Gulfport ENERGY

INVESTOR PRESENTATION

NOVEMBER 2017

Forward Looking Statement

This presentation includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that Gulfport expects or anticipates will or may occur in the future, future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of Gulfport's business and operations, plans, market conditions, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements. These statements are based on certain assumptions and analyses made by Gulfport in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate in the circumstances. However, whether actual results and developments will conform with Gulfport's expectations and predictions is subject to a number of risks and uncertainties, general economic, market, credit or business conditions; the opportunities (or lack thereof) that may be presented to and pursued by Gulfport; Gulfport's ability to identify, complete and integrate acquisitions of properties (including the properties recently acquired from Vitruvian II Woodford, LLC) and businesses; competitive actions by other oil and gas companies; changes in laws or regulations; and other factors, many of which are beyond the control of Gulfport. Information concerning these and other factors can be found in the Company's filings with the Securities and Exchange Commission, including its Forms 10-K, 10-Q and 8-K. Consequently, all of the forward-looking statements made in this news release are qualified by these cautionary statements and there can be no assurances that the actual results or developments anticipated by Gulfport will be realized, or even if realized, that they will have the expected consequences to or effects on Gulfport, its business or operations. Gulfport has no intention, and disclaims any obligation, to update or revise any forward-looking statements, whether as a result of new information, future results or otherwise.

Gulfport's estimated proved reserves as of December 31, 2016 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI") with respect to Gulfport's assets in the Utica Shale of Eastern Ohio and Gulfport's WCBB and Hackberry fields and by Gulfport's personnel with respect to its Niobrara field, overriding royalty and non-operated interests (less than 1% of its proved reserves at December 31, 2016), and comply with definitions promulgated by the SEC. NSAI is an independent petroleum engineering firm. In this presentation, we may use the terms "EUR," or other descriptions of volumes of hydrocarbons to describe volumes of resources potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines prohibit it from including in filings with the SEC. "EUR" does not reflect volumes that are demonstrated as being commercially or technically recoverable. Even if commercially or technically recoverable, a significant recovery factor would be applied to these volumes to determine estimates of volumes of proved reserves. Accordingly, these estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the Company. The methodology for "EUR" may also be different than the methodology and guidelines used by the Society of Petroleum Engineers and is different from the SEC's guidelines for estimating probable and possible reserves.

EBITDA is a non-GAAP financial measure equal to net income (loss), the most directly comparable GAAP financial measure, plus interest expense, income tax (benefit) expense, accretion expense, depreciation, depletion and amortization and impairment of oil and gas properties. Adjusted EBITDA is a non-GAAP financial measure equal to EBITDA less non-cash derivative (gain) loss, acquisition expense and (income) loss from equity method investments. Cash flow from operating activities before changes in operating assets and liabilities is a non-GAAP financial measure equal to cash provided by operating activity before changes in operating assets and liabilities. Adjusted net income is a non-GAAP financial measure equal to pre-tax net loss less non-cash derivative (gain) loss, acquisition expense and (income) loss from equity method investments. The Company has presented EBITDA and adjusted EBITDA because it uses these measures as an integral part of its internal reporting to evaluate its performance and the performance of its senior management. These measures are considered important indicators of the operational strength of the Company's business and eliminate the uneven effect of considerable amounts of non-cash depletion, depreciation of tangible assets and amortization of certain intangible assets. A limitation of these measures, however, is that they do not reflect the periodic costs of certain capitalized tangible and intangible assets used in generating revenues in the Company's business. Management evaluates the costs of such tangible and intangible assets and the impact of related impairments through other financial measures, such as capital expenditures, investment spending and return on capital. Therefore, the Company believes that these measures provide useful information to its investors regarding its performance and overall results of operations. EBITDA, adjusted EBITDA, adjusted net income and cash flow from operating activities before changes in operating assets and liabilities are not intended to be performance measures that should be regarded as an alternative to, or more meaningful than, either net income as an indicator of operating performance or to cash flows from operating activities as a measure of liquidity. In addition, EBITDA, adjusted EBITDA, adjusted net income and cash flow from operating activities before changes in operating assets and liabilities are not intended to represent funds available for dividends, reinvestment or other discretionary uses, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. The EBITDA, adjusted EBITDA, adjusted net income and cash flow from operating activities before changes in operating assets and liabilities presented in this presentation may not be comparable to similarly titled measures presented by other companies, and may not be identical to corresponding measures used in the Company's various agreements.

Gulfport Company Overview

Primary Areas of Operation[4]

Utica Shale
Acreage: ~213,000 Net Acres
YE 2016 Proved Reserves: 2.3 Net Tcfe
3Q2017 Net Production: 987.2 Mmcfepd

SCOOP
Acreage: ~92,900 Net Reservoir Acres
YE 2016 Proved Reserves: 1.2 Net Tcfe
3Q2017 Net Production: 194.4 Mmcfepd

Key Statistics

Market Capitalization[1]	**$2.5 Billion**
Enterprise Value[2]	**$4.3 Billion**
Pro Forma Liquidity[3]	**~$968 Million**
2016 Average Daily Production	**719.8 MMcfepd**
1Q16	692.2 MMcfepd
2Q16	664.7 MMcfepd
3Q16	734.1 MMcfepd
4Q16	787.0 MMcfepd
2017E Average Daily Production	**1,065 – 1,100 MMcfepd**
1Q17	849.6 MMcfepd
2Q17	1,038.4 MMcfepd
3Q17	1,199.6 MMcfepd
Net Core Acreage[4]	
Utica Shale	~213,000 acres
SCOOP	~92,900 acres
Identified Gross Locations	
Utica Shale[5]	~1,214 gross locations
SCOOP	~1,750 gross locations

1. Market capitalization calculated as of the close of the market on 10/31/17 at a price of $13.70 per diluted share using shares outstanding from the Company's 3Q2017 financial statements.
2. Enterprise value calculated as of the close of the market on 10//31/17 at a price of $13.70 per share using shares outstanding, short-term debt, long-term debt, and cash and cash equivalents from the Company's 3Q2017 financial statements; pro forma for the October 2017 Senior Notes offering.
3. Liquidity calculated as of 9/30/17 using borrowing base availability, letters of credit outstanding, and cash and cash equivalents from the Company's 3Q2017 financial statements; pro forma for the October 2017 Senior Notes offering.
4. Acreage as of 11/1/17; SCOOP acreage includes ~50,400 Woodford and ~42,500 Springer net reservoir acres.
5. Assumes net undeveloped locations grossed up from 75% working interest.

Overview of Gulfport

- Gulfport Energy Corporation ("GPOR") is an independent E&P company based in Oklahoma City, OK
  - Company born from legacy assets in South Louisiana
  - Free cash flow from legacy assets facilitated expansion into North America's premier resource plays

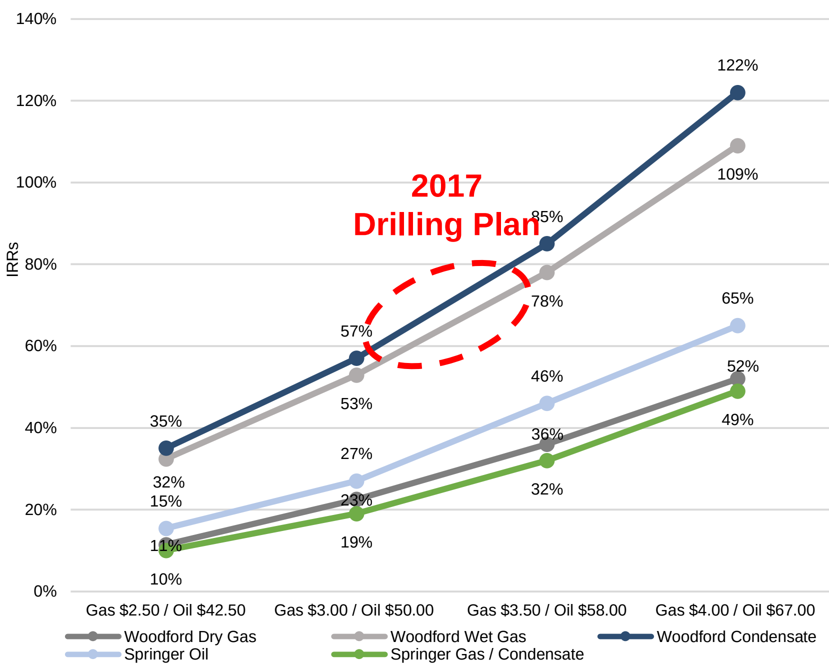
1997 – 1998	1998 – 2005	2005 – 2007	2007 – 2012	2012 – Today
Phase 1: Formation / Asset Focus	**Phase 2: Low Risk Development**	**Phase 3: Resource Diversification**	**Phase 4: Resource Play Addition**	**Phase 5: Resource Development and Expansion**
— Gulfport Energy was formed in July 1997 — Initial assets were those of WRT Energy and a 50% working interest in the West Cote Blanche Bay ("WCBB") field contributed by DLB Oil and Gas — Gulfport divested a number of assets during this period leaving a cleaner balance sheet and focused asset base	— Focused on production and cash flow growth from low risk development activities principally in WCBB — Reprocessed 3D seismic in WCBB field — Created a track record of successful drilling	— Continued successful drilling and growth at the WCBB field — Conducted a 3-D seismic shoot and drilled first exploratory wells in Hackberry field — Amassed solid acreage position in Canadian Oil Sands and launched core hole drilling program — Acquired interest in Phu Horm natural gas field in Thailand	— Acquired initial acreage position in Permian Basin and expanded through acquisitions — Acquired larger interest in second natural gas field in Thailand — Secured sizable position in the core of the Utica Shale achieving early entrant advantages — Began vertical integration efforts in the Utica Shale to secure access to quality services	— Initiated drilling program to begin developing Utica Shale resource and currently actively developing acreage — Contributed Permian Basin interests in Diamondback Energy, Inc. IPO — Contributed certain services investments into Mammoth Energy Services, Inc. IPO — Acquired assets in the core of the SCOOP play and currently actively developing acreage

2017 Activity Economic Focus

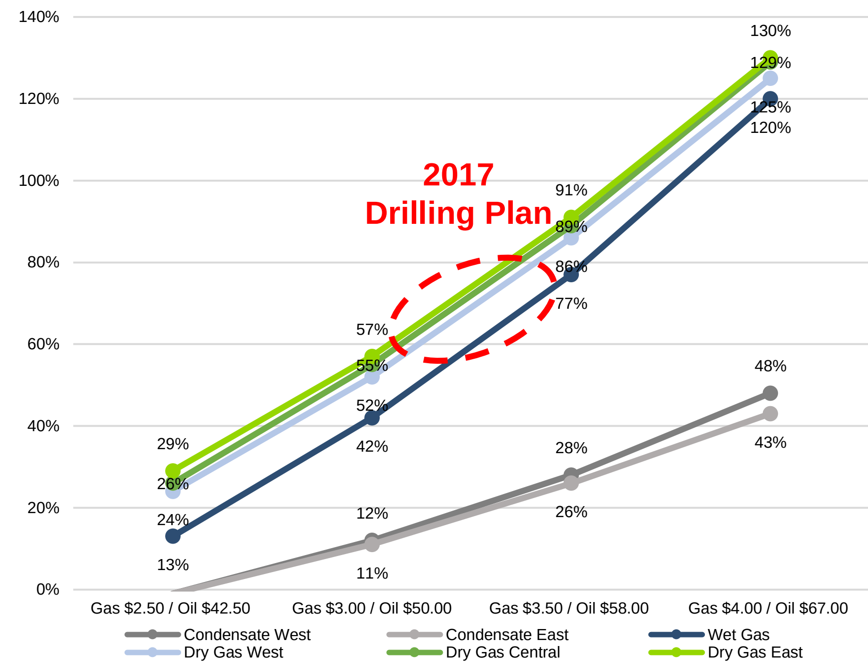
— During 2017, plan to focus Utica Shale activity in the dry gas windows and SCOOP activity in the wet gas window of the play

— Allocation of capital split between two top-tier basins with dry gas and liquids inventory

SCOOP Single Well Economics[1,2]



Utica Single Well Economics[1,2]



	Woodford Dry Gas	Woodford Wet Gas	Woodford Condensate	Springer Gas Condensate	Springer Oil
Gross Undeveloped Locations	402	528	249	215	354
Net Undeveloped Locations	65	182	33	72	70

	Condensate West	Condensate East	Wet Gas	Dry Gas West	Dry Gas Central	Dry Gas East
Gross Undeveloped Locations[3]	134	77	119	182	444	258
Net Undeveloped Locations	100	58	89	137	333	193

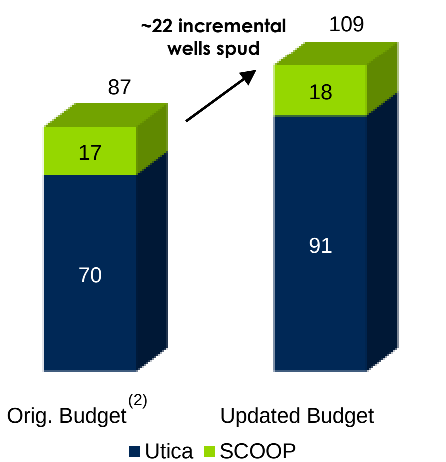
1. Assumes ethane rejection.
2. Well economics are adjusted for transport fees and regional price differentials.
3. Assumes net undeveloped locations grossed up from 75% working interest.

Updated 2017 Guidance

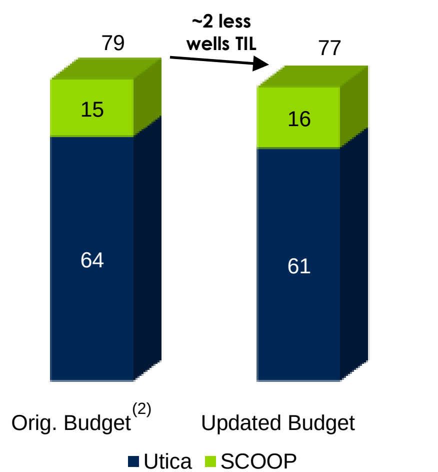
Key Highlights

- Gulfport has successfully acquired leasehold organically on the ground within units scheduled in our near-term development plan
  - Acquired leasehold has led to a significant increase in working interests on 2017 wells spud and now estimate to spud an incremental 22.0 net wells
  - Additional spend will be partially offset by a reduction in approximately 2.4 net turn-in-lines
- Gulfport conducted additional exploratory activity in the SCOOP to potentially organically delineate additional resource across the acreage
  - In support of these efforts, Gulfport has acquired additional 3-D seismic, well cores and geophysical and geological studies in the play
- Gulfport has updated its 2017 CAPEX budget to reflect an additional $35 million in connection with delineation activities in the SCOOP and an incremental $75 million in connection with the increase in working interests on 2017 wells spud and related leasehold spend
  - Now expect to invest ~$1.16 billion in 2017 on drilling and completion, midstream and leasehold activities
- Gulfport forecasts 2017 full-year production to be trending towards the upper-end of the previously increased guidance range, despite a slight reduction in turn-in-lines, highlighting the continued strong production performance from both the Utica Shale and SCOOP assets

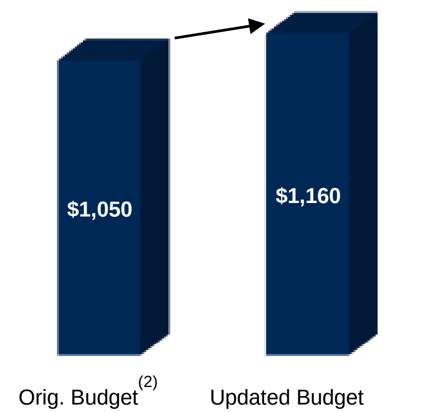
2017E Net Wells Spud



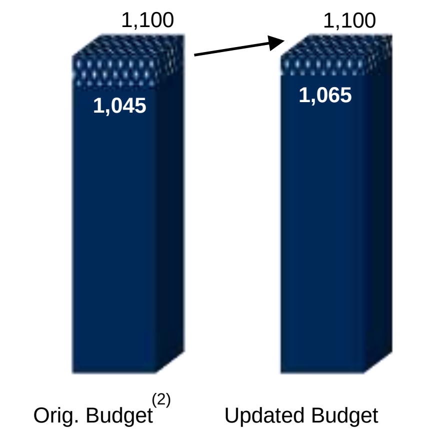
2017E Net Wells Turned-to-Sales



2017E Total CAPEX ($MM)



2017E Avg. Daily Prod. (MMcfepd)



1. Guidance for the year ending 12/31/17 is based on multiple assumptions and certain analyses made by the Company in light of its experience and perception of historical trends and current conditions and may change due to future developments. Actual results may not conform to the Company's expectations and predictions. Please refer to page 2 for more detail of forward looking statements.
2. Based on the midpoint of original 2017 budget.

Updated 2017 Guidance

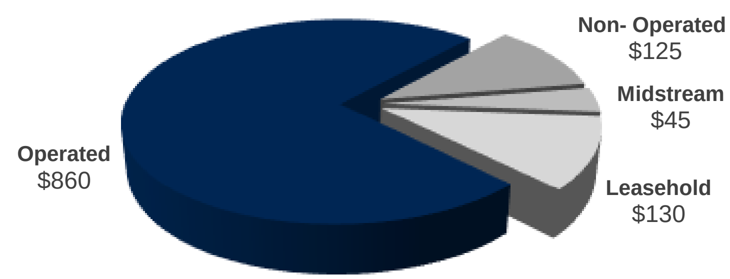
2017E Capital Budget

	Year Ending 12/31/2017	
Forecasted Production		
Average Daily Gas Equivalent – MMcfepd	1,065	1,100
% Gas	~88%	
% NGLs	~8%	
% Oil	~4%	
Forecasted Realizations (before the effects of hedges)[1]		
Natural Gas (Differential to NYMEX) - $ per Mcf	($0.62)	($0.68)
NGL (% of WTI)	45%	50%
Oil (Differential to NYMEX WTI) - $ per Bbl	($3.25)	($3.75)
Projected Operating Costs		
Lease Operating Expense - $/Mcfe	$0.18	$0.23
Midstream Gathering and Processing - $/Mcfe	$0.55	$0.62
Production Taxes - $/Mcfe	$0.08	$0.09
General and Administrative[2] - $/Mcfe	$0.15	$0.17
Depreciation, Depletion, and Amortization - $/Mcfe	$0.85	$0.90
Budgeted D&C Capital Expenditures – in Millions:		
Operated	$860	
Non - Operated	$125	
Total Budgeted D&C Capital Expenditures	$985	
Budgeted Midstream Capital Expenditures – in Millions:	$45	
Budgeted Leasehold Capital Expenditures – in Millions:	$130	
Total Budgeted Capital Expenditures – in Millions:	$1,160	

2017E Forecasted Activity

	Year Ending 12/31/2017
Net Wells Drilled	
Utica – Operated	91
Utica – Non – Operated	8
Total	99
SCOOP – Operated	18
SCOOP – Non - Operated	1
Total	19
Net Wells Turned-to-Sales	
Utica – Operated	61
Utica – Non - Operated	9
Total	70
SCOOP – Operated	16
SCOOP – Non - Operated	1
Total	17

2017E CAPEX (in millions)

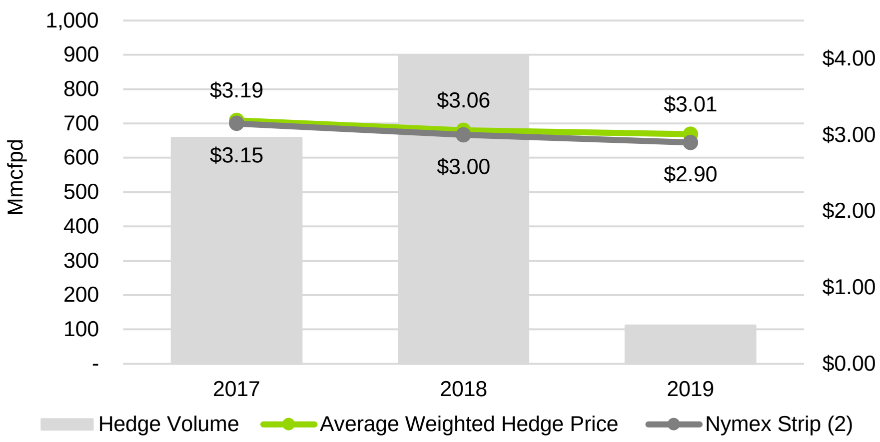


1. Based upon current forward pricing and basis marks.
2. Includes non-cash stock compensation.

Note: Guidance for the year ending 12/31/17 is based on multiple assumptions and certain analyses made by the Company in light of its experience and perception of historical trends and current conditions and may change due to future developments. Actual results may not conform to the Company's expectations and predictions. Please refer to page 2 for more detail of forward looking statements.

