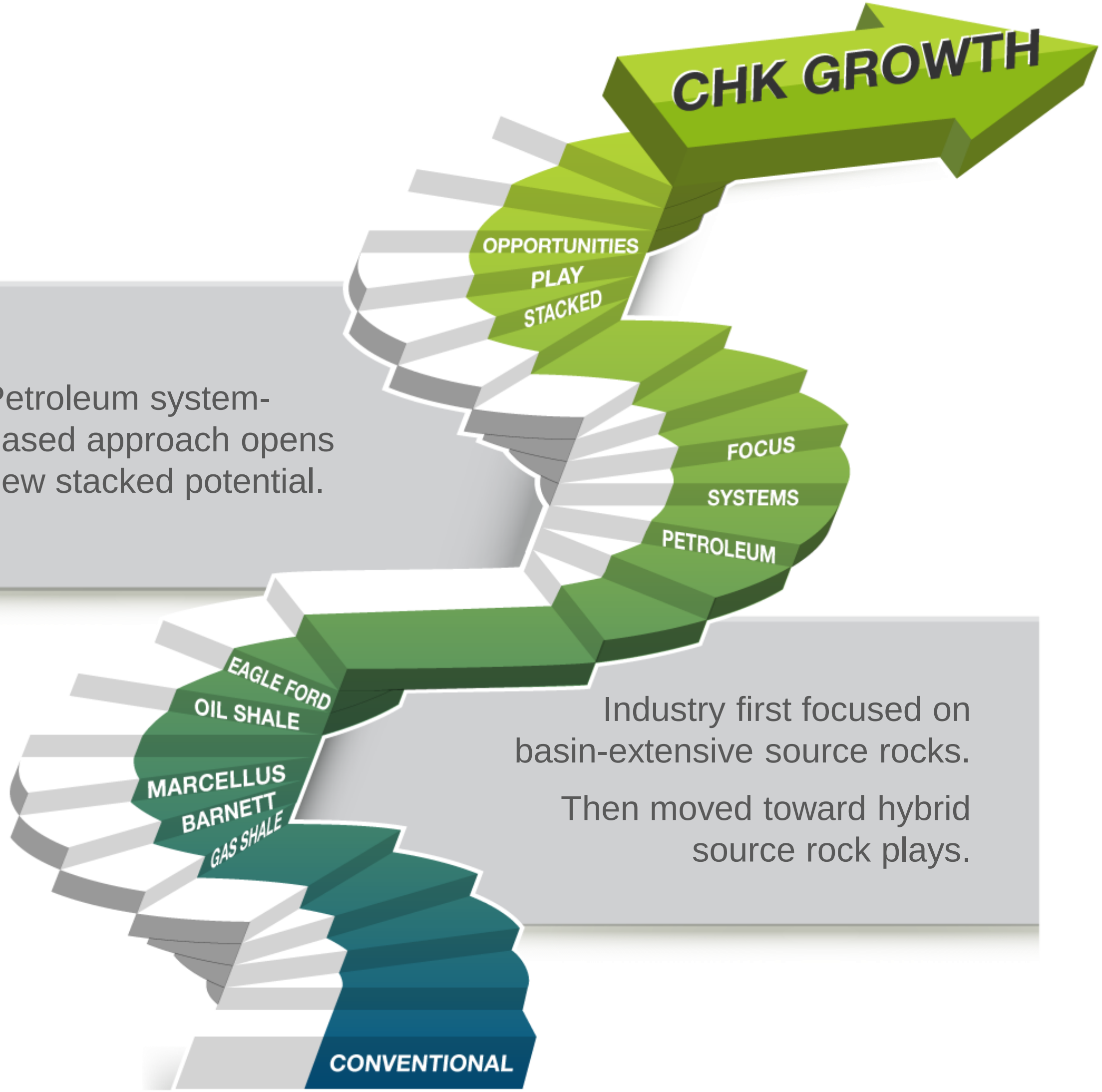


Target B
Oil-saturated reservoir



Target B
Hydrocarbon fluorescence

IT’S NOT *ALL* ABOUT SHALE

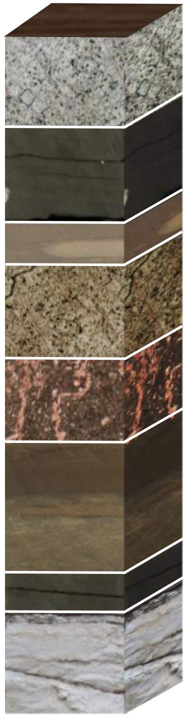


Petroleum system-based approach opens new stacked potential.

Industry first focused on basin-extensive source rocks.

Then moved toward hybrid source rock plays.

Our Future is Stacked!



Conventional sands:
Red Fork, Springer

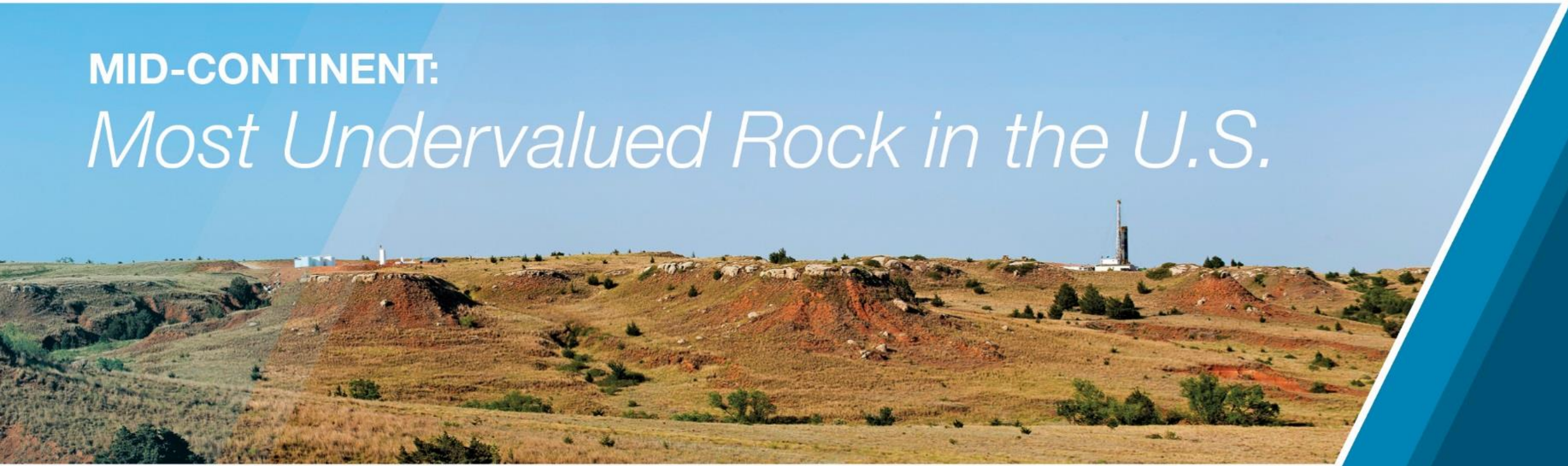
Source rock plays:
Eagle Ford, Haynesville

Low-perm clastics:
Sussex, Turner

Low-perm carbonate plays:
Oswego

Mixed clastic/ carbonate plays:
Meramec

Fractured plays:
Austin Chalk



MID-CONTINENT:

Most Undervalued Rock in the U.S.

FRANK PATTERSON

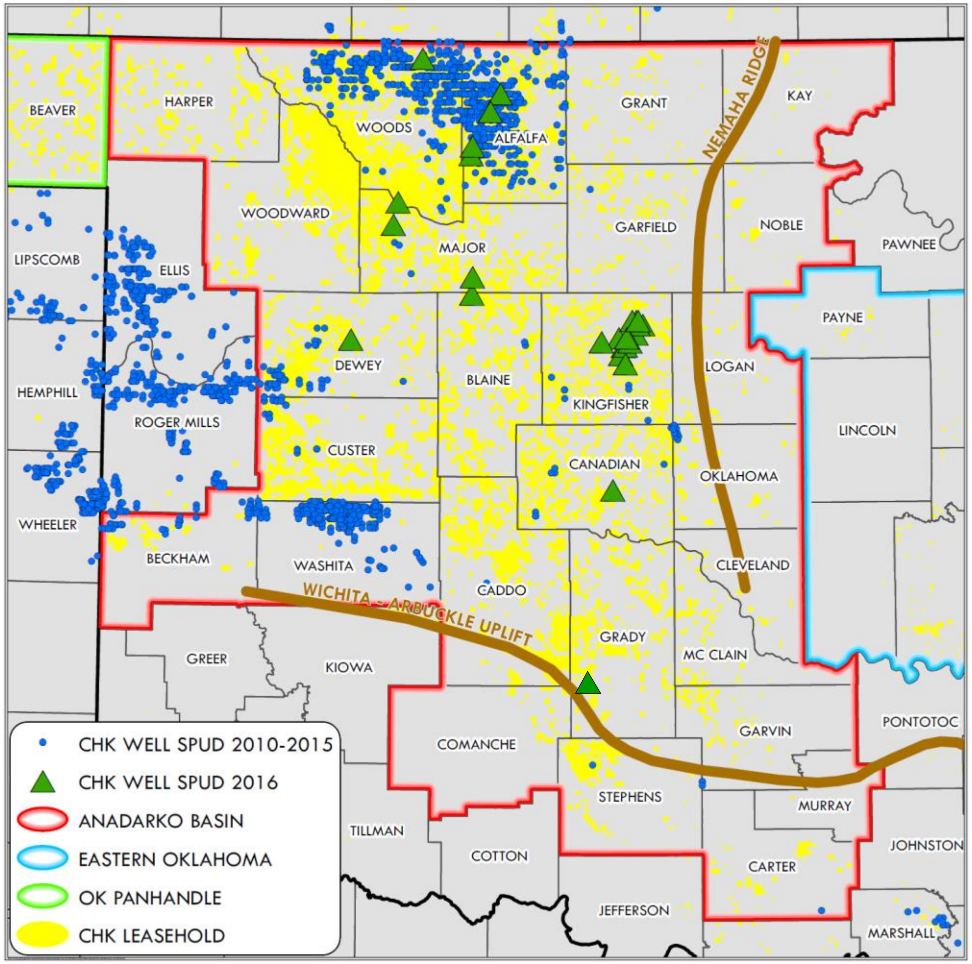
MID-CONTINENT IS NOT WHAT YOU REMEMBER

- Shift from historical plays to new concepts and formations
- Substantial NAV value
- Legacy acreage position offers extensive opportunity
- Oswego – a bridge to oil production growth
- Actively exploiting ***“The Wedge”*** opportunity

3 – 4 rigs

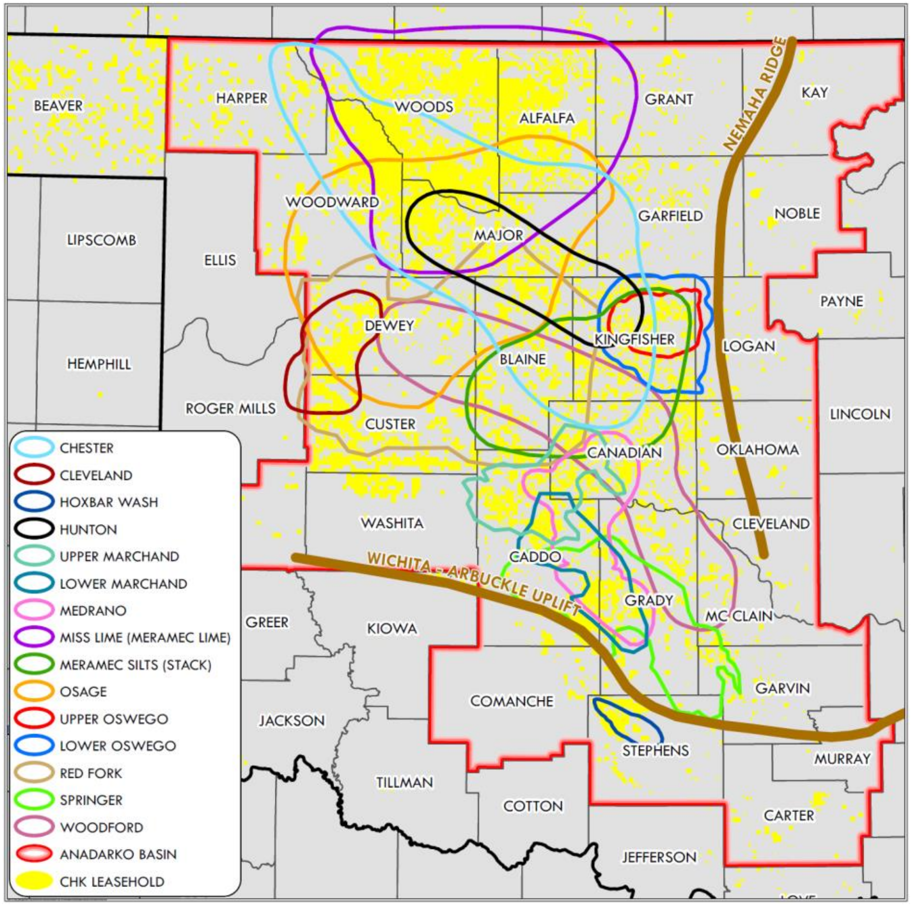
Active in 2017

~1.5mm Net Acres in Mid-Continent



MASSIVE MID-CONTINENT LAND POSITION

1.5MM ACRES IN OKLAHOMA



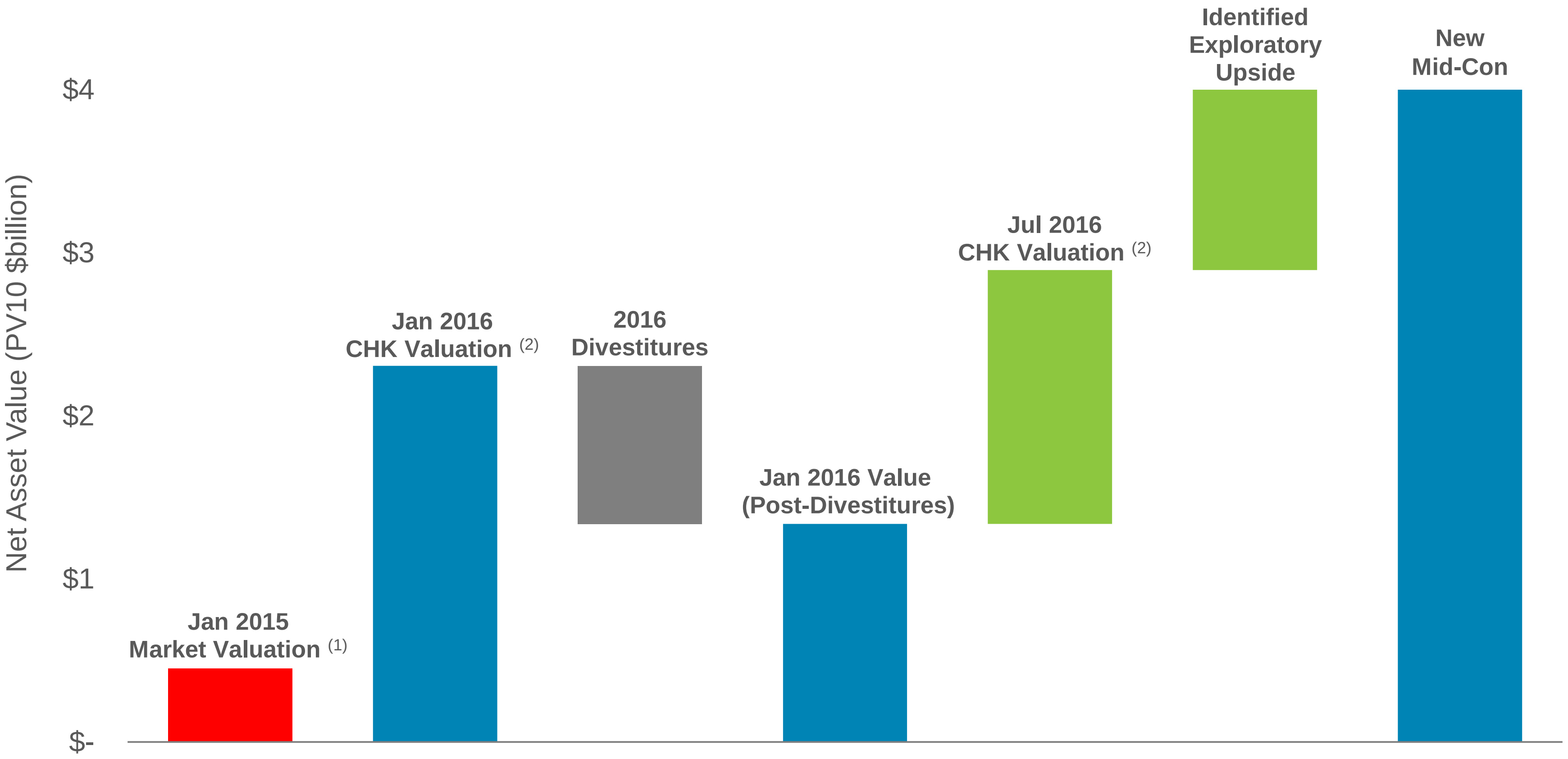
Chesapeake Leasehold	Net Acres	% of Total Mid-Con	% HBP
Anadarko Basin	*1,150,000*	*77%*	*94%*
Eastern Oklahoma	*200,000*	*13%*	*100%*
OK Panhandle	*150,000*	*10%*	*100%*
Total Mid-Continent	*1,500,000*	*100%*	*95%*

- Top leasehold position in Oklahoma
- Leasehold > 95% HBP
- 3,200 identified remaining drilling locations

Evaluating 15+ horizons – multiple commercial plays available

NAV CONTINUES TO GROW

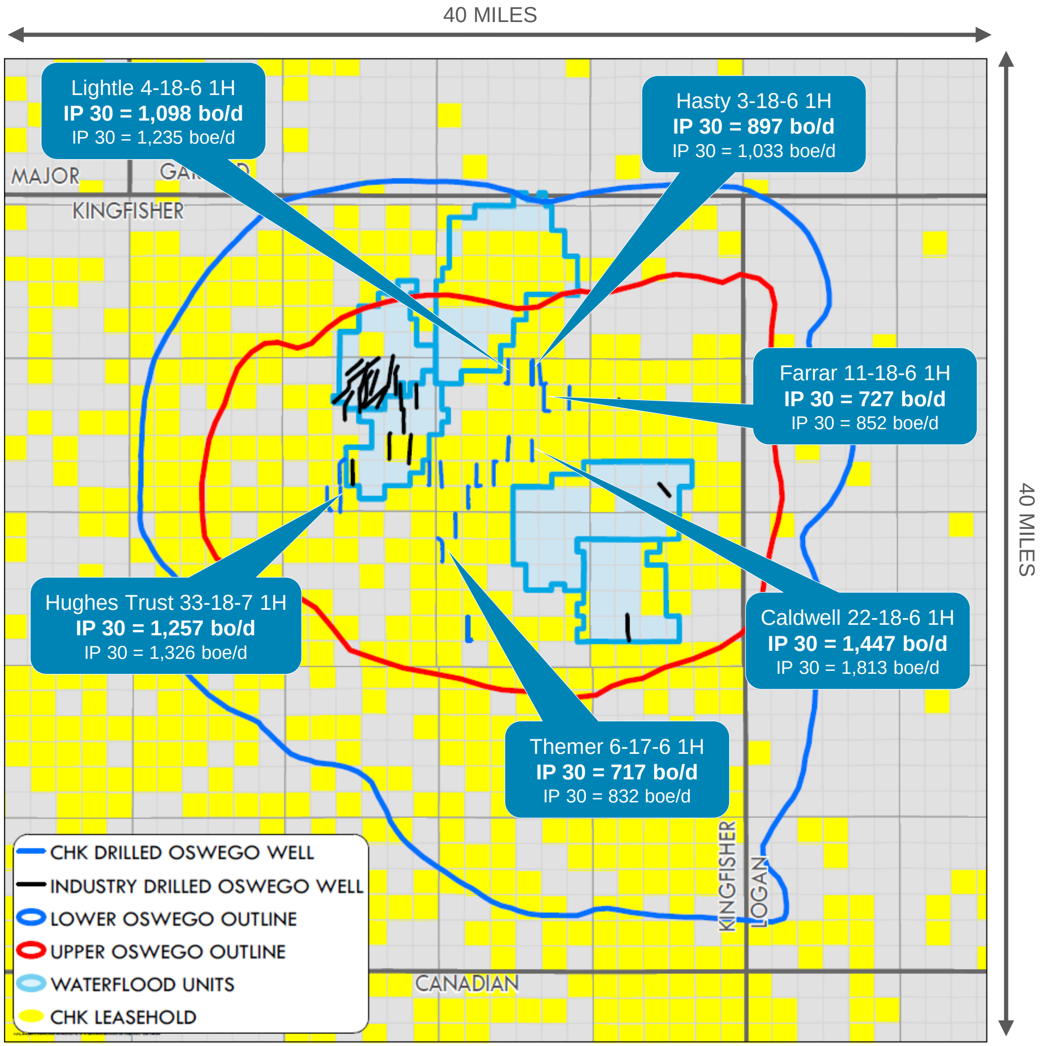
Valued at $2.8 billion after $1.0 billion in 2016 asset sales



(1) Jan 2015 average of seven analysts who provided breakout of total development value remaining in CHK's Mid-Continent asset

(2) Internal valuation based on $3/mcf gas and $60/bbl oil price flat

OSWEGO DELIVERING IMPRESSIVE RESULTS



Lightle 4-18-6 1H
IP 30 = 1,098 bo/d
IP 30 = 1,235 boe/d

Hasty 3-18-6 1H
IP 30 = 897 bo/d
IP 30 = 1,033 boe/d

Farrar 11-18-6 1H
IP 30 = 727 bo/d
IP 30 = 852 boe/d

Hughes Trust 33-18-7 1H
IP 30 = 1,257 bo/d
IP 30 = 1,326 boe/d

Caldwell 22-18-6 1H
IP 30 = 1,447 bo/d
IP 30 = 1,813 boe/d

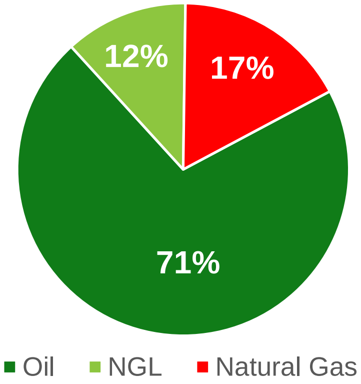
Themer 6-17-6 1H
IP 30 = 717 bo/d
IP 30 = 832 boe/d

$3.0mm/well

Development cost

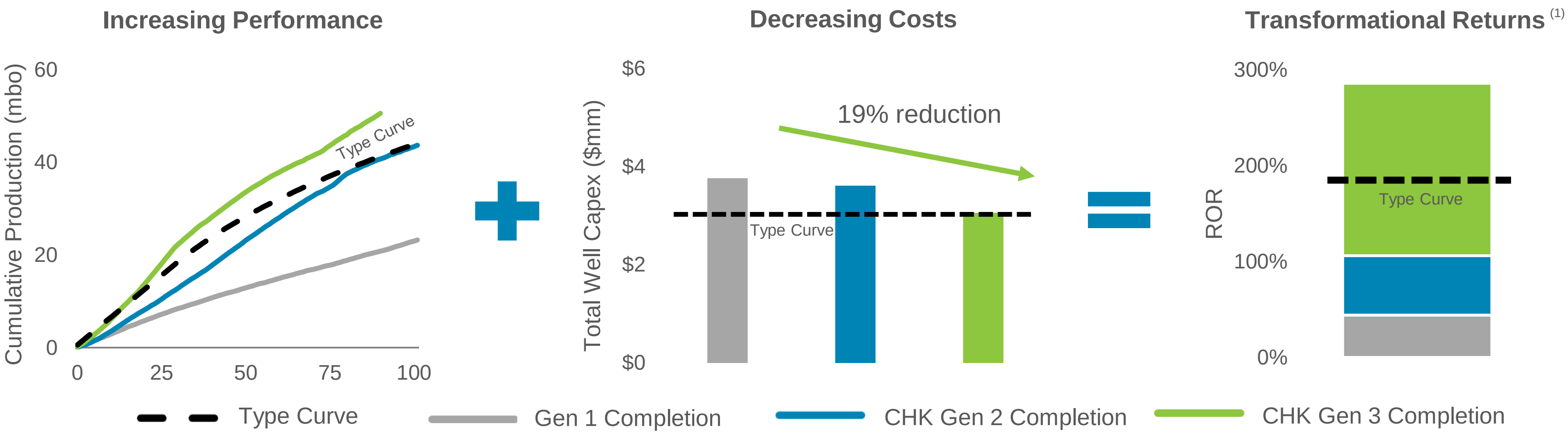
~400 mboe EUR

83% liquid, average WI 53%



THE OSWEGO TRANSFORMATION

UNLOCKING VALUE THROUGH RAPID OPTIMIZATION



Well deliverability increased by

140%

Total well capex reduced by

19%

Single-well returns across the play of

170%

100 locations at 170% ROR and 200 upside locations

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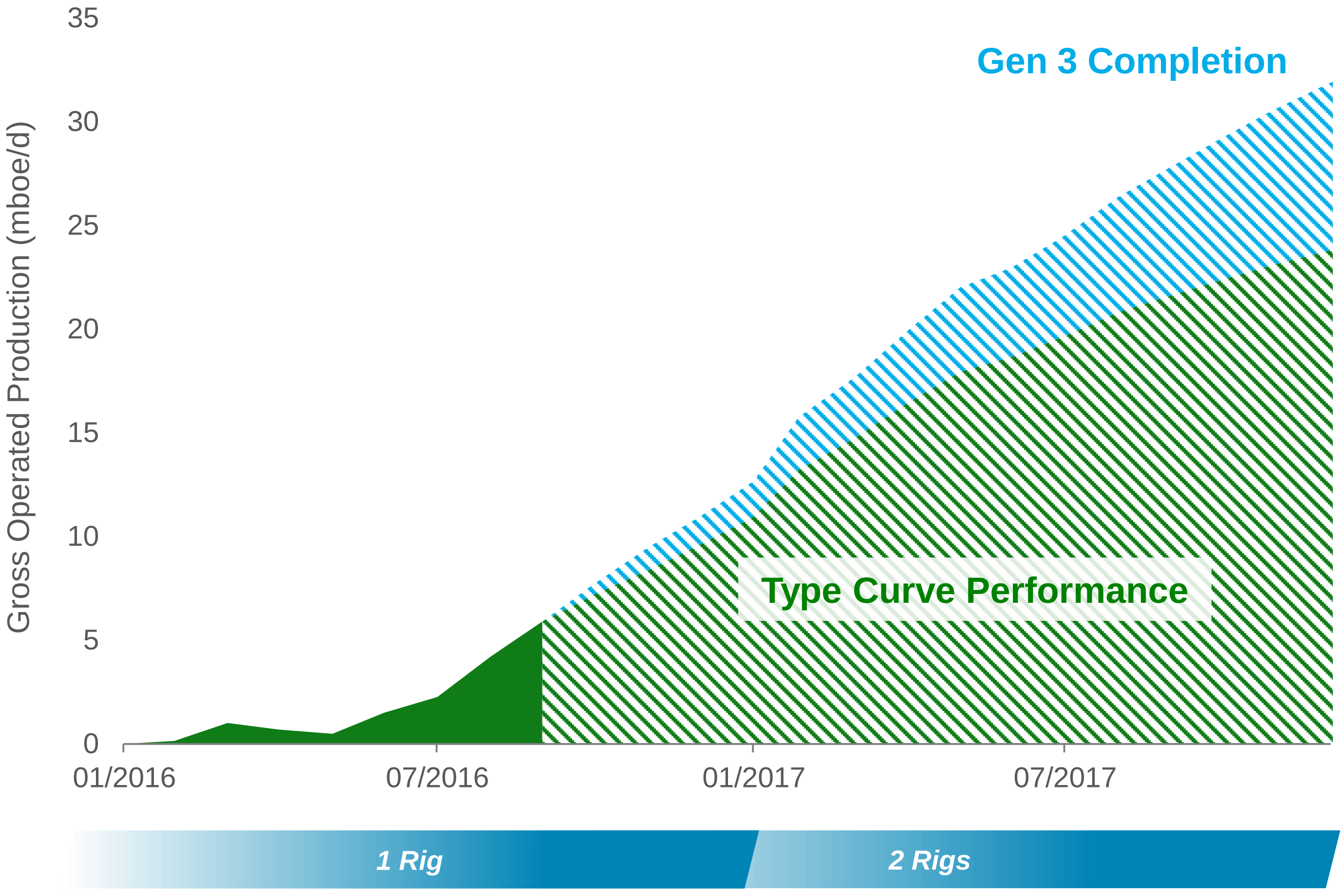
(1) Price deck: $3/mcf and $60/bbl flat

OSWEGO DELIVERING TREMENDOUS GROWTH



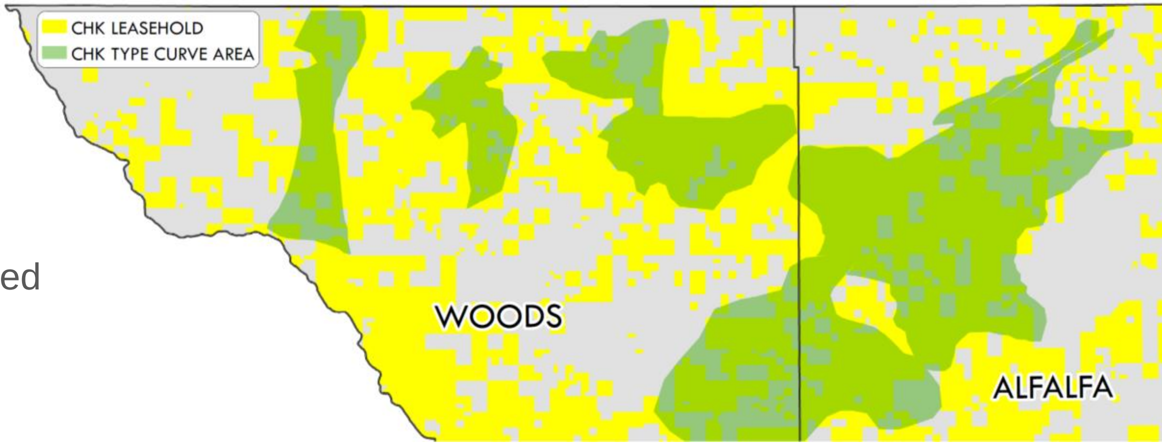
High-volume, low-cost production quick to market

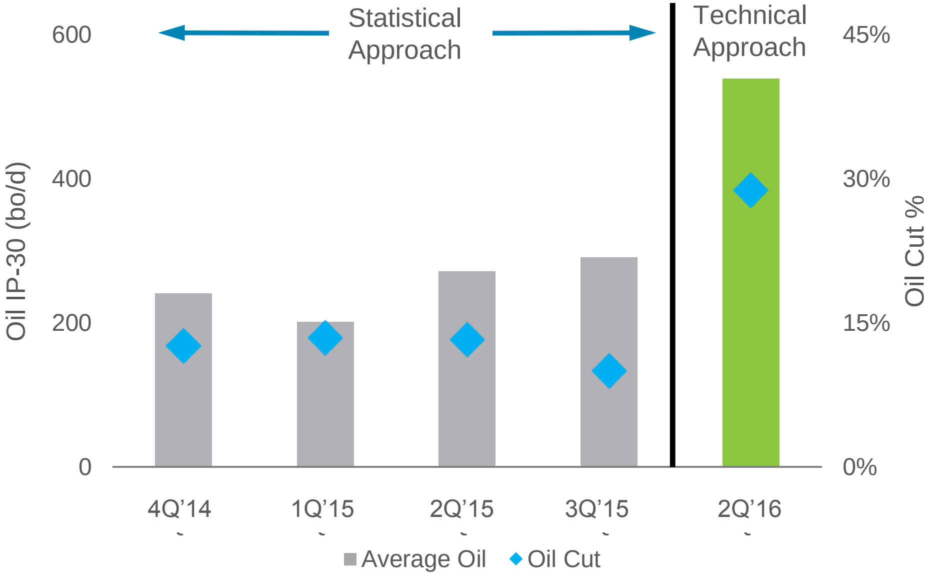
MISS LIME CONTINUES TO DELIVER

TREMENDOUS FUTURE OPTIONALITY

Transformational strategy

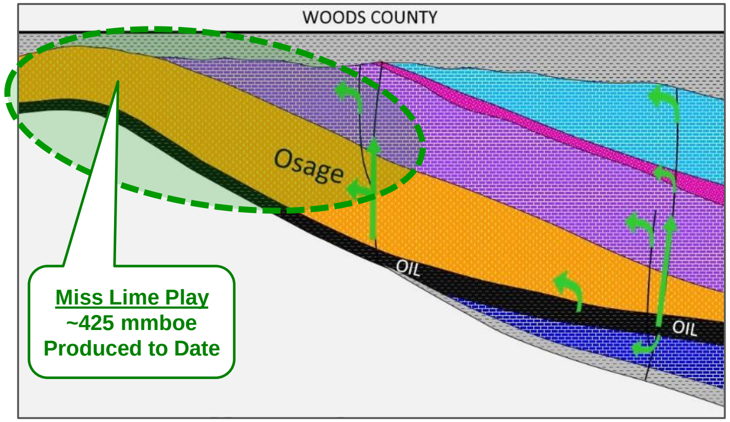
- Shift from statistical to technical field development approach
- New wells selected on basis of improved subsurface technical understanding
- Targeted completion design improves oil-to-water cut





Abundant potential development

- 300 development wells with >50% ROR (1)
- 700 incremental upside inventory



Miss Lime Play
~425 mmboe
Produced to Date

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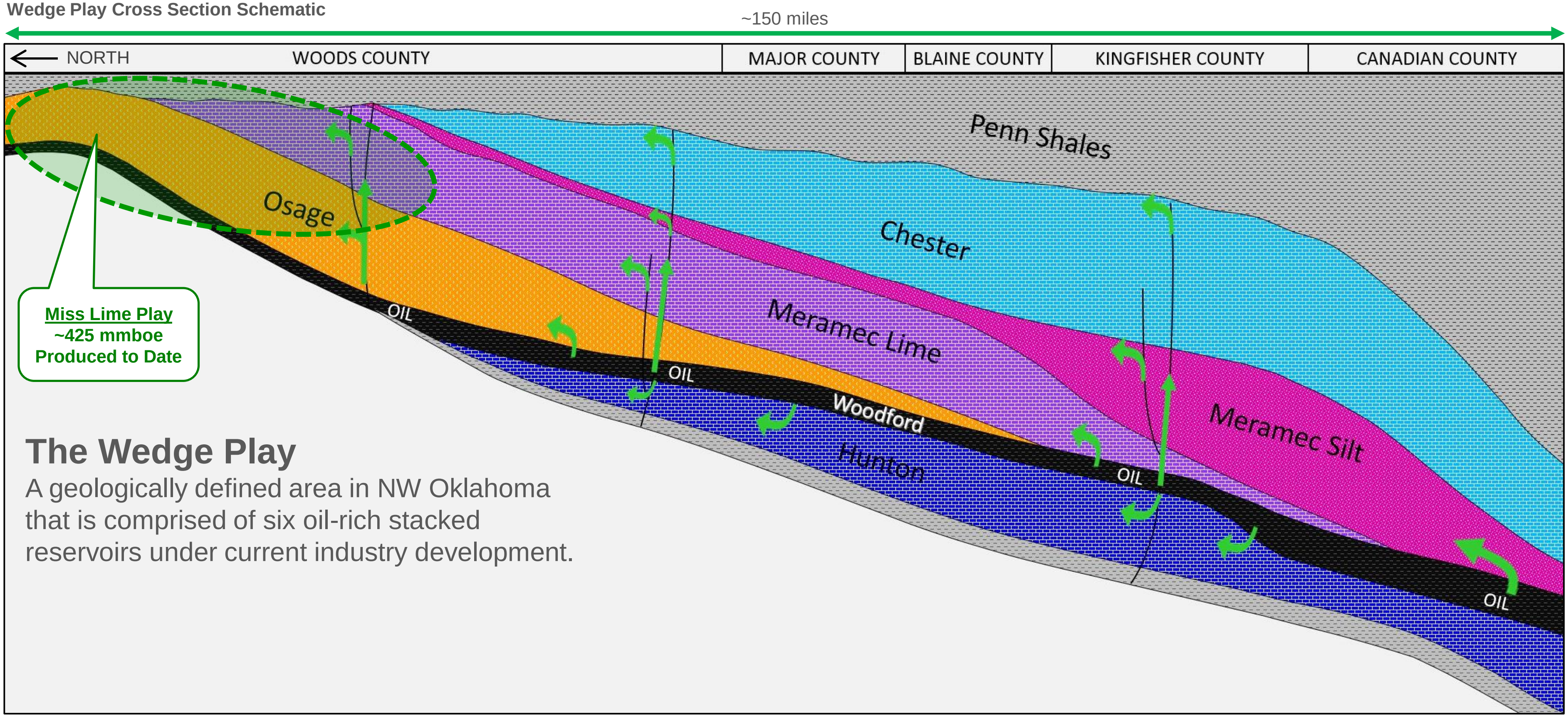
(1) Price deck: $3/mcf for gas and $60/bbl oil flat

THE WEDGE PLAY

PROLIFIC OIL-RICH RESERVOIRS

150-mile fairway of stacked pay

Wedge Play Cross Section Schematic



Miss Lime Play
~425 mmboe
Produced to Date

The Wedge Play

A geologically defined area in NW Oklahoma that is comprised of six oil-rich stacked reservoirs under current industry development.

