RSP PERMIAN

Barclays CEO Energy-Power Conference

September 6, 2016

Forward-Looking Statements

Certain statements and information in this presentation may constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. The words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “should,” “would,” “could” or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, the volatility of commodity prices, product supply and demand, competition, access to and cost of capital, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the assumptions underlying production forecasts, our hedging strategy and results, the quality of technical data, environmental and weather risks, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the costs and results of drilling and operations, the availability of equipment, services, resources and personnel required to complete RSP’s operating activities, access to and availability of transportation, processing and refining facilities, the financial strength of counterparties to the Company’s credit facility and derivative contracts and the purchasers of RSP’s production and third parties providing services to RSP and acts of war or terrorism.

For additional information regarding known material factors that could cause our actual results to differ from our projected results, please see our filings with the United States Securities and Exchange Commisson (SEC), including our Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q.

Existing and prospective investors are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

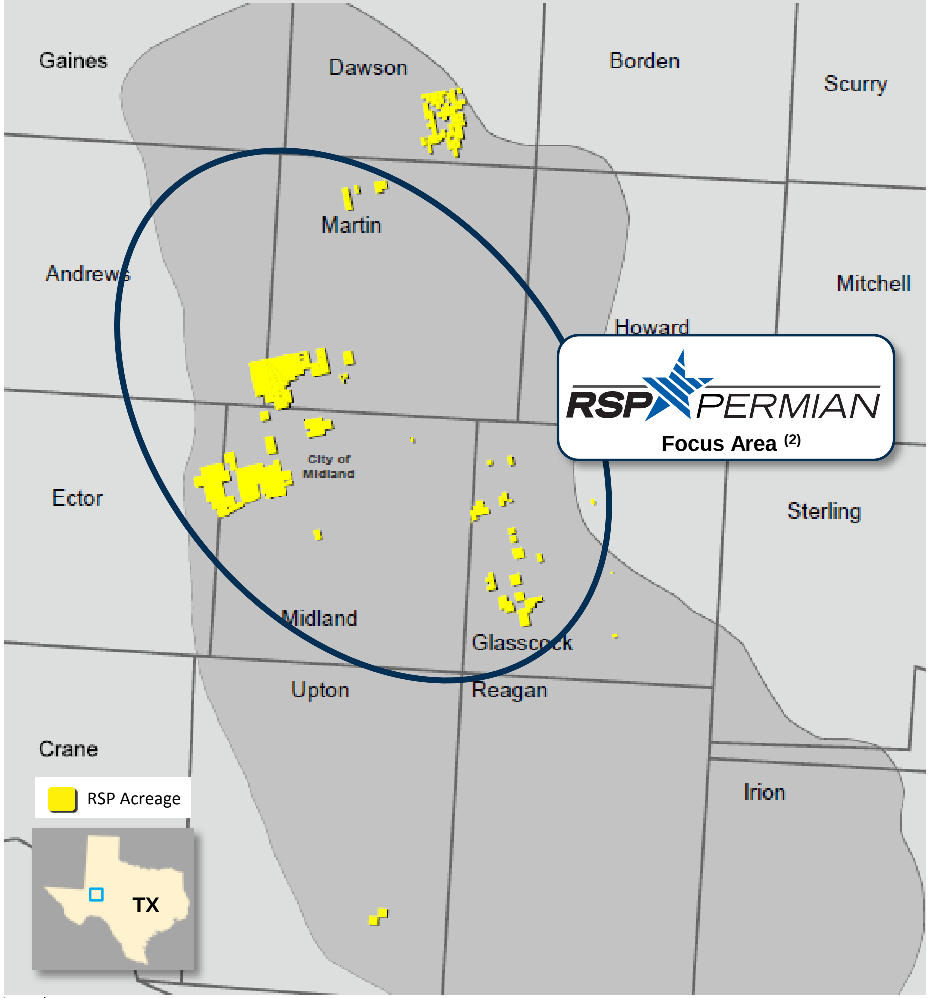
RSP Permian Overview (NYSE: RSPP)

- **Large, contiguous acreage blocks in the core of the Midland Basin**
  - ~63,000 net surface acres and ~262,000 net "effective horizontal acres"(1)
    - 96% operated
    - ~94% of net "effective horizontal acres" are undeveloped
  - ~2,600 horizontal locations in inventory with significant upside of an additional ~1,770 horizontal locations at tighter spacing
  - Average horizontal lateral length >7,000'
- **Efficient operator – focused on execution**
  - Leading F&D costs, reserve replacement ratios and operating costs
  - Drilled wells in five different horizontal benches

Key Statistics

Market Capitalization (9/2/16):	**$4.0 billion**
2Q16 Average Production:	**26.4 MBoe/d**
YE 2015 Proved Reserves:	**159.2 MMBoe**
Net Debt / TTM EBITDAX(3)(4):	**2.7x**
Liquidity as of 6/30/16:	**$632 million**

Concentrated Acreage Position in the Core of the Midland Basin



(1) Combined horizontal acreage position that management believes is prospective for hydrocarbon production across each target horizontal zone.
(2) Defined as adjacent counties of Midland, Martin, Andrews, Ector, and Glasscock.
(3) Please see reconciliation of Adjusted EBITDAX in Appendix.
(4) Based on Q2 2016 net debt and TTM Adjusted EBITDAX.

Second Half of 2016 Operating Plan

Increased 2016 Guidance

- Expected full-year production range increased to 26.5 - 28.5 MBoe/d
  - Higher forecast due primarily to increased well productivity
- Development capital expenditure budget increased to $285 - $315 million
  - Impact to production largely beginning in 2017

Accelerating Development

- With strengthening oil prices, RSP added 3rd Hz rig in 3Q16
  - Drilling four additional wells on Johnson Ranch LS spacing pilot
  - Allows RSP to have one rig committed to continuous drilling across Glasscock position
- RSP currently has one full-time frac crew scheduled for remainder of 2016

Mitigating Price Risk

- Currently ~67%[1] of 2H16 projected oil production is protected by hedge contracts at a weighted average price of $43.44/bbl
  - Recently executed additional deferred premium[2] puts that more than doubled existing downside oil price protection at $45/bbl in 2H16, while retaining upside
- RSP will layer on additional hedge contracts with improving prices

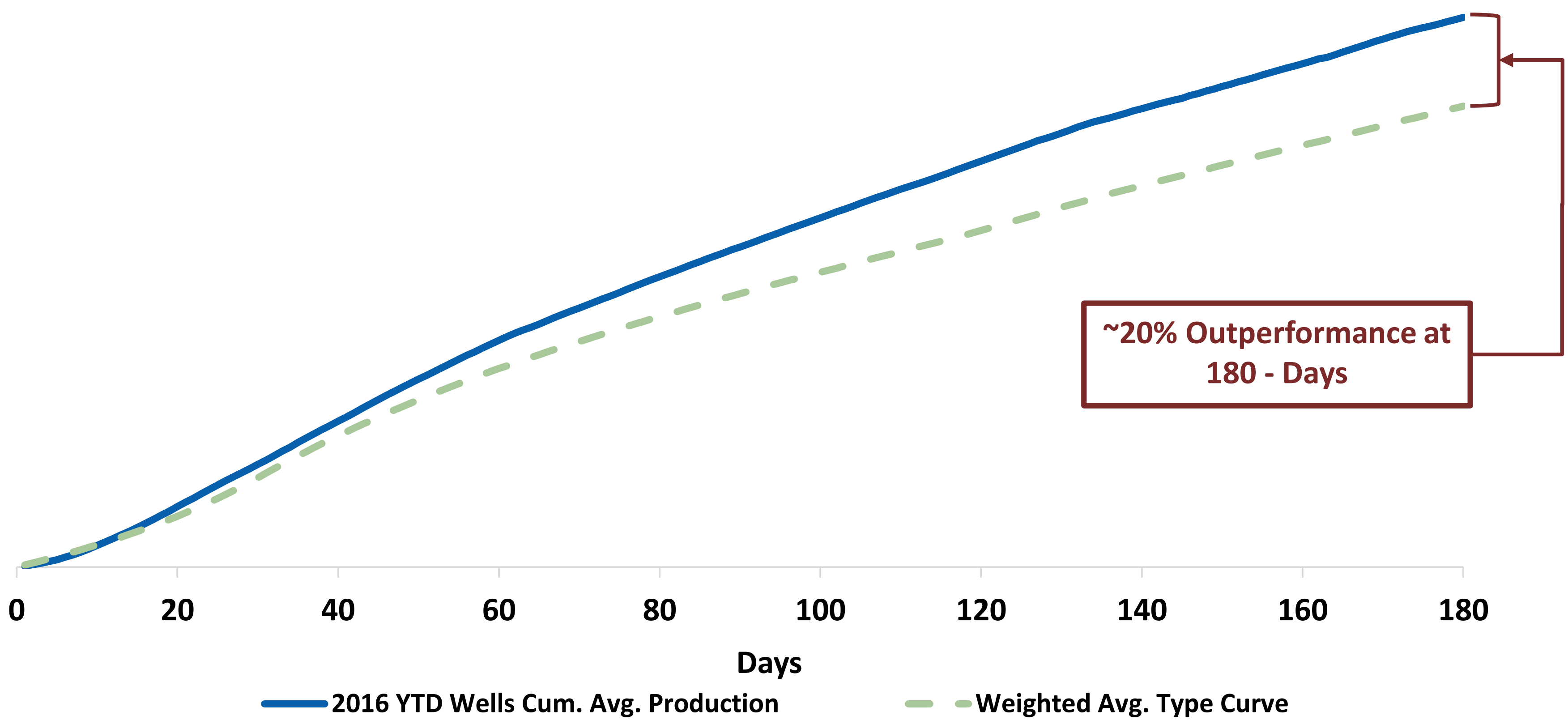
With strong liquidity, no near-term maturities, an improving hedge position and increasing cash flow from recovering oil prices, RSP can readily accelerate activity beyond current levels

(1) *Utilizing FY 2016 mid-point daily oil volume guidance.*
(2) *Deferred premium is not paid until expiration date, aligning cash inflows and outflows with the settlement of the derivative contract.*

2016 Horizontal Well Performance Exceeding Type Curves

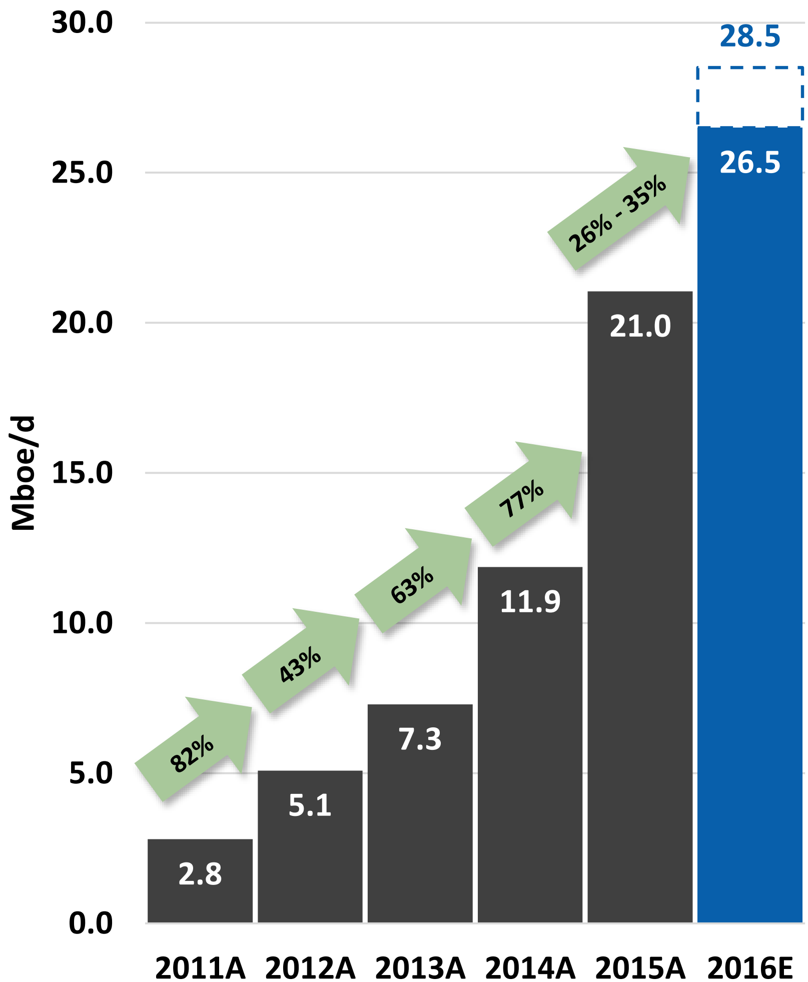
- The average of all operated horizontal wells brought online in 2016 YTD is outperforming the weighted average internal type curve by ~20%
- This group of wells includes, among others, R&D wells testing high density stimulation, increased density spacing and alternate landing zone tests

