

PetroQuest Energy, Inc.

February 22, 2018

ENERCOM DALLAS 2018
The Oil & Gas Conference

Forward-Looking Statements

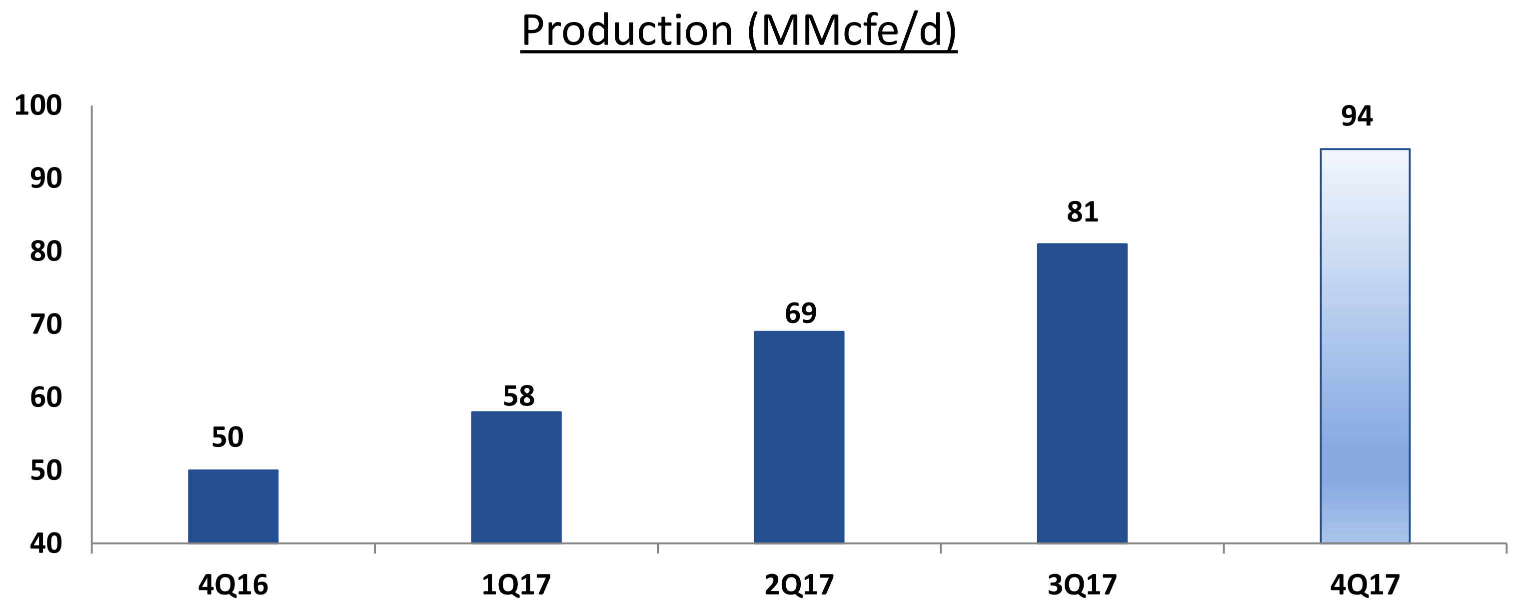
This presentation contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this presentation are forward-looking statements. Although PetroQuest believes that the expectations reflected in these forward-looking statements are reasonable, these statements are based upon assumptions and anticipated results that are subject to numerous uncertainties and risks. Actual results may vary significantly from those anticipated due to many factors, our ability to successfully close the previously disclosed commitment for a four-year multi-draw term loan facility or receive any proceeds from draws thereunder; the sufficiency of our current liquidity; the volatility of oil and natural gas prices and significantly depressed oil prices since the end of 2014; our indebtedness and the significant amount of cash required to service our indebtedness; our ability to improve our liquidity position and refinance or restructure our indebtedness, including our 2017 Notes and 2021 2L Notes; the potential need to sell assets or seek bankruptcy protection; our estimate of the sufficiency of our existing capital sources, including availability under our bank credit facility and the result of any borrowing base redetermination; our ability to post additional collateral to satisfy our offshore decommissioning obligations; our ability to hedge future production to reduce our exposure to price volatility in the current commodity pricing market; ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices; our ability to raise additional capital to fund cash requirements for future operations; limits on our growth and our ability to finance our operations, fund our capital needs; our ability to find, develop and produce oil and natural gas reserves that are economically recoverable and to replace reserves and sustain production; approximately 50% of our production being exposed to the additional risk of severe weather, including hurricanes, tropical storms and flooding, and natural disasters; losses and liabilities from uninsured or underinsured drilling and operating activities; changes in laws and governmental regulations as they relate to our operations; the operating hazards attendant to the oil and gas business; the volatility of our stock price; and our ability to meet the continued listing standards of the New York Stock Exchange with respect to our common stock or to cure any deficiency with respect thereto. In particular, careful consideration should be given to cautionary statements made in the various reports the Company has filed with the SEC. The Company undertakes no duty to update or revise these forward-looking statements. In particular, careful consideration should be given to cautionary statements made in the various reports PetroQuest has filed with the Securities and Exchange Commission. PetroQuest undertakes no duty to update or revise these forward-looking statements.

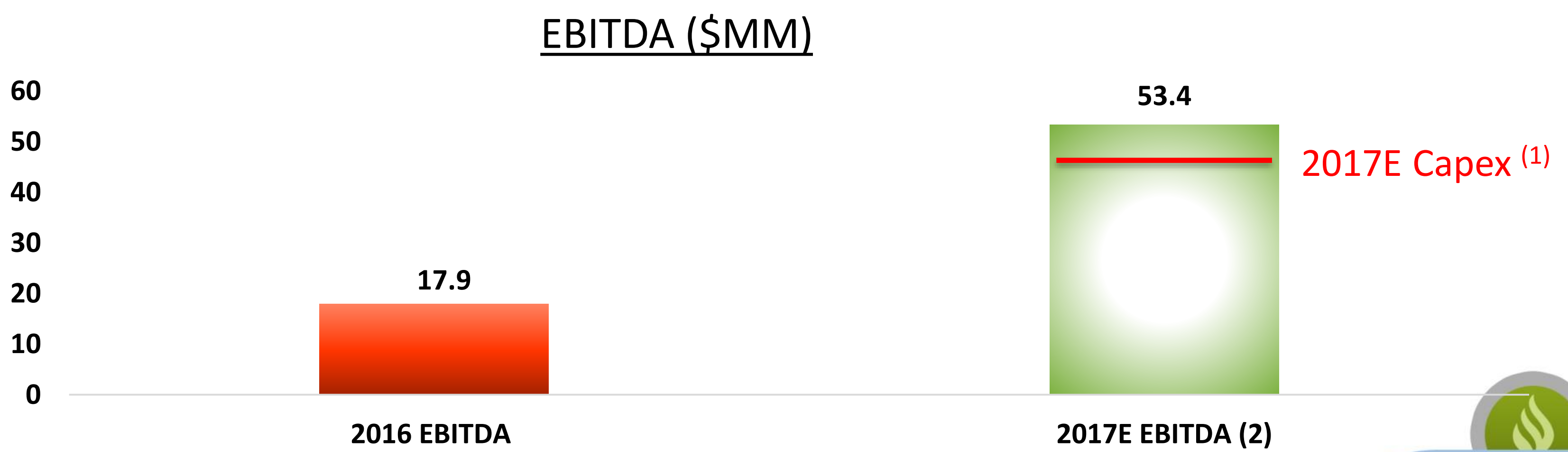
Prior to 2010, the Securities and Exchange Commission generally permitted oil and gas companies, in their filings, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Beginning with year-end reserves for 2009, the SEC permits the optional disclosure of probable and possible reserves. We have elected not to disclose our probable and possible reserves in our filings with the SEC. We use the terms “reserve inventory,” “gross unrisked reserves,” “EUR,” “inventory”, “unrisked resource potential”, 3P reserves 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 us from including in filings with the SEC. Estimates of reserve inventory, gross unrisked reserves EUR, inventory, unrisked 3P reserves do 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 estimating unrisked inventory, gross unrisked reserves, EUR, or unrisked resource potential or 3P reserves 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.

Recap of 2017

- 2017 execution of goals led to substantial growth from 2016:
  - Production up 17% (4Q17 vs 4Q16 up 87%)
  - Reserves up 34% (F&D estimated ~$0.75/Mcfe)
  - PV10 up 90%
  - 2017 EBITDA expected to be up >200% from 2016
  - 4Q17 annualized leverage ratio down substantially from 13X at 4Q16
- Acquired low-cost position in the Austin Chalk providing opportunity for oil growth and acreage value appreciation (potential liquidity source)
- Sold GOM assets in early 2018 to remove Surety risk, regulatory risk and substantial P&A burden