Strong Post Acquisition Liquidity, Capitalization and Hedge Position

Gas Hedges[1]



Key Highlights

— Gulfport's strategic commitment to the balance sheet and conservative leverage metrics provided the ability to pursue an aggressive growth plan in 2017

— For 2018, the Company is committed to a disciplined capital program targeting cash flow neutrality for the calendar year

- At strip pricing[2], Gulfport forecasts approximately 30% production growth in 2018 over 2017

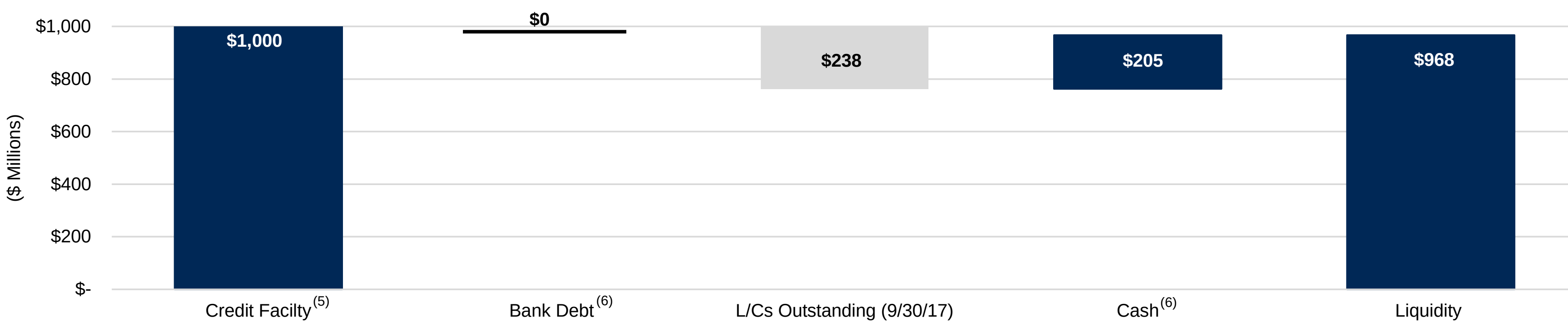
— Strong hedge position in 2017

- Approximately 70%[6] of expected 2017 natural gas production hedged at $3.19 per MMBtu

— Large base of hedges for 2018

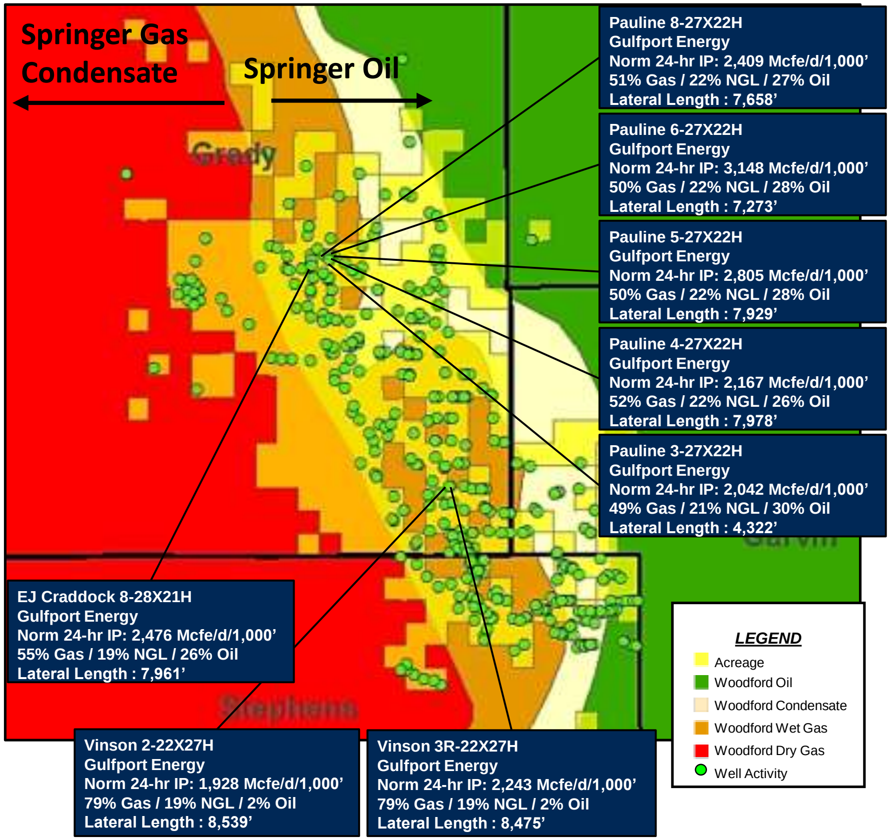
- Approximately 70%[4] of expected 2018 production hedged at $3.06 per MMBtu

Liquidity Position[3]



1. Hedge volume and weighted average price excludes swaptions. Detailed overview in appendix of the presentation.
2. Price forecast as of 10/31/17.
3. Liquidity calculated as of 9/30/17 using borrowing base availability, letters of credit outstanding, and cash and cash equivalents from the Company's 3Q2017 financial statements; pro forma for the October 2017 Senior Notes Offering.
4. Based upon consensus estimates and preliminary growth target given alongside Company's 3Q17 earnings assuming strip pricing at that time.
5. In connection with the scheduled fall redetermination, Gulfport's lead lenders have proposed an increase to the Company's borrowing base from $1.0 billion to $1.2 billion with elected commitments to total $1.0 billion.
6. Pro forma for the Company's October 2017 Senior Notes offering.
7. Based on the midpoint of 2017 guidance and excludes swaptions. Detailed overview in appendix of the presentation.

SCOOP – Recent Well Results



Overview

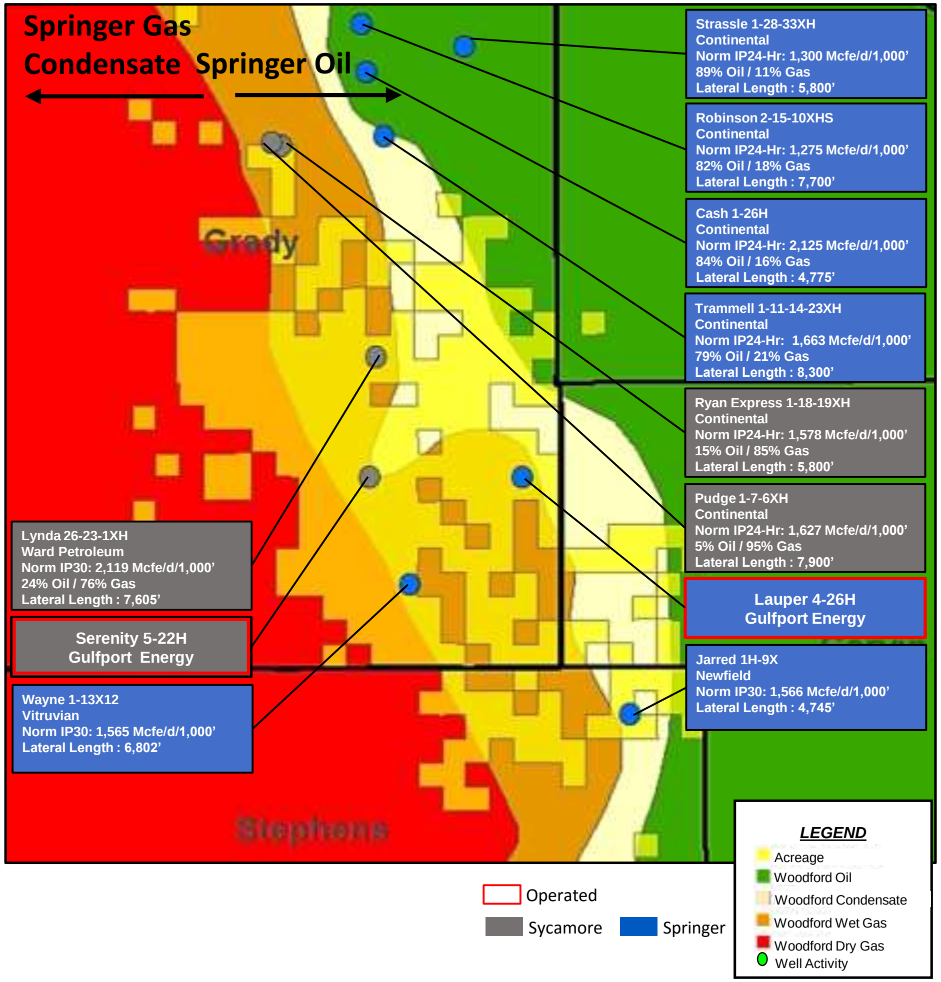
- Gulfport closed the SCOOP acquisition in February 2017 and has been running four horizontal rigs on the acreage
  - After taking over the assets, the Gulfport team focused on the high-grading of equipment for our rig fleet to drive efficiencies and lower drill days in the play
- Gulfport began pumping first operated completion on March 1, 2017
  - Frac design on the wells to date includes an enhanced completion when compared to historical practices for the area
- Turned-to-sales first two operated wells during the second quarter of 2017
- Gulfport has provided initial production rates on eight operated Woodford wells in the play and all wells are outperforming on average relative to their offsets and type curves

Recent Well Results Summary

	County	Phase Window	Stimulated Lateral	Wellhead BTU	NGLs Per MMcf	% Shrink	Product Mix[1]			Average Prod. Rates (Mmcfepd)			
							Gas	NGLs	Oil	24-Hr	30-Day	60-Day	90-Day
EJ Craddock 8-28X21H	Central Grady	Woodford Wet Gas	7,961	1,171	47.0	16%	55%	19%	26%	19.7	17.3	n/a	n/a
Pauline 3-27X22H	Central Grady	Woodford Wet Gas	4,322	1,212	57.3	18%	49%	21%	30%	8.8	8.0	n/a	n/a
Pauline 4-27X22H	Central Grady	Woodford Wet Gas	7,978	1,212	57.3	18%	52%	22%	26%	17.3	16.1	n/a	n/a
Pauline 5-27X22H	Central Grady	Woodford Wet Gas	7,929	1,216	57.4	22%	50%	22%	27%	22.2	19.1	n/a	n/a
Pauline 6-27X22H	Central Grady	Woodford Wet Gas	7,273	1,216	57.4	22%	50%	22%	28%	22.9	19.6	n/a	n/a
Pauline 8-27X22H	Central Grady	Woodford Wet Gas	7,658	1,210	58.8	19%	51%	22%	27%	18.4	18.6	n/a	n/a
Vinson 2-22X27H	SE Grady	Woodford Wet Gas	8,539	1,118	35.7	11%	79%	19%	2%	16.5	15.7	14.4	13.4
Vinson 3R-22X27H	SE Grady	Woodford Wet Gas	8,475	1,118	35.7	11%	79%	19%	2%	19.0	18.7	17.3	16.3

Note: All well results presented on this slide are based upon three-stream production data and assume contractual ethane recovery.
1. Product mix calculated utilizing 24-hr initial production rate.

SCOOP – Springer & Sycamore Activity



Overview

- The Sycamore formation is age equivalent to the Meramec and Osage being developed in the STACK and is located between the organic-rich Woodford and Caney Shales
  - ~250 feet thick across the acreage position, presenting a significant future development target
  - Encouraged by the recent activity near Gulfport's acreage position
  - Gulfport holds in excess of ~40,000 net reservoir acres prospective in the Sycamore
- The Springer formation is an organic rich shale interval that has thus far been predominately oil productive
  - Strata contains several laterally extensive siliceous black shales that possess highly connected organic pores
  - Recent results have shown strong production and suggest high repeatability
  - Gulfport holds ~42,500 net reservoir acres in the Springer
- During 2017, Gulfport spud both its first Sycamore and Springer tests
  - The Sycamore well is located in the heart of the acreage position, on the western side of the wet gas window of the Woodford and is targeting the lower portion of the Sycamore formation
    - Recently completed drilling and plan to complete the well during the fourth quarter of 2017
  - The Springer well is located on the eastern side of the acreage position in the oily area of the play and is targeting the thick-porous, oil-rich section of the upper member of the Springer formation
    - In the very early stages of flowback and look forward to providing initial results in the coming weeks
- The locations of Gulfport's test will further delineate our position and derisk incremental acreage in the play

Source: Company provided data and publicly available information. All well results presented on this slide are based upon two-stream production data

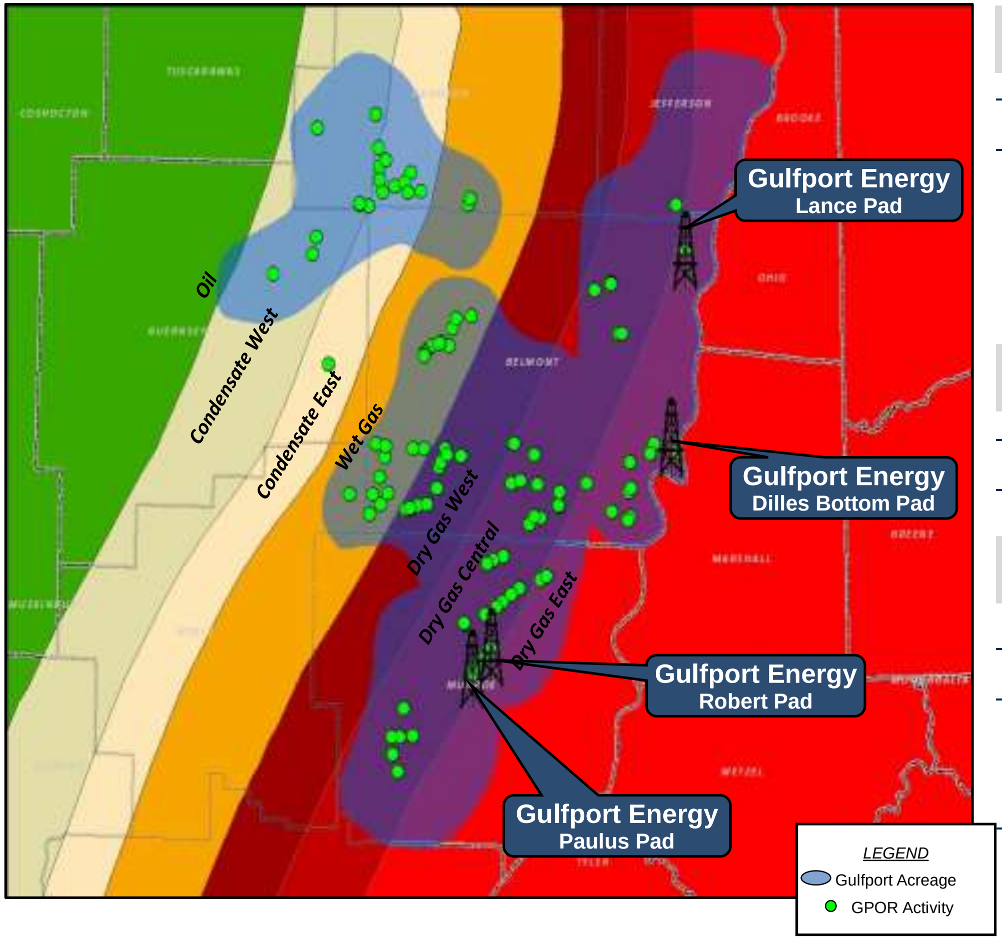
Key Investment and Financial Highlights

High Quality Assets	— Core acreage positions in two of the most prolific, high-quality natural gas plays in North America – Basin diversification provides optionality to allocate capital across two premier assets – Significant inventory in two lost cost basins with low well breakeven economics and IRRs in excess of 70%[1] — Significant exposure to the core of the Utica Shale with approximately ~213,000[2] net acres under lease – Development expected to provide further catalyst for reserves and production growth — Low-risk, highly contiguous SCOOP acreage with approximately ~92,900[2] net reservoir acres in the core of the play – Stacked-pay zones provide significant upside – Liquids exposure in attractive market complements production base, enhances cash margins and provides drilling optionality from dry gas to liquids rich wet gas
Financial Philosophy and Hedge Position	— Strong balance sheet and cash flow expected to allow Gulfport to continue to drive production growth – Liquidity of ~$968 million[3] — Gulfport hedges a portion of its expected production to lock in prices and returns, providing certainty of cash flows to execute on its capital plans – Currently ~70%[4] of 2017E natural gas production is hedged at $3.19 per MMBtu – Gulfport has ~70%[5] of 2018E natural gas production hedged at $3.06 per MMBtu – Company has historically targeted hedged 50% to 70% of expected twelve-month run rate total production
Well Positioned for 2017 and Beyond	— Gulfport is currently running a four rig program in the Utica and four rig program in the SCOOP – Anticipated 2017 D&C capital budget of ~$985 million, yielding top-tier year-over-year growth of approximately 48% to 53% — As Gulfport plans for 2018, the company is targeting cash flow neutrality for the calendar year, which at strip pricing, Gulfport forecasts would generate approximately 30%[5] production growth in 2018 over 2017 — The combination of Utica and SCOOP provides the opportunity to optimize the strengths of Gulfport's business through strategic capital allocation across the portfolio, further diversifying Gulfport's commodity price exposure, affording investors a low-risk and high-growth opportunity in two of North America's lowest cost natural gas basins

1. Well economics assume a flat price case of $3.50 / MMBtu gas, $58.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.
2. Acreage as of 11/1/17; SCOOP acreage includes ~50,400 Woodford and ~42,500 Springer net reservoir acres.
3. Liquidity calculated as of 9/30/17 using borrowing base availability, letters of credit outstanding, and cash and cash equivalents from the Company's 3Q2017 financial statements; pro forma for the October 2017 Senior Notes offering.
4. Based on the midpoint of 2017 guidance and excludes swaptions. Detailed overview in appendix of the presentation.
5. Based upon consensus estimates and preliminary growth target given alongside Company's 3Q17 earnings assuming strip pricing at that time.

Utica Asset Overview

Utica Shale Overview



Asset Overview

- Net proved reserves of 2.3 Tcfe(1)
- ~213,000 net acres(2)
  - Oil - ~1%
  - Condensate - ~11%
  - Wet Gas - ~13%
  - Dry Gas - ~75%

2017 Activities Update(3)

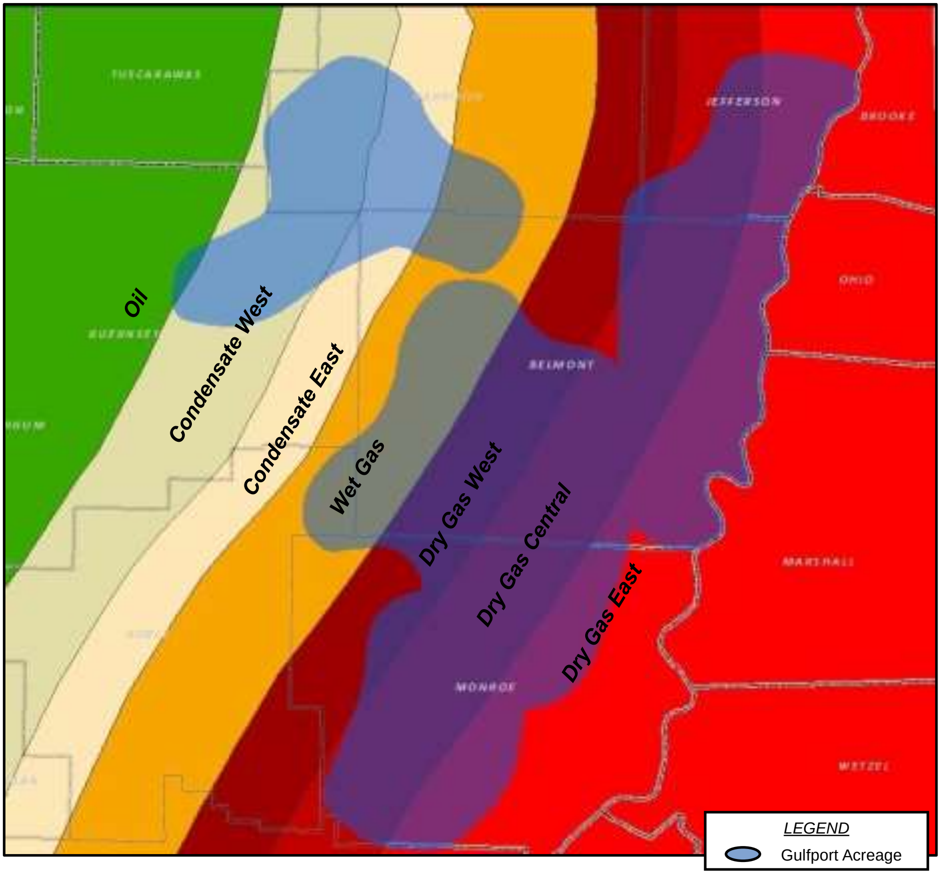
- Average net production of 987.2 MMcfepd
- ~82% of Gulfport's total net production

Planned Activities(4)

- Currently running 4 gross operated rigs
- Operated Activity
  - Drill 96 gross (91 net) wells
  - Turn-to-sales 68 gross (61 net) wells
- Non-Operated Activity
  - Drill 24 gross (8 net) wells
  - Turn-to-sales 45 gross (9 net) wells

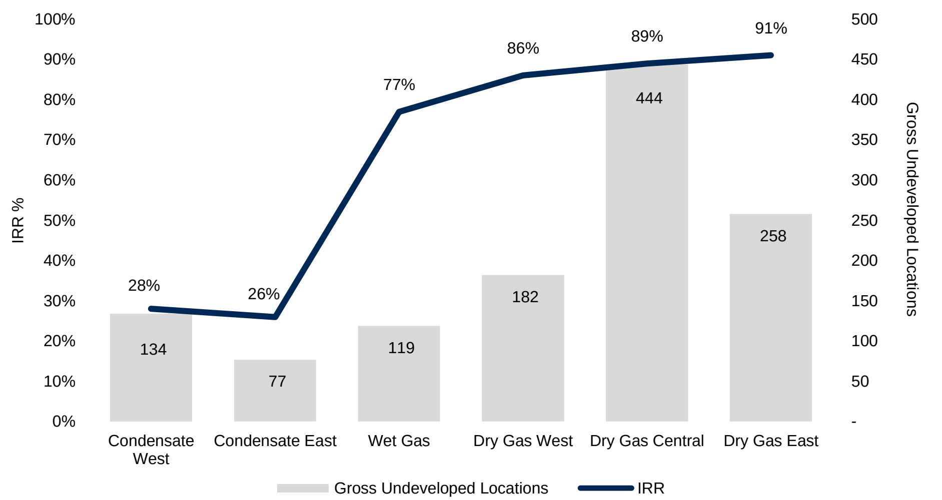
Note: Please refer to page 2 for detail on forward looking statements.
1. As of 12/31/16.
2. Acreage as of 11/1/17.
3. During the three months ended 9/30/17.
4. As of 11/1/17.