All Horizontal Wells Completed YTD vs. Weighted Average Type Curve (Boe)



Strong Historical Growth with Significant Organic Growth Potential

Historical Production Growth



Illustrative Rig Scenarios

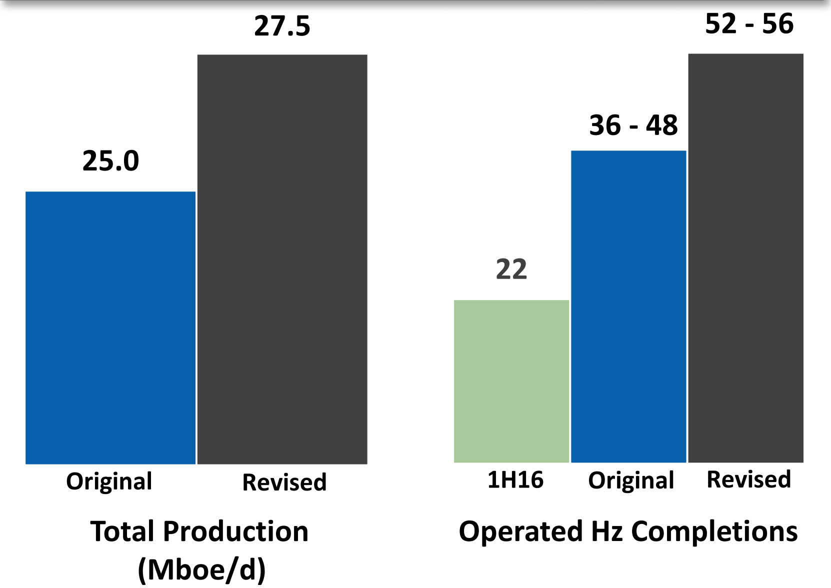
Oil Price	Operated Hz Rigs	Debt / EBITDAX	Annualized Production Growth
$55+	5+	<2x	30%+
$45 – $55	3 – 5	2x – 3x	10% – 30%
$40 – $45	2 – 3	<4x	0% – 10%

- **Proven historical track record of delivering strong production growth while maintaining a healthy balance sheet**
- **Significant operational flexibility heading into 2017**
- **RSP has decades of high-return horizontal inventory and the organizational capacity to drive meaningful organic growth**

Updated 2016 Guidance

- Increased production guidance range to 26.5 - 28.5 MBoe/d, or 10% above original midpoint
- Capex range revised to $285MM - $315MM
- Expect to complete 54 operated Hz wells in 2016, up from prior midpoint of 42 operated Hz wells
  - Full year 2016 avg. lateral length of ~7,300 ft. and avg. working interest of ~80%
- Incremental capital and completions in 2016 primarily impact 2017 growth profile

Guidance Comparison (1)



1H 2016 Actuals and Full Year Guidance

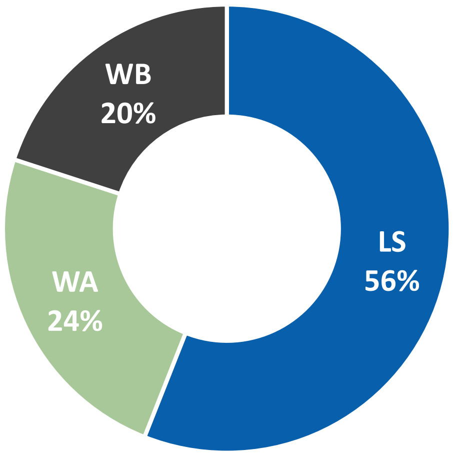
Production	1H 2016 Actual	Original Full Year 2016 Guidance (1)	Revised Full Year 2016 Guidance
Average Daily Production (Boe/d)	25,505	23,000 - 27,000	26,500 - 28,500
% Oil	75%	75% - 76%	75% - 76%
% Natural Gas	11%	10% - 11%	10% - 11%
% NGLs	14%	13% - 14%	13% - 14%
Income Statement ($/Boe)			
LOE (Including Workovers)	$5.45	$5.00 - $6.00	$5.00 - $6.00
Gathering & Transportation	$0.40	$0.45 - $0.50	$0.45 - $0.50
Exploration Expenses	$0.10	$0.25 - $0.30	$0.10 - $0.15
Cash G&A	$2.12	$2.00 - $2.50	$2.00 - $2.25
Recurring Non-Cash G&A	$1.42	$1.25 - $1.50	$1.25 - $1.50
DD&A	$19.79	$18.00 - $20.00	$19.00 - $21.00
Prod. & Ad Val. (% of Rev.)	6.6%	7.0% - 8.0%	6.0% - 7.0%
Capital Expenditures ($MM)			
Drilling & Completion	$122.1	$185 - $235	$270 - $290
Infrastructure & Other	$3.4	$15 - $25	$15 - $25
Total Development Capital	$125.5	$200 - $260	$285 - $315
% Non-Operated	18%	10%	10% - 15%
Completions			
Operated Gross Hz	22	36 - 48	52 - 56
Operated Gross Vt	3	5	5

(1) *Prior guidance reflects that which was published by RSP in January 2016.*

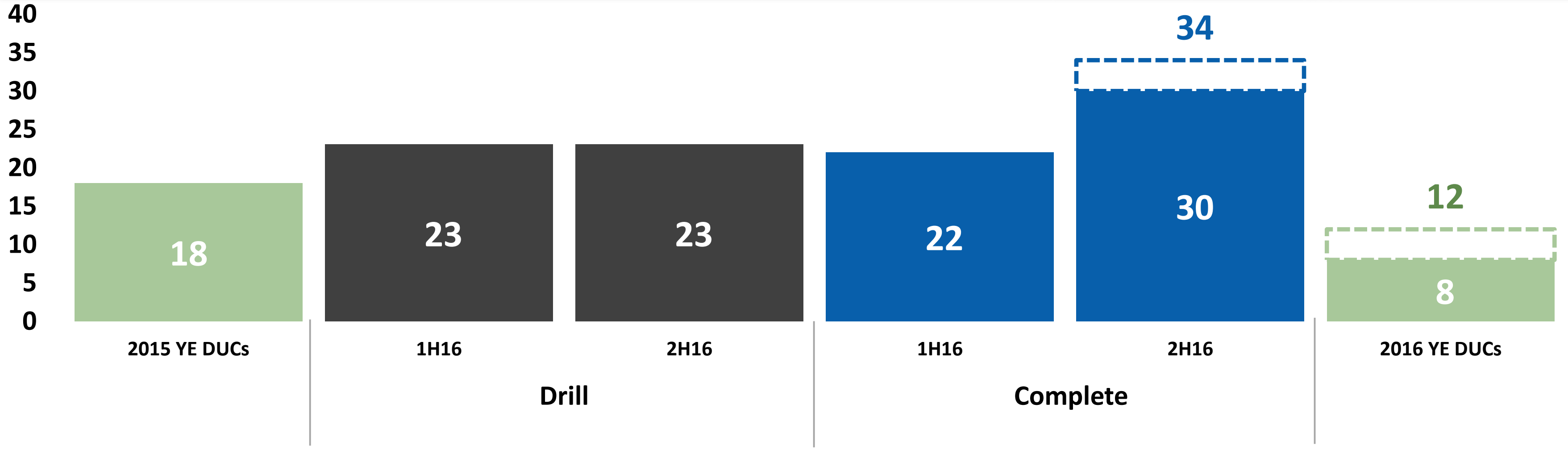
2H16 Operational Activity Update

- In 2H16, RSP expects to complete 30-34 operated wells
  - ~50%+ focused in the Lower Spraberry zone
- 2H16 drilling and completion activity noted below contemplates:
  - 2 existing rigs; adding 1 additional rig in 3Q16
  - 1 full-time frac crew
- Expect to end 2016 with 8-12 DUCs
  - Dependent upon completion pace, as dictated by commodity pricing

2H16 Operated Completions by Zone



2016 Operated Horizontal Drilling & Completion Summary[1]

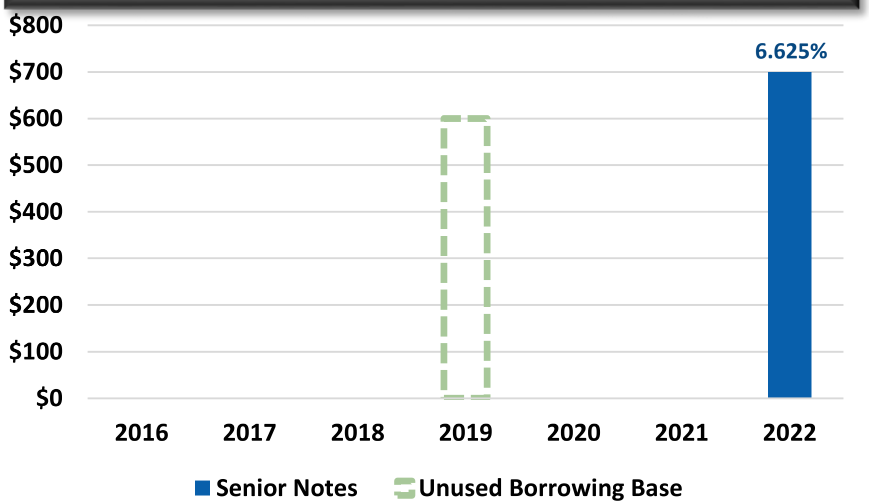


(1) *Includes 2 wells that were acquired after drilling but prior to completion during 2Q16.*

RSP is in a Strong Financial Position

- **Selective use of capital markets to fund acquisitions & maintain a strong balance sheet**
- **Earliest debt maturity is undrawn Revolving Credit Facility in 2019; Senior Unsecured Notes mature in 2022**
- **During 1Q16, Moody's confirmed RSP's B3 rating on its senior notes and S&P upgraded the senior notes a notch to B+**

Debt Maturities ($MM)



Capitalization Table

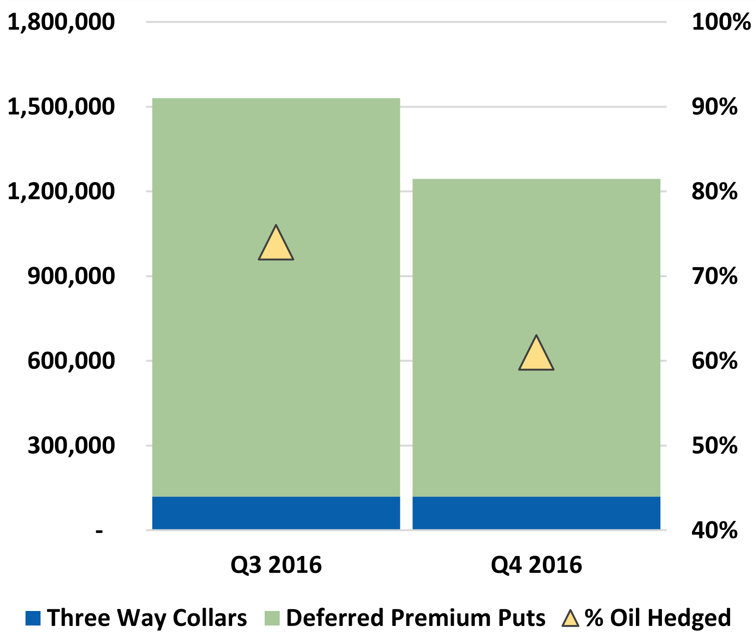
($ in millions)	**Q2 2016**
Cash	$33
Revolving Credit Facility	–
6.625% Senior Unsecured Notes Due 2022	700
Total Debt	$700
Net Debt	$667
Liquidity	
Borrowing Base	**$600**
Less: Borrowings & LCs	(1)
Plus: Cash	33
Liquidity	**$632**
Financial & Operating Statistics	
Q2 2016 TTM Adjusted EBITDAX (1)	$246.8
Q2 2016 Daily Production (MBoe/d)	26.4
Credit Metrics	
Net Debt / TTM Adjusted EBITDAX	2.7x
Net Debt / Latest Daily Production ($/Boe/d)	$25,264

(1) Please see reconciliation of Adjusted EBITDAX in Appendix.