THE WEDGE PLAY

CHESAPEAKE'S FUTURE MID-CONTINENT GROWTH ASSET

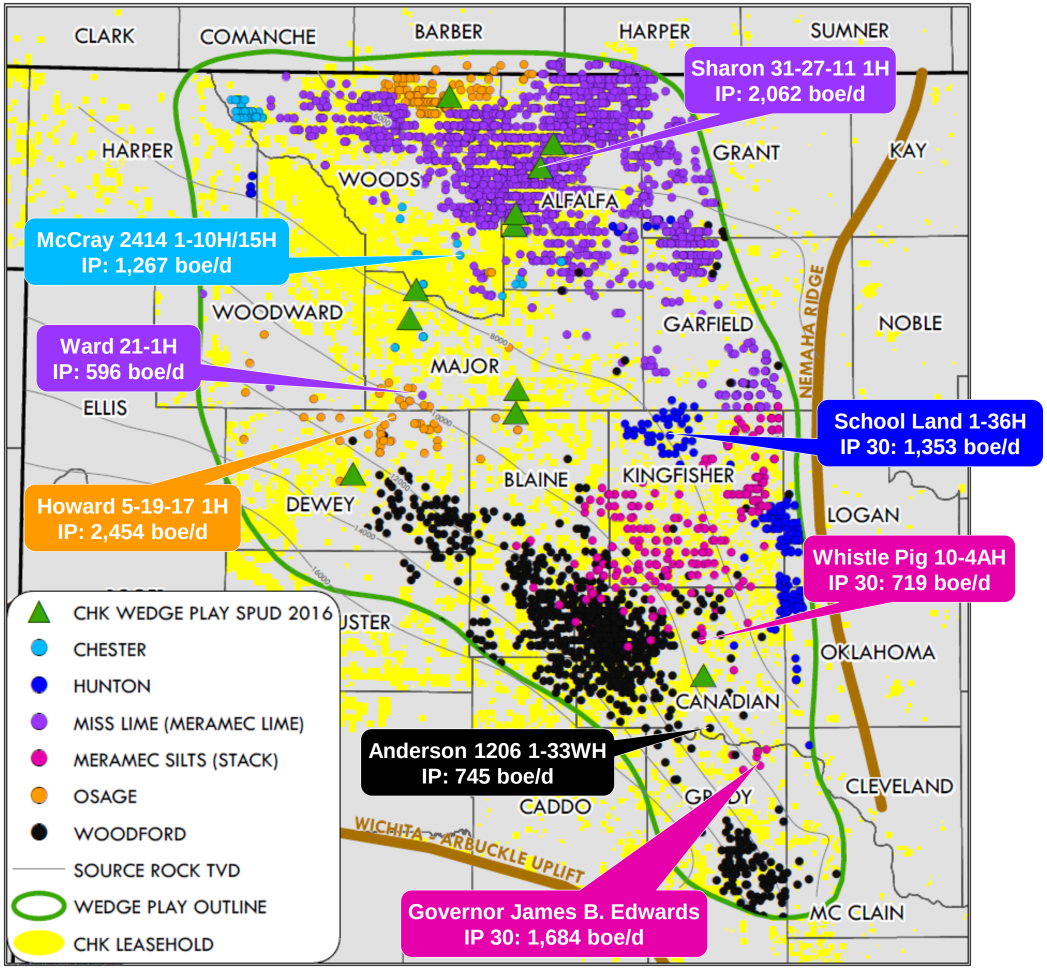
Strong economics – large land position

- ~870,000 net acres
  - 94% HBP
- Robust economics
  - ~500 locations at 50% ROR [1,2]
- Significant running room
  - ~1,400 additional upside locations
- Efficient capital spend
  - Industry actively de-risking plays

New Wedge step-out test

1,073 boe/d (51% oil)

One-mile lateral with opportunity
for two-mile development



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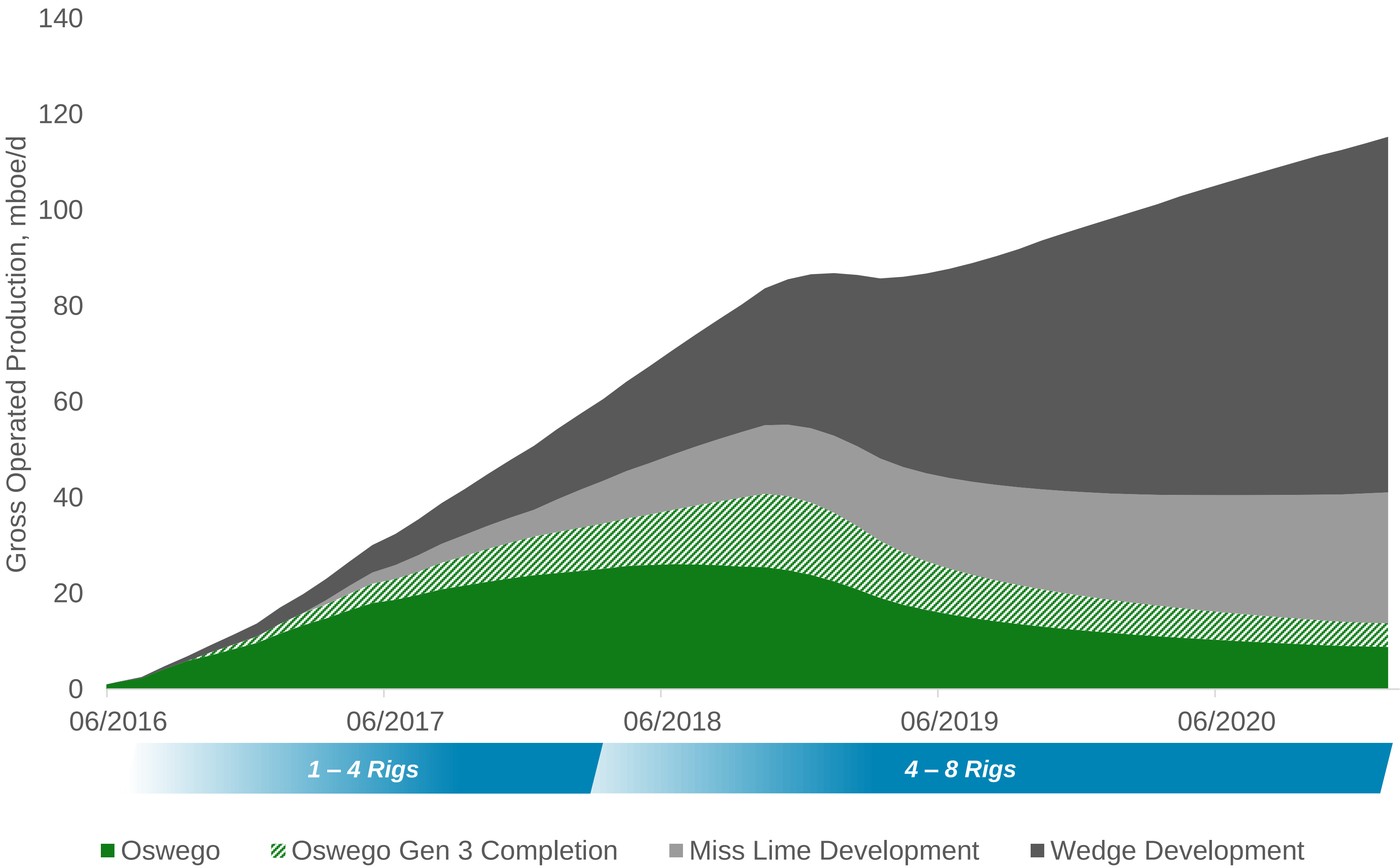
(1) Location counts exclude Miss Lime locations

(2) Price deck: $3/mcf for gas and $60/bbl oil flat

MID-CON GROWTH ENGINE

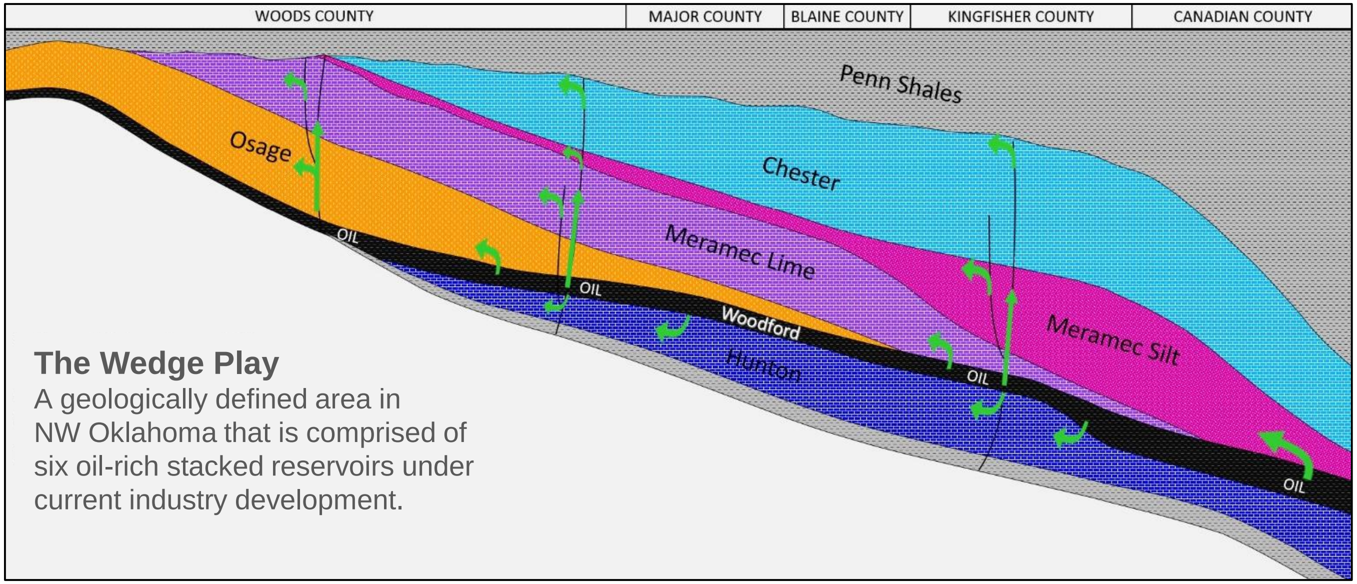
SCALABLE GROWTH FROM OSWEGO AND THE WEDGE



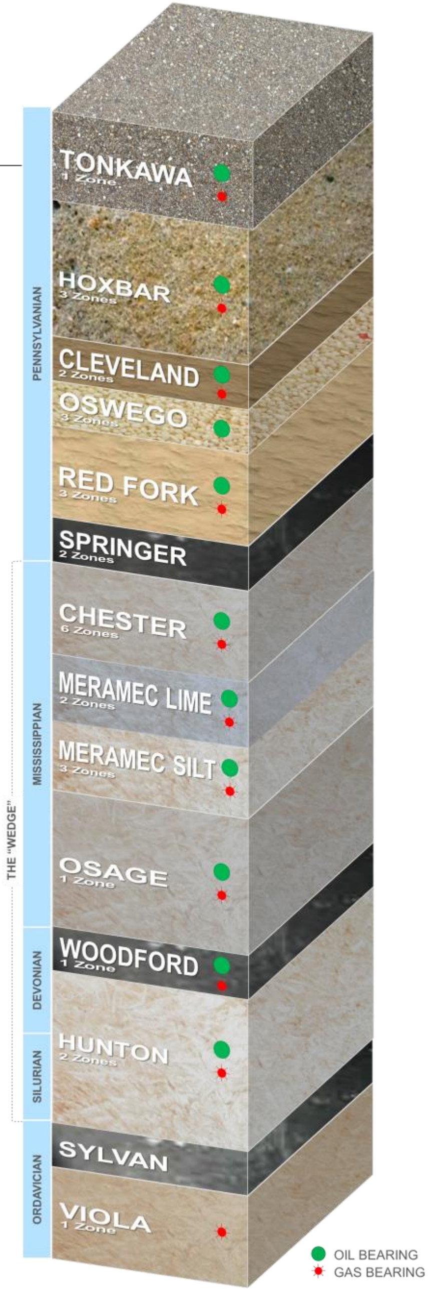
Development model only reflects the first 100 Oswego locations

MOST UNDERVALUED ROCK IN THE U.S.

- Current value of $2.8 billion plus upside
- 1.5 million acres – 95% HBP
- Oswego generating industry-leading economics
- 500 Wedge locations with 50% ROR (1)
- Evaluating 15+ horizons for future growth
- Legacy acreage position allows de-risking through competitor activity



The Wedge Play
A geologically defined area in NW Oklahoma that is comprised of six oil-rich stacked reservoirs under current industry development.



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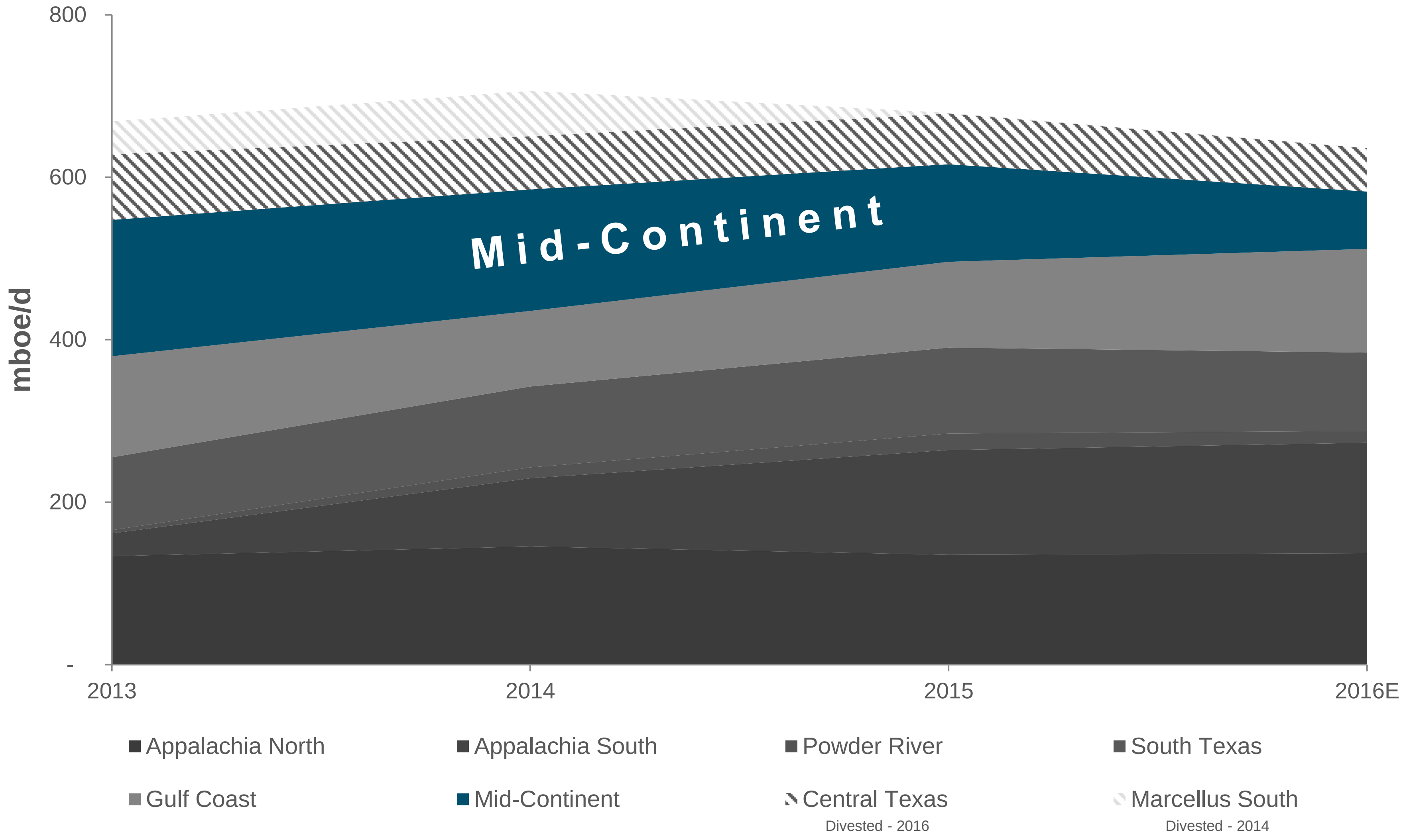
(1) Price deck: $3/mcf for gas and $60/bbl oil flat

APPENDIX

NET EQUIVALENT PRODUCTION

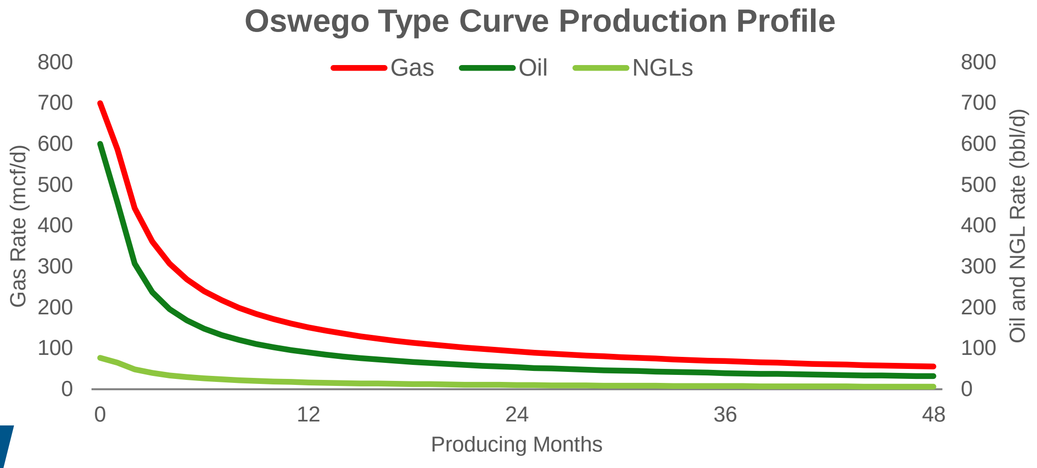
MID-CONTINENT: ~11% TOTAL PRODUCTION 2016E



OSWEGO MODELING INPUTS

Base Production[1]	
3Q'16E Net Production	3 mboe/d
4 Yr. Average Annual Decline[2]	33%

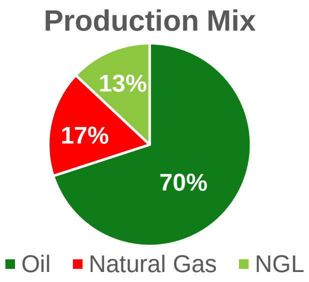
2017 Expenses & Differential Estimates[1]	
Production Expense[3] ($/boe)	$3.80 – $4.20
GP&T[4] ($/boe)	$5.75 – $5.95



2017 – 2020 Blended Development Program

Curve Parameters	
IP[5] (Oil / Gas)	600 bbl/d / 700 mcf/d
Decline (Oil / Gas)	85.5%/79%
B-factor (Oil / Gas)	1.30/1.30
Shrink	85%
NGL Yield	110 bbl/mmcf
EUR	393 mboe
Lateral Length	4,800 ft.

Gross Capex	
Drilling[6] (32 days to TIL)	$1.4mm
Completion (17 days to TIL)	$0.7mm
TIL	$0.9mm
TOTAL	***$3.0mm***



Interest / Gross Locations	
WI / NRI[7]	53%/42%
Producing	15
DUCs	2
Undrilled[8]	300
Rig Count	1 – 2

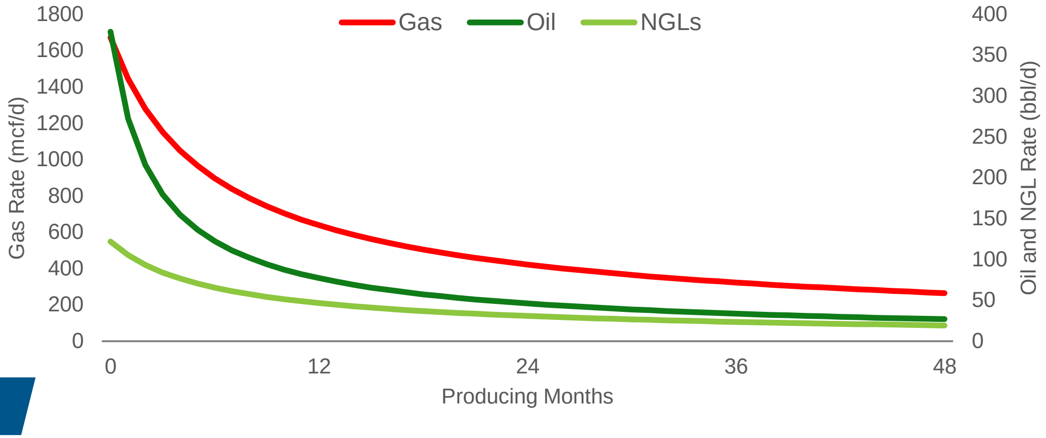
(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 10 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020

WEDGE AND MISS LIME MODELING INPUTS

Base Production[1]	
3Q'16E Net Production	52 mboe/d
4 Yr. Average Annual Decline[2]	13%

2017 Expenses & Differential Estimates[1]	
Production Expense[3] ($/boe)	$6.75 – $7.35
GP&T[4] ($/boe)	$5.75 – $5.95

The Wedge Type Curve Production Profile



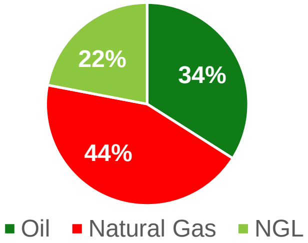
2017 – 2020 Blended Development Program

Curve Parameters	
IP[5] (Oil / Gas)	380 bbl/d / 1.7 mmcf/d
Decline (Oil / Gas)	83%/64%
B-factor (Oil / Gas)	1.20/1.30
Shrink	87%
NGL Yield	72 bbl/mmcf
EUR	658 mboe
Lateral Length	5,400 ft.

Gross Capex	
Drilling[6] (41 days to TIL)	$2.0mm
Completion (18 days to TIL)	$1.3mm
TIL	$0.6mm
TOTAL	***$3.9mm***

Interest / Gross Locations	
WI / NRI[7]	61%/49%
Producing	3,485
DUCs	45
Undrilled[8]	2,900
Rig Count	3 – 10

Production Mix



(1) Applies to total asset inclusive of non-operated
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(3) Reflects net asset level production expense including LOE, overhead and Ad Val
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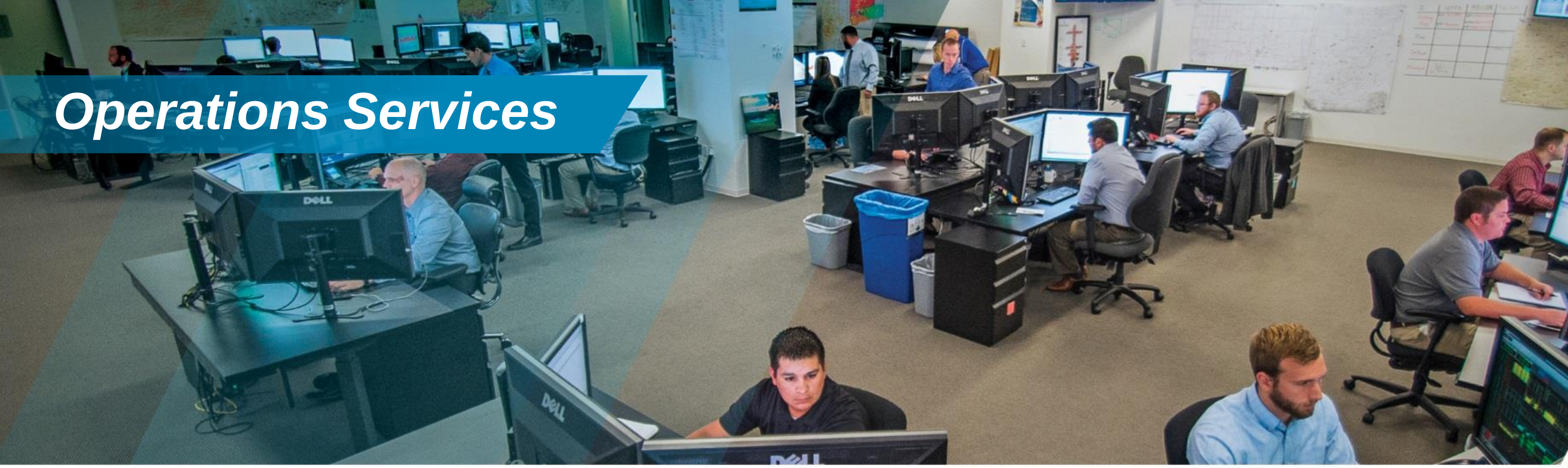
(5) 30 day average IP
(6) 18 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020

Operations and Technical Services

JASON PIGOTT



Operations Services

Drilling

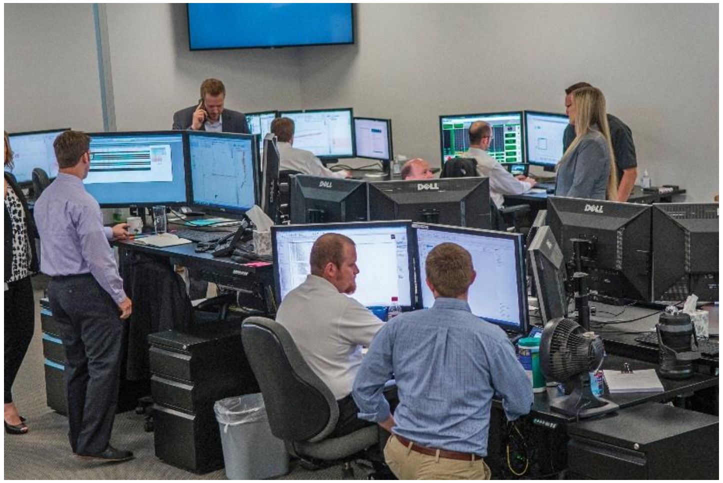
Completions

Chesapeake
ENERGY

CHESAPEAKE'S COMPETITIVE ADVANTAGE

Industry-Leading Operations Support

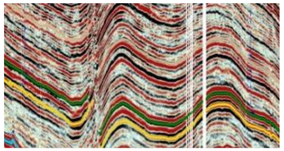
- 24x7 real-time monitoring
- Advanced processing technology
  - High-volume, high-variety, high-velocity data analytics
- Collaborative environment
  - Engineering, geology and technology expertise



Superior Well Data

120mm ft.
Drilled

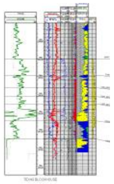
70 trillion
Sensor data points



96,000 square mi.
3D seismic

26,000
Producing wells

65,000 ft.
Analyzed core



2.5mm
Well logs

150mm
GPS readings

BETTER PLANNING REDUCES TROUBLE TIME

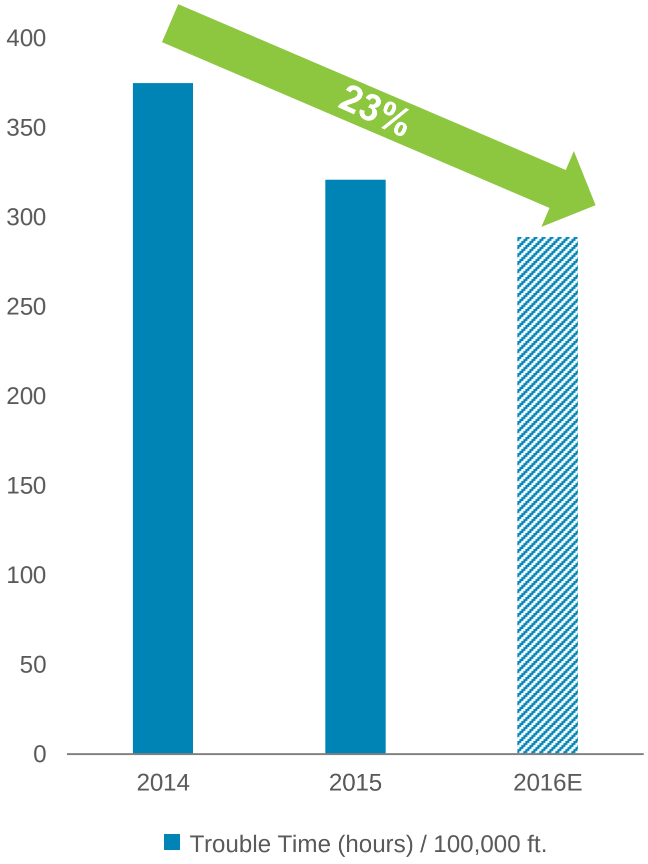
- Better well planning and continuous monitoring dramatically reduce trouble time
- Well road maps predict problems before they happen
- Collaborative culture improves response time when unanticipated challenges occur

~116 days per year

Efficiency gain

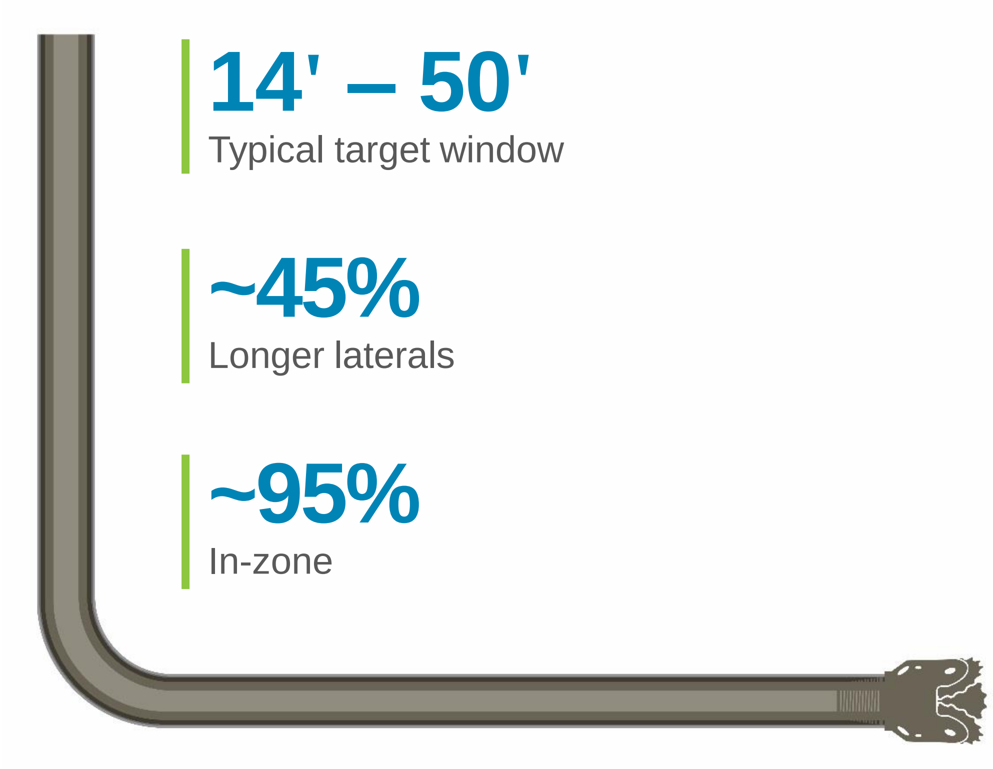
$14mm

Incremental value generated in 2016E



MAINTAINING TARGET ACCURACY IN LONGER LATERALS

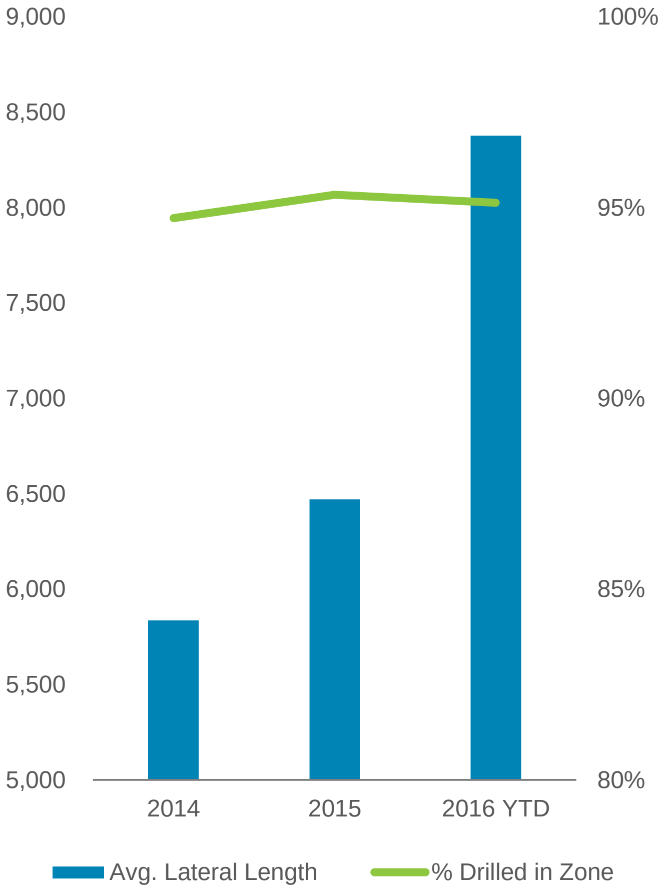
- Continuous monitoring maintains targeting accuracy
- Minimizes impact on well recovery when drilling longer laterals



14' – 50'
Typical target window

~45%
Longer laterals

~95%
In-zone



Operations Services

Drilling

Completions

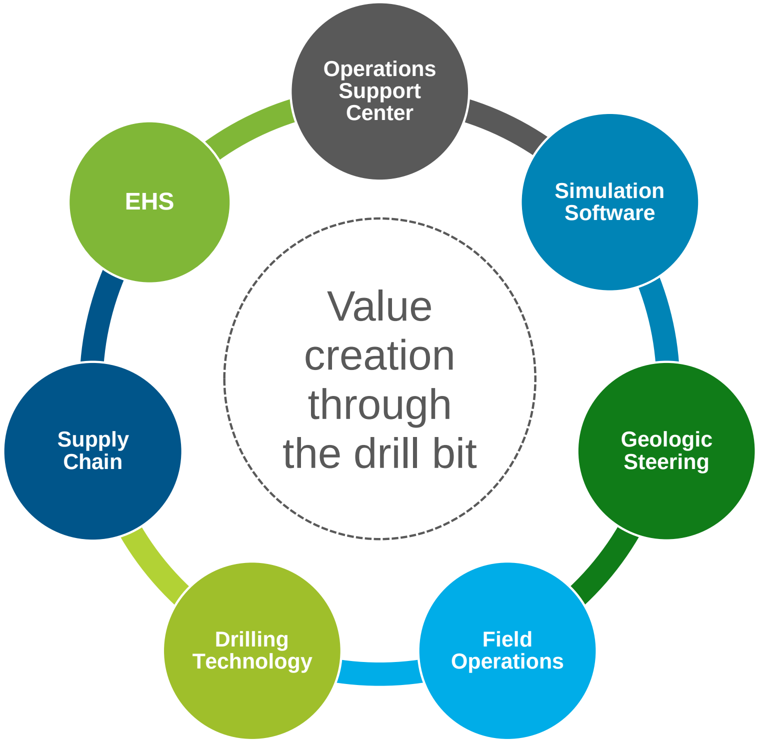
Chesapeake
ENERGY

CHESAPEAKE DRILLING

PREDICTABLE, REPEATABLE, PERFORMANCE LEADER

The Chesapeake Drilling Advantage

- Extensive extra-long-lateral experience
- State-of-the-art real-time operations center
- Repeatable and sustained performance
- Industry-leading health and safety record