Utica Shale – Type Curve Assumptions



Type Curve Assumptions[1]	Condensate		Wet	Dry Gas		
	West	East	Gas	West	Central	East
Lateral Length	8,000	8,000	8,000	8,000	8,000	8,000
Well Cost ($MM)	$7.7	$7.7	$8.3	$8.5	$8.7	$8.9
Well Cost ($ per foot)	$962	$964	$1,035	$1,060	$1,085	$1,110
Total EUR (Bcfe / 1,000)	0.7	1.0	2.0	2.2	2.4	2.6
Total EUR (Bcfe)	5.7	8.1	16.0	17.2	19.0	20.7
% Gas	42%	56%	77%	100%	100%	100%
Assumed Well Spacing (ft)	600	600	1,000	1,000	1,000	1,000
Gross Undeveloped Locations[3]	134	77	119	182	444	258
Net Undeveloped Locations	100	58	89	137	333	193

Utica Single Well Economics[1, 2]

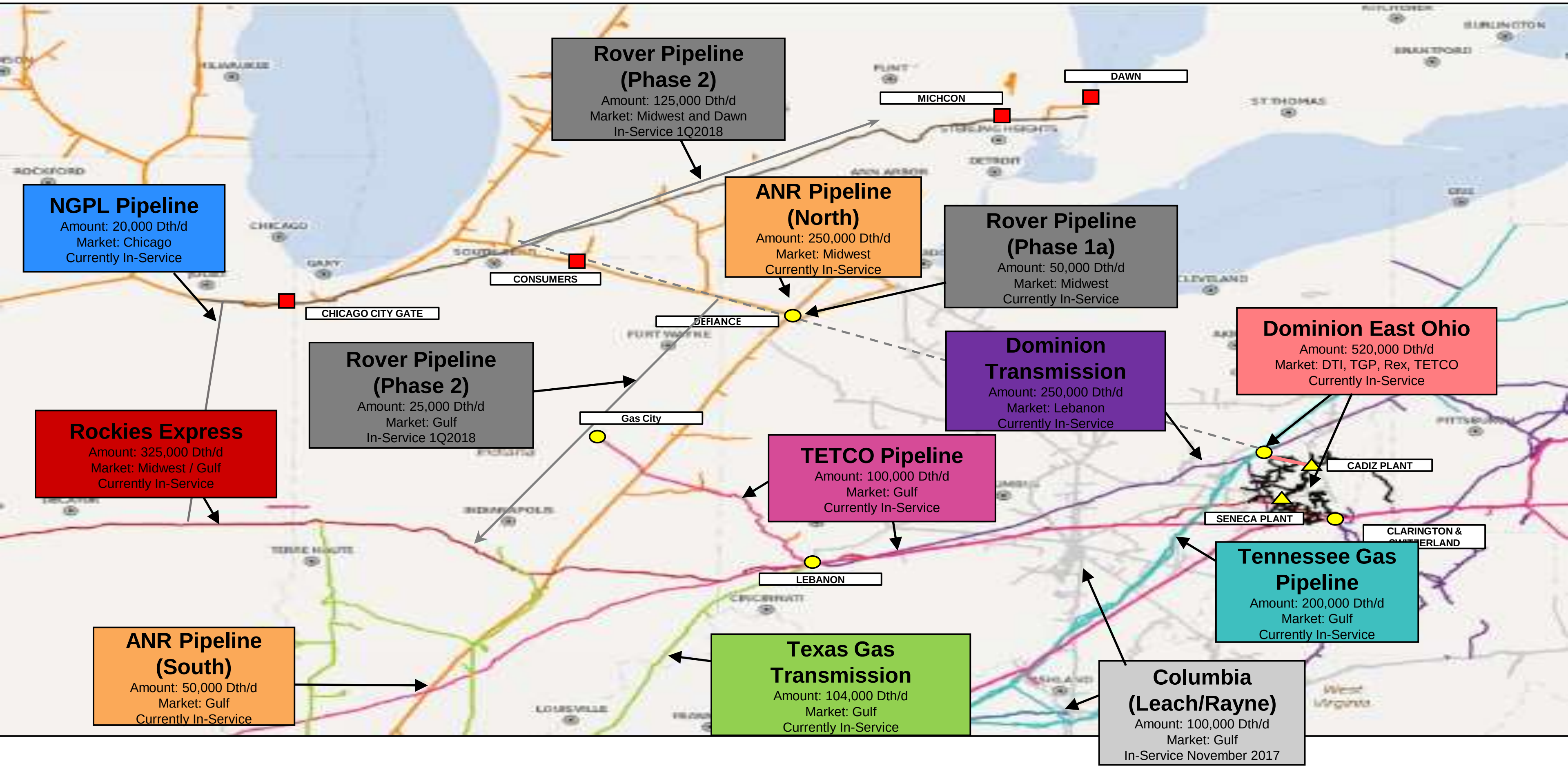


Based on midpoint Note: See appendix slide 27 for detailed assumptions used to generate single well IRRs and slide 34 for net undeveloped locations.

1. Assumes ethane rejection.
2. Well economics assume a flat price case of $3.50 / MMBtu gas, $58.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.
3. Assumes net undeveloped locations grossed up from 75% working interest.

Utica Shale – Diversified End Market Portfolio

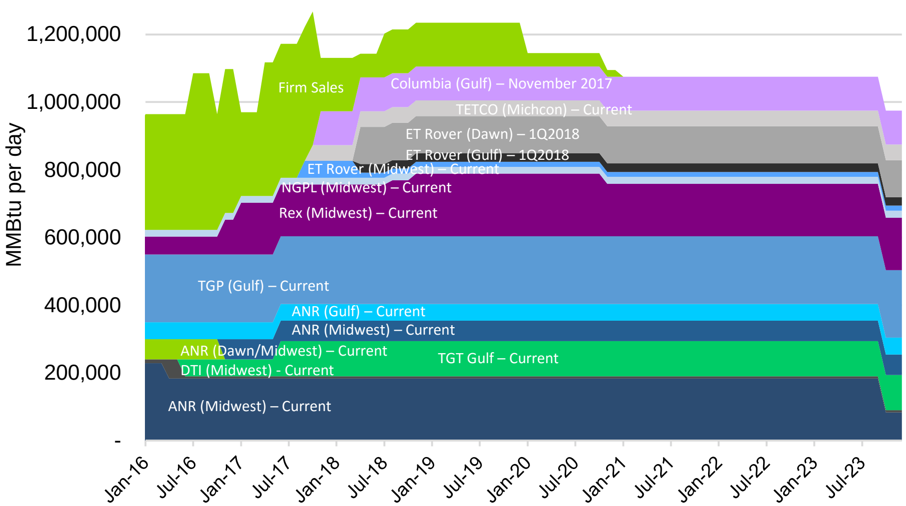
Overview[1]



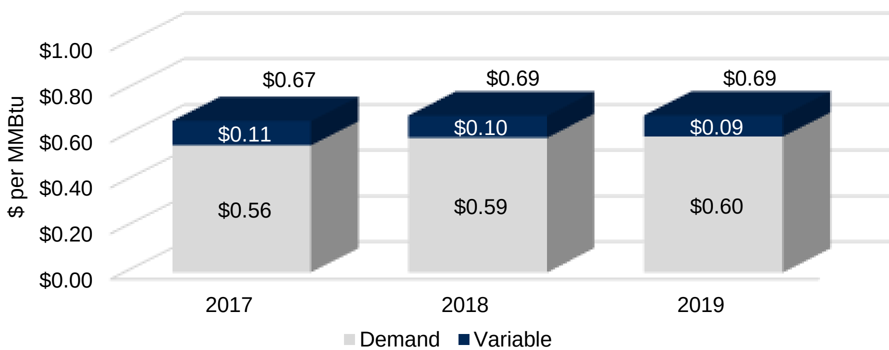
1. Commitments presented as gross volumes.

Utica Shale – Firm Transportation and Sales Outlets

Firm Commitments (MMBtu per day)



Firm Transportation Costs ($ per MMBtu)



Overview[1]

	YE2014	YE2015	YE2016	YE2017 +
	(MMBtu / day)			
Midwest Markets				
ANR Pipeline	184,000	229,000	184,000	244,000
Dominion Transmission Pipeline		11,000	6,000	6,000
NGPL		20,000	20,000	20,000
Rockies Express Pipeline		53,000	103,000	153,000
Rover Pipeline				15,000
TETCO				46,000
Canadian Markets				
ANR Pipeline	60,000	60,000	60,000	
Rover Pipeline				110,000
Gulf Coast Markets				
ANR Pipeline		50,000	50,000	50,000
Tennessee Gas Pipeline		200,000	200,000	200,000
Texas Gas Transmission			50,000	104,000
Rover Pipeline				25,000
Columbia Pipeline				100,000
Firm Sales Agreements				
Dominion South Point	5,000	5,000		
TETCO M2	50,000	75,000	75,000	75,000
Chicago City Gate	50,000			
Fixed Basis	33,000	207,000	257,000	77,000
TOTAL	**382,000**	**910,000**	**1,005,000**	**1,225,000**

1. Commitments presented as gross volumes.

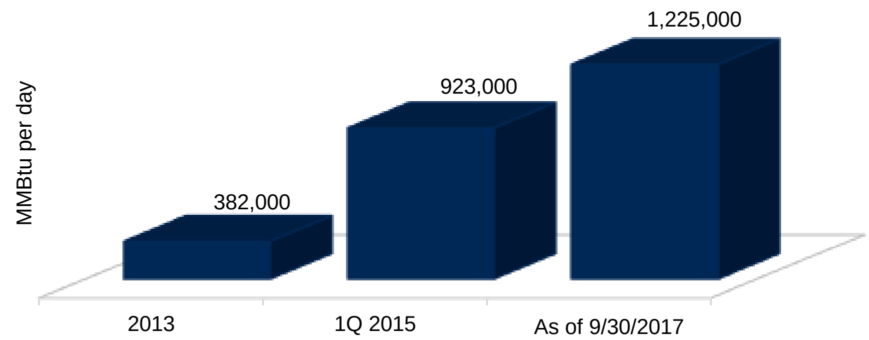
Utica Shale – Overview of Firm Portfolio

Overview

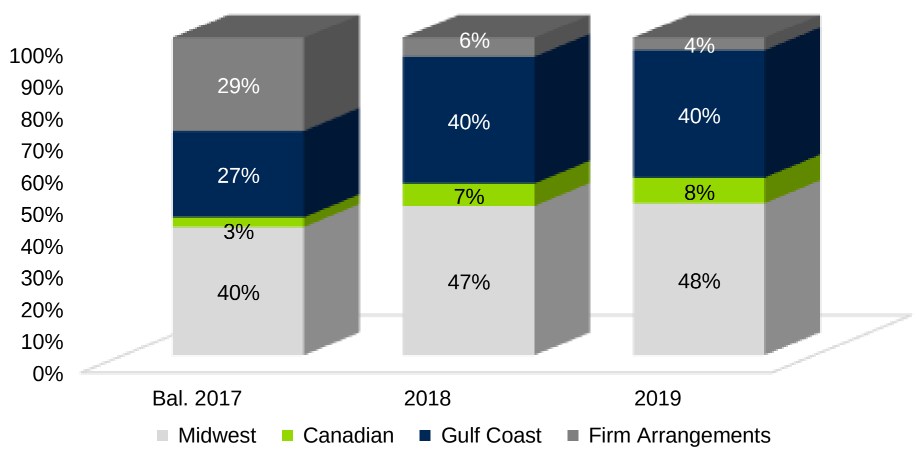
— Gulfport was first-mover in securing early access to premium Midwest markets and early transport at low costs out of the basin

— Gulfport's incremental growth volumes in 2018 will be priced into a basis tightening, local market, advantaged relative to our average cost of firm transportation

YE 2017 Secured Firm Commitments[1]



Regional Exposure and Realized Pricing of Firm Portfolio

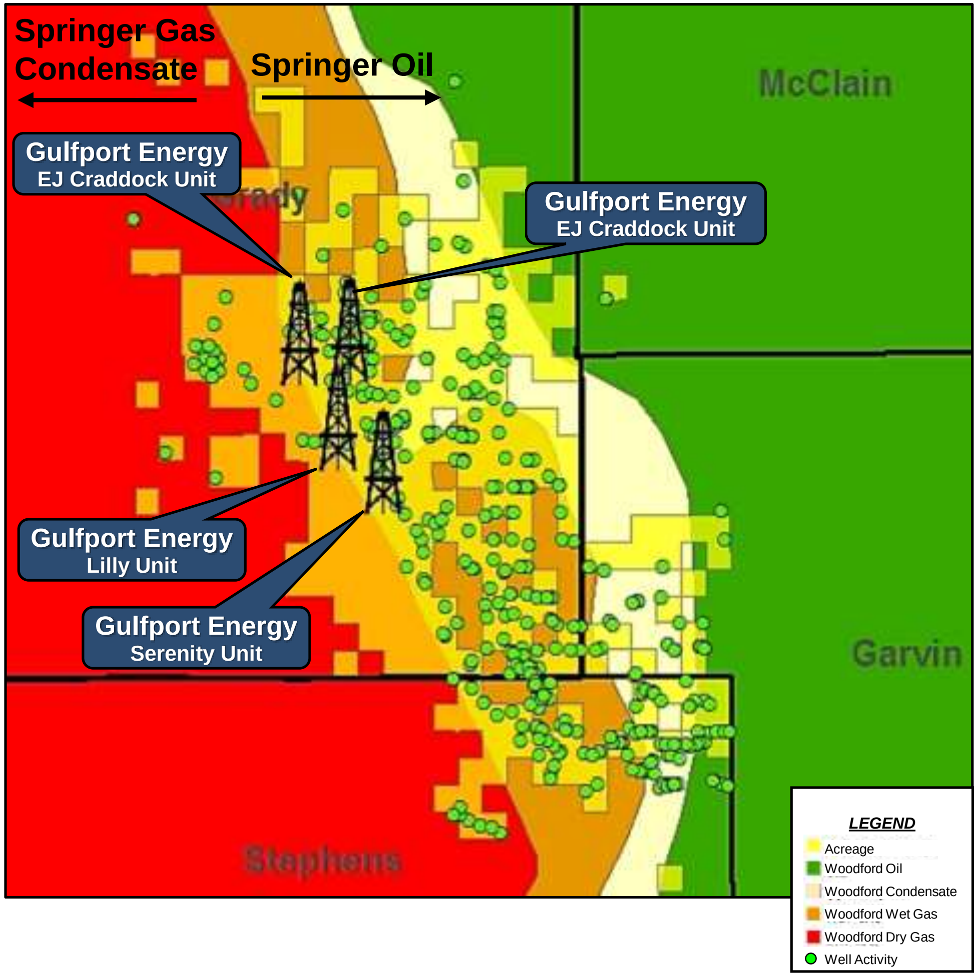


		2017		2018		2019
NYMEX Strip ($ / MMBtu)	$	3.17	$	3.06	$	2.91
Basis Impact ($/ MMBtu)	$	(0.36)	$	(0.21)	$	(0.21)
Firm Variable Costs ($/ MMBtu)	$	(0.08)	$	(0.09)	$	(0.09)
Firm Demand Costs ($/ MMBtu)	$	(0.40)	$	(0.56)	$	(0.57)
Pre-Hedge Realized Price ($/ MMBtu)	**$**	**2.33**	**$**	**2.20**	**$**	**2.04**
BTU Uplift (MMBtu / Mcf)	$	0.16	$	0.17	$	0.15
Pre-Hedge Realized Price ($/ Mcf)	**$**	**2.49**	**$**	**2.37**	**$**	**2.19**
Total Firm Expense + Basis ($ / MMBtu)	**$**	**(0.83)**	**$**	**(0.86)**	**$**	**(0.87)**
Total Firm Expense + Basis ($ / Mcf)	**$**	**(0.67)**	**$**	**(0.70)**	**$**	**(0.71)**
Dominion South Point Strip ($ / MMBtu)	**$**	**(0.87)**	**$**	**(0.54)**	**$**	**(0.53)**

1. Commitments presented as gross volumes.

SCOOP Asset Overview

SCOOP Overview



Asset Overview

- ~92,900[1] net reservoir acres in the core of the SCOOP play in Grady, Stephens, and Garvin Counties, OK
  - Includes ~50,400 Woodford and ~42,500 Springer acres in over-pressure liquids rich to dry gas windows of the play
    - Operates ~80% of Woodford net acres w/ an average 70% WI and an average 80% NRI
  - ~82% Woodford and ~79% Springer acreage held by production
  - Estimate in excess of 40,000 net acres prospective for Sycamore
- Deep inventory of delineated, high-return drilling locations at current strip pricing

2017 Activities Update[2]

- Average net production of 194.4 MMcfepd
  - ~70% natural gas, 20% natural gas liquids and 10% oil

Planned Activities[3]

- Currently running 4 gross operated rigs
- Operated Activity
  - Drill 22 gross (18 net) wells
  - Turn-to-sales 18 gross (16 net) wells
- Non-Operated Activity
  - Drill ~1 net wells
  - Turn-to-sales ~1 net wells

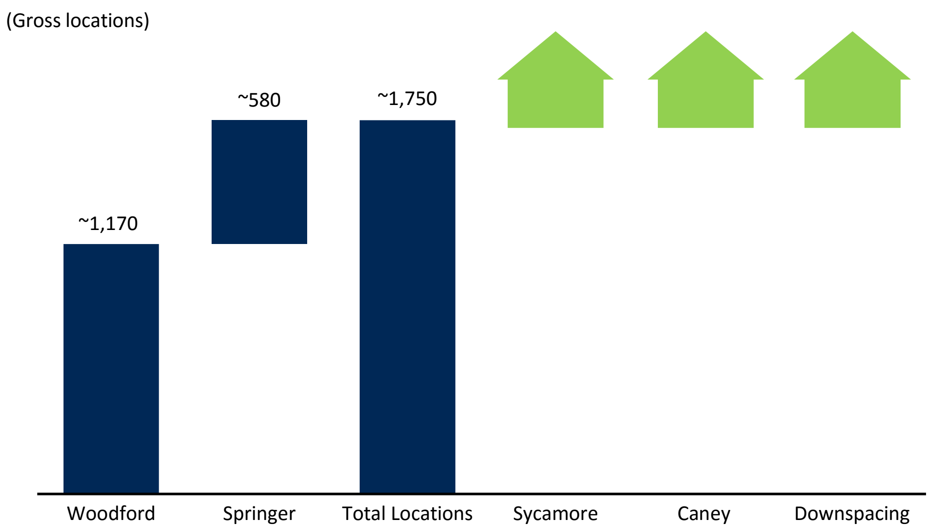
Note: Please refer to page 2 for detail on forward looking statements.
1. Acreage as of 11/1/17.
2. During the three months ended 9/30/17.
3. As of 11/1/17.