Hedging Program Summary

- RSP opportunistically layers on hedges to protect returns and support planned capital expenditures
- Recently executed additional deferred premium puts that more than doubled existing downside oil price protection at $45/bbl in 2H16
- Deferred put structure allows RSP to retain upside to future oil price increases

Hedged Oil Volumes[2]



Oil Hedge Contract Detail

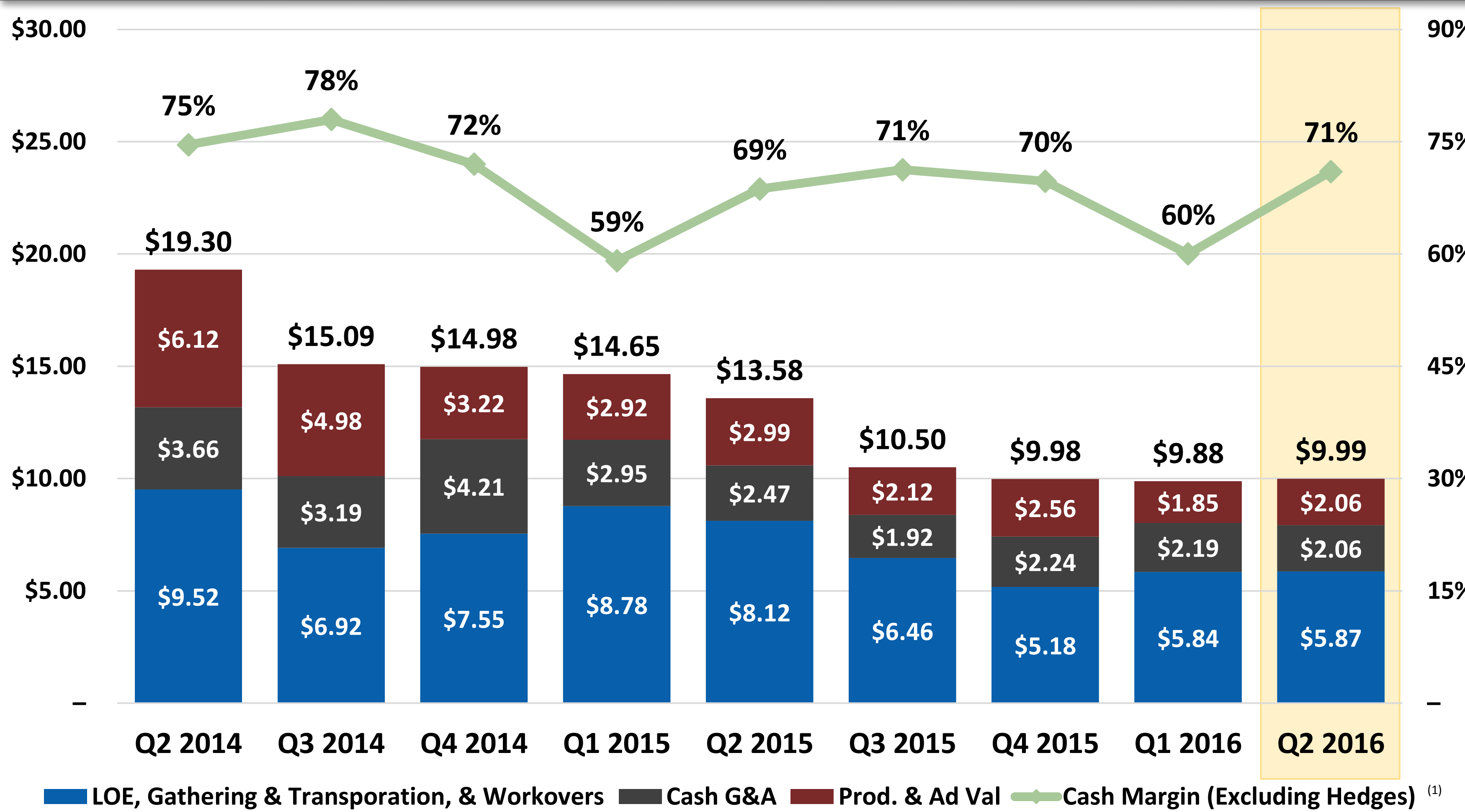
	Q3 2016	Q4 2016	2H16
Three Way Collars			
Volumes (Bbls)	120,000	120,000	240,000
Avg. Ceiling ($/Bbl)	$74.41	$74.41	$74.41
Avg. Floor ($/Bbl)	$55.00	$55.00	$55.00
Avg. Short Put ($/Bbl)	$45.00	$45.00	$45.00
Deferred Premium Puts			
Volumes (Bbls)	1,410,000	1,125,000	2,535,000
Avg. Floor ($/Bbl)	$45.00	$45.00	$45.00
Avg. Deferred Premium ($/Bbl)	$2.59	$2.74	$2.65
Total Oil Volumes Hedged (Bbls)	**1,530,000**	**1,245,000**	**2,775,000**
Total Weighted Net Avg Floor[1]	**$43.40**	**$43.49**	**$43.44**
Daily Volumes (Bbls/day)	***16,630***	***13,533***	***15,082***
% Oil Hedged (Bbls/day)[2]	***74%***	***61%***	***67%***

(1) *Utilizing long put from three way collar and floor price net of deferred premium from deferred put.*
(2) *Utilizing 2H16 midpoint oil volume guidance.*

Low Cost Structure and Strong Margins

- **Operating margins remain strong despite drop in realized oil prices due to cost controls and prolific wells**

Historical Cash Margins and Costs (per Boe)

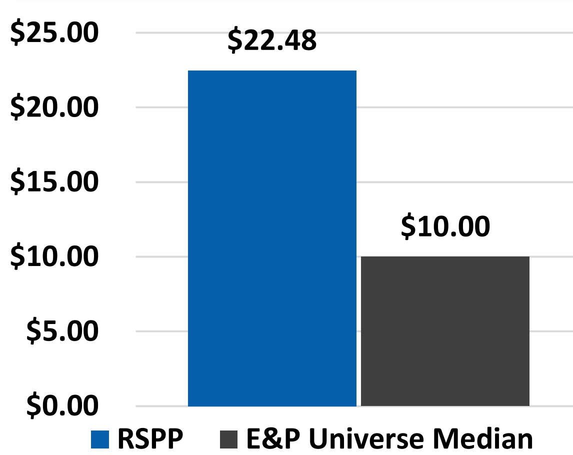


(1) Cash Margin (Excluding Hedges) is calculated as the Realized Price per Boe (Excluding Hedges) less the cash costs listed in the chart, divided by the Realized Price per Boe (Excluding Hedges)

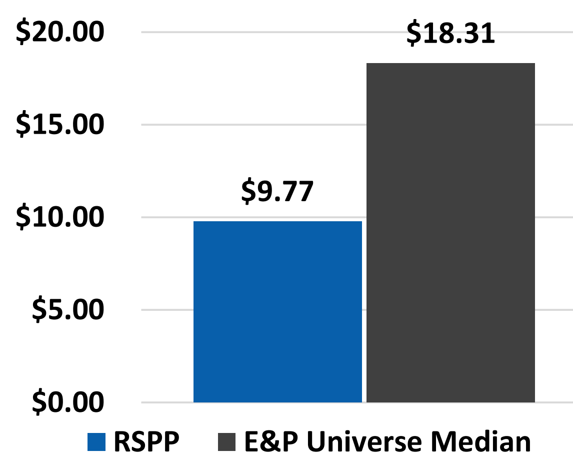
Superior Recycle Ratio

- Premier assets and operational expertise leading to one of highest recycle ratios in the E&P industry
  - Leading cash flow margin/Boe and low F&D cost/Boe
- High cash margins driven by low cost operations and strong well performance
- Low PDP F&D costs[1] a result of intense focus on maximizing EURs and reducing D&C costs

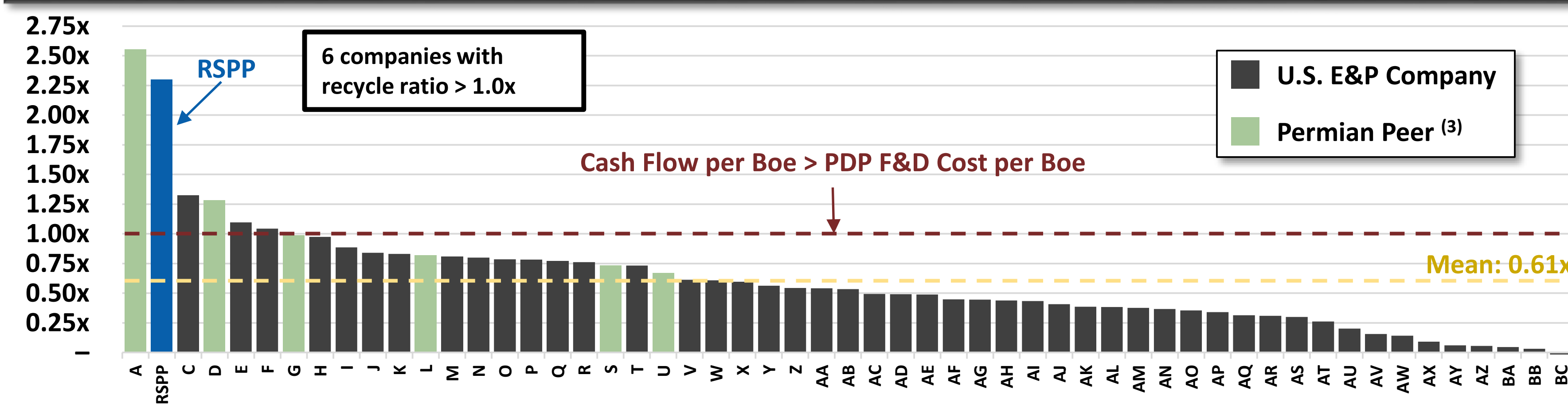
2Q16 Cash Margin / Boe



2015 PDP F&D Cost [1] / Boe



E&P Universe Q2 2016 Recycle Ratio [2]



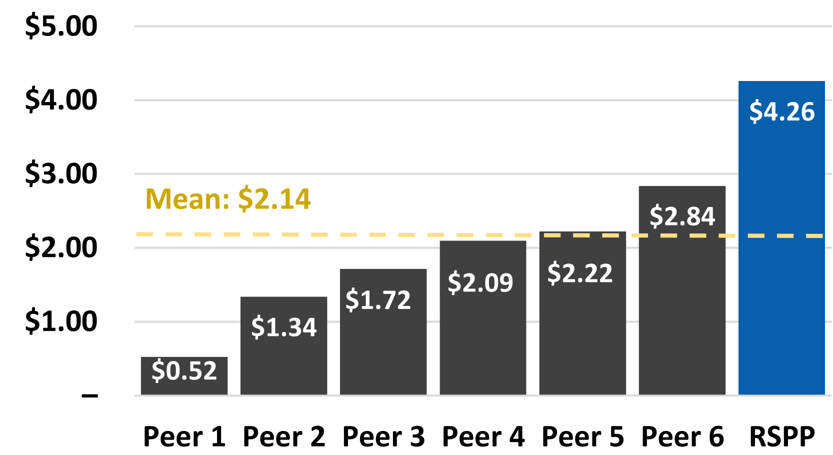
Note: Per Seaport Global Securities ("SGS") estimates.

