21 The Oil & Gas Conference Denver

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Investor Presentation

August 2016

Forward-Looking Statements

CAUTIONARY STATEMENTS RELEVANT TO FORWARD-LOOKING INFORMATION FOR THE PURPOSE OF “SAFE HARBOR” PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This presentation of Gastar Exploration Inc. contains forward-looking statements relating to Gastar’s operations that are based on management’s current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as “anticipates,” “expects,” “intends,” “plans,” “targets,” “projects,” “believes,” “seeks,” “schedules,” “estimates,” “budgets” and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond the company’s control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: changing crude oil and natural gas prices; changing refining, marketing and chemical margins; actions of competitors or regulators; timing of exploration expenses; timing of crude oil liftings; the competitiveness of alternative-energy sources or product substitutes; technological developments; the results of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company’s net production or manufacturing facilities or delivery/transportation networks due to war, accidents, political events, civil unrest, sever weather or crude oil production quotas that might be imposed; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental statutes, regulations and litigation; the potential liability resulting from other pending or future litigation; the company’s future acquisition or disposition of assets and gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; the effects of changed accounting rules under generally accepted accounting principals promulgated by rule-setting bodies; and the factors set forth under the heading “Risk Factors” in the company’s 2015 Annual Report on Form 10-K. In addition, such statements could be affected by general domestic and international economic and political conditions. Unpredictable or unknown factors not discussed in this presentation could also have material adverse effects on forward-looking statements. The company undertakes no obligation to publicly update or revise any forward-looking statements except as required by law.

Statement on Hydrocarbon Quantities

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions (using unweighted average 12-month first day of the month prices), operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The SEC also permits the disclosure of separate estimates of probable or possible reserves that meet SEC definitions for such reserves, however, we currently do not disclose probable or possible reserves in our SEC filings.

We may use the terms "resource potential" and "EUR" in this presentation to describe estimates of potentially recoverable hydrocarbons that the SEC rules prohibit from being included in filings with the SEC. These are based on the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These quantities do not constitute "reserves" within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules. "EUR," or Estimated Ultimate Recovery, refers to our management's internal estimates based on per well hydrocarbon quantities that may be potentially recovered from a hypothetical future well completed as a producer in the area. For areas where the Company has no or very limited operating history, EURs are based on publicly available information relating to operations of producers operating in such areas. For areas where the company has sufficient operating data to make its own estimates, EURs are based on internal estimates by the Company's management and reserve engineers.

"Well costs" are based on internally generated company estimates and actual results may vary. "Drilling locations" represent the number of locations that we currently estimate could potentially be drilled in a particular area estimated by well spacing and geological characteristic assumptions applicable to that area. The actual number of locations drilled and quantities that may be ultimately recovered from the Company's interests will differ substantially. There is no commitment by the Company to drill all of the drilling locations which have been attributed these quantities.

"Net acreage" is calculated using net well locations, 640 acre drilling units and the spacing assumptions for a given formation.

Factors affecting ultimate recovery include: (1) the scope of our on-going drilling program, which will be directly affected by factors that include the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and (2) actual drilling results, including geological and mechanical factors affecting recovery rates. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

The following is a description of the referenced terms we have used to refer to hydrocarbon quantities:

1P reserves*: estimates of proved reserves which in this presentation are estimated by Wright & Company as of June 30, 2016 using SEC pricing and definitions.*

EURs*: estimated ultimate recoveries per well based on estimated future production type curves using NYMEX futures curve pricing as of August 1, 2016, as follows:*

- *for Meramec, based on June 30, 2016 Wright & Company proved reserve type curve assuming 5,000' lateral;*
- *for Upper Hunton and Lower Hunton in the West Edmond Hunton Lime Unit (WEHLU), based on June 30, 2016 Wright & Company proved reserve type curve and assuming 6,000' lateral*

Corporate Overview



Gastar Overview

Mid-Continent focused operator with high exposure to prolific STACK Play

Mid-Continent STACK Play

STACK Optionality

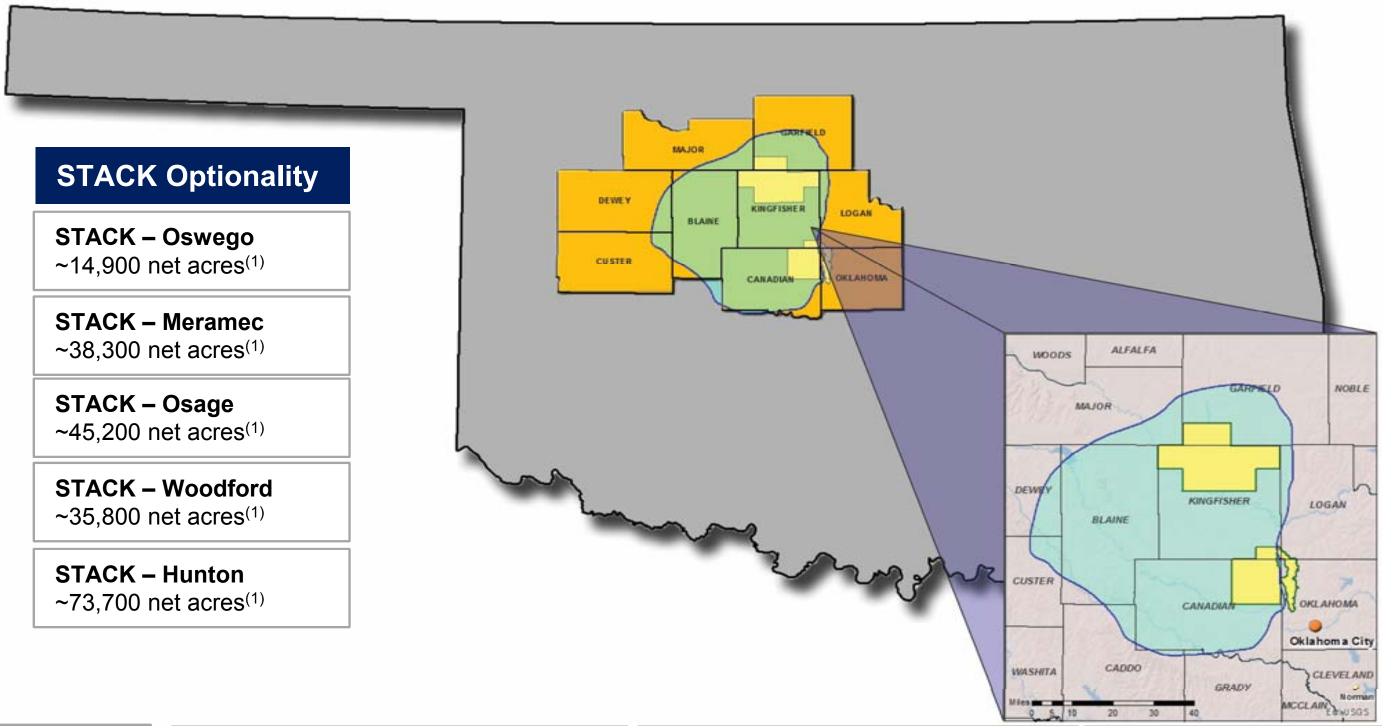
STACK – Oswego
~14,900 net acres(1)

STACK – Meramec
~38,300 net acres(1)

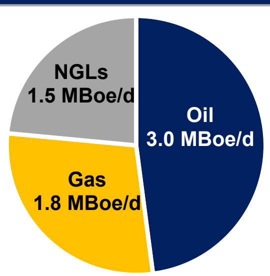
STACK – Osage
~45,200 net acres(1)

STACK – Woodford
~35,800 net acres(1)

STACK – Hunton
~73,700 net acres(1)

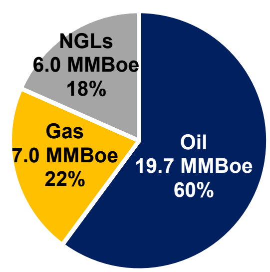


Q2'16 Net Prod. – Mid-Con



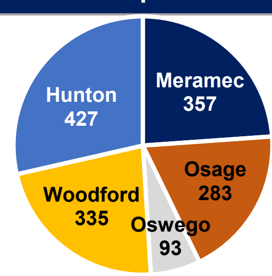
6.2 MBoe/d

Mid-Con Proved Reserves(2)



32.8 MMBoe

Net Undeveloped Drill. Loc.(1)



1,495

Corporate Profile

Headquarters: Houston
NYSE Market Ticker: GST
Pref. Stock Ticker: GST-PA & GST-PB
Market Capitalization(3): $119 million
Enterprise Value(3): $648 million
Shares Outstanding(3): 131.7 million
Institutional Ownership(4): 34%

1. Acreage and drilling locations developed by the Company based on assumptions and methodology described on page 3 of this presentation as of 06/30/2016
2. Based on 06/30/16 Wright & Company, Inc. report utilizing SEC pricing
3. Stock Price as of 08/09/2016, includes issued and outstanding preferred shares of $154.6 million face value, $425 million of debt and $50.8 million of cash as of 06/30/2016. Share count as of 08/01/2016
4. Source: Bloomberg as of 08/09/2016

Key Investment Criteria

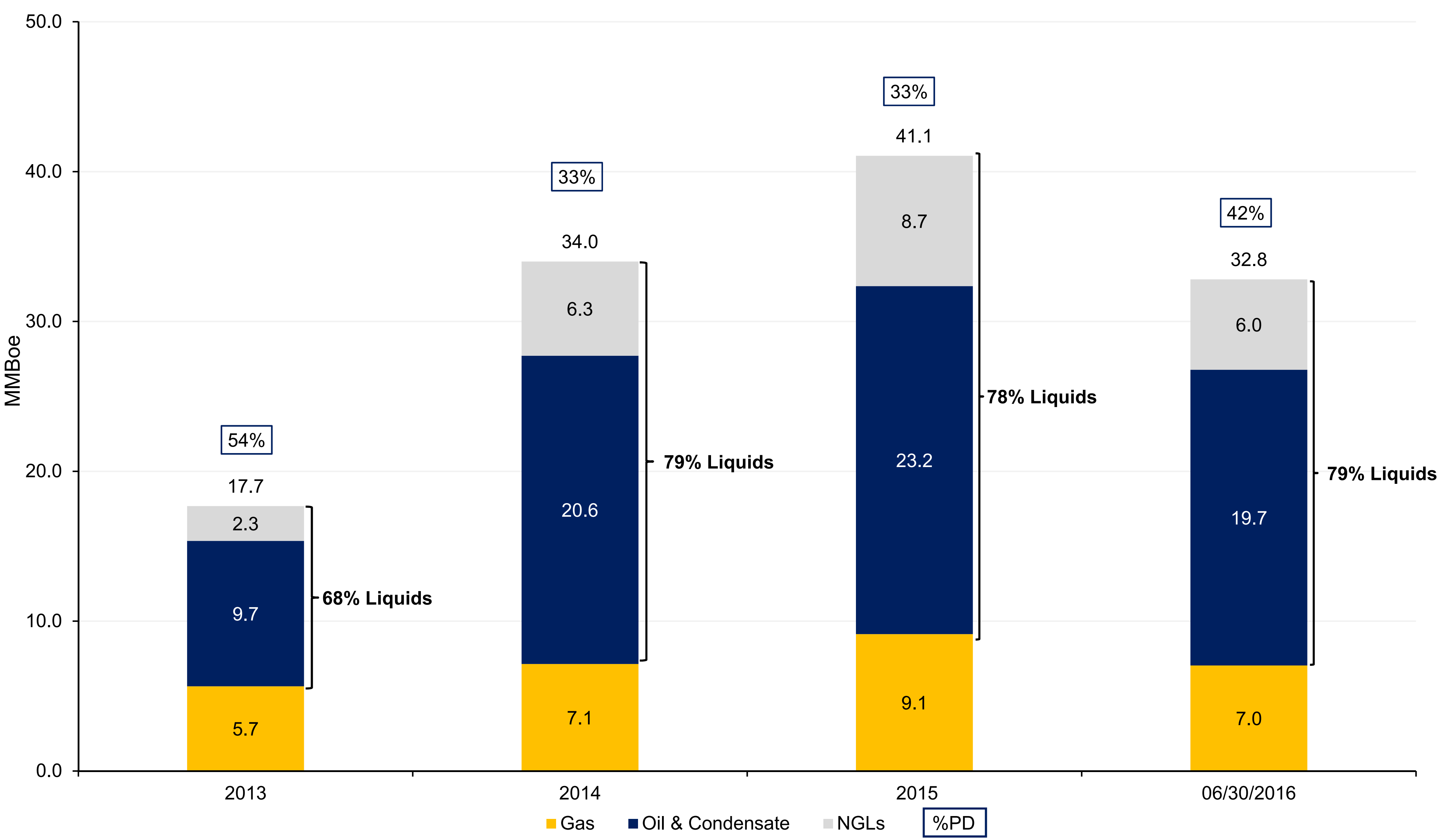
High-Quality STACK Resource Base	▪ Pure play Mid-Continent STACK operator ▪ Large acreage position in coveted Mid-Continent STACK play ▪ Strong drilling results in the Meramec shale and Hunton Limestone oil play ▪ Offset STACK Play wells (Meramec-Osage-Oswego-Woodford-Hunton) successful
Organic Growth Strategy Through Drill Bit & Strategic Acquisitions	▪ ~3,942 gross, ~1,495 net undrilled horizontal locations (Meramec-Oswego-Osage-Woodford-Hunton)(1) ▪ Robust inventory of economic drilling locations in multiple benches at today's low price environment ▪ Continued delineation of core Meramec position ▪ Currently drilling first Osage test well
Strong Oil Weighted Proved Reserve Profile	▪ Mid-Continent proved reserves of 32.8 MMBoe(2) (60% oil) ▪ Mid-Continent oil reserves of 19.7 MMBbls(2)
Strong Financial Profile & Hedge Position	▪ No near term debt maturities ▪ Active hedging program – 2016 PDP hedge position – 75% of oil PDP production and 80% of gas PDP production(3) ▪ Flexibility in capital expenditures program
Low Cost Structure with Ability to Drive Costs Lower	▪ Mid-Continent: total direct costs Q2'2016 $9.19/Boe(4), down from $9.52/Boe(4) YE 2015 ▪ Operational control creates ability to drive down costs

1. Drilling locations developed by the Company based on assumptions and methodology described on page 3 of this presentation as of 06/30/2016
2. Based on 06/30/16 Wright & Company, Inc. report utilizing SEC pricing
3. Hedges as of 08/01/2016. Oil hedges include WTI for NGL proxy hedges and 30% of NGL PDP
4. Mid-Continent LOE including workover expense Q2'2016, excluding workover Mid-Continent total directs costs for Q2'2016 of $9.57/Boe up from $7.54/Boe YE 2015