Operations Support Center

Simulation Software

Geologic Steering

Field Operations

Drilling Technology

Supply Chain

EHS

Value creation through the drill bit

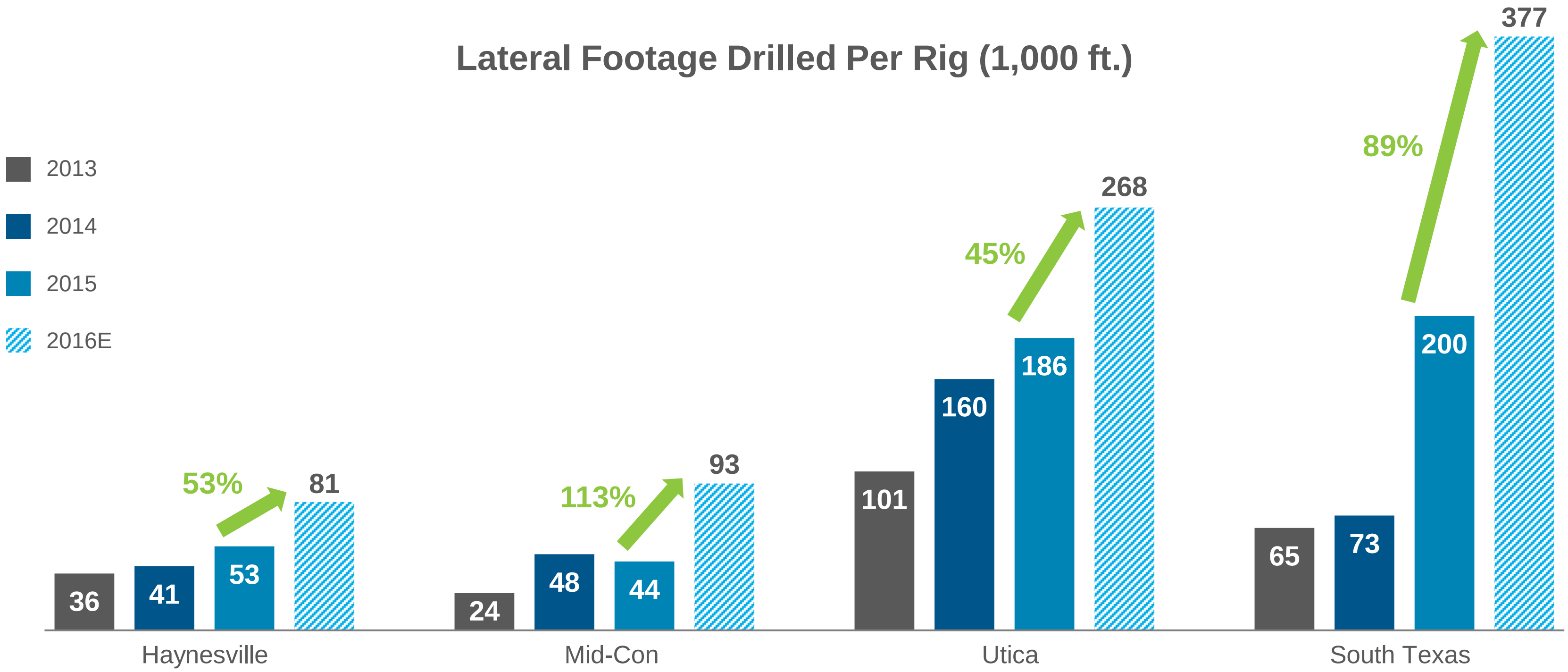
CHK drilled around the world – footage drilled in the last 10 years

Leading horizontal driller worldwide

>11,000 wells drilled

DRILLING COMPETITIVE ADVANTAGES

10 RIGS IS THE NEW 35 RIGS AT CHESAPEAKE



Drilled more lateral footage in first nine months of 2016 than all of 2015

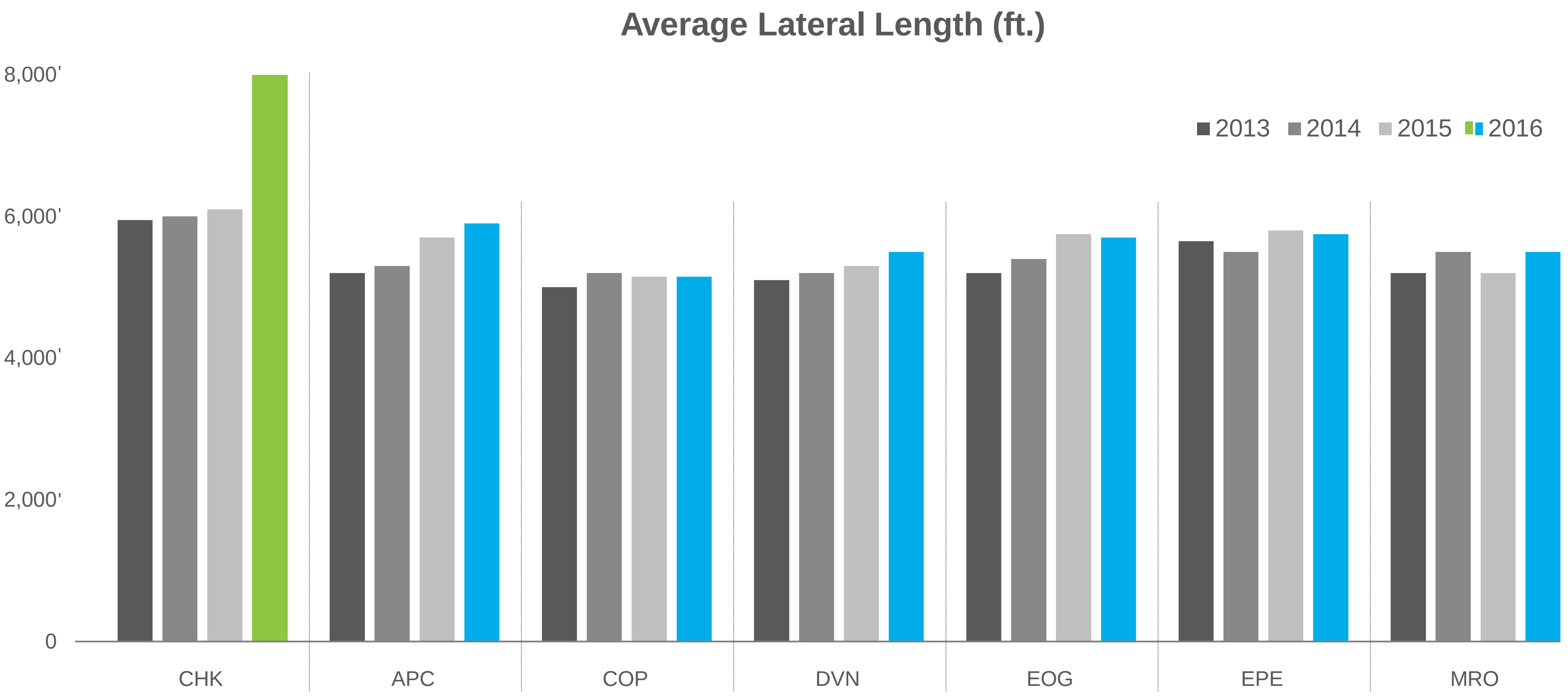
- *Maximize capital efficiency*
- *Less capital intensity*
- *Smaller surface footprint*

45% – 113% gain

In lateral footage drilled per rig

EAGLE FORD SHIFT TO LONGER LATERALS

A CRUCIAL VALUE-CREATION DECISION



Source: Bloomberg, September 2016

Operations Services

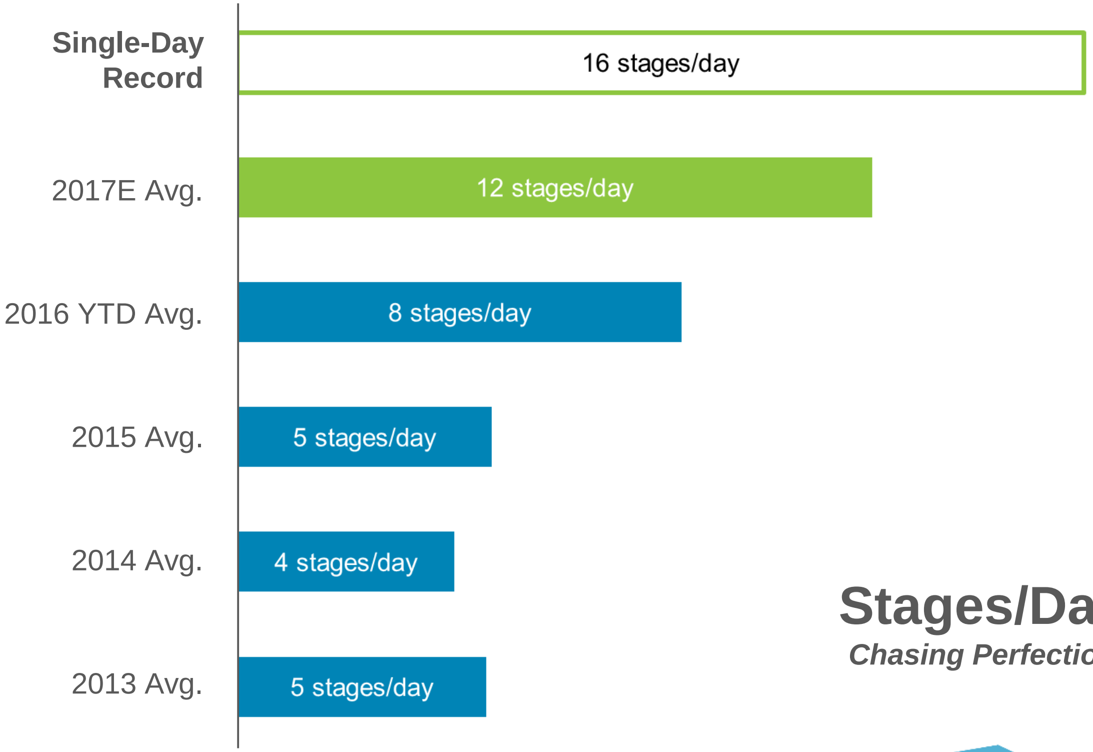
Drilling

Completions

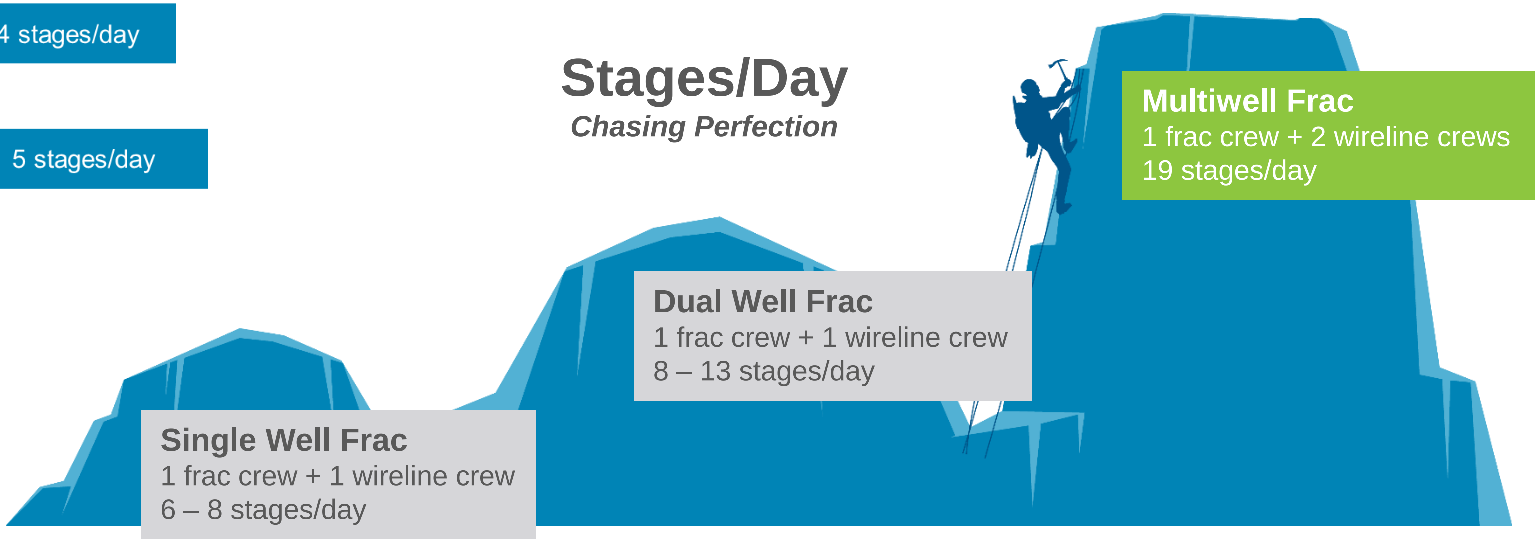
Chesapeake ENERGY

SUPERIOR OPERATIONAL EFFICIENCIES

EAGLE FORD SHALE



Continuing to break efficiency records



Stages/Day

Chasing Perfection

Single Well Frac
1 frac crew + 1 wireline crew
6 – 8 stages/day

Dual Well Frac
1 frac crew + 1 wireline crew
8 – 13 stages/day

Multiwell Frac
1 frac crew + 2 wireline crews
19 stages/day

HAYNESVILLE COMPLETION OPTIMIZATION

IT'S A WHOLE NEW BALL GAME

Vintage
≥1,500 lbs./ft.
Pre 2012

Modern
≥1,750 lbs./ft.
2015

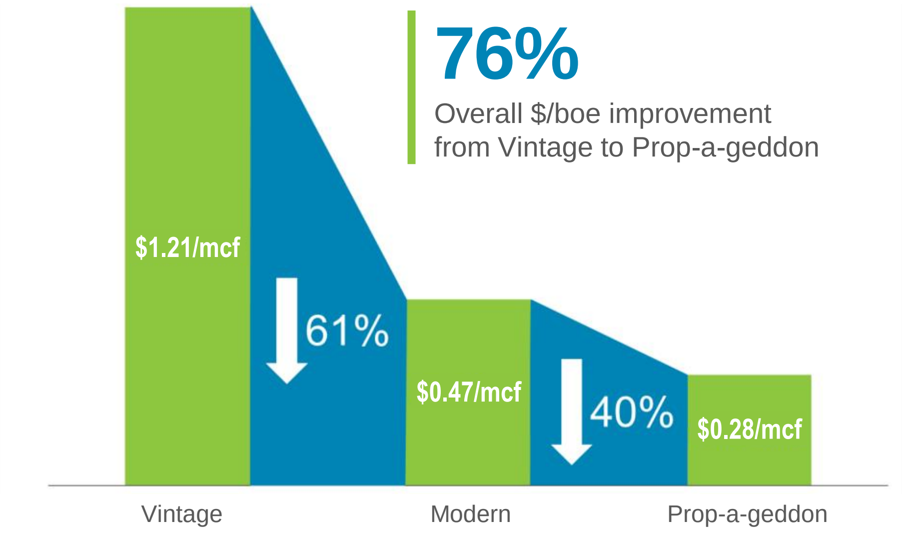
Prop-a-geddon
≥3,000 lbs./ft.
Current

More Productivity for Your Dollar

Gross Completions Capital / Gross EUR

76%

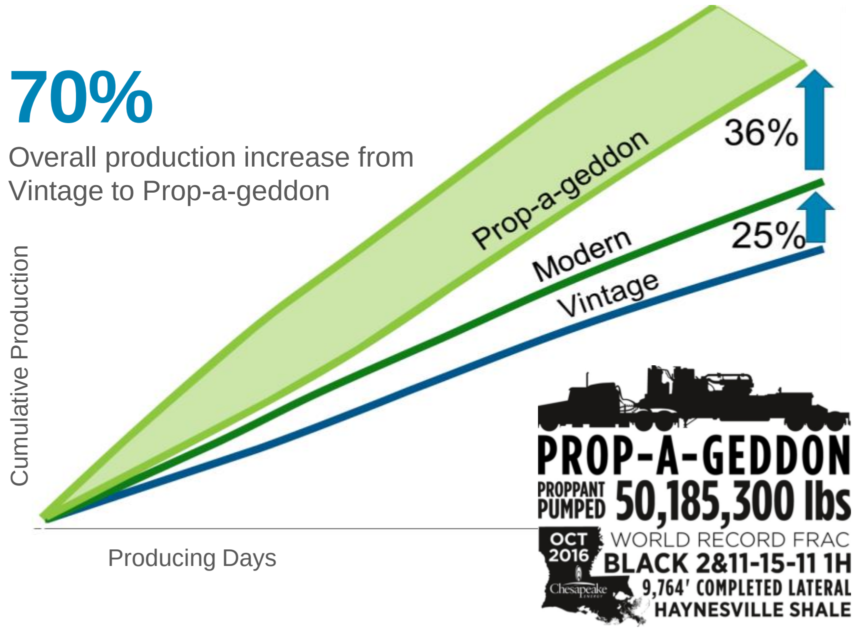
Overall $/boe improvement from Vintage to Prop-a-geddon



Proven Results from Optimization

70%

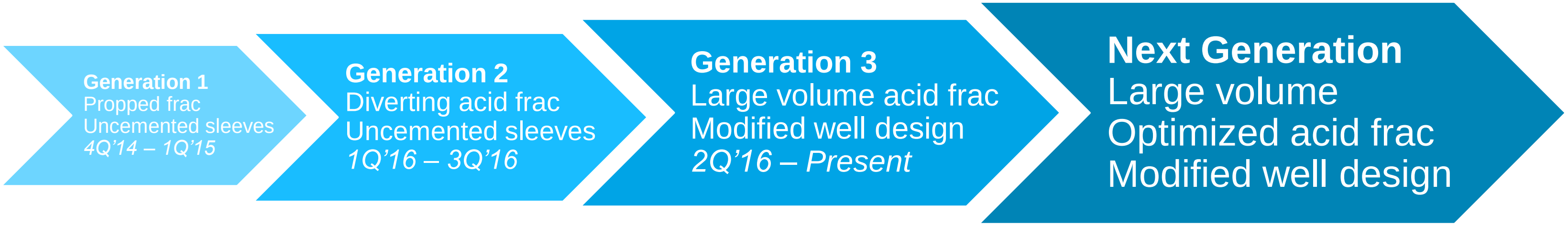
Overall production increase from Vintage to Prop-a-geddon



Unlocking additional opportunities and expanding the core with completion technology

OSWEGO COMPLETION OPTIMIZATION

MORE SAND ISN'T ALWAYS THE ANSWER



Generation 1
Propped frac
Uncemented sleeves
4Q'14 – 1Q'15

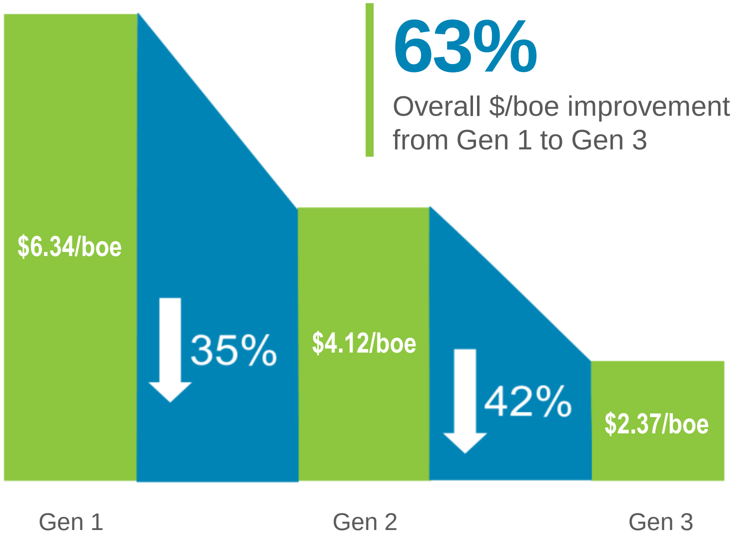
Generation 2
Diverting acid frac
Uncemented sleeves
1Q'16 – 3Q'16

Generation 3
Large volume acid frac
Modified well design
2Q'16 – Present

Next Generation
Large volume
Optimized acid frac
Modified well design

Transformative Capital Efficiency

Gross Completions Capital / Gross EUR



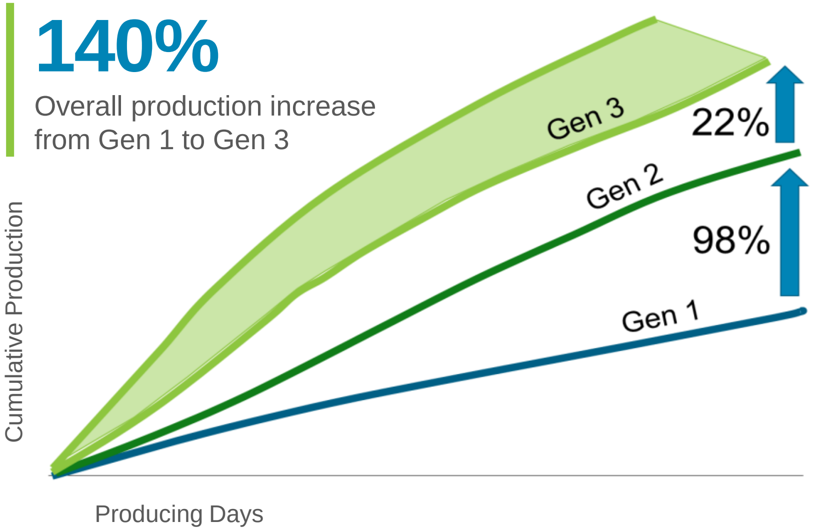
63%

Overall $/boe improvement from Gen 1 to Gen 3

Dramatic Performance Improvement

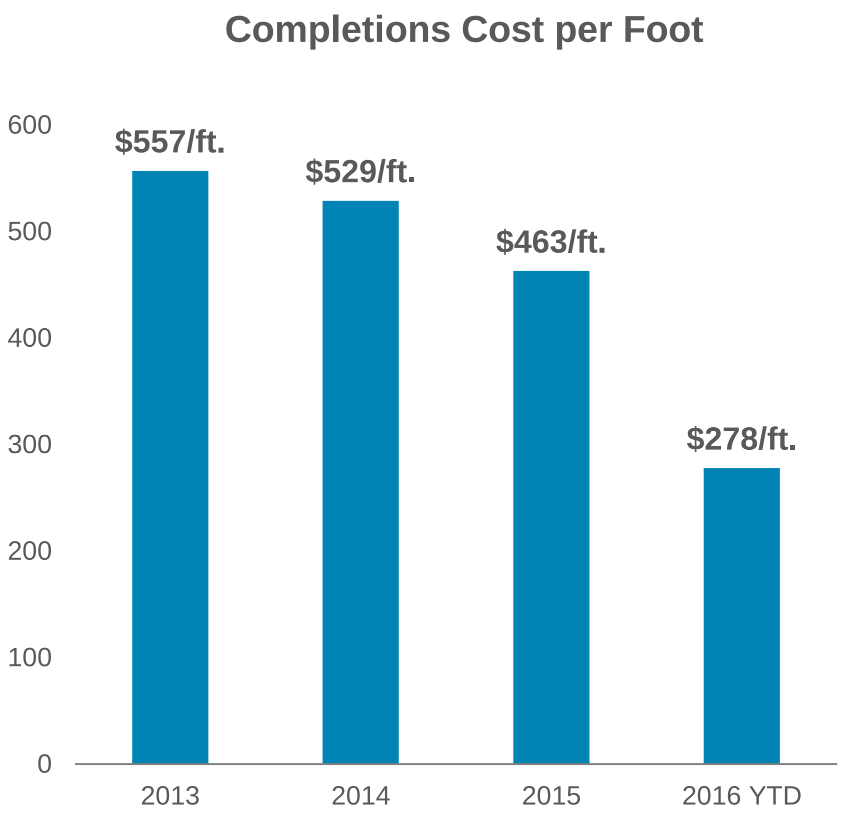
140%

Overall production increase from Gen 1 to Gen 3



Optimizing completion design adds significant value

PROVEN RESULTS LEAD TO HUGE SUCCESS



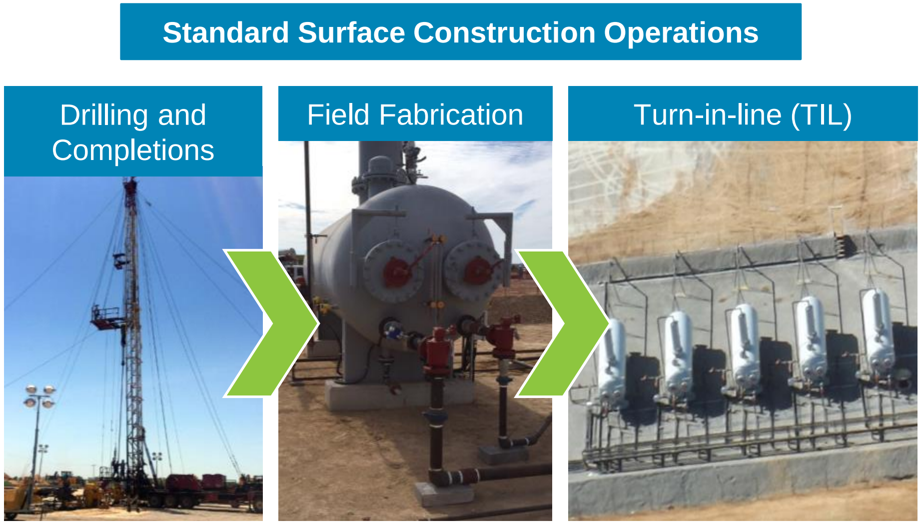
~$1.8 billion saved

Total gross cost savings since 2013

50% reduction

In completion cost per foot since 2013

DELIVERING VALUE THROUGH STANDARDIZATION, PLANNING AND DESIGN

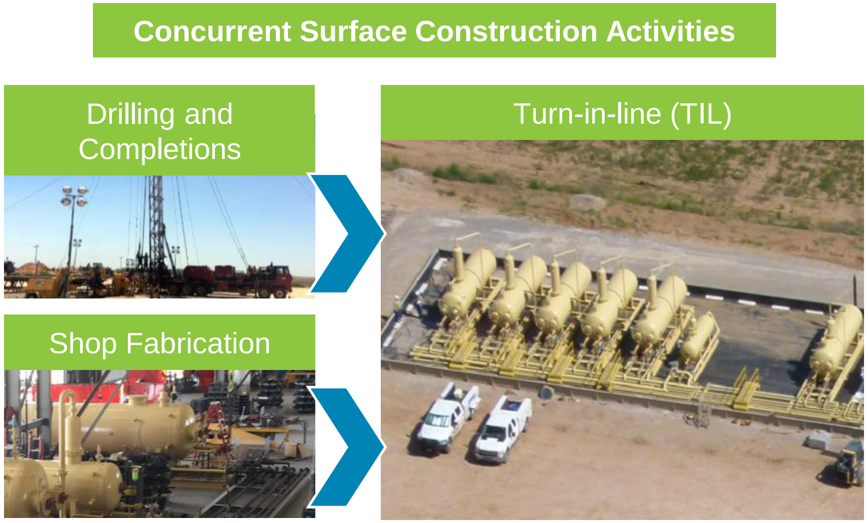


Standard Surface Construction Operations

Drilling and Completions

Field Fabrication

Turn-in-line (TIL)



Concurrent Surface Construction Activities

Drilling and Completions

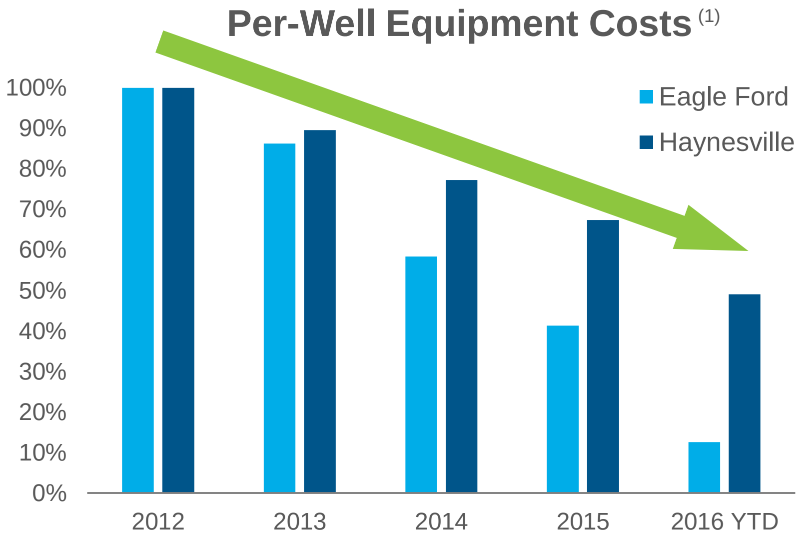
Shop Fabrication

Turn-in-line (TIL)

- Decreasing construction costs
- Reducing cycle time
- Improving quality
- Driving continuous improvement

50% – 80% reduction

In equipment costs



Per-Well Equipment Costs (1)

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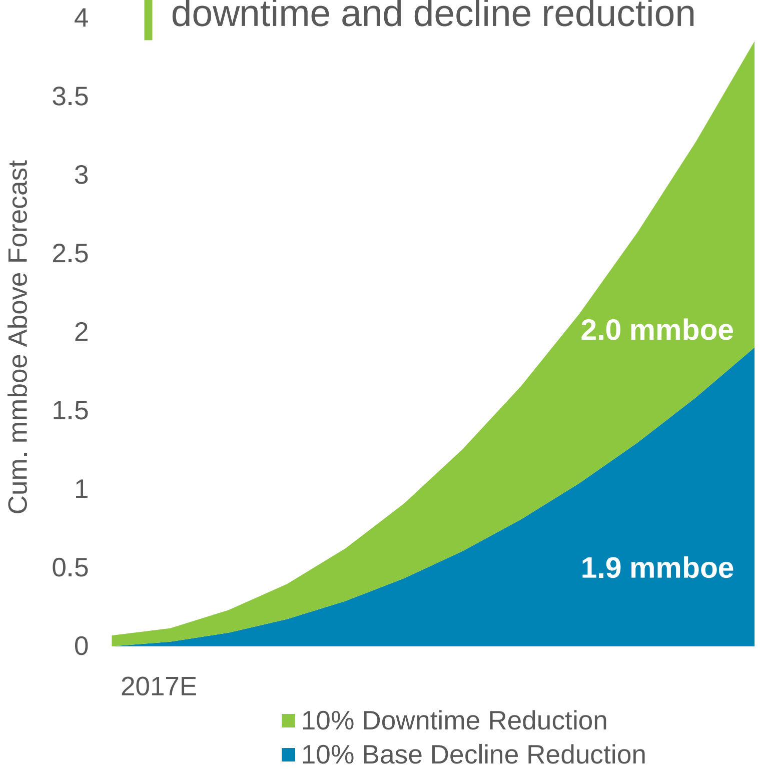
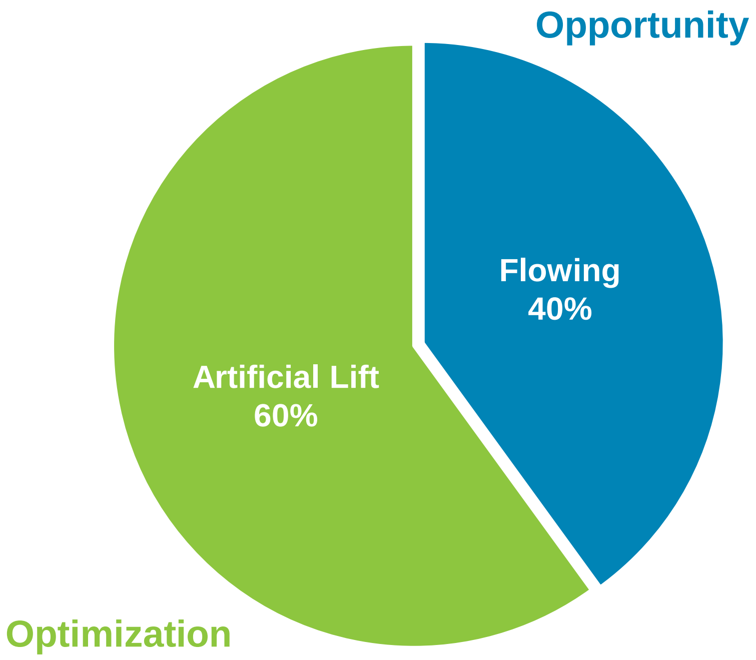
(1) Base year 2012 equipment costs of $727,000 for Eagle Ford and $365,000 for Haynesville

BASE OPTIMIZATION

3.9 mmboe

Potential uplift in 2017 from downtime and decline reduction

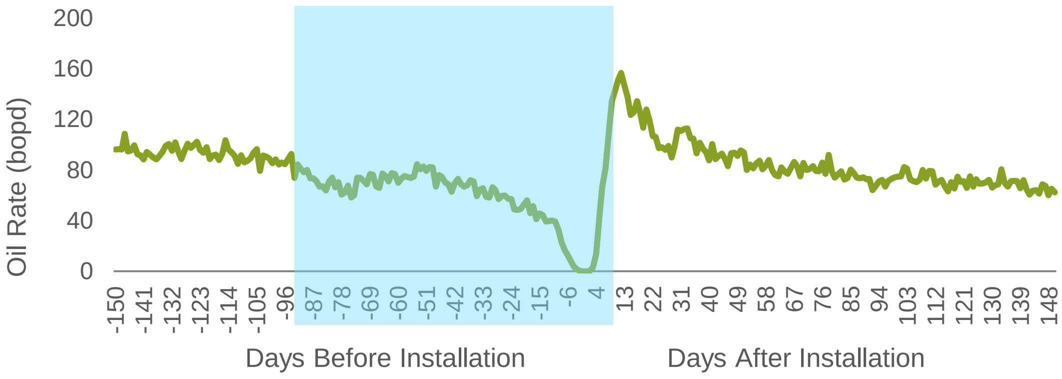


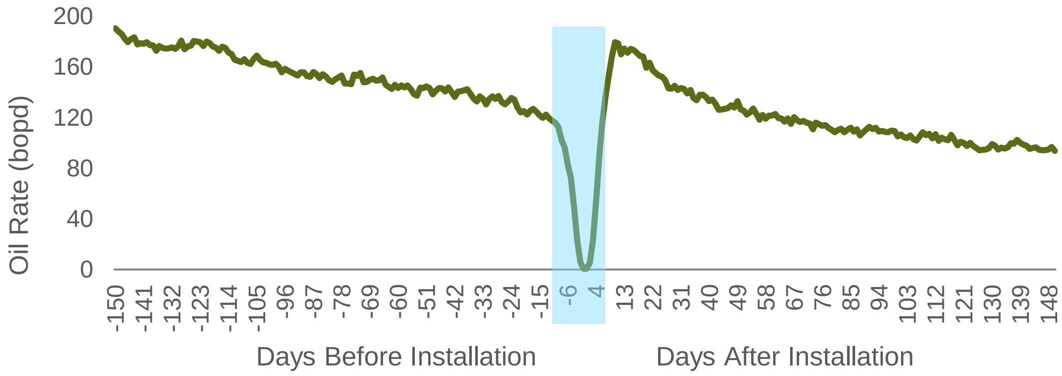


EAGLE FORD ARTIFICIAL LIFT INSTALLS

Proactive artificial lift program

- Anticipates well needs
- Reduces suboptimal performance
- Reduces downtime
- Improves supply chain efficiencies


Legacy Approach


Proactive Approach

Proactive well set begins January 2014

SOUTH TEXAS:

Operational Excellence, Positioned for Growth

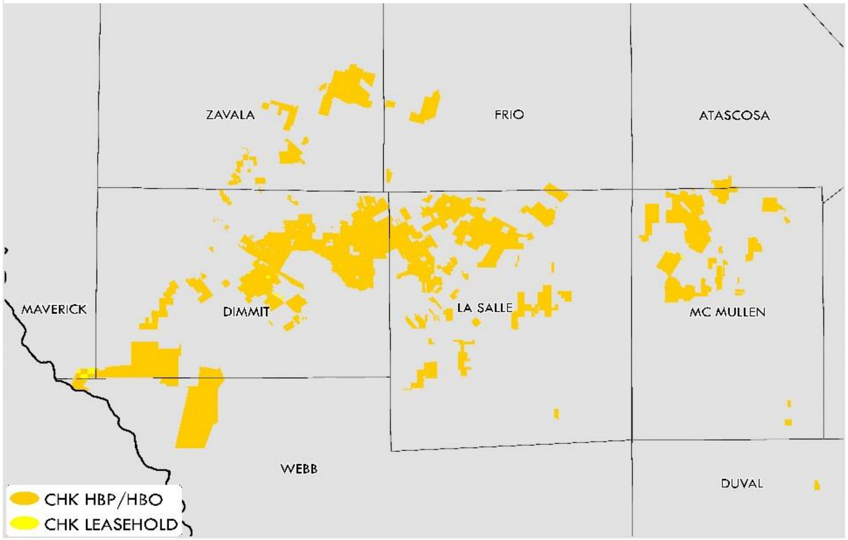
JASON PIGOTT

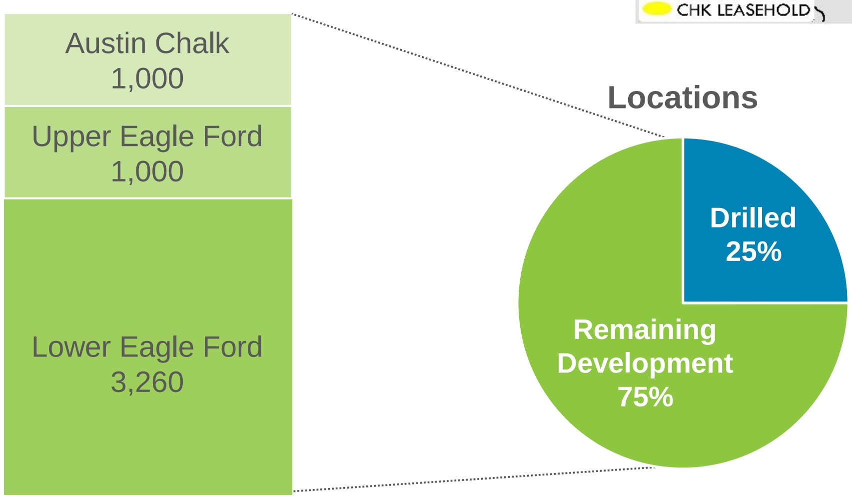
SOUTH TEXAS ASSET OVERVIEW

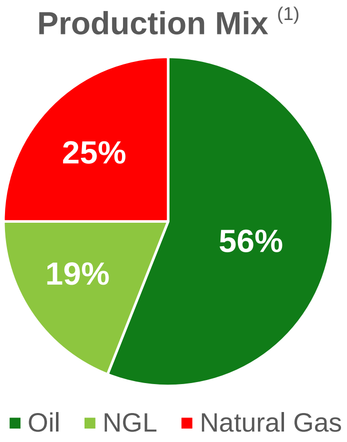
UNDRILLED ACREAGE, POSITIONED FOR GROWTH

- Secure acreage position
- Best-in-class operations
- Extended laterals are working
- Broad investment portfolio

~270,000 Net Acres in Eagle Ford – 99% HBP/ HBO







(1) Net processed production mix

SOUTH TEXAS EXTENDED LATERALS

DRIVING CHESAPEAKE'S COMPETITIVE COST ADVANTAGE

63% reduction

In development cost per foot with 79% increase in drilled lateral

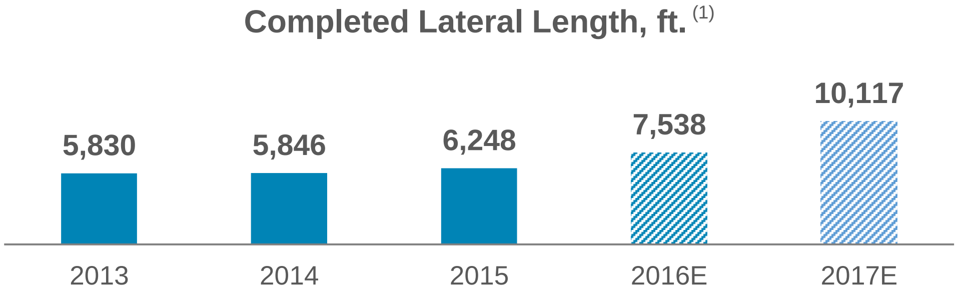
Retain 65%

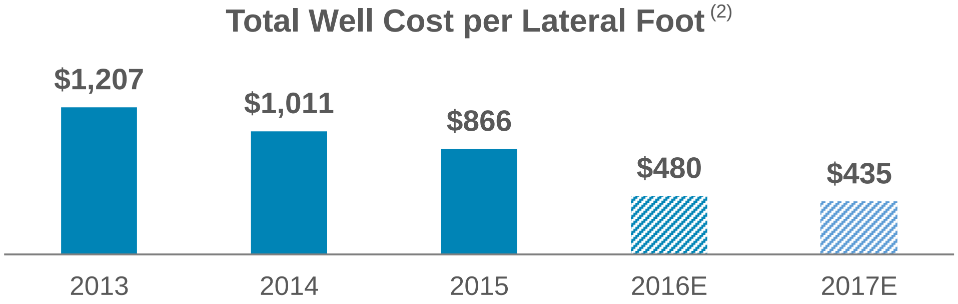
Cost savings captured from efficiencies, not market reductions

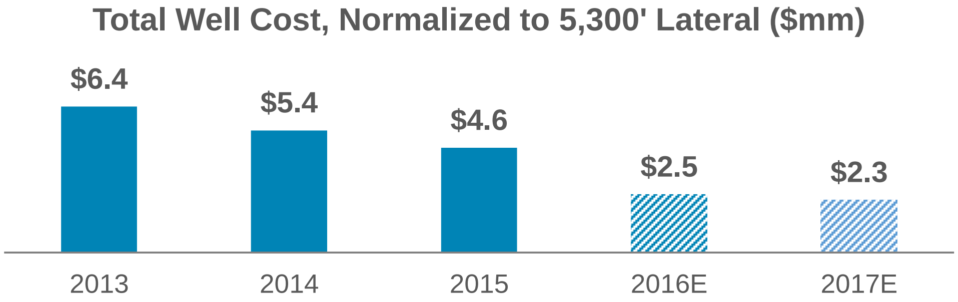
Extended laterals today

Outperform

At $50 oil vs. 2014 program at $80 oil


Completed Lateral Length, ft. (1)


Total Well Cost per Lateral Foot (2)


Total Well Cost, Normalized to 5,300' Lateral ($mm)

---

(1) Completed lateral length based on frac date; includes 142 DUC locations with an average of 7,089 feet

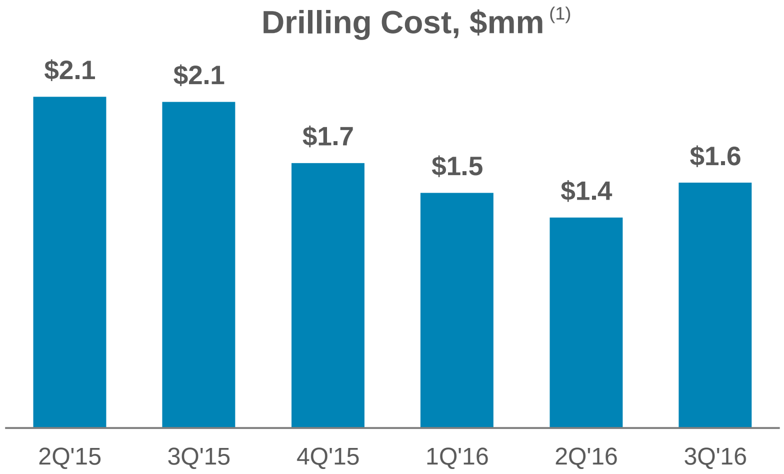
(2) Average cost per foot of wells drilled and/or completed within the time period.