1) *Defined as exploration and development costs divided by PDP reserve additions as calculated by SGS.*
2) *Q2 2016 Recycle Ratio calculated as unhedged Q2 2016 cash operating margin per Boe divided by PDP F&D cost per Boe as calculated by SGS.*
3) *Permian peers include CPE, CXO, FANG, LPI, PE, and PXD.*

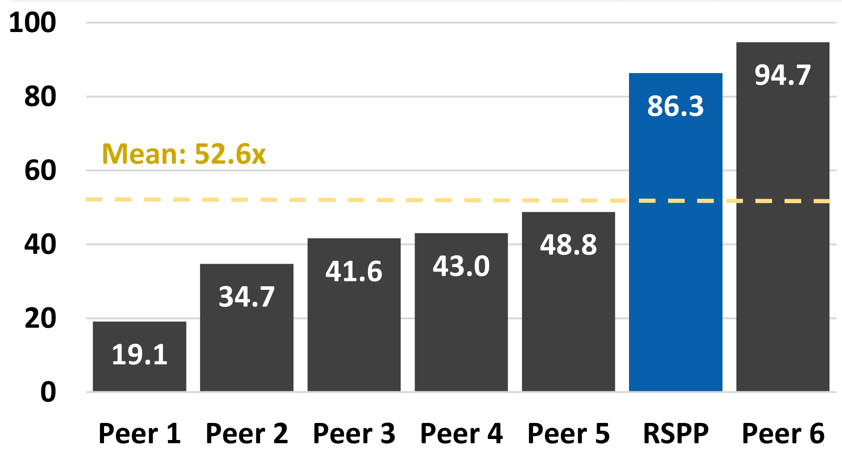
Efficient Operator Coupled with Strong Growth

- Strong production and reserve growth with low corporate overhead
- Contiguous assets and lean operating structure allow for ability to deploy substantial capital and generate high production per employee
- Strong well results lead to superior reserve replacement metrics

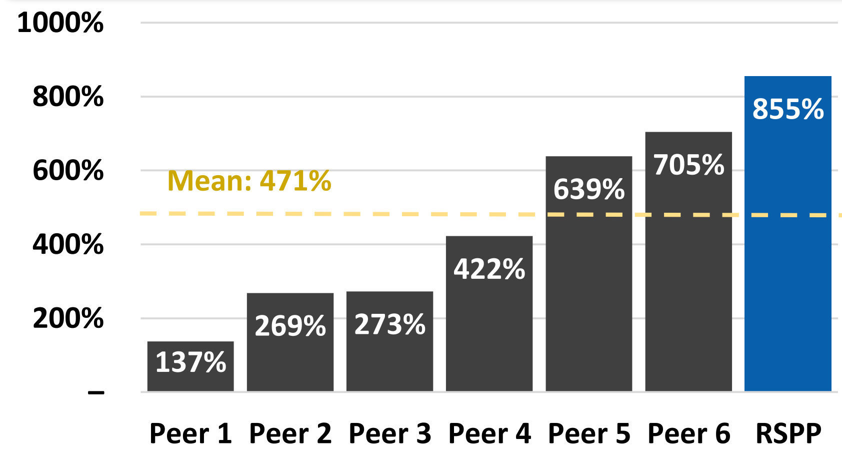
2015 CAPEX per Average Headcount ($MM) (2)



2015 Production per Average Headcount (MBoe) (1)



2015 Organic Reserve Replacement Ratio (3)

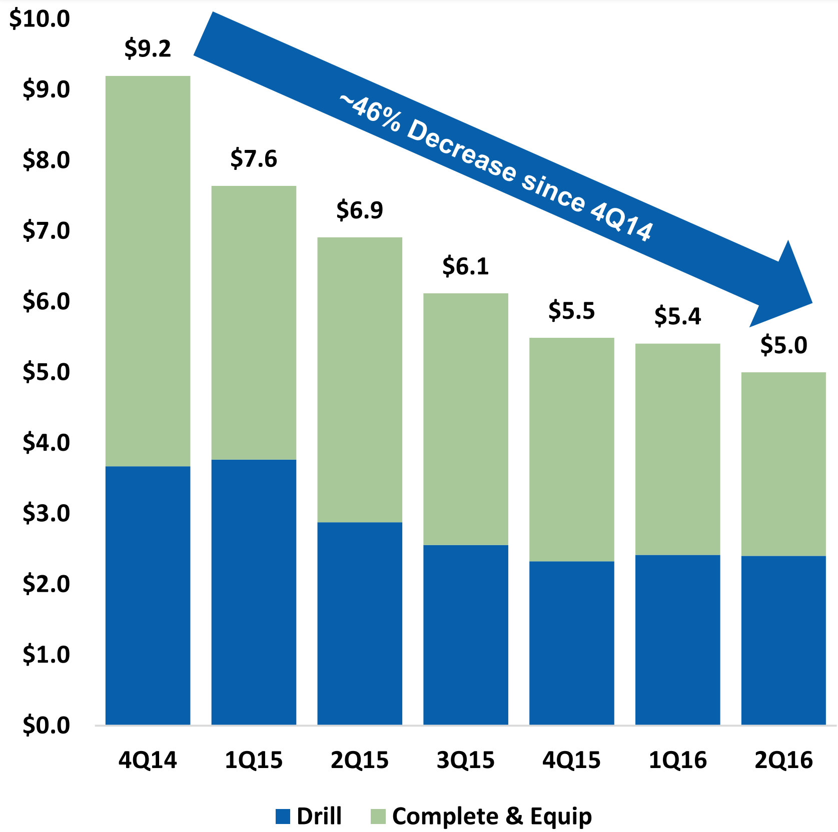


Permian peers include CPE, CXO, FANG, LPI, PE, and PXD. Information based on public filings.
(1) 2015 total production (MBoe) divided by the average YE 2014 & YE 2015 employee counts.
(2) Defined as exploration and development CAPEX divided by the average YE 2014 & YE 2015 employee counts.
(3) Defined as the sum of extensions, discoveries, and non-price revisions, divided by annual production.

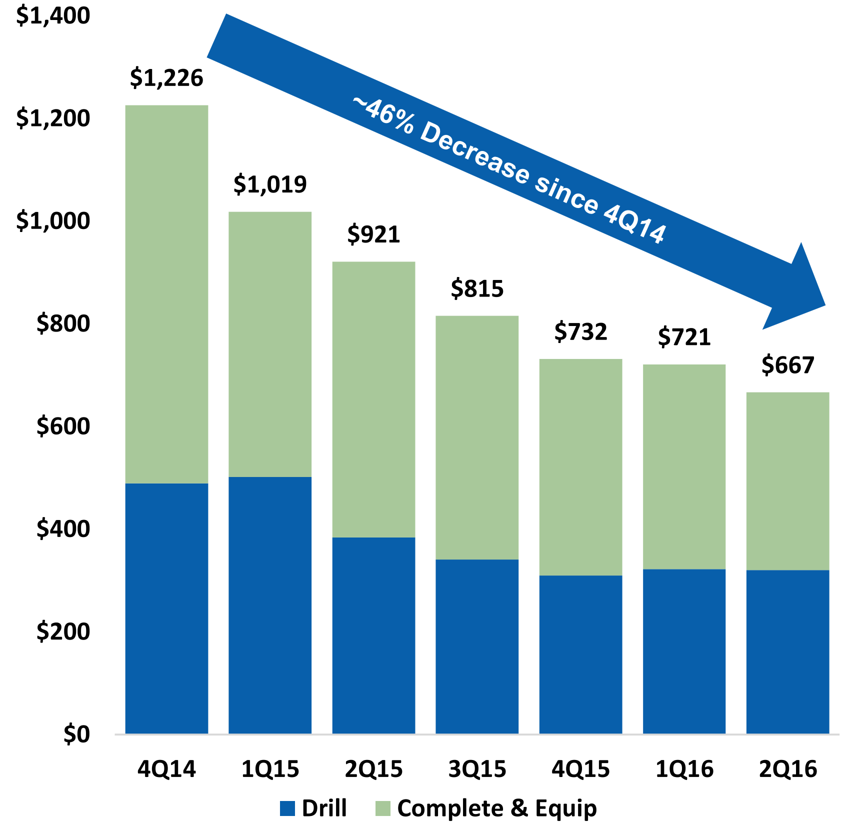
Well Costs Continue to Decline

- Drilling, completion & equipping costs have declined for six straight quarters on an actual and per lateral foot basis
- As a result of continued increase in frac density, latest vintage completion designs may result in a per well cost increase in the future
  - Expect enhanced well performance to more than offset incremental cost, resulting in a net positive impact on per well and per section NPVs

Drilling, Completion & Equip. Cost (7,500' lateral)(1) (2)



Actual Well Cost / Lateral Foot(1)

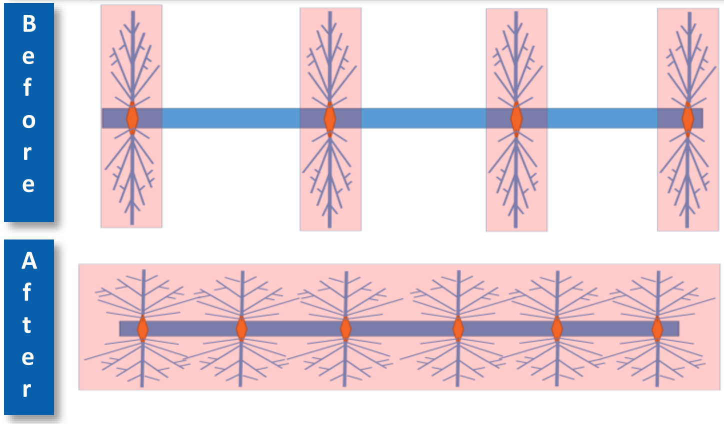


(1) *Limited to wells with lateral lengths of 7,000' – 8,000'.*
(2) *Normalized to 7,500'.*

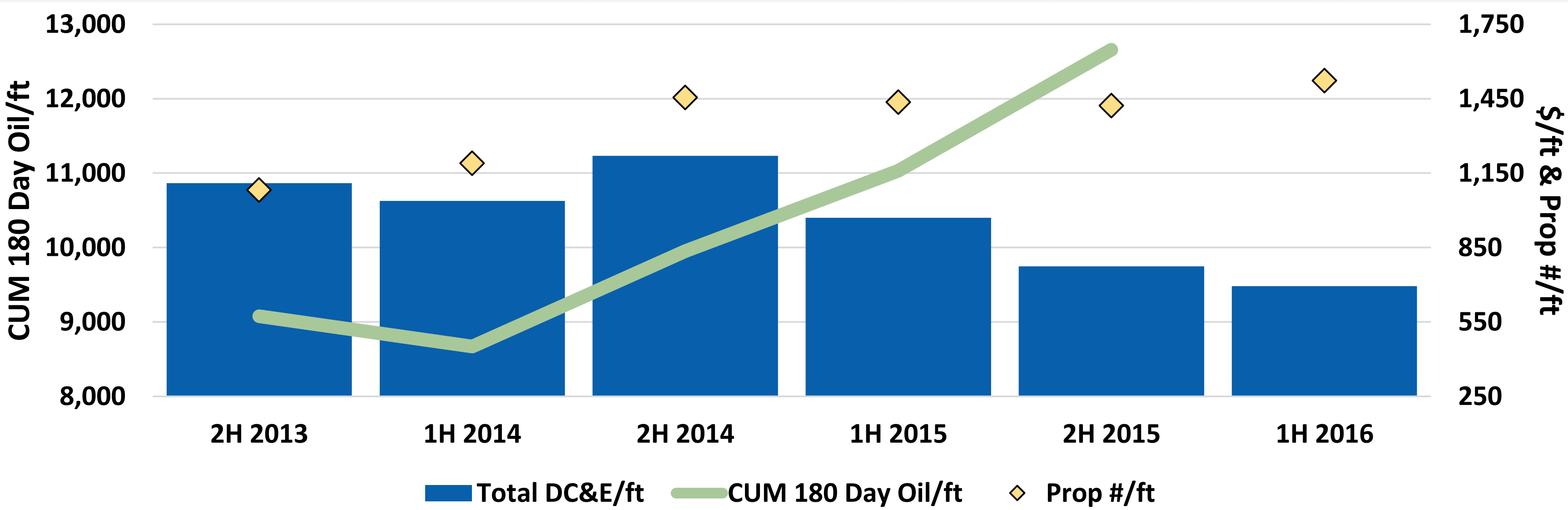
Evolution of Stimulation Design Ongoing

- RSP is using a variety of tools to optimize stimulation efficiency with a goal of increasing productivity near wellbore, reducing costs and maximizing recovery per zone
- Early industry stimulations created long fracture lengths and inefficient drainage patterns
- High density stimulations have resulted in a substantial increase in well performance
  - ~40% increase in avg. 180 day oil cum. production since 2H13