Mid-Continent Reserve Summary

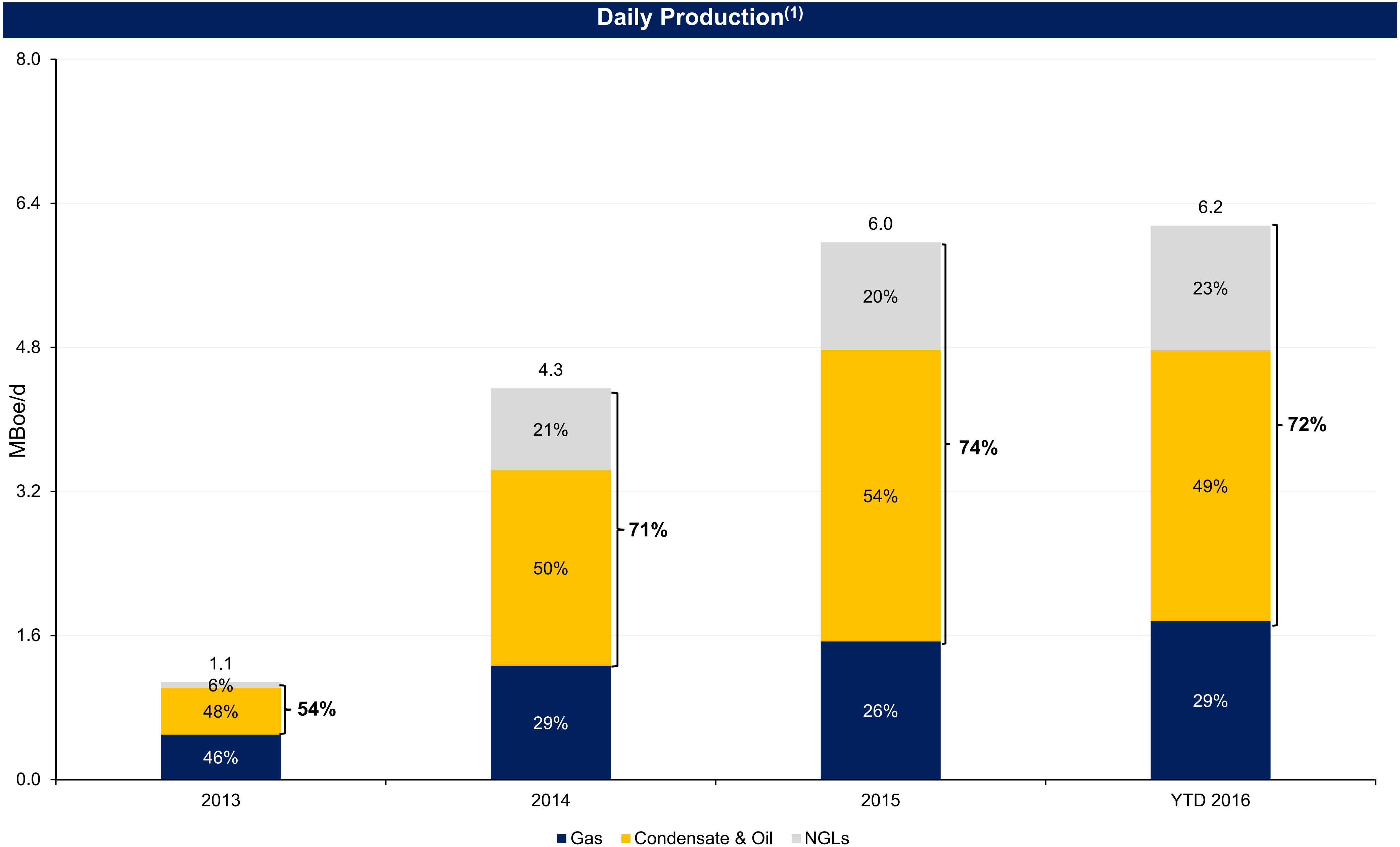
GASTAR

Mid-Continent Proved Reserves By Product[1]



1. Gas converted to oil equivalent on basis of 6 Mcf:1 Boe

Mid-Continent Production Growth



1. Gas converted to oil equivalent on basis of 6 Mcf:1 Boe

Summary Target Economics

- **Based on Wright & Co. proved reserve type curve assumptions[1]**

	Meramec	WEHLU Upper Hunton	WEHLU Lower Hunton
Number of net drilling locations	~357	~111	~108
EURs			
Processed	843 Mboe	402 Mboe	557 Mboe
Wet Gas	752 Mboe	380 Mboe	527 Mboe
Daily Peak Rate (wet gas)	1,196 Boe/d	400 Boe/d	373 Boe/d
% Gas (processed)	32%	14%	14%
% Liquids (processed)	68%	86%	86%
% Oil (wet gas)	48%	75%	75%
IRR	45%	49%	43%
Costs ($MM)	$4.5	$3.0	$4.5
PV-10 ($MM)	$3.5	$3.1	$4.5
F&D Costs (processed)	$6.80/Boe	$9.12/Boe	$9.87/Boe
Est. Average Proc. Cum. Daily Rate[2]:			
1st 30 Days	184 Boe/d	397 Boe/d	386 Boe/d
1st 60 Days	620 Boe/d	372 Boe/d	373 Boe/d
1st 90 Days	677 Boe/d	351 Boe/d	361 Boe/d

1. EURs, related type curves, and drilling locations are developed by the Company based on assumptions and methodologies described on page 3 of this presentation as of 06/30/2016
2. Cumulative daily rates calculated using processed gas stream

Capital Budget

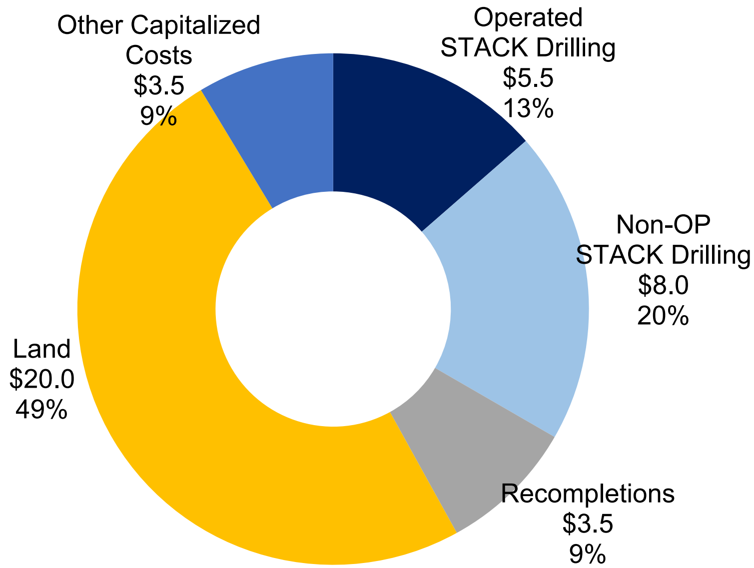
Preliminary 2016 Budget Detail

Area	Capital ($MM)	% of Total
STACK Operated Drilling	$5.5	14%
STACK Non-Operated Drilling	8.0	20%
Recompletions	3.5	9%
Land	20.0	49%
Other Capitalized Costs	3.5	9%
Total	**$40.5**	**100%**

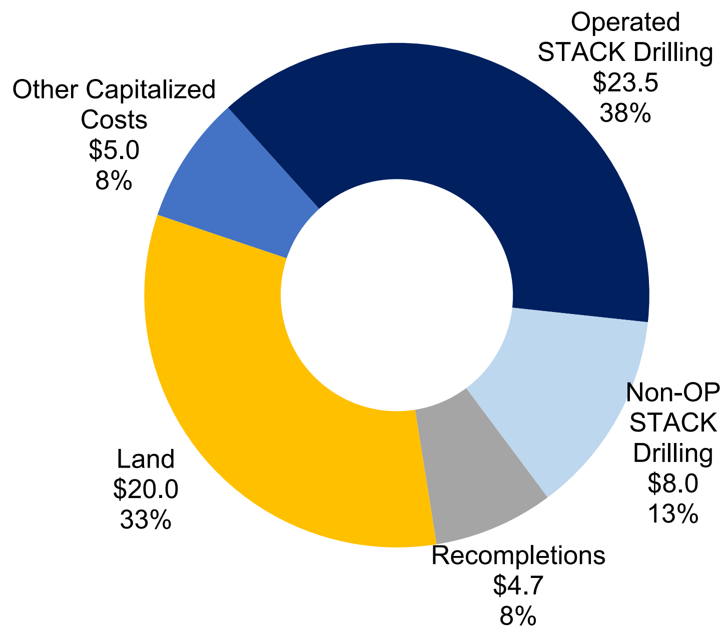
Revised 2016 Budget Detail

Area	Capital ($MM)	% of Total
STACK Operated Drilling	$23.5	38%
STACK Non-Operated Drilling	8.0	13%
Recompletions	4.7	8%
Land	20.0	33%
Other Capitalized Costs	5.0	8%
Total	**$61.2**	**100%**

Preliminary Budget Allocation



Revised Budget Allocation

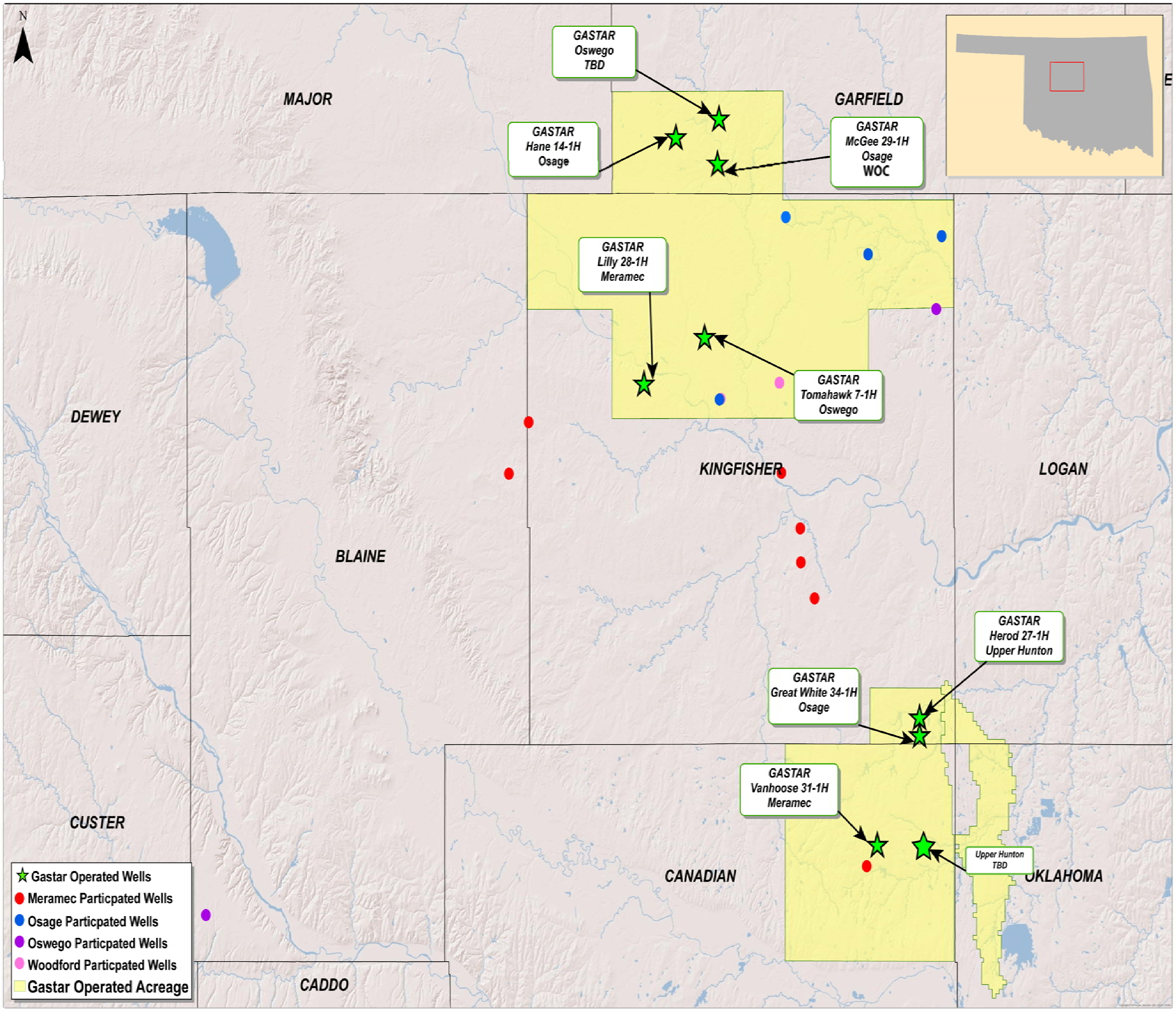


2016 /17 Delineation Drilling Program

Highlights

- De-risk multiple formations across a large geographic area to support and grow NAV
- Maximizes impact of limited drilling capital with locations in key areas to further delineate core STACK acreage

Delineation Drilling Program	Gross Wells
Meramec	2
Osage	3
Oswego	2
Hunton	2
Total	**9**

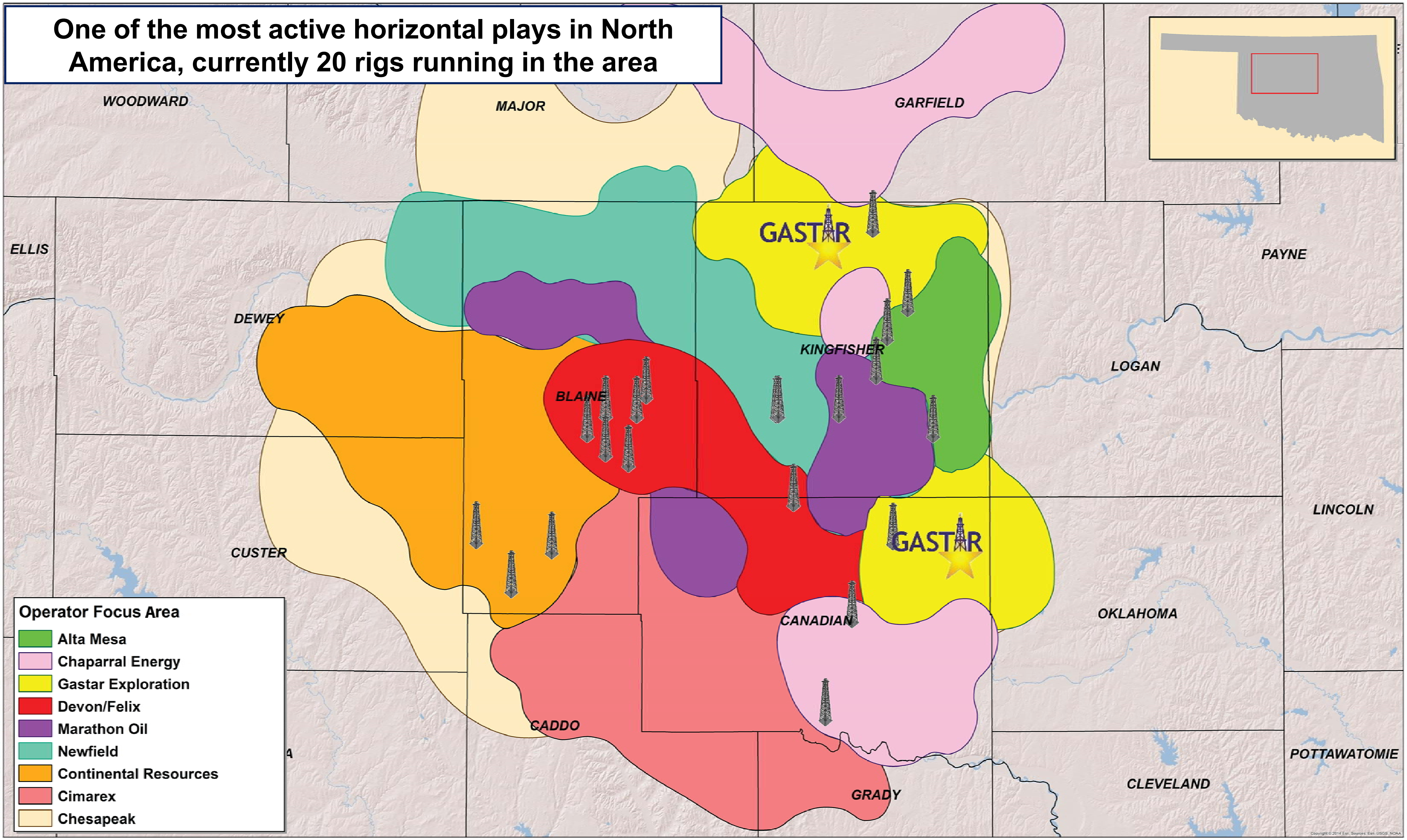


Mid-Continent STACK Asset Overview



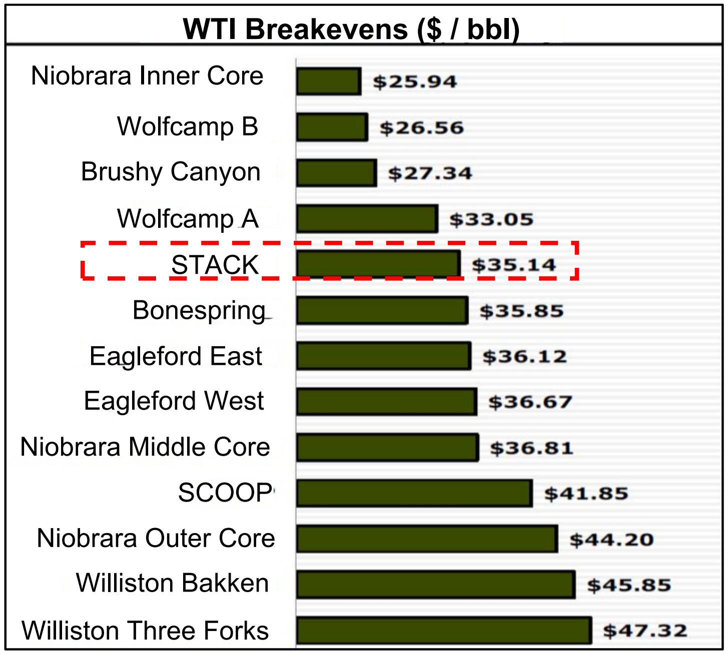
Mid-Continent STACK Operator Map

One of the most active horizontal plays in North America, currently 20 rigs running in the area