SCOOP – Large Stacked Multi-Pay Inventory

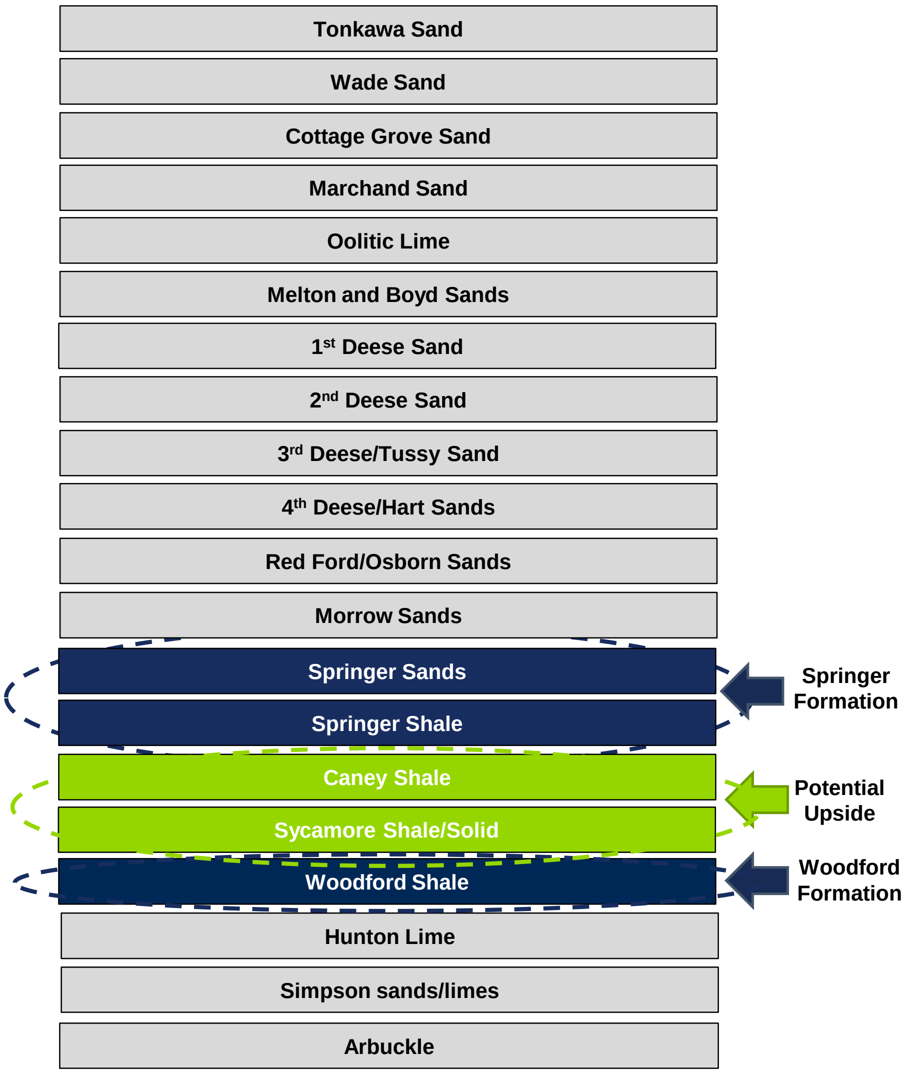
Overview

- 50,400 net surface acres located in the heart of the SCOOP condensate and over-pressured gas windows with exposure to stacked pay zones
  - ~1,180 gross identified locations in the Woodford formation
  - ~580 gross identified locations in the Springer formation
  - Additional upside from Sycamore, Caney and downspacing
- ~15 years of identified drillable locations with significant upside potential
- Highly delineated play with high well and seismic control
  - Approximately 3,000 producing wells
  - Well understood reservoir dynamics and geological characteristics

Significant Inventory



Formation Overview



SCOOP – Recent Well Results

Lynda 26-23-1XH
Ward Petroleum
Norm IP30: 2,119
Lateral Length : 7,605'

Tyemax Bia 1-35RXH
Marathon
Norm IP30: 2,587
Lateral Length : 7,286'

Charlie Brown 1-17-8XH
Continental
Norm IP30: 1,820
Lateral Length : 5,220'

Lane 13-24-1XH
Apache
Norm IP30: 1,534
Lateral Length : 5,293'

Peppered Ranch 1-36-25
Continental
Norm IP30: 2,140
Lateral Length : 8,571'

Vinson 2-22X27H
Gulfport Energy
Norm IP30: 1,666
Lateral Length: 8,539'

Vinson 1-22H
Vitruvian
Norm IP30: 1,515
Lateral Length : 4,045'

Newy 6-25-24-13XH
Continental
Norm IP30: 1,595
Lateral Length : 10,991'

Newy 7-25-24-13XH
Continental
Norm IP30: 1,778
Lateral Length : 10,710'

Pauline 3-27X22H
Gulfport Energy
Norm IP30: 1,656
Lateral Length: 4,322'

Pauline 4-27X22H
Gulfport Energy
Norm IP30: 1,799
Lateral Length: 7,978'

Pauline 8-27X22H
Gulfport Energy
Norm IP30: 2,169
Lateral Length: 7,658'

EJ Craddock 8-28X21H
Gulfport Energy
Norm IP30: 1,989
Lateral Length: 7,961'

Fowler 4N6W 3-9X16H
Vitruvian
Norm IP30: 1,526
Lateral Length : 8,700'

Parks 4-14X23H
Vitruvian
Norm IP30 : 1,522
Lateral Length : 7,417'

Cheyenne 8-10X15H
Vitruvian
Norm IP30: 1,635
Lateral Length : 7,026'

Anita Fowler 1-27X26H
Vitruvian
Norm IP30 : 3,166
Lateral Length : 5,950'

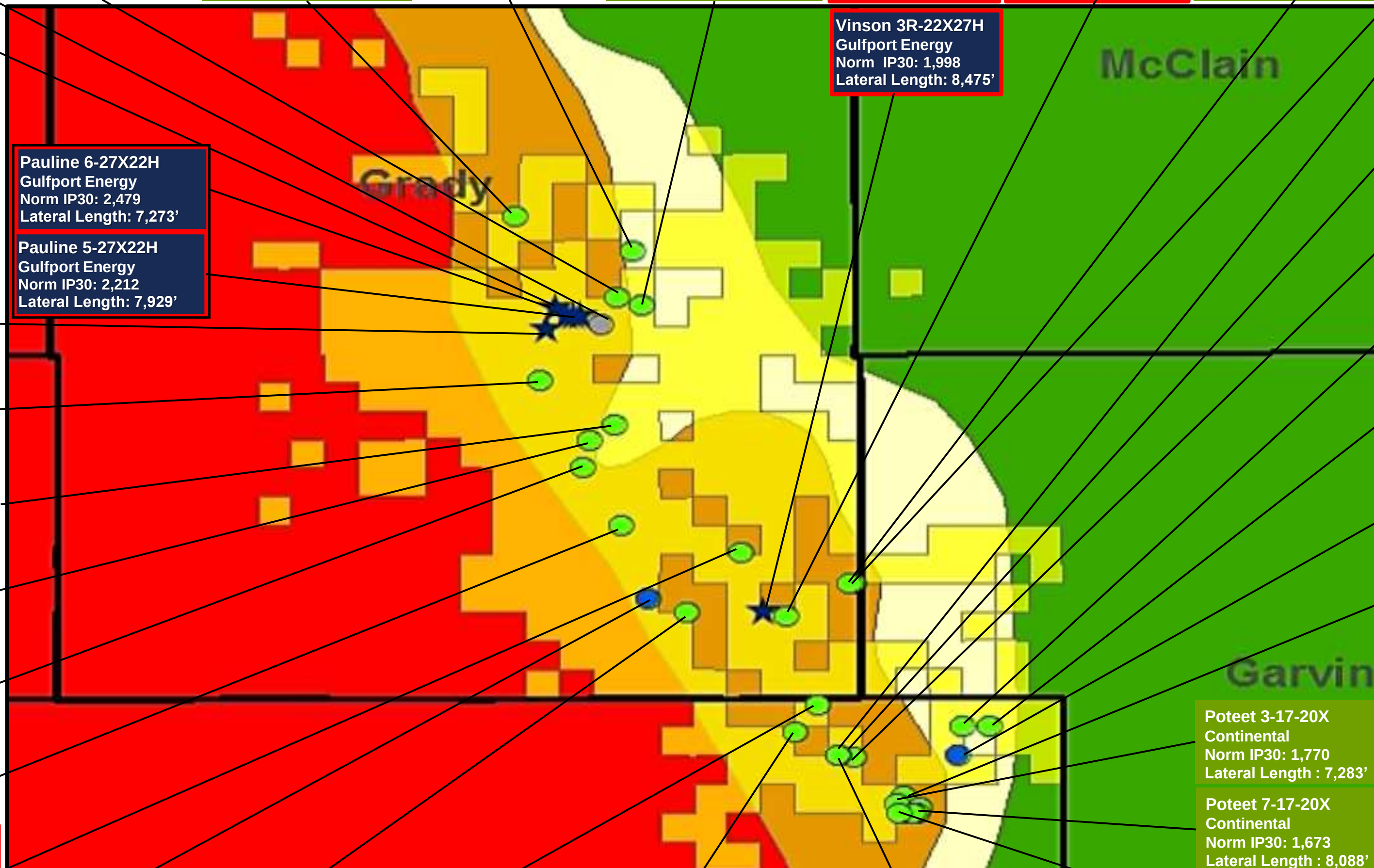
Castle 1-35H
Vitruvian
Norm IP30: 1,988
Lateral Length : 4,661'

Burnside 3-09X16H
Vitruvian
Norm IP30: 1,530
Lateral Length : 7,529'

Pauline 6-27X22H
Gulfport Energy
Norm IP30: 2,479
Lateral Length: 7,273'

Pauline 5-27X22H
Gulfport Energy
Norm IP30: 2,212
Lateral Length: 7,929'

Vinson 3R-22X27H
Gulfport Energy
Norm IP30: 1,998
Lateral Length: 8,475'



Turner Trust 3-12H
Vitruvian
Norm IP30: 1,912
Lateral Length : 4,507'

Turner Trust 2-12H
Vitruvian
Norm IP30: 1,557
Lateral Length : 3,960'

Snodgrass 1-12H
Vitruvian
Norm IP30: 1,510
Lateral Length : 4,764'

Vanarkel 3-15-10XH
Continental
Norm IP30: 1,547
Lateral Length : 7,208'

Vanarkel 7-1510XH
Continental
Norm IP30: 1,622
Lateral Length : 7,562'

Jarred 1H-9X
Newfield
Norm IP30: 1,566
Lateral Length : 4,745'

Poteet 8-17-20X
Continental
Norm IP30: 2,815
Lateral Length : 4,866'

Poteet 5-17-20X
Continental
Norm IP30: 1,965
Lateral Length : 8,113'

Poteet 3-17-20X
Continental
Norm IP30: 1,770
Lateral Length : 7,283'

Poteet 7-17-20X
Continental
Norm IP30: 1,673
Lateral Length : 8,088'

Poteet 4-17-20X
Continental
Norm IP30: 1,905
Lateral Length : 7,849'

Poteet 6-17-20X
Continental
Norm IP30: 1,843
Lateral Length : 8,110'

Wayne 1-13X12
Vitruvian
Norm IP30: 1,565
Lateral Length : 6,802'

Murphree 1-19H
Vitruvian
Norm IP30: 2,109
Lateral Length : 4,759'

Turner 1-35H
Vitruvian
Norm IP30: 2,055
Lateral Length : 3,703'

Hussey 3-11H
Marathon
Norm IP30: 2,826
Lateral Length : 3,410'

Turner Trust 2N5W 1-12H
Vitruvian
Norm IP30: 1,547
Lateral Length : 4,082'

Poteet 9-17-20X
Continental
Norm IP30: 1,776
Lateral Length : 8,528'

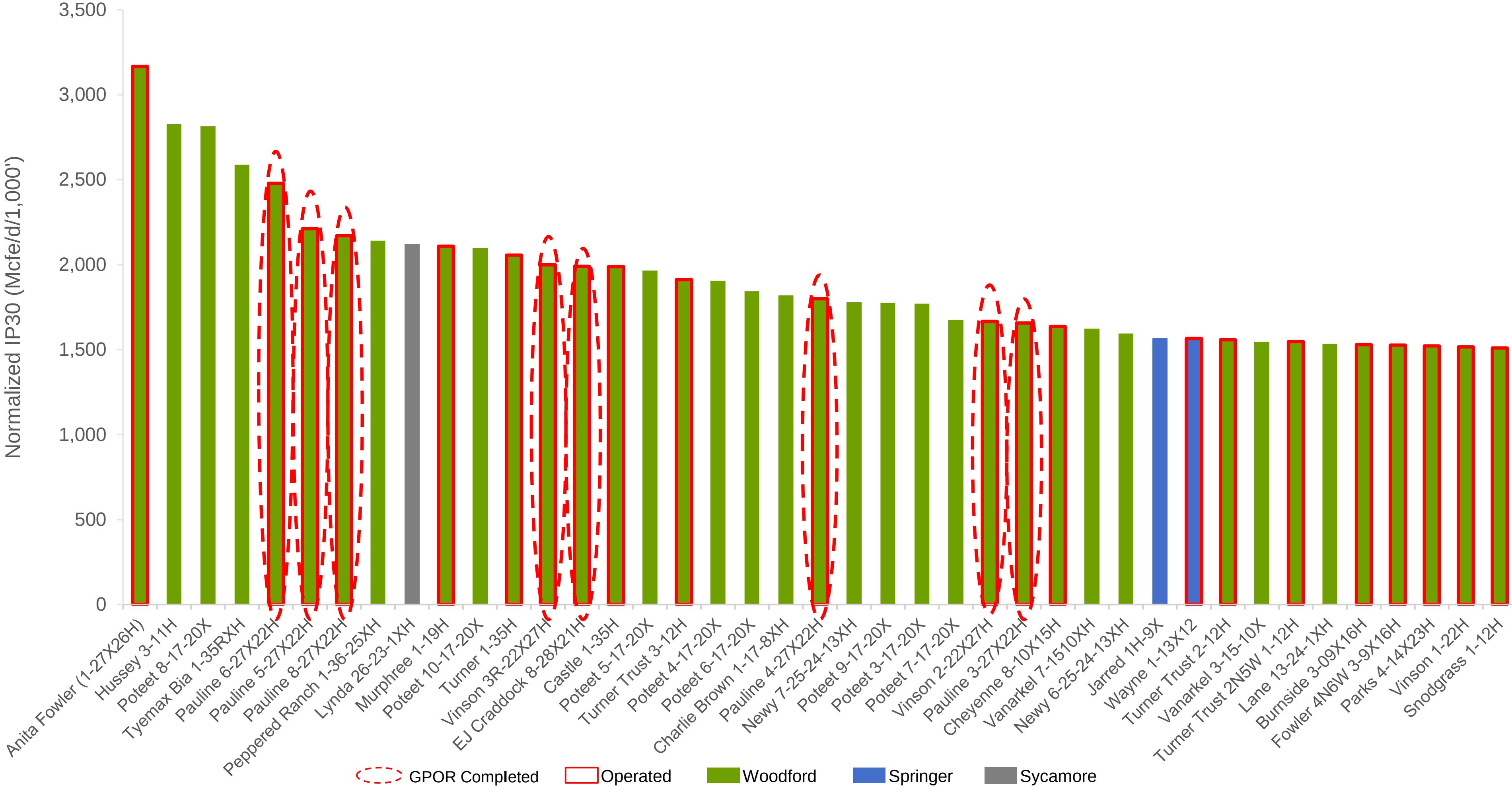
Poteet 10-17-20X
Continental
Norm IP30: 2,097
Lateral Length : 7,098'

Operated | Springer | Woodford | Sycamore

Source: Company provided data and publicly available information. All well results are based upon two-stream production data and normalized to Mcfe/d/1,000'

SCOOP acreage is central to the strongest performing wells

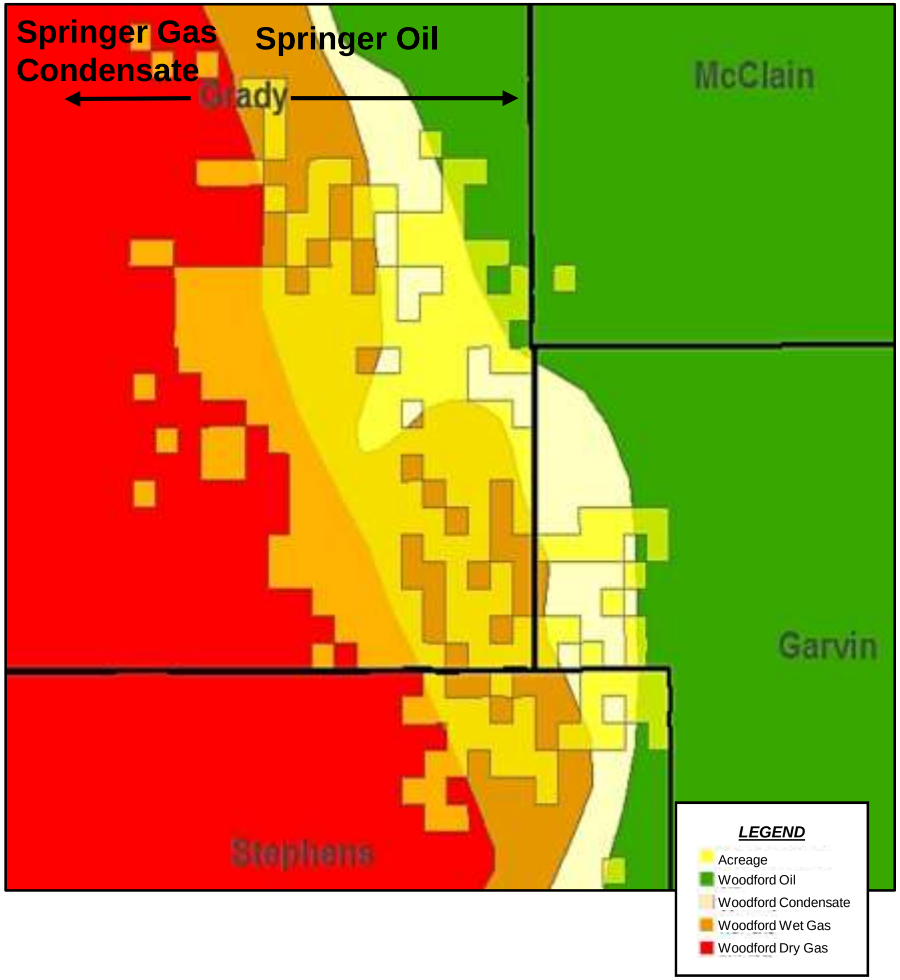
SCOOP – List of High Quality Results Continues to Expand



Operated wells make up over half of the top well results

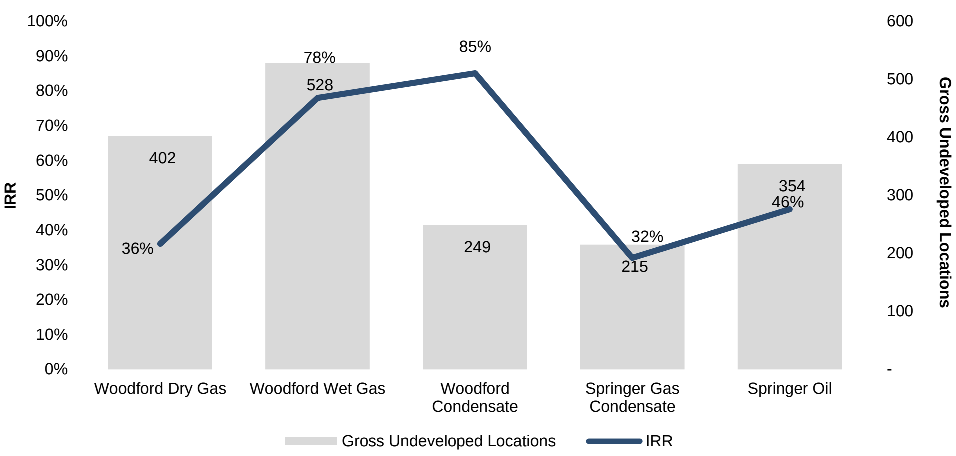
Source: Company provided data and publicly available information. All well results are based upon two-stream production data