Illustrative Fracture Evolution

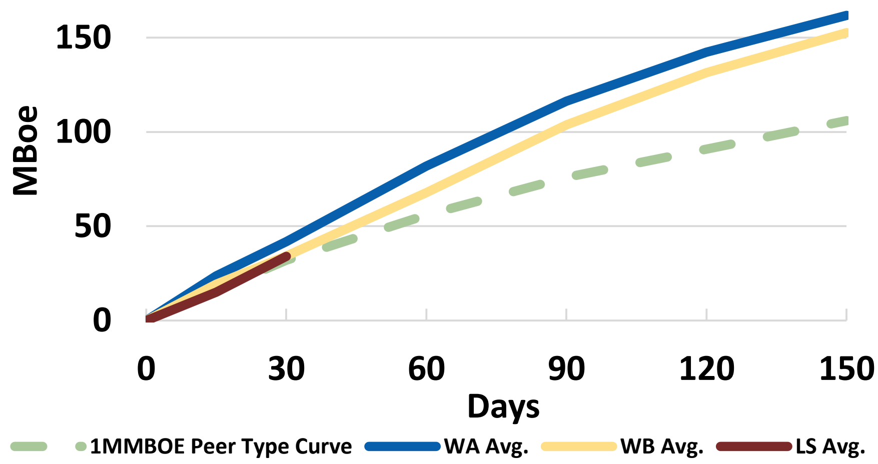


New Stimulation Designs Have Increased Well Performance

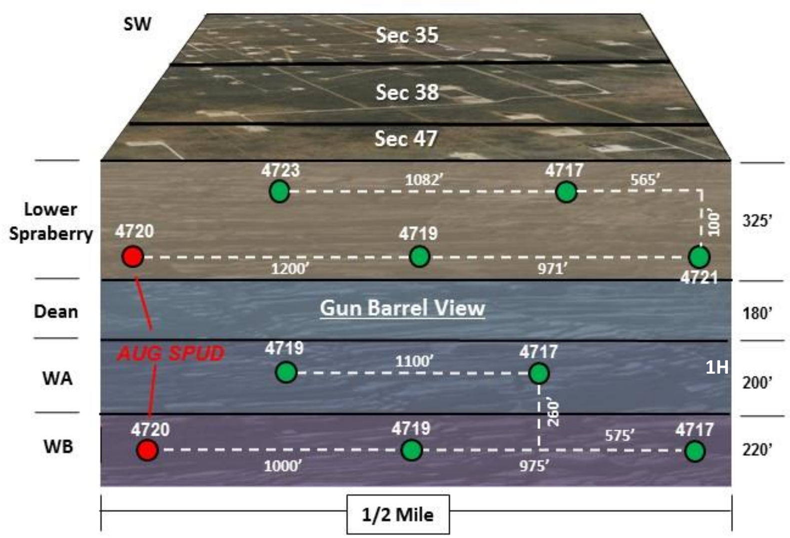


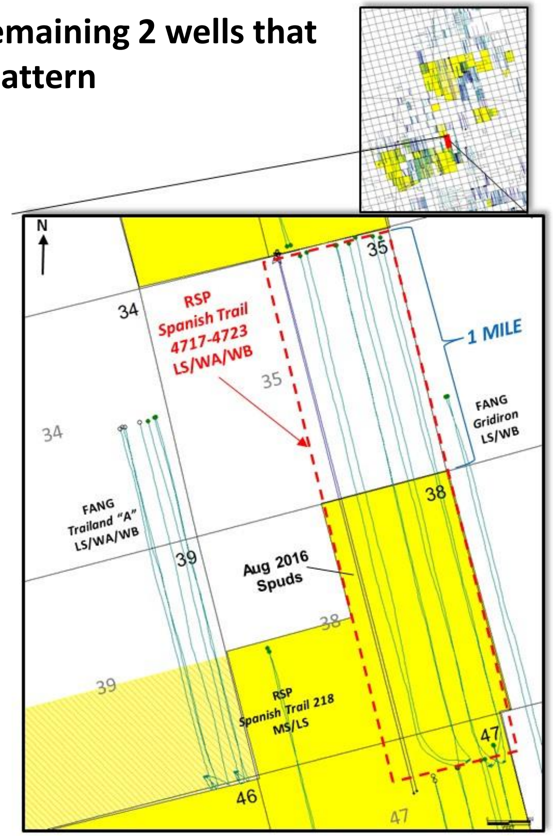
Spanish Trail – Long Laterals Exceeding 1MMBoe Peer Type Curve

Spanish Trail Long Laterals Update



- RSP's longest laterals to date drilled in Spanish Trail Section 47
- 8 wells have been completed to date, all with TD's in excess of 10,500'
- Currently drilling remaining 2 wells that will complete the pattern

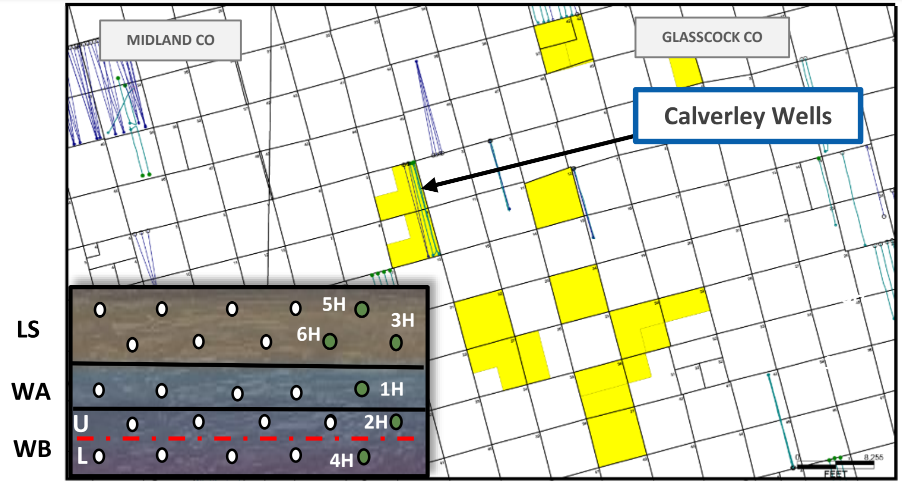




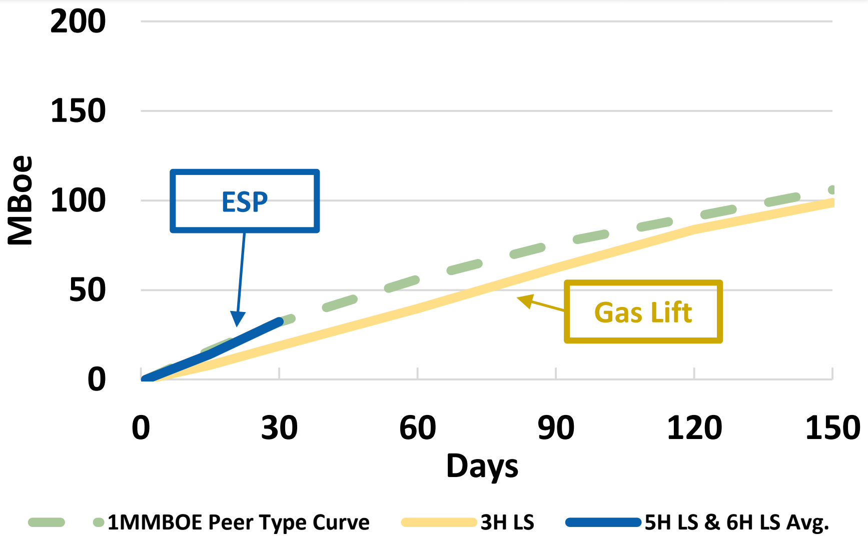
Western Glasscock – Generating Strongest Economics Across Leasehold

Calverley Area Update

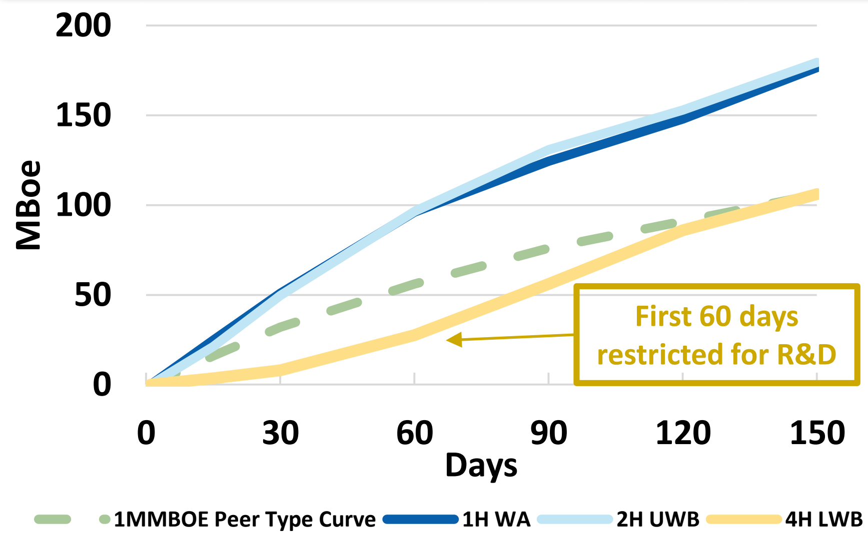
- Two initial Calverley wells continue to outperform peer 1MMBOE type curve
- Two test wells in Western Glasscock, 3H LS and 4H LWB, are approaching peer 1MMBOE type curve after R&D efforts reduced upfront well results
- Two recently completed LS wells were placed on ESP, have been producing for ~30 days and are tracking peer 1MMBOE type curve
- Two additional Upper Wolfcamp wells scheduled to be drilled during 2H16



Calverley LS Performance

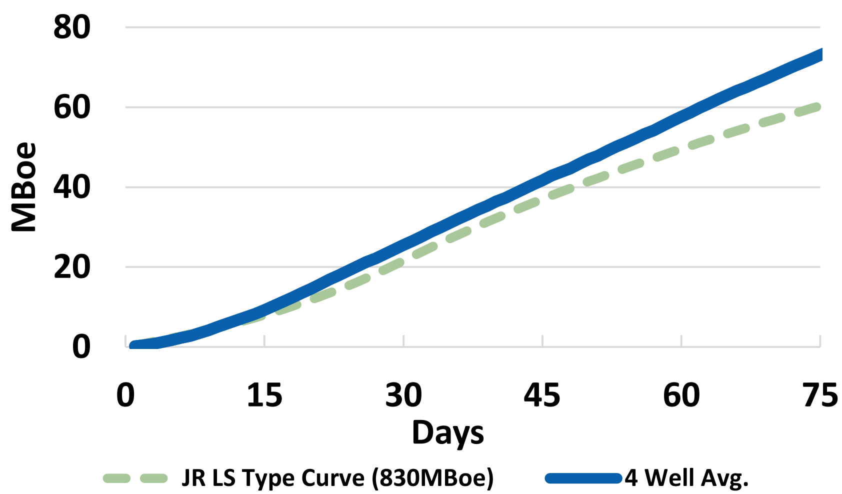


Calverley WC Performance

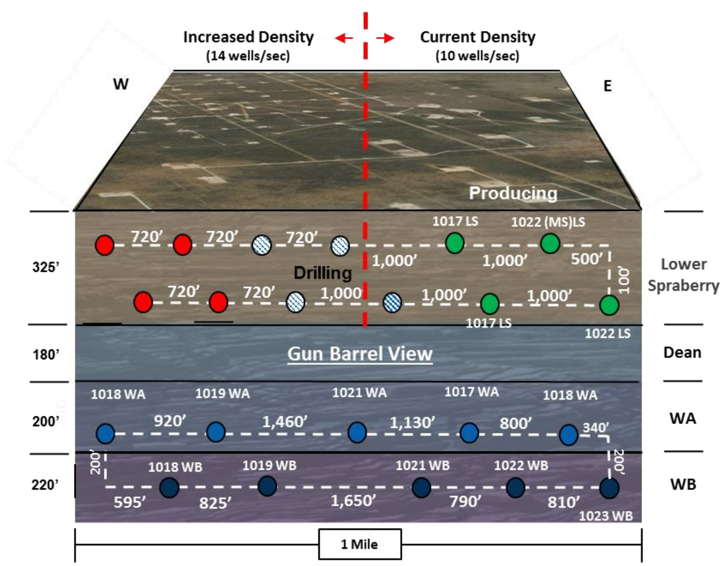


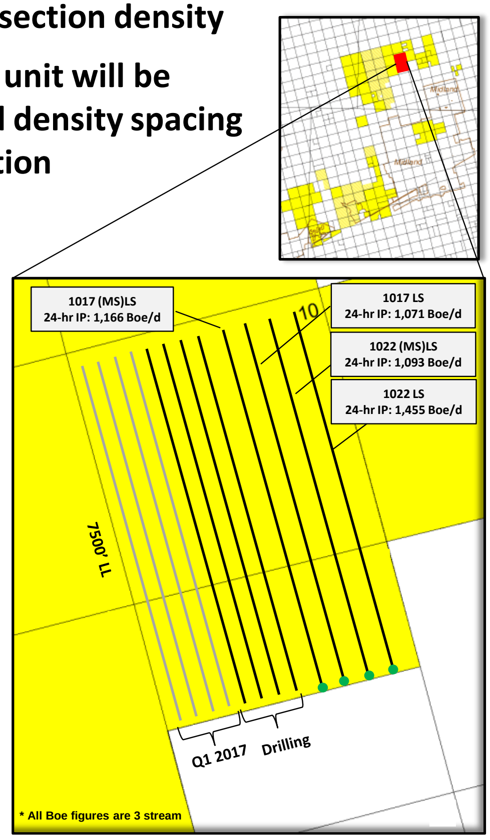
Johnson Ranch – Lower Spraberry Increased Density Pilot