2017 Production & EBITDA Growth Profiles

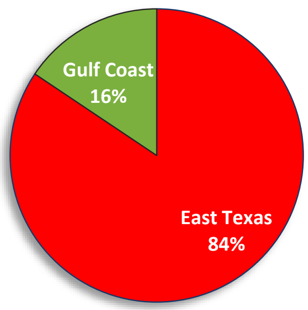




(1) Based upon mid-point of guidance
(2) Factset average analyst estimate

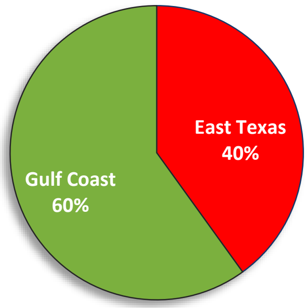
Our Properties

2017 Reserves



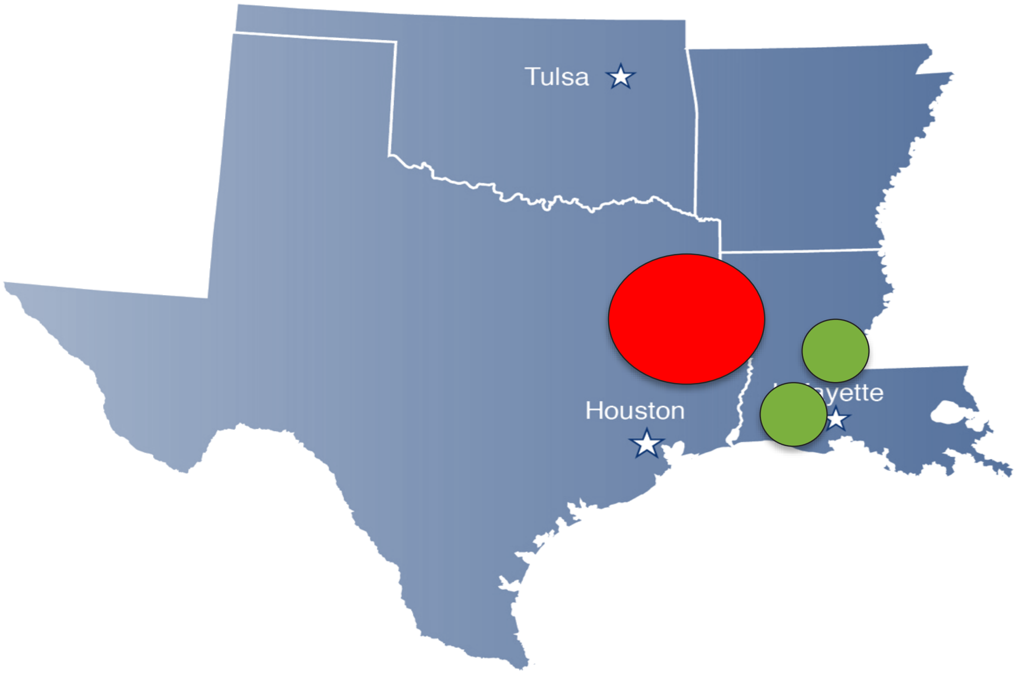
156 Bcfe

4Q17 Production



94 Mmcfe/d

75% Gas
14% NGL
11% Oil



Louisiana Austin Chalk Entry Rationale for PQ

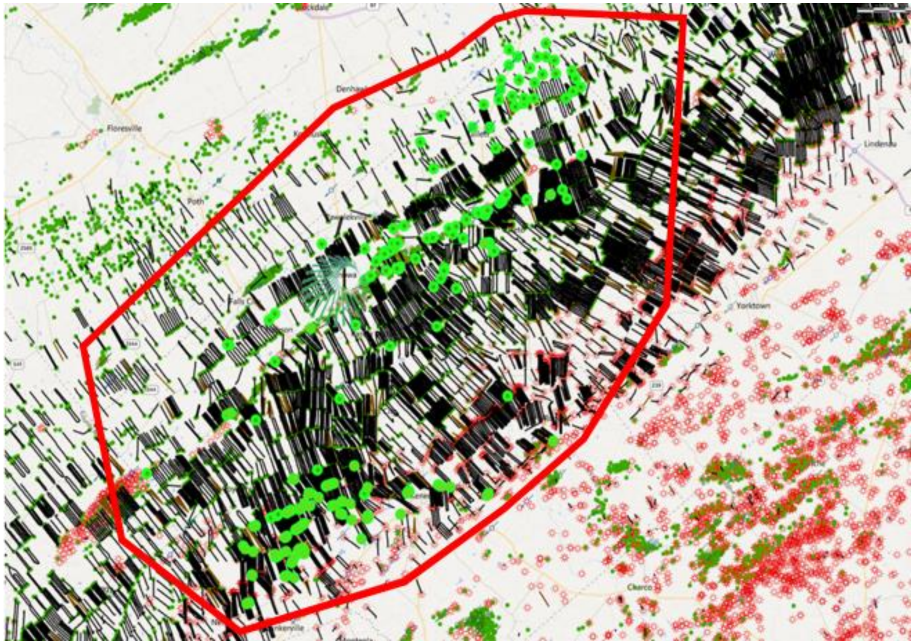
- **Familiar development story:** access existing fields that had variable production success using conventional development techniques and apply the latest horizontal/completion technologies to significantly enhance recoveries
  - Examples: Permian, Eagle Ford, Scoop/Stack, Cotton Valley, etc
  - Hundreds of control points in the area from vintage unfracked Austin Chalk/Tuscaloosa wells
- **Increase oil production/reserves in portfolio:** Louisiana Austin Chalk production mix is approximately 80% oil
- **Attractive leasehold position:** early mover action resulted in acreage position offsetting the initial EOG test well – first 79 days of production have total approximately 70,000 bbls of oil
- **Strong economics:** base case estimate of 600,000 Bbl/well is projected to generate 60% IRR at $50 oil
- **Liquidity building options:** recent offers at $2,000+ per acre. Considering sell-down structures to recoup acquisition cost and fund initial drilling program

Austin Chalk Trend Regional Overview

- Austin Chalk trend has produced over 1.3 billion barrels of oil
- Several large cap companies with Austin Chalk experience in Texas have established leasehold positions in the Louisiana Austin Chalk
  - Goal is to replicate the recent Texas Austin Chalk results in Louisiana
  - Over 300,000 acres have been leased with additional aggressive leasing activity ongoing in 5-6 Louisiana parishes
- Latest horizontal **<u>fracked</u>** Austin Chalk wells in Karnes County, Texas have EURs on average (22 wells) over 600,000 BOE – 500% uplift over unfracked wells (119,000 BOE)

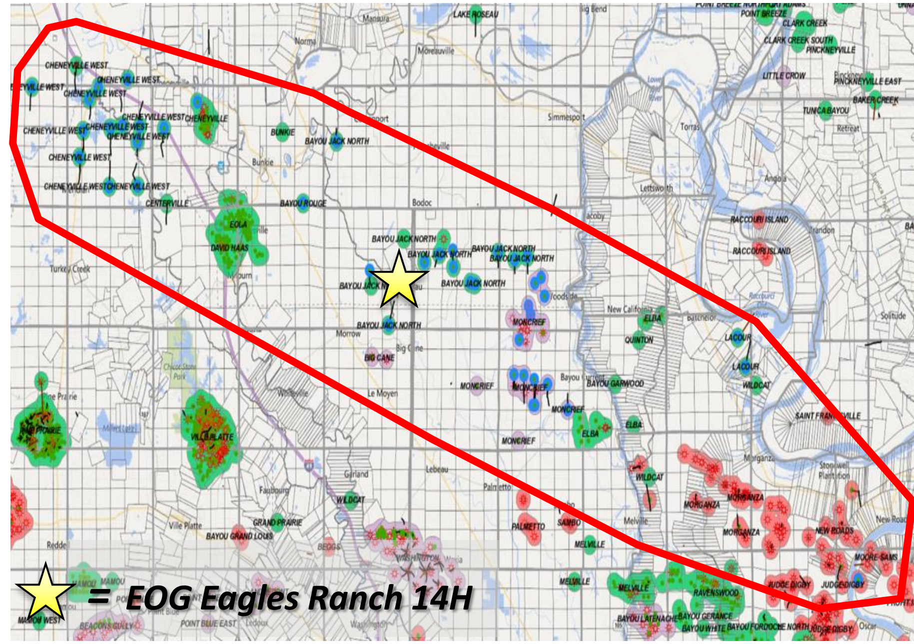
CHALK COMPARISON: TEXAS – LOUISIANA

Karnes County, TX



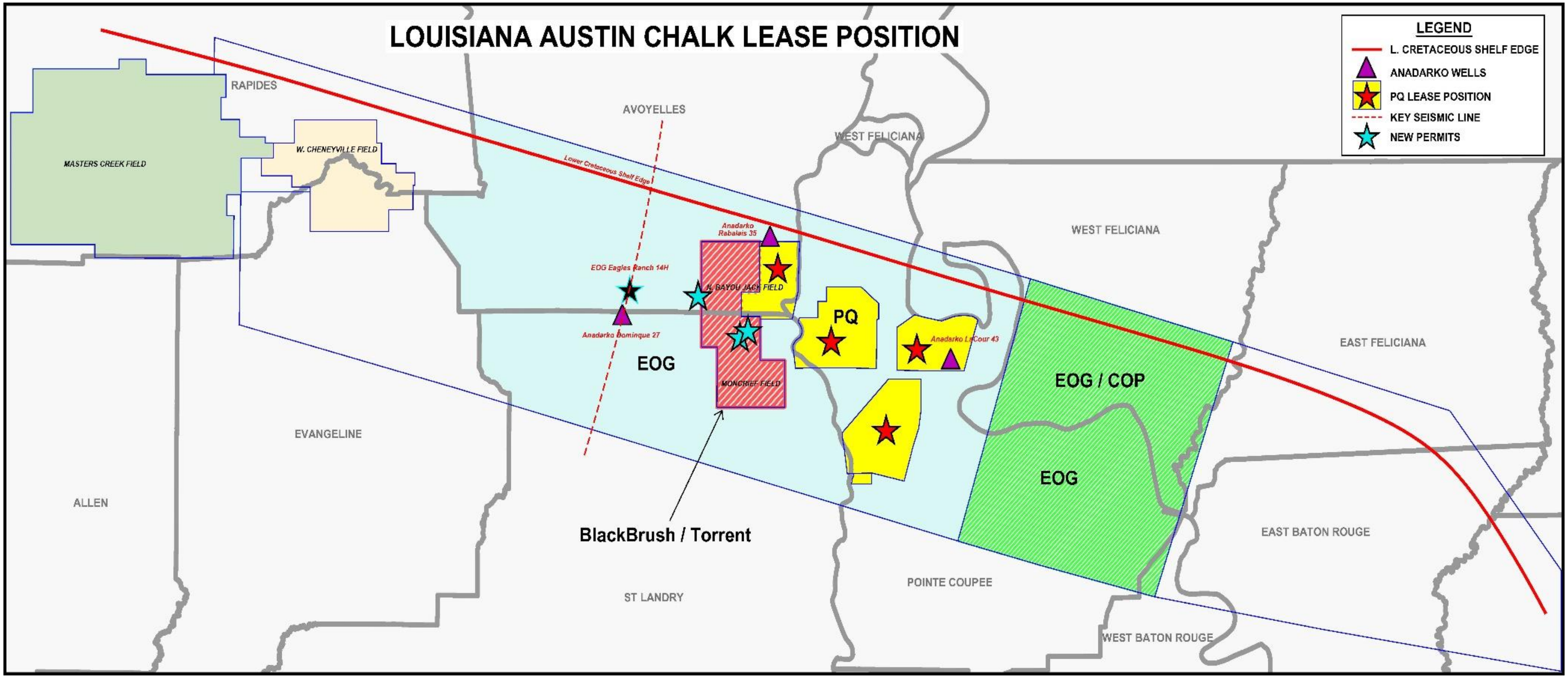
● = Austin Chalk Wells	MBOE
Avg. pre-fracked Horizontal Oil CUM (*Pre-2013*)	104
EOG: Avg. Fracked Horizontal Oil **EUR** (*2016–Current*)	632
Percent increase	508%