SCOOP – Type Curve Assumptions



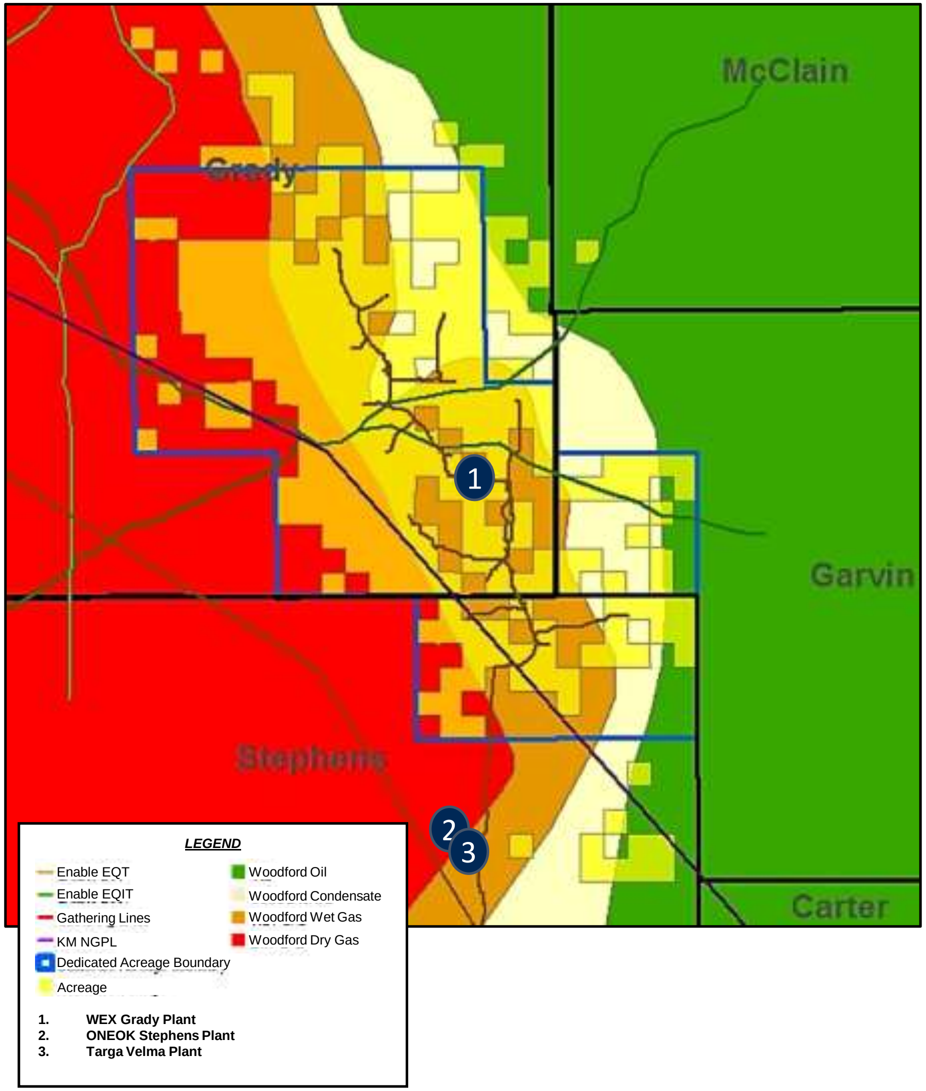
	Woodford			Springer	
	Dry Gas	Wet Gas	Condensate	Springer Gas Condensate	Springer Oil
Type Curve Assumptions					
Lateral Length	7,500	7,500	7,500	7,500	7,500
Well Cost ($MM)	$12.3	$10.5	$9.7	$10.7	$11.0
Well Cost ($ per foot)	$1,633	$1,395	$1,295	$1,429	$1,461
Total EUR (Bcfe / 1,000)	2.6	2.6	1.5	1.7	0.8
Total EUR (Bcfe)	19.8	19.7	11.5	12.7	5.8
% Gas	100%	76%	52%	78%	22%
Wells per section	8	8	8	6	6
Identified Gross Operated Locations	99	218	39	96	88
Identified Net Operated Locations	44	157	22	59	54
Identified Gross Non-Op Locations	303	310	210	119	266
Identified Net Non-Op Locations	21	25	11	13	16
Total Identified Gross Locations	402	528	249	215	354
Total Identified Net Locations	65	182	33	72	70

SCOOP Single Well Economics[1, 2]



Note: See appendix slide 36 for detailed assumptions used to generate single well IRRs.
1. Assumes contractual ethane recovery.
2. Well economics assume a flat price case of $3.50 / MMBtu gas, $58.00 / Bbl oil, and are adjusted for transport fees and regional price differentials.

SCOOP – Midstream Gathering and Processing Overview



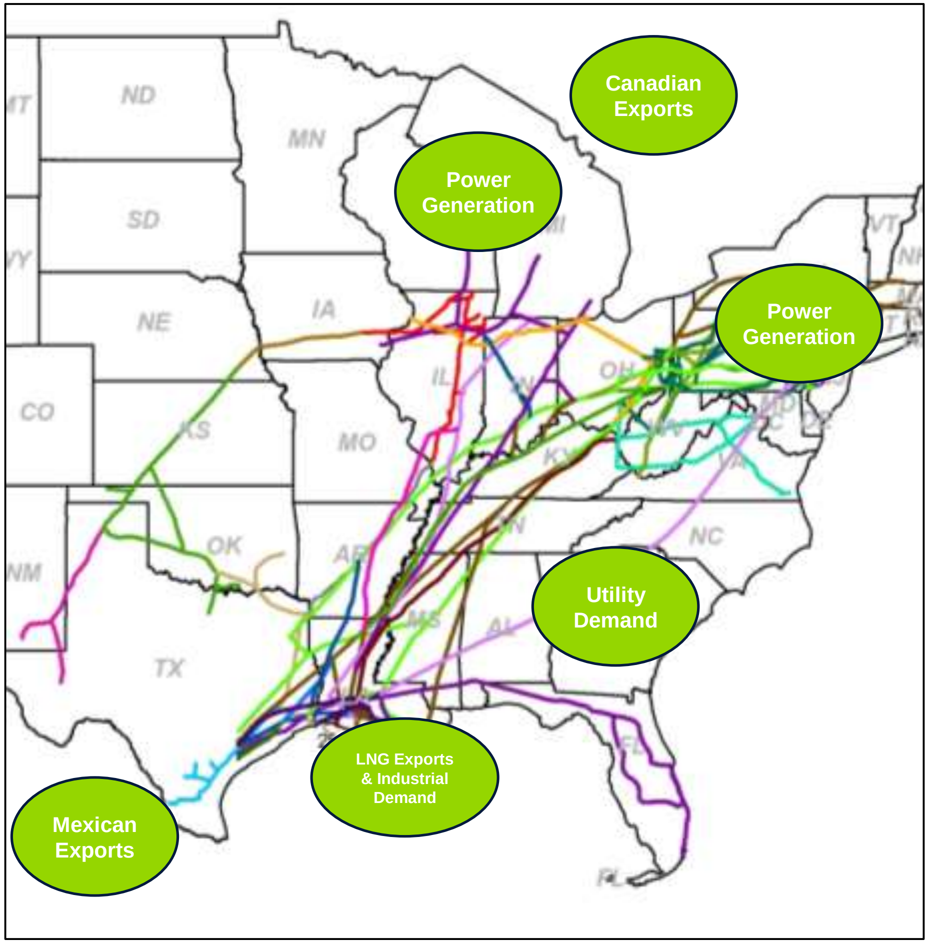
Key Highlights

- Acreage dedication arrangement for all horizontal development to Woodford Express ("WEX") for gathering and processing
  - Competitive gathering and processing contracts with fixed fees, fuels and recoveries
- Gathering overview:
  - Recently laid 16" and 20" trunk lines throughout the dedication area
  - Operating pressure no greater than 600# at the pad
- Processing overview:
  - Primary connection to WEX Grady Plant
    - Existing 210 MMcf/d processing capacity
      - Planned expansion with a third 200 MMcf/d train in December 2017
    - Additional connections to Enable, ONEOK and Targa processing plants
- Takeaway overview:
  - Residue Gas: Enable, EOIT, EGT and NGPL (will also include Midship in 1Q2019)
    - Have 200,000+ MMBtu/d of firm arrangements, including deliveries to Bennington and Perryville
  - NGLs: DCP, ONEOK

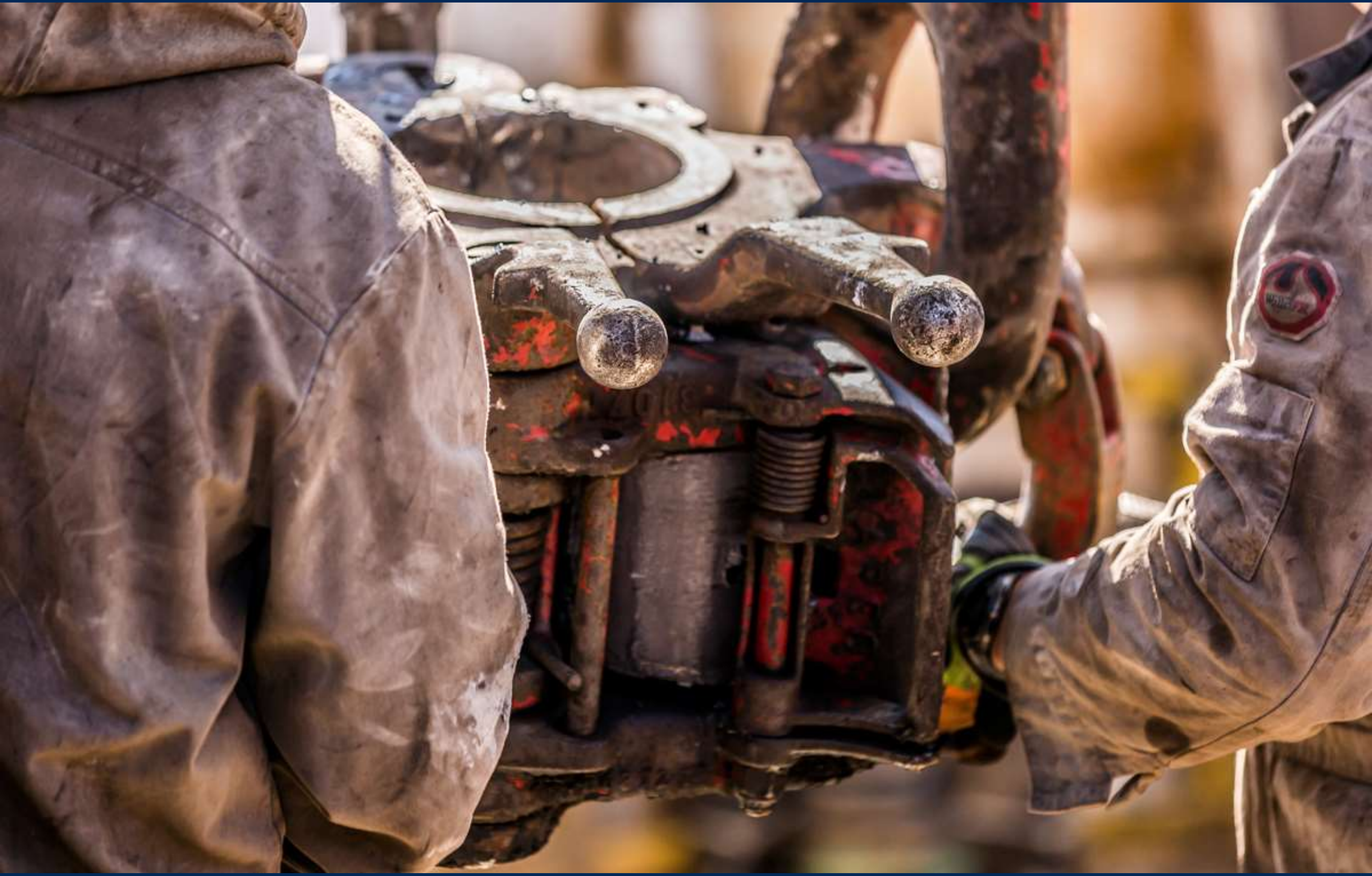
SCOOP – Marketing Overview

Key Highlights

- Building a diversified gas takeaway portfolio
  - Gulfport holds firm transportation of varying duration into connecting pipes with multiple deliveries including Bennington, Perryville and points further into the Gulf
  - Firm sales for various terms and pricing flexibility off a combination of pricing locations
  - Complimentary to our existing Gulf Coast firm transport out of the Utica
  - Bringing in new pipeline to the basin as a foundation shipper on Cheniere's Midship Pipeline
- Low cost supply basin centrally located and advantaged by proximity to growing demand centers in the Gulf Coast regions
  - LNG
  - Mexican Exports
  - Industrial Demand
  - Increasing power generation and utility loads
- Asset base located closer to physical hubs which typically set benchmark pricing
  - Henry Hub for natural gas
  - Mont Belvieu for NGLs
  - Cushing for crude
- Favorable transport costs via pipe, rail or truck to these premium markets
- Diversifies risk by increasing liquids exposure, which provides uplift to realized pricing and enhances corporate margins



Utica Appendix



Utica Shale – Type Curve Assumptions

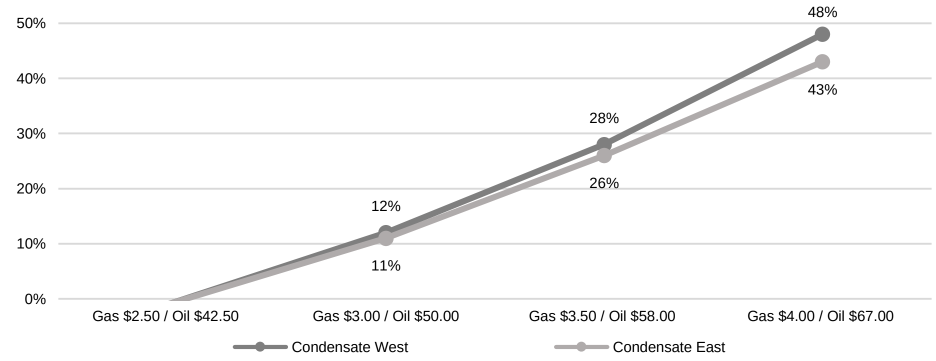
	Condensate West	Condensate East	Wet Gas	Dry Gas West	Dry Gas Central	Dry Gas East
Identified Gross Locations(4)	**134**	**77**	**119**	**182**	**444**	**258**
Identified Net Locations	**100**	**58**	**89**	**137**	**333**	**193**
Type Curve Assumptions						
Lateral Length (ft.)	8,000	8,000	8,000	8,000	8,000	8,000
Initial Gas Production (Mcf/d)(1)	2,500	3,300	12,000	14,000	14,000	14,000
Flat Period (days)	90	90	274	243	274	304
Shrink	13%	13%	12%	N/A	N/A	N/A
NGL Yield (Bbls/MMcf)	71	65	44	N/A	N/A	N/A
Residue BTU	1,140	1,135	1,095	1,070	1,060	1,050
Pre-Processed EUR (Bcfe)	4.9	6.7	14.0	17.2	19.0	20.7
Pre-Processed % Gas	56%	78%	100%	100%	100%	100%
Post-Processed EUR (Bcfe / 1,000')(2)	0.7	1.0	2.0	2.2	2.4	2.6
Post-Processed EUR (Bcfe)(2)	5.7	8.1	16.0	17.2	19.0	20.7
Oil (MBbl)	358	249	7	-	-	-
NGL (MBbl)	196	338	614	-	-	-
Residue Gas (MMcf)	2,389	4,527	12,227	17,202	18,952	20,711
Post Processed % Gas	42%	56%	77%	100%	100%	100%
Unhedged Pricing (3)						
Gas ($ / MMBtu off NYMEX)	$ (0.65)	$ (0.65)	$ (0.65)	$ (0.65)	$ (0.65)	$ (0.65)
Condensate ($ / Bbl off WTI)	$ (8.00)	$ (8.00)	$ (8.00)			
NGL (% of WTI)	40%	40%	40%			
Operating Expenses						
OPEX - Year 1						
Fixed ($/well/mo)	$ 25,000	$ 25,000	$ 15,000	$ 12,500	$ 12,500	$ 12,500
Variable ($/Mcf)	$ 0.17	$ 0.15	$ 0.05	$ 0.05	$ 0.05	$ 0.05
OPEX - Year 2						
Fixed ($/well/mo)	$ 20,000	$ 20,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Variable ($/Mcf)	$ 0.08	$ 0.07	$ 0.02	$ 0.02	$ 0.02	$ 0.02
OPEX - Year 3+						
Fixed ($/well/mo)	$ 15,000	$ 15,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Variable ($/Mcf)	$ 0.09	$ 0.07	$ 0.02	$ 0.02	$ 0.02	$ 0.02
Gathering & Compression ($/Mcf)	$ 0.64	$ 0.64	$ 0.56	$ 0.40	$ 0.40	$ 0.40
Processing ($/Mcf)	$ 0.65	$ 0.65	$ 0.52	N/A	N/A	N/A
Severance Tax	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Well Cost Assumptions						
Well Cost ($MM)	$ 7.7	$ 7.7	$ 8.3	$ 8.5	$ 8.7	$ 8.9
Well Cost ($ per foot)	$ 962	$ 964	$ 1,035	$ 1,060	$ 1,085	$ 1,110

1. Note: See appendix slide 34 for detailed assumptions used to net undeveloped locations.
2. Represents 24-hour rate well head gas production.
3. Assumes ethane rejection.
4. Includes transportation costs and basis differentials.
5. Assumes net undeveloped locations grossed up from 75% working interest.

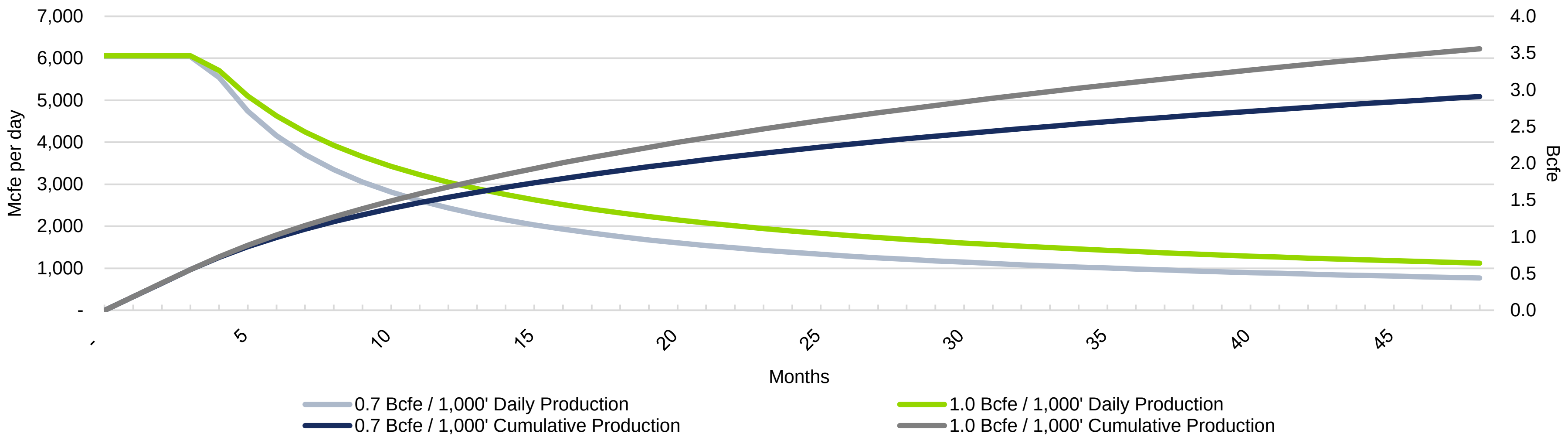
Utica Shale – Condensate Window Type Curves

Type Curve Assumptions[1]	Condensate West	Condensate East
Lateral Length	8,000	8,000
Well Cost ($MM)	$7.7	$7.7
Well Cost ($ per foot)	$962	$964
Total EUR (Bcfe / 1,000)	0.7	1.0
Total EUR (Bcfe)	5.7	8.1
% Gas	42%	56%
Assumed Well Spacing (ft)	600	600
Gross Undeveloped Locations[2]	134	77
Net Undeveloped Locations	100	58

Single Well Economics[1]



Condensate Type Curves[1]

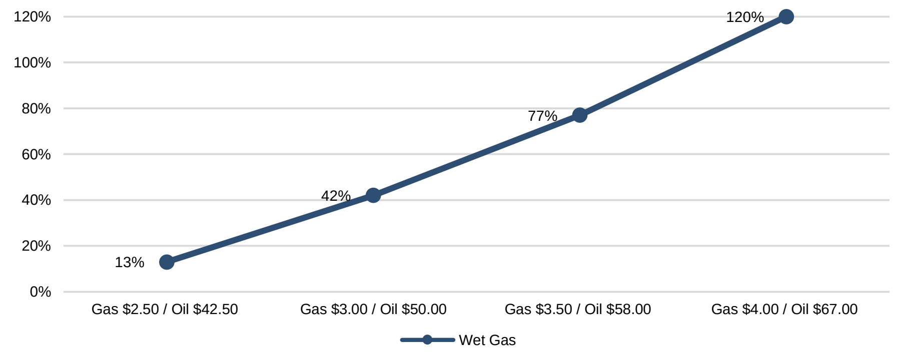


Note: See appendix slide 27 for detailed assumptions used to generate single well IRRs and slide 34 for net undeveloped locations.
1. Assumes ethane rejection.
2. Assumes net undeveloped locations grossed up from 75% working interest