Johnson Ranch LS Density Pilot Update



- RSP has completed the first 4 wells on the Johnson Ranch LS spacing test with encouraging results; 4 additional wells currently drilling
- The eastern half of the unit is being developed on 10 wells/section density
- The western half of the unit will be developed on increased density spacing pattern of 14 wells/section





RSP Permian – Delivering Value

High Quality Assets

Focused on Returns and Execution

Strong Financial Position

Experienced Management

Appendix

2Q16 Update

Financial Results	▪ Average daily production of 26.4 MBoe/d (73% oil, 15% NGLs, 12% Natural Gas), up 7% from 1Q16 and 33% over 2Q15 ▪ Adjusted EBITDAX of $58.5MM (up 64% from 1Q16), on $57.6MM of 2Q16 development Capex ▪ Net loss of $9.8MM, adjusted net loss of $3.8MM, or ($0.04) per share ▪ Cash operating expenses of $9.99/Boe, consistent with 1Q16, and 26% lower than 2Q15
2Q Operational Activity	▪ Operated two Hz rigs, with one full time completion crew ▪ Average quarterly D&C(1) of ~$5.0MM/well ▪ Completed 11 operated Hz wells, 1 operated Vt well and 6 non-op Hz wells ▪ Invested $56.5MM on D&C and $1.1MM on infrastructure and other ▪ $11.2MM of which was attributable to non-op properties ▪ Began quarter with 20 operated Hz DUCs(2) (20 non-op DUCs) and finished with 19 operated Hz DUCs (24 non-op Hz DUCs) ▪ Picking up 3rd operated Hz rig in 3Q16
Liquidity / Hedging	▪ $632MM of liquidity with $33MM in cash and untapped $600MM borrowing base ($1MM LC) ▪ Earliest debt maturity is undrawn revolving credit facility in 2019 ▪ ~67% of 2H16 production hedged, with $45.00 deferred premium puts, protecting downside and leaving upside intact

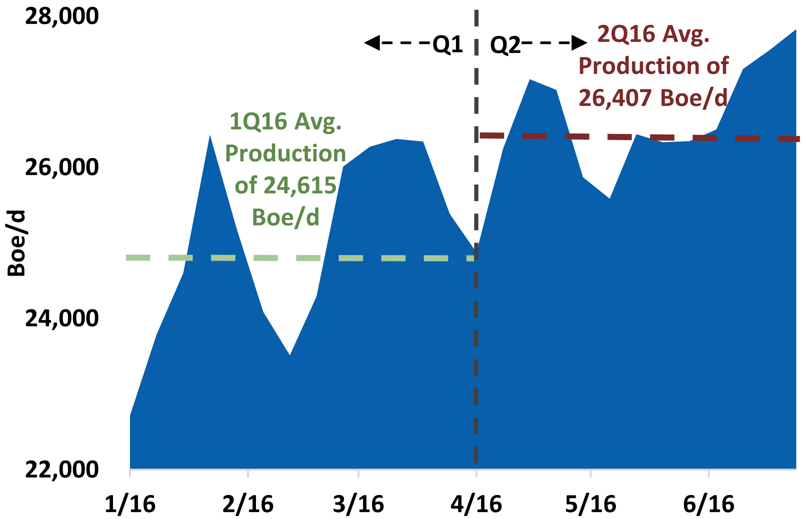
Increased 2016 Guidance	▪ Expected full-year production range increased to 26.5 - 28.5 MBoe/d
	    ▪ Higher forecast due primarily to increased well productivity
	▪ Development capital expenditure budget increased to $285 - $315 million
	    ▪ Impact to production largely beginning in 2017
	▪ RSP has flexibility to further accelerate or moderate activity levels depending on commodity prices

(1) *D&C includes drill, complete and equip costs of a 7,500' horizontal well.*
(2) *DUC is a drilled but uncompleted well.*

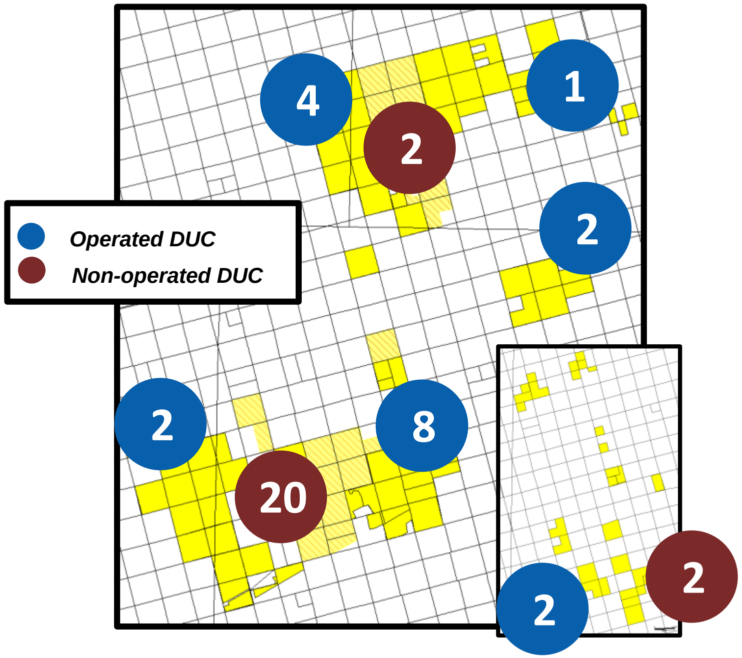
2Q16 Activity Summary

- In 2Q16 RSP completed 11 operated Hz wells (10 LS, 1 WA) and 1 Vt well
- Ended 2Q16 with 19 operated Hz DUCs (24 non-operated DUCs) distributed across core acreage position
- Production averaged 26,407 Boe/d during 2Q16, up from 24,615 Boe/d during 1Q16

Progression of 1H16 Net Production (Weekly Basis)



2Q16 DUC Locator



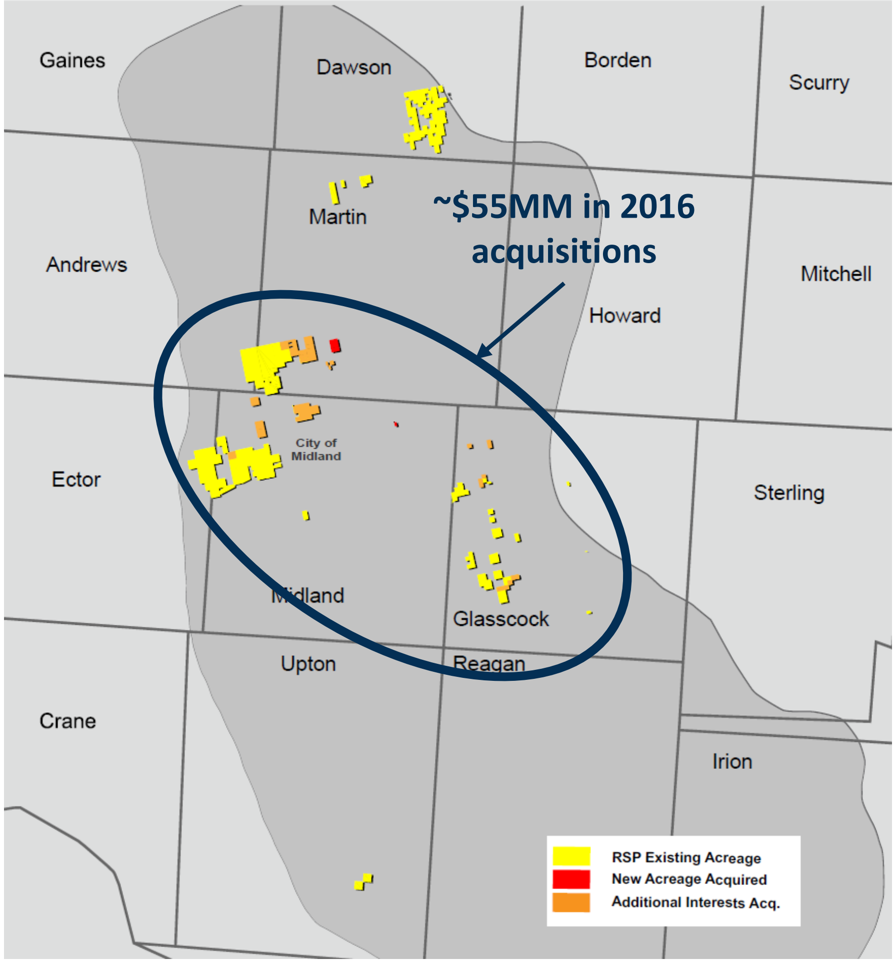
2Q16 Drilling & Completion Activity Summary

	1Q16 DUCs	Drilled	Completed	2Q16 DUCs
Operated				
Horizontal	**20**	**10**	**11**	**19**
Vertical	**1**	**-**	**1**	**-**
Total	**21**	**10**	**12**	**19**
Non-Operated				
Horizontal	20	10	6	24
Vertical	-	-	-	-

Executing Accretive Acquisitions in Core Areas

- **YTD 2016 (through July), RSP has acquired ~$55 million of oil and gas properties:**
  - **~2,180 net acres located in core Midland, Martin, and Glasscock Counties**
  - **~500+ Boe/d of current net production**
  - **46 net horizontal locations**
- **$14 million of acquisitions in 2Q16**
- **Acquisitions funded with cash on the balance sheet**

Locator Map of 2016 YTD Acquisitions



Significant Upside to Focus Area Inventory from Further Downspacing

- RSP believes spacing tests may show significant upside to current spacing assumptions
- Higher density spacing cases based on RSP evaluation of original oil in place and estimated recovery factors
- Spacing tests to further validate higher density cases are in process

Spacing Assumptions (Wells per 1-Mile Section)

	Current Spacing	Increased Density	High Density
Middle Spraberry	10	12 - 16	14 - 18
Lower Spraberry	10	12 - 16	14 - 20
Wolfcamp A	5	5 - 8	8 - 10
Wolfcamp B	5 - 10	6 - 10	8 - 12
Wolfcamp D	5	6	7
Jo Mill	5	6	7
Clearfork	5	6	7
Wolfcamp C	5	6	7

Current Spacing

Target Recovery Factor: <8%

Gross Locations	2,602
Net Locations	1,704

+ 31%

Increased Density

Target Recovery Factor: 8-10%

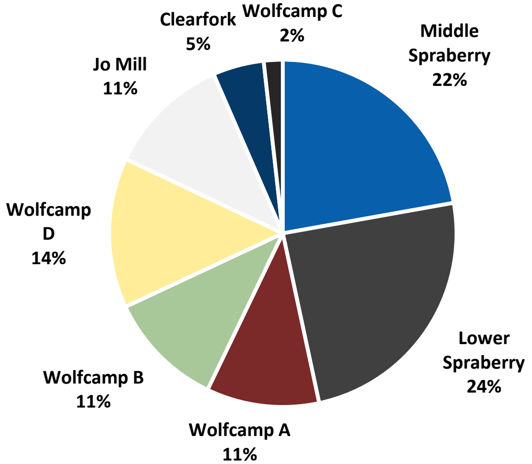
Gross Locations	3,418
Net Locations	2,242