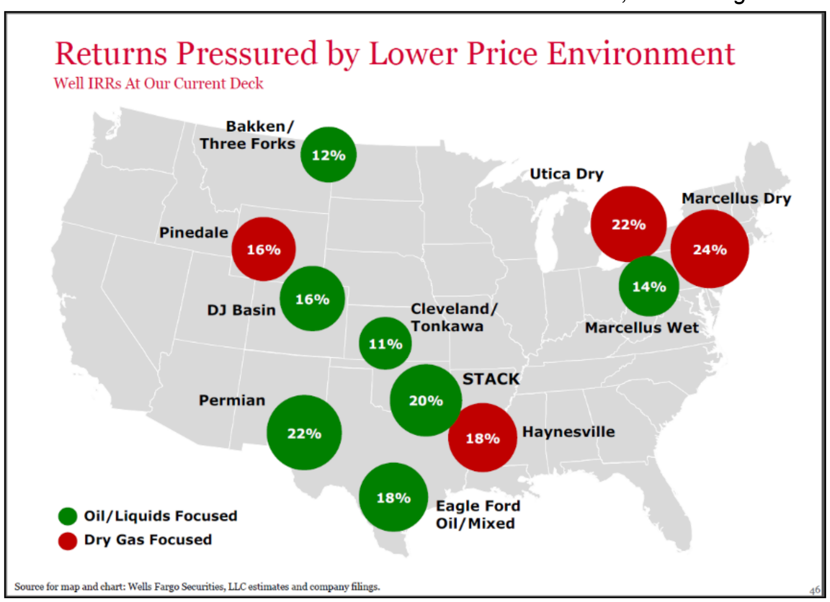
Note: Rig data obtained from Drillinginfo as of 07/15/2016

Recent STACK Research



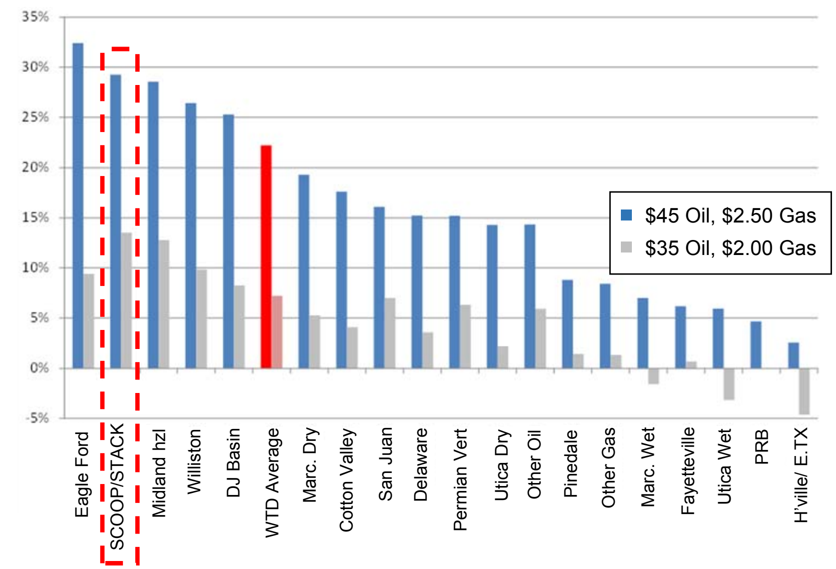
WELLS FARGO SECURITIES

David Tameron, Wells Fargo – 2/1/2016



Wells Fargo – 02/01/2016

heikkinen ENERGY ADVISORS



*"The Eagle Ford is the most economic at higher prices while the **SCOOP/STACK** has the highest returns at a lower deck"*

Heikkinen Energy Advisors – 3/18/2016

RBC Capital Markets

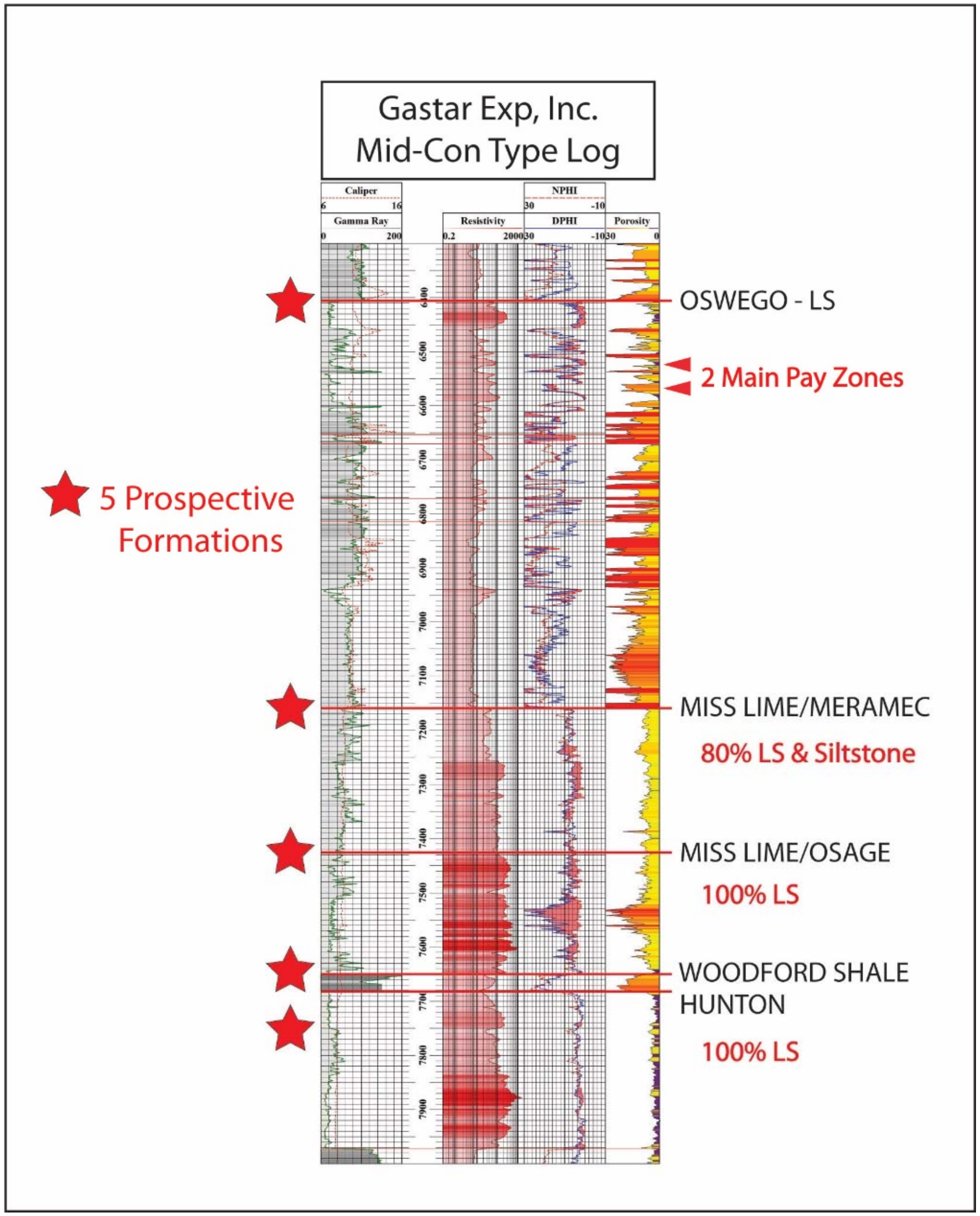
*"**Hottest New Play** On The Street. The SCOOP/STACK has quickly emerged as the premier oily growth play outside of the Permian. While still early innings, the play has attracted the attention of key industry players given its multi-zone stacked pay potential, highly prolific oily well results, and premium prices in recent M&A activity."*

Stark Remeny, RBC – 3/17/2016

STACK Play - Overview

Overview

- Five prospective formations across acreage position
  - Multiple formations may be stacked depending on specific area
  - Multiple benches within prospective formations
- Offers large quantity of drilling projects from which to select the highest returns and strategic benefits
- Multiple formations can be drilled from the same site
  - Possible stacked horizontal wellbores or sawtooth horizontal placement
  - Third most economic play behind only core Niobrara and Permian[1]



1. Per Wells Fargo equity research, February 2016

Mid-Continent Focused Operator

Large, contiguous acreage position with multiple stacked horizontal targets

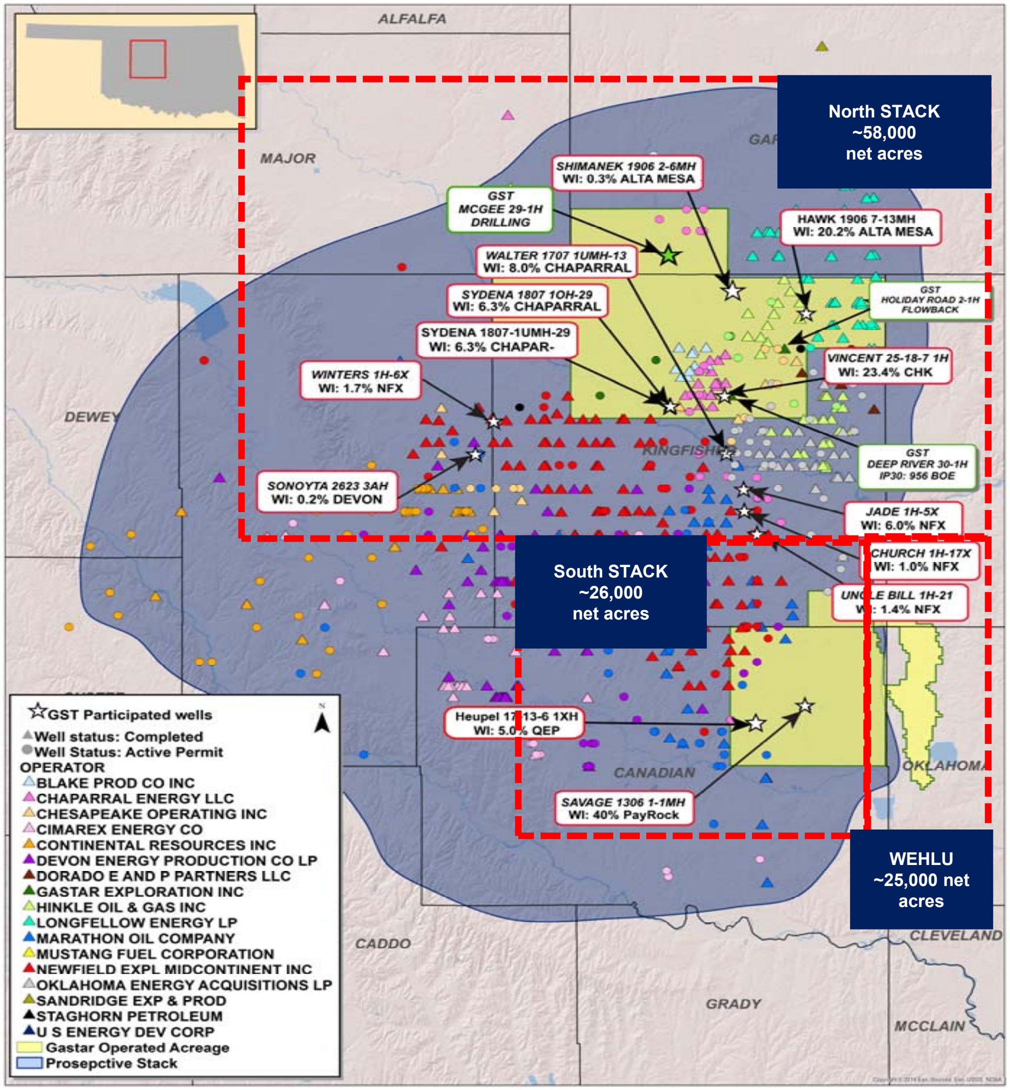
Mid-Continent Asset Overview

- ~109,200 net acres
- Meramec play key target
- Osage gaining momentum
- GST & other operators activity de-risking and extending the play
- STACK[1] activity - 219 active permits and 384 completed wells in the area[2]

Undeveloped Drilling Potential Overview[3]

Zone	Gross Wells	Net Wells	Well Costs
Meramec	1,069	357	~$4.0-$4.5MM
Osage	763	283	~$3.5-$5.0MM
Oswego	288	93	~$2.5-$4.0MM
Woodford	1,023	335	~$5.0-$6.0MM
Hunton	799	427	~$3.0-$5.0MM
Total STACK	**3,942**	**1,495**	

Mid-Continent Asset Map



1. Sooner Trend Anadarko Canadian Kingfisher
2. Based on data obtained from DrillingInfo as of 07/15/2016
3. Acreage & drilling locations are developed by the Company based on assumptions and methodology described on page 3 of this presentation as of 06/30/2016