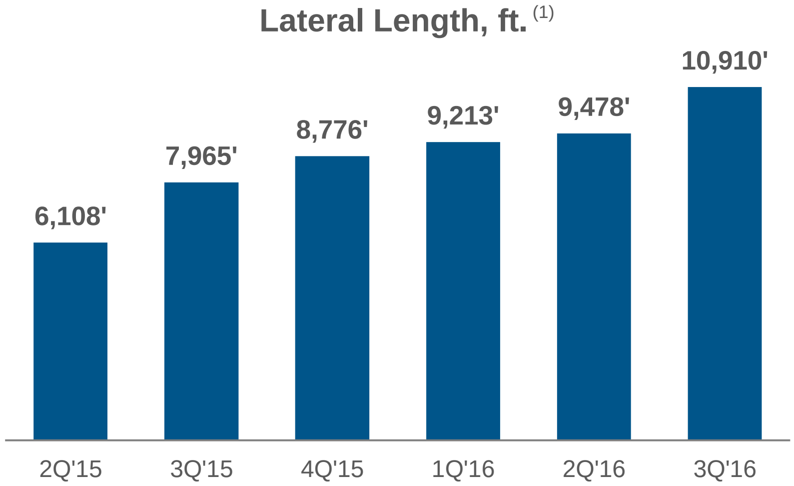
DRILLING PERFORMANCE

RELENTLESSLY PURSUING EXCELLENCE

2016 Performance Records

- Eight days spud to rig release – for 17,446' total well depth
- 5,837' – 24-hour footage record
- $65/ft. drilling cost – lowest monthly average
- 14,289' – single-well record lateral length





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(1) Drilled lateral length and drilling cost based on spud date

COMPLETION PERFORMANCE

RELENTLESSLY PURSUING EXCELLENCE

2016 Performance Records

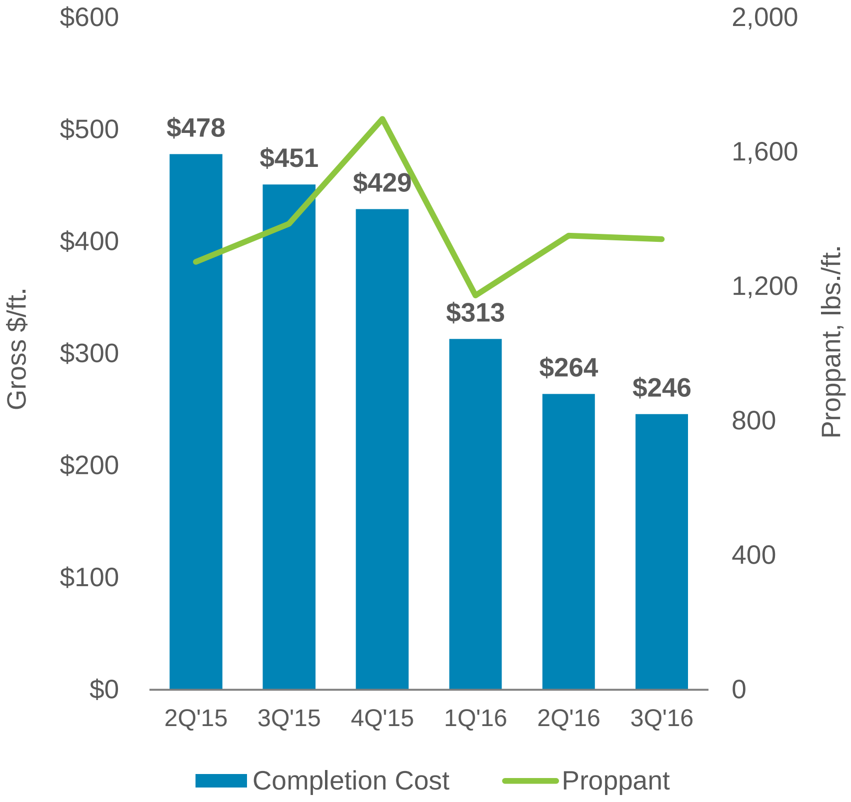
- 16 stages completed in a single day
- 284 stages in one month with one crew
- 757 stages in a single quarter with one crew

2016 Testing Focus

- Reinvesting $12mm into 38 completions tests YTD
- Applying optimal completion design from test results to deliver incremental value

49% reduction

In cost per lateral foot without sacrificing well performance

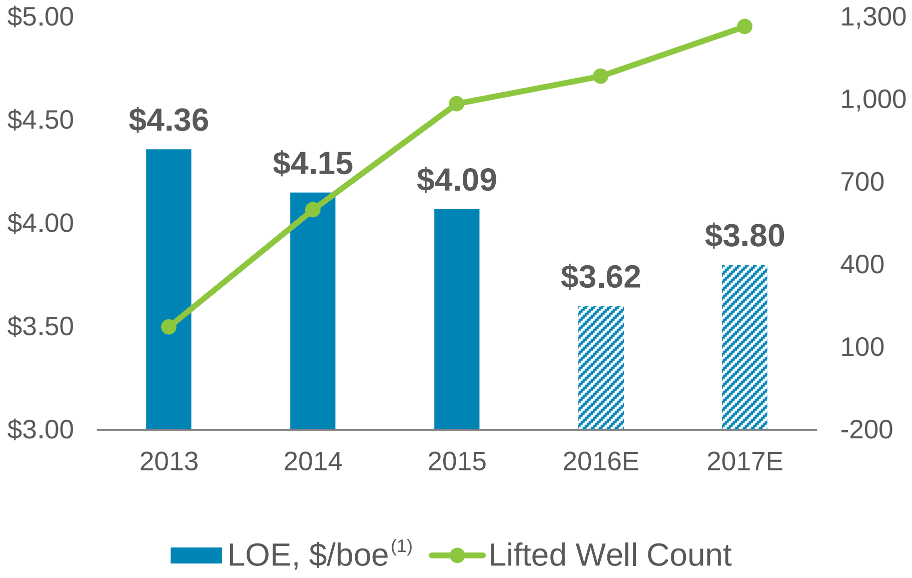


CONTINUOUS FOCUS ON REDUCING LOE

LOW-COST LEADER

17% reduction in LOE

Lifted well count increase
5X since 2013



Basin LOE Pacesetter, $/boe (2)

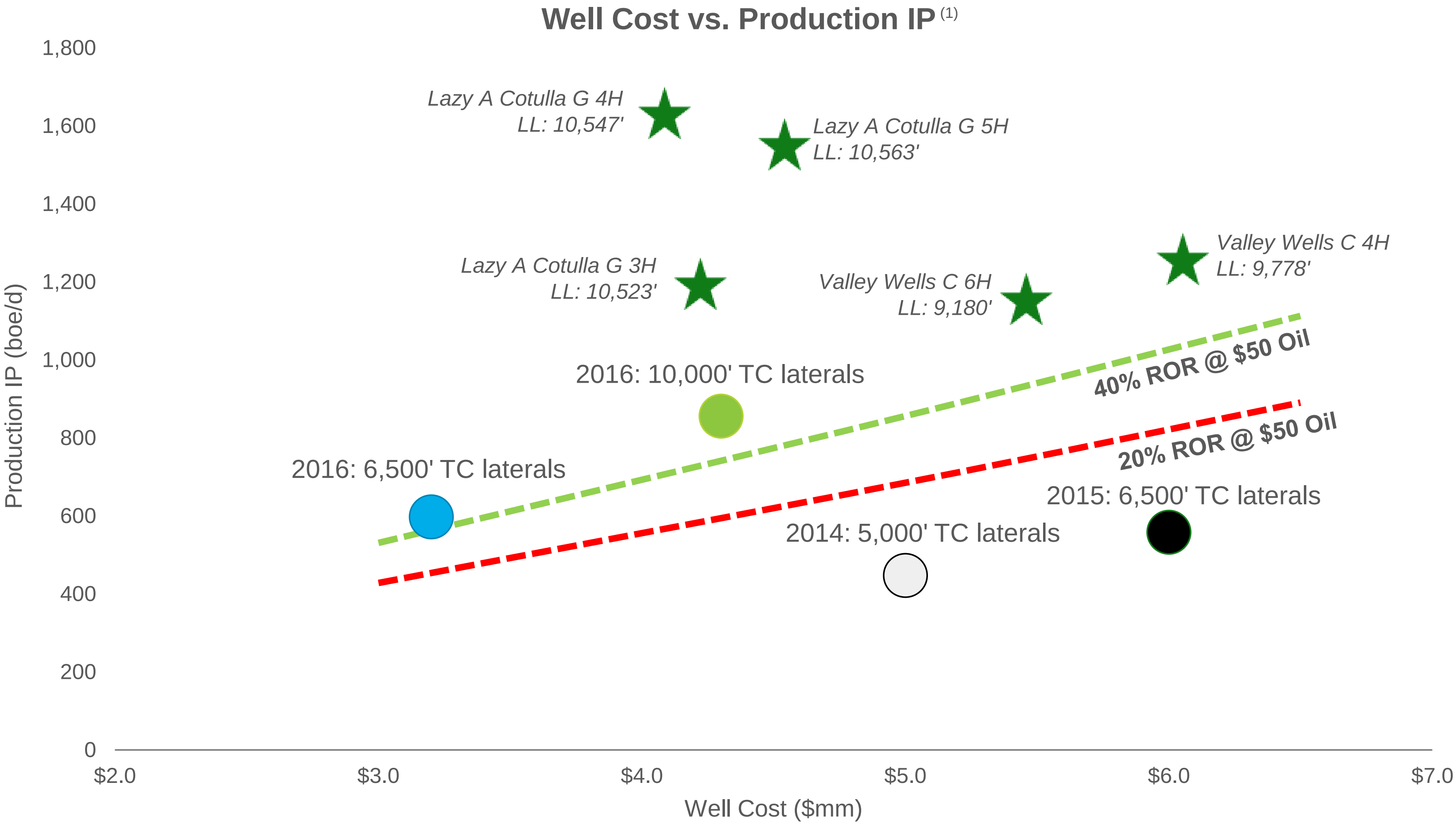
40% below

Average peer group LOE

(1) Data represents operated net lease production expenses excluding Ad Valorem taxes / net equivalent volume
(2) Peer group includes CRZO, DVN, EOG, MRO and MUR, data is sourced from public data bases and IR materials

TRANSFORMING THE LOWER EAGLE FORD

EXTENDED LATERALS UNLOCK VALUE IN LOW PRICE ENVIRONMENT



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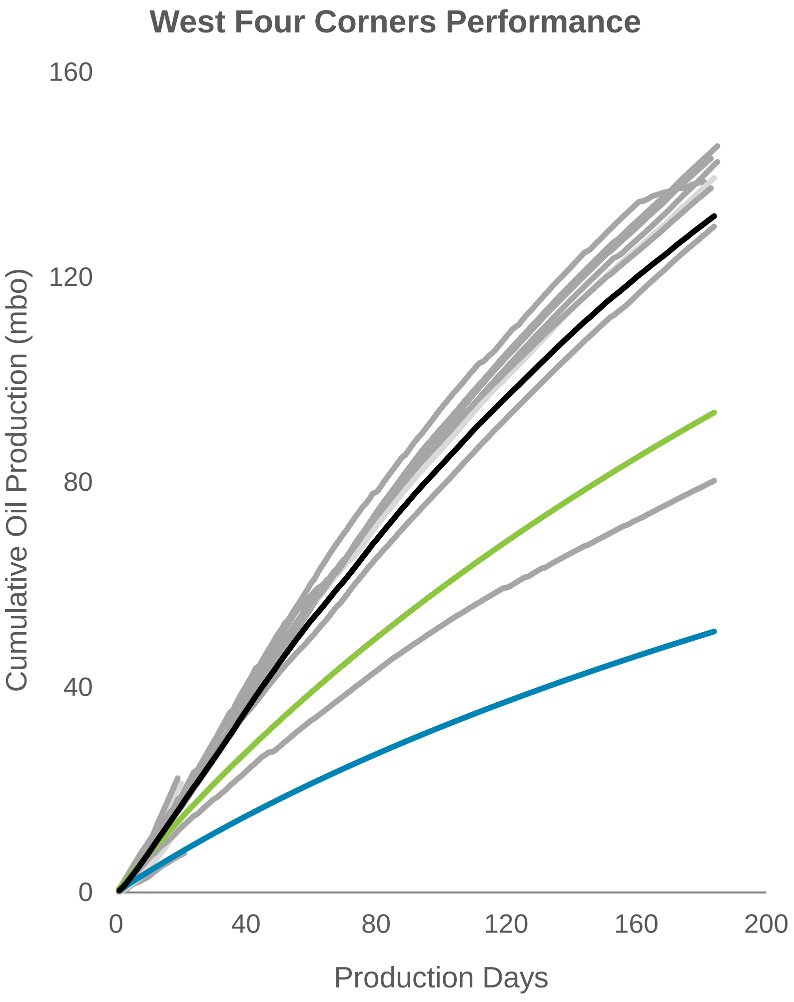
(1) Assumes $3/mcf gas price flat

ACCELERATING VALUE USING EXTENDED LATERALS

CURRENT RESULTS BEATING TYPE CURVE EXPECTATIONS

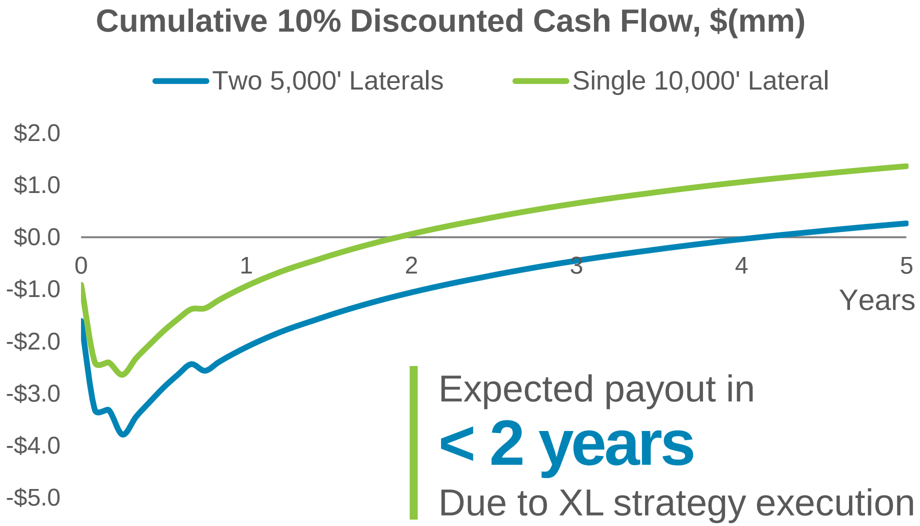


Beating the type curve

11 of 13 extended lateral wells are outperforming the type curve

Value acceleration

Extended laterals provide 2-for-1 NPV



Expected payout in

< 2 years

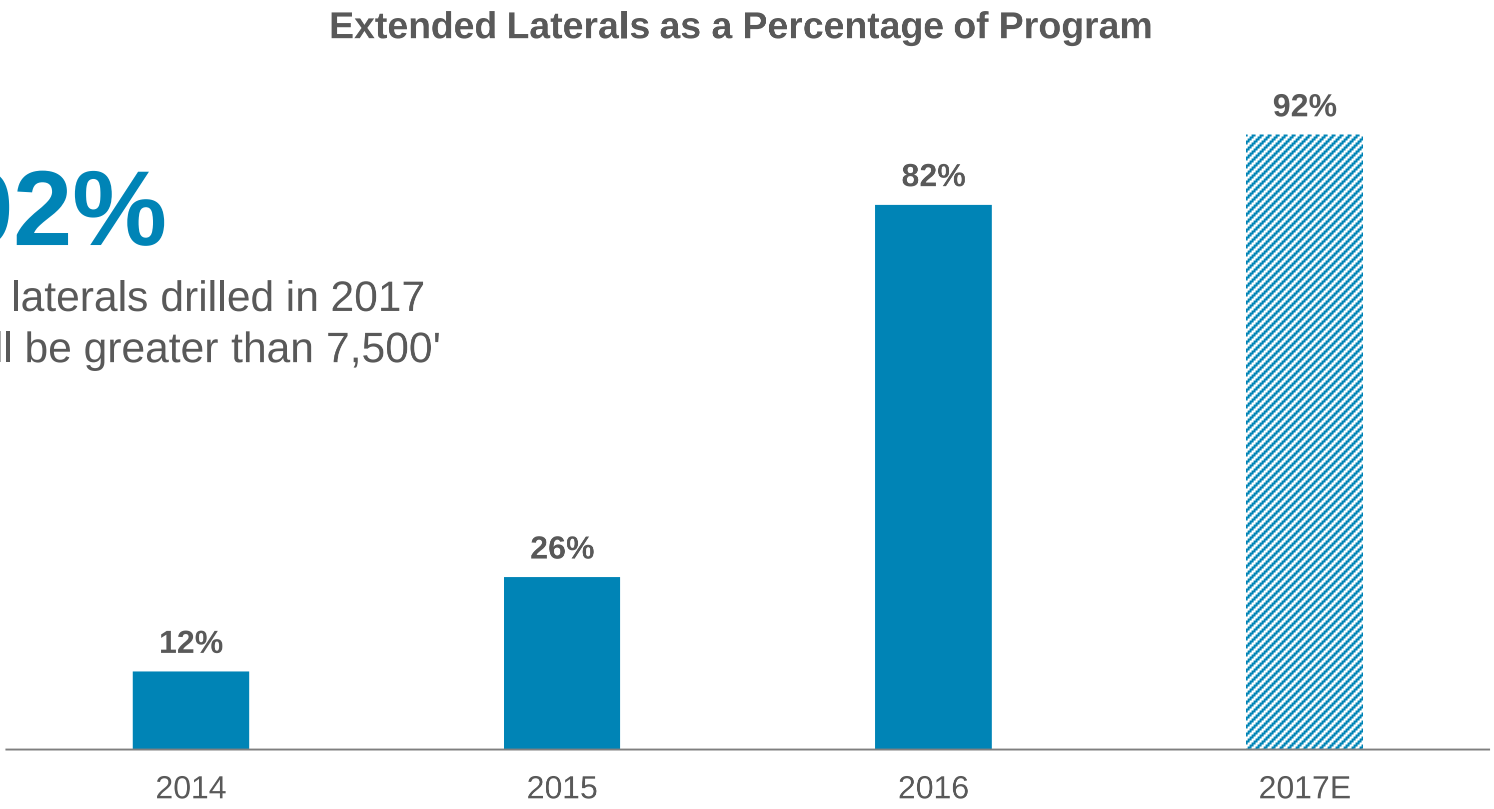
Due to XL strategy execution

SOUTH TEXAS LATERAL LENGTH EVOLUTION

COMMITTED TO THE STRATEGY

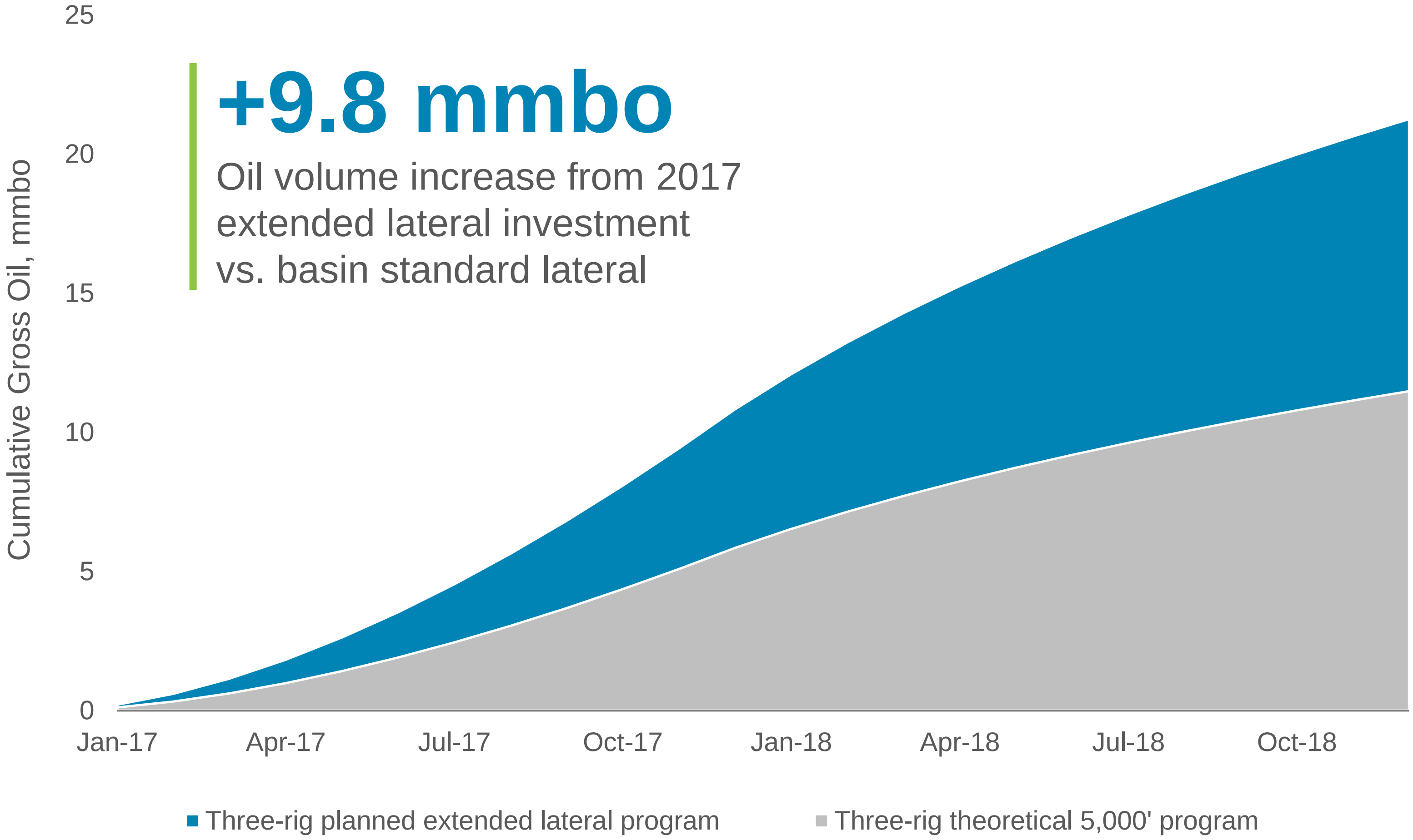
92%

Of laterals drilled in 2017 will be greater than 7,500'



SOUTH TEXAS EXTENDED LATERAL PROGRAM

IMPACT ON 2017 WEDGE PRODUCTION



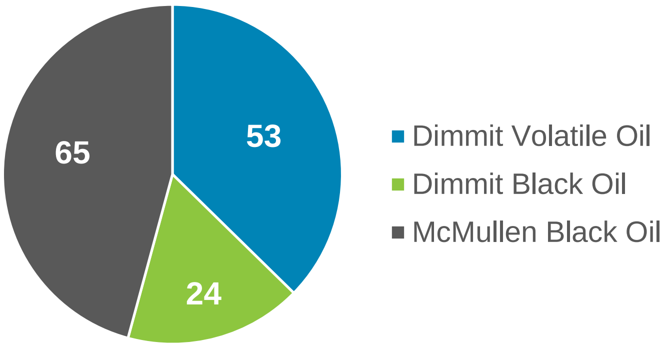
+9.8 mmbo

Oil volume increase from 2017 extended lateral investment vs. basin standard lateral

2016 DUC PROGRAM

FRAC-A-PALOOZA

Well Count and Location



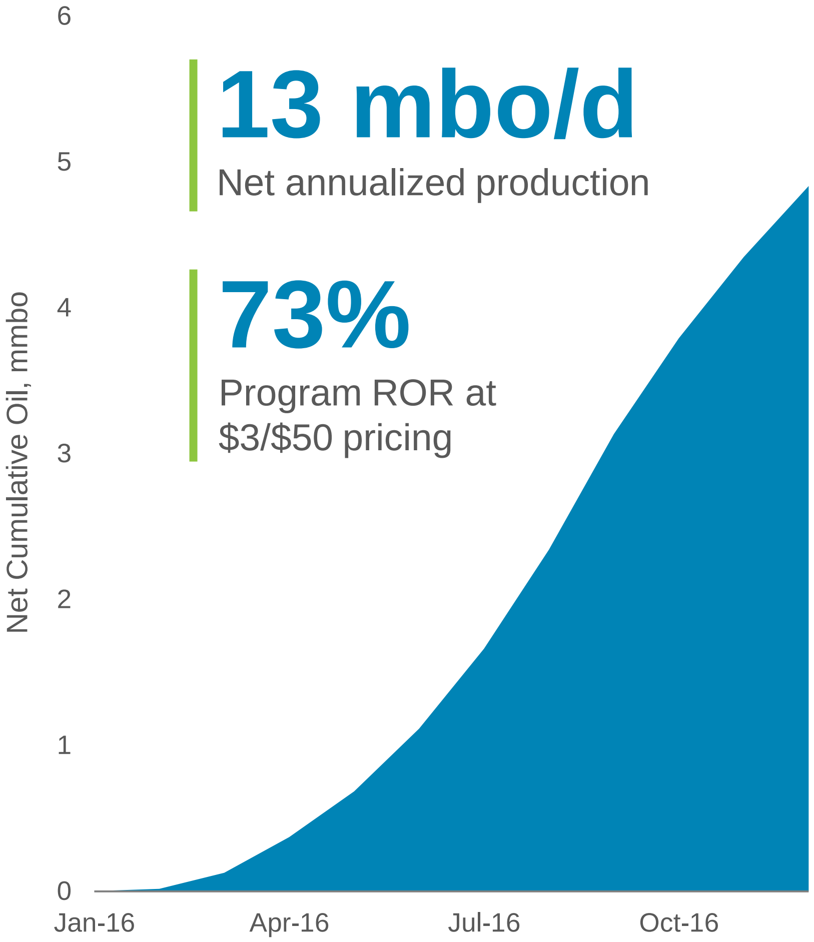
142 wells

Completed and turned in line in 2016

1 million

Feet of lateral treated

Program Impact



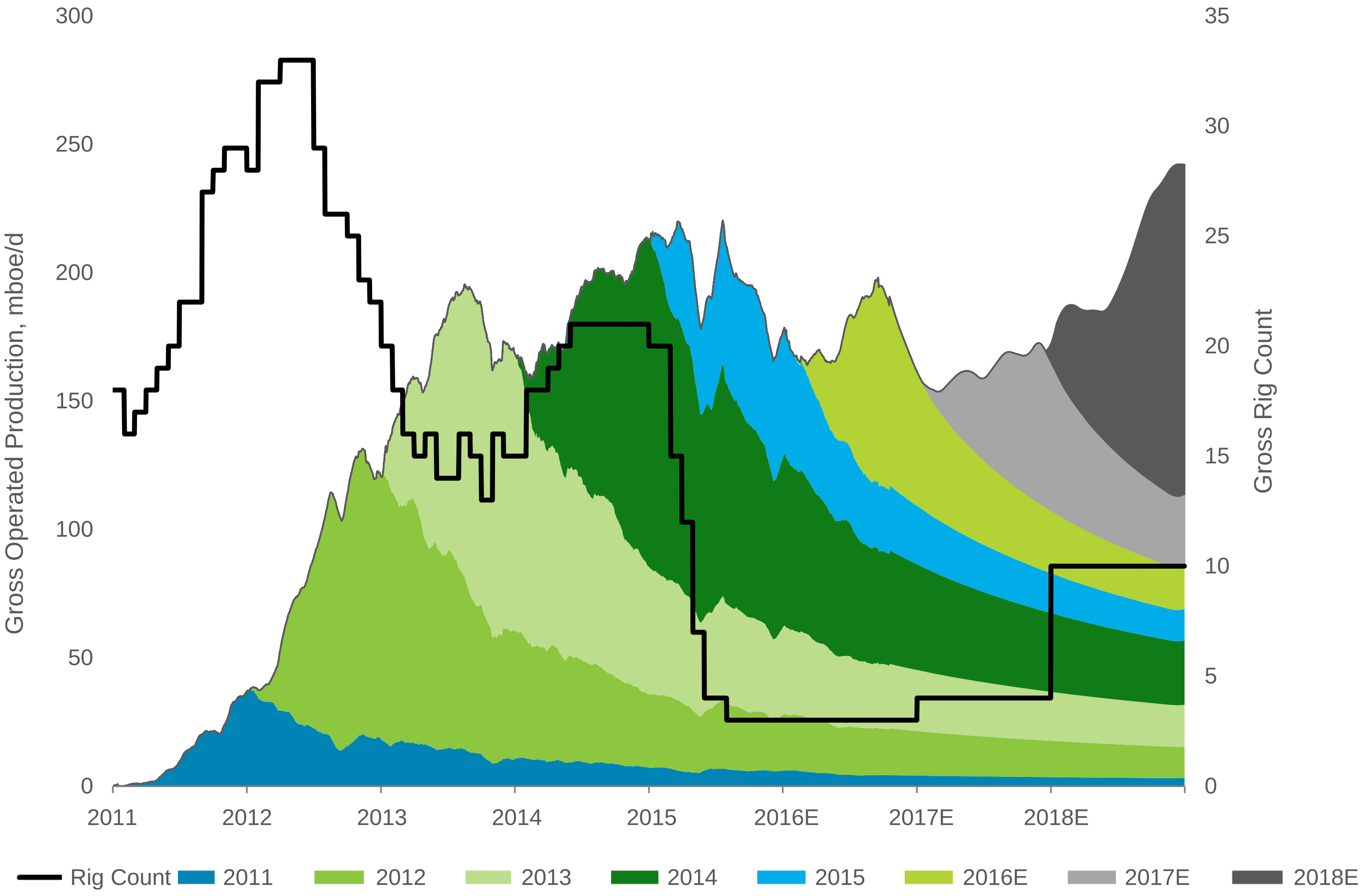
13 mbo/d

Net annualized production

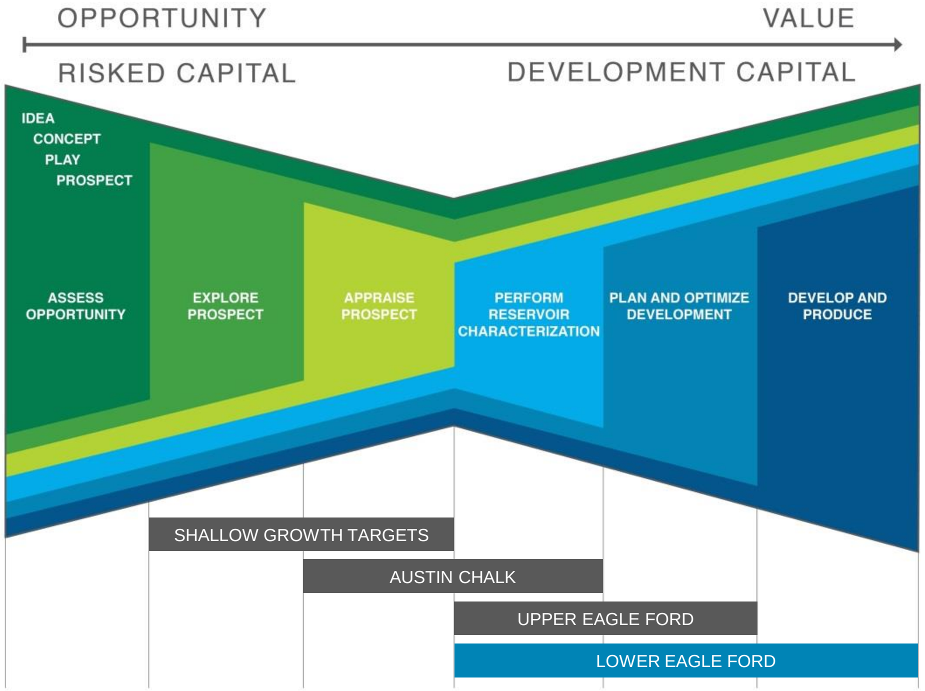
73%

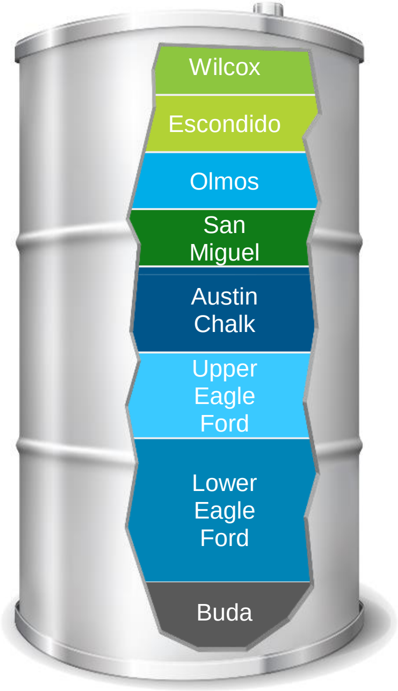
Program ROR at $3/$50 pricing

WELL POSITIONED TO GROW



MASSIVE UNTAPPED RESOURCE POTENTIAL





>28 bboe

Gross total resource OIP on CHK acreage

0.3 bboe

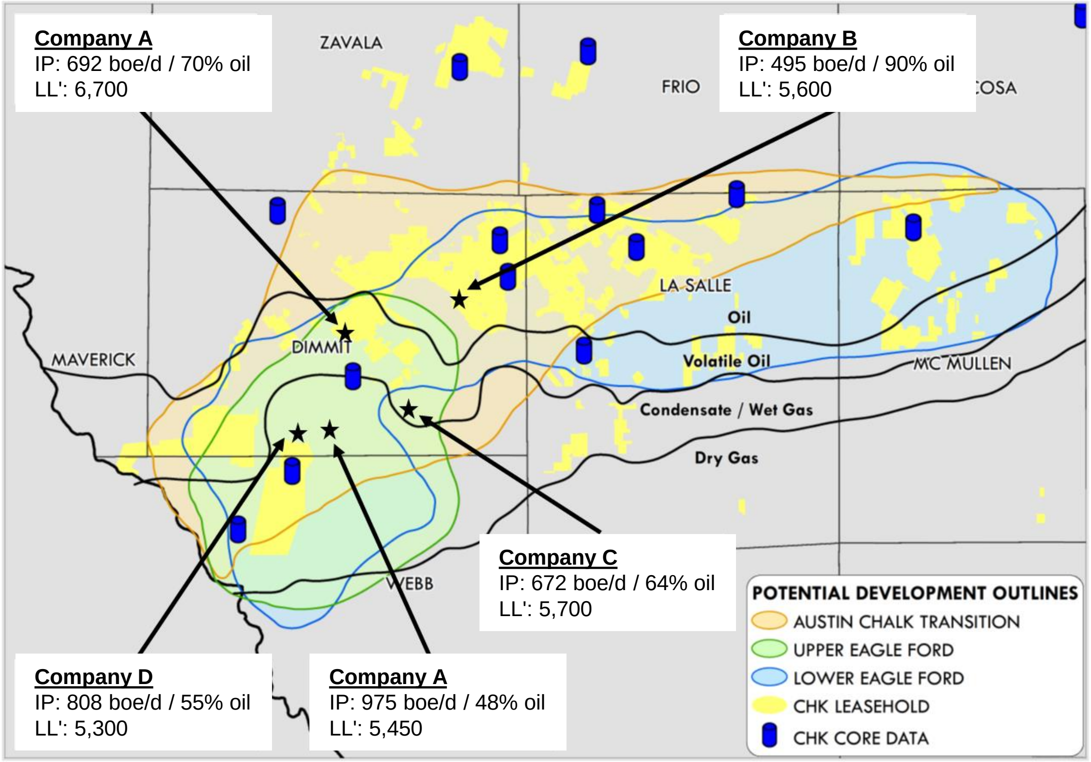
Gross produced from CHK acreage

>3.6 bboe

Estimated gross undeveloped resource

MULTIZONE DEVELOPMENT POTENTIAL

AREAS OF INTEREST AND COMPETITOR ACTIVITY



Company A
IP: 692 boe/d / 70% oil
LL': 6,700

Company B
IP: 495 boe/d / 90% oil
LL': 5,600

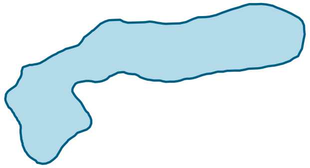
Company C
IP: 672 boe/d / 64% oil
LL': 5,700