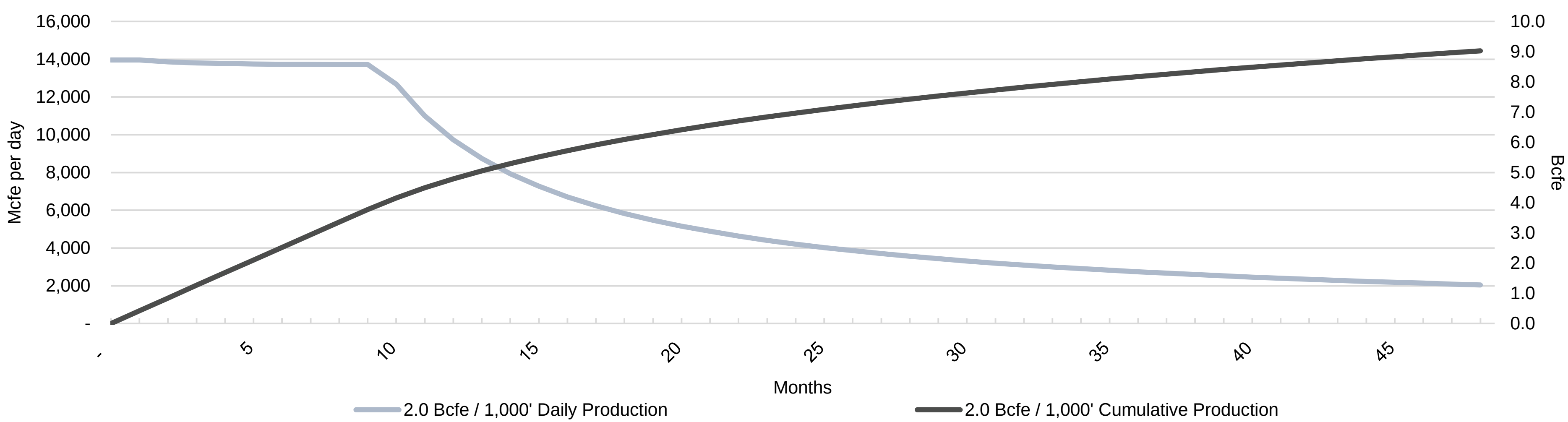
Utica Shale – Wet Gas Window Type Curves

Type Curve Assumptions[1]	Wet Gas
Lateral Length	8,000
Well Cost ($MM)	$8.3
Well Cost ($ per foot)	$1,035
Total EUR (Bcfe / 1,000)	2.0
Total EUR (Bcfe)	16.0
% Gas	77%
Assumed Well Spacing (ft)	1,000
Gross Undeveloped Locations[2]	119
Net Undeveloped Locations	89

Single Well Economics[1]



Wet Gas Type Curves[1]



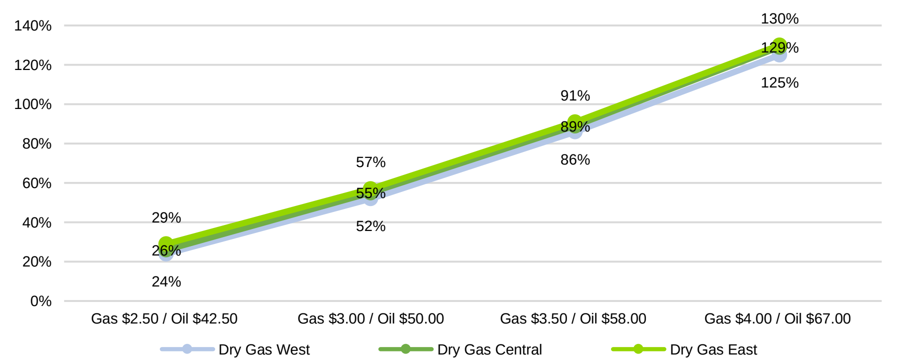
Note: See appendix slide 27 for detailed assumptions used to generate single well IRRs and slide 34 for net undeveloped locations.

1. Assumes ethane rejection.
2. Assumes net undeveloped locations grossed up from 75% working interest.

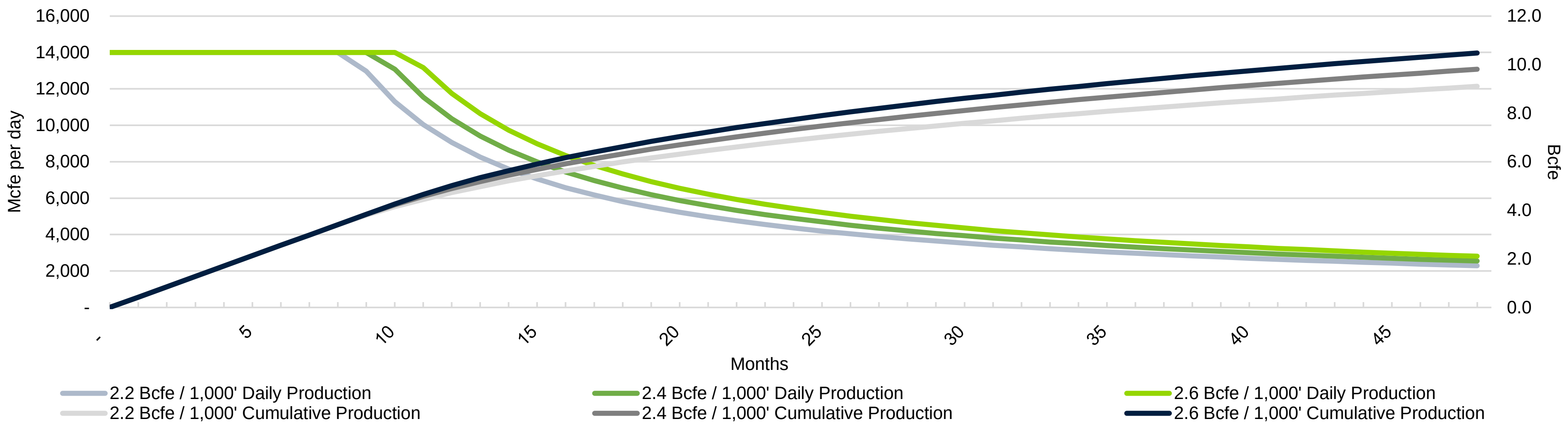
Utica Shale – Dry Gas Window Type Curves

Type Curve Assumptions[1]	Dry Gas		
	West	Central	East
Lateral Length	8,000	8,000	8,000
Well Cost ($MM)	$8.5	$8.7	$8.9
Well Cost ($ per foot)	$1,060	$1,085	$1,110
Total EUR (Bcfe / 1,000)	2.2	2.4	2.6
Total EUR (Bcfe)	17.2	19.0	20.7
% Gas	100%	100%	100%
Assumed Well Spacing (ft)	1,000	1,000	1,000
Gross Undeveloped Locations[2]	182	444	258
Net Undeveloped Locations	137	333	193

Single Well Economics[1]



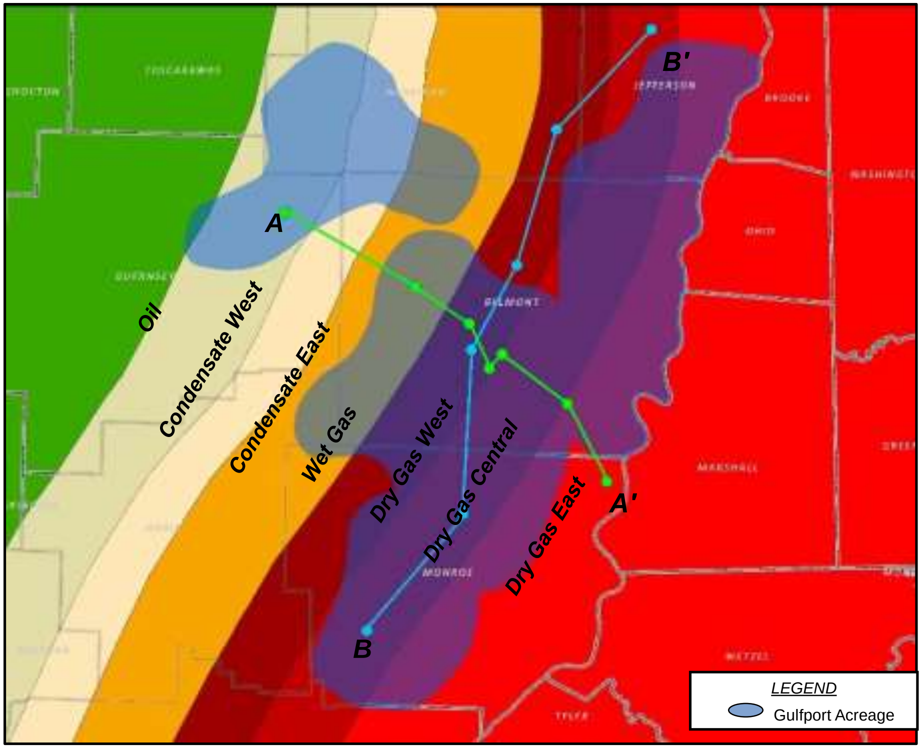
Dry Gas Type Curves[1]

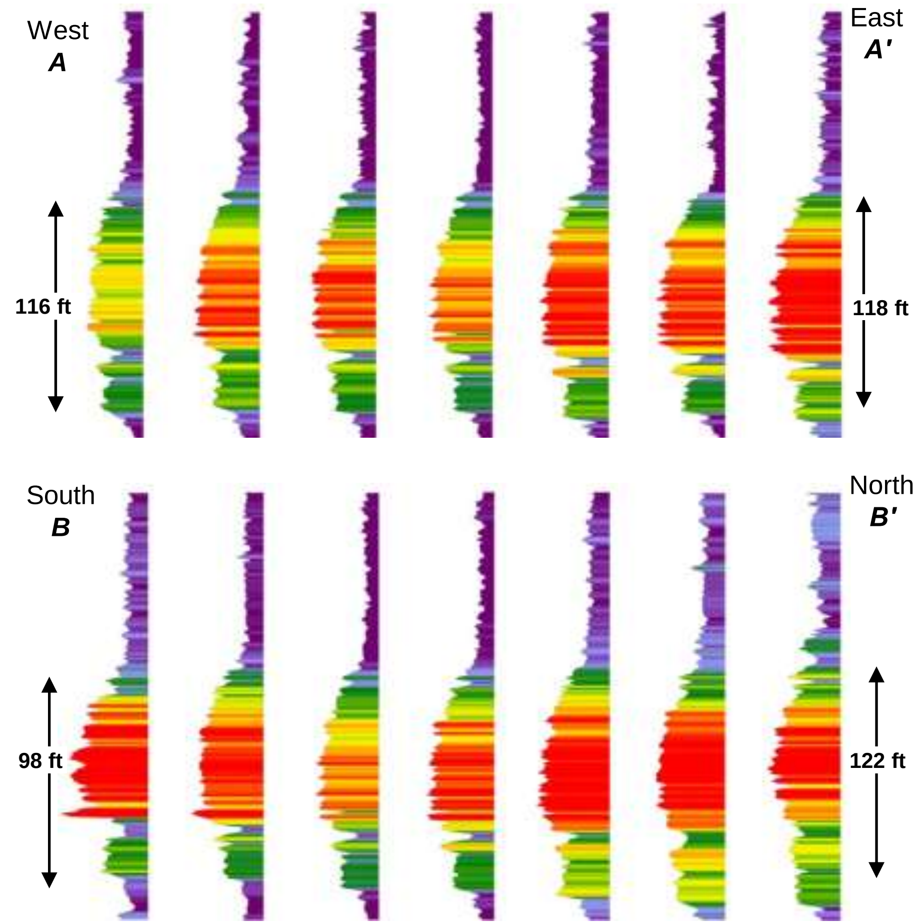


Note: See appendix slide 27 for detailed assumptions used to generate single well IRRs and slide 34 for net undeveloped locations.

1. Assumes ethane rejection.
2. Assumes net undeveloped locations grossed up from 75% working interest.

Utica Shale – Consistency of Reservoir

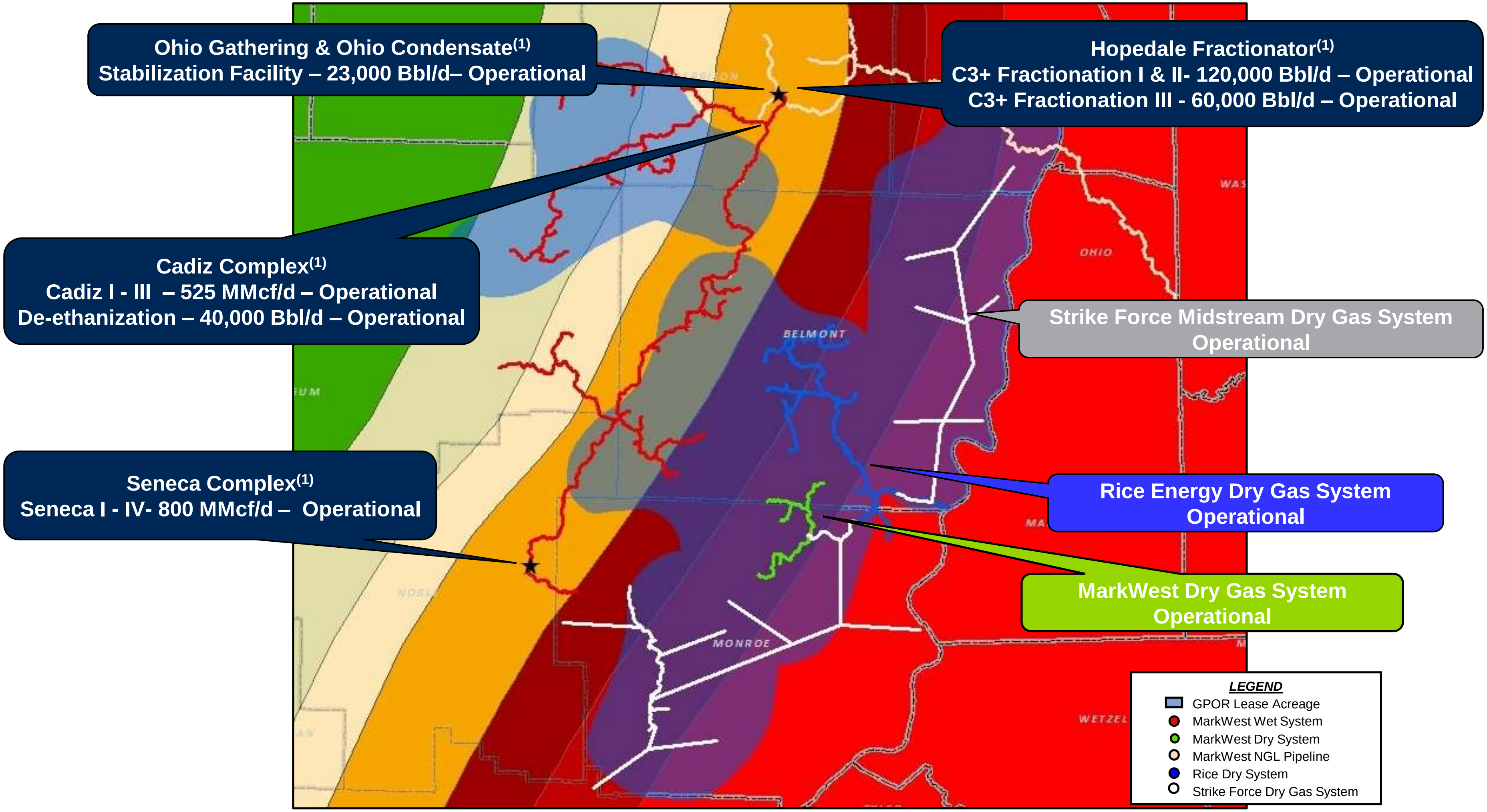




Key Highlights

- Consistency of the reservoir enables us to stay within the target zone, the Point Pleasant
  - Highly uniformed stratigraphy and limited reservoir variation
  - Structural simplicity, low dip and minimal faults
  - Petrophysical properties extremely uniform across the play
- Stratigraphy and structural simplicity allow for highly repeatable results

Utica Shale – Midstream Infrastructure



1. Per MPLX Energy Investor Presentation on October 26, 2017.

Northeast Pipeline Expansion List

	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19	3Q19	4Q19	1Q20	2Q20	3Q20	4Q20
NE Marcellus to Northeast																				
Transco NE Connector Project	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
TGP Rose Lake Expansion	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
TGP Niagara Expansion	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158
NFG West Side Expansion	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
TGP Susquehanna West Project								145	145	145	145	145	145	145	145	145	145	145	145	145
Empire Central Tioga City Extension												300	300	300	300	300	300	300	300	300
AGT Access Northeast														925	925	925	925	925	925	925
Constitution Pipeline															650	650	650	650	650	650
Total	**663**	**663**	**663**	**663**	**663**	**663**	**663**	**808**	**808**	**808**	**808**	**1,108**	**1,108**	**2,033**	**2,683**	**2,683**	**2,683**	**2,683**	**2,683**	**2,683**
NE Marcellus to Mid-Atlantic/South																				
TCO East Side Expansion	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
TRANSCO Leidy Southeast Project	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525	525
Transco Diamond East										500	500	500	500	500	500	500	500	500	500	500
Transco Atlantic Sunrise											1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
PennEast												1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Total	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**835**	**1,335**	**3,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**
Wet Marcellus & Utica Takeaway projects to the MidCon and Canada																				
REX Seneca Lateral Phase 1	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
REX Seneca Lateral Phase 2	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350	350
REX East-to-West	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
TETCO Uniontown to Gas City	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425	425
ANR Glen Karn	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
EQT Ohio Valley Connector				850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850
REX Zone 3 Capacity Enhancement				480	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Rover Pipeline Phase I								1,000	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210	2,210
Rover Pipeline Phase II										1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
TETCO Lebanon Extension								102	102	102	102	102	102	102	102	102	102	102	102	102
Nexus											1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Total	**2,359**	**2,359**	**2,359**	**3,689**	**4,009**	**4,009**	**4,009**	**5,111**	**6,321**	**7,361**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**	**8,861**
Wet Marcellus & Utica Takeaway projects to the MidAtlantic and the South																				
TETCO TEAM 2014	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
TETCO TEAM South	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
TCO West Side Expansion	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444	444
TETCO OPEN	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
TGP Broad Run Flexibility	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590
TGT OH-LA Access			626	626	626	626	626	626	626	626	626	626	626	626	626	626	626	626	626	626
TETCO Gulf Market Expansion Ph 1				250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
TGT Northern Supply Access						384	384	384	384	384	384	384	384	384	384	384	384	384	384	384
TETCO Adair Southwest								200	200	200	200	200	200	200	200	200	200	200	200	200
TETCO Access South								320	320	320	320	320	320	320	320	320	320	320	320	320
TCO Leach Express								1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530	1,530
TCO Rayne Xpress								1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
TGP SW Louisiana Supply Project									900	900	900	900	900	900	900	900	900	900	900	900
TGP Broad Run Expansion										200	200	200	200	200	200	200	200	200	200	200
TCO Mountaineer Xpress												2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
TCO Gulf Xpress												900	900	900	900	900	900	900	900	900
EQT Mountain Valley												2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
TCO WB Xpress												1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
Dominion Atlantic Coast Pipeline																1,500	1,500	1,500	1,500	1,500
Total	**2,484**	**2,484**	**3,110**	**3,360**	**3,360**	**3,744**	**3,744**	**6,894**	**7,794**	**7,994**	**7,994**	**14,894**	**14,894**	**14,894**	**14,894**	**16,394**	**16,394**	**16,394**	**16,394**	**16,394**
Cumulative by End Market	**6,341**	**6,341**	**6,967**	**8,547**	**8,867**	**9,251**	**9,251**	**13,648**	**15,758**	**17,498**	**20,698**	**28,898**	**28,898**	**29,823**	**30,473**	**31,973**	**31,973**	**31,973**	**31,973**	**31,973**
Northeast Premium	663	663	663	663	663	663	663	808	808	808	808	1,108	1,108	2,033	2,683	2,683	2,683	2,683	2,683	2,683
MidAtlantic/South	3,319	3,319	3,945	4,195	4,195	4,579	4,579	7,729	8,629	9,329	11,029	18,929	18,929	18,929	18,929	20,429	20,429	20,429	20,429	20,429
MidCon/Canada	2,359	2,359	2,359	3,689	4,009	4,009	4,009	5,111	6,321	7,361	8,861	8,861	8,861	8,861	8,861	8,861	8,861	8,861	8,861	8,861

Source: Morgan Stanley Commodities Research, “Northeast Pipeline Export Capacity,” October 2017. Utilizes Company data, Bentek Energy, and Morgan Stanley Commodities Research

Additional Disclosures

Net Undeveloped Locations[1]

	Condensate West	Condensate East	Wet Gas	Dry Gas West	Dry Gas Central	Dry Gas East
Net Undeveloped Location Summary						
Net Acres	13,820	9,206	28,563	33,603	82,336	43,717
Lateral Length	8,000	8,000	8,000	8,000	8,000	8,000
Location Spacing	600	600	1,000	1,000	1,000	1,000
Net Potential Locations	125	84	156	183	448	238
Less approximate wells turned to sales[2]	14	19	57	31	78	23
Unrisked Net Undeveloped Locations	111	64	99	152	370	215
Estimated Risking Factor	10%	10%	10%	10%	10%	10%
Risked Net Undeveloped Locations	**100**	**58**	**89**	**137**	**333**	**193**

Determination of Identified Drilling Locations as of November 1, 2017:

Net Undeveloped Locations: Calculated by taking Gulfport's total net acreage and multiplying such amount by a risking factor which is then divided by Gulfport's expected well spacing. Gulfport then subtracts net producing wells to arrive at undeveloped net drilling locations.