Avoyelles Parish, LA

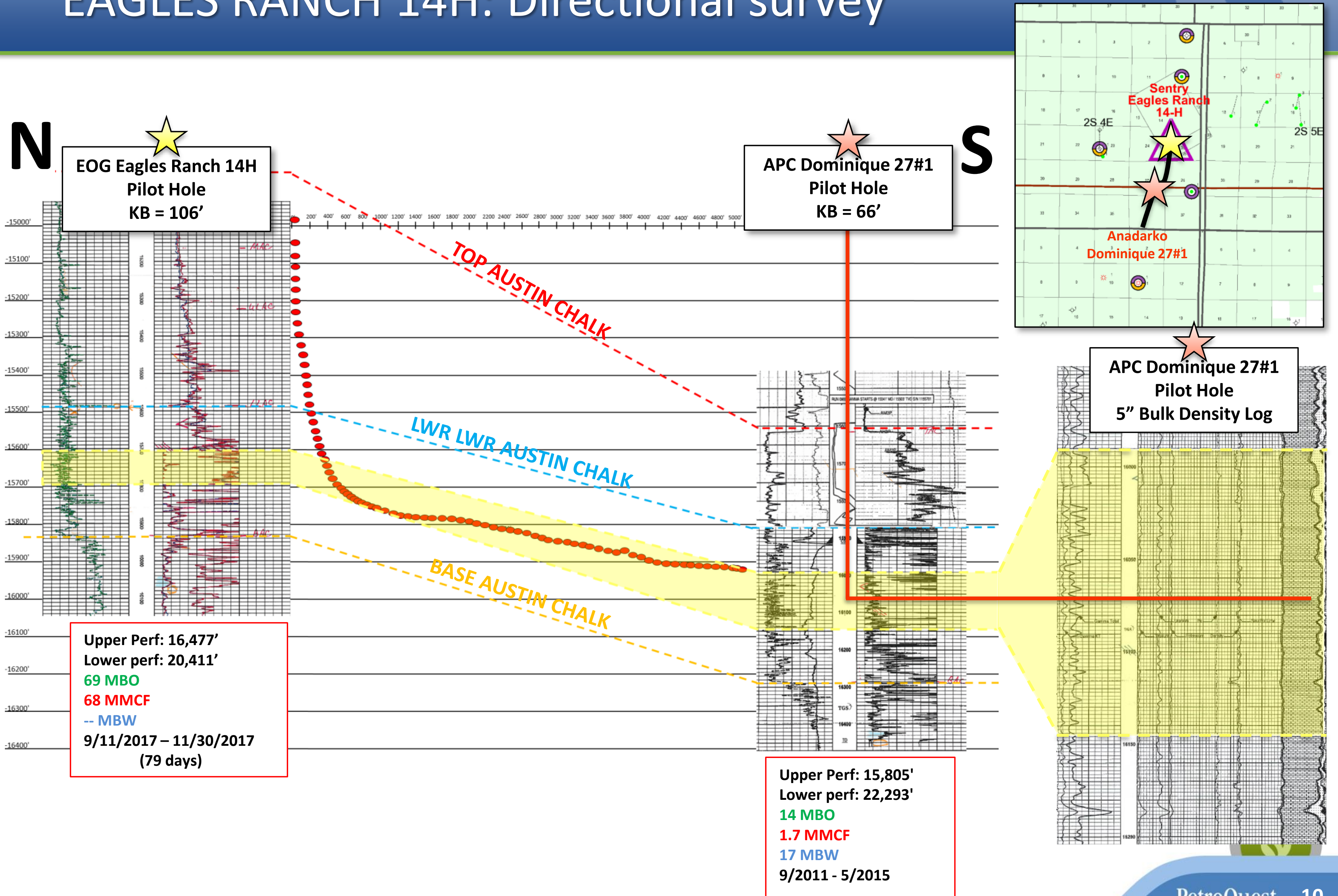


● = Austin Chalk Wells	MBOE
Avg. pre-fracked Horizontal Oil CUM	119
Estimated Fracked Horizontal Oil **EUR** (*based on % increase in 22 sample EOG wells in Karnes County*)	*732*
Estimated Percent Increase	508%

LOUISIANA ACREAGE MAP (>500,000 acres)



EAGLES RANCH 14H: Directional survey

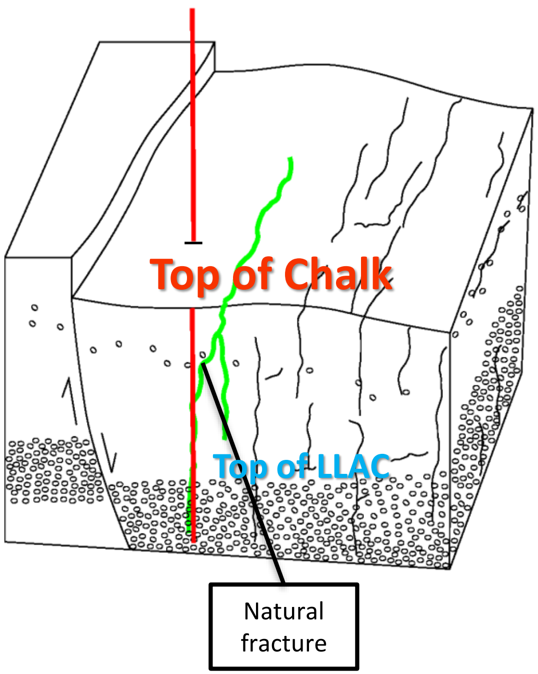


HYDRAULIC FRACTURE UPLIFT

Historical production uplift

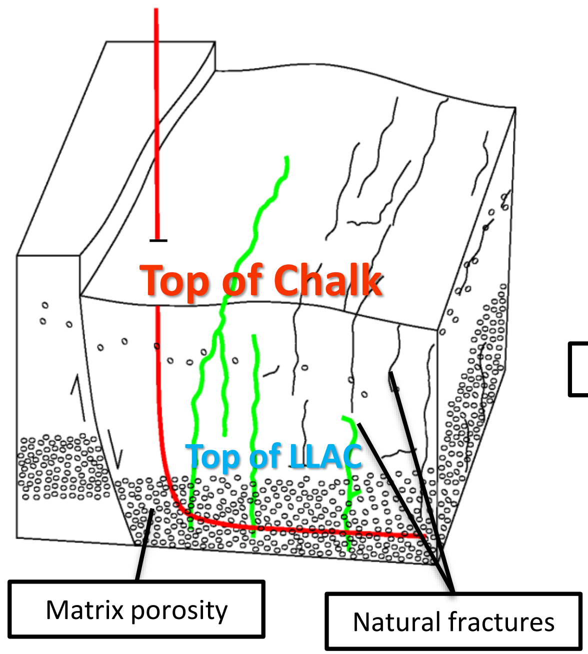
Unfracked **Verticals**

- Chalk production entirely from natural fractures



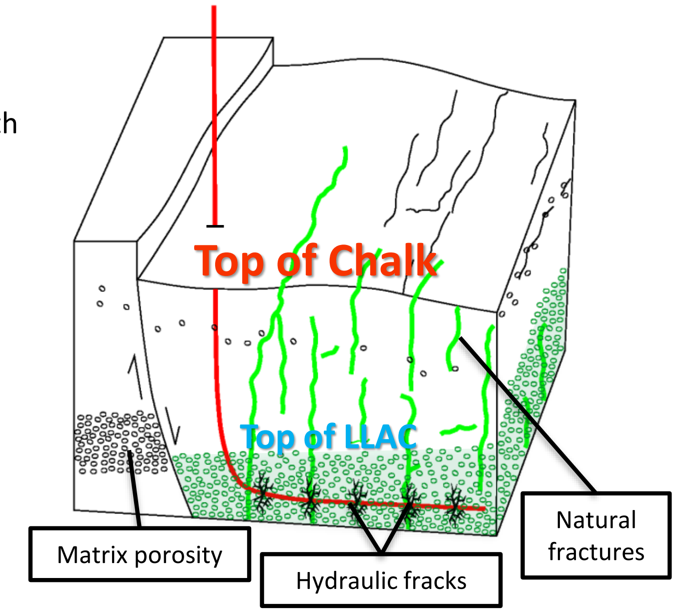
Unfracked **Horizontals**

- Chalk production primarily from natural fractures in contact with the wellbore, with some production coming from pore space



Fracked **Horizontals**

- Chalk production primarily from Matrix porosity, with permeability created by hydraulic fracturing, with natural fracture upside



Baird Energy Report - Top 11 Basins

Baird Energy Big Data Analytics report —draws from a dataset of over **60,000 wells** —ranks operators by average revenue* per lateral foot for the first **90 days of production**

Operator Name	Basin	90 Days Gross Revenue/Lateral Foot
EOG	**Austin Chalk (TX)**	**$ 1,280**
Enervest	**Austin Chalk (TX)**	**$ 1,274**
Encana	**Austin Chalk (TX)**	**$ 1,204**
Pioneer	Eagleford	$ 1,122
EOG -Eagles Ranch Well	**Austin Chalk (LA)**	**$ 852**
Cabot	Marcellus	$ 723
Marathon	Bakken	$ 694
Energen	Delaware Basin	$ 622
Chesapeake	Haynesville	$ 589
Devon	Powder River Basin	$ 560

Only 79 Days of production

*$50/ bbl of oil and $3/mcf of gas

Louisiana Austin Chalk - Economic Sensitivities Estimates

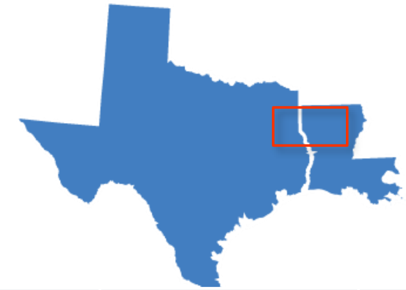
		IRR	ROI	PV(10)
High Side Case	800 MBO/Well	97%	2.98	$12.5 MM
Expected Case	600 MBO/Well	60%	2.08	$6.4 MM
Low Side Case	400 MBO/Well	16%	1.23	$0.4 MM