+ 28%

High Density

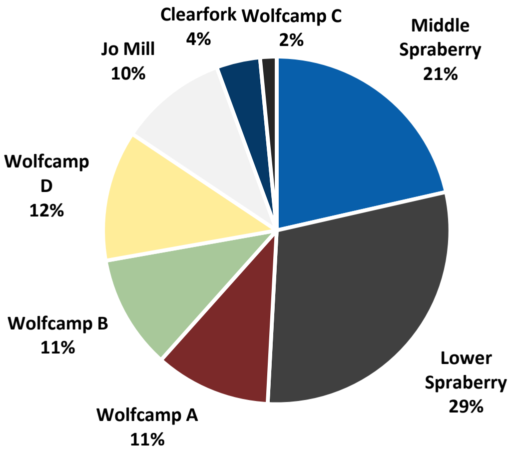
Target Recovery Factor: 10-12%

Gross Locations	4,371
Net Locations	2,858



Identified 68% upside to current spacing assumptions

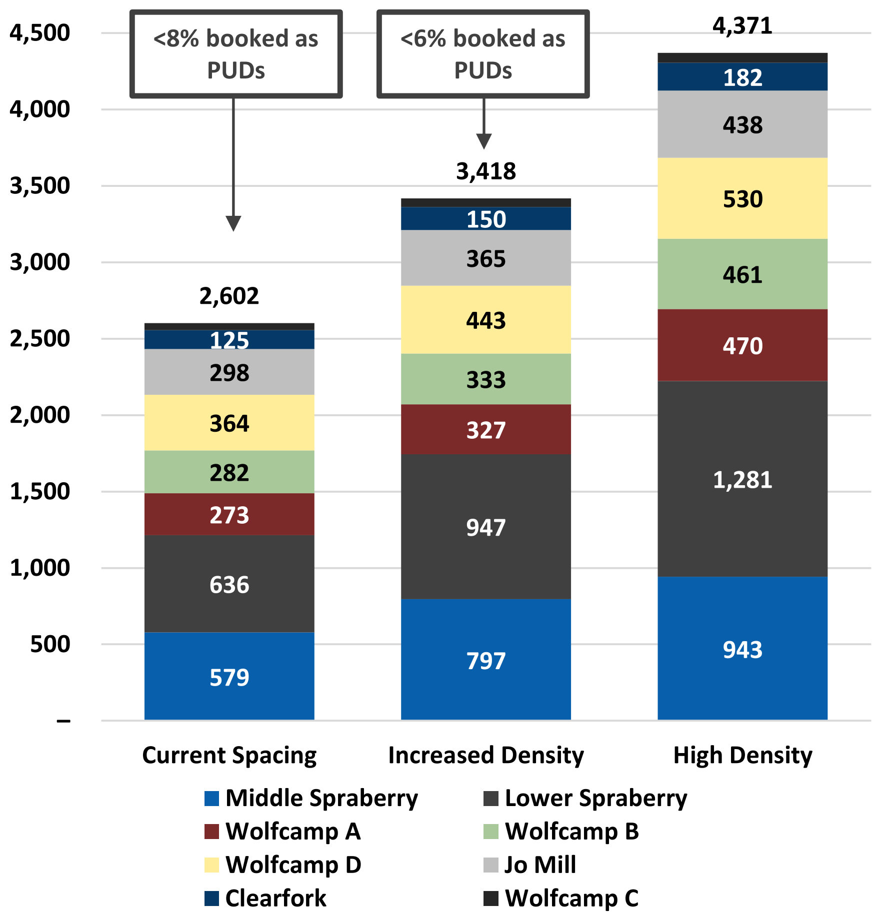
Additional locations add to inventory in RSP's best zones



Note: As of June 2016.

Extensive Multi-Year Drilling Inventory with Strong Rates of Return

Gross Focus Area Horizontal Inventory

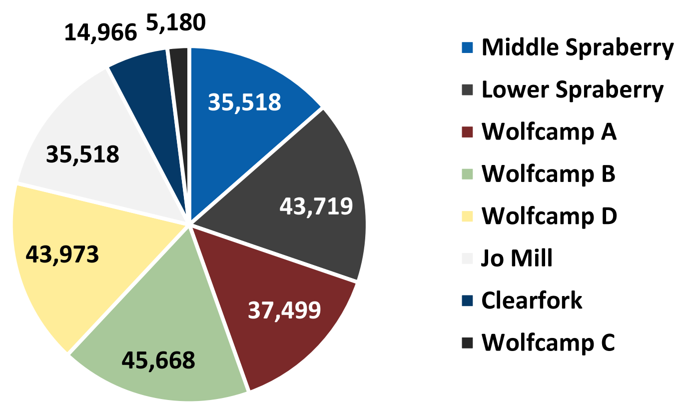


- *Excludes locations in Dawson County, additional zones (Strawn, Atoka, etc.) and more than 1,500 vertical locations on 40- and 20-acre spacing*

Net Focus Area Horizontal Inventory

	Net Locations		
	Current	Increased	High Density
Middle Spraberry	365	504	602
Lower Spraberry	420	619	834
Wolfcamp A	168	207	291
Wolfcamp B	203	238	319
Wolfcamp D	236	289	349
Jo Mill	189	233	280
Clearfork	82	98	121
Wolfcamp C	43	53	62
Total	1,704	2,242	2,858

~262,000 Net Effective Horizontal Acres [(1)]



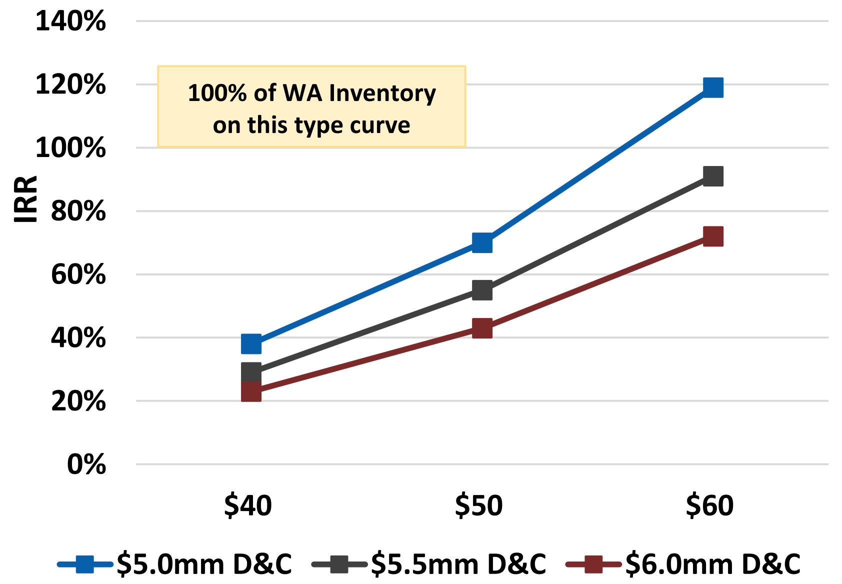
Note: As of June 2016.

(1) Combined horizontal acreage position that management believes is prospective for hydrocarbon production across each target horizontal zone.

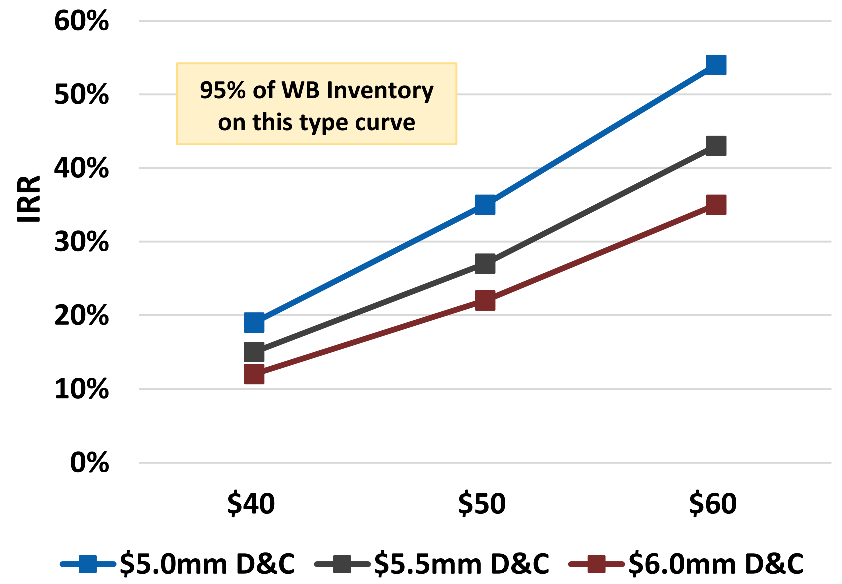
Wolfcamp A & B Overview

- **Performance of Wolfcamp A wells to date is as strong as any zone in RSP's inventory**
  - **RSP now has 17 core Wolfcamp A wells with production history**
- **RSP's plan is to simultaneously develop the Wolfcamp A and Wolfcamp B to maximize recovery from the zones**

Single Well Economics – Wolfcamp A [(1)]



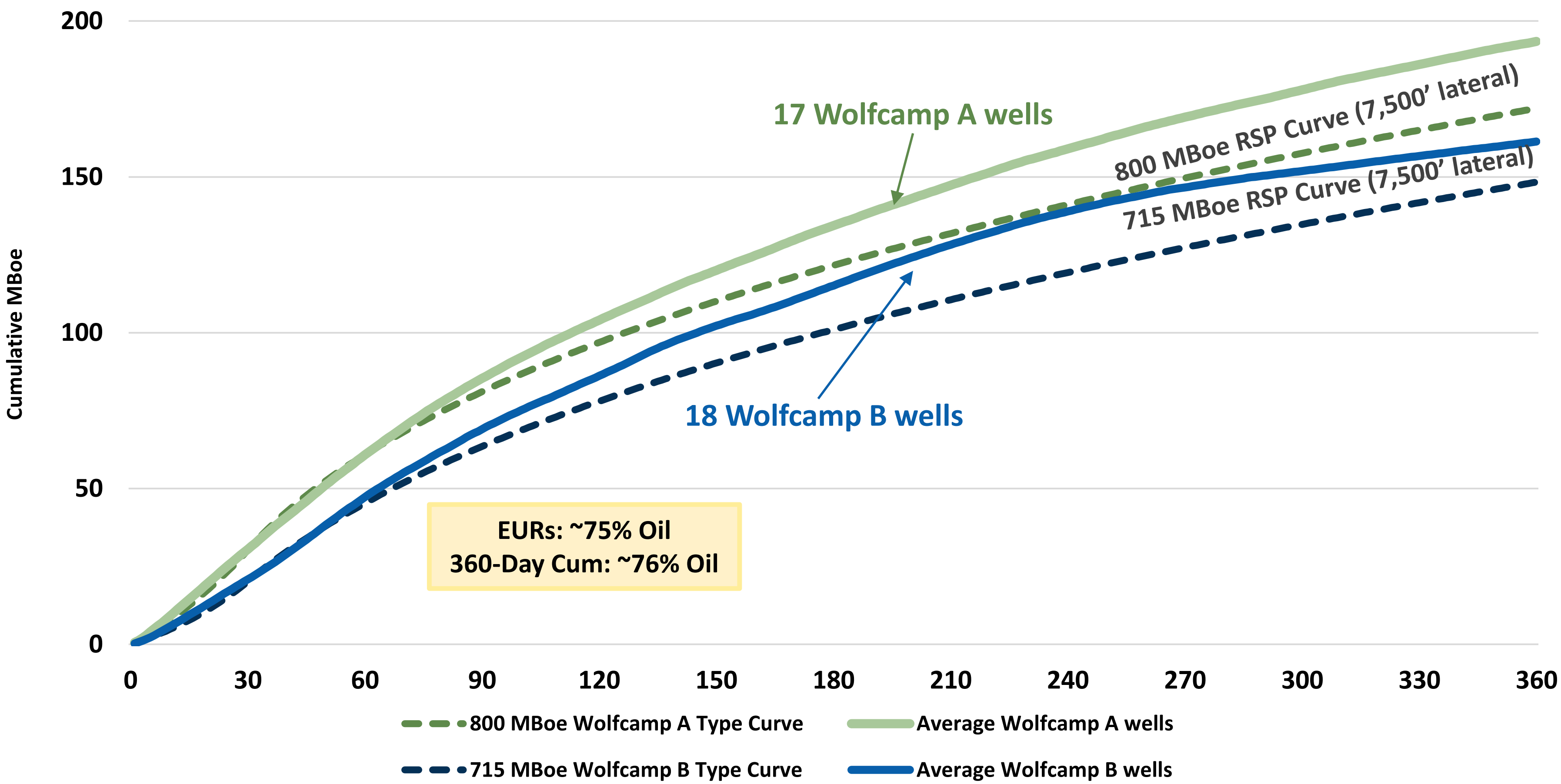
Single Well Economics – Wolfcamp B [(1)]



(1) Assumes 7,500' lateral type curve in Core Counties. Core Counties defined as Midland, Martin, Andrews and Glasscock.

Wolfcamp A and Wolfcamp B Type Curves

Wolfcamp A/B Type Curves and Operated Wells in Core Counties since Mid-2014 (Normalized to 7,500')

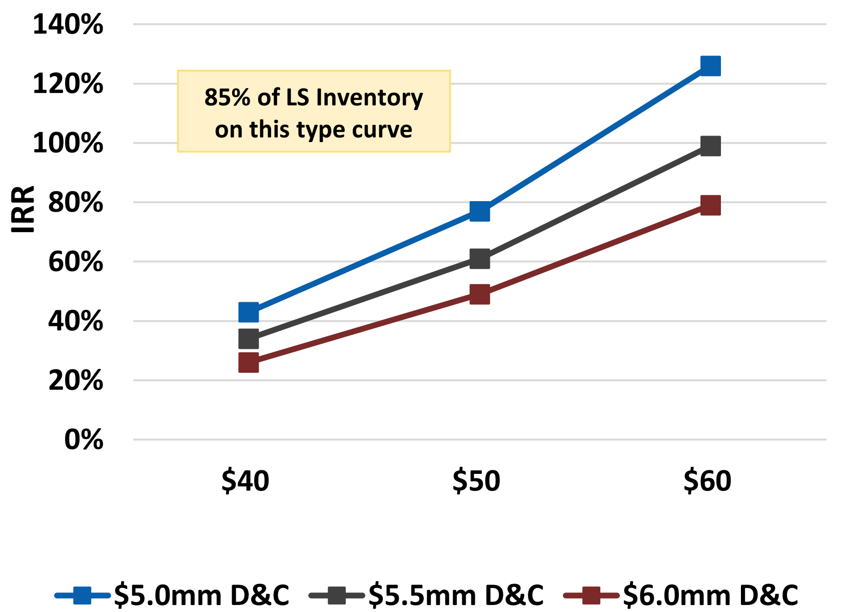


Note: Core Counties are defined as Midland, Martin , Andrews, and Glasscock. Production data normalized for operational downtime. As of August 2016.