STACK - Meramec

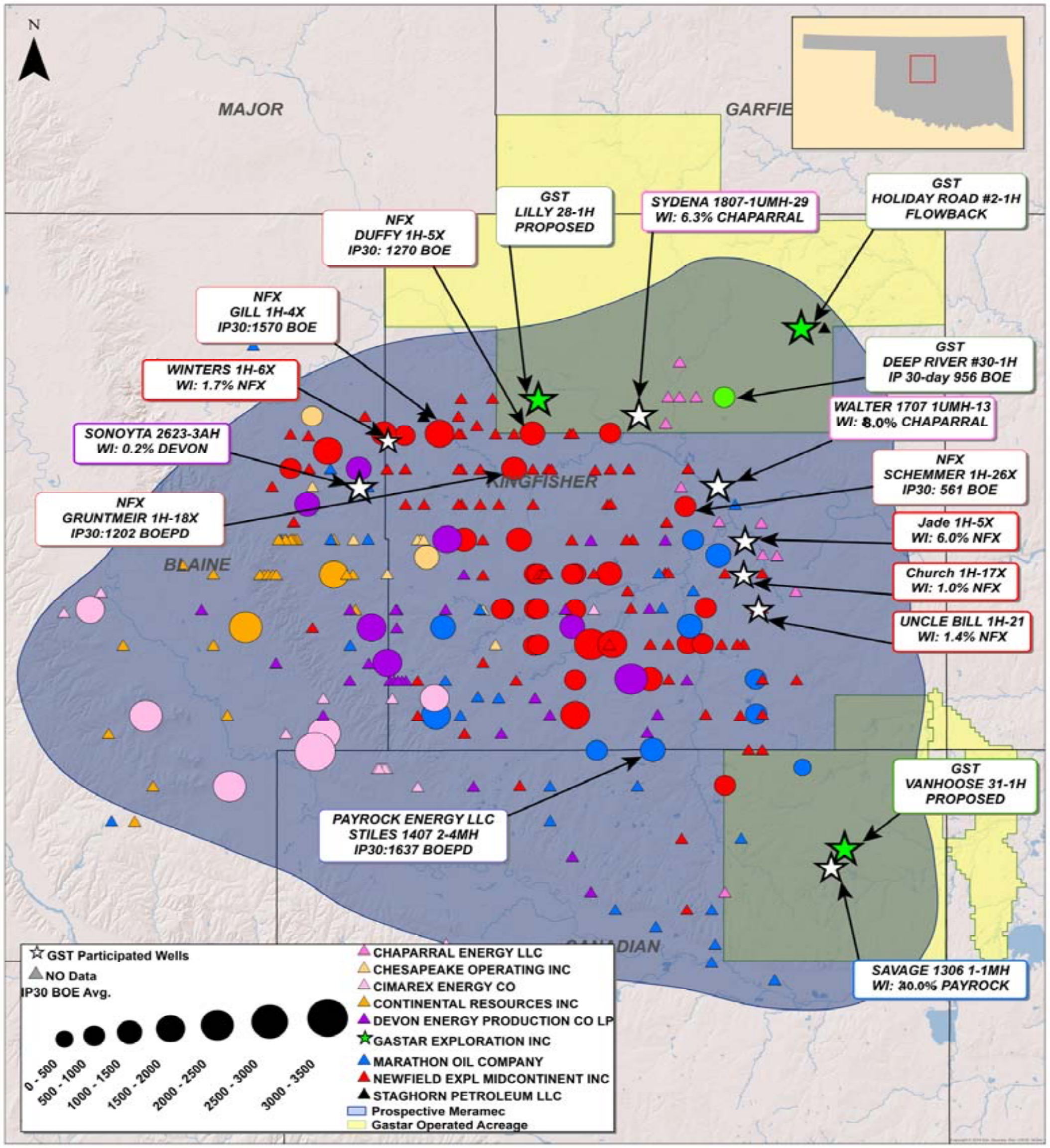
Overview

- Offset operator IPs range up to ~2,200 Boe/d (68% oil)
- Meramec returns attractive at today's commodity price environment
- Meramec activity - 109 active permits and 180 completed wells in the area[1]
- Non-operated participation in 12 wells
- Meramec potential net acres: ~38,300[2]
- Est. locations[3]:

Zone	Gross Wells	Net Wells
Meramec	1,069	357

- ~$4.0-$4.5MM CWC
- 2 horizontal operated Meramec wells drilled (2 producing)
- 2 Meramec PUDS on STACK acreage

Activity Map[4]



1. Based on data obtained from DrillingInfo as of 07/15/2016
2. Acreage as of 06/30/2016
3. Well locations assumed using six wells per section and are developed by the Company based on assumptions and methodology described on page 3 of this presentation as of 06/30/2016
4. Other operator production rates obtained from third-party company data, investor presentations, public filings and other sources that have not been independently verified by Gastar Exploration Inc

STACK Meramec Development

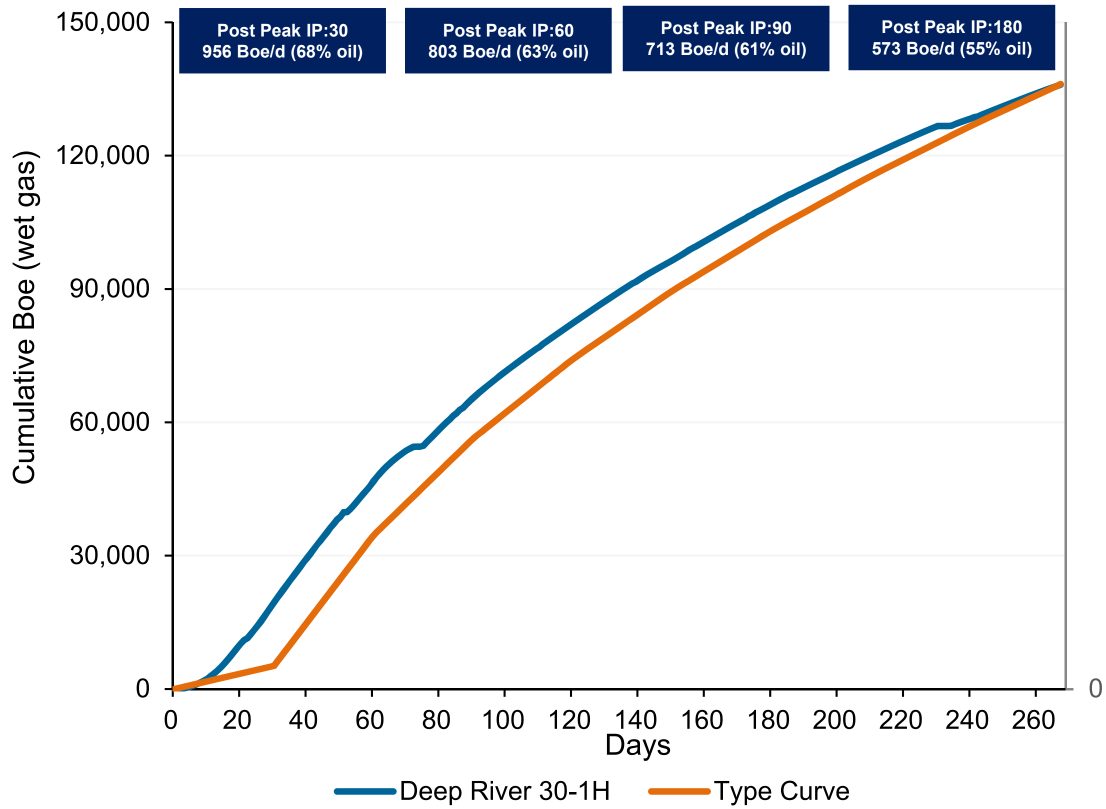
GST Meramec Development

- Deep River 30-1H
  - Drilled to TD in 34 days
  - Peak 24-Hr IP 1,094 Boe/d (71% oil)
  - ~$6.5MM CWC
  - EUR ~737 Mboe (wet gas) (41% oil)
- Holiday Road 2-1H
  - Drilled to TD in 12 days
  - Flowback commenced 04/11/2016
  - Currently producing - 281 Bo/d, 373 Mcf/d, 2,199 Bw/d
  - ~$4.1MM[4] gross anticipated cost

Completion Information

- Deep River 30-1H
  - ~5,100 foot lateral
  - 34 frack stages
  - ~12MM pounds of proppant
- Holiday Road 2-1H
  - ~4,300 foot lateral
  - 34 frack stages
  - ~12MM pounds of proppant

Deep River 30-1H Production[1]



Meramec Summary Economics[2]

EUR	% Oil	Well Cost	IRR	PV-10
843 MBoe	43%	$4.5MM	45%	$3.5MM

Average Type Curve Daily Rate[3]

	Peak	1st 30 Days	1st 60 Days	1st 90 Days
Boe/d	1,196	174	577	626

1. Through production date of 07/31/2016.
2. EURs: three-phase estimated ultimate recoveries per well based on estimated future production type curves using assumptions and methodologies described on page 3 of this presentation
3. Cumulative daily rates calculated using unprocessed gas stream
4. Excludes $520,000 of wireline fishing charges

STACK - Osage

Overview

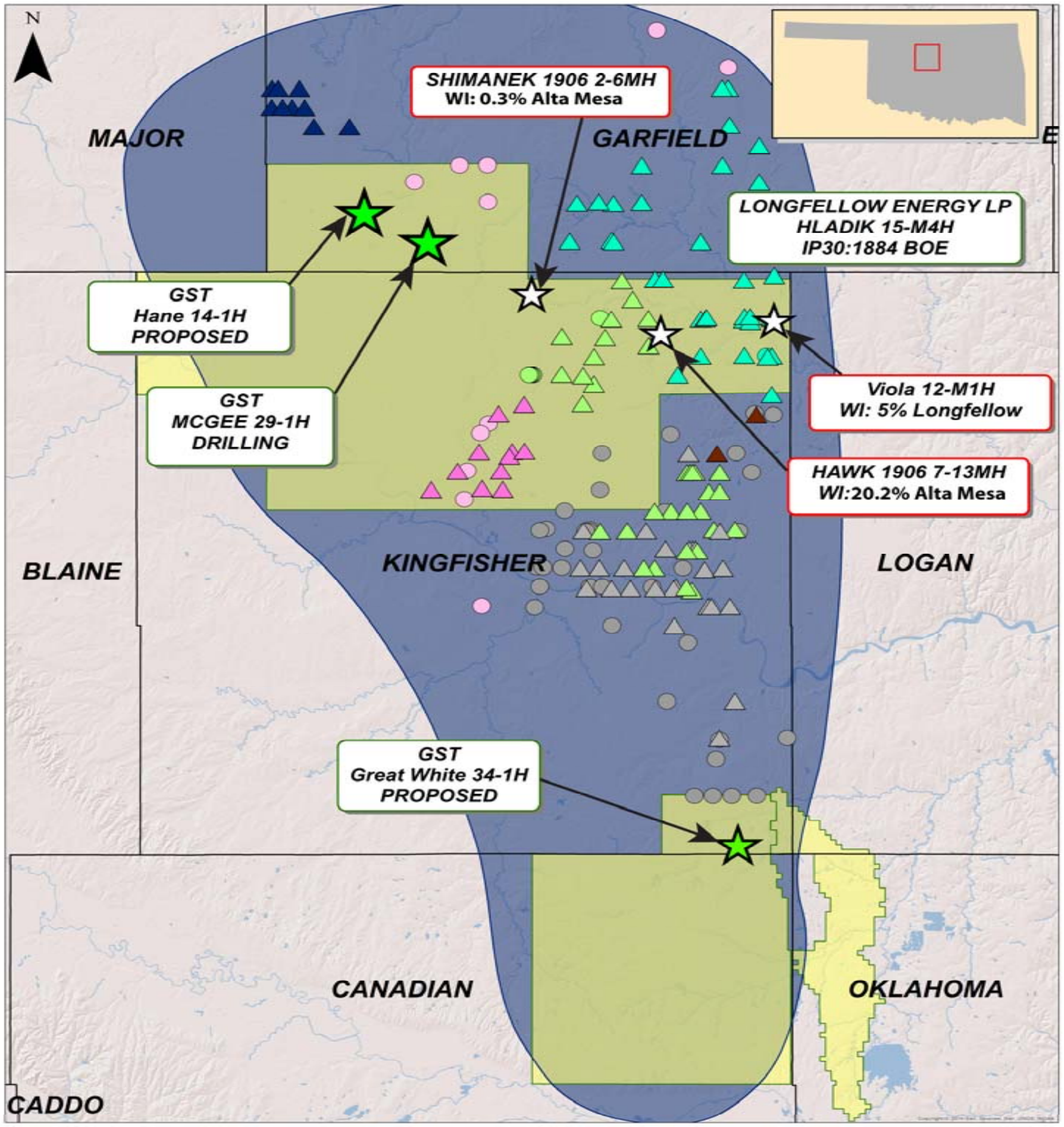
- Offset operator IPs range up to ~1,900 Boe/d
- Currently drilling 1st Osage test well McGee 29-1H
- Non-operated participation in four wells
- Osage activity – 55 active permits and 96 completed wells in the area(1)
- Osage potential net acres: ~45,200(2)
- Est. locations(3):

Zone	Gross Wells	Net Wells
Osage	763	283

Osage Reserve & Well Cost(4)

EUR MBOE	% Oil	Well Cost
350 - 600	35-45%	$4.0-$4.5MM

Activity Map(5)



1. Based on data obtained from DrillingInfo as of 07/15/2016
2. Acreage as of 06/30/2016
3. Well locations assumed using four wells per section and are developed by the Company based on assumptions and methodology described on page 3 of this presentation as of 06/30/2016
4. EURs: Two-phase estimated ultimate recoveries per well based on estimated future production type curves using internally generated assumptions and methodologies.
5. Other operator production rates obtained from third-party company data, investor presentations, public filings and other sources that have not been independently verified by Gastar Exploration Inc

STACK - Oswego

Overview

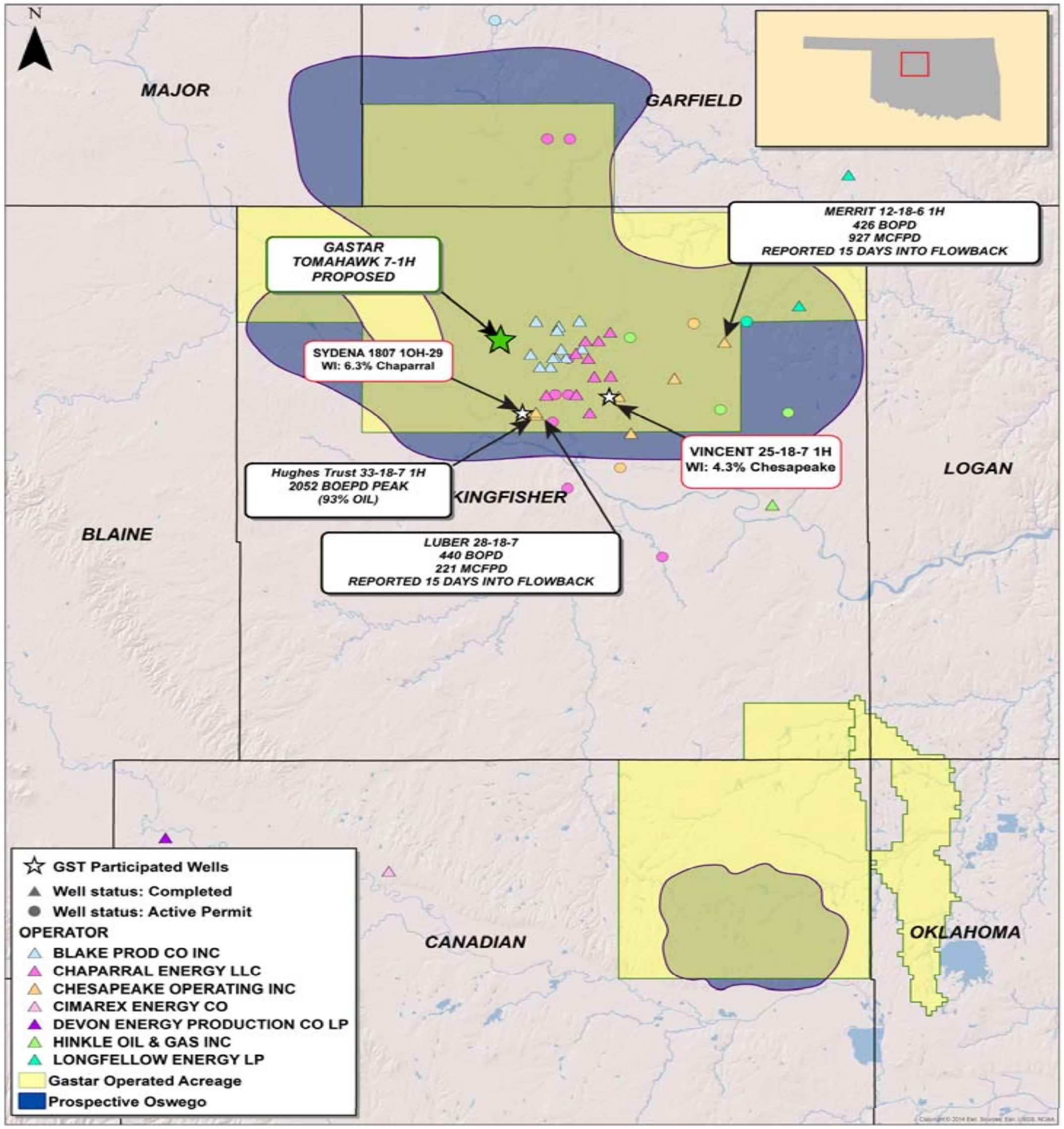
- Offset operator IPs up to ~2,100 Boe/d (93%+ oil)
- A growing horizontal target in the basin
  - Up to four porosity-driven targets within the Oswego
- Other operators activity de-risking the play
- Non-operated participation in five wells
- Oswego activity – 20 active permits and 35 completed wells in the area[(1)]
- Oswego potential net acres: ~14,900[(2)]
- Est. locations[(3)]:

Zone	Gross Wells	Net Wells
Oswego	288	93

Oswego Reserve & Well Cost[(4)]

EUR MBOE	% Oil	Well Cost
250 - 350	80-90%	$3.0-$3.5MM

Activity Map[(5)]



1. Based on data obtained from DrillingInfo as of 07/15/2016
2. Acreage as of 06/30/2016
3. Well locations assumed using four wells per section and are developed by the Company based on assumptions and methodology described on page 3 of this presentation as of 06/30/2016
4. EURs: two-phase estimated ultimate recoveries per well based on estimated future production type curves using internally generated assumptions and methodologies.
5. Other operator production rates obtained from third-party company data, investor presentations, public filings and other sources that have not been independently verified by Gastar Exploration Inc

STACK - Woodford

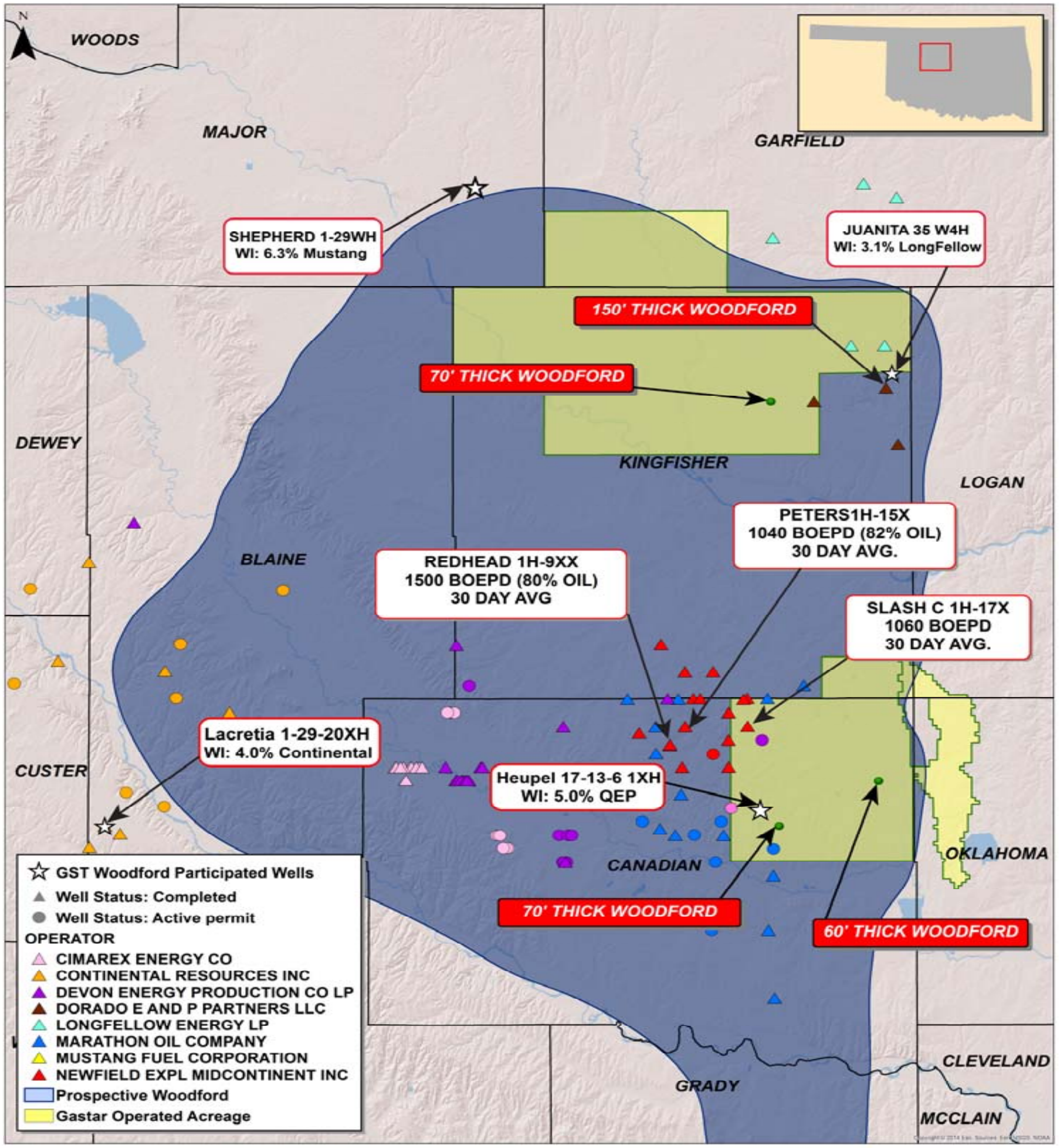
Overview

- Offset operator IPs up to ~1,500 Boe/d (80%+ oil)
- Other operator activity de-risking the play
- Non-operated participation in five wells
- Woodford activity – 35 active permits and 73 completed wells in the area[1]
- Net potential acres: ~35,800[2]
- Est. locations[3]:

Zone	Gross Wells	Net Wells
Woodford	1,023	335

- ~$5.0-$6.0MM CWC

Activity Map[4]



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3. Well locations assumed using six wells per section and are developed by the Company based on assumptions and methodology described on page 3 of this presentation as of 06/30/2016
4. Other operator production rates obtained from third-party company data, investor presentations, public filings and other sources that have not been independently verified by Gastar Exploration Inc

WEHLU

WEHLU-Hunton offers a substantial source of high return projects

Upper Hunton Overview

- 31 PUDs on northern WEHLU acreage
- Seven well average results:
  - Peak rate of 568 Boe/d (86% oil)

Lower Hunton Overview

- 18 PUDS on northern WEHLU acreage
- Ten well average results:
  - Peak rate of 443 Boe/d (82% oil)

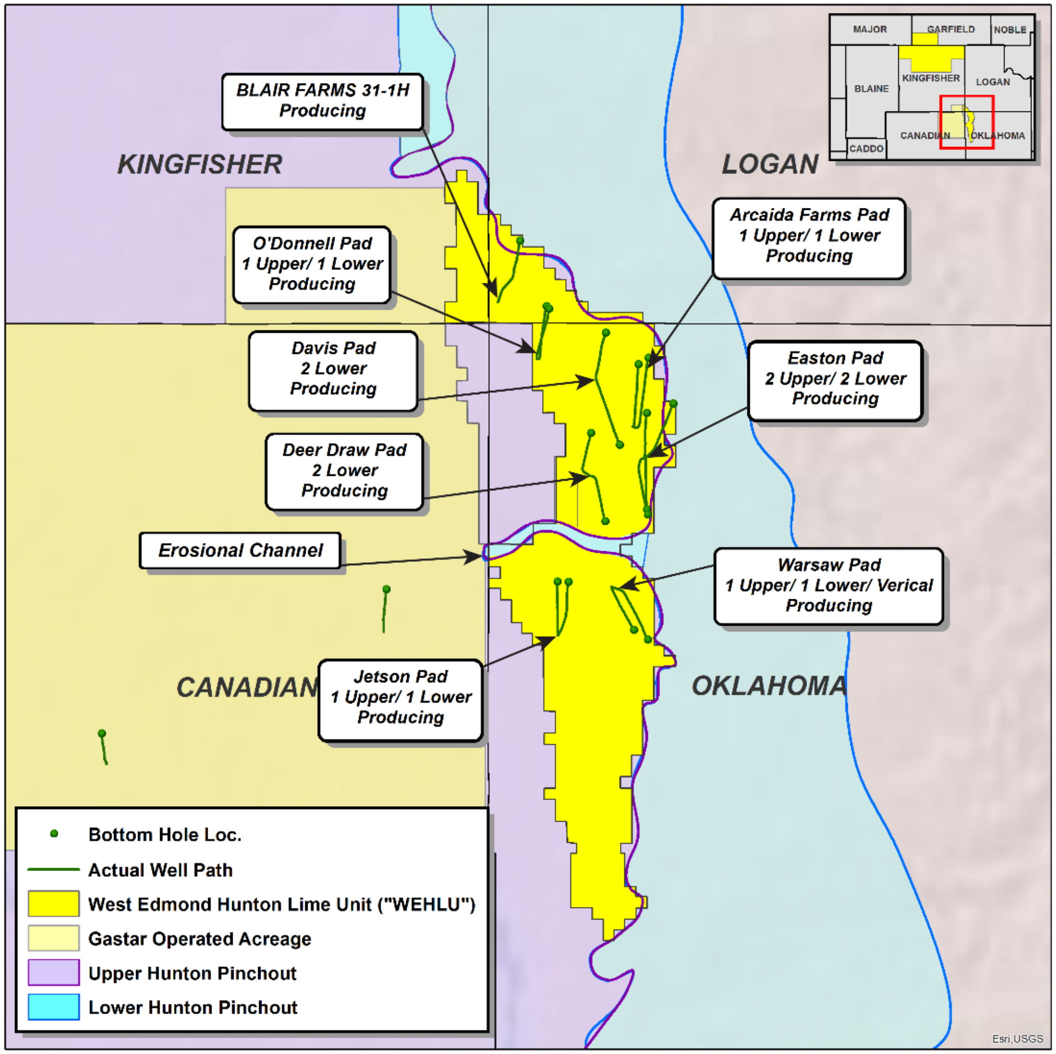
WEHLU - Upper Summary Economics(1)

EUR	% Oil	Well Cost	IRR	PV-10
402 MBoe	71%	$3.0MM	49%	$3.1MM
Average Type Curve Daily Rate(2)				
	Peak	1st 30 Days	1st 60 Days	1st 90 Days
Boe/d	400	376	352	332

WEHLU - Lower Summary Economics(1)

EUR	% Oil	Well Cost	IRR	PV-10
557 MBoe	71%	$4.5MM	43%	$4.5MM
Average Type Curve Daily Rate(2)				
	Peak	1st 30 Days	1st 60 Days	1st 90 Days
Boe/d	373	365	353	341

WEHLU Map



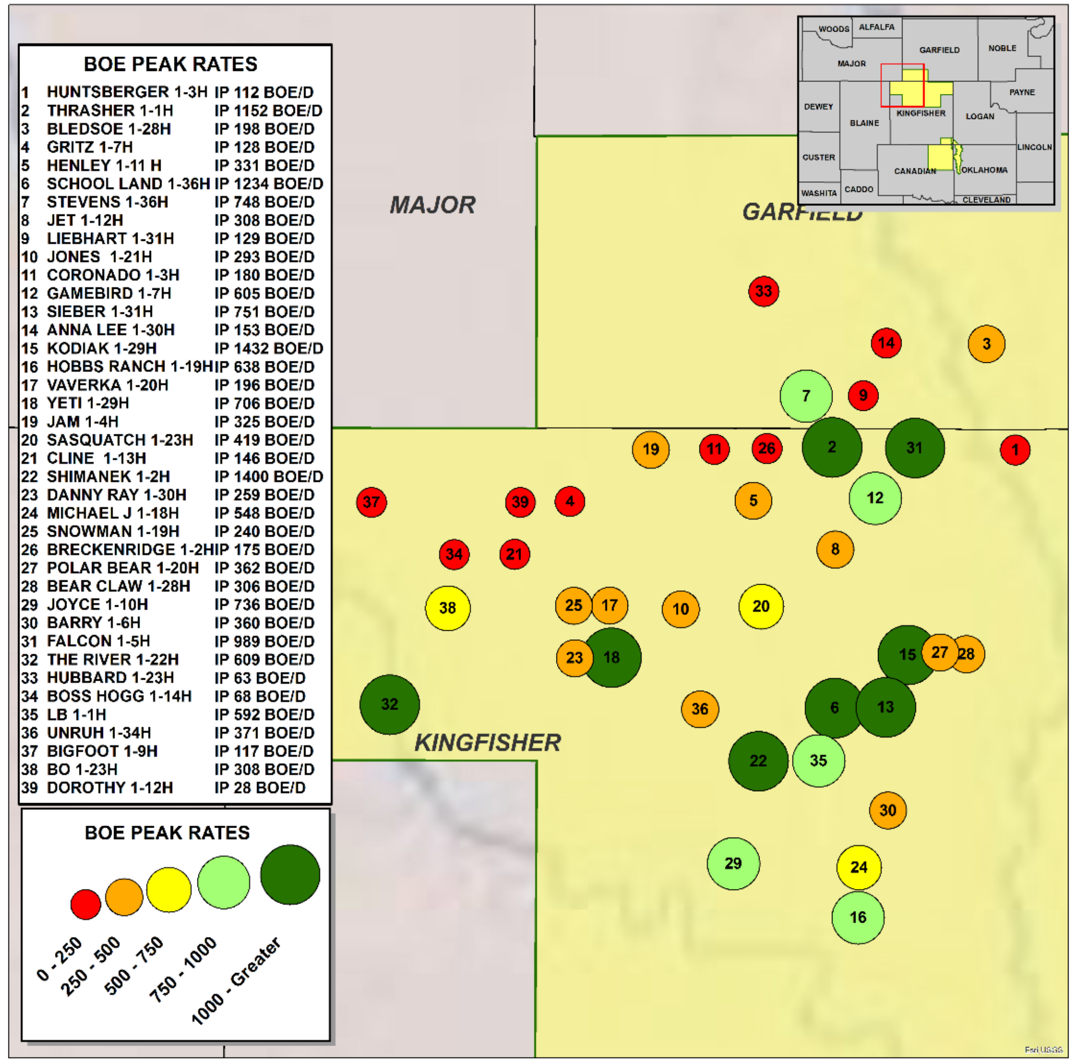
1. EURs: three-phase estimated ultimate recoveries per well based on estimated future production type curves using assumptions and methodologies described on page 3 of this presentation
2. Cumulative daily rates calculated using unprocessed gas stream