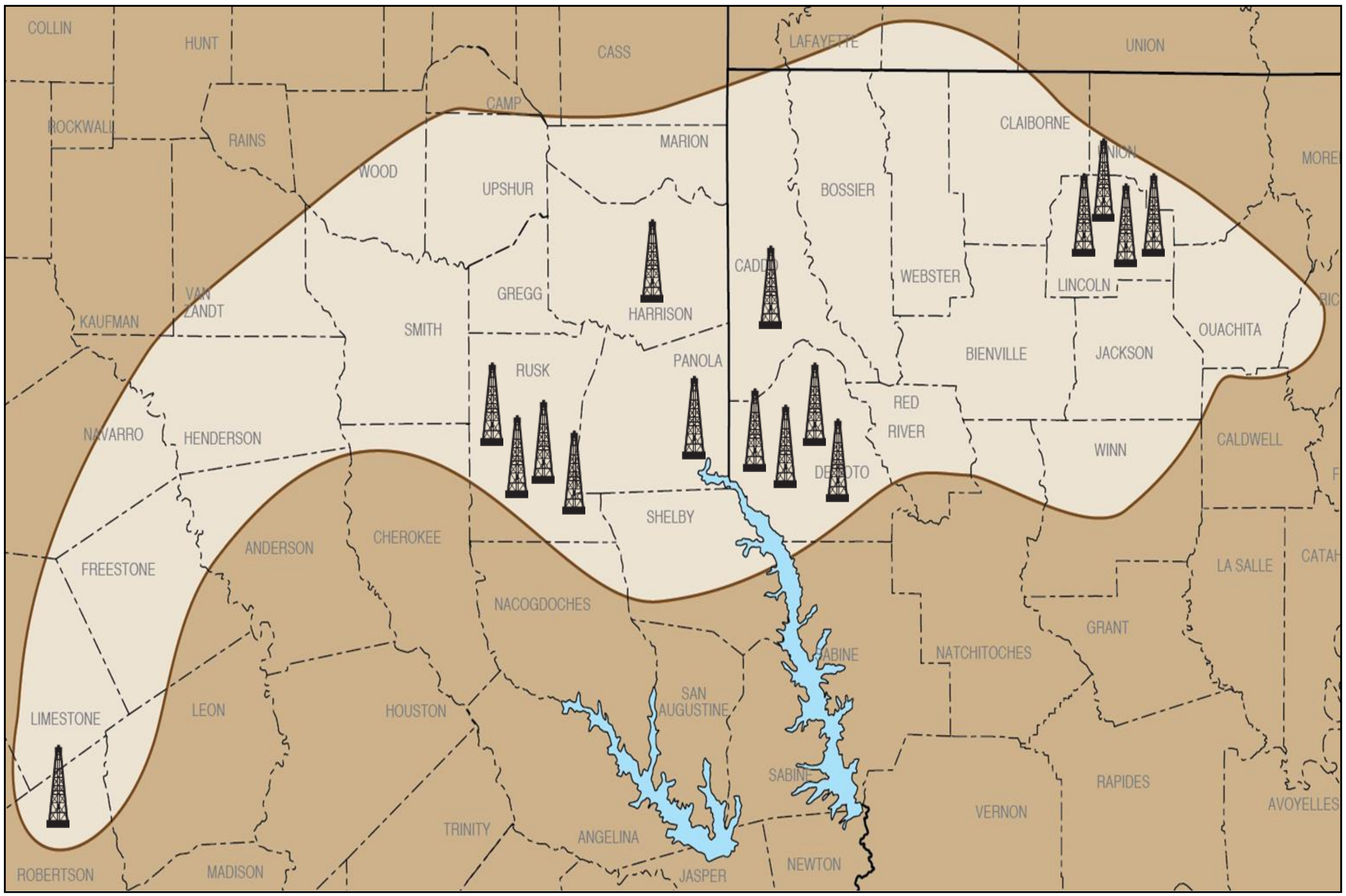
Assumptions:

Well Cost = $9.0 MM
Facility and SWD Cost of $375 M/well
Product Pricing: $50/BO, $3.00/MMBtu, $25.50/Bbl NGL

Industry Activity - Cotton Valley Trend (16 Rigs)

Relative Rock Quality Comparison		
Porosity	Haynesville (3-14%)	**PQ Cotton Valley (10%)**
Permeability	Haynesville (<0.001)	**PQ Cotton Valley (~0.1)**



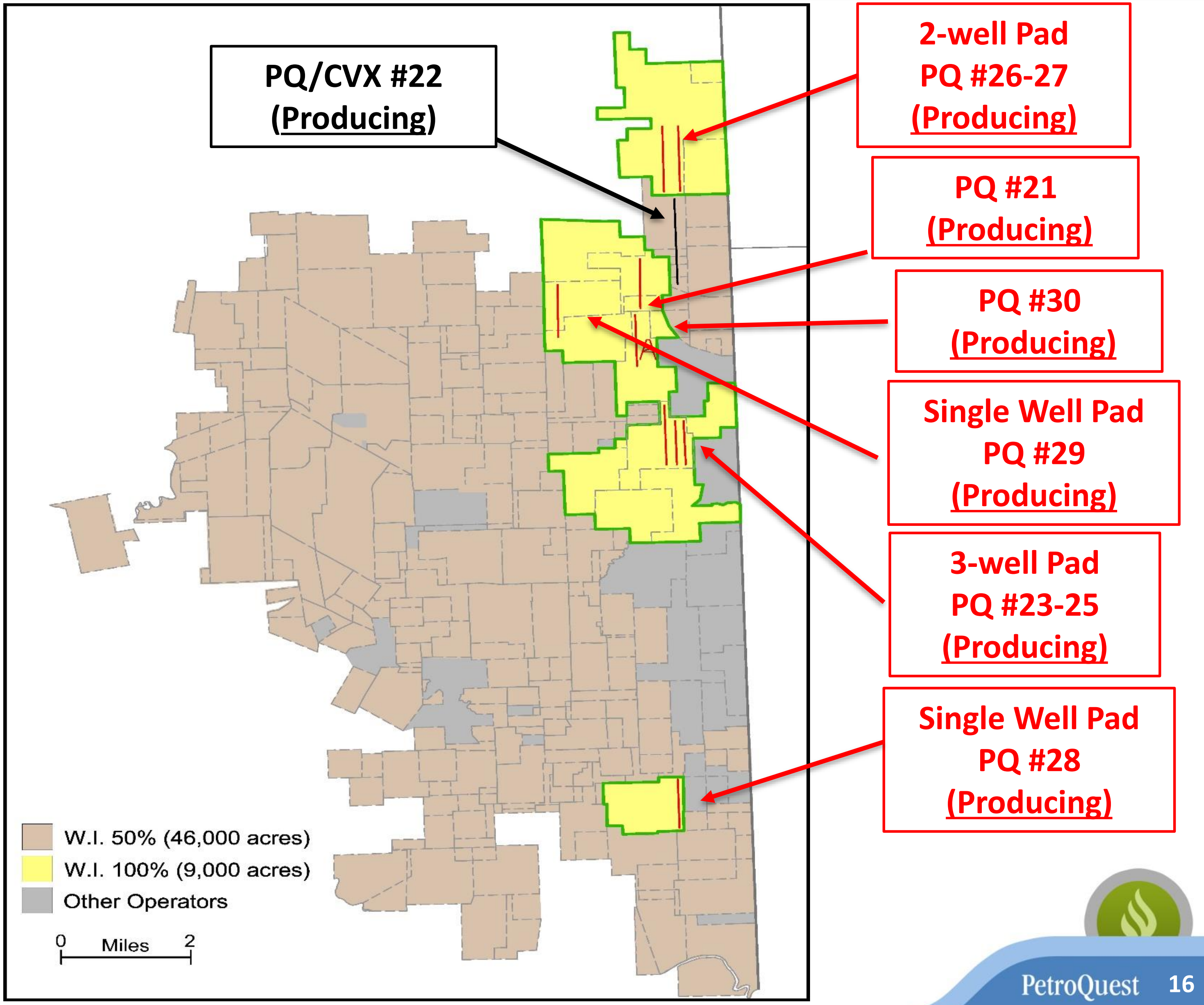


County	Company	Rig Count
Caddo	BHP Billiton Petro (TXLA)	1
De Soto	Covey Park Gas LLC	2
	Indigo Minerals LLC	2
Lincoln	Wildhorse Res Mgmt	1
	Range LA Oper	3
Harrison	RHE Operating, LLC	1
Panola	Tanos Exploration II, LLC	1
Robertson	O'Benco Inc.	1
Rusk	Sabine Oil & Gas Corp	1
	Sojitz Energy Venture, Inc.	1
	Tanos Exploration II, LLC	1
	KJ Energy LLC	1

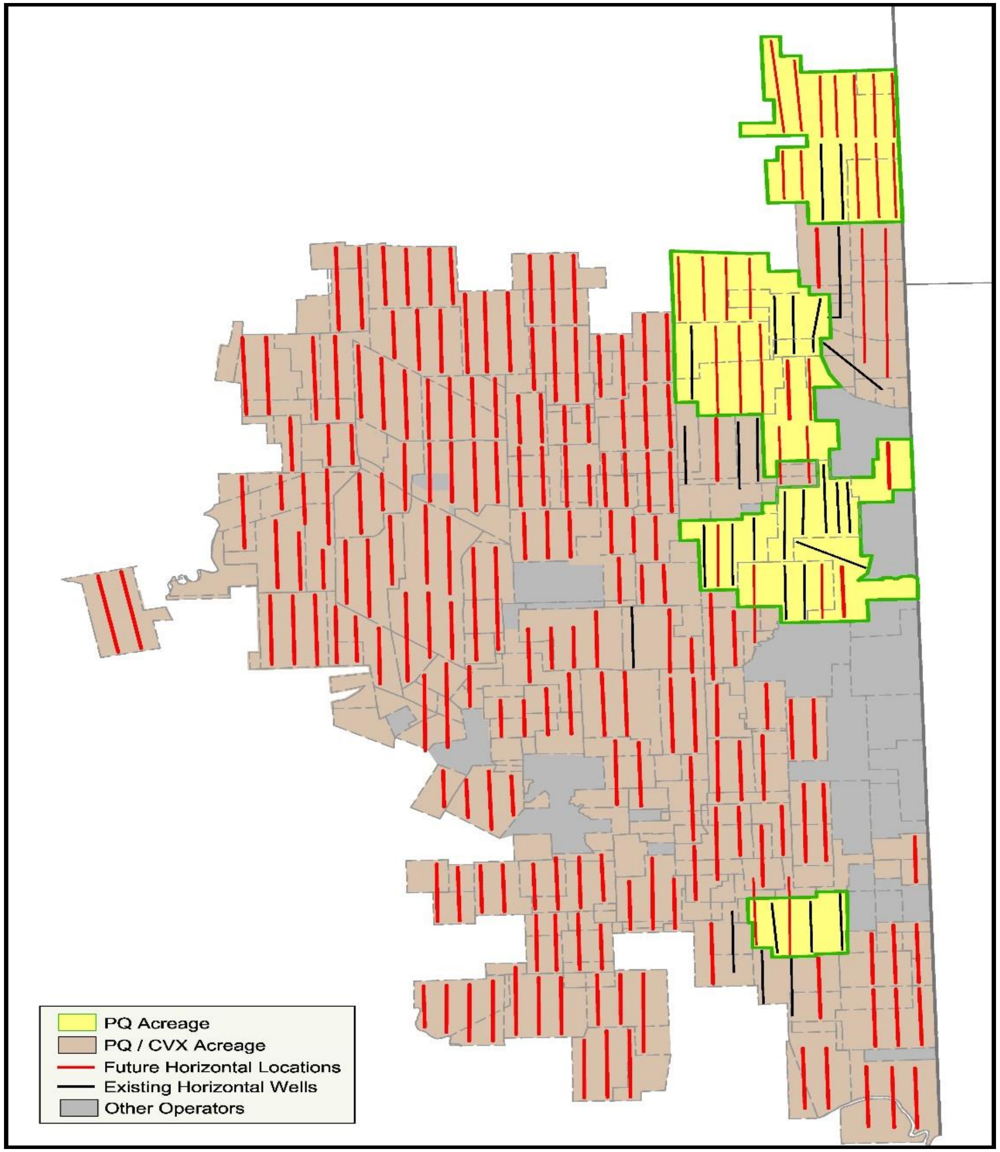
Advantages of PQ’s Cotton Valley

- **Geology:** high permeability sandstones relative to low permeability shales
- **Multiple targets:** >1,400’ thick sand column with seven benches to target
- **Low risk:** hundreds of vertical wells with decades of production history, cores and logs
- **Large resource potential:** previous vertical wells didn’t efficiently drain the producing zone – perfect application for horizontal development
- **Low cost:** normal pressure drilling environment, simple frac design and low operating costs
- **Superior location**: premium Gulf Coast pricing, supportive land owners and state/local agencies
- **Exceptional returns:** 67% IRR using a $3.00/Mcf natural gas price assumption and most recent well cost