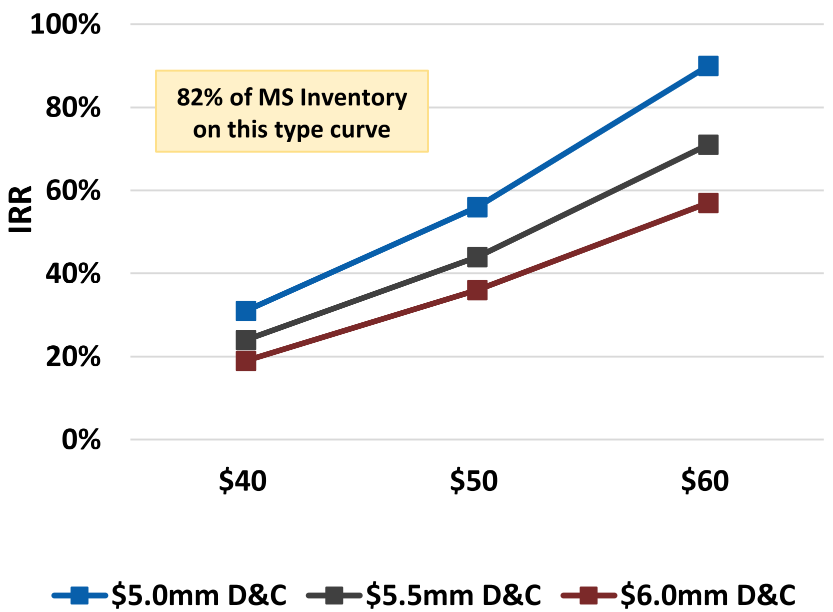
Lower & Middle Spraberry Overview

- Lower Spraberry remains the top performing zone in RSP's inventory, but Middle Spraberry economics also reflect robust potential
- The majority of RSP's activity continues to target the Lower Spraberry
- Multiple sections have Lower Spraberry wells drilled to 500' or closer spacing
  - Evaluations are ongoing but early results are promising

Single Well Economics – Lower Spraberry (1)



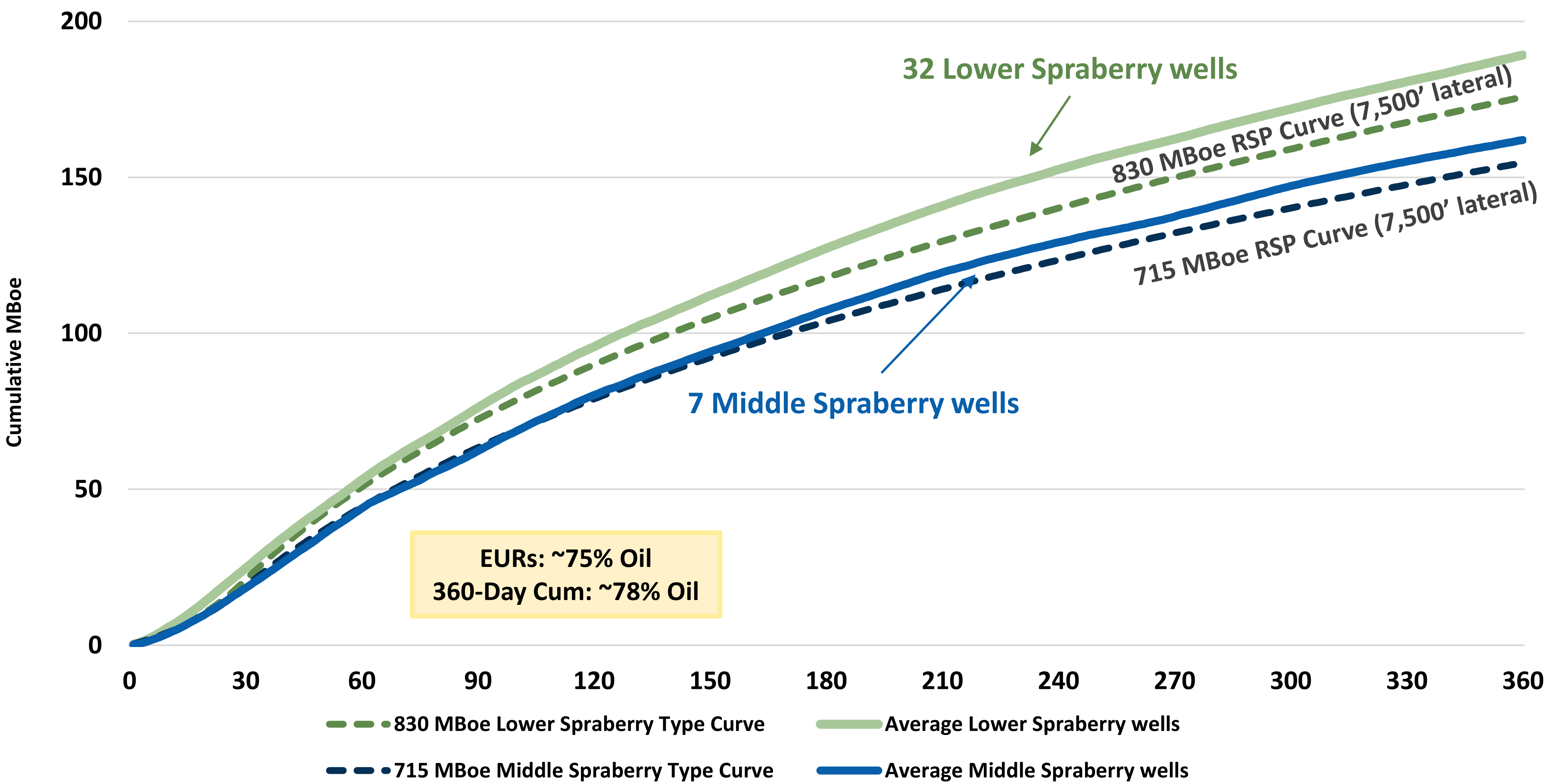
Single Well Economics – Middle Spraberry (1)



(1) *Assumes 7,500' lateral type curve in Core Counties. Core Counties defined as Midland, Martin, Andrews and Glasscock.*

Lower Spraberry and Middle Spraberry Type Curves

Spraberry Type Curve and Operated Wells in Core Counties since Mid-2014 (Normalized to 7,500')



Note: Core Counties are defined as Midland, Martin , Andrews, and Glasscock. Production data normalized for operational downtime. As of August 2016.

2Q16 Financial Results

	2Q16	2Q15	Change	1Q16	Change
Avg Daily Production (Boe/d)	**26,407**	**19,879**	***33%***	**24,615**	***7%***
% Oil	*73%*	*76%*	*(4%)*	*76%*	*(4%)*
Average NYMEX Oil Price	$45.59	$57.94	*(21%)*	$33.45	*36%*
Avg Realized Prices (Incl. Hedges)					
Oil (per Bbl)	$43.05	$67.22	*(36%)*	$31.50	*37%*
Natural Gas (per Mcf)	1.47	1.97	*(25%)*	1.64	*(10%)*
NGLs (per Bbl)	11.69	9.69	*21%*	5.88	*99%*
Total (per Boe)	**$34.32**	**$53.68**	***(36%)***	**$25.79**	***33%***
Total Revenues + Realized Hedges ($MM)	**$82.5**	**$97.1**	***(15%)***	**$57.8**	***43%***
Adjusted EBITDAX ($MM)	**58.5**	**72.6**	***(19%)***	**35.6**	***64%***
Adjusted Net Income ($MM)	**(3.8)**	**13.0**	***(129%)***	**(16.2)**	***77%***
Cash Expenses (per Boe)					
LOE	$5.37	$7.63	*(30%)*	$5.54	*(3%)*
Gathering & Transportation	0.49	0.49	–	0.31	*58%*
Production & Ad Valorem	2.06	2.99	*(31%)*	1.85	*11%*
Cash G&A	2.06	2.47	*(17%)*	2.19	*(6%)*
Total Cash Expenses	**$9.99**	**$13.58**	***(26%)***	**$9.89**	***1%***
Non-Cash Expenses (per Boe)					
Recurring Stock Comp	1.46	1.14	*28%*	1.38	*6%*
Non-Recurring Stock Comp	0.28	0.19	*47%*	–	–
DD&A	19.68	21.90	*(10%)*	19.89	*(1%)*
Capital Expenditures					
Drilling & Completion	$56.5	$134.9	*(58%)*	$65.5	*(14%)*
Infrastructure & Other	1.1	12.1	*(91%)*	2.3	*(52%)*
Total Capital Expenditures	**$57.6**	**$147.0**	***(61%)***	**$67.8**	***(15%)***

Note: Please see reconciliation of Adjusted EBITDAX and Adjusted Net Income on slide 31.

Adjusted EBITDAX and Adjusted Net Income Reconciliation

Reconciliation of Adjusted EBITDAX to Net Income

(in thousands)

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Three Months Ended March 31, 2016
Net income (loss)	$ (9,801)	$ (5,453)	$ (17,416)
Interest expense	12,954	9,367	12,941
Income tax expense (benefit)	(4,438)	(6,001)	(9,298)
Depreciation, depletion, and amortization	47,296	39,620	44,558
Asset retirement obligation accretion	123	84	113
Exploration	405	889	64
Impairments	3,177	—	173
Loss (gain) on derivative instruments	3,684	12,962	(396)
Net cash payments on settled derivative instruments	974	18,646	1,950
Stock-based compensation, net	4,183	2,401	3,094
Other income, net	(104)	37	(173)
Adjusted EBITDAX	**$ 58,453**	**$ 72,552**	**$ 35,610**

Reconciliation of Adjusted Net Income to Net Income

(in thousands)

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Three Months Ended March 31, 2016
Net income (loss)	$ (9,801)	$ (5,453)	$ (17,416)
Impairments	3,177	—	173
Loss (gain) on derivative instruments	3,684	12,962	(396)
Net cash payments on settled derivative instruments	974	18,646	1,950
Stock-based compensation - non-recurring	682	—	—
Other income, net	(104)	37	(173)
Income tax expense (benefit) for above items	(2,370)	(13,146)	(369)
Adjusted Net Income (Loss)	**$ (3,758)**	**$ 13,046**	**$ (16,231)**

Additional Disclosures

Supplemental Non-GAAP Financial Measures

We define Adjusted EBITDAX as oil and gas revenues including net cash receipts (payments) on settled derivative instruments and premiums paid on put options that settled during the period, less lease operating expenses, production and ad valorem taxes, and general and administrative expenses excluding stock based compensation. Adjusted net income deducts from Adjusted EBITDAX depreciation, depletion, and amortization, accretion on asset retirement obligations, exploration expenses, interest expense, stock-based compensation and adjusted income tax expense.

Management believes Adjusted EBITDAX and adjusted net income are useful because they allow us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above in arriving at Adjusted EBITDAX and adjusted net income because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX and adjusted net income should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX and adjusted net income are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX and adjusted net income may not be comparable to other similarly titled measures of other companies.

Certain Reserve Information

Cautionary Note to U.S. Investors: The SEC prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than “reserves,” as that term is defined by the SEC. This presentation discloses estimates of quantities of oil and gas using certain terms, such as “resource potential,” “net recoverable resource potential,” “resource base,” “estimated ultimate recovery,” “EUR” or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC’s definitions of proved, probable and possible reserves, and which the SEC’s guidelines strictly prohibit the Company from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by the Company. U.S. investors are urged to consider closely the disclosures in the Company’s periodic filings with the SEC. Such filings are available from the Company at 3141 Hood Street, Suite 500, Dallas, Texas 75219, Attention: Investor Relations, and the Company’s website at www.rsppermian.com. These filings also can be obtained from the SEC by calling 1-800-SEC-0330.