Northern Hunton Development

Northern Hunton Development

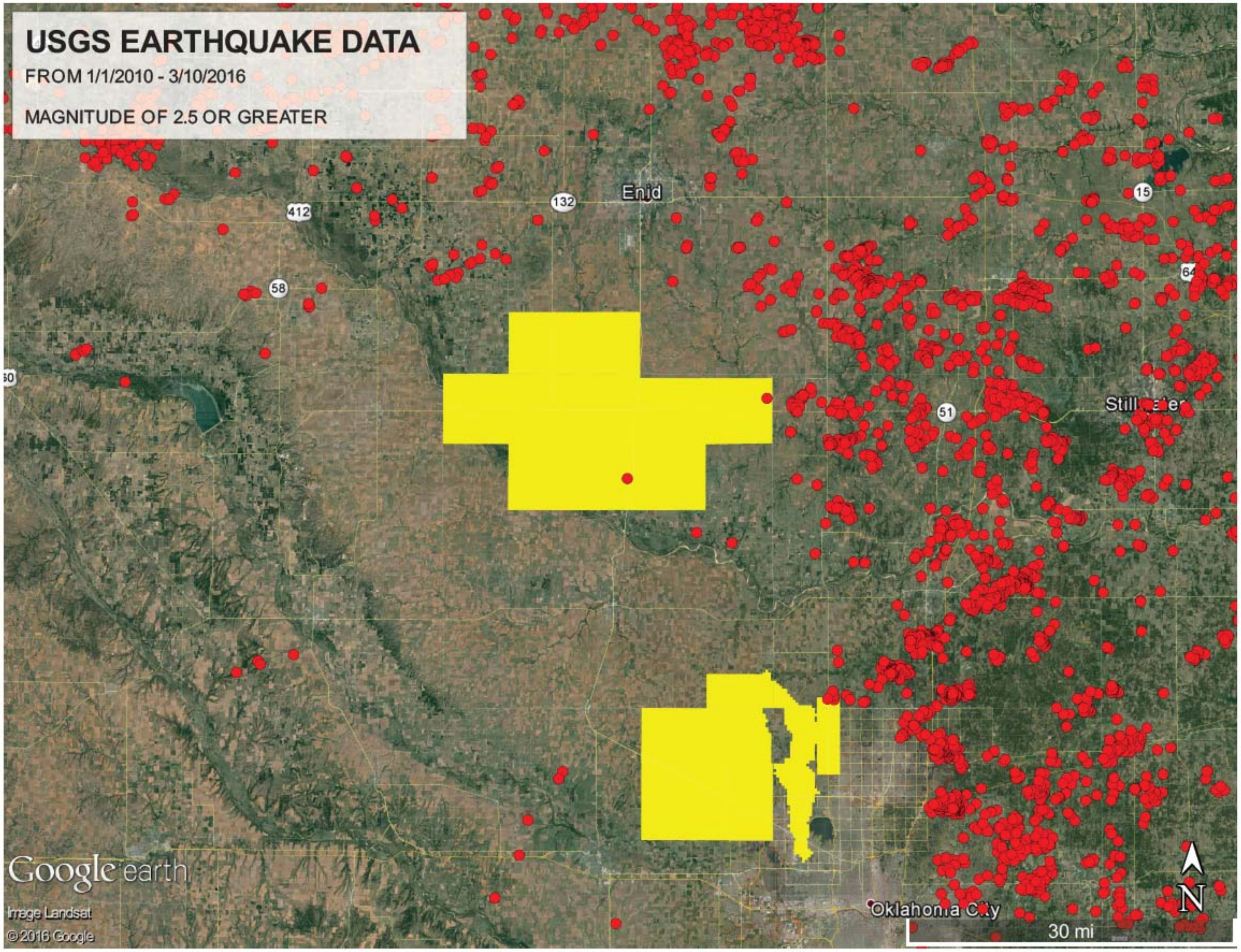
- Established position in 2012 to focus on Lower Hunton development
- Took over operatorship with closing of acquisition in December 2015
- 39 horizontal wells drilled over large geographic area to date
  - Two Upper Hunton
  - 37 Lower Hunton

Northern Hunton Activity Map



Earthquake Seismicity Map

- Low seismicity around Gastar leasehold
- Gastar recently re-completed a SWD well in the Wilcox to mitigate limitations of disposing in the Arbuckle
  - Other operators are following this trend
- Gastar uses third parties for a majority of disposal water
  - Contracts for transportation and disposal at fixed $/bbl



Financial Overview

Financial Strategy

Leverage Ratios and Liquidity	▪ Continue to review strategic opportunities to reduce leverage and enhance liquidity ▪ Raised $44.8MM in May 2016 to address liquidity concerns
Hedging Program	▪ Protect cash flow ▪ As of 08/01/2016, hedged 75% of 2016 PDP oil and NGLs production with $70.75 average floor[1] ▪ As of 08/01/2016, hedged 80% of 2016 PDP gas production with $3.48 average floor[1]
Operating Margins and Efficiency	▪ Liquids weighted production profile allows focus on highest operating margin ▪ Continued focus on lowering cash operating costs per Boe ▪ Working to reduce drilling times and improve completion design in STACK Play

1. Hedges as of 08/01/2016. Oil hedges include WTI for NGL proxy hedges and 30% of NGL PDP. Average Floor prices represent average floor of swap and long put volumes.

Capitalization and Liquidity

Capitalization

($ in millions)	**06/30/2016**
Cash	$50.8
Long Term Debt	
Senior Secured Notes due 2018 (face value)	$325.0
Revolving Credit Facility	99.6
Total Debt	**$424.6**
Stockholders Equity	
Preferred Equity (face value)	$154.6
Common Equity (Includes Accumulated Deficit) [1]	(316.3)
Total Stockholders Equity (Deficit)	**($161.7)**
Total Capitalization	**$262.9**

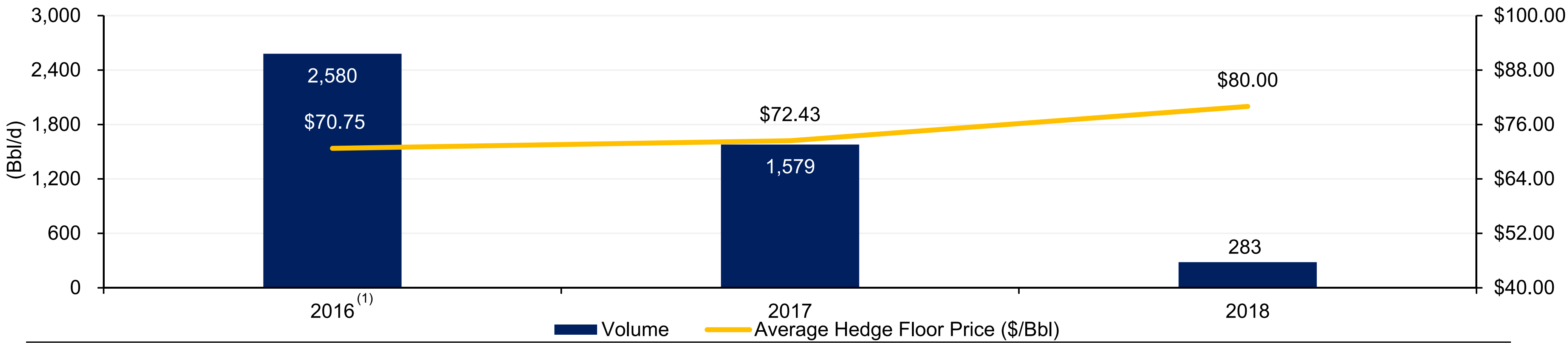
Liquidity

Revolver Borrowing Base	$100.0
Less: Revolver Balance[2]	100.0
Plus: Cash	50.8
Liquidity	**$50.8**

1. Includes ITD ceiling impairments $813.5MM
2. Includes letters of credit outstanding

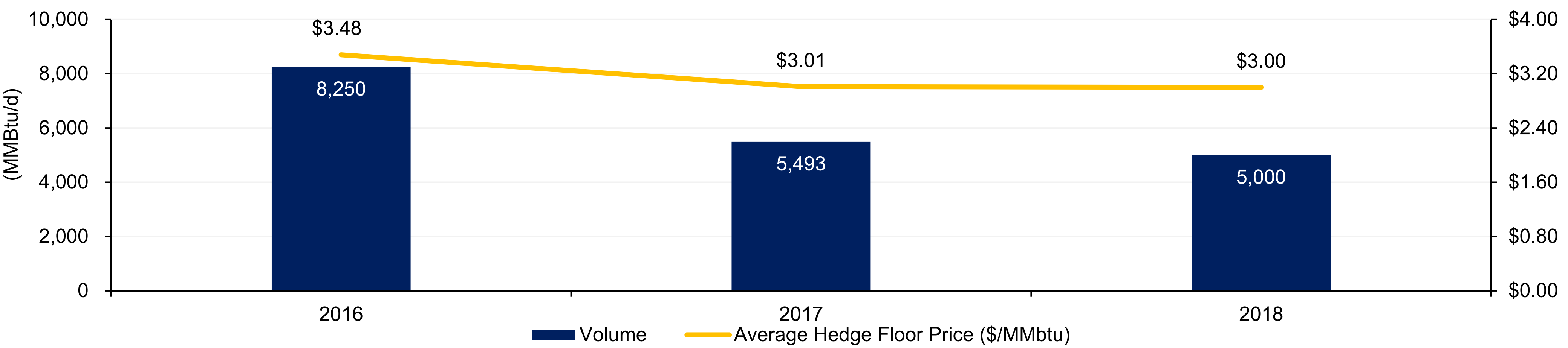
PDP Hedging Program

Oil and NGLs Hedging Strategy



Downside Hedged % [2]	**75%**	**72%**	**16%**

Gas Hedging Strategy



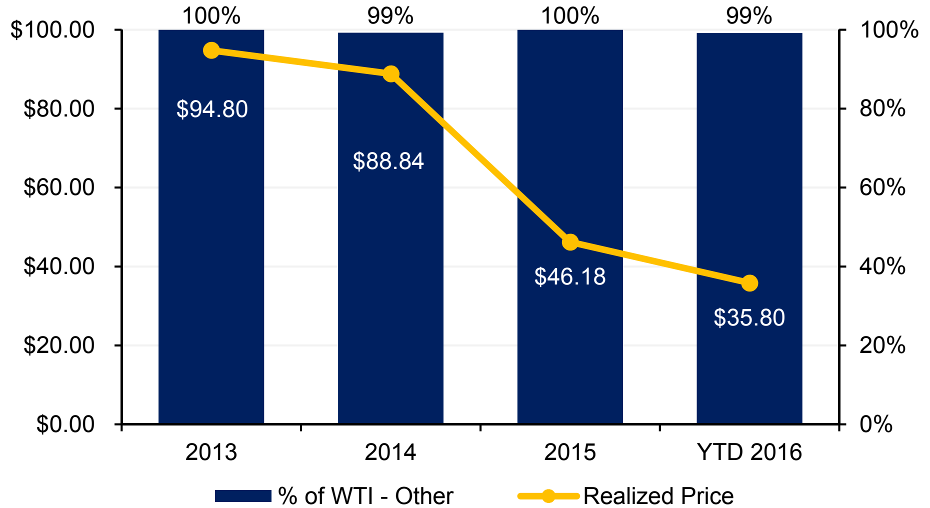
Downside Hedged %	**80%**	**64%**	**72%**

Note: Hedges as of 08/01/2016. Average Floor prices represent average floor of swap and long put volumes

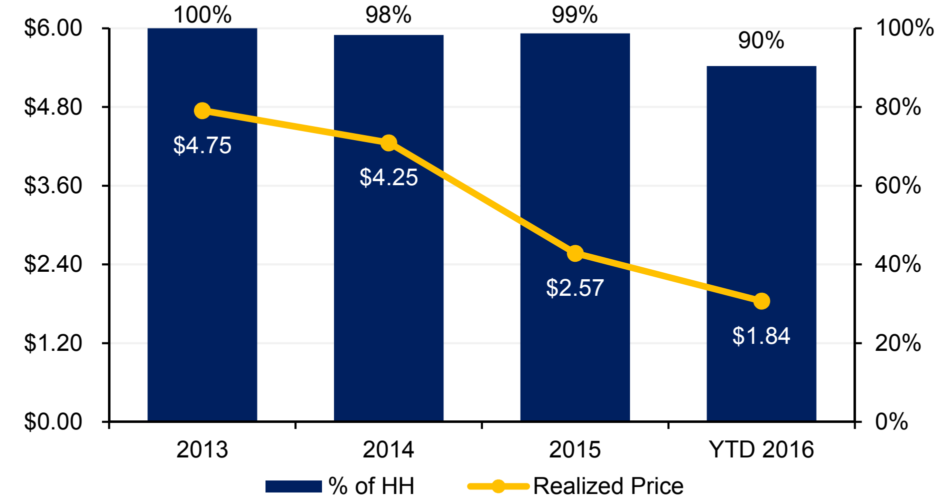
1. Volume includes 500 Bbl/d propane swap at $20.79. Price represents WTI average floor
2. Includes WTI for NGL proxy hedges and 30% of NGL PDP

Realized Prices Mid-Continent

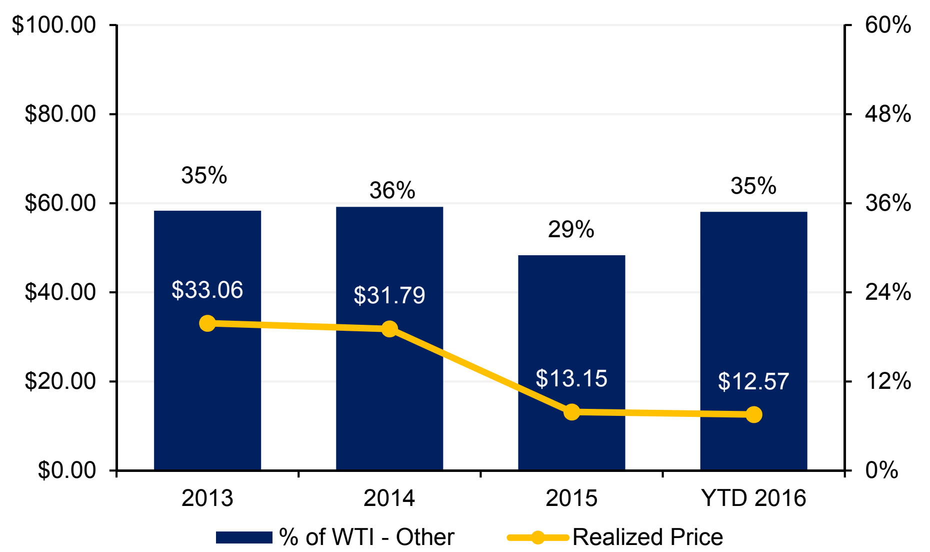
Realized Oil Prices



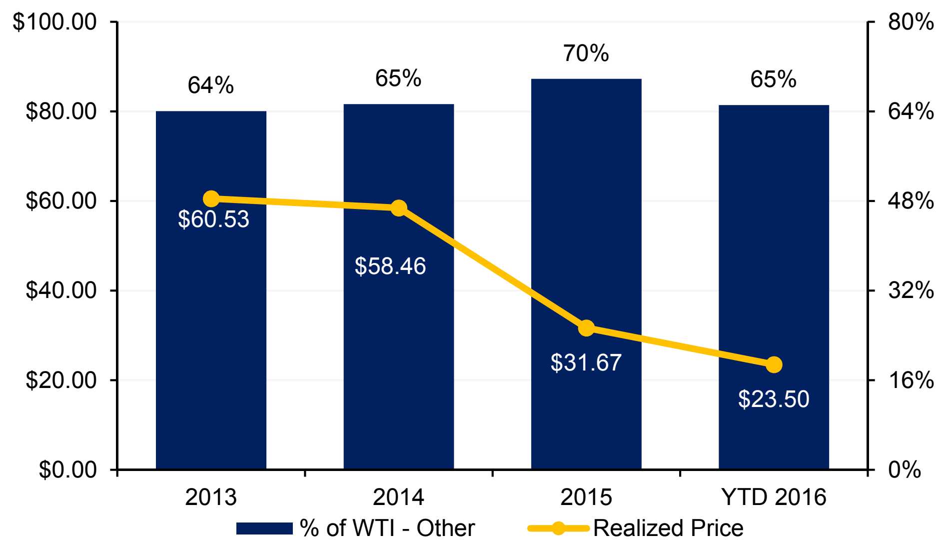
Realized Gas Prices



Realized NGL Price



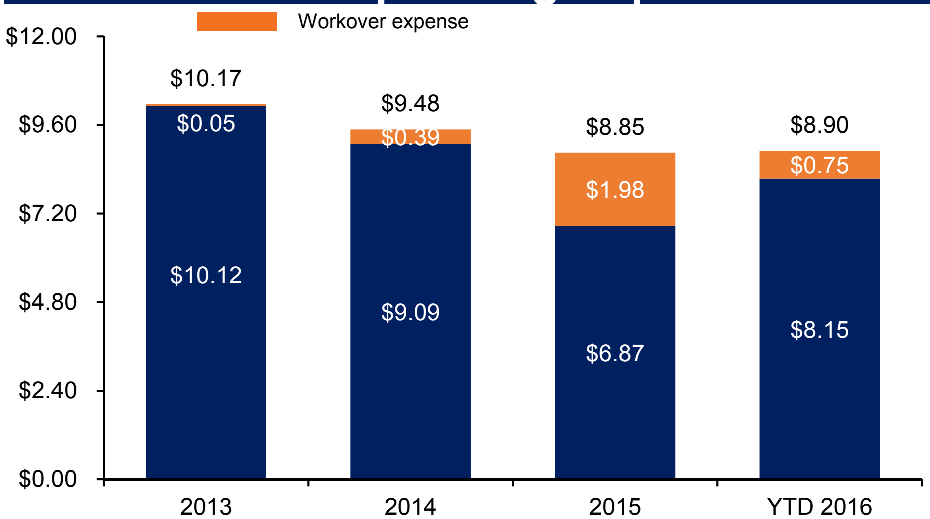
Realized Boe Price



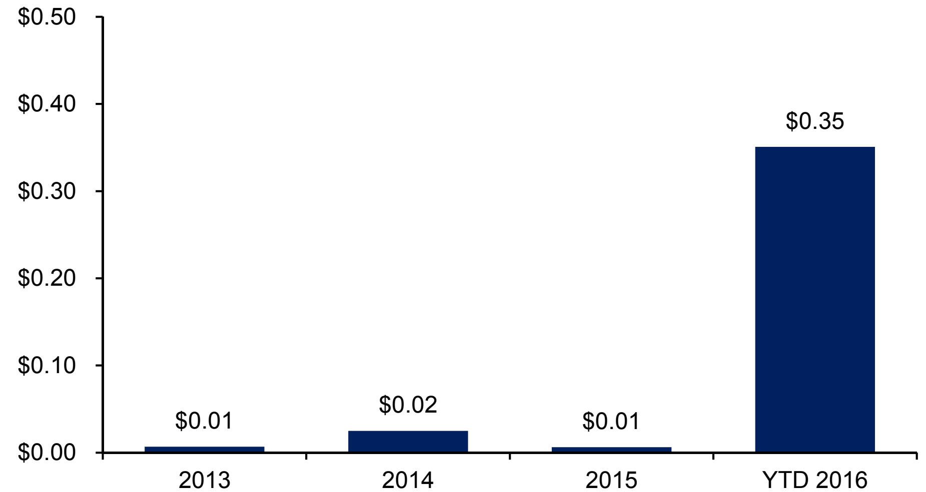
Note: Excludes impact of hedge gains and losses