Net Undeveloped Utica Condensate West Locations: Gulfport assumes these locations have 8,000 foot laterals and 600 foot spacing between wells which yields approximately 110 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Condensate East Locations: Gulfport assumes these locations have 8,000 foot laterals and 600 foot spacing between wells which yields approximately 110 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Wet Gas Locations: Gulfport assumes these locations have 8,000 foot laterals and 1,000 foot spacing between wells which yields approximately 184 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Dry Gas West Locations: Gulfport assumes these locations have 8,000 foot laterals and 1,000 foot spacing between wells which yields approximately 184 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Dry Gas Central Locations: Gulfport assumes these locations have 8,000 foot laterals and 1,000 foot spacing between wells which yields approximately 184 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

Net Undeveloped Utica Dry Gas East Locations: Gulfport assumes these locations have 8,000 foot laterals and 1,000 foot spacing between wells which yields approximately 184 acre spacing. We apply a 10% risking factor to the net acreage to account for inefficient unitization and the risk associated with the inability to force pool in Ohio.

1. All acreage as of 11/1/17.
2. Wells turned to sales as of 9/30/17 Assumes net undeveloped locations grossed up from 75% working interest.

SCOOP Appendix

SCOOP – Type Curve Assumptions

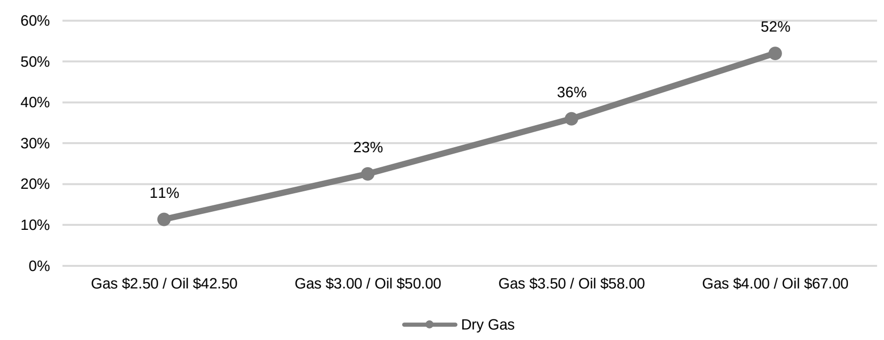
	Woodford Dry Gas	Woodford Wet Gas	Woodford Condensate
Identified Gross Locations	**402**	**528**	**249**
Identified Net Locations	**65**	**182**	**33**
Type Curve Assumptions			
Lateral Length (ft.)	7,500	7,500	7,500
Wells/section	8	8	8
Initial Gas Production (Mcf/d)[1]	14,000	11,000	6,000
Initial Oil Production (Bbl/d)[1]	-	325	740
Shrink	-	13%	16%
NGL Yield (Bbls/MMcf)	-	31	75
Residue BTU	1,000	1,060	1,095
Pre-Processed EUR (Bcfe)	19.8	18.8	11.3
Pre-Processed % Gas	100%	92%	77%
Post-Processed EUR (Bcfe / 1,000')[2]	2.6	2.6	1.5
Post-Processed EUR (Bcfe)[2]	19.8	19.7	11.5
Oil (MBbl)	-	250	374
NGL (MBbl)	-	536	540
Residue Gas (MMcf)	19,800	15,021	6,048
Post Processed % Gas	100%	76%	52%
Unhedged Pricing[3]			
Gas ($ / MMBtu off NYMEX)	$ (0.45)	$ (0.45)	$ (0.45)
Condensate ($ / Bbl off WTI)		$ (3.25)	$ (3.25)
NGL (% of WTI)		45%	45%
Operating Expenses			
OPEX – 3 Months			
Fixed ($/well/mo)	$ 8,000	$ 10,000	$ 10,000
OPEX - Remaining			
Fixed ($/well/mo)	$ 6,000	$ 8,000	$ 8,000
Variable ($/Mcf)	$ 0.05	$ 0.05	$ 0.05
Gathering & Compression ($/Mcf)	$ 0.41	$ 0.49	$ 0.52
Processing (% of Revenue)	-	1.5%	1.5%
Severance Tax – Years 1-3	2.2%	2.2%	2.2%
Years 4+	7.2%	7.2%	7.2%
Well Cost Assumptions			
Well Cost ($MM)	$ 12.3	$ 10.5	$ 9.7
Well Cost ($ per foot)	$ 1,633	$ 1,395	$ 1,295

1. Represents 24-hour rate well head production.
2. Assumes contractual ethane recovery.
3. Includes transportation costs and basis differentials.

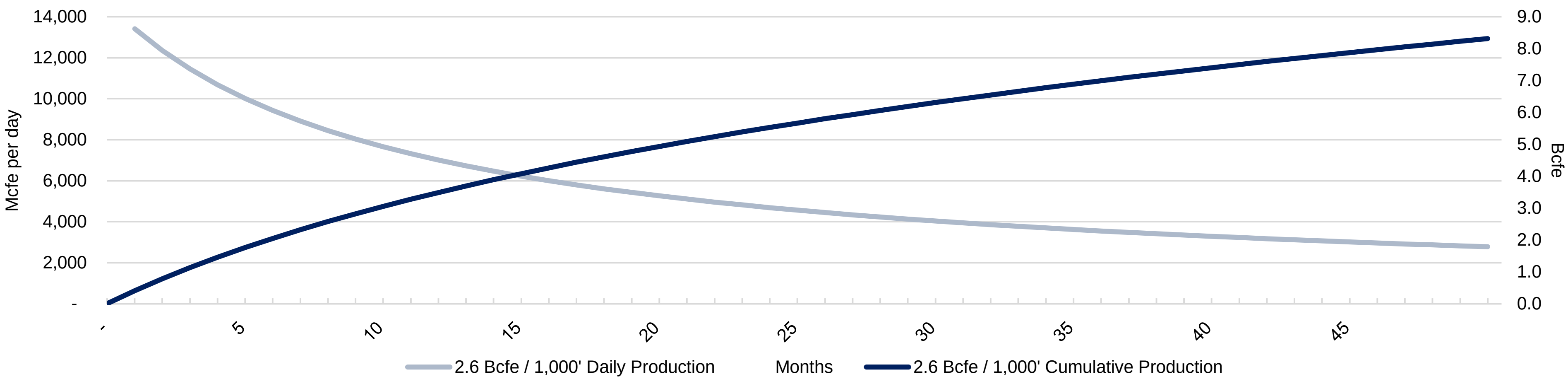
SCOOP – Woodford Dry Gas Window Type Curves

Type Curve Assumptions[1]	Woodford Dry Gas
Lateral Length	7,500
Well Cost ($MM)	$12.3
Well Cost ($ per foot)	$1,633
Total EUR (Bcfe / 1,000)	2.6
Total EUR (Bcfe)	19.8
% Gas	100%
Wells per section	8
Gross Undeveloped Locations	402
Net Undeveloped Locations	65

Single Well Economics[1]



Woodford Dry Gas Type Curves[1]



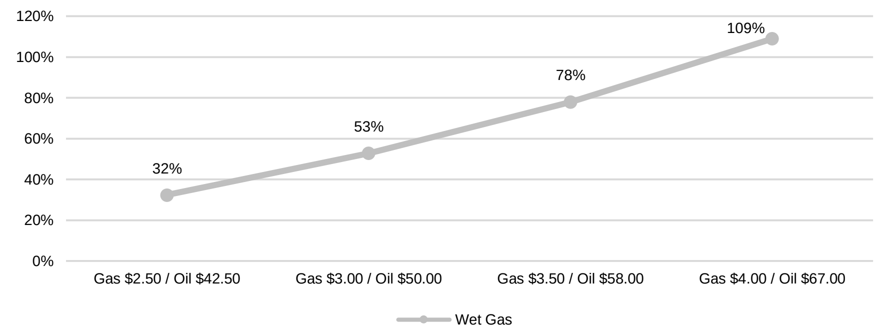
Note: See appendix slide 36 for detailed assumptions used to generate single well IRRs.

1. Assumes contractual ethane recovery..

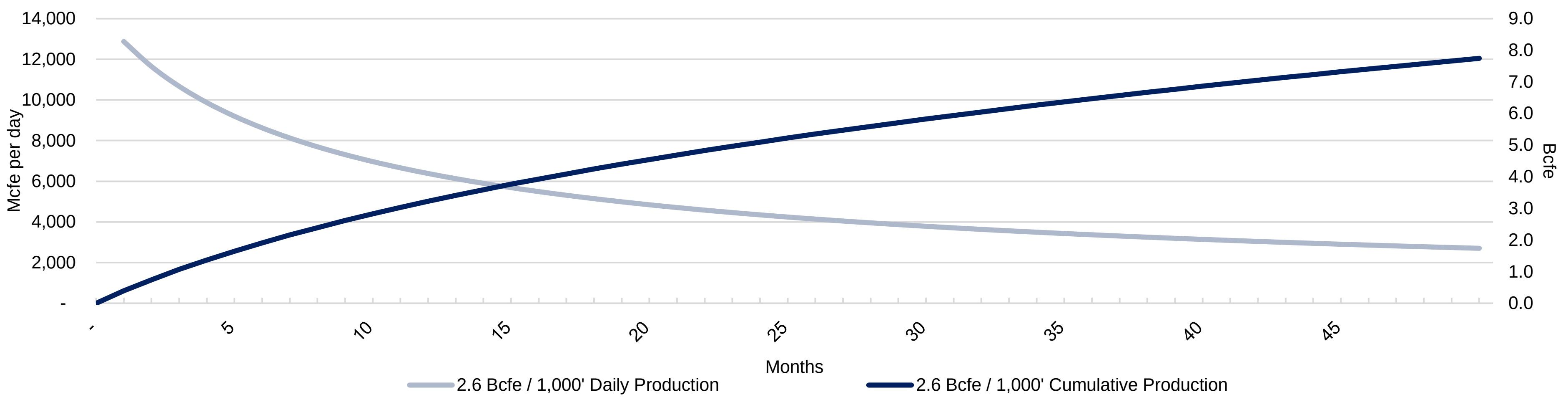
SCOOP – Woodford Wet Gas Window Type Curves

Type Curve Assumptions[1]	Woodford Wet Gas
Lateral Length	7,500
Well Cost ($MM)	$10.5
Well Cost ($ per foot)	$1,395
Total EUR (Bcfe / 1,000)	2.6
Total EUR (Bcfe)	19.7
% Gas	76%
Wells per section	8
Gross Undeveloped Locations	528
Net Undeveloped Locations	182

Single Well Economics[1]



Woodford Wet Gas Type Curves[1]

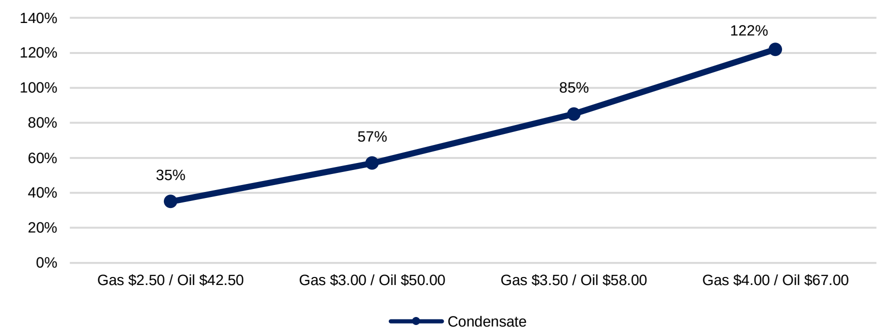


Note: See appendix slide 36 for detailed assumptions used to generate single well IRRs.
1. Assumes contractual ethane recovery.

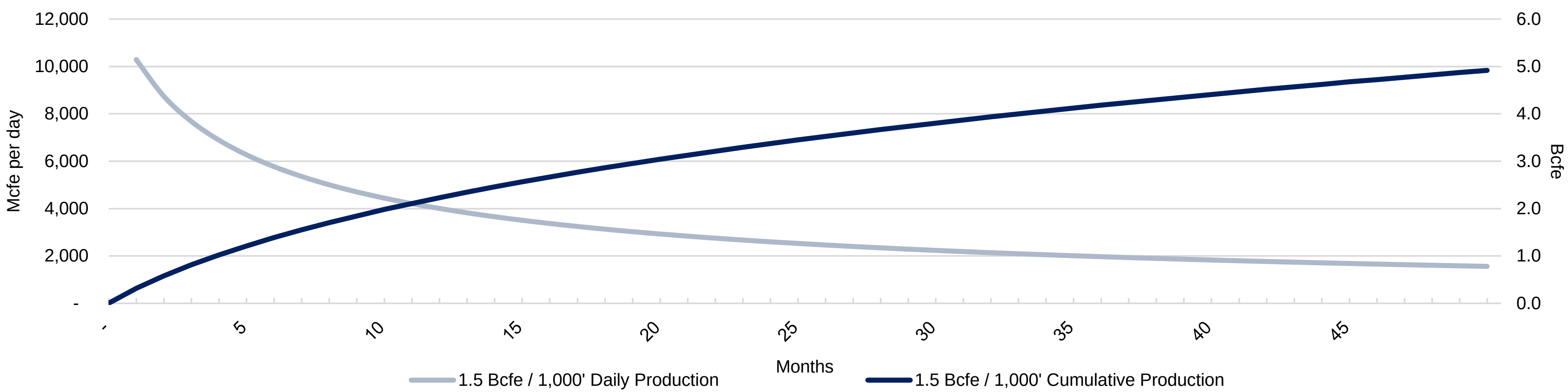
SCOOP – Woodford Condensate Window Type Curves

Type Curve Assumptions[1]	Woodford Condensate
Lateral Length	7,500
Well Cost ($MM)	$9.7
Well Cost ($ per foot)	$1,295
Total EUR (Bcfe / 1,000)	1.5
Total EUR (Bcfe)	11.5
% Gas	52%
Wells per section	8
Gross Undeveloped Locations	249
Net Undeveloped Locations	33

Single Well Economics[1]



Woodford Condensate Type Curves[1]

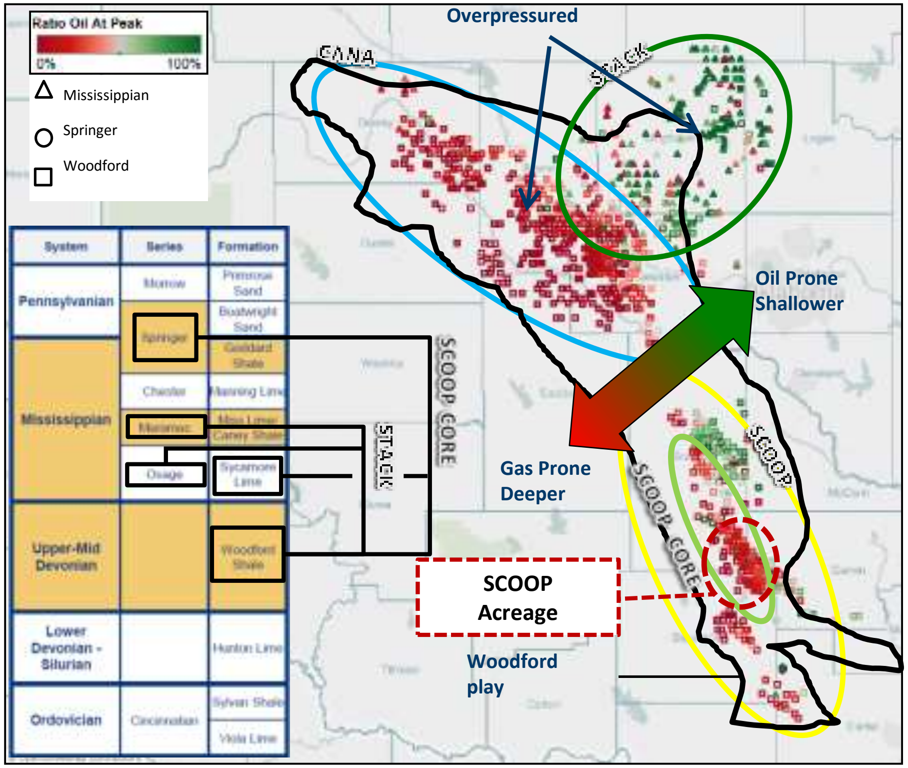


Note: See appendix slide 36 for detailed assumptions used to generate single well IRRs.

1. Assumes contractual ethane recovery..

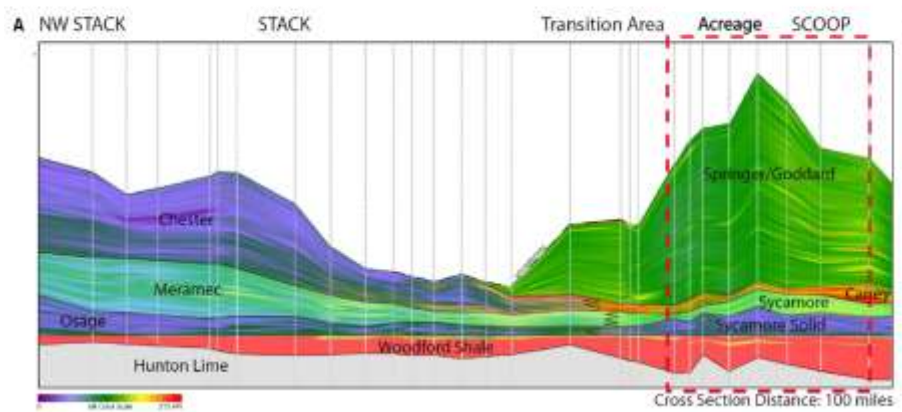
SCOOP – Geologic Overview

Overview



Regional Stratigraphy

- Woodford was deposited on an erosional surface and varies in thickness, increasing to the south into the SCOOP
- Sycamore section in the basinal time-equivalent to the Meramec and Osage units in the STACK
- Springer group thins to the north and east and is removed by an erosional surface
- Depositional fairway of high quality reservoir is over 2,000 ft. thick and covers the Woodford, Springer and Sycamore plays – with superior porosity and permeability and over-pressured hydrocarbons yield top flow rates



SCOOP acreage contains the thickest Woodford section of the SCOOP/STACK play enhanced by a substantial resource in the Springer

Source: IHS performance evaluator, investor presentations.

Appendix

Southern Louisiana

Asset Overview[1]

- Net proved reserves of 2.6 MMBoe
- 10,834 net acres
- Gulfport operated

2017 Activities Update[2]

- Average net production of 2,846 Boepd during 3Q2017
- ~1% of Gulfport's total net production
- ~98% oil weighted production mix
  - Priced as high quality LLS crude and sold at a premium to WTI

Note: Please refer to page 2 for detail on forward looking statements.
1. As of 12/31/16.
2. During the three-month period ended 9/30/17.