Company D
IP: 808 boe/d / 55% oil
LL': 5,300

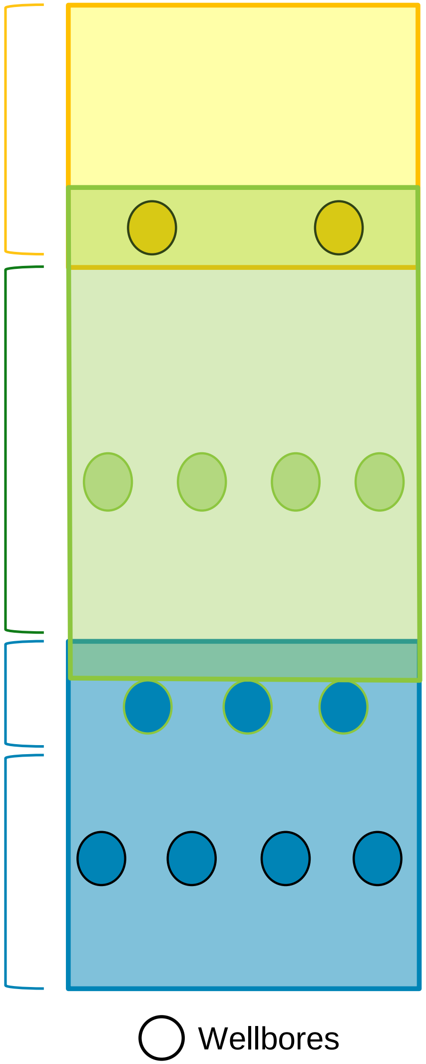
Company A
IP: 975 boe/d / 48% oil
LL': 5,450

ASTN Chalk Transition
18 wells

UEGFD
142 wells



LEGFD Stacked
102 wells



Austin Chalk

Upper Eagle Ford

Lower Eagle Ford Transition

Lower Eagle Ford

○ Wellbores

SOUTH TEXAS STAYING POWER

~30 years of drilling (1)

- >5,200 undrilled locations
- >3,200 high-confidence Lower Eagle Ford locations
- >1,700 strong ROR locations

>3.6 bboe

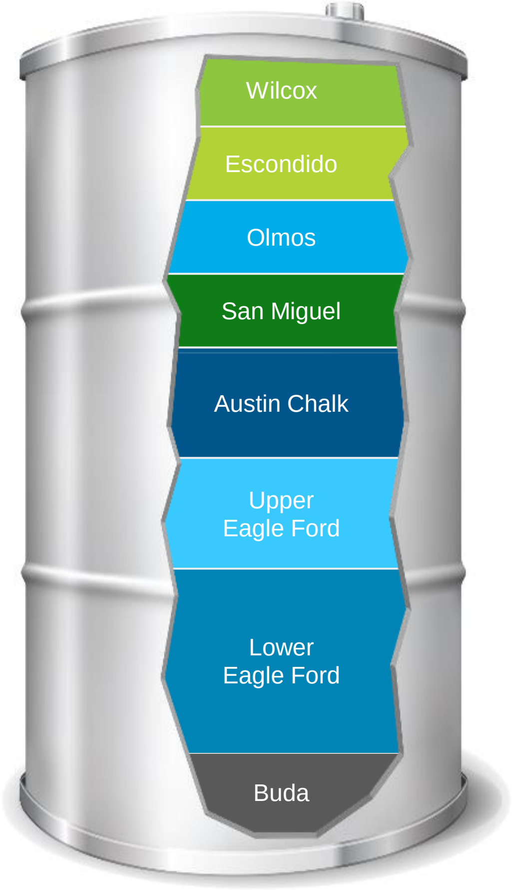
Estimated gross undeveloped resources

$13.2 billion

Future development costs eliminated (2016 vs. 2014) (2)

Culture of excellence

- Relentless focus on capital efficiencies
- Commitment to test new concepts and technologies
- Striving to be the low-cost operator
- Leverage existing acreage and infrastructure
- Safety culture and environmental stewardship champion



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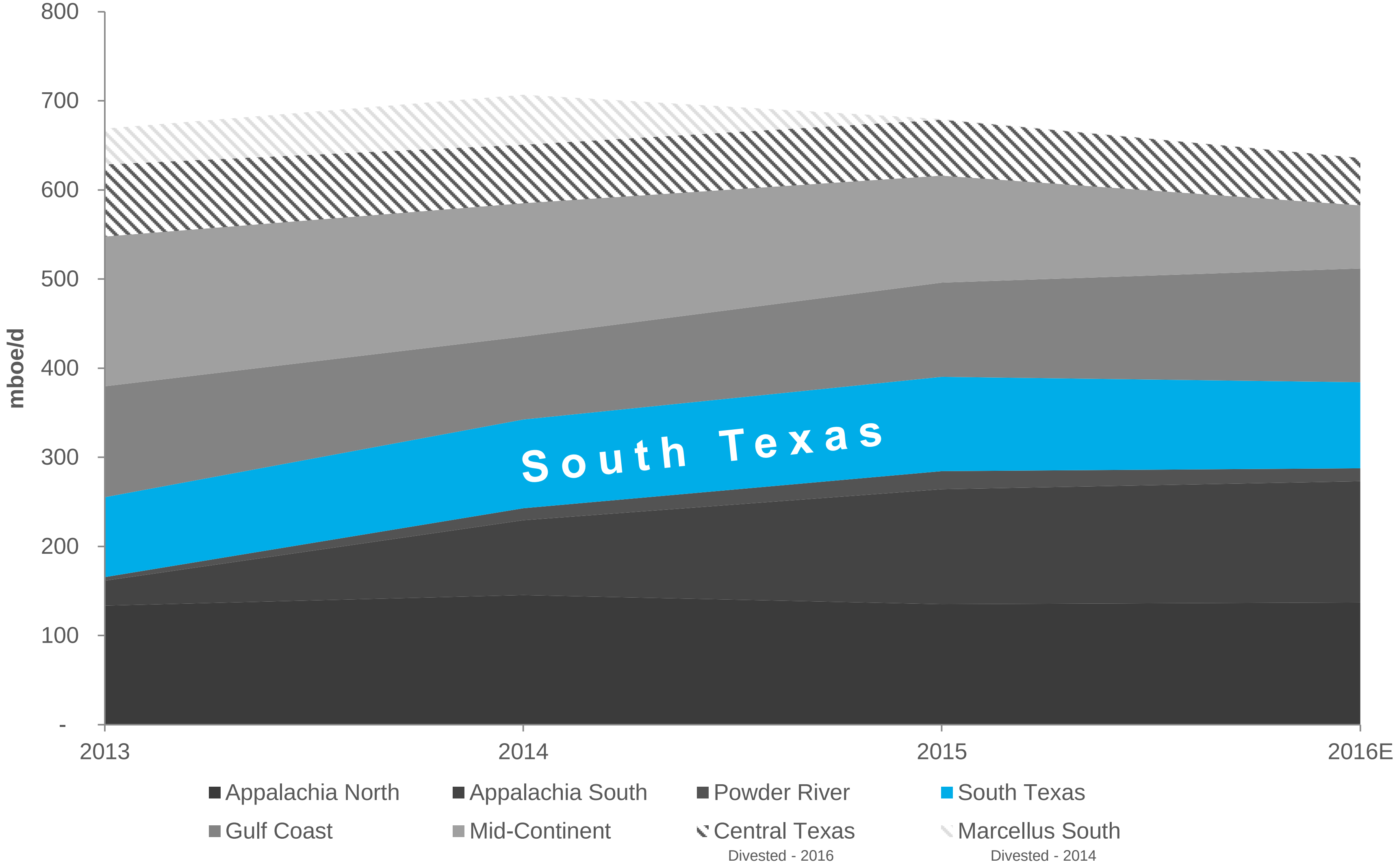
(1) Based on five rigs and 36 wells/rig
(2) Value estimate is gross and undiscounted based on remaining 3,200 Lower Eagle Ford locations and 5,200 South Texas locations

APPENDIX

NET EQUIVALENT PRODUCTION

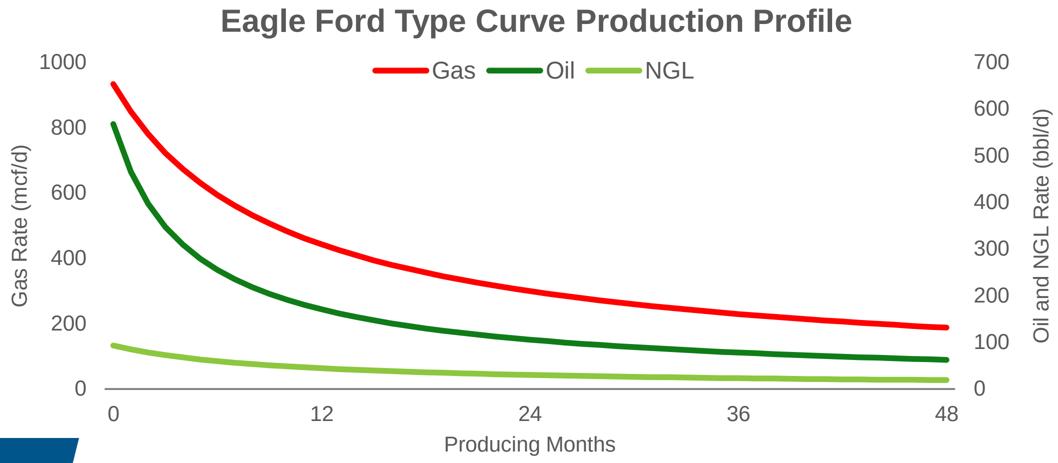
SOUTH TEXAS: ~15% TOTAL PRODUCTION 2016E



SOUTH TEXAS MODELING INPUTS

Base Production[1]	
3Q'16E Net Production	101 mboe/d
4 Yr. Average Annual Decline[2]	21%

2017 Expenses & Differential Estimates[1]	
Production Expense[3] ($/boe)	$4.45 – $4.85
GP&T[4] ($/boe)	$10.55 – $10.75

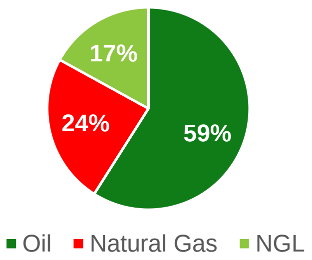

Eagle Ford Type Curve Production Profile

2017 – 2020 Blended Development Program

Curve Parameters	
IP[5] (Oil / Gas)	575 bbl/d / 855 mcf/d
Decline (Oil / Gas)	72.5%/54%
B-factor (Oil / Gas)	1.18/1.18
Shrink	85%
NGL Yield	100 bbl/mmcf
EUR	810 mboe
Lateral Length	8,400 ft.

Gross Capex	
Drilling[6] (120 days to TIL)	$1.4mm
Completion (58 days to TIL)	$2.1mm
TIL	$0.7mm
TOTAL	***$4.2mm***

Production Mix



Interest / Gross Locations	
WI / NRI[7]	63%/47%
Producing	1,580
DUCs	50
Undrilled[8]	3,200
Rig Count	5 – 15

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 13 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020; excludes Upper Eagle Ford and Austin Chalk locations

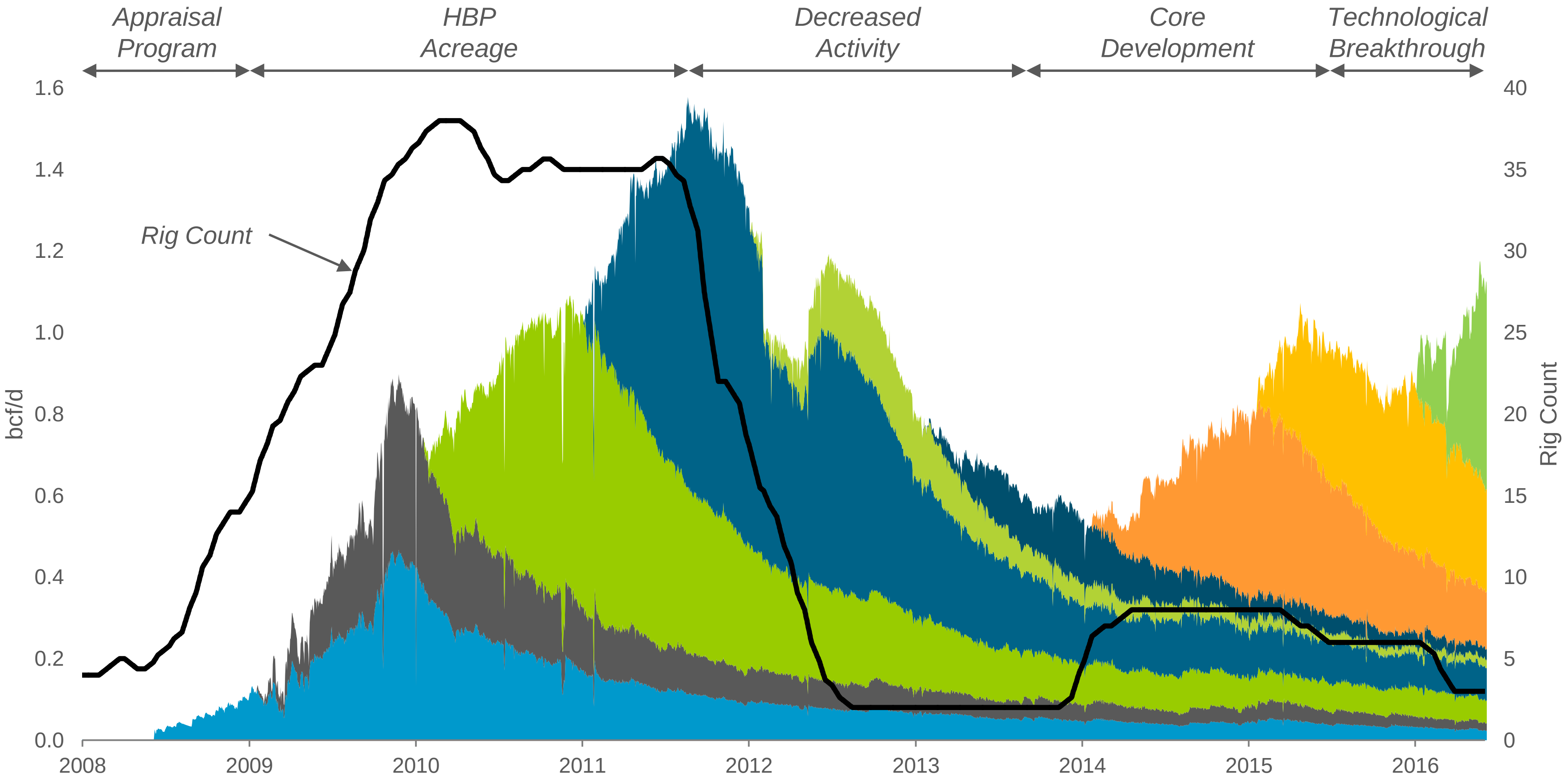
GULF COAST:

Unique Position, Extraordinary Asset

JASON PIGOTT

CHESAPEAKE OWNS THE HAYNESVILLE

GROSS PRODUCTION AND RIG COUNT

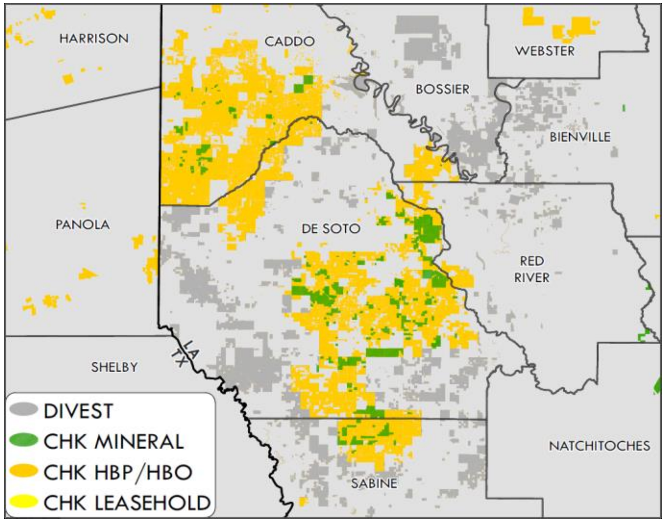


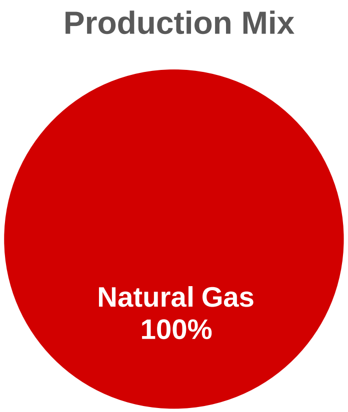
GULF COAST – HAYNESVILLE

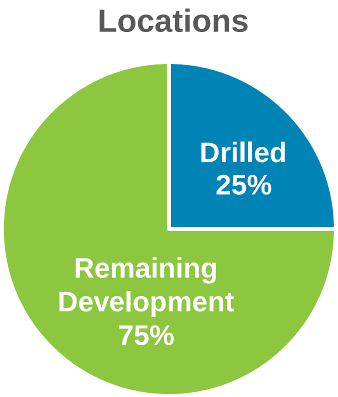
ASSET OVERVIEW

- Acreage position is 100% HBP, 25% developed – ideal for long lateral development
- Completions breakthrough is scalable across entire acreage position
- Greater than 200% improvement in year-over-year gas production generated per rig line in 2016
- Ample takeaway capacity to markets with favorable pricing
- Tremendous re-stimulation and Bossier upside

~385,000 Net Acres in Haynesville & Bossier – 100% HBP







Play Statistics

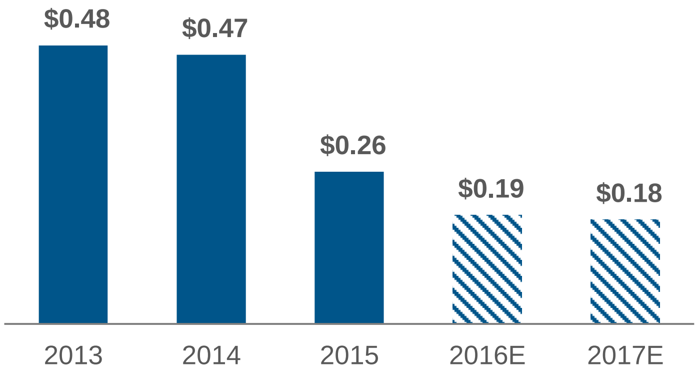
	Current	Post Divestiture
Producing	810	610
DUC Inventory	20	20
Undrilled	2,070	1,425
Acreage	~385,000	~255,000
Production	1.2 bcf/d	1.1 bcf/d

OPERATIONAL PERFORMANCE

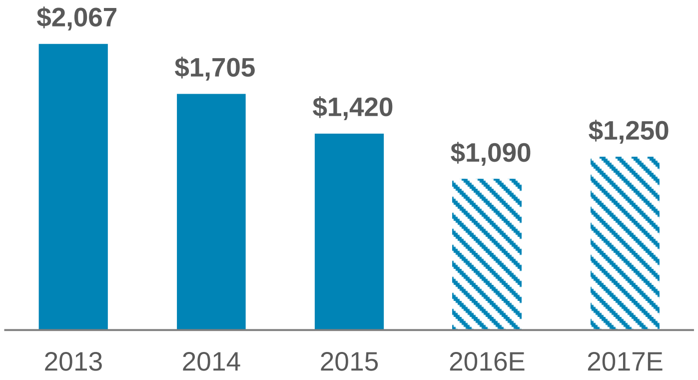
GULF COAST

- Leading drilling performance founded on a culture of continuous improvement
- Record-setting productivity delivers more reserves per dollar invested
- Ultra-high density, large volume frac jobs and XL laterals significantly improve capital efficiency
- Relentless pursuit of value drives low production costs and greater efficiency

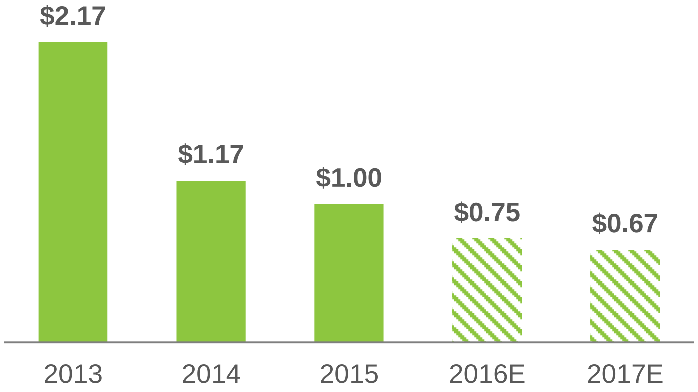
LOE ($/mcf) (1)



Cost per Lateral Foot (2)

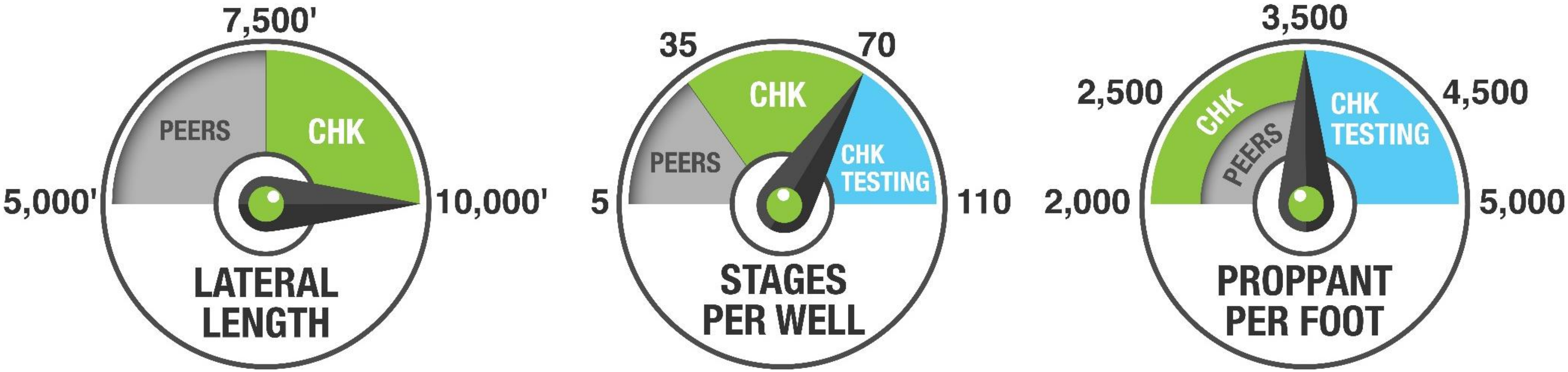


F&D Cost ($/mcf) (3)



(1) Data represents operated net lease operating expenses excluding taxes / net equivalent volume.
(2) Average cost per foot of wells drilled and/or completed within the time period.
(3) Data represents average net D&C / net EUR, grouped by TIL year.

CHESAPEAKE'S COMPETITIVE ADVANTAGE



50mm pounds

Proppant planned for the Black 2&11-15-11 1H
Completion in progress: 70 of 85 stages pumped

19 of 20 longest laterals

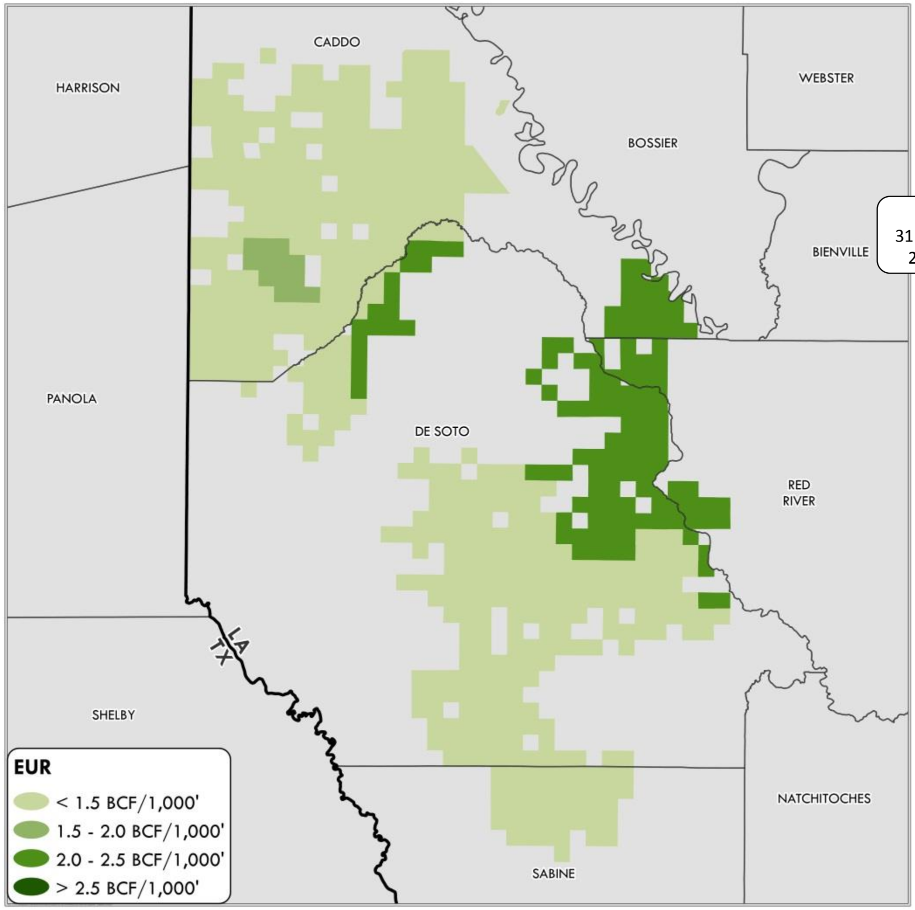
Drilled by Chesapeake in the Louisiana Haynesville Shale

OLD CORE VS. NEW CORE

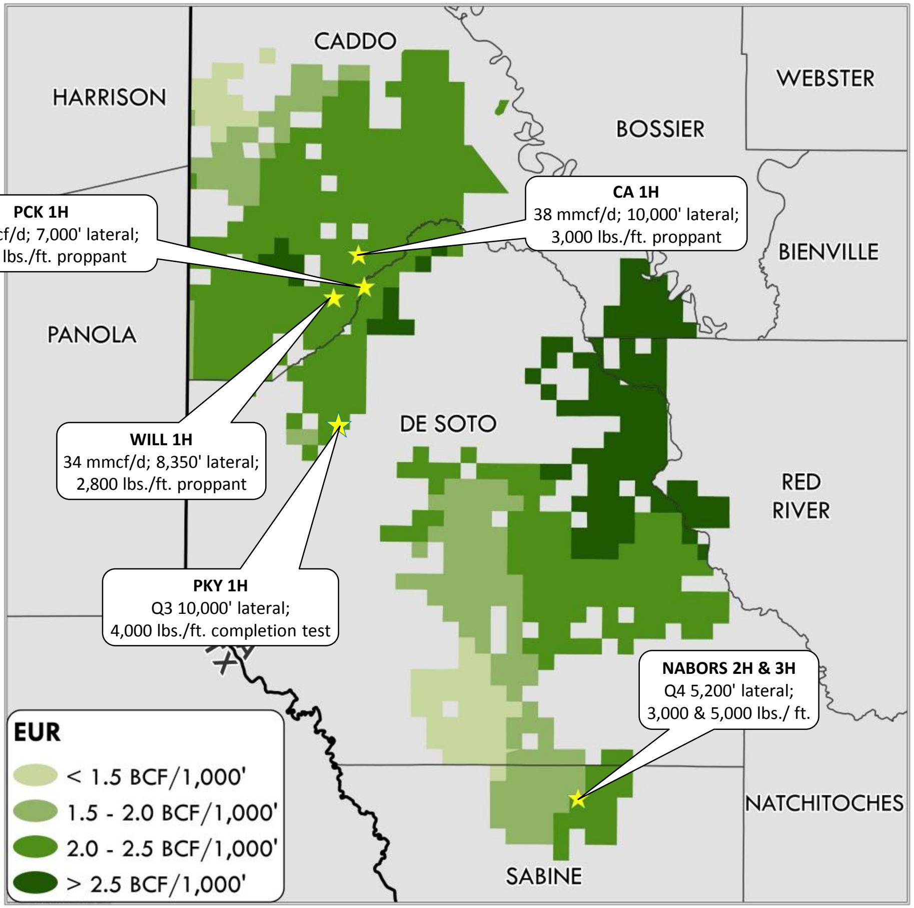
FULL-FIELD PARADIGM SHIFT

Completion designs increase field-wide productivity to unprecedented levels

PRE 2016



TODAY



PCK 1H
31 mmcf/d; 7,000' lateral;
2,700 lbs./ft. proppant

CA 1H
38 mmcf/d; 10,000' lateral;
3,000 lbs./ft. proppant

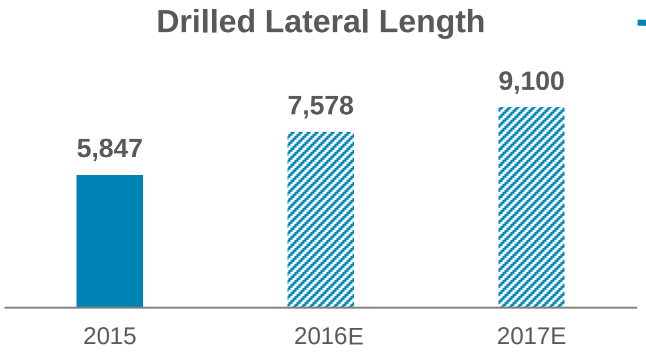
WILL 1H
34 mmcf/d; 8,350' lateral;
2,800 lbs./ft. proppant

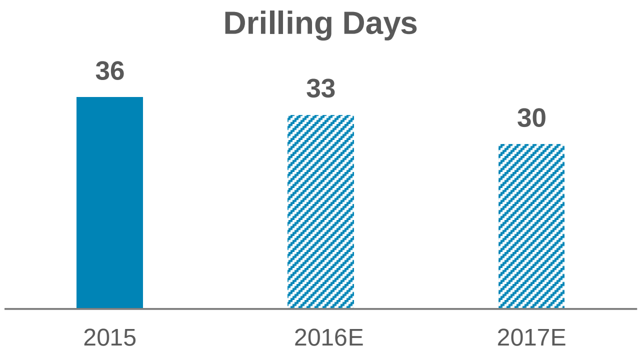
PKY 1H
Q3 10,000' lateral;
4,000 lbs./ft. completion test

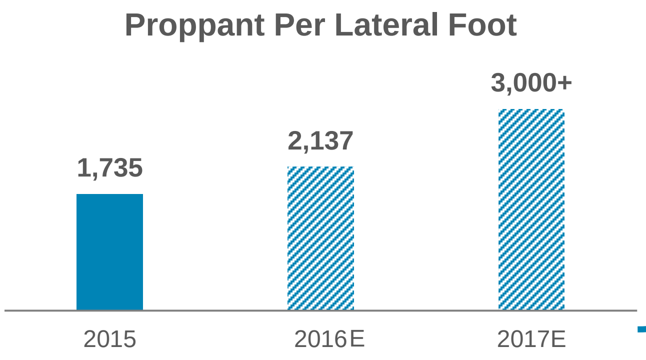
NABORS 2H & 3H
Q4 5,200' lateral;
3,000 & 5,000 lbs./ ft.

Chesapeake retained acreage after planned divestitures

DELIVERING EXCEPTIONAL PRODUCTIVITY





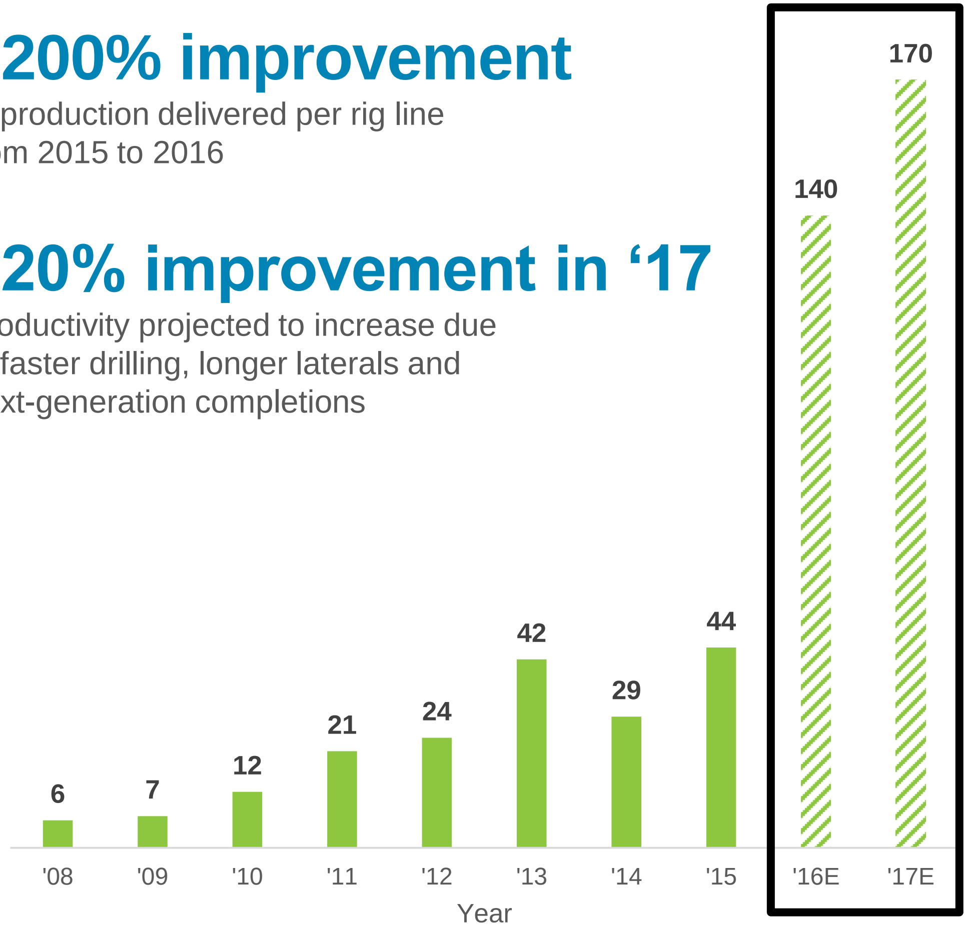


>200% improvement

In production delivered per rig line from 2015 to 2016

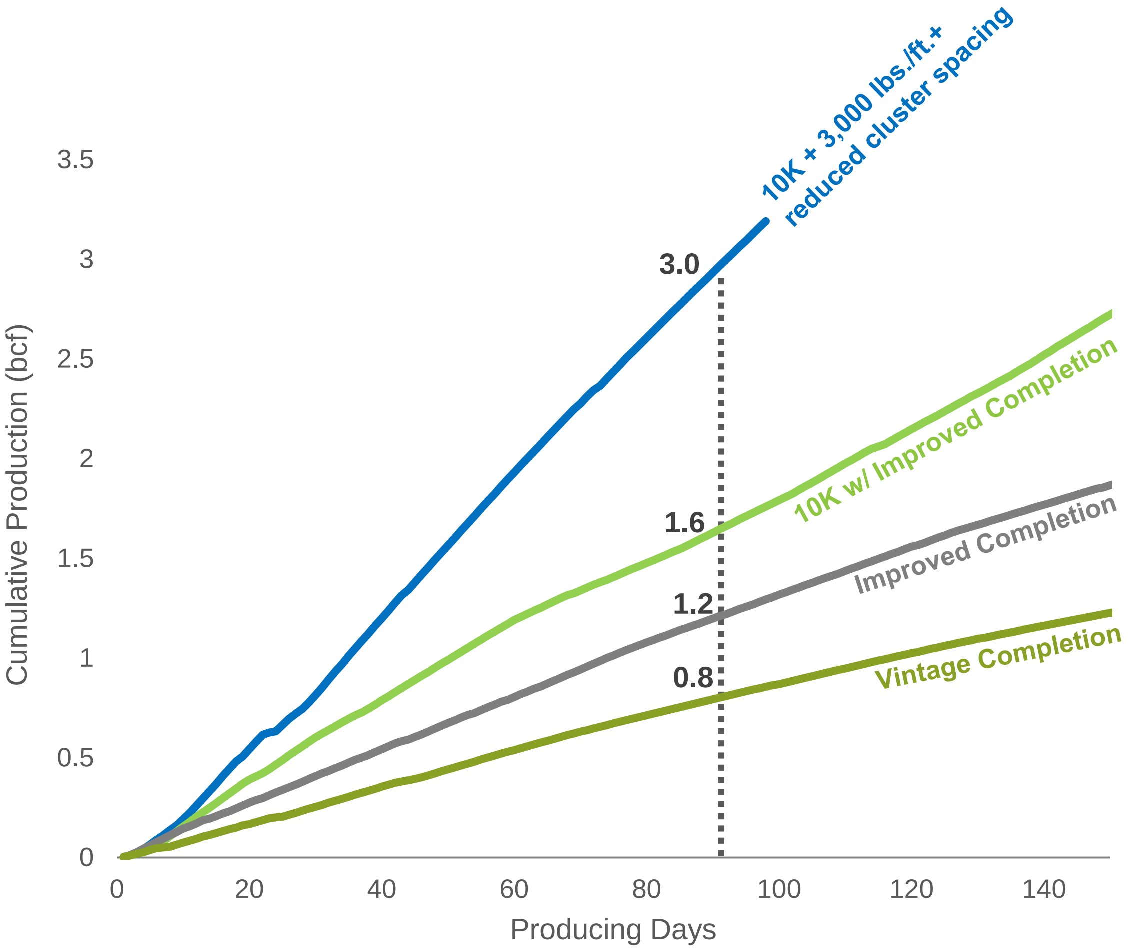
~20% improvement in ‘17

Productivity projected to increase due to faster drilling, longer laterals and next-generation completions



Annualized Gas Rate per Rig (mmcf/d/rig)

GAME-CHANGING PERFORMANCE
LONGER LATERALS AND BIGGER COMPLETIONS



New CHK wells delivering monster IPs

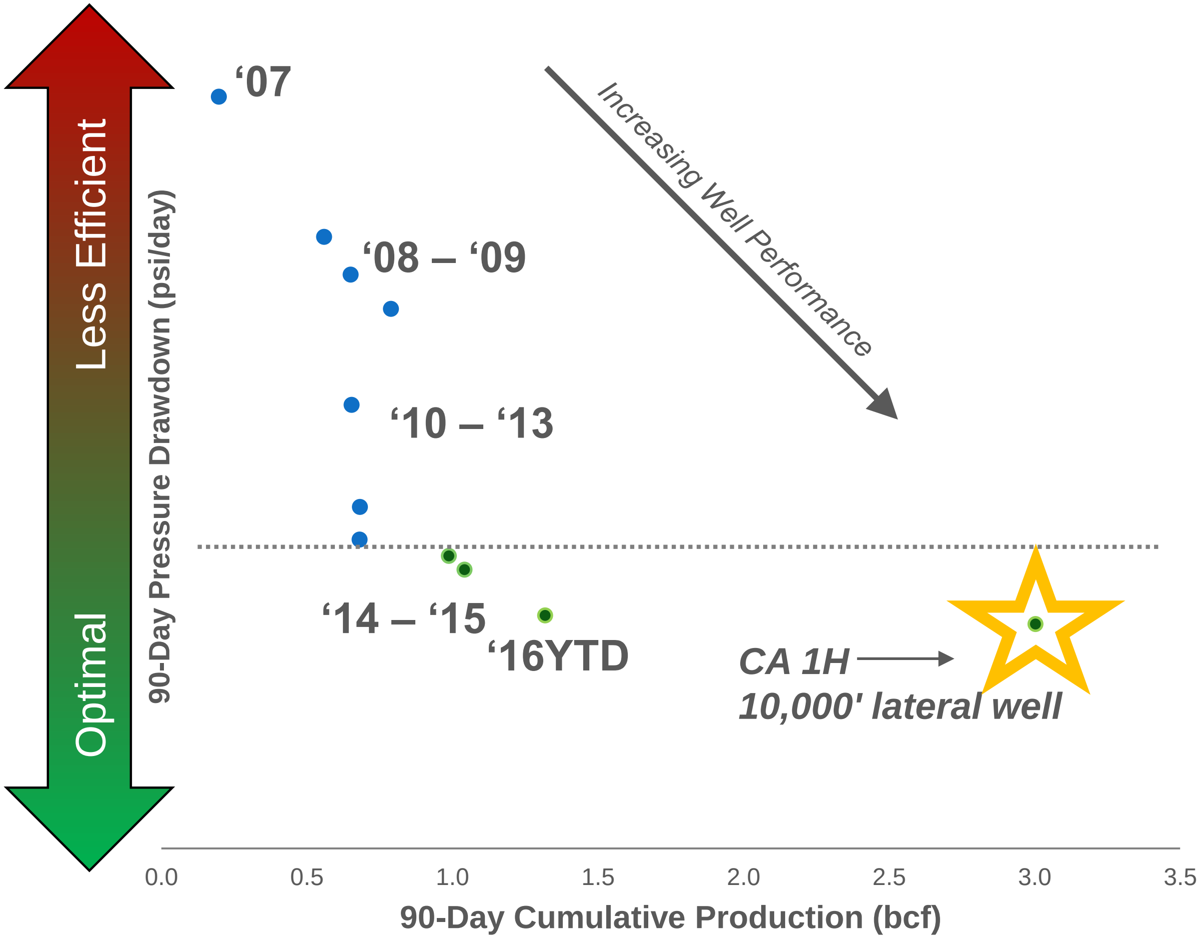
CA 1H – 38 mmcf/d, 10,000' lateral
PCK 1H – 31 mmcf/d, 7,000' lateral
WILL 1H – 34 mmcf/d, 8,350' lateral

>250% increase

In 90-day production with extended laterals, increased proppant loading and reduced cluster spacing

DRAWDOWN MANAGEMENT

RECORD PRODUCTIVITY WITH RESPONSIBLE DRAWDOWN



3 bcf in 90 days

CA 1H cumulative production – a 63% improvement over the ***next-best CHK well*** in the play

9.3 bcf in first year

CA 1H first year estimated cumulative production – a ~50% increase over a 10K lateral with an improved completion

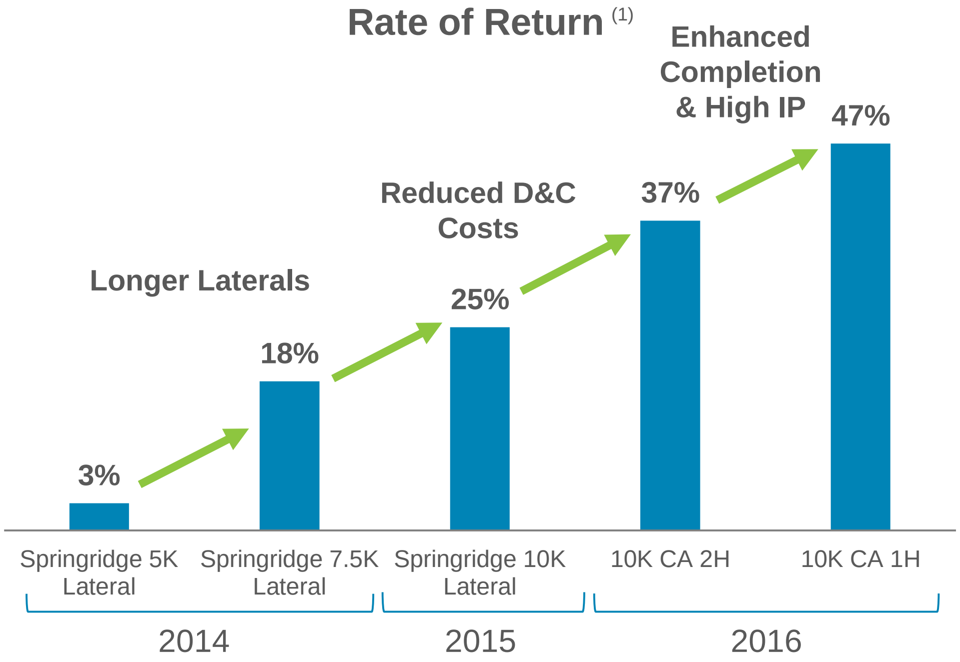
One-year payout

CA 1H estimate – Haynesville wells driving short-cycle cash flow

Prioritizing long-term value over short-term gains

NEW TECHNOLOGY DRIVES VALUE CREATION

LONGER LATERALS AND BIGGER COMPLETIONS



3% ROR → 47% ROR [(1)]

Combination of extended laterals and current completions revolutionize economics

$2.30 break-even

CA 1H PV10 break-even gas price

10,000' wells remaining

660 Haynesville locations
190 Bossier locations

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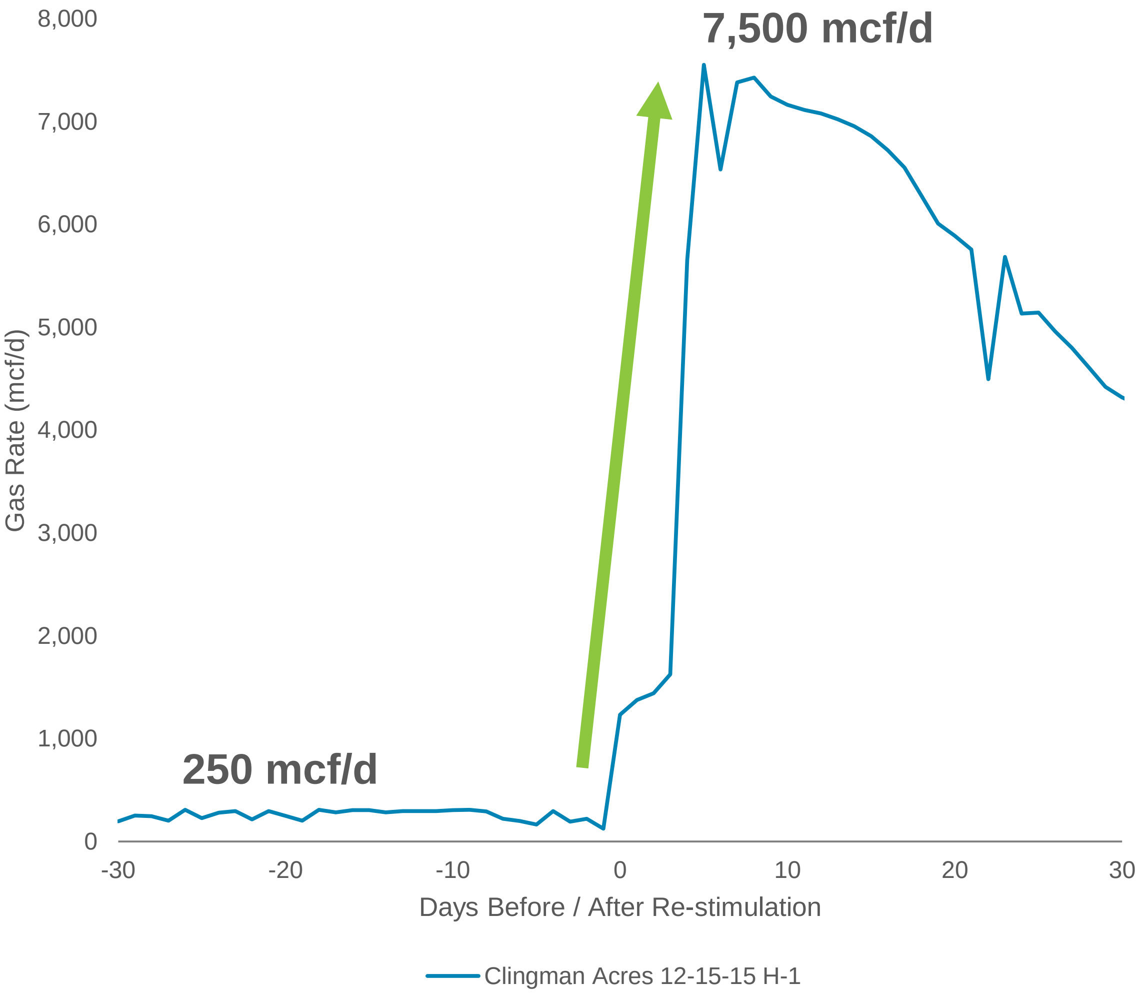
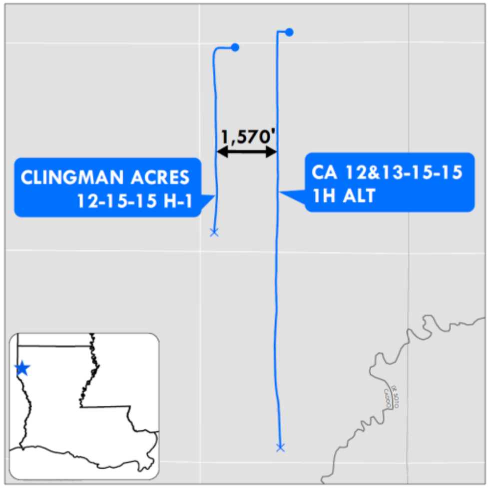
(1) Assumes $3.00 flat price deck

OFFSET FRAC UPLIFT

BREATHING NEW LIFE INTO AGING WELLS





7,250 mcf/d increase

In production from the Clingman Acres 1H after the CA 1H stimulation

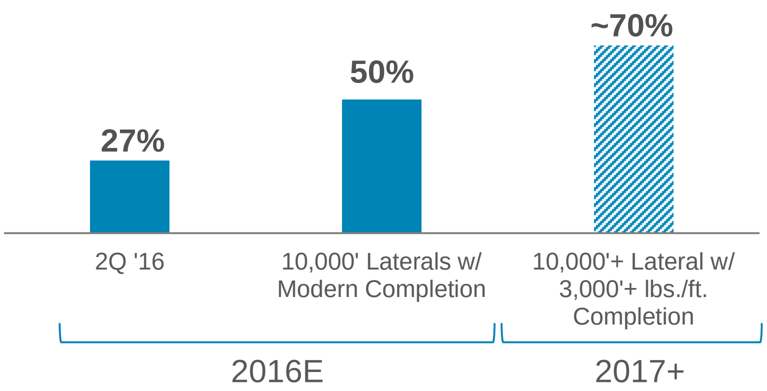
85% success rate

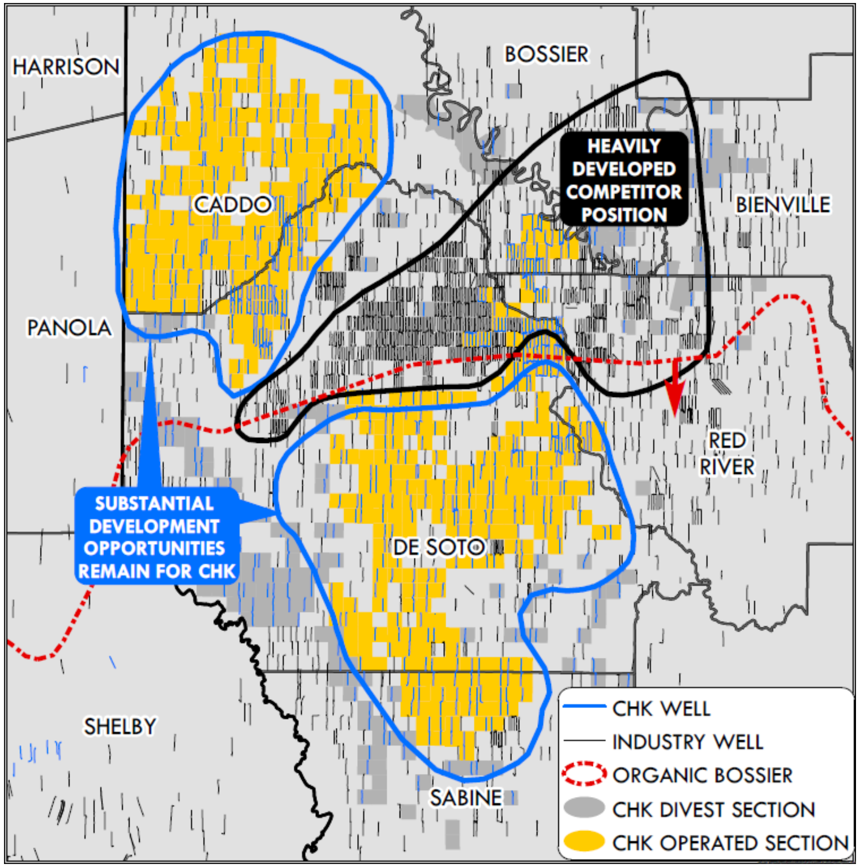
In 26 trials the existing well production uplift >1,000 mcf/d after offsetting stimulation

GULF COAST
WORLD-CLASS RESOURCE

- CHK Haynesville position is ***100% HBP*** and ***only 25% developed***
- Unique opportunity to develop field with newest technology
- Industry-leading Bossier position and re-stimulation potential

Future Returns of the Gulf Coast (1)





HEAVILY DEVELOPED COMPETITOR POSITION

SUBSTANTIAL DEVELOPMENT OPPORTUNITIES REMAIN FOR CHK

The Haynesville is no longer a Chesapeake obligation – it is a world-class investment opportunity

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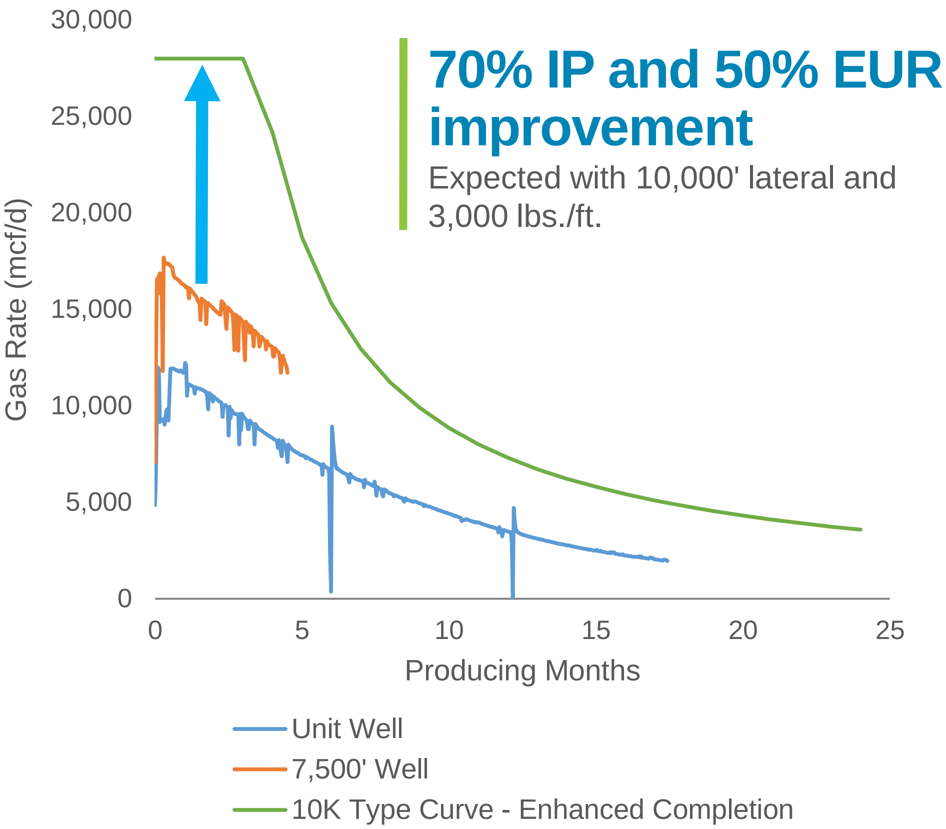
(1) Assumes $3 mcf gas price

APPENDIX

BOSSIER SHALE

SIGNIFICANT UPSIDE POTENTIAL

- First 7,500' lateral drilled in 2015
  - IP 17.7 mmcf/d at 7,480 psi
  - 1,900 lbs. of proppant per ft.
- Completions optimization
  - Promising results observed with vintage completions
  - ***Substantial*** uplift anticipated with 3,000 – 5,000 lbs./ft.
- Significant upside potential across CHK-operated acreage
  - Estimated 190 10,000' lateral locations
  - Nearly 5 tcf of recoverable reserves



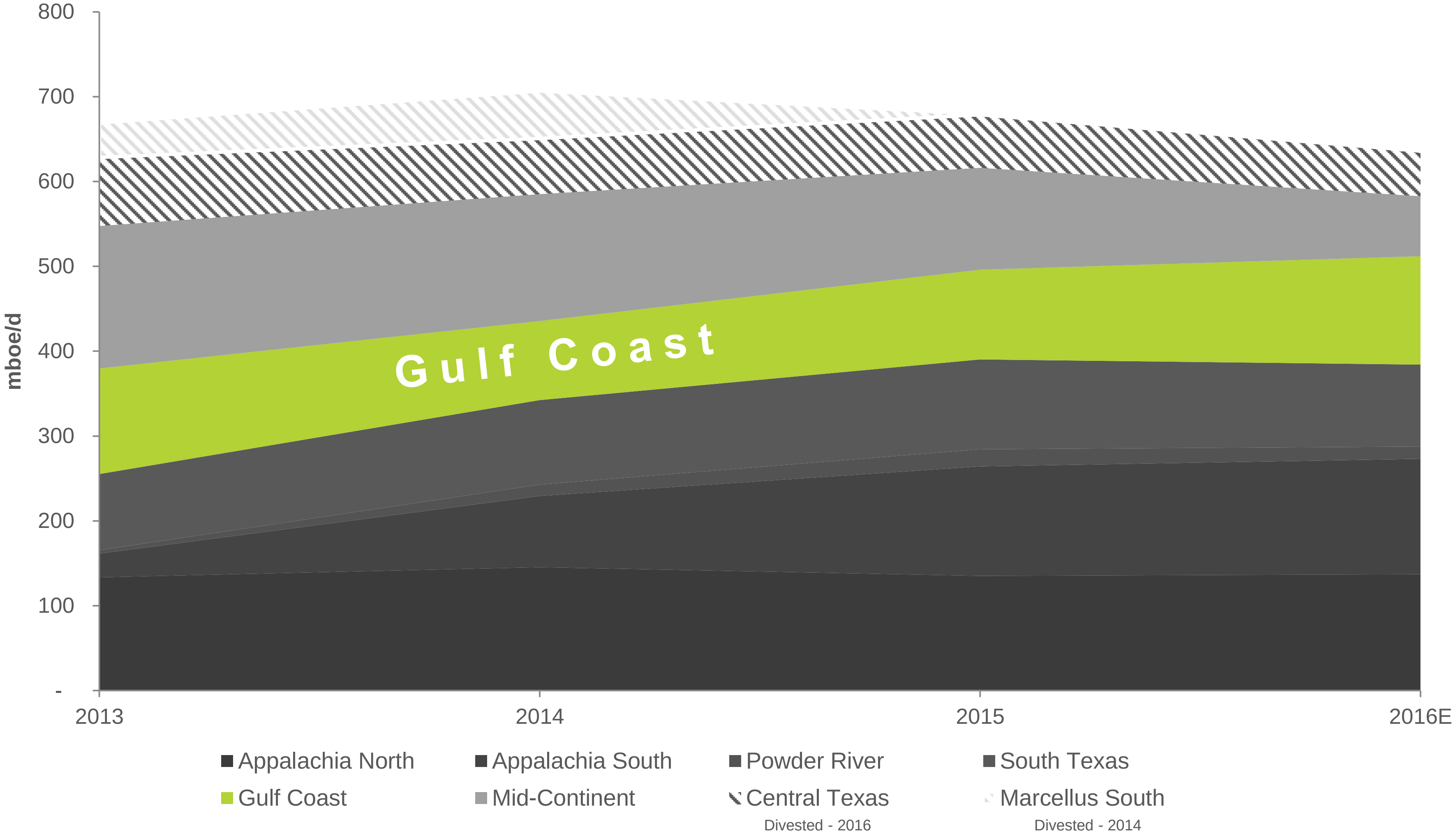
70% IP and 50% EUR improvement

Expected with 10,000' lateral and 3,000 lbs./ft.

The Bossier is a blank canvas upon which we can apply eight years of learnings from the Haynesville

NET EQUIVALENT PRODUCTION

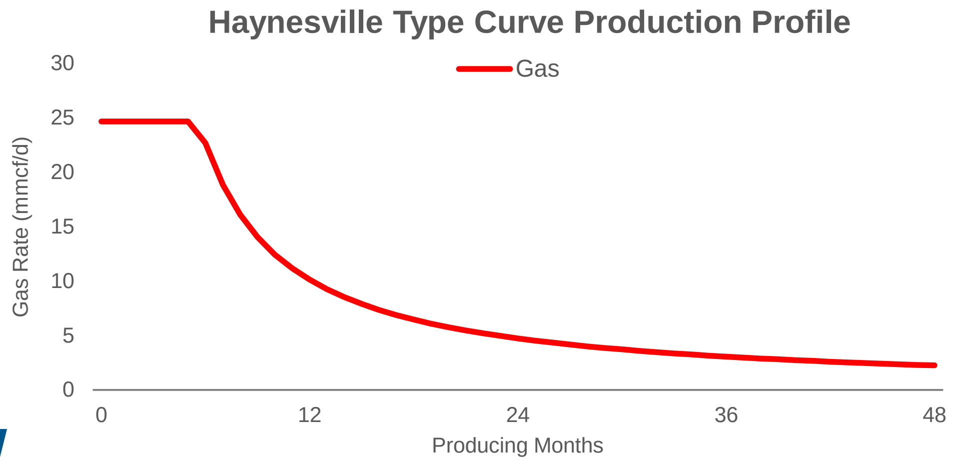
GULF COAST: ~20% TOTAL PRODUCTION 2016E



GULF COAST MODELING INPUTS

Base Production[1]	
3Q'16E Net Production	835 mmcf/d
4 Yr. Average Annual Decline[2]	30%

2017 Expenses & Differential Estimates[1]	
Production Expense[3] ($/mcf)	$0.20 - $0.26
GP&T[4] ($/mcf)	$0.90 – $1.00



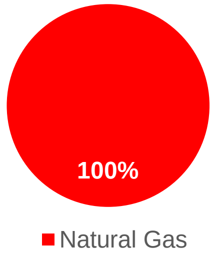
2017 – 2020 Blended Development Program

Curve Parameters	
IP[5]	24.6 mmcf/d
Decline	73.5%
B-factor	0.96
EUR	19.9 bcf
Lateral Length	9,800 ft.

Gross Capex	
Drilling[6] (133 days to TIL)	$3.8mm
Completion (37 days to TIL)	$5.7mm
TIL	$0.8mm
TOTAL	***$10.3mm***

Interest / Gross Locations	
WI / NRI[7]	80%/63%
Producing	810
DUCs	20
Undrilled[8]	2,070
Rig Count	2 – 4

Production Mix



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(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 6 month flat period
(6) 35 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020

FINANCE:
Capital Structure and Outlook

NICK DELL'OSSO

WHERE WE'VE COME FROM

Substantial progress on every front

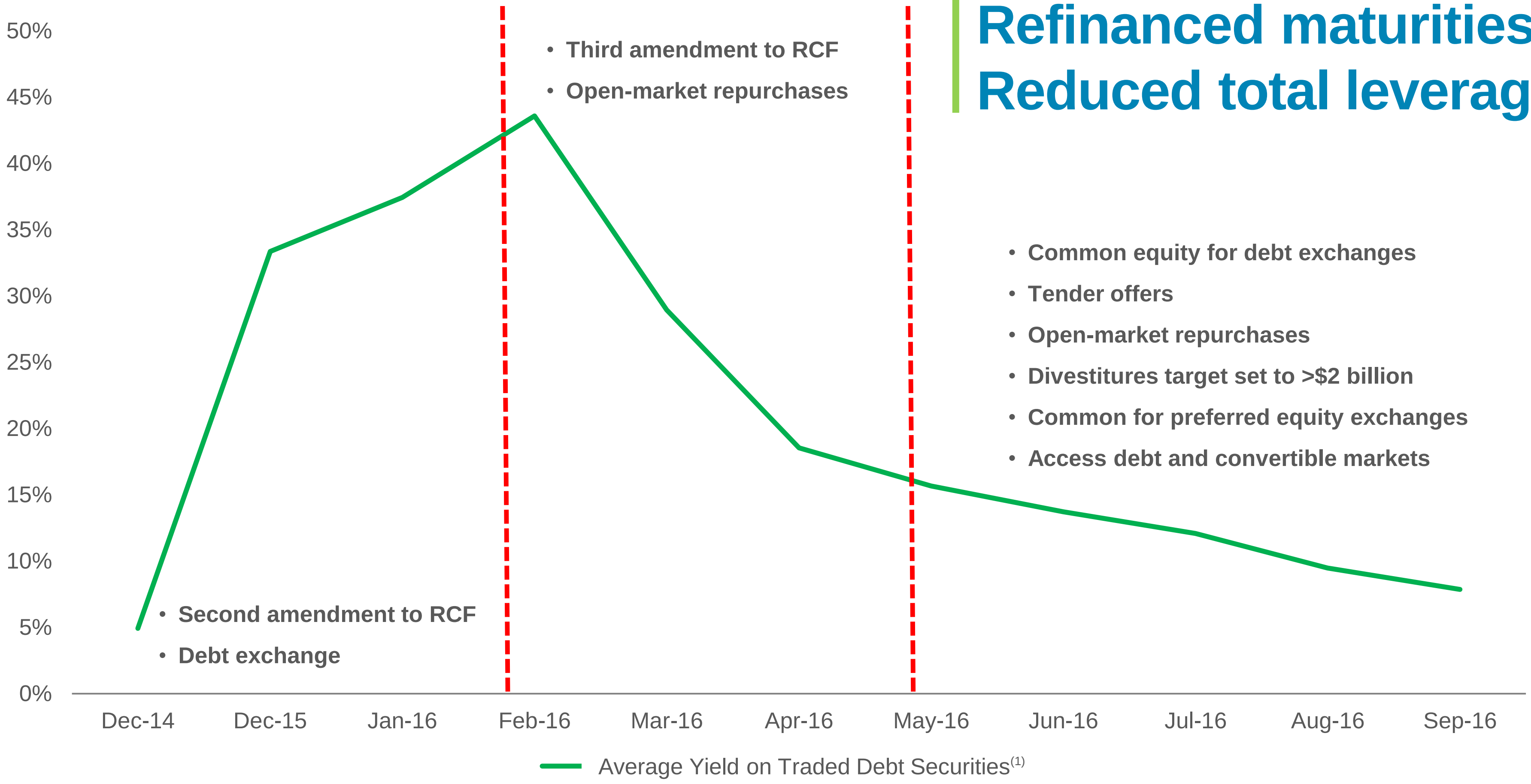
2012 – 2016

- ✓ *Reduced total net leverage by ~50% ($10.9 billion)*
- ✓ *Improved cash costs by ~50% per boe*
- ✓ *Reduced financial and balance sheet complexity*

- » *Led to substantial reduction in financing costs*
- » *Increase in margins on $/boe basis*
- » *Reduction in overhead due to simpler structure*

RESTORING COST OF CAPITAL

Restored liquidity
Refinanced maturities
Reduced total leverage



- **Second amendment to RCF**
- **Debt exchange**

- **Third amendment to RCF**
- **Open-market repurchases**

- **Common equity for debt exchanges**
- **Tender offers**
- **Open-market repurchases**
- **Divestitures target set to >$2 billion**
- **Common for preferred equity exchanges**
- **Access debt and convertible markets**

Source: Bloomberg

(1) The composite yield represents the weighted-average yield by outstanding principal for nine different bonds with maturities ranging from 2017 to 2023

REDUCED TOTAL LEVERAGE AND COMPLEXITY

Chesapeake continues to simplify the business:

> Eliminated finance leases, subsidiary preferred equity and seven VPPs

> Optimizing the capital structure

↓ **~50% reduction** (1)

In total net leverage

= $10.9 billion (1)

($mm)	2012	2013	2014	2015	3Q'16	Pro Forma 3Q'16 (1)	
Credit Facility	$418	$405	$0	$0	$240	$0	
Term Loan (2)	$2,000	$2,000	$0	$0	$1,500	$1,500	
Second-Lien Notes	$0	$0	$0	$2,425	$2,425	$2,425	
Long-Term Bonds (3)	$10,647	$10,825	$11,756	$7,281	$4,552	$5,697	
Less: Cash	($287)	($837)	($4,108)	($825)	($4)	($900)	
Net Debt	**$12,778**	**$12,393**	**$7,648**	**$8,881**	**$8,713**	**$8,722**	↓ **-32%**
VPPs	$3,186	$2,454	$1,702	$1,289	$675	$675	
Operating and Finance Leases	$1,255	$948	$0	$0	$0	$0	
Subsidiary Preferred	$2,500	$2,310	$1,250	$0	$0	$0	
Corporate Preferred (4)	$1,531	$1,531	$1,531	$1,531	$1,518	$932	
Total Adjusted Net Leverage	**$21,250**	**$19,636**	**$12,131**	**$11,701**	**$10,906**	**$10,329**	↓ **-51%**

(1) Pro forma convertible note offering, preferred stock for common stock exchanges and open market repurchases of outstanding long-term bonds in October
(2) 2016 security is 1.5 Lien Term Loan
(3) Assumes euro-denominated notes are converted to USD at the relevant exchange rate for each calendar period; for pro forma 3Q'16E, exchange rate as of 9/30/16
(4) Using Moody's valuation methodology

WHERE WE ARE GOING

Strategic financial targets

- *Grow production 5 – 15% annually*
- *Retire $2 – $3 billion of debt*
- *Reduce leverage to 2X net debt/ebitda*
- *Achieve free cash flow neutrality*
- *More than double ebitda by 2018*

- *Leads to investment grade metrics*
- *Allows more stable development profile through cycles*
- *Provides flexibility to pursue opportunities for growth*

2016E AND 2017E OUTLOOK SUMMARY

	2016E		2017E
Adjusted Production Growth (1)	**0% – 3%**	Adjusted Production Growth (1)	**(5%) – 0%**
Absolute Production:		Absolute Production:	
Liquids – mmbbls	56 – 60	Liquids – mmbbls	51 – 55
Oil – mmbbls	33 – 35	Oil – mmbbls	33 – 35
NGL – mmbbls	23 – 25	NGL – mmbbls	18 – 20
Natural gas – bcf	**1,020 – 1,040**	Natural gas – bcf	860 – 900
Total absolute production – mmboe	**226 – 233**	Total absolute production – mmboe	194 – 205
Absolute daily rate – mboe	**617 – 637**	Absolute daily rate – mboe	532 – 562
Operating Costs per Boe of Projected Production:		Operating Costs per Boe of Projected Production:	
Production expenses, production taxes and G&A (2)	$4.25 – $4.75	Production expenses, production taxes and G&A (2)	**$4.00 – $4.50**
Gathering, processing and transportation expenses	$7.60 – $8.10	Gathering, processing and transportation expenses	**$7.00 – $7.50**
Capital Expenditures ($mm) (3)	**$1,400 – $1,500**	Capital Expenditures ($mm) (3)	$1,600 – $2,400
Capitalized Interest ($mm)	**$250**	Capitalized Interest ($mm)	**$220**
Total Capital Expenditures ($mm)	**$1,650 – $1,750**	Total Capital Expenditures ($mm)	**$1,820 – $2,620**