Production Costs Mid Continent – ($/Boe)

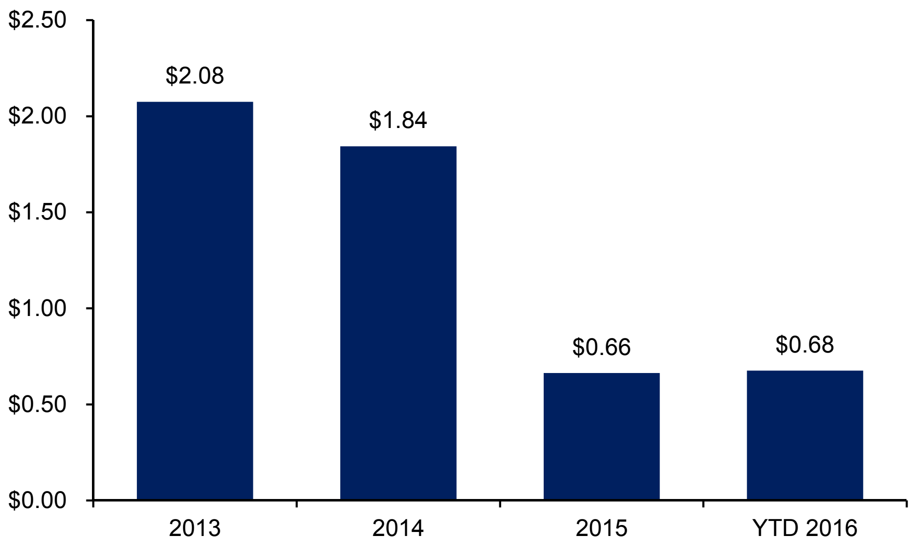
Lease Operating Expense



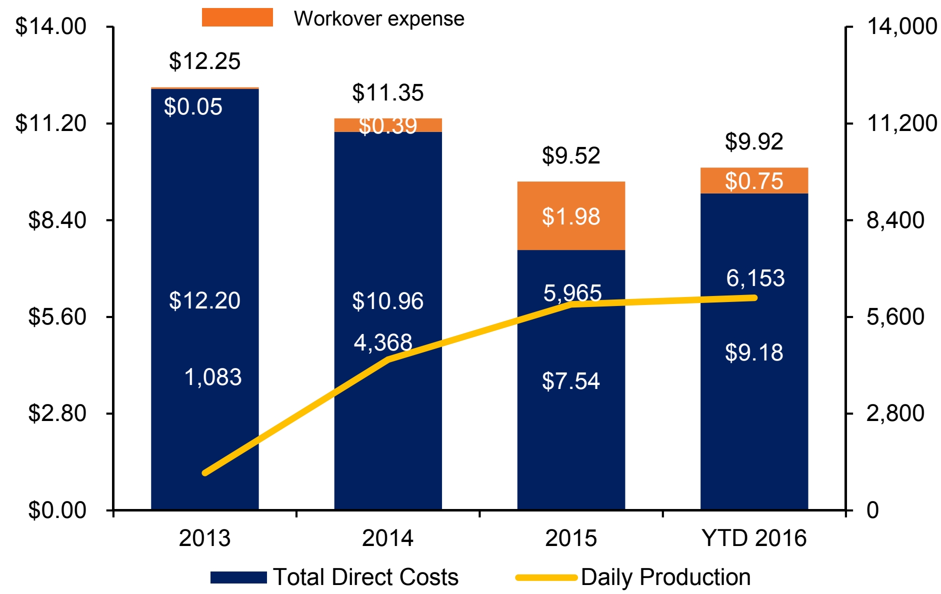
Transportation



Prod. Tax



Total Direct Costs vs. Daily Production



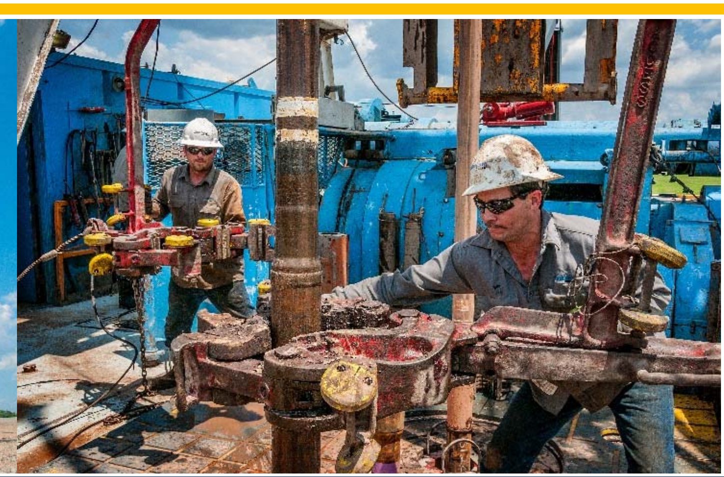
Note: Excludes impact of hedge gains and losses

Appendix



Recent Transformative Transactions

Pure Play Mid-continent Operator



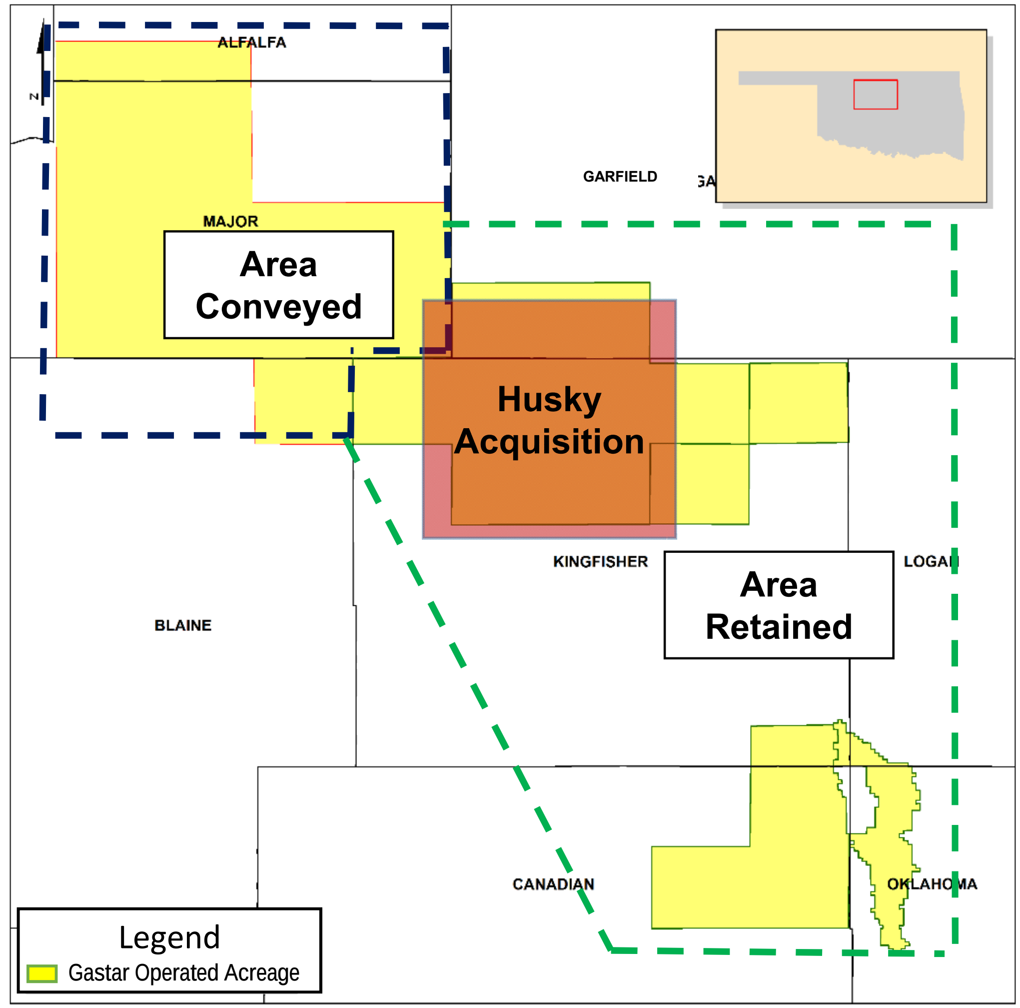
Mid-Continent Acquisition Overview

Take over operatorship and increase interest in coveted core Mid-continent STACK area

Deal Overview

- Closed December 16, 2015
- $42.1MM purchase price
  - In addition to gross proceeds, conveyance of ~11,000 net non-core/non-producing acres assigned to buyer
- 15,700 net acquired acres in Kingfisher and Garfield Counties (STACK [1] Play)
  - GST Acreage position now 109,200 net acres in Oklahoma[2]
- Interest in 103 gross (10.2 net) producing wells

Asset Map



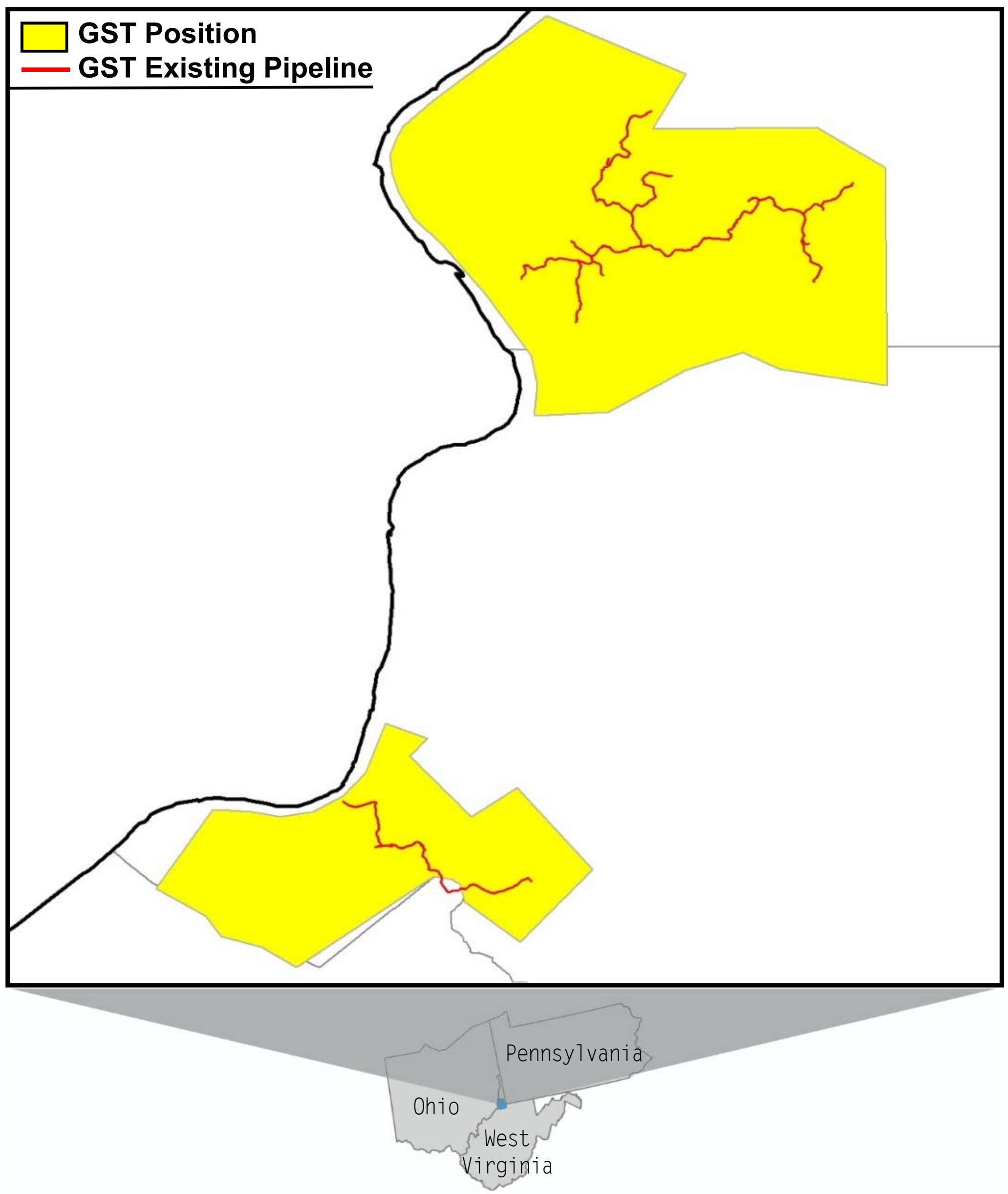
1. Sooner Trend Anadarko Canadian Kingfisher
2. Acreage as of 06/30/2016

NE Divestiture Overview

Deal Overview

- Effective date 01/01/2016
- Closed April 8, 2016
- Purchase price of $80.0MM(1)
- Creates pure-play Mid-continent small cap player
- Alleviates requirement for land / drilling capex to keep acreage position together in NE
- Corporate realized prices will improve dramatically
  - Less volatile oil, gas and NGL pricing market in OK
- Post sale, remaining Oklahoma assets have a higher % of volumes hedged