Mammoth Energy Services

Mammoth Energy Overview[1]

— Mammoth Energy is a North American provider of diverse oil field services for the onshore unconventional oil and gas sector

— On October 19, 2016, Mammoth Energy completed its initial public offering and it now listed on the NASDAQ under ticker symbol "TUSK"

- Gulfport contributed its 30.5% equity interest at the time of the IPO

— On March 20, 2017, Mammoth Energy announced the acquisition of Taylor Frac, Stingray Energy Services and Stingray Cementing, all entities in which Gulfport holds an equity interest

- Gulfport received ~2.1 million shares of TUSK shares at the time of the closing

— Gulfport holds ~11.2 million[1] shares, equating to ~25.1% of TUSK's total shares outstanding

— Mammoth operates under four service divisions:

- Completion and production services:
- Natural sand proppant services:
- Contract land and directional drilling services:
- Other energy services:

— Gulfport's ownership in Mammoth Energy equates to approximately ~ $220 million[2] in value

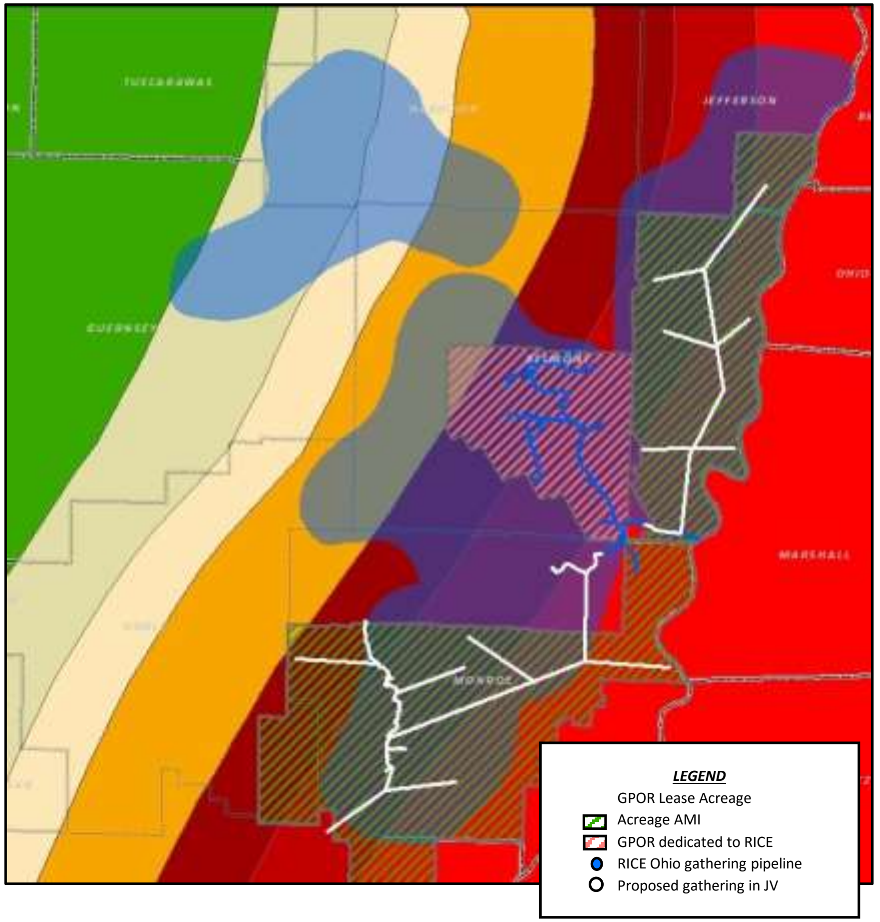
Note: Gulfport Energy Corporation holds ~11.2 million shares of Mammoth Energy Services, Inc. (NASDAQ: TUSK), which includes ~2.1 million shares acquired upon closing of the previously announced acquisition of Taylor Frac, Stingray Energy Services and Stingray Cementing. Please refer to page 2 for detail on forward looking statements.

1. As of 11/1/17.
2. Calculated as of the close of the market on 10/31/17 at a price of $19.73 per share.

Strike Force Midstream Joint Venture

Overview

- GPOR and RICE formed midstream JV, Strike Force Midstream LLC, to provide gas gathering and compression to GPOR's Eastern Belmont and Monroe acreage
  - Approximately 165 miles of high and low pressure 12" – 30" dry gas gathering pipeline to be constructed
  - Approximately 1.8 MMDth/d of estimated throughput capacity
- Facilitates third party opportunities within ~320,000 acre AMI
- Ownership: GPOR 25% and RICE 75% with RICE to construct and operate all JV assets
- Creates enhanced alignment with midstream provider, providing certainty to timing of infrastructure buildout and further predictability to Gulfport's production profile
- Provides Gulfport with connectivity of our gathering systems and interchangeability of molecules across our firm portfolio
- Gulfport anticipates to spend approximately $45 million on midstream activities within the JV area during 2017



Participating in Extensive Dry Gas System in One of the Most Prolific Natural Gas Plays

NGL Marketing Overview

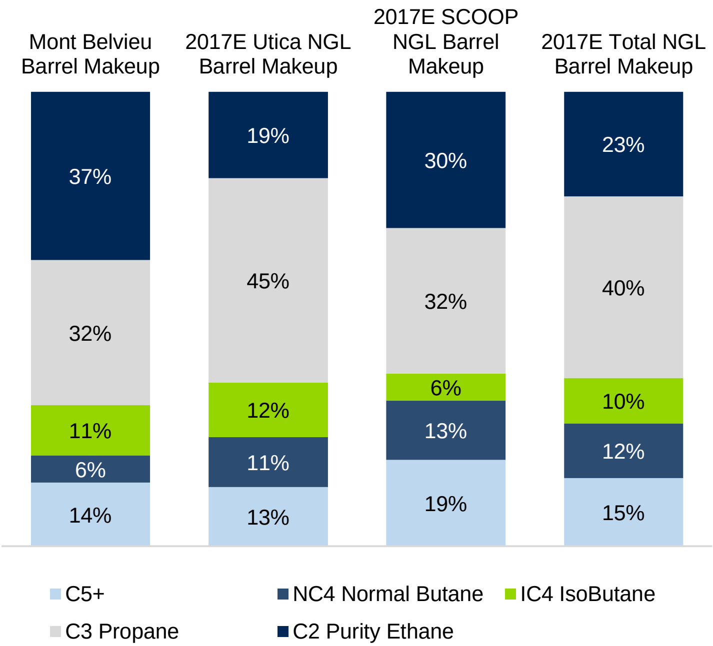
Key Highlights

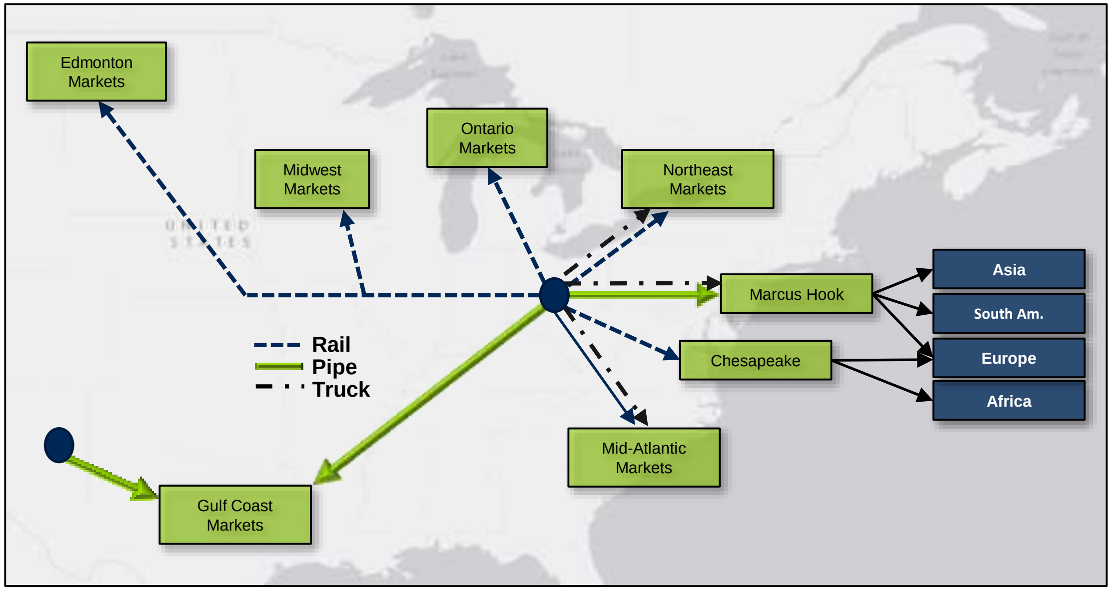
— Gulfport forecasts realizing approximately 45% to 50% of WTI for NGLS during 2017

— SCOOP barrel provides a strong baseload with Mont Belvieu exposure, while Utica purity products provide clarity into market dynamics

— Increased access to pipe provides additional reliability to Gulfport's NGL distribution network

NGL Barrel Composition





Markets	% of 2016 C3+ Bbl
Northeast	23%
Export	8%
Gulf Coast	53%
Edmonton	6%
Midwest	5%
Mid-Atlantic	3%
Ontario	2%
	100%

Transport Method	% of 2016 C3+ Bbl
By Rail	30 - 35%
By Pipeline	60 - 65%
By Truck	5 - 10%

Hedged Production

Hedge Book[1]

	4Q17	2017	2018	2019
Natural Gas Contract Summary:				
Natural Gas Fixed Price Swaps (NYMEX)				
Volume (BBtupd)	765	629	898	112
Weighted Average Price ($/MMBtu)	$ 3.19	$ 3.19	$ 3.06	$ 3.01
Natural Gas Fixed Price Swaptions (NYMEX)[2]				
Volume (BBtupd)	65	60	103	135
Weighted Average Price ($/MMBtu)	$ 3.11	$ 3.12	$ 3.25	$ 3.07
Total Potential Natural Gas Volumes (BBtupd)	830	689	1,000	247
Total Weighted Average Price ($/MMBtu)	$ 3.19	$ 3.19	$ 3.08	$ 3.04
Basis Contract Summary:				
Tetco M2				
Volume (BBtupd)	-	12	-	-
Differential ($/MMBtu)	$ -	$ (0.59)	$ -	$ -
NGPL MidCon				
Volume (BBtupd)	50	38	12	-
Differential ($/MMBtu)	$ (0.26)	$ (0.26)	$ (0.26)	$ -
Oil Contract Summary:				
Oil Fixed Price Swaps (LLS)				
Volume (Bblpd)	1,500	1,748	753	-
Weighted Average Price ($/Bbl)	$ 53.12	$ 51.97	$ 53.91	$ -
Oil Fixed Price Swaps (WTI)				
Volume (Bblpd)	4,500	3,353	3,779	-
Weighted Average Price ($/Bbl)	$ 54.89	$ 54.98	$ 52.20	$ -
Total Potential Crude Oil (Bblpd)	6,000	5,101	4,533	-
Total Weighted Average Price ($/Bbl)	$ 54.45	$ 53.95	$ 52.48	$ -
Propane Contract Summary:				
C3 Propane Fixed Price Swaps				
Volume (Bblpd)	3,000	2,545	3,500	-
Weighted Average Price ($/Gal)	$ 0.63	$ 0.64	$ 0.67	$ -
C5+ Pentane Fixed Price Swaps				
Volume (Bblpd)	250	250	500	-
Weighted Average Price ($/Gal)	$ 1.17	$ 1.17	$ 1.11	$ -

1. As of November 1, 2017.
2. Counterparty has option to call.

Financial and Operational Summary

	2015					2016					2017				FY2017E		3Q2017	
	1Q2015	2Q2015	3Q2015	4Q2015	FY 2015	1Q2016	2Q2016	3Q2016	4Q2016	FY 2016	1Q2017	2Q2017	3Q2017	YTD 2017			Q-o-Q	Y-o-Y
Production																		
Gas - Bcf	26.0	33.1	48.1	48.9	156.2	53.3	52.8	58.2	63.4	227.6	66.3	82.9	97.8	247.0			18%	68%
Oil - MBbls	765.6	727.1	732.1	674.6	2,899.4	601.8	551.5	521.4	451.2	2,125.9	513.7	650.0	685.3	1,849.0			5%	31%
Liquids – MBbls	1,273.3	941.0	1,168.9	1,040.5	4,423.6	1,012.6	734.6	1,043.7	1,055.8	3,846.7	1,182.6	1,281.1	1,405.0	3,868.6			10%	35%
Total Equivalent (Bcfe)	38.2	43.1	59.5	59.2	200.1	63.0	60.5	67.5	72.4	263.4	76.5	94.5	110.4	281.3			17%	63%
Total Daily Equivalent (MMcfepd)	424,425	473,935	647,062	643,832	548,188	692,230	664,743	734,144	786,998	719,753	849,569	1,038,351	1,199,636	1,030,468	1,065,000	1,100,000	16%	63%
Product Mix																		
Gas	68%	77%	81%	83%	78%	85%	87%	86%	87%	86%	87%	88%	88%	88%	~88%			
Liquids	32%	23%	19%	17%	22%	15%	13%	14%	13%	14%	13%	12%	12%	12%	~8			
															~4			
Realized Prices																		
Average Realized Prices before the impact of derivatives ($/Mcfe)	**$3.30**	**$2.84**	**$2.33**	**$2.00**	**$2.53**	**$1.58**	**$1.81**	**$2.35**	**$2.67**	**$2.13**	**$3.05**	**$2.74**	**$2.61**	**$2.78**			(5%)	11%
Average Realized Prices incl. cash-settlement of derivatives ($/Mcfe)	**$3.30**	**$3.41**	**$2.83**	**$2.79**	**$3.13**	**$2.61**	**$2.82**	**$2.54**	**$2.80**	**$2.69**	**$2.96**	**$2.79**	**$2.74**	**$2.82**			(2%)	8%
Average Realized Prices including derivatives ($/Mcfe)	**$4.61**	**$2.60**	**$3.87**	**$3.21**	**$3.54**	**$2.49**	**($0.47)**	**$2.87**	**$0.88**	**$1.46**	**$4.36**	**$3.43**	**$2.41**	**$3.28**				
Average NYMEX Henry Hub ($/MMBtu)	$2.98	$2.64	$2.77	$2.27	$2.66	$2.09	$1.95	$2.81	$2.99	$2.46	$3.31	$3.18	$3.00	$3.16				
Differential to Henry Hub ($/MMBtu)	(0.44)	(0.59)	(0.87)	(0.78)	(0.75)	(0.79)	(0.60)	(0.85)	(0.80)	(0.73)	(0.81)	(0.87)	(0.87)	(0.87)				
Natural Gas Realized Price before the impact of derivatives ($/MMBtu)	$2.54	$2.05	$1.90	$1.49	$1.91	$1.30	$1.35	$1.96	$2.19	$1.73	$2.50	$2.32	$2.13	$2.30				
BTU Upgrade (MMBtu / Scf)	0.23	0.18	0.17	0.13	0.17	0.09	0.09	0.14	0.15	0.12	0.18	0.16	0.15	0.16				
Natural Gas Realized Price before the impact of derivatives ($/Mcf)	$2.77	$2.23	$2.07	$1.62	$2.08	$1.39	$1.44	$2.10	$2.34	$1.85	$2.68	$2.48	$2.28	$2.46				
Differential to Henry Hub ($/Mcf)	*(0.21)*	*(0.41)*	*(0.70)*	*(0.65)*	*(0.58)*	*(0.70)*	*(0.51)*	*(0.71)*	*(0.65)*	*(0.61)*	*(0.63)*	*(0.70)*	*(0.72)*	*(0.71)*	($0.62)	($0.68)		
Impact of cash settled derivatives ($/Mcf)	0.67	0.74	0.55	0.86	0.71	1.10	1.09	0.20	0.15	0.60	(0.11)	0.03	0.13	0.03				
Natural Gas Realized Price incl. cash-settlement of derivatives ($/Mcf)	**$3.44**	**$2.97**	**$2.62**	**$2.48**	**$2.79**	**$2.49**	**$2.53**	**$2.31**	**$2.49**	**$2.45**	**$2.57**	**$2.51**	**$2.41**	**$2.49**			(4%)	5%
Average NYMEX WTI ($/Bbl)	$48.57	$57.96	$46.44	$42.64	$48.88	$33.51	$45.60	$44.94	$49.33	$43.37	$51.86	$48.29	$48.19	$49.43				
Differential to WTI ($/Bbl)	(6.85)	(7.81)	(5.91)	(6.25)	(6.59)	(7.19)	(3.60)	(3.13)	(4.17)	(5.18)	(4.34)	(2.96)	(2.29)	(3.28)	($3.25)	($3.75)		
Oil Realized Price before the impact of derivatives ($/Mcf)	$41.72	$50.15	$40.53	$36.38	$42.29	$26.32	$42.00	$41.81	$45.15	$38.18	$47.52	$45.33	$45.90	$46.15				
Impact of cash settled derivatives ($/Mcf)	1.88	(0.01)	4.30	$6.62	3.12	10.54	6.49	1.62	0.22	5.11	0.16	3.58	4.37	2.92				
Oil Realized Price incl. cash-settlement of derivatives ($/Bbl)	**$43.59**	**$50.14**	**$44.84**	**$43.00**	**$45.41**	**$36.86**	**$48.49**	**$43.43**	**$45.37**	**$43.29**	**$47.68**	**$48.91**	**$50.26**	**$49.07**			3%	16%
NGL Realized Price before the impact of derivatives ($/Gal)	$0.41	$0.30	$0.19	$0.34	$0.31	$0.22	$0.33	$0.33	$0.56	$0.37	$0.63	$0.45	$0.57	$0.55				
Impact of cash settled derivatives ($/Gal)	-	-	-	0.00	0.00	0.01	-	-	(0.01)	(0.01)	-	-	(0.03)	(0.01)				
NGL Realized Price incl. cash-settlement of derivatives ($/Gal)	**$0.41**	**$0.30**	**$0.19**	**$0.34**	**$0.31**	**$0.23**	**$0.33**	**$0.33**	**$0.55**	**$0.36**	**$0.63**	**$0.45**	**$0.54**	**$0.54**			20%	63%
% WTI	***36%***	***22%***	***17%***	***34%***	***27%***	***29%***	***30%***	***31%***	***47%***	***35%***	***51%***	***39%***	***50%***	***47%***	45%	50%		
Operating Expenses per Mcfe																		
Lease operating expense	$0.44	$0.39	$0.30	$0.30	$0.35	$0.26	$0.24	$0.26	$0.28	$0.26	$0.25	$0.22	$0.18	$0.21	$0.18	$0.23	(17%)	(30%)
Production taxes	$0.11	$0.08	$0.06	$0.06	$0.07	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.08	$0.09	10%	(6%)
Midstream gathering and processing	$0.66	$0.76	$0.71	$0.64	$0.69	$0.60	$0.65	$0.67	$0.60	$0.63	$0.63	$0.62	$0.63	$0.63	$0.55	$0.62	1%	(7%)
Unit Operating Costs	**$1.22**	**$1.23**	**$1.06**	**$1.01**	**$1.11**	**$0.91**	**$0.94**	**$0.98**	**$0.93**	**$0.94**	**$0.93**	**$0.89**	**$0.86**	**$0.89**	**$0.81**	**$0.94**	(3%)	(13%)
Revenues (in thousands)																		
Gas sales	$118,570	$65,871	$179,215	$144,070	$507,726	$131,094	($57,860)	$155,185	$25,776	$254,195	$264,114	$262,035	$216,264	$742,412				
Oil and condensates sales	35,500	34,465	41,747	30,104	141,816	17,121	20,533	23,507	$14,625	75,786	35,316	37,611	24,888	97,815				
Liquid sales	22,007	11,958	9,431	16,052	59,448	8,746	9,168	15,000	$23,015	55,929	33,574	24,307	24,347	82,229				
Other income, net	240	(24)	176	93	485	2	7	(6)	(132)	(129)	-	-	-	-				
Total Revenue	$176,317	$112,270	$230,569	$190,319	$709,475	$156,963	($28,152)	$193,686	$63,284	$385,781	$333,004	$323,953	$265,499	$922,456				
Plus non-cash hedge (gain) loss	(31,324)	34,633	(62,182)	(24,798)	(83,671)	7,685	198,685	(22,357)	139,290	323,303	(106,796)	(59,871)	36,974	(129,693)				
Total Revenue excl. non-cash impact from derivatives	**$144,993**	**$146,903**	**$168,387**	**$165,521**	**$625,804**	**$164,648**	**$170,533**	**$171,329**	**$202,574**	**$709,084**	**$226,208**	**$264,082**	**$302,473**	**$792,764**			15%	77%
Expenses (in thousands)																		
Lease operating expense	$16,980	$16,863	$17,568	$18,064	$69,475	$16,657	$14,661	$17,471	$20,088	$68,877	$19,303	$20,721	$20,020	$60,044				
Production taxes	4,285	3,285	3,593	3,577	14,740	3,111	2,856	3,525	3,784	13,276	3,906	5,139	5,419	14,464				
Midstream gathering and processing	25,381	32,904	42,166	38,139	138,590	37,652	39,349	45,475	43,496	165,972	47,941	58,945	69,372	176,258				
General and administrative	10,799	9,515	11,001	10,652	41,967	10,620	11,854	10,467	10,468	43,409	12,600	12,257	13,065	37,922				
Other	(9)	(248)	(279)	(107)	(643)	(94)	(391)	(337)	(408)	(1,230)	(1,158)	(250)	(382)	(1,790)				
Adjusted EBITDA	**$87,557**	**$84,584**	**$94,338**	**$95,196**	**$361,675**	**$96,702**	**$102,204**	**$94,728**	**$125,146**	**$418,780**	**$143,616**	**$167,270**	**$194,978**	**$505,864**				
Depreciation, depletion and amortization	89,909	71,155	90,329	86,301	337,694	65,477	55,652	62,285	62,560	245,974	65,991	82,246	106,650	254,887				
Adjusted Net Income (Loss)	**($7,187)**	**$250**	**($8,694)**	**($609)**	**($16,240)**	**$15,146**	**$30,366**	**$20,018**	**$44,253**	**$109,783**	**$53,864**	**$60,426**	**$57,979**	**$172,269**				

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