Recent Cotton Valley Drilling Program

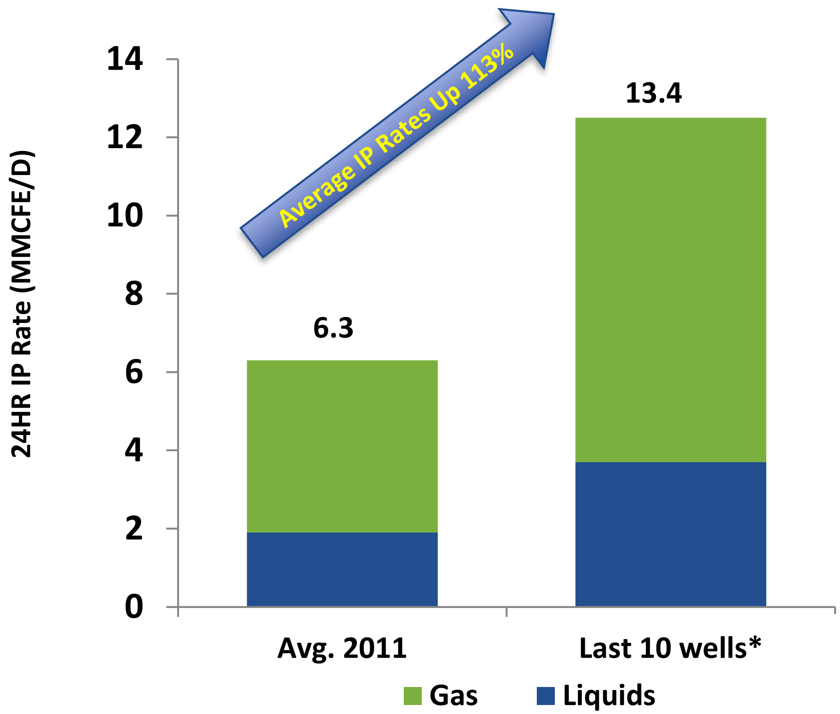


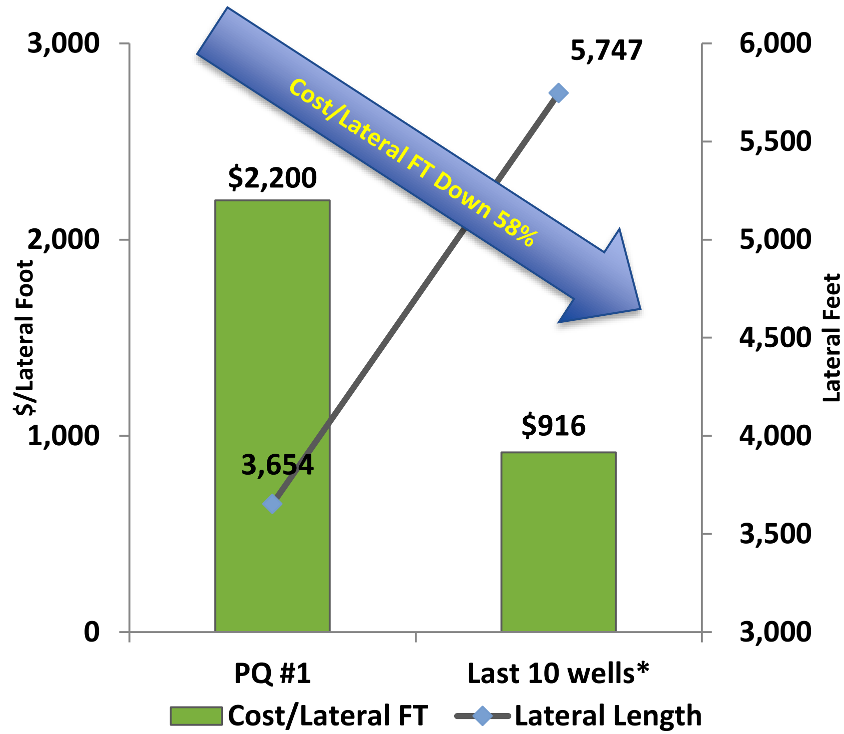
PQ Cotton Valley - 838 Future Locations



Cotton Valley Horizontal – Production Up with Costs Down

Improving Well Performance



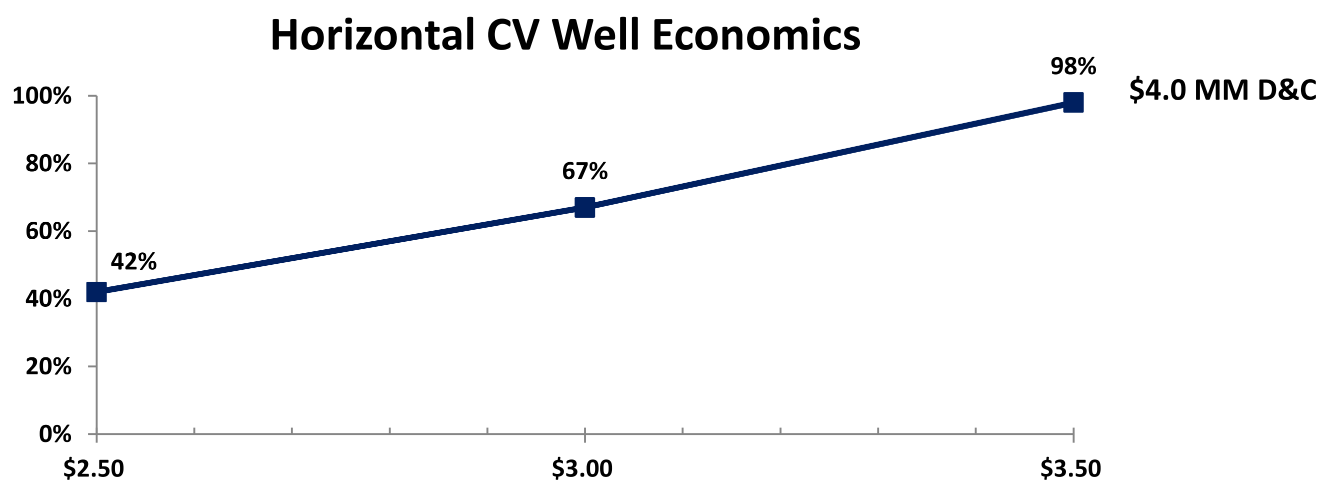


Goal to Consistently Execute Drilling @ Less than $1,000/lateral foot

* Excludes PQ #24 due to mechanical issues

Cotton Valley Horizontal Economics

Sensitivity to Gas Prices

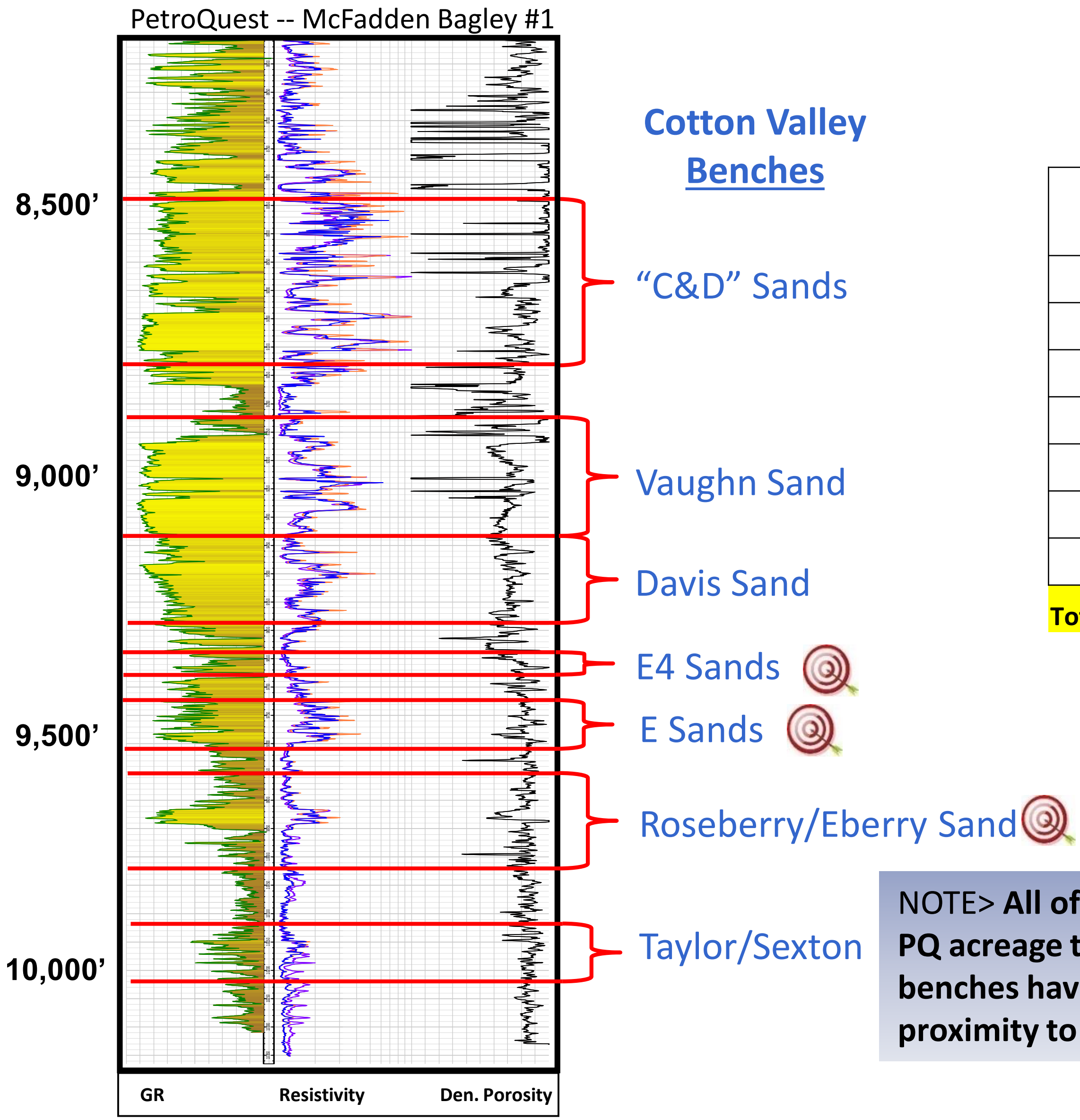


Economic Assumptions

Assumptions	
Gross Well Cost ($MM)	**4.0 (~$900/lateral foot)**
EUR (Bcfe) (1)	**8.0**
IP Rate (Mmcfe/d) (1)	**11**
% Gas / Liquids	**70% / 30%**
IRR (%)	**67%**

(1) 2015 Avg. well performance with laterals in excess of 4,500 feet - $3.00/Mcf gas, $18 NGL/Bbl and $50 oil/Bbl

Multi Bench Cotton Valley Opportunities



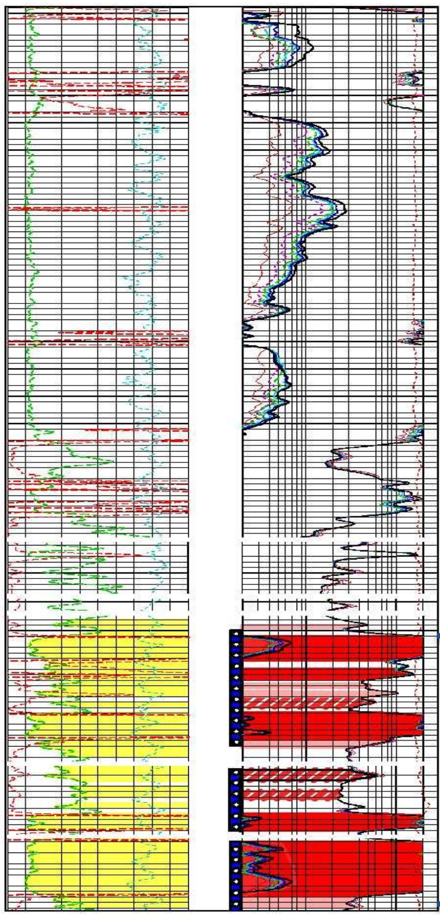
Cotton Valley Drilling Locations

Bench	Gross Drilling Locations*
C&D	124
Vaughn	124
Davis	229
E4	63
E	116
Eberry/Roseberry	154
Sexton/Taylor	28
Total Gross Drilling Locations	**838**

* Locations based on 1,200' spacing within area of estimated economic net feet of pay determined by offsetting vertical well logs

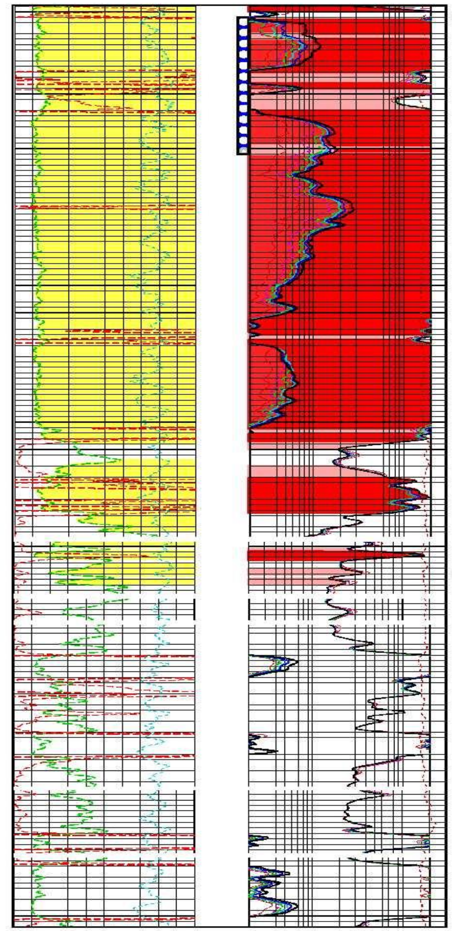
NOTE> **All of the above benches are productive on PQ acreage through >140 vertical wells and all benches have been tested horizontally in close proximity to PQ acreage**

Thunder Bayou Recompletion



Bottom Zone
Cum Prod: 14.6 Bcfe
Original 1P: 8.6 Bcfe

~$35MM in field level cash flow



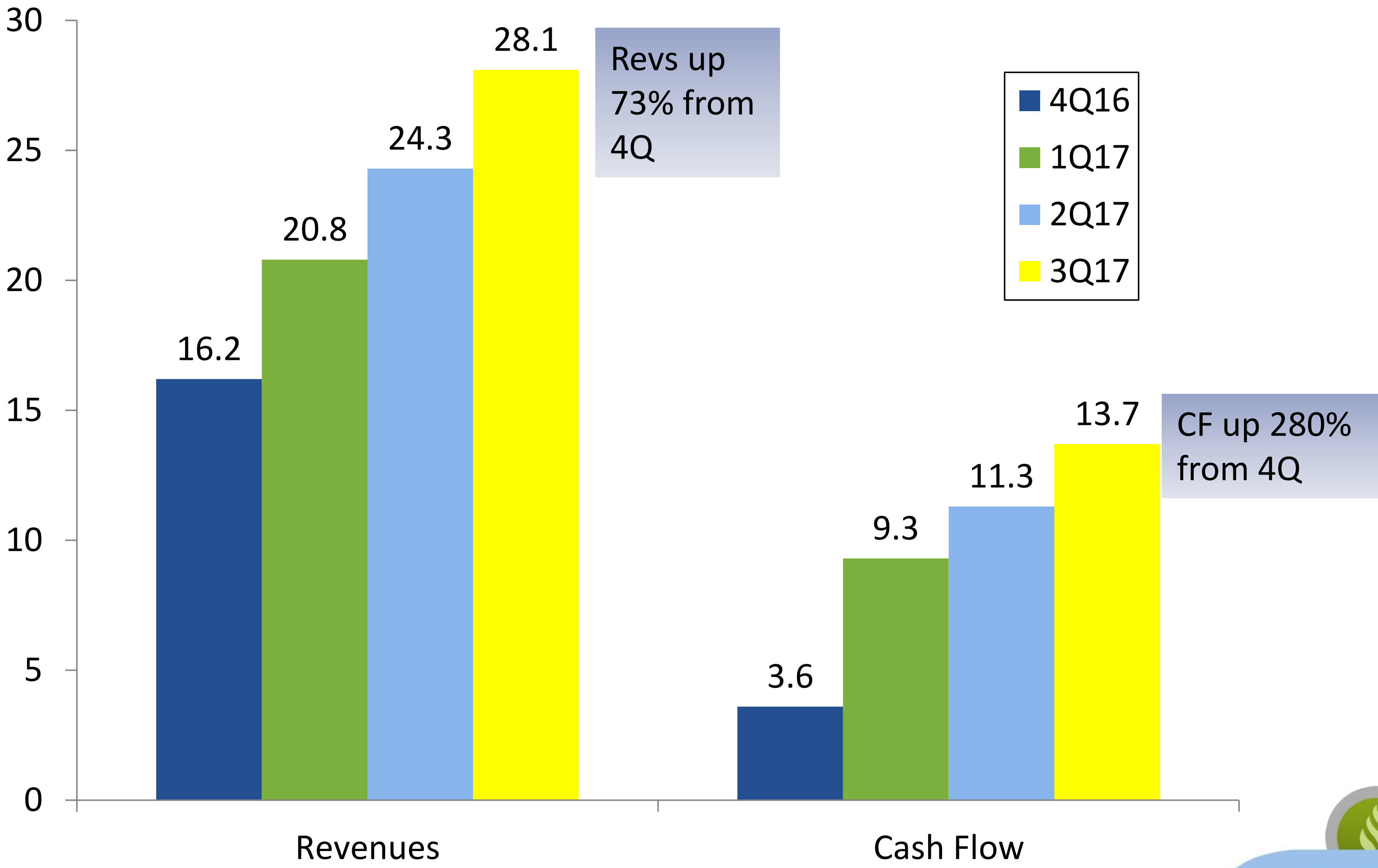
Recompletion
Current Production:
~61 MMCFE/D
39 MMCF/D of Gas
1,500 Bbls/D Oil
2,200 Bbls/D NGLs
3P Est: ~140 Bcfe

Thunder Bayou/La Cantera 3P Value

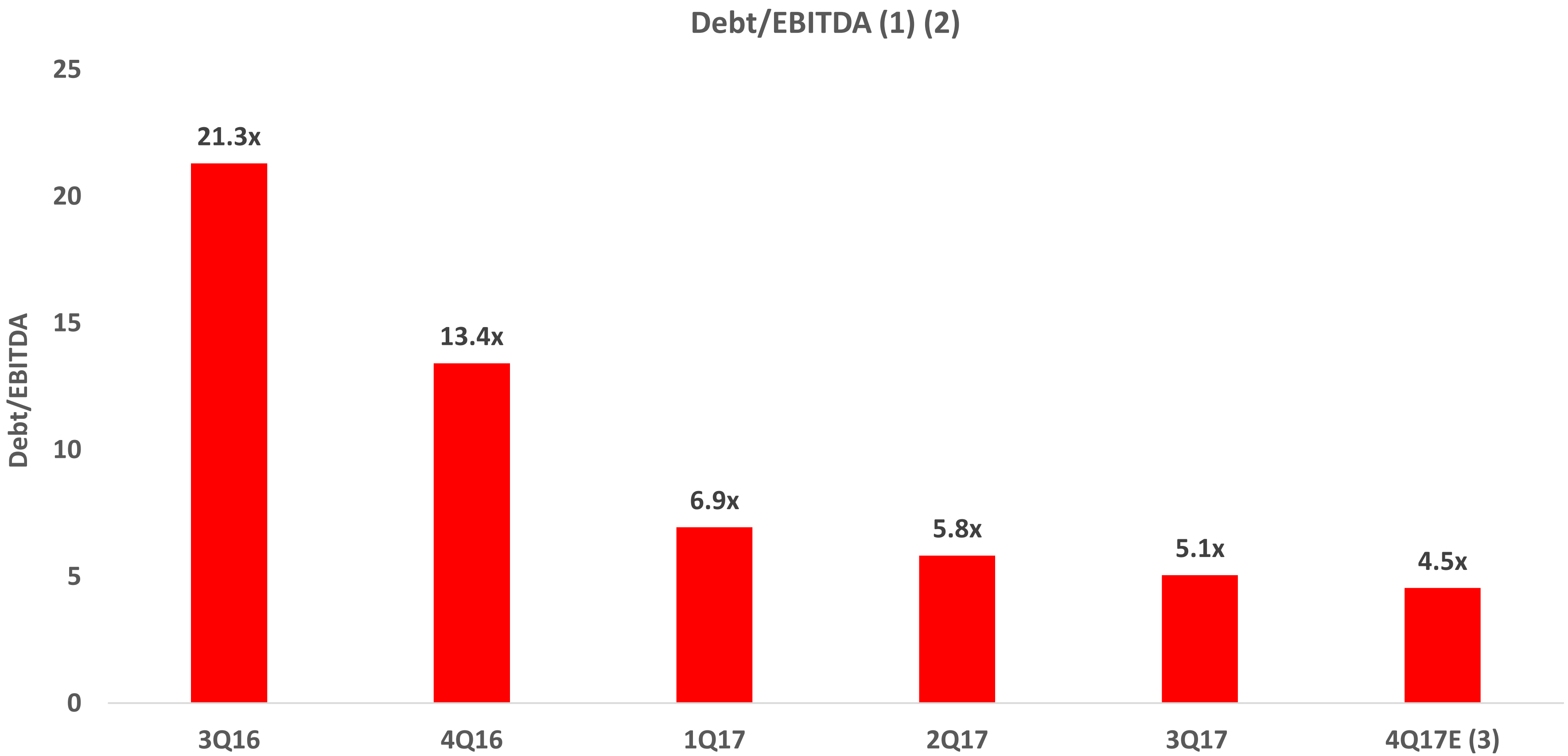
Remaining Gross 3P Reserves	~200 Bcfe
3Q17 Cash Margin(1)	$3.21
Remaining Gross 3P Value(undiscounted)	$642 MM
PQ Weighted Avg. NRI	31%
Net Value to PQ	$199 MM
Shares O/S	25,000,000
Value per Share	**$7.96**

(1) Revenues (oil, gas and ngl) less lifting costs (LOE and sev taxes)

Sequential Growth Profile ($mm)

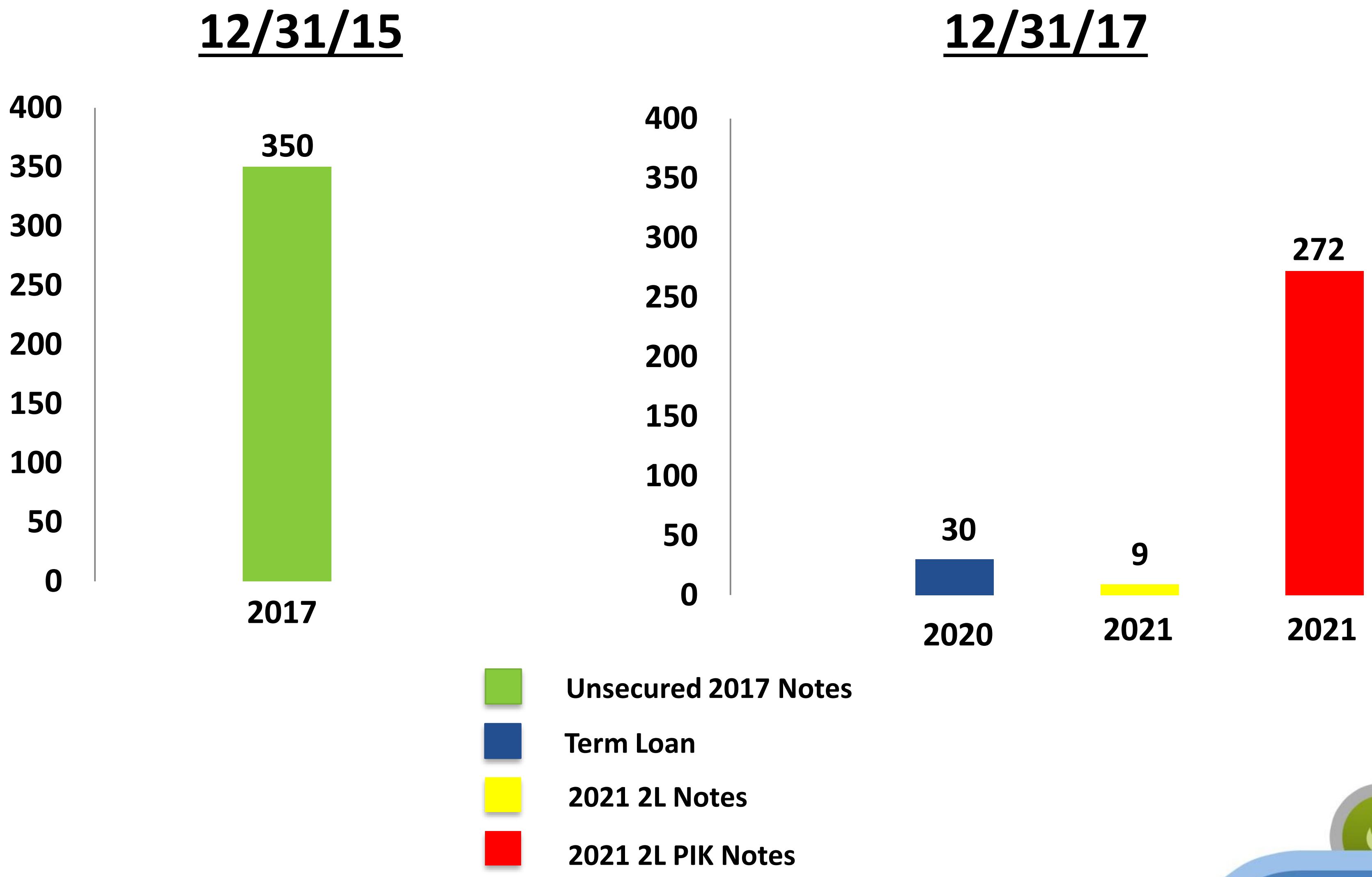


Relative Deleveraging Through Cash Flow Growth



(1) Debt balance assumes PIK option is selected
(2) Quarterly EBITDA annualized
(3) FactSet quarterly average analyst estimate annualized

Changes to Maturity Profile ($000s)



Summary

- **Substantial Growth accomplished in 2017 through Cotton Valley development and Thunder Bayou recompletion**
  - **4Q17E production up 87% from 4Q16**
  - **3Q17 EBITDA up 43% from 4Q16**
    - **Annualized Debt/EBITDA at 9/30/17 down 61% from 12/31/16**
  - **Last 6 Cotton Valley wells achieved average IP rate of 14.4 MMcfe/d**
- **Significant exposure to emerging Louisiana Austin Chalk Oil Trend**
  - **~25,000 acres in the core of the trend**
  - **Initial well expected to spud in 2Q18**
- **2016 Exchanges Provide Window for Growth**
  - **Refinanced or repaid 100% of the YE15 debt of $350MM**
  - **No material near-term maturities until 2021**
  - **Generating significant cash interest savings via debt reduction/PIK**

Appendix

Appendix 1 - Hedging Positions

Natural Gas	Hedged Volumes (Bcfe)	Price
1Q18	3.2 (36 MMcf/d)	$3.24

Oil	Hedged Volumes (Bbls)	Price
2018	91,250 (250 Bbls/d)	$55.00 (LLS)

$17.2 MM of revenue hedged for 2018

Appendix 2 – Adjusted EBITDA Reconciliation

($ in thousands)	2012	2013	2014	2015	1Q16	2Q16	3Q16	4Q16	2016	1Q17	2Q17	3Q17
Net Income (Loss) available to common stockholders	($137,218)	$8,943	$26,051	($299,977)	($39,137)	($24,143)	($23,306)	($4,310)	($90,896)	($4,918)	($3,385)	($3,085)
Income tax expense (benefit)	1,636	320	(2,941)	2,673	86	475	(18)	-	543	-	(189)	(84)
Interest expense & preferred dividends	14,947	27,025	34,420	38,905	9,751	7,788	9,022	8,807	35,368	8,543	8,432	8,655
Depreciation, depletion, and amortization	60,689	71,445	87,818	63,497	10,138	7,193	6,030	5,359	28,720	6,117	6,841	8,795
Share based compensation expense	6,910	4,216	5,248	4,617	442	483	436	83	1,444	425	401	312
Gain on Asset Sale	-	-	-	(21,937)	-	-	-	-	-	-	-	-
Accretion of asset retirement obligation	2,078	1,753	2,958	3,259	608	618	670	619	2,515	547	553	571
Derivative (income) expense	233	(233)	-	-	-	-	-	-	-	-	-	-
Ceiling test writedown	137,100	-	-	266,562	18,857	12,782	8,665	-	40,304	-	-	-
Adjusted EBITDA	$86,375	$113,469	$153,554	$57,599	$745	$5,196	$1,499	$10,558	$17,998	$10,714	$12,653	$15,164

- Adjusted EBITDA represents net income (loss) available to common stockholders before income tax expense (benefit), interest expense (net), preferred stock dividends, depreciation, depletion, amortization, loss on early extinguishment of debt, share based compensation expense, gain on asset sale, non-cash gain on legal settlement, accretion of asset retirement obligation, derivative (income) expense, costs incurred to issue 2021 Notes and ceiling test writedowns. We have reported Adjusted EBITDA because we believe Adjusted EBITDA is a measure commonly reported and widely used by investors as an indicator of a company's operating performance. We believe Adjusted EBITDA assists such investors in comparing a company's performance on a consistent basis without regard to depreciation, depletion and amortization, which can vary significantly depending upon accounting methods or nonoperating factors such as historical cost. Adjusted EBITDA is not a calculation based on generally accepted accounting principles, or GAAP, and should not be considered an alternative to net income in measuring our performance or used as an exclusive measure of cash flow because it does not consider the impact of working capital growth, capital expenditures, debt principal reductions and other sources and uses of cash which are disclosed in our consolidated statements of cash flows. Investors should carefully consider the specific items included in our computation of Adjusted EBITDA. While Adjusted EBITDA has been disclosed herein to permit a more complete comparative analysis of our operating performance relative to other companies, investors should be cautioned that Adjusted EBITDA as reported by us may not be comparable in all instances to Adjusted EBITDA as reported by other companies. Adjusted EBITDA amounts may not be fully available for management's discretionary use, due to certain requirements to conserve funds for capital expenditures, debt service and other commitments, and therefore management relies primarily on our GAAP results.

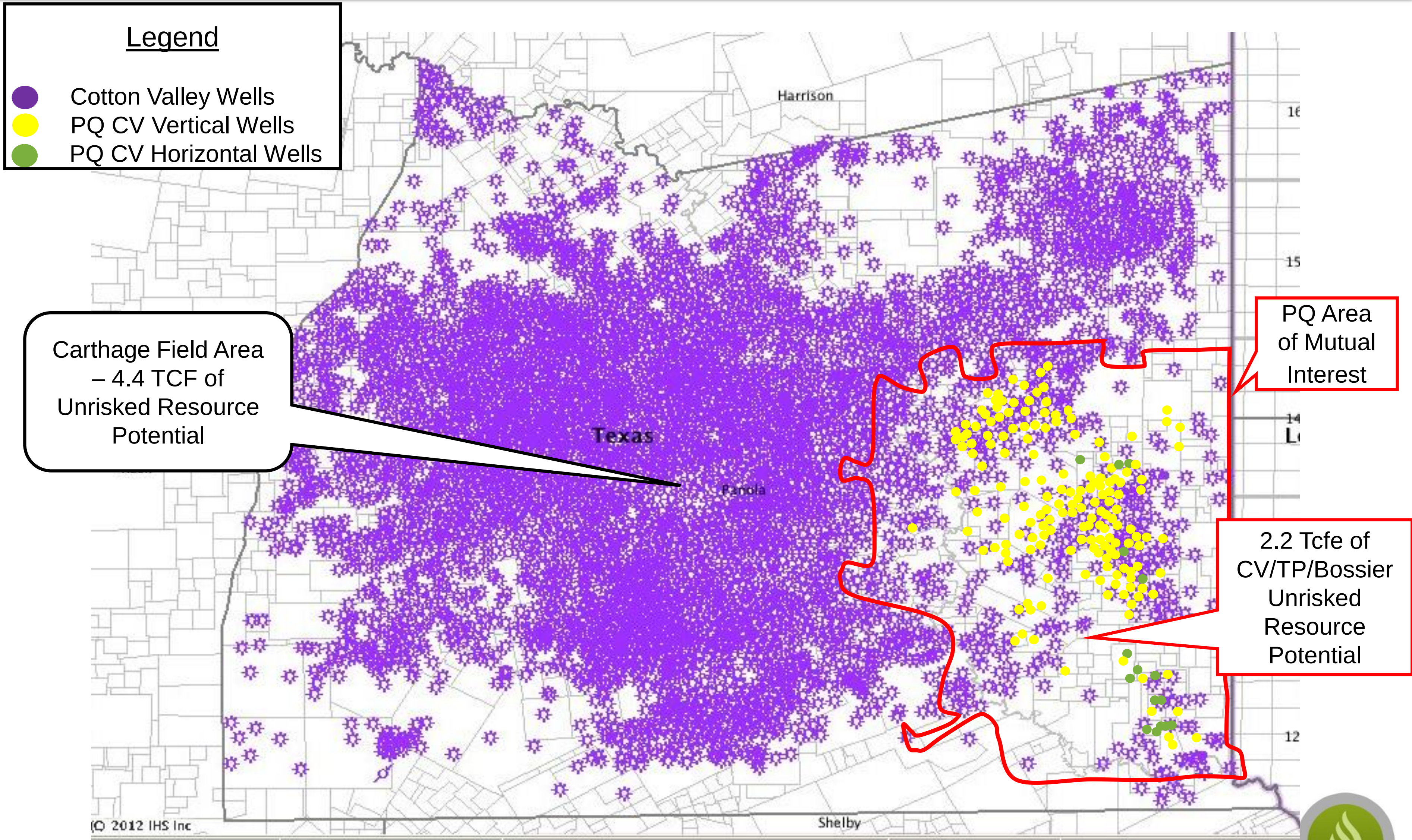
- Adjusted EBITDA is not intended to represent net income as defined by GAAP and such information should not be considered as an alternative to net income, cash flow from operations or any other measure of performance prescribed by GAAP in the United States. The above table reconciles net income (loss) available to common stockholders to Adjusted EBITDA for the periods presented.

Appendix 3 - Discretionary Cash Flow Reconciliation

($ in thousands)	2011	2012	2013	2014	2015	1Q16	2Q16	3Q16	4Q16	2016	9M17
Net income (loss)	$10,548	($132,079)	$14,082	$31,190	($294,838)	($37,643)	($22,858)	($22,021)	($8,374)	($90,896)	($7,533)
Reconciling items:											
Income tax expense (benefit)	(1,810)	1,636	320	(2,941)	2,673	86	475	(18)	-	543	(274)
Depreciation, depletion and amortization	58,243	60,689	71,445	87,818	63,497	10,138	7,193	6,030	5,359	28,720	21,753
Share based compensation expense	4,833	6,910	4,216	5,248	4,617	442	483	436	83	1,444	825
Gain on Asset Sale	-	-	-	-	(21,937)	-	-	-	-	-	-
Ceiling test write down	18,907	137,100	-	-	266,562	18,857	12,782	8,665	-	40,304	--
Accretion of asset retirement obligation	2,049	2,078	1,753	2,958	3,259	608	618	670	619	2,515	1,671
Costs incurred to issue 2021 Notes	-	-	-	-	-	4,740	68	5,265	66	10,139	-
Non-cash PIK interest	-	-	-	-	-	-	-	-	5,722	5,722	16,973
Other	625	1,114	1,240	2,188	2,259	562	248	1,180	116	2,106	561
Discretionary cash flow	$93,395	$77,448	$93,056	$126,461	$26,092	($2,210)	($991)	207	3,591	597	34,332
Changes in working capital accounts	26,686	13,770	(29,867)	55,370	6,789	(23,516)	3,166	(25,509)	(8,167)	(54,026)	3,273
Payments to settle asset retirement obligations	(905)	(2,627)	(3,335)	(3,623)	(2,776)	(464)	(2,051)	(369)	(285)	(3,169)	(2,277)
Net cash flow provided by operating activities	$119,176	$88,591	$59,854	$178,208	$30,105	($26,190)	$124	($25,671)	($4,861)	($56,598)	$35,328

Note: Management believes that discretionary cash flow is relevant and useful information, which is commonly used by analysts, investors and other interested parties in the oil and gas industry as a financial indicator of an oil and gas company's ability to generate cash used to internally fund exploration and development activities and to service debt. Discretionary cash flow is not a measure of financial performance prepared in accordance with generally accepted accounting principles ("GAAP") and should not be considered in isolation or as an alternative to net cash flow provided by operating activities. In addition, since discretionary cash flow is not a term defined by GAAP, it might not be comparable to similarly titled measures used by other companies.

Appendix 4 - Panola County Cotton Valley – Room to Run



Appendix 5 – Cotton Valley Production Profile

Recent Horizontal Cotton Valley Results

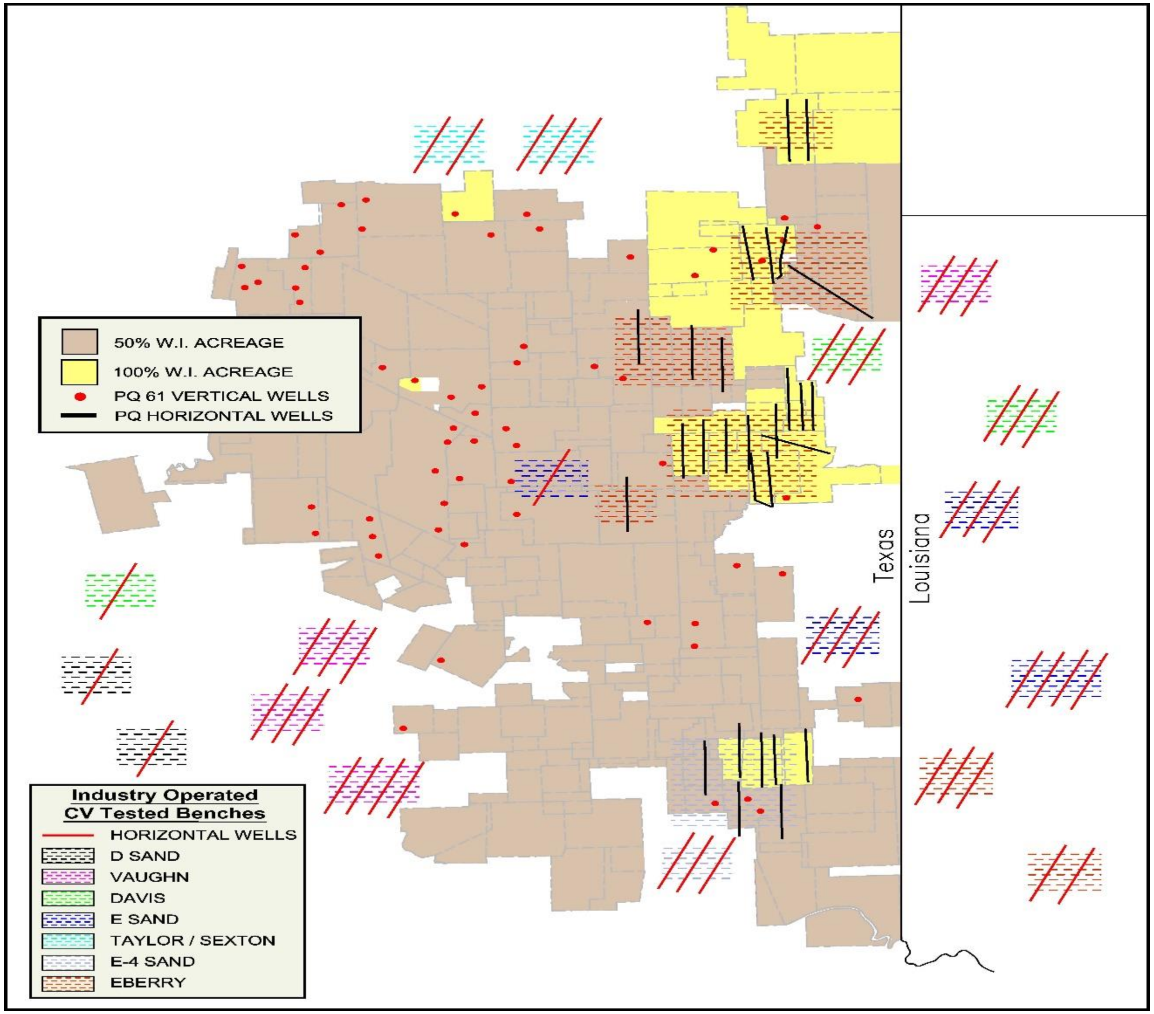
	PQ #19	PQ #20	PQ #21	PQ #22	PQ #23	PQ #24*	PQ #25	PQ #26	PQ #27	PQ #28	PQ #29	PQ #30	Avg.**
IP Rate (Mmcfe/d)	12.5	14.8	7.1	10.6	14.5	5.4	18.3	12.7	13.3	15.4	11.5	15.4	13.2
30 Day Avg. Rate (Mmcfe/d)	11.4	11.5	6.0	7.6	12.3	3.9	14.7	N/A	N/A	N/A	N/A	N/A	10.6
60 Day Avg. Rate (Mmcfe/d)	10.6	10.4	5.2	7.7	11.2	3.2	12.3	N/A	N/A	N/A	N/A	N/A	9.6
90 Day Avg. Rate (Mmcfe/d)	9.8	9.9	4.6	7.4	10.3	N/A	11.1	N/A	N/A	N/A	N/A	N/A	8.9

- PQ #24 experienced mechanical issues (directional equipment failure) during the drilling process resulting in 50% of the well being drilled out of section

** Average excludes PQ #24 due to mechanical issues

Appendix 6 - Cotton Valley Acreage Position

55,000 Gross Acres (100% HBP)
~800 Gross Future Locations (420 Net)



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