Lonestar Resources US, Inc.

Third Quarter 2018 Conference Call

November 6, 2018

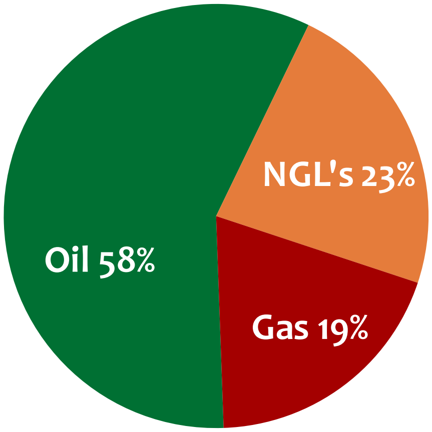
Forward-Looking Statements
Safe Harbor & Disclaimer

Lonestar Resources US, Inc. cautions that this presentation (including oral commentary that accompanies this presentation) contains forward-looking statements, including, but not limited to, statements about performance expectations related to our assets and technical improvements made thereto; drilling and completion of wells; and other statements regarding our business strategy and operations. These statements involve substantial known and unknown risks, uncertainties and other important factors that may cause our actual results, levels of activity, performance or achievements to be materially different from the information expressed or implied by these forward-looking statements. These risks and uncertainties include, but are not limited to, the following: volatility of oil, natural gas and NGL prices, and potential write-down of the carrying values of crude oil and natural gas properties; inability to successfully replace proved producing reserves; substantial capital expenditures required for exploration, development and exploitation projects; potential liabilities resulting from operating hazards, natural disasters or other interruptions; risks related using the latest available horizontal drilling and completion techniques; uncertainties tied to lengthy period of development of identified drilling locations; unexpected delays and cost overrun related to the development of estimated proved undeveloped reserves; concentration risk related to properties, which are located primarily in the Eagle Ford Shale of South Texas; loss of lease on undeveloped leasehold acreage that may result from lack of development or commercialization; inaccuracies in assumptions made in estimating proved reserves; our limited control over activities in properties Lonestar does not operate; potential inconsistency between the present value of future net revenues from our proved reserves and the current market value of our estimated oil and natural gas reserves; risks related to derivative activities; losses resulting from title deficiencies; risks related to health, safety and environmental laws and regulations; additional regulation of hydraulic fracturing; reduced demand for crude oil, natural gas and NGLs resulting from conservation measures and technological advances; inability to acquire adequate supplies of water for our drilling operations or to dispose of or recycle the used water economically and in an environmentally safe manner; climate change laws and regulations restricting emissions of “greenhouse gases” that may increase operating costs and reduce demand for the crude oil and natural gas; fluctuations in the differential between benchmark prices of crude oil and natural gas and the reference or regional index price used to price actual crude oil and natural gas sales; and the other important factors discussed under the caption “Risk Factors” in our Amended Annual Report on Form 10-K/A filed with the Securities and Exchange Commission, or the SEC, on November, 2, 2018, our Quarterly Reports on Form 10-Q/A filed with the SEC, as well as other documents that we have filed and may file from time to time with the SEC. We may not actually achieve the plans, intentions or expectations disclosed in our forward-looking statements, and you should not place undue reliance on our forward-looking statements. Actual results or events could differ materially from the plans, intentions and expectations disclosed in the forward-looking statements we make. The forward-looking statements in this presentation represent our views as of the date of this presentation. We anticipate that subsequent events and developments will cause our views to change. However, while we may elect to update these forward-looking statements at some point in the future, we have no current intention of doing so except to the extent required by applicable law. You should, therefore, not rely on these forward-looking statements as representing our views as of any date subsequent to the date of this presentation.

This presentation also contains estimates and other statistical data made by independent parties and by us relating to well performance, finding and development costs, recycle ratio and other data about our industry. This data involves a number of assumptions and limitations, and you are cautioned not to give undue weight to such estimates. In addition, projections, assumptions and estimates of our future performance and the future performance of the markets in which we operate are necessarily subject to a high degree of uncertainty and risk.

Quarterly Highlights

3Q18 Production by Product



Product	Volume
Crude Oil	7,183 bbl/d
NGL's	2,855 bbl/d
Natural Gas	14,600 Mcf/d
Total	**12,471 Boe/d**

Third Quarter 2018 Highlights
- Production increased to 12,471 Boe/d, up 63%, year-over-year and up 12% sequentially
- Adjusted EBITDAX increased to $37.0 million, up 82% year-over-year and 27% sequentially
- Debt / EBITDAX ratio reduced from 3.4x in 1Q18 to 2.5x in 3Q18.

More Outperformance In Financial Results
- Production 12,471 Boe/d, exceeding guidance of 11,800 to 12,200 boe/d
- Adjusted EBITDAX of $37.0 million, exceeded guidance of $32.0 to $34.0 million
- Flooding at Burns Ranch reduced September production by 250 boe/d

2018 New Completions Are Substantially Outperforming
- Hawkeye (Gonzales)- online January, Max-30 day rates 938 Boe/d, 24% above Type Curve to date
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Tack-On Acquisitions Add Reserves, Enhance Wellbore Returns
- 3Q18 Tack-Ons totaled ~3,000 acres at a cost of $3.0 MM in Karnes & Gonzales Counties
- Increase lateral lengths on 41 drilling locations by an average of 42%
- Year-to-date, added ~4,000 net acres, which we estimate adds 8.2 MMBOE and $90 MM PV-10[1]

Reiterating 2019 Outlook…
- 17 gross / 16 net wells at a cost of $120 to $130 million
- 2019 Production Outlook of 13,000 – 14,000 Boe/d, an increase of 27%
- 2019 Adjusted EBITDAX Outlook of $140 to $160 million, an increase of 23%

…Currently Sharpening Our Views On Costs and Well Timing
- Bidding out drilling services for 2019
- Negotiating a dedicated frac spread for 2019

Key Financial Highlights

Financial Commentary

3Q18 Volumes Up 63% to 12,471 Boe/d

- **Materially Contributing Completions**
  - *Horned Frog NW #2H & 3H (LaSalle County)*
    - Onstream June, 2018
    - 2.0 gross / 2.0 net wells
  - *Cyclone DM #14H & #3H (Gonzales County)*
    - Onstream July, 2018
    - 2.0 gross / 2.0 net wells
  - *Georg #24H, #25H, & #26H (Karnes County)*
    - Onstream August, 2018
    - 3.0 gross / 2.4 net wells
  - *Culpepper #3-2H, #3-3H, & #3-4H (Gonzales County)*
    - Onstream September, 2018
    - 3.0 gross / 2.4 net wells

Product Pricing Improved 34%...

- **Oil & Gas Prices All Improved**
- **Basis Differentials Improved for All Three Products**
  - *Oil price differentials were **+$2.90/bbl** vs. WTI*
    - Benchmark price increased $24.44 vs. 3Q17
    - Better LLS pricing
  - *NGL price differentials were **37%** of WTI*
    - Realizations up 60% , or $9.67/bbl vs. 3Q17
    - 3Q18 was 37% of WTI vs. 34% of WTI in 3Q17
  - *Gas price differentials were **+$0.15/Mcf** vs. HH*
    - Benchmark price increased 5% vs. 2Q17

Per-Unit Cash Expenses Are Declining…

- **LOE- $5.14 per Boe, ↓9% Y-o-Y, ↓ 5% Q-o-Q**
- **G,P&T- $0.69 per Boe, ↓8% Y-o-Y, ↓13% Q-o-Q**
- **Taxes- $2.80 per Boe, ↑28% Y-o-Y, ↑ 3% Q-o-Q**
- **G&A- $3.13 per Boe, ↓11%, Y-o-Y, ↑ 5% Q-o-Q**
- **Int. Exp.- $8.00 per Boe, ↑ 12% Y-o-Y, ↓ 2% Q-o-Q**
- **Total.- $19.76 per Boe, ↑ 3% Y-o-Y, ↓ 1% Q-o-Q**

…Increasing Cash Margins in 3Q18

- **Revenues- $51.19 per Boe, ↑ 34% Y-o-Y, ↑8% Q-o-Q**
- **Expenses- $19.76 per Boe, ↑ 3% Y-o-Y, ↓ 1% Q-o-Q**
- **Total.- $31.43 per Boe, ↑ 66% Y-o-Y, ↑ 16% Q-o-Q**

Daily Production

Product	3Q17	Mix	3Q18	Mix
Crude Oil	5,250	69%	7,183	58%
NGL's	1,228	16%	2,855	23%
Natural Gas	7,105	15%	14,600	19%
Total	**7,662**	**100%**	**12,471**	**100%**

Product Pricing / Revenues

	$MM			$ / Boe		
Product	3Q17	3Q18	Chg.	3Q17	3Q18	Chg.
Crude Oil	$23.2	$47.8	+107%	$47.96	$72.40	+51%
NGL's	$1.8	$6.8	+271%	$16.20	$25.87	+60%
Nat. Gas	$1.9	$4.1	+117%	$2.89	$3.05	+5%
Total	**$26.9**	**$58.7**	**+118%**	**$38.14**	**$51.19**	**+34%**

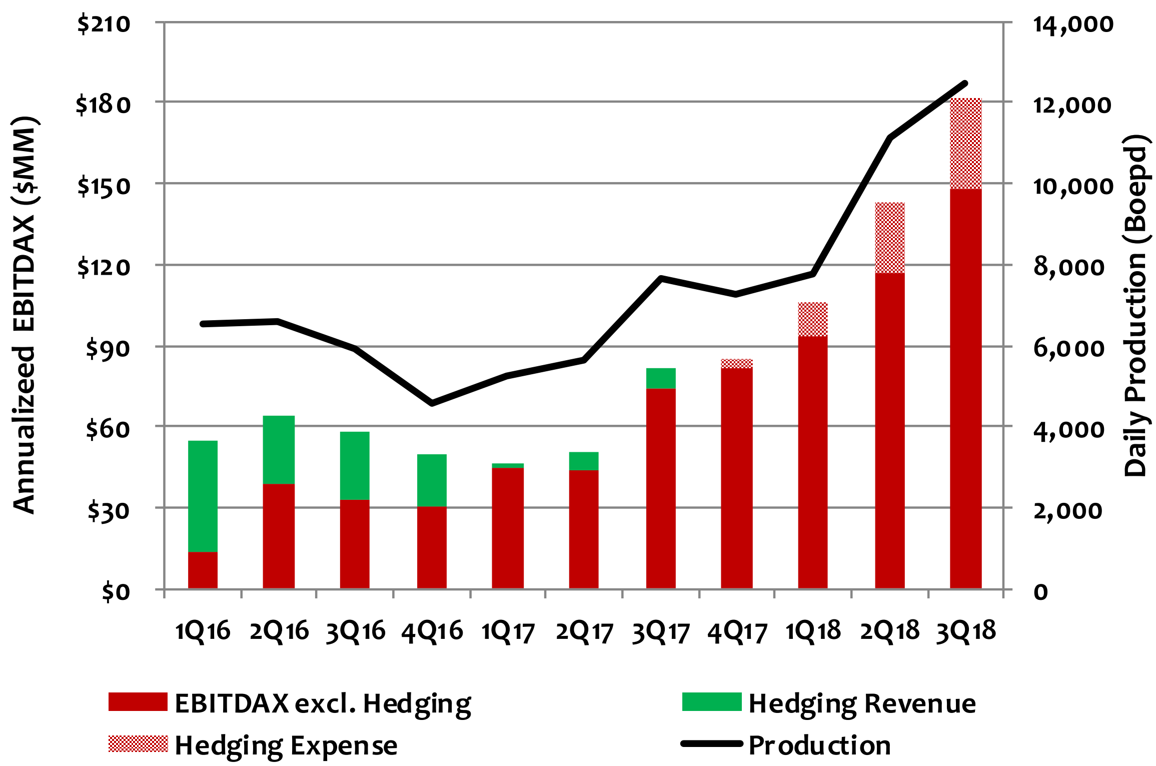
Cash Expenses[1]

	$MM			$ / Boe		
Expense	3Q17	3Q18	Chg.	3Q17	3Q18	Chg.
LOE[2]	$4.0	$5.9	+48%	$5.66	$5.14	(9%)
G,P&T[3]	$0.5	$0.8	+50%	$0.74	$0.69	(8%)
Taxes	$1.5	$3.2	+109%	$2.19	$2.80	+28%
G&A[4]	$2.5	$3.6	+45%	$3.51	$3.13	(11%)
Int. Exp.[5]	$5.0	$9.2	+82%	$7.14	$8.00	+12%
Total	**$13.6**	**$22.7**	**+67%**	**$19.24**	**$19.76**	**+3%**
Cash Margin	**$13.3**	**$36.1**	**+171%**	**$18.90**	**$31.43**	**+66%**

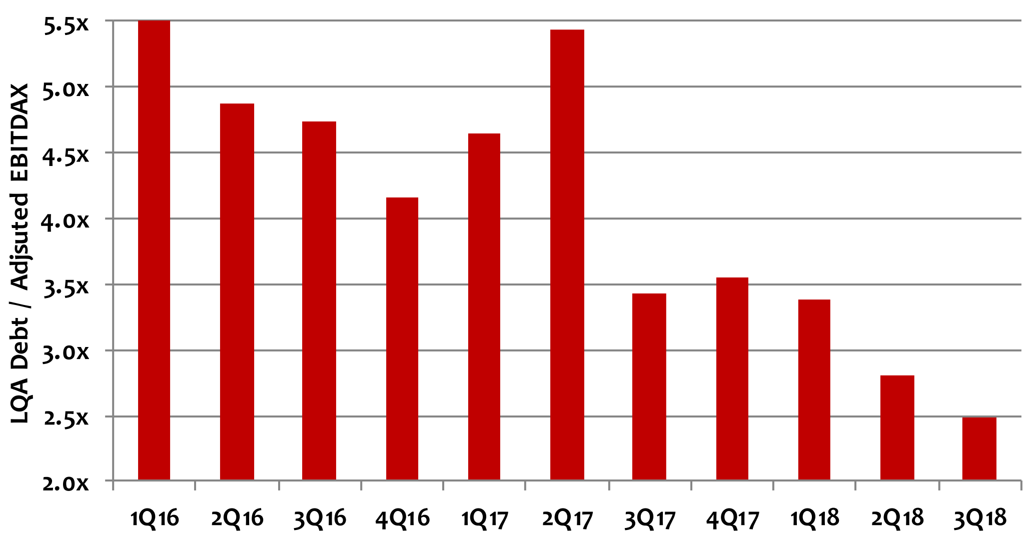
[1] *Cash Operating Costs are controllable expenses incurred by the Company*
[2] *LOE – Excludes $0.2 million of nonrecurring legal expenses*
[3] *G,P&T – Gathering, processing and transportation expense*
[4] *Excludes stock based compensation*
[5] *Excludes amortization of debt issuance cost, premiums & discounts*

Rapidly Improving Financial Metrics

Average Daily Production vs. Annualized Adjusted EBITDAX[1]



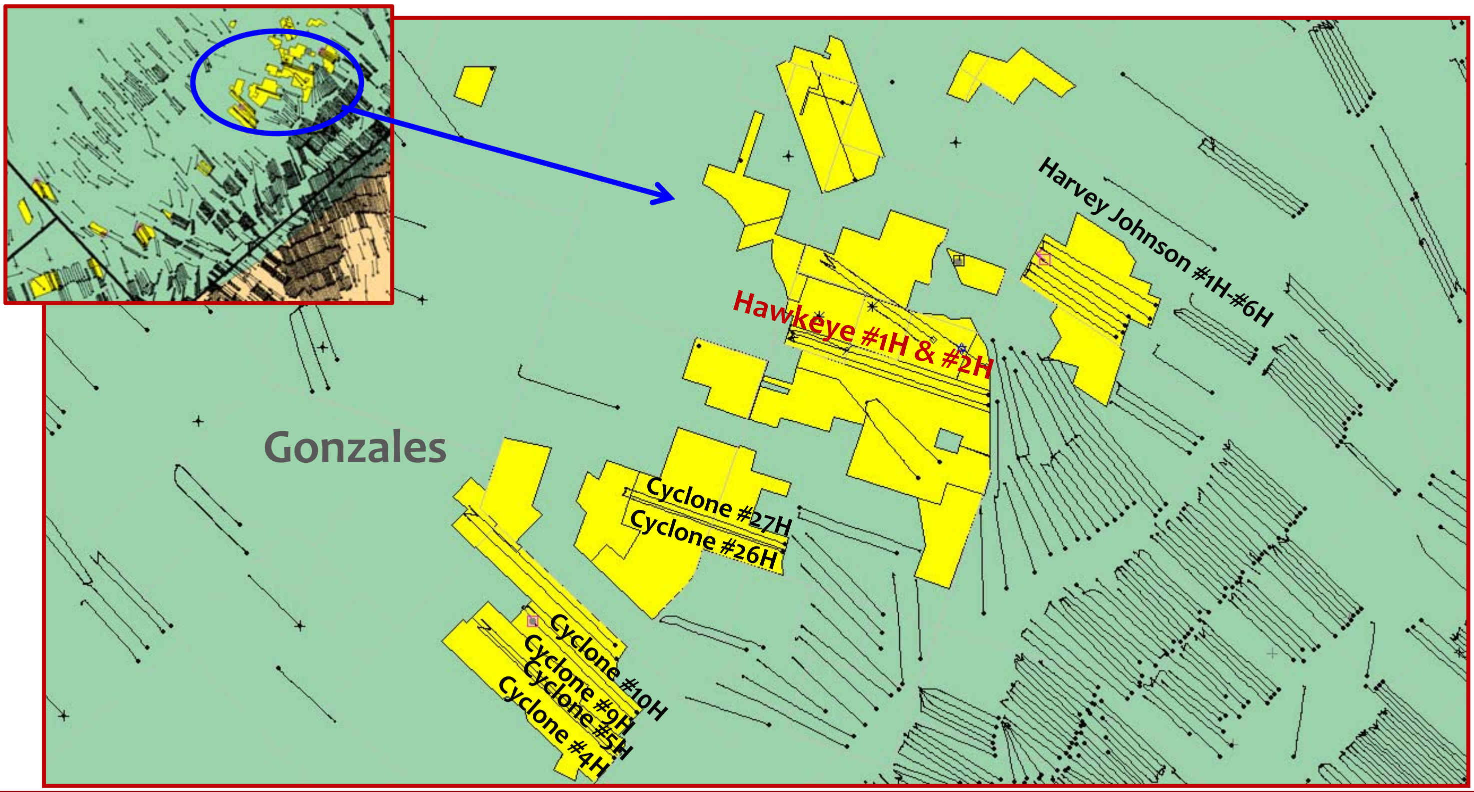
Debt / Adjusted EBITDAX



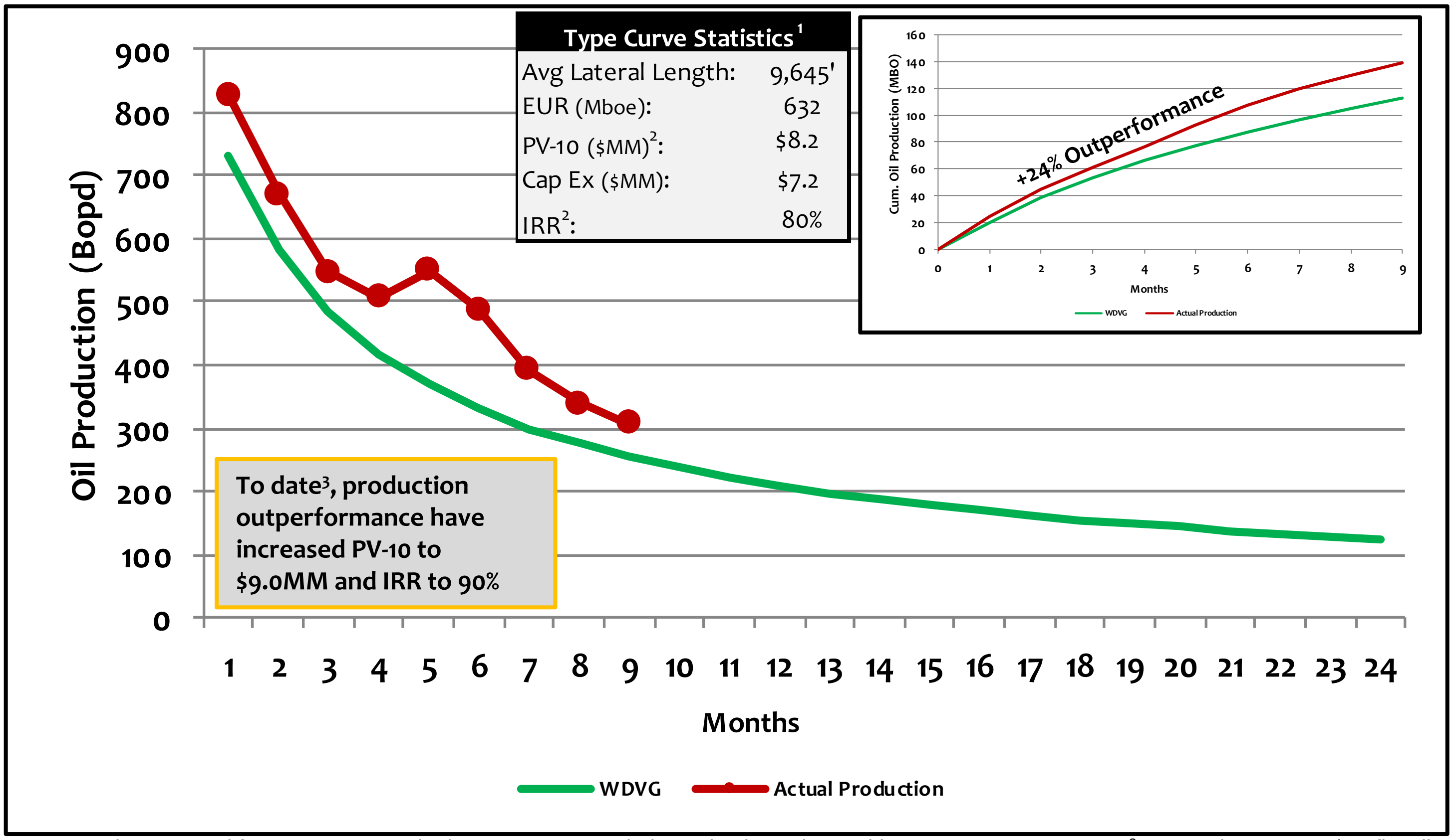
[1] *Annualized Adjusted EBITDAX is reported quarterly Adjusted EBITDAX multiplied by 4*

Gonzales County Performance Update

Cyclone / Hawkeye Area Lease Map



Hawkeye #1H/#2H vs. Type Curve

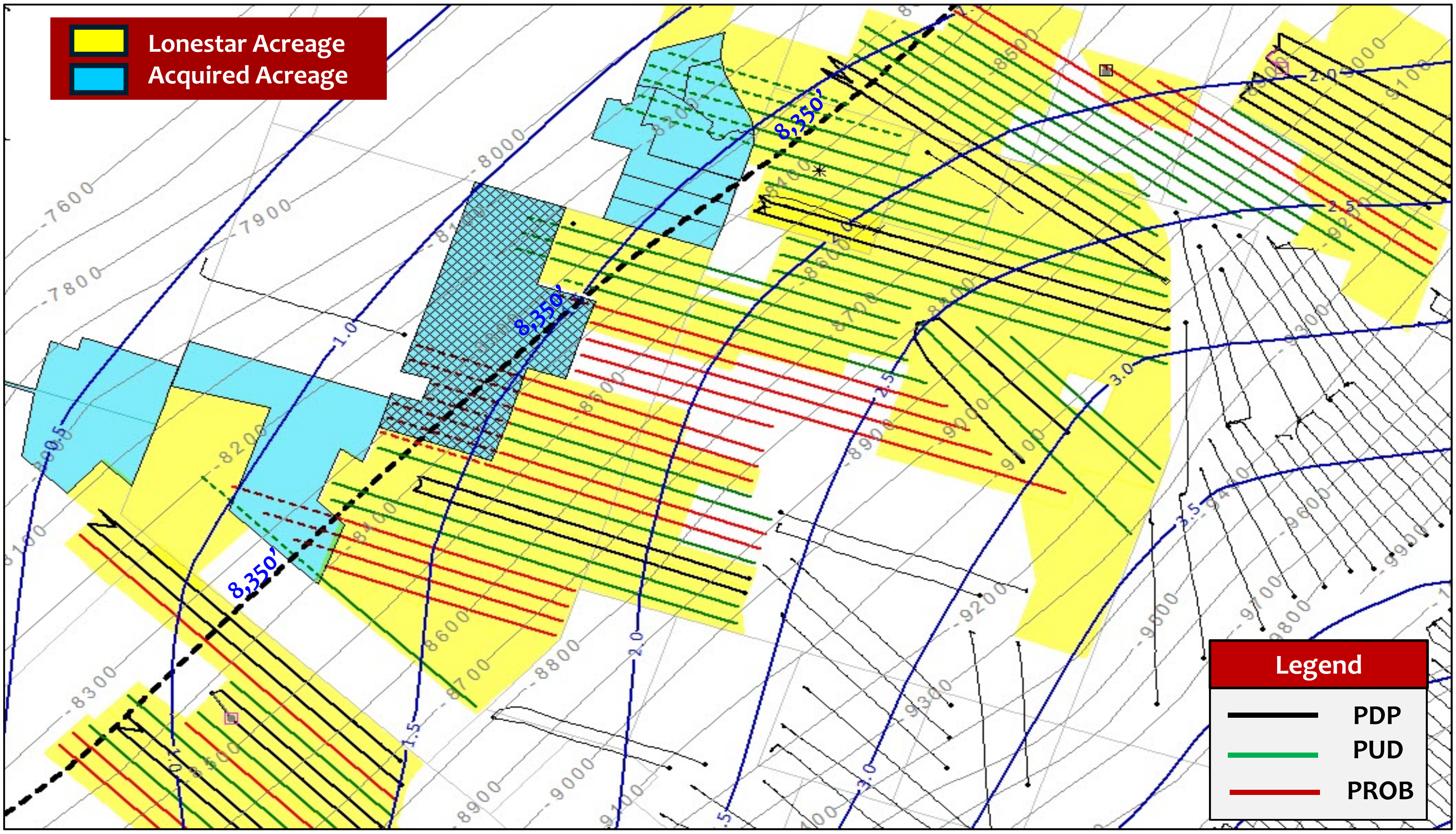


Type Curve Statistics[1]	
Avg Lateral Length:	9,645'
EUR (Mboe):	632
PV-10 ($MM)[2]:	$8.2
Cap Ex ($MM):	$7.2
IRR[2]:	80%

[1] Type Curve data sourced from Lonestar's 12/31/17 reserve report, independently engineered by WD Von Gonten & Co. [2] Economics assume $65 flat oil price and $2.75 flat gas deck. [3] Production outperformance assumes actuals to date and type curve thereafter.

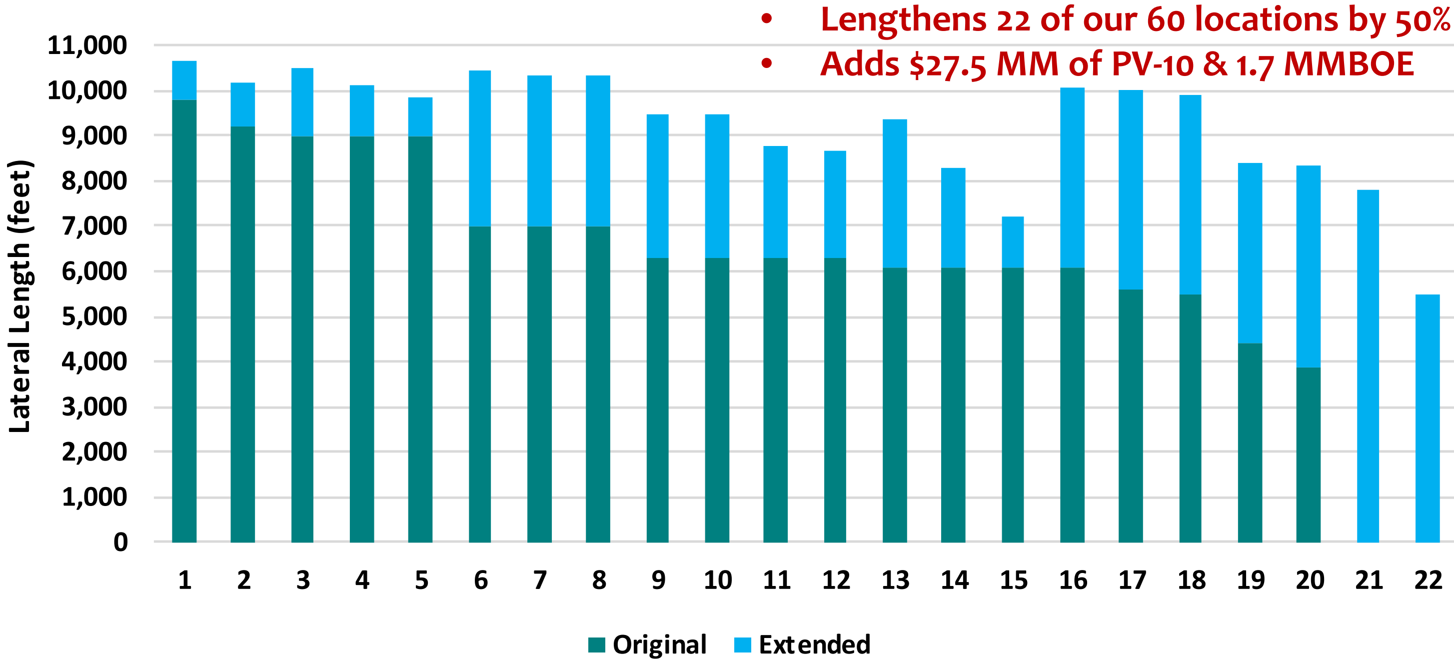
Gonzales County Lateral Extensions

Cyclone / Hawkeye Area Development Map



Lateral Inventory

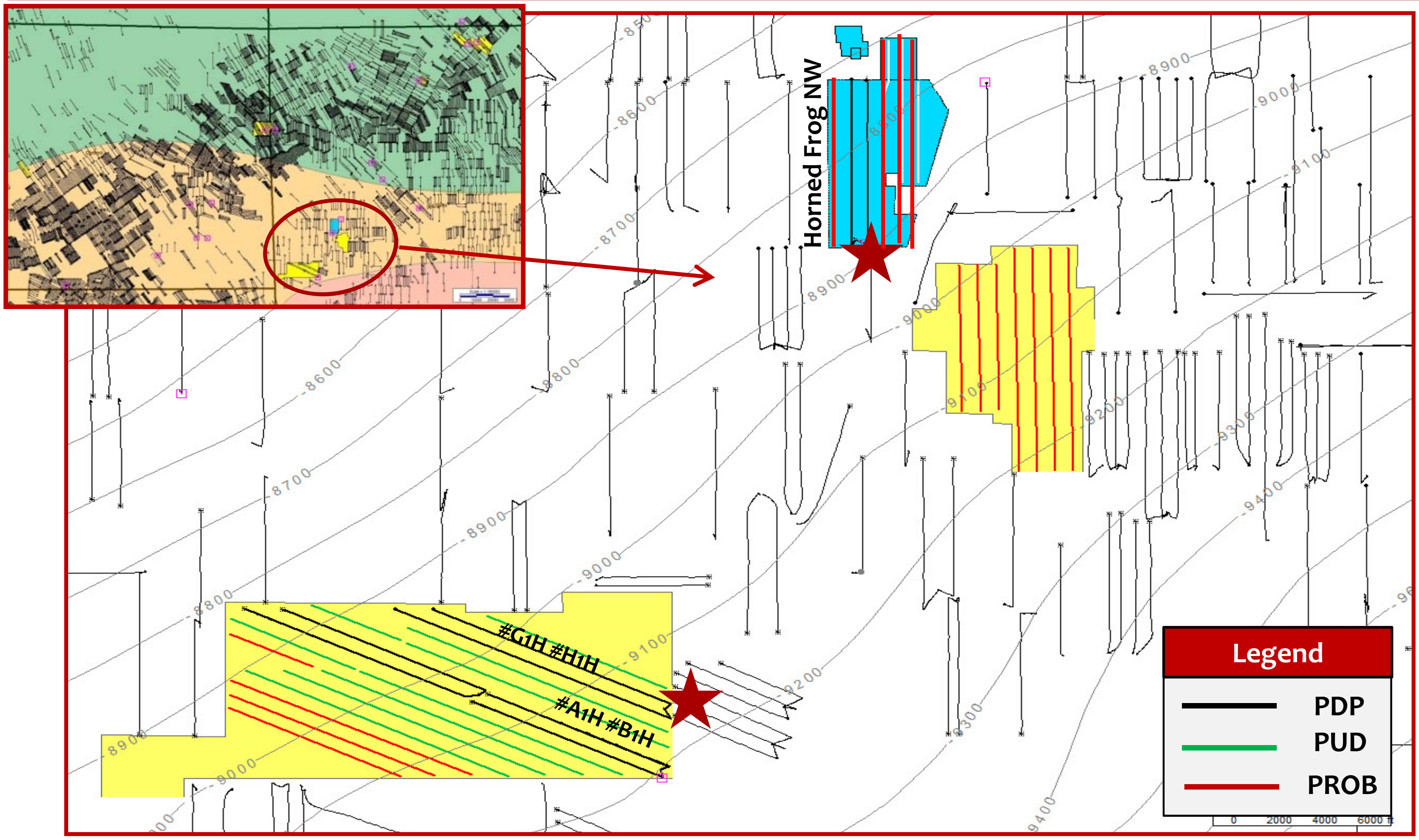
- Lengthens 22 of our 60 locations by 50%
- Adds $27.5 MM of PV-10 & 1.7 MMBOE