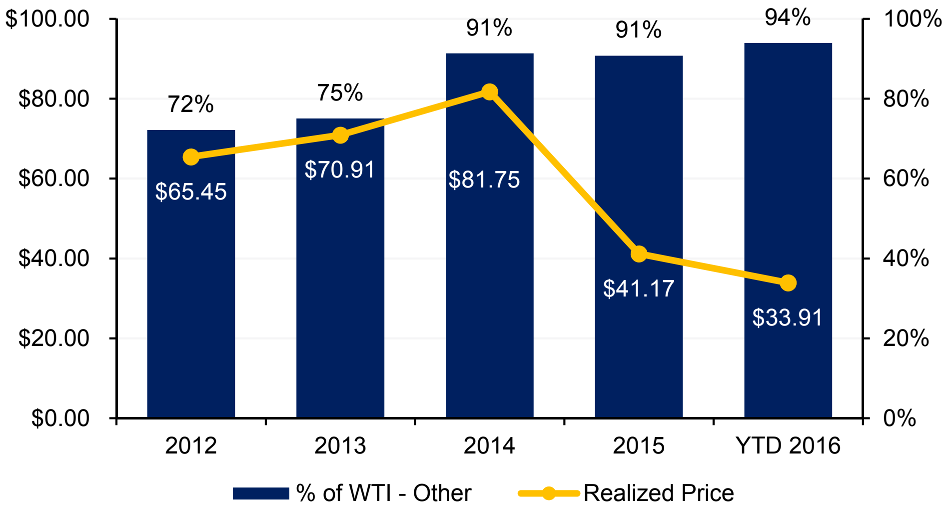
Asset Map



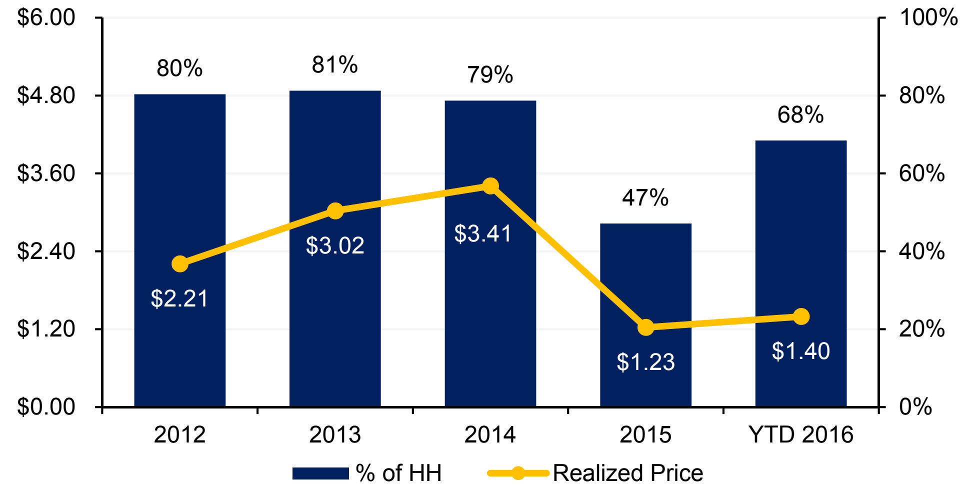
1. Net proceeds, after adjustments and revenue suspense funds, of $76.6MM

Realized Prices - Historical

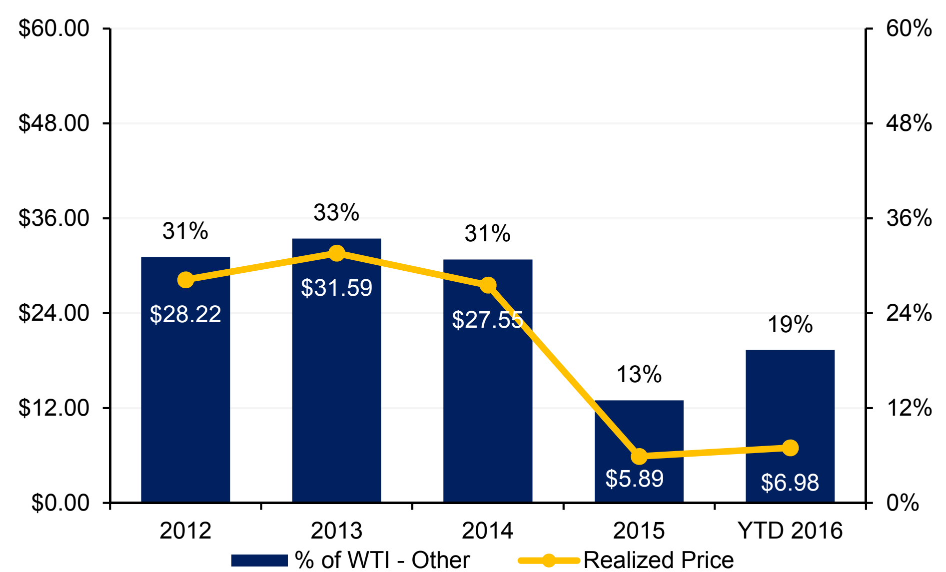
Realized Oil Prices



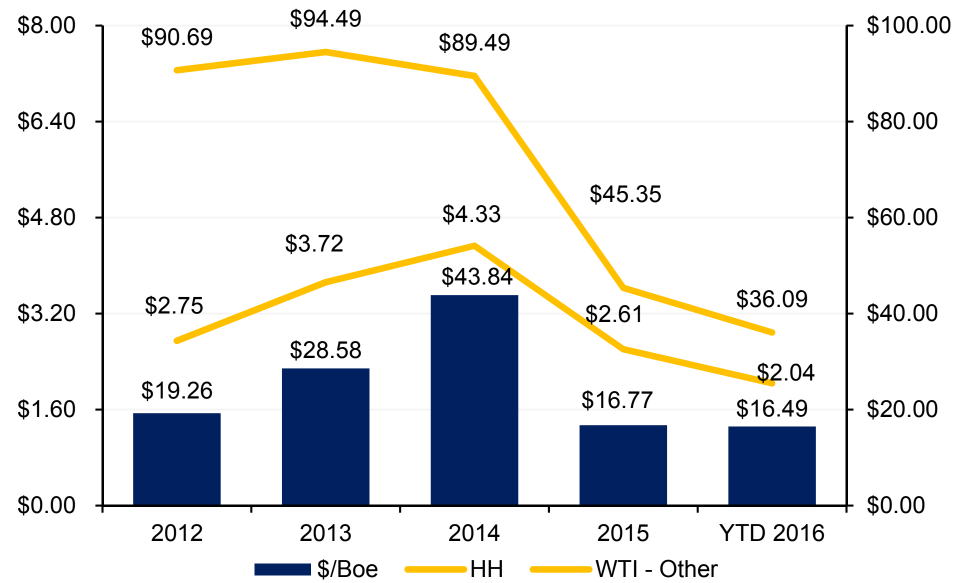
Realized Gas Prices



Realized NGL Price



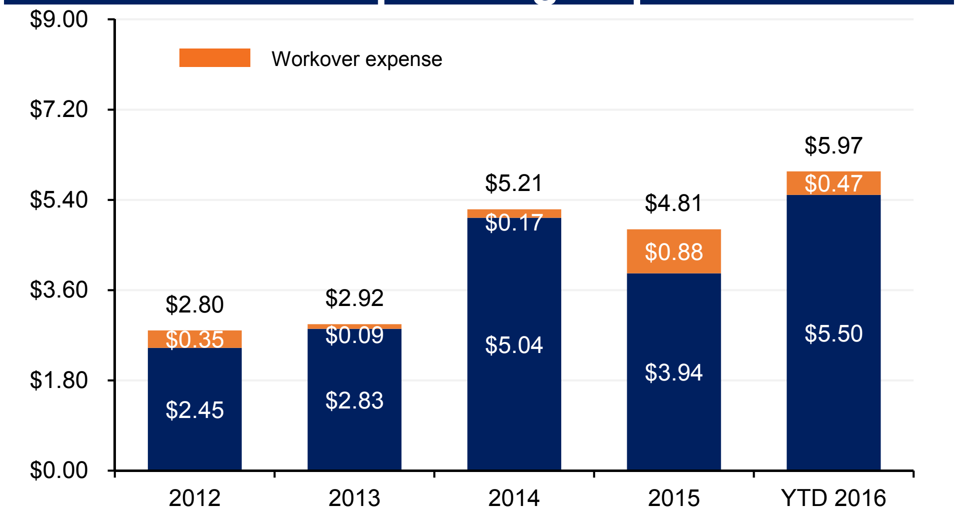
Commodity Prices



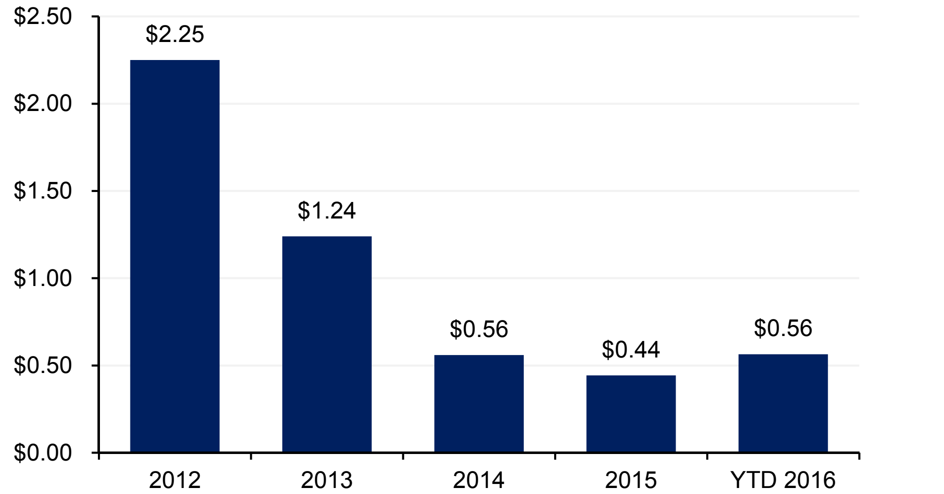
Note: Excludes impact of hedge gains and losses and 2014 arbitration settlement

Production Costs – Historical ($/Boe)

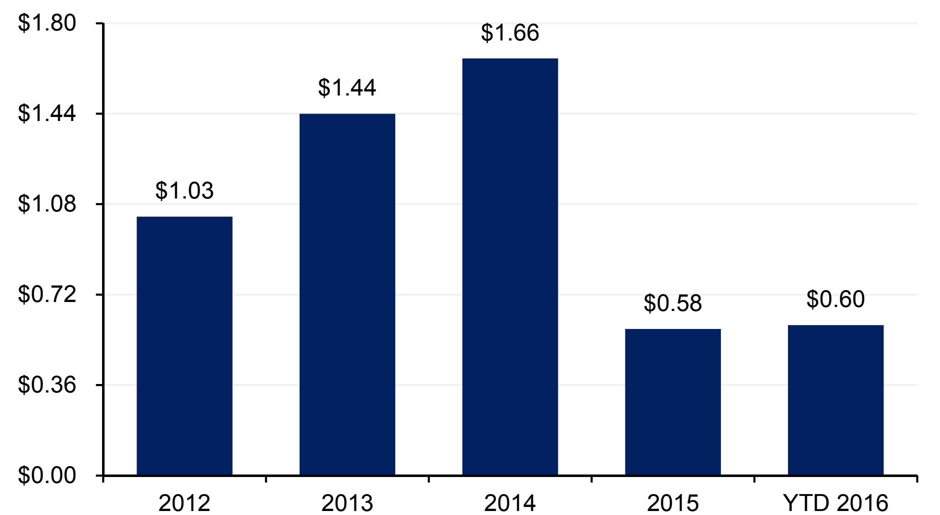
Lease Operating Expense



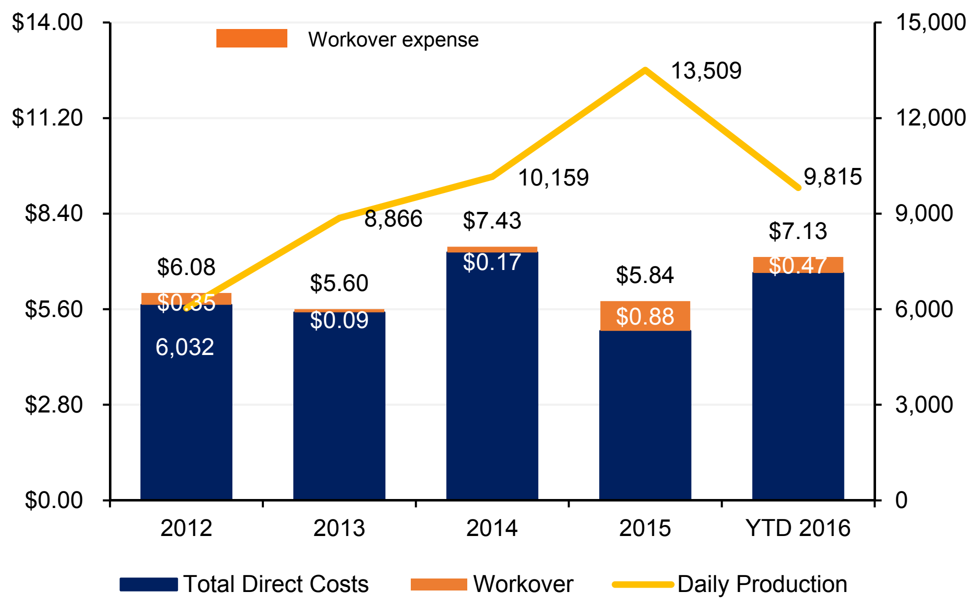
Transportation



Prod. Tax



Total Direct Costs vs. Daily Production



Note: Excludes impact of 2014 arbitration settlement

Drilling Overview

Well Results

Well	Peak Rate	30 Day Post Peak	60 Day Post Peak	90 Day Post Peak	180 Day Post Peak	270 Day Post Peak	360 Day Post Peak	Current 5 Day Average[3]	% Oil[2]
	Post IP Production Averages[1] (Boe/d)								
Meramec									
Deep River 1-30H	1,094	956	803	713	573	NA	NA	268	57%
Holiday Road 2-1H	NA	NA	NA	NA	NA	NA	NA	343	81%
Type Curve Well [3]	1,196	980	852	767	613	524	465		48%

1. Represents the actual 2-Stream post peak average daily Boe production
2. Inception to date percentage oil production. Reflects unprocessed gas stream.
3. Based on EURs and related type curves developed by the Company using assumptions and methodologies described on page 3 of this presentation. Reflects unprocessed gas stream.

Note: Through production date of 07/31/2016.

Hedge Detail

Natural Gas			
Period	Contract Type	Volume Hedged	Price
Sep - Oct 16	3-Way	2,500 MMBtu/d	$3.00 / $2.25 / $3.65
Sep - Dec 16	3-Way	2,000 MMBtu/d	$4.00 / $3.25 / $4.58
Sep - Dec 16	3-Way	5,000 MMBtu/d	$3.40 / $2.65 / $4.10
Jan - Dec 17	3-Way	5,000 MMBtu/d	$3.00 / $2.35 / $4.00
Jan - Mar 17	Collar	2,000 MMBtu/d	$3.10 / $3.78
Jan - Dec 18	3-Way	5,000 MMBtu/d	$3.00 / $2.35 / $4.00

Deferred Put Premiums	
Year	Amount ($MM)
2016	$0.91
2017	$1.65
2018	$0.97

Oil			
Period	Contract Type	Volume Hedged	Price
Aug - Dec 16	3-Way	250 Bbl/d	$85.00 / $65.00 / $95.10
Aug - Dec 16	3-Way	330 Bbl/d	$80.00 / $65.00 / $97.35
Aug - Dec 16	3-Way	450 Bbl/d	$57.50 / $42.50 / $80.00
Aug - Dec 16	Put Spread	550 Bbl/d	$85.00 / $65.00
Aug - Dec 16	Swap	300 Bbl/d	$56.30
Aug - Dec 16	Swap	200 Bbl/d	$50.00
Jan - Jun 17	Swap	300 Bbl/d	$50.10
Jan - Jun 17	Protective Spread	200 Bbl/d	$60.00 / $42.50
Jan - Jun 17	Protective Spread	200 Bbl/d	$57.50 / $42.50
Jan - Dec 17	3-Way	280 Bbl/d	$80.00 / $65.00 / $97.25
Jan - Dec 17	3-Way	250 Bbl/d	$80.00 / $60.00 / $98.70
Jan - Dec 17	Put Spread	500 Bbl/d	$82.00 / $62.00
Jul - Dec 17	3-Way	200 Bbl/d	$60.00 / $42.50 / $85.00
Jul - Dec 17	3-Way	200 Bbl/d	$57.50 / $42.50 / $76.13
Jan - Aug 18	Put Spread	425 Bbl/d	$80.00 / $60.00

NGL			
Period	Contract Type	Volume Hedged	Price
Aug - Dec 16	Propane Swap	500 Bbl/d	$20.79

Note: Hedges as of 08/01/2016