(1) Based on 2015 production of **550** mboe per day, adjusted for 2015 and 2016 sales
(2) Includes stock-based compensation
(3) Includes capital expenditures for drilling and completion, leasehold, geological and geophysical costs, rig termination payments and other property and plant and equipment

(1) Based on 2016 estimated production of **548** mboe per day, adjusted for 2016 sales. Subject to future A&D activity.
(2) Includes stock-based compensation
(3) Includes capital expenditures for drilling and completion, leasehold, geological and geophysical costs, rig termination payments and other property and plant and equipment

SIGNIFICANT REDUCTIONS IN CASH COSTS

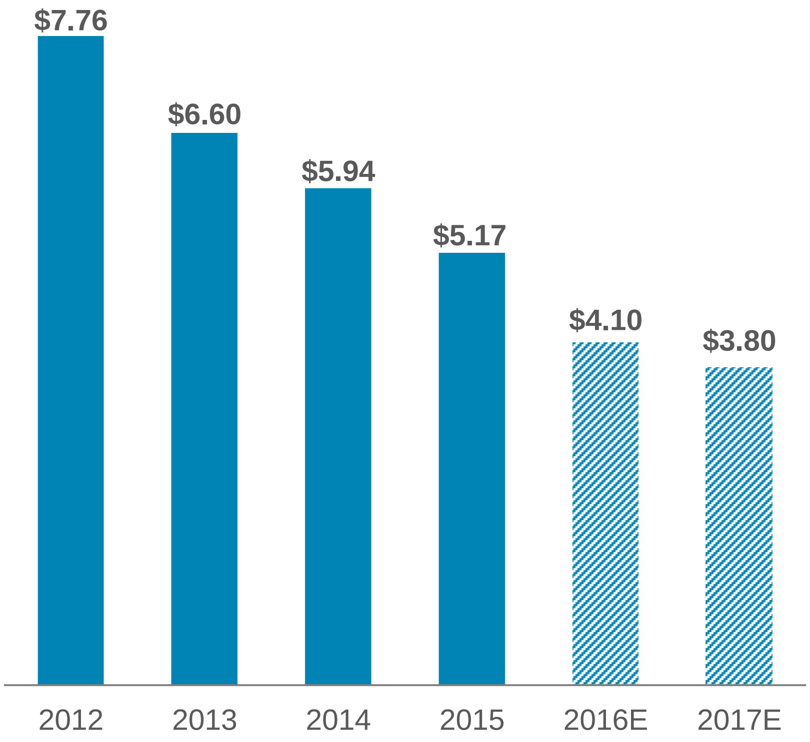
Industry-leading cash cost structure:

- Relentless focus on cost management
- Operational leadership and technical capabilities provide industry-leading production expense

~50% reduction

In production and G&A expenses per boe since 2012

Production Expense and G&A ($/boe) (1,2)



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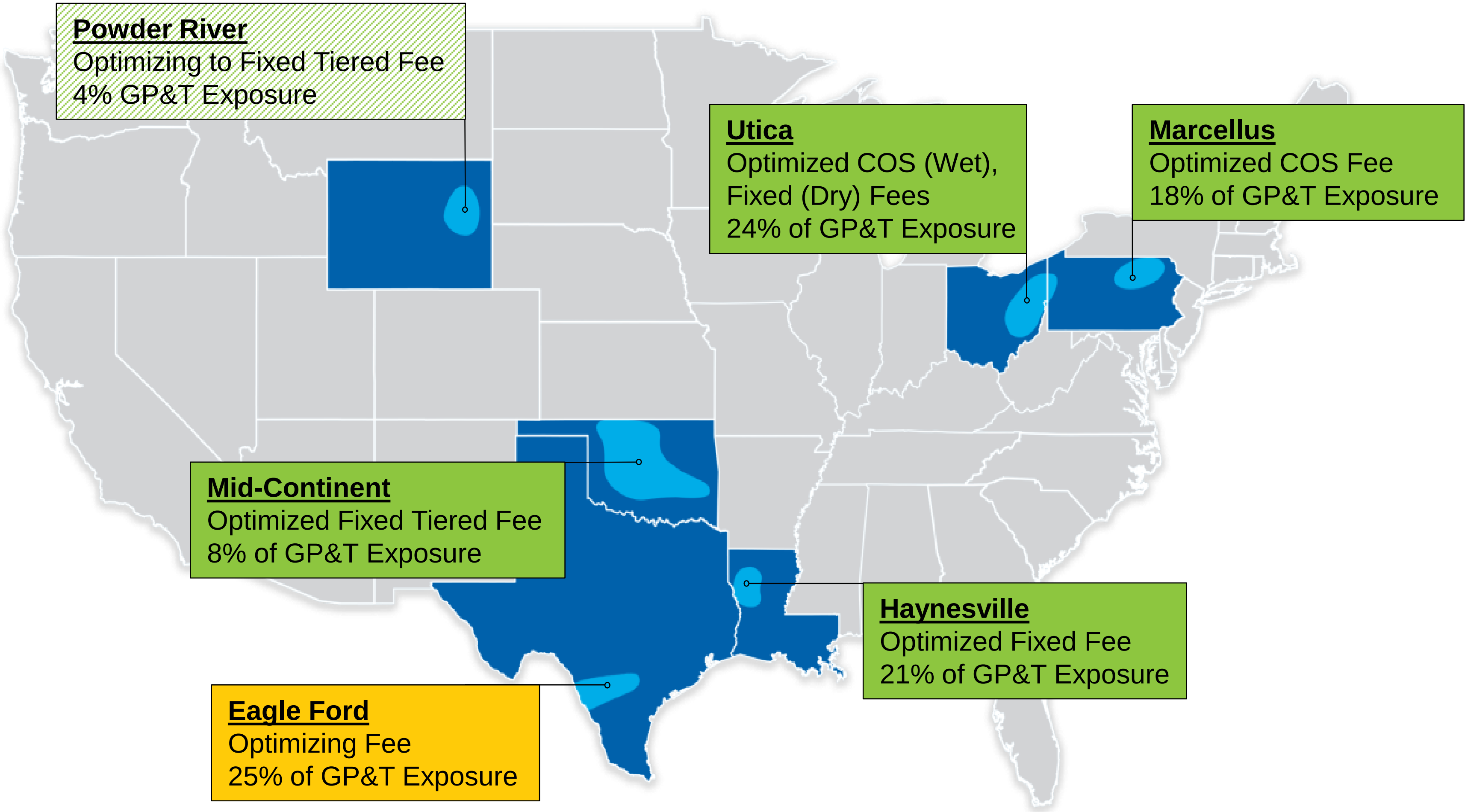
(1) Includes production expenses and general and administrative expenses, including stock-based compensation

(2) 2016E and 2017E represents current guidance midpoints

CONTINUED IMPROVEMENT IN MIDSTREAM FEES



Powder River
Optimizing to Fixed Tiered Fee
4% GP&T Exposure

Utica
Optimized COS (Wet), Fixed (Dry) Fees
24% of GP&T Exposure

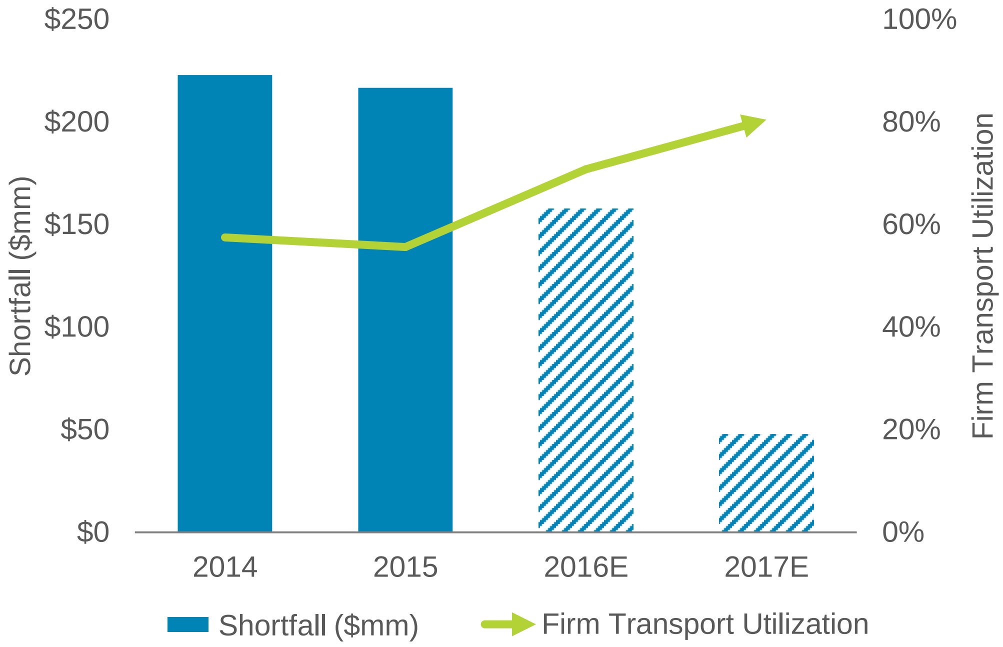
Marcellus
Optimized COS Fee
18% of GP&T Exposure

Mid-Continent
Optimized Fixed Tiered Fee
8% of GP&T Exposure

Haynesville
Optimized Fixed Fee
21% of GP&T Exposure

Eagle Ford
Optimizing Fee
25% of GP&T Exposure

OPTIMIZING COMMITMENTS TO FURTHER INCREASE EBITDA



~$59mm reduction

In natural gas transportation shortfall in 2016

~25% improvement

In natural gas transportation utilization in 2016

GP&T Commitments ($ billion)

YE'14	YE'15	YE'16E (1,2)
$16.0	$14.0	$11.1

~$5.0 billion reduction

In midstream and marketing commitments since 2014

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(1) 2016E excludes Barnett (divestment pending)

(2) Also have additional gas gathering agreements with cost-of-service based fees; redetermined annually or tiered fees based on volumes

~15% IMPROVEMENT IN GP&T COSTS SINCE 2015

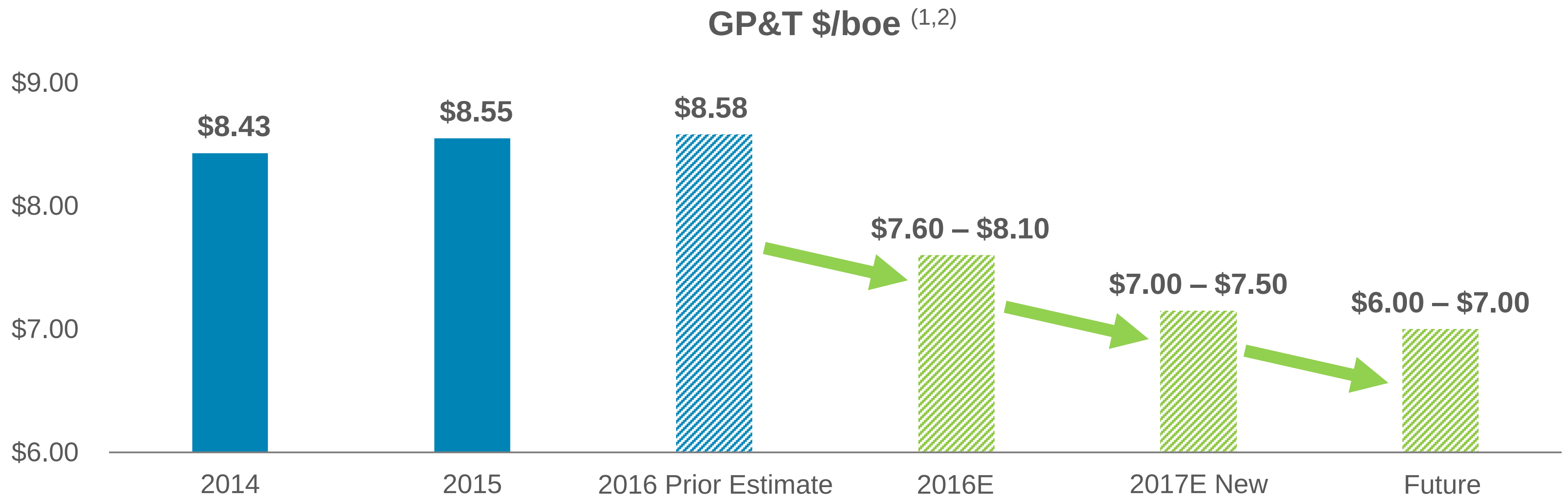
Marcellus
Optimized
COS fee
✓ PRE AUG 2015

Utica Dry & Haynesville
Restructured COS
fee to fixed fee
✓ SEPT 2015

Mid-Con & Barnett
Restructured fixed fee in Mid-Con
and signed PSA in Barnett;
Reduced several transportation
commitments
✓ AUG 2016

Powder River
Under binding LOI
to restructure COS fee
to fixed fee
✓ OCT 2016

Eagle Ford
Optimizing fee
80%+ of revenues
driven by oil
✓


GP&T $/boe (1,2)

2017: Expect 14% improvement in GP&T due to recent Mid-Con restructuring and Barnett divestiture (pending)

(1) Includes MVC shortfall
(2) Excludes all intercompany marketing fees

THE PATH TO FCF NEUTRAL

Cost structure improvements are clearing the path to FCF neutrality in 2018

~$5.50/boe reduction

In LOE, G&A and GP&T from peak rates since 2012 (1)

$10.9 billion

In total net leverage reduction since 2012

40% – 60% improvement

In capital efficiency since 2012

~$600mm reduction

In annual leverage service costs since 2012 (2)

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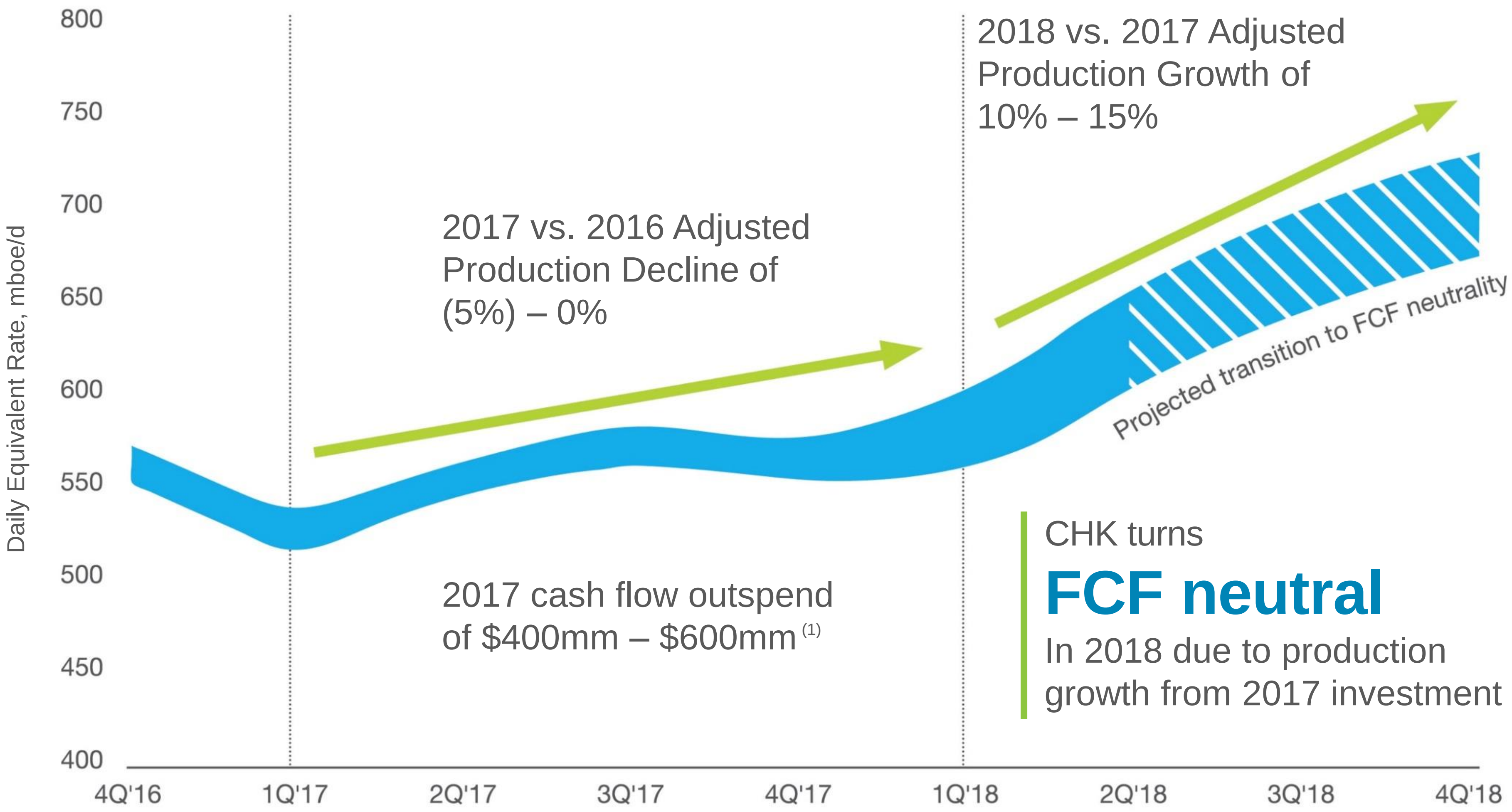
(1) Compared to 2017 guidance midpoints

(2) Represents reductions to corporate preferred dividends, subsidiary preferred dividends and interest expense on debt instruments and financing leases

CASH FLOW NEUTRAL IN 2018



2017 vs. 2016 Adjusted Production Decline of (5%) – 0%

2017 cash flow outspend of \$400mm – \$600mm (1)

2018 vs. 2017 Adjusted Production Growth of 10% – 15%

CHK turns

FCF neutral

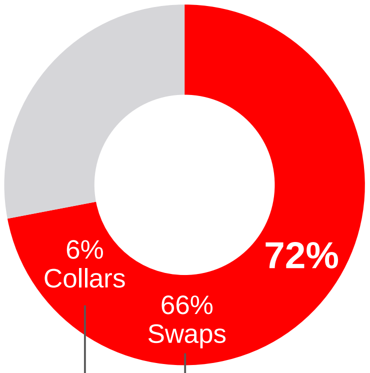
In 2018 due to production growth from 2017 investment

(1) Excluding judgment for BONY litigation and debt maturities

APPENDIX

HEDGING POSITION

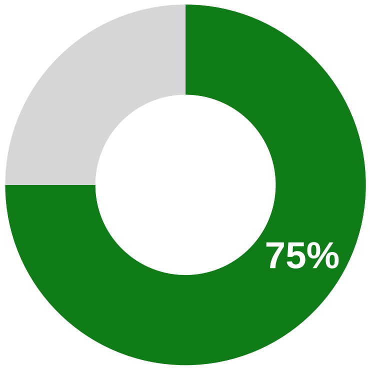
Natural Gas
2016 (1)



$3.00/$3.48/mcf
NYMEX

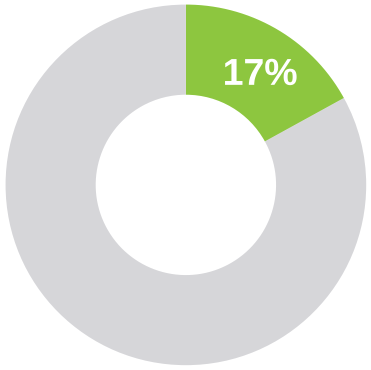
$2.85/mcf
NYMEX

Oil
2016 (1)



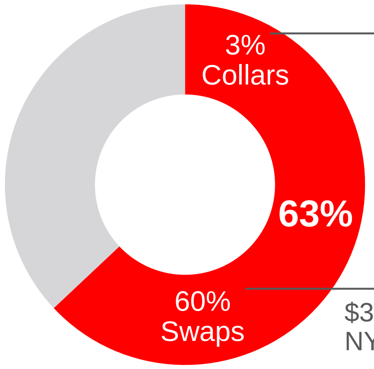
Swaps $46.84/bbl

NGL
2016 (1)



Ethane Swaps $0.17/gal
Propane Swaps $0.46/gal

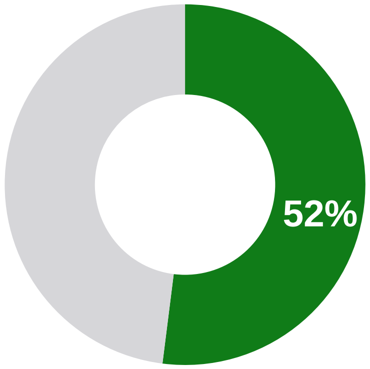
Natural Gas
2017 (2)



$3.00/$3.48/mcf
NYMEX

$3.07/mcf
NYMEX

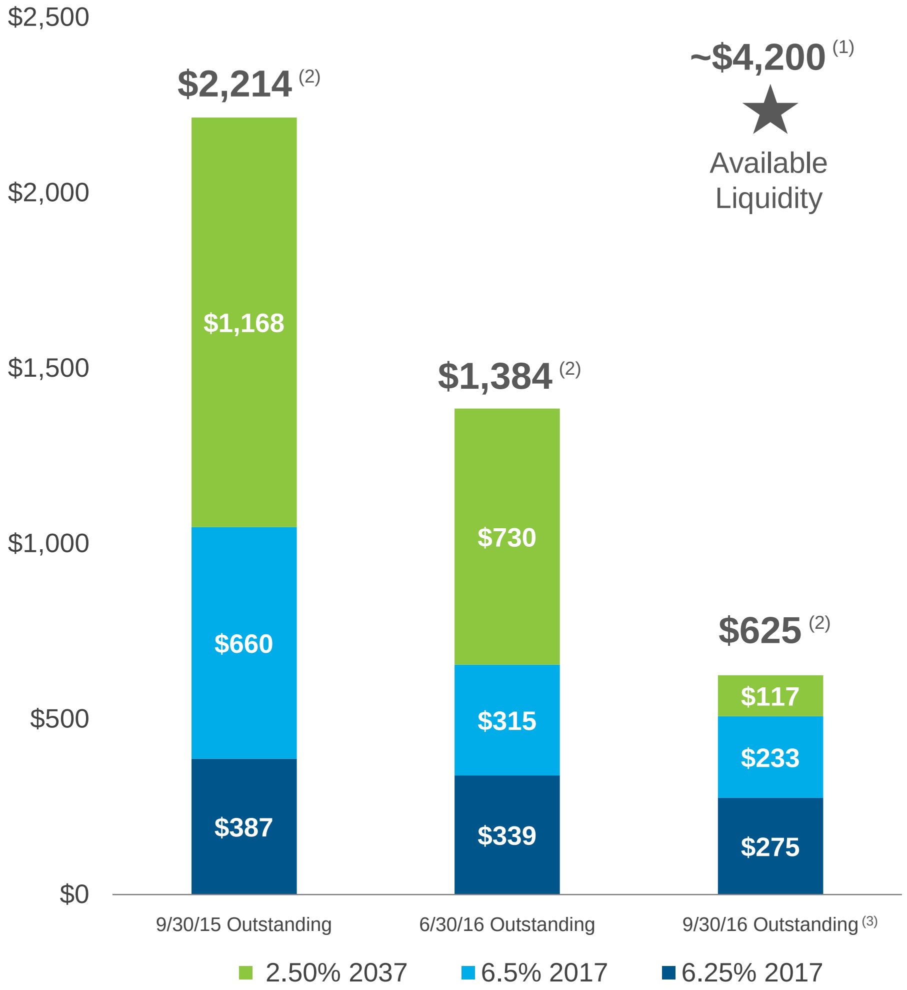
Oil
2017 (2)



Swaps $49.68/bbl

(1) Calculated off of 4Q production forecast as of 10/10/16
(2) Using midpoints for projected 2017 total production from 8/9/2016 Outlook

REDUCTION IN 2017 MATURITIES



70% reduction

In maturities from 9/30/15 to 9/30/16 (3)

Financial Transaction		Liquidity Savings (4)
Debt Exchange	$305mm of second-lien notes	**$291mm**
Open Market Repurchases	$138mm of cash	**$85mm**
Debt for Equity Exchanges	68.6mm shares (valued at $295mm)	**$354mm**
Tender Offer	$722mm of 1.5 lien term loan	**$684mm**

~$1.4 billion

Sources: Company management and disclosures. Note: $ in millions.

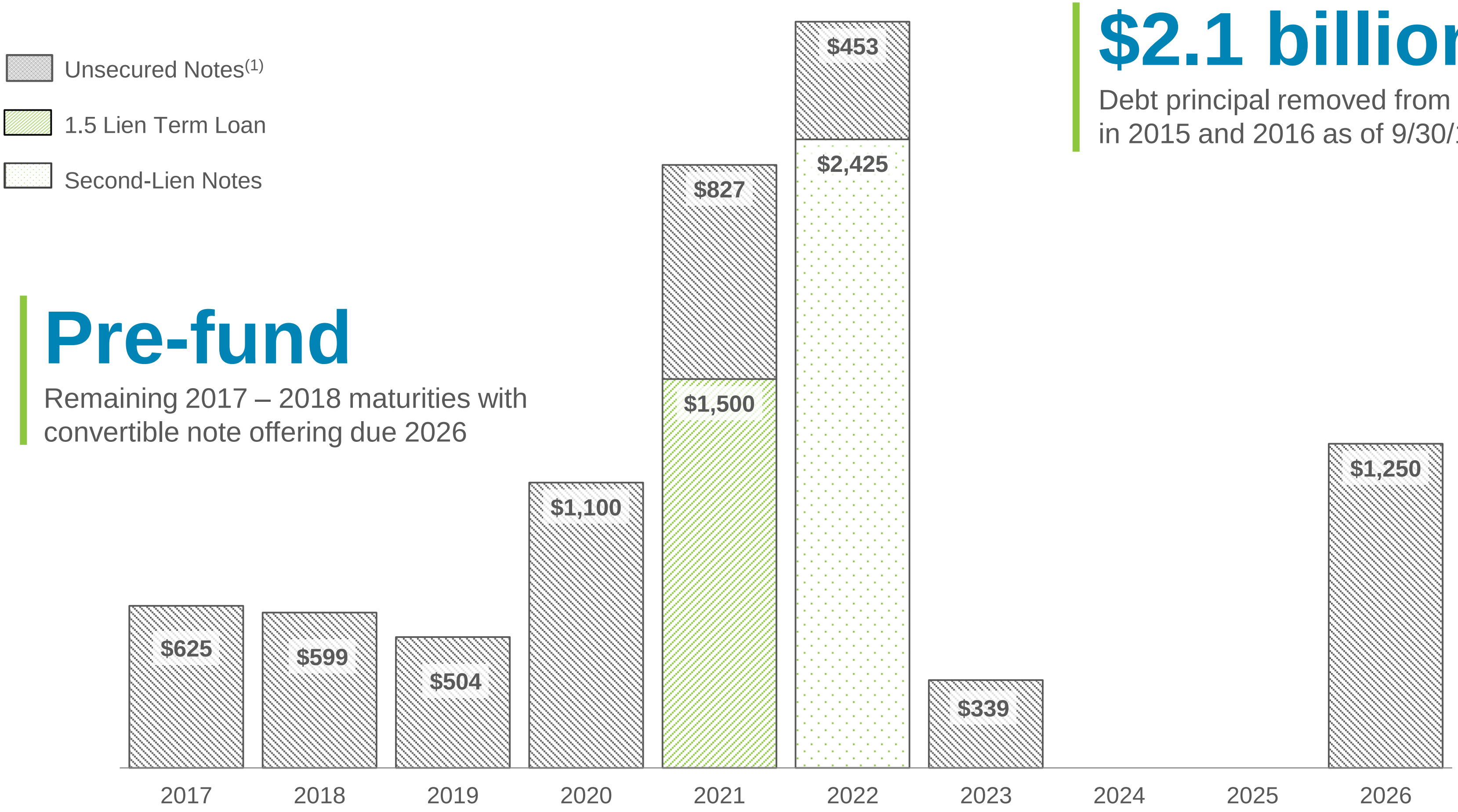
(1) $4.0 billion credit facility plus cash pro forma the convertible note funds, less outstanding letters of credit as of 9/30/2016

(2) 6.25% 2017's converted to USD for entire period using exchange rate of $1.1235 to €1.00 as of 9/30/2016

(3) Pro forma open market repurchases in October 2016

(4) Incremental liquidity savings includes principal savings and net interest impact

DEBT MATURITY PROFILE



Pre-fund

Remaining 2017 – 2018 maturities with convertible note offering due 2026

$2.1 billion

Debt principal removed from books in 2015 and 2016 as of 9/30/16 (2)

---

(1) Recognizes earliest investor put option as maturity for the 2.75% 2035, 2.50% 2037 and 2.25% 2038 Contingent Convertible Senior Notes

(2) Pro forma convertible note offering and open market repurchases in October 2016

PREFERRED STOCK EXCHANGES

To further improve the capital structure, Chesapeake negotiated agreements to exchange shares of preferred stock for common shares

- Issued an aggregate of 110.3 millions of shares of common stock to eliminate approximately $1.2 billion of preferred stock obligations from capital structure
- Secured annual dividend savings of approximately $67mm

	Position as of 9/30/16			Exchange Transaction Summary			Position as of 10/20/16		
Series	**Annual Dividend ($000)**	**Preferred Shares**	**Liquidation Preference Value ($000)**	**Preferred Shares Eliminated**	**Preference Value Eliminated ($000)**	**Common Shares Issued**	**Annual Dividend ($000)**	**Preferred Shares**	**Liquidation Preference Value ($000)**
4.50%	$11,515	2,558,900	$255,890	-	-	-	$11,515	2,558,900	$255,890
5.00%	$10,478	2,095,615	$209,562	134,000	$13,400	1,012,032	$9,808	1,961,615	$196,162
5.75%	$84,663	1,472,399	$1,472,399	606,271	$606,271	55,083,869	$49,802	866,128	$866,128
5.75% (A)	$63,181	1,098,799	$1,098,799	553,007	$553,007	54,243,322	$31,383	545,792	$545,792
	$169,837	7,225,713	$3,036,650	1,293,278	$1,172,678	110,339,223	$102,508	5,932,435	$1,863,972

$586mm reduction

In leverage from cap structure (1)

$67mm reduction

In cumulative annual dividends

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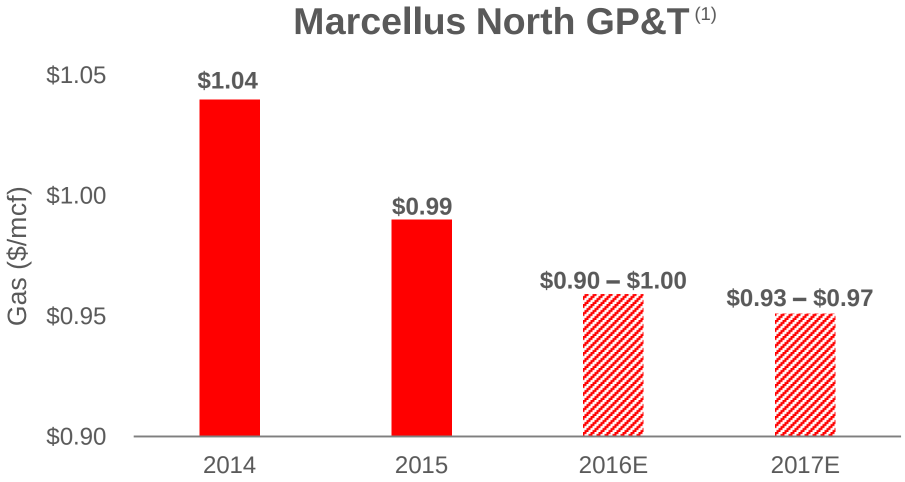
(1) Using Moody's valuation methodology

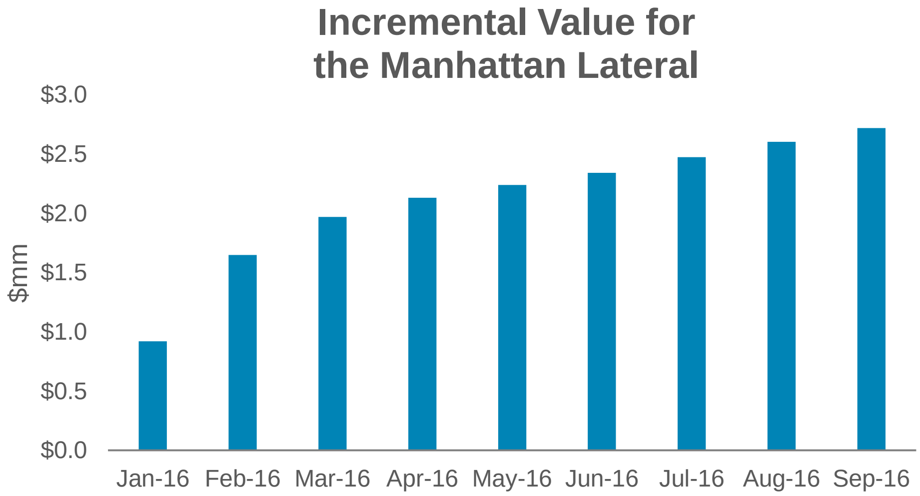
MARCELLUS NORTH



Cost-of-service advantage

Continued fee reduction through midstream optimization

- Increase infrastructure utilization
- Decrease capex for wedge production
- 20% decrease in gathering fees since 2014



Transport optionality enables margin capture above postings

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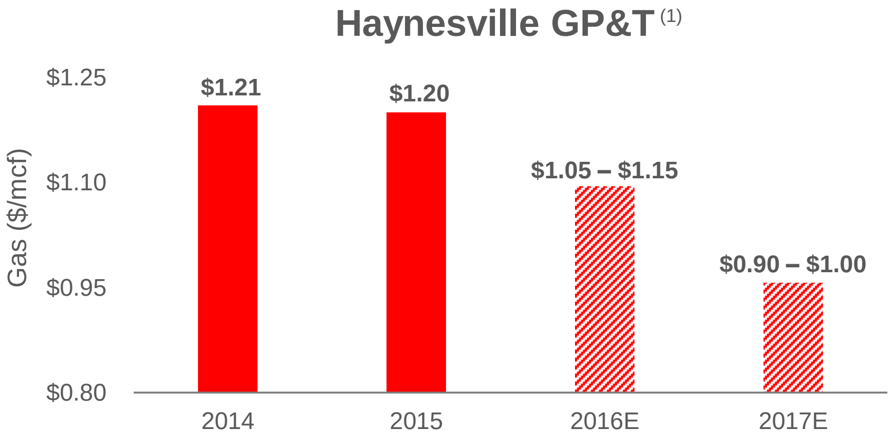
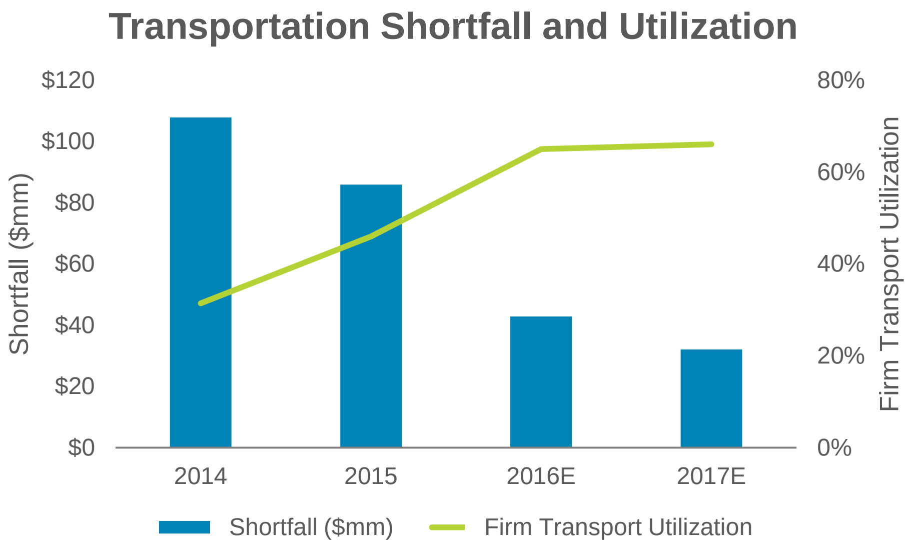
(1) Excludes all intercompany marketing fees

HAYNESVILLE





Transportation portfolio

Allows access to major market hubs, industrial market centers and export markets for LNG and Mexico

Improved Tiger commitment by 30% – 50%

In 2016

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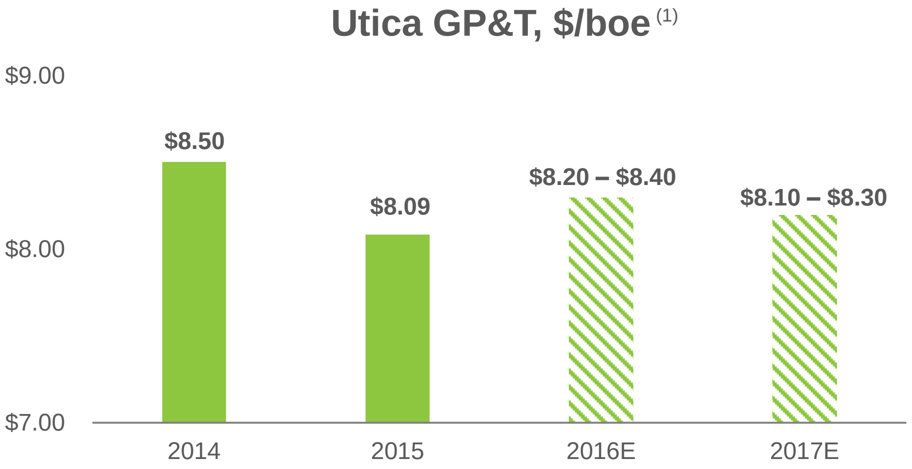
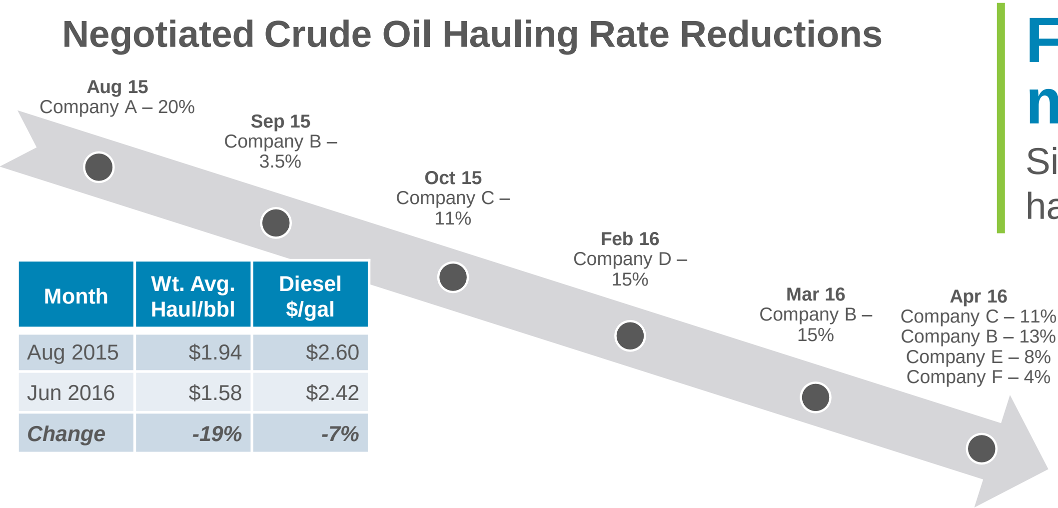
(1) Excludes all intercompany marketing fees

UTICA



Selling gas to premium out-of-basin locations with limited basis exposure



Aug 15
Company A – 20%

Sep 15
Company B – 3.5%

Oct 15
Company C – 11%

Feb 16
Company D – 15%

Mar 16
Company B – 15%

Apr 16
Company C – 11%
Company B – 13%
Company E – 8%
Company F – 4%

Month	Wt. Avg. Haul/bbl	Diesel $/gal
Aug 2015	$1.94	$2.60
Jun 2016	$1.58	$2.42
Change	*-19%*	*-7%*

Focus on expanding margins

Significant cost savings on crude oil hauling realized over past 14 months

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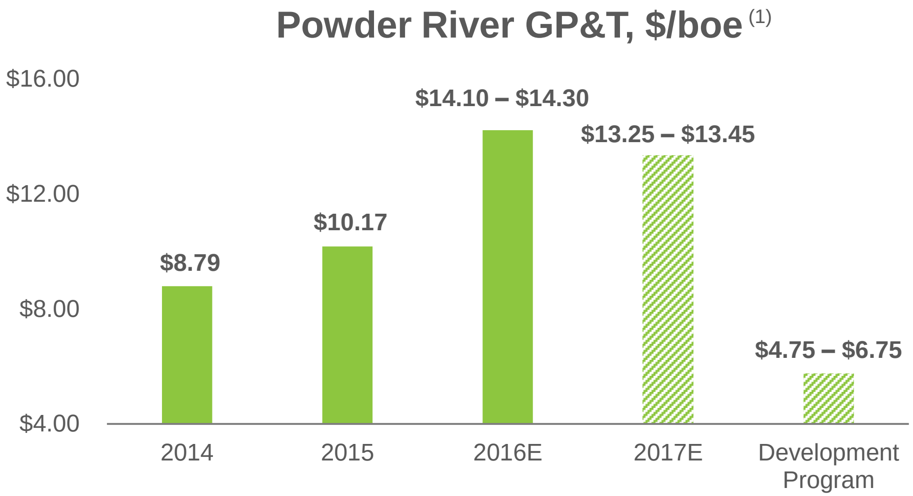
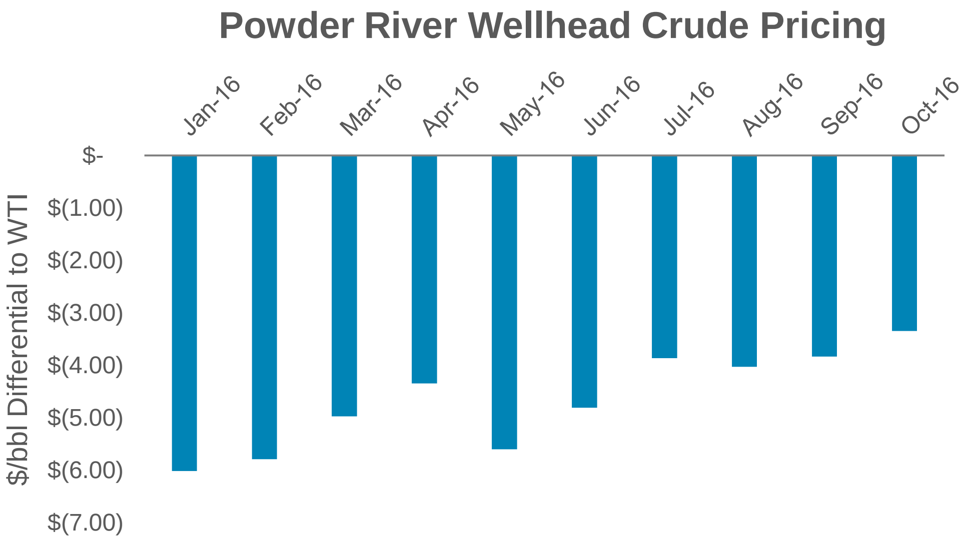
(1) Excludes all intercompany marketing fees

POWDER RIVER



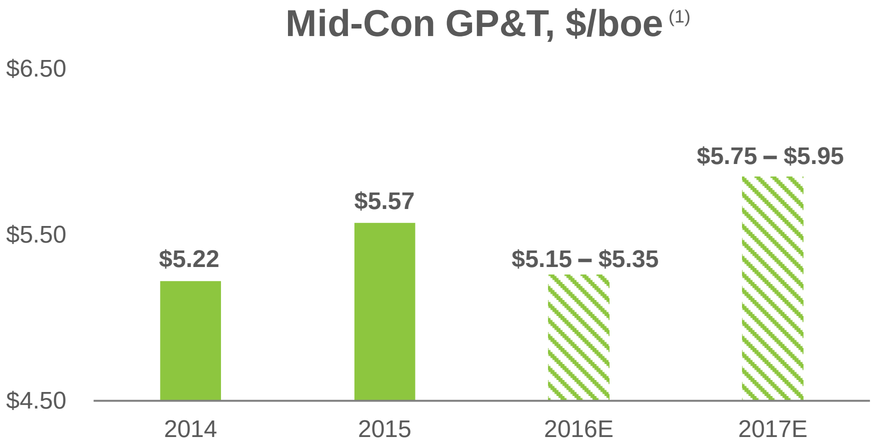


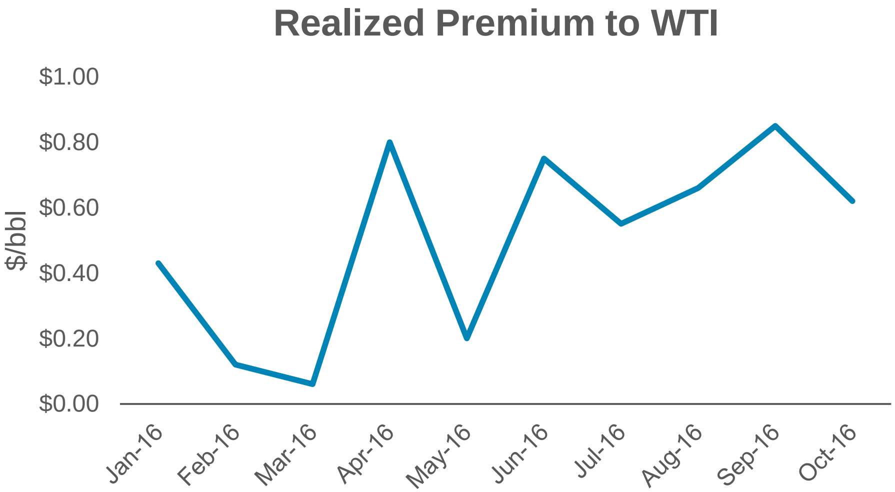
Targeting downstream markets with a premium to CIG

Development of crude takeaway from basin leads to improved margins

(1) Excludes all intercompany marketing fees

MID-CONTINENT





Increased revenue through additional NGL recovery

Wedge production under fixed-fee contracts allow greater NGL yields from gas production (vs. historical POP contracts)

Recognizing increasing premiums for Miss Lime production

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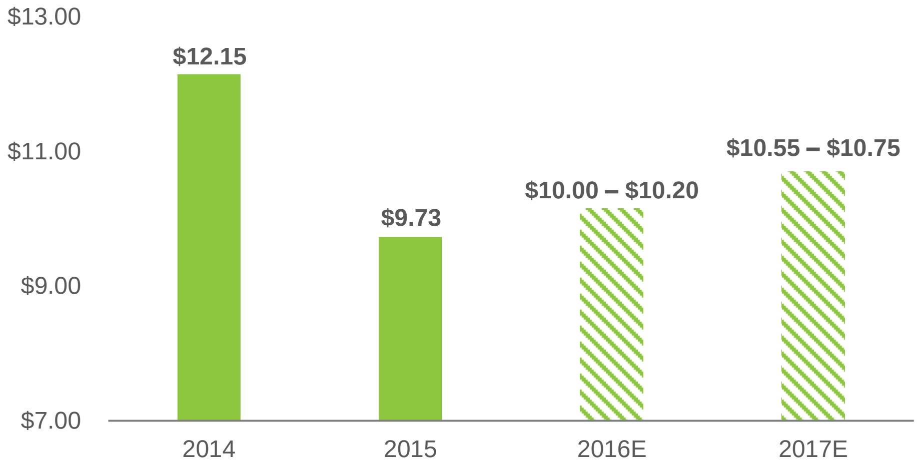
(1) Excludes all intercompany marketing fees. 2017 Mid-Con impact from NGL wedge production under fixed processing fee.

SOUTH TEXAS

Eagle Ford GP&T, $/boe (1)

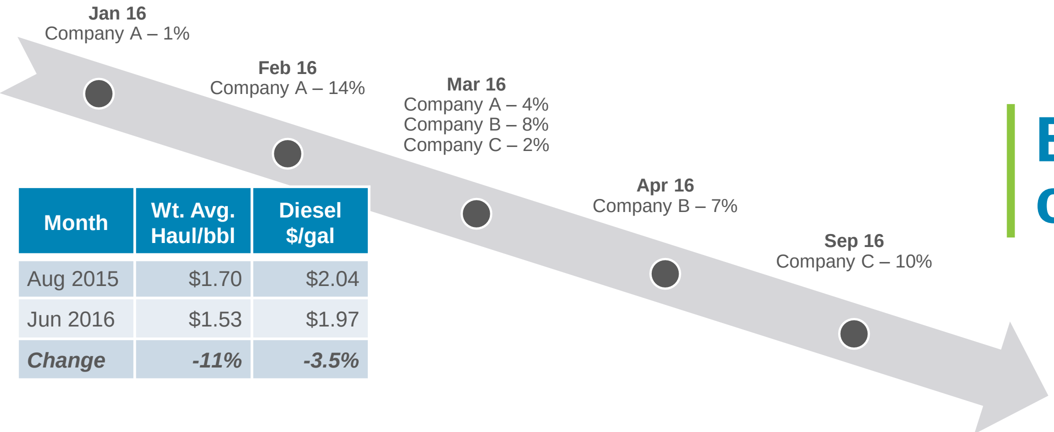


Better margins through downstream marketing

Crude market access to:

- ~2,500 mbo/d per day refinery demand in Houston
- ~700 mbo/d per day refinery demand in Corpus
- Multiple deep-water docks for potential exports

Negotiated Crude Oil Hauling Rate Reductions



Month	Wt. Avg. Haul/bbl	Diesel $/gal
Aug 2015	$1.70	$2.04
Jun 2016	$1.53	$1.97
Change	*-11%*	*-3.5%*

Better margins through crude oil hauling

(1) Excludes all intercompany marketing fees

MARKETING COMMITMENTS ESTIMATES ($MM)

~15% improvement in transport utilization since 2015 (1)

Category	2016 (2)	2017	2018	2019	2020	2021	Thereafter
Barnett Gathering	415	-	-	-	-	-	-
Barnett Transportation	165	-	-	-	-	-	-
Haynesville Gathering	215	195	-	-	-	-	-
Haynesville Transportation	160	160	150	150	125	115	425
Northeast Gathering	10	25	45	45	45	45	550
Northeast Transport	275	270	260	260	260	255	2470
NGL Transportation	60	70	90	90	90	90	600
Crude Oil Transportation	260	290	260	255	260	255	580
Processing/Treating	150	150	155	155	150	125	680
Other Commitments	230	210	210	185	185	85	10
Total	**1,940**	**1,370**	**1,170**	**1,140**	**1,115**	**970**	**5,315**

(1) Continuing to optimize firm transportation shortfalls through capacity releases, third-party gas purchases and asset management agreements
(2) Also have additional gas gathering agreements with cost-of-service based fees; redetermined annually or tiered fees based on volumes

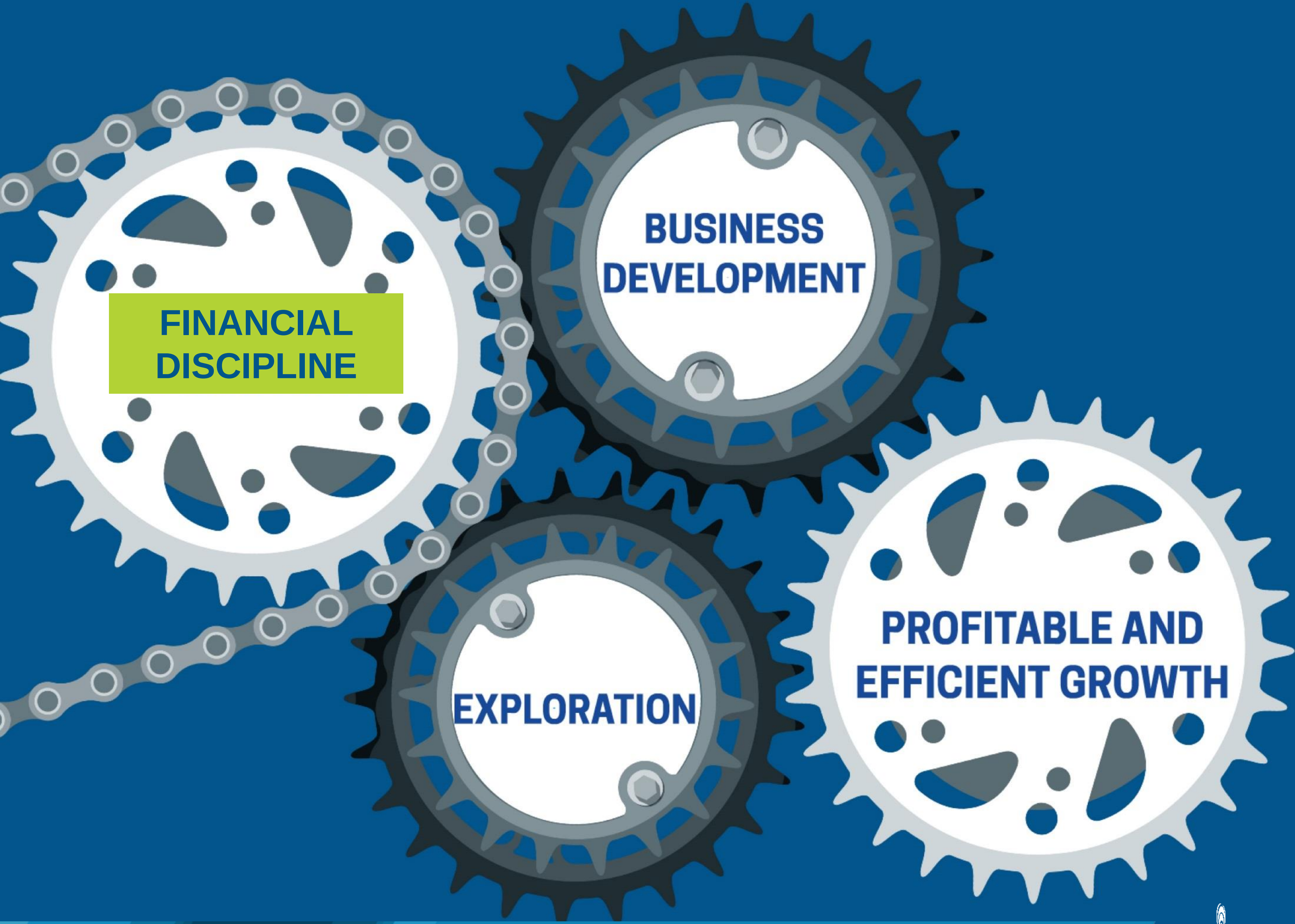
RECONCILIATION OF PV10 TO STANDARDIZED MEASURE

PV10 is a non-GAAP metric used by the industry, investors and analysts to estimate the present value, discounted at 10% per annum, of estimated future cash flows of the company's estimated proved reserves before income tax and asset retirement obligations. The following table shows the reconciliation of PV10 to the company's standardized measure of discounted future net cash flows, the most directly comparable GAAP measure, for the year ended December 31, 2015 and for the interim period ended June 30, 2016. Management believes that PV10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural 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, management believes the use of a pre-tax measure is valuable for evaluating the company. PV10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP. With respect to PV10 calculated as of an interim date, it is not practical to calculate taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

PV10 – June 30, 2016 @ NYMEX Strip		11,050
Less: Change in pricing assumption from NYMEX Strip to SEC		(7,995)
PV10 – June 30, 2016 @ SEC		3,055
Change in PV10 from 12/31/15 to 6/30/16		1,672
PV10 – December 31, 2015 @ SEC		4,727
Less: Present value of future income tax discounted at 10%		(34)
Standardized measure of discounted future cash flows – December 31, 2015	$	4,693

Summary and Path Forward

DOUG LAWLER

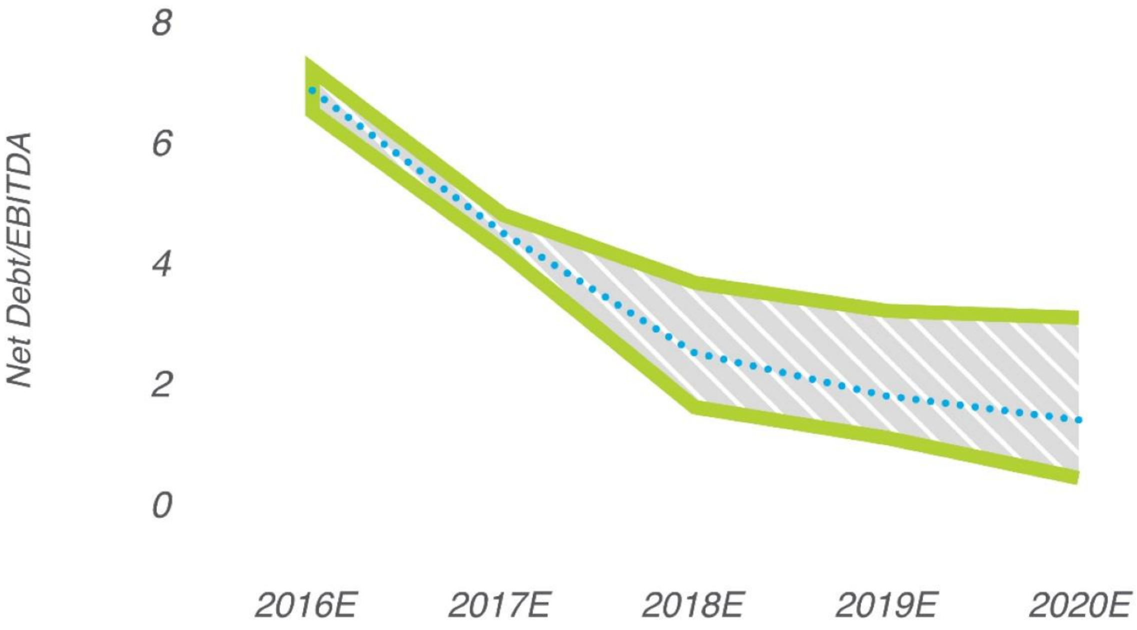


FINANCIAL DISCIPLINE
BUSINESS DEVELOPMENT
EXPLORATION
PROFITABLE AND EFFICIENT GROWTH

$2–3 BILLION

in additional planned debt reduction

REDUCE LEVERAGE TO 2X Debt/EBITDA



*Assumes retirement of maturities in 2017 and 2018 as well as conversion to equity of convertible note in 2019; 5 – 15% production growth and gas and oil price assumptions range from $2.50 – $3.50 and $50 – $70

BUSINESS DEVELOPMENT

FINANCIAL DISCIPLINE

EXPLORATION

PROFITABLE AND EFFICIENT GROWTH

- **Active Portfolio Management**

- **Committed to high-grading the portfolio through value-accretive transactions**

FINANCIAL DISCIPLINE
BUSINESS DEVELOPMENT
EXPLORATION
PROFITABLE AND EFFICIENT GROWTH

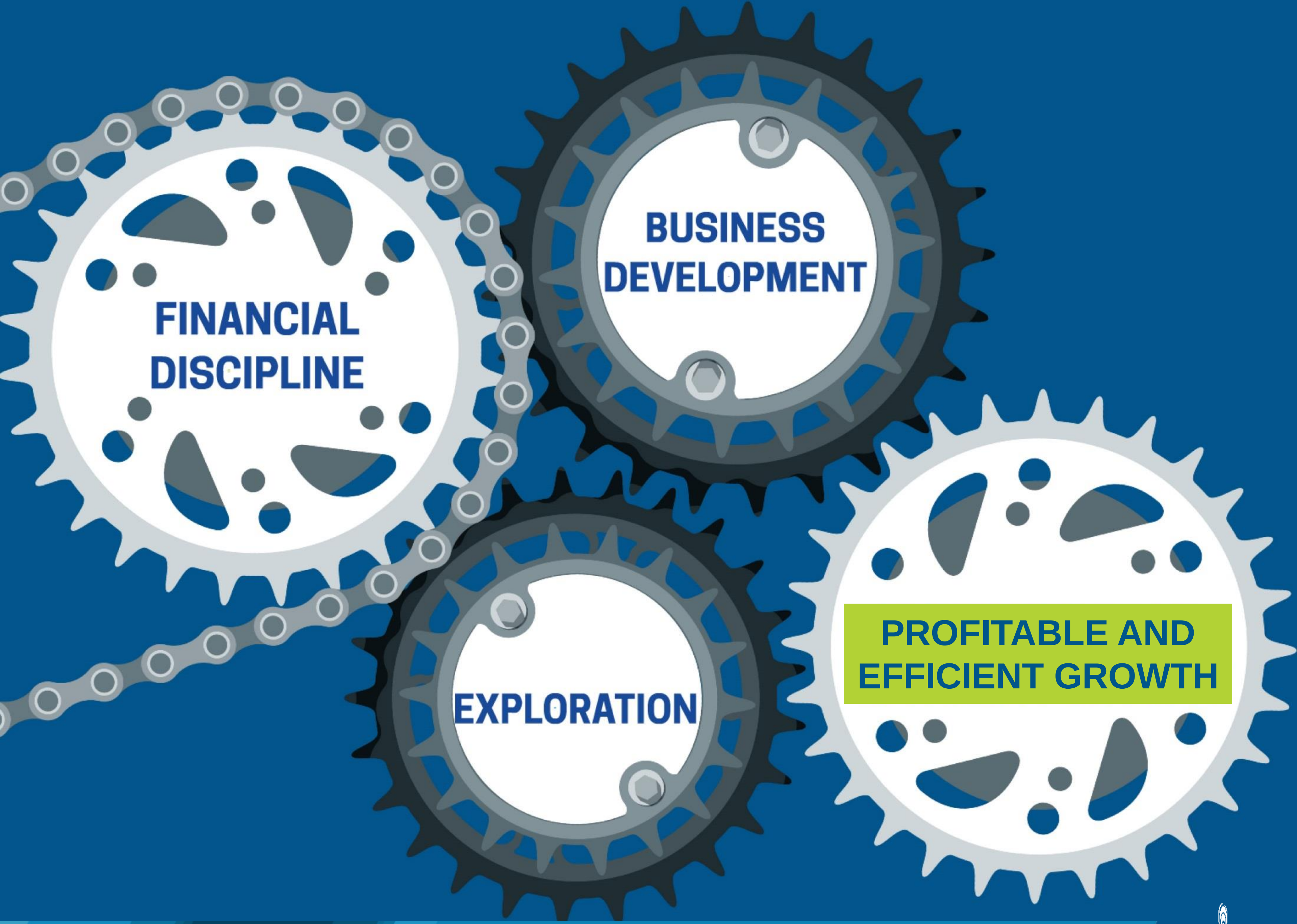
Exploration Opportunities

17 Prospects adding value to current HBP position

15 Growth opportunities in CHK-operated basins

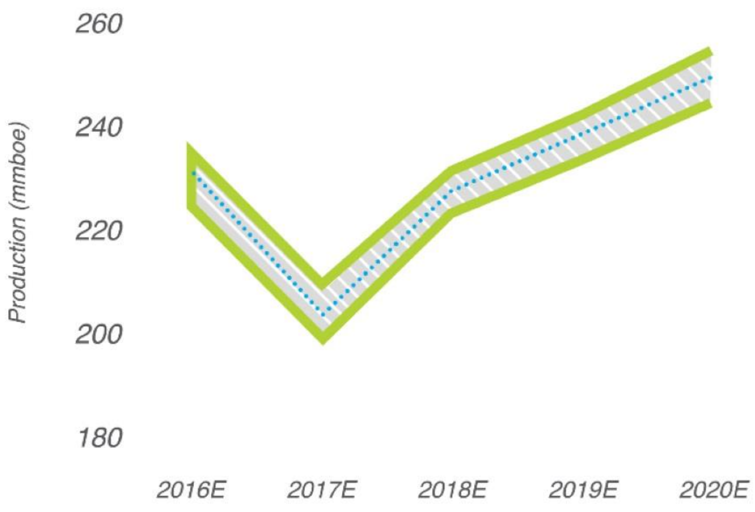
11 New basin-entry plays

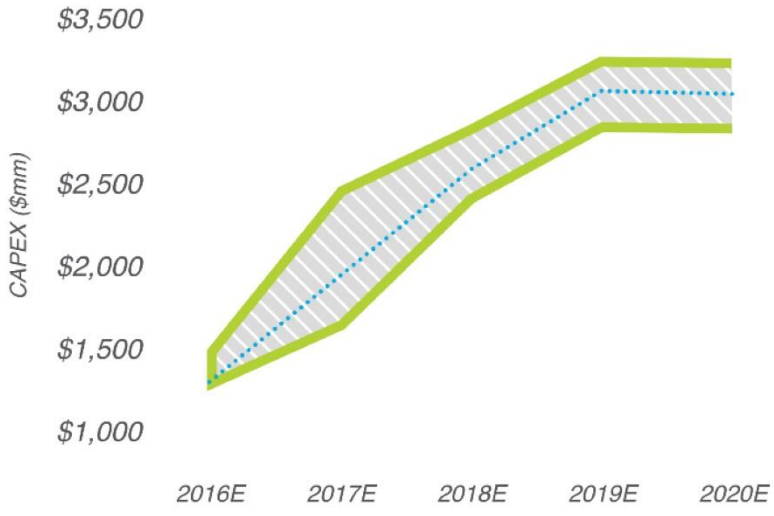
COMMITTED TO FURTHER STRENGTHEN PORTFOLIO THROUGH EXPLORATION



FINANCIAL DISCIPLINE
BUSINESS DEVELOPMENT
EXPLORATION
PROFITABLE AND EFFICIENT GROWTH

TARGETING
5–15%
GROWTH THROUGH
END OF DECADE





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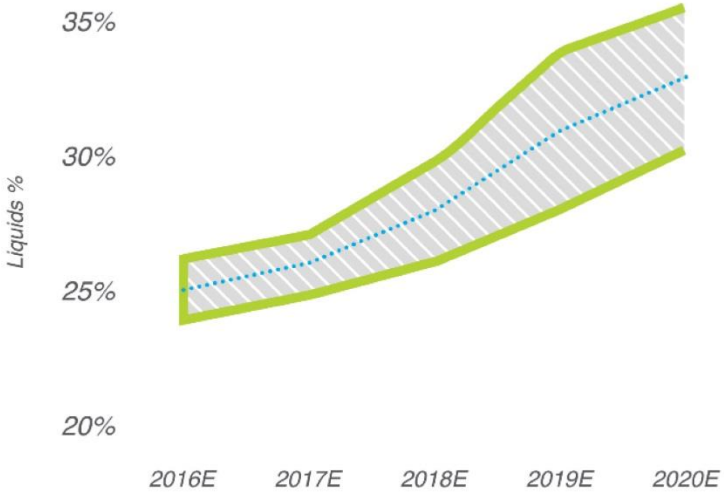
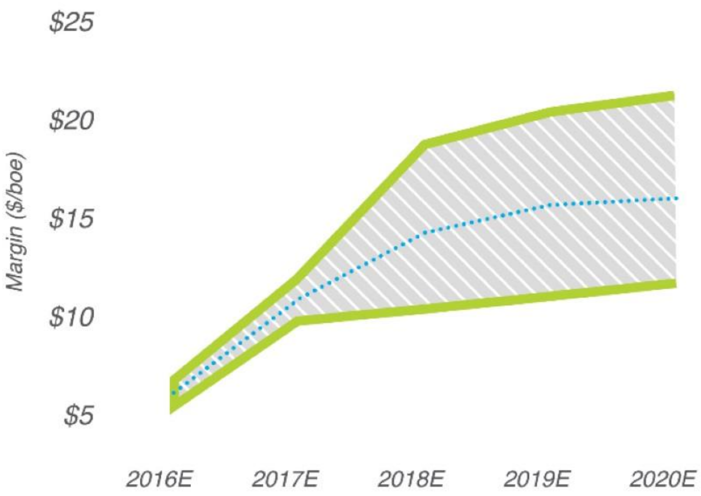
*5 – 15% represents an adjusted production growth; capital ranges dependent on anticipated pricing

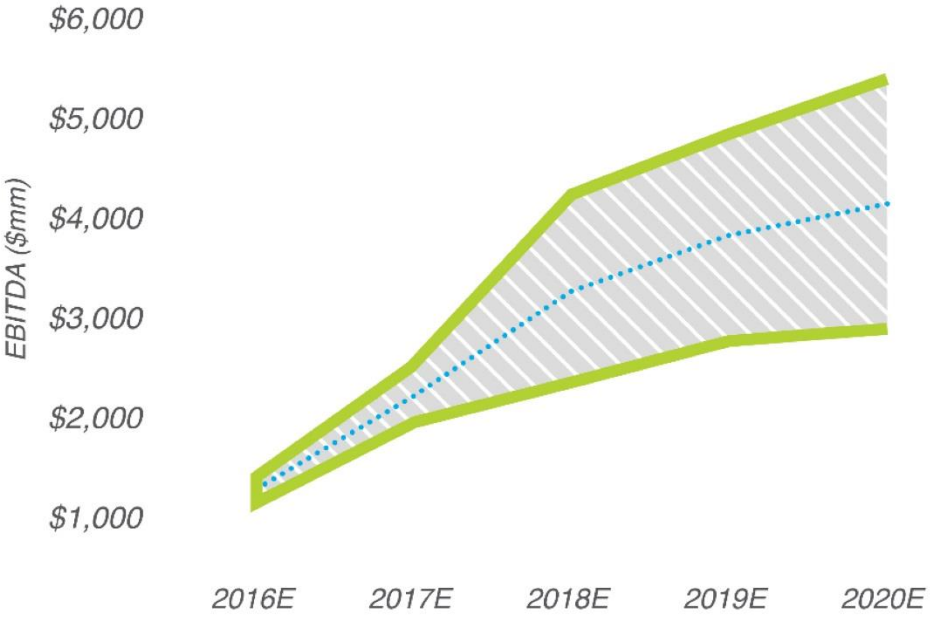
3X MARGIN EXPECTED TO TRIPLE



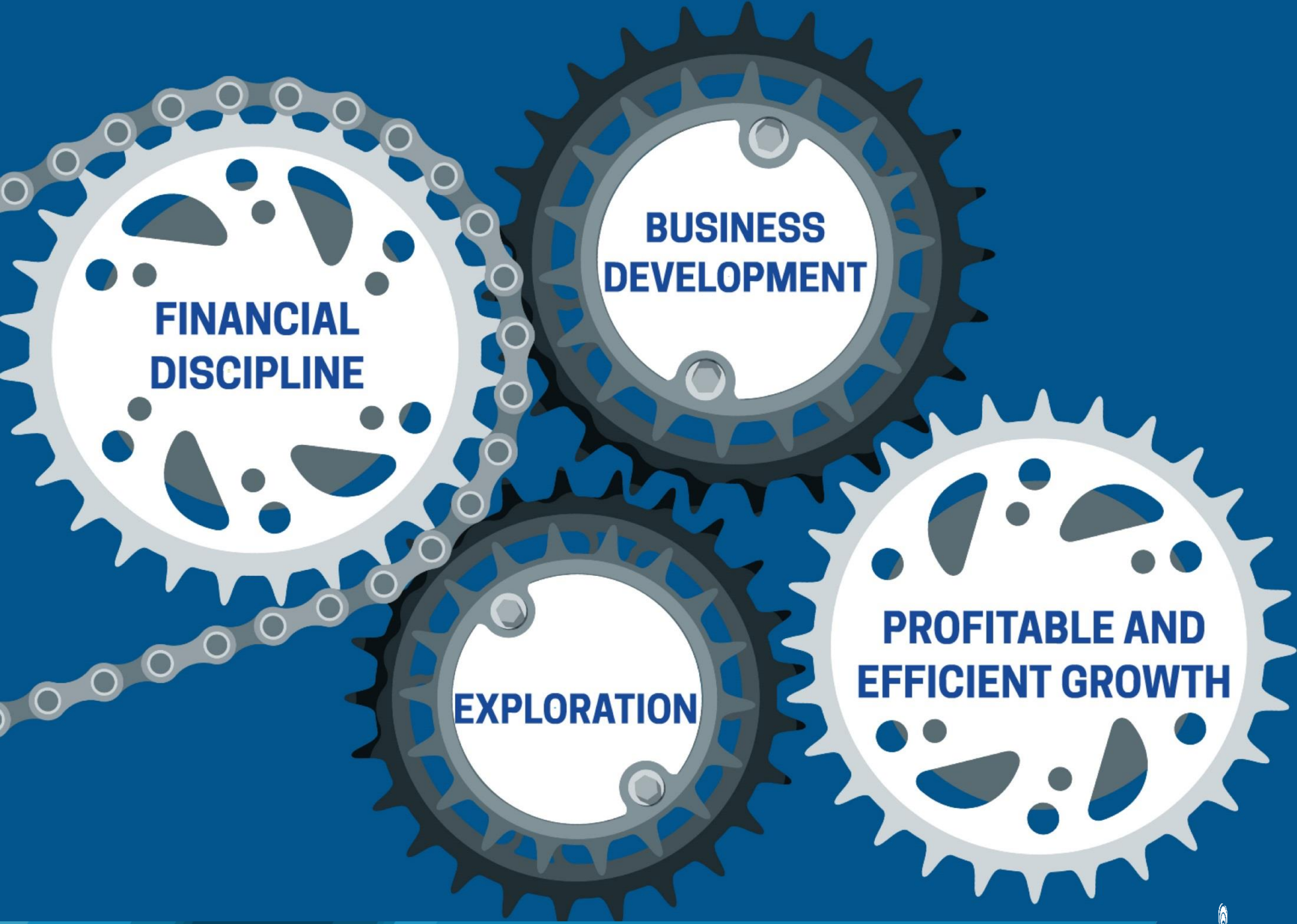


*5 – 15% production growth and gas and oil price assumptions range from $2.50 – $3.50 and $50 – $70

EBITDA GROWTH
MORE THAN DOUBLE
BY 2018



*5 – 15% production growth and gas and oil price assumptions range from $2.50 – $3.50 and $50 – $70



FINANCIAL DISCIPLINE

BUSINESS DEVELOPMENT

EXPLORATION

PROFITABLE AND EFFICIENT GROWTH

Chesapeake Energy Rediscovered

Done more, doing more, more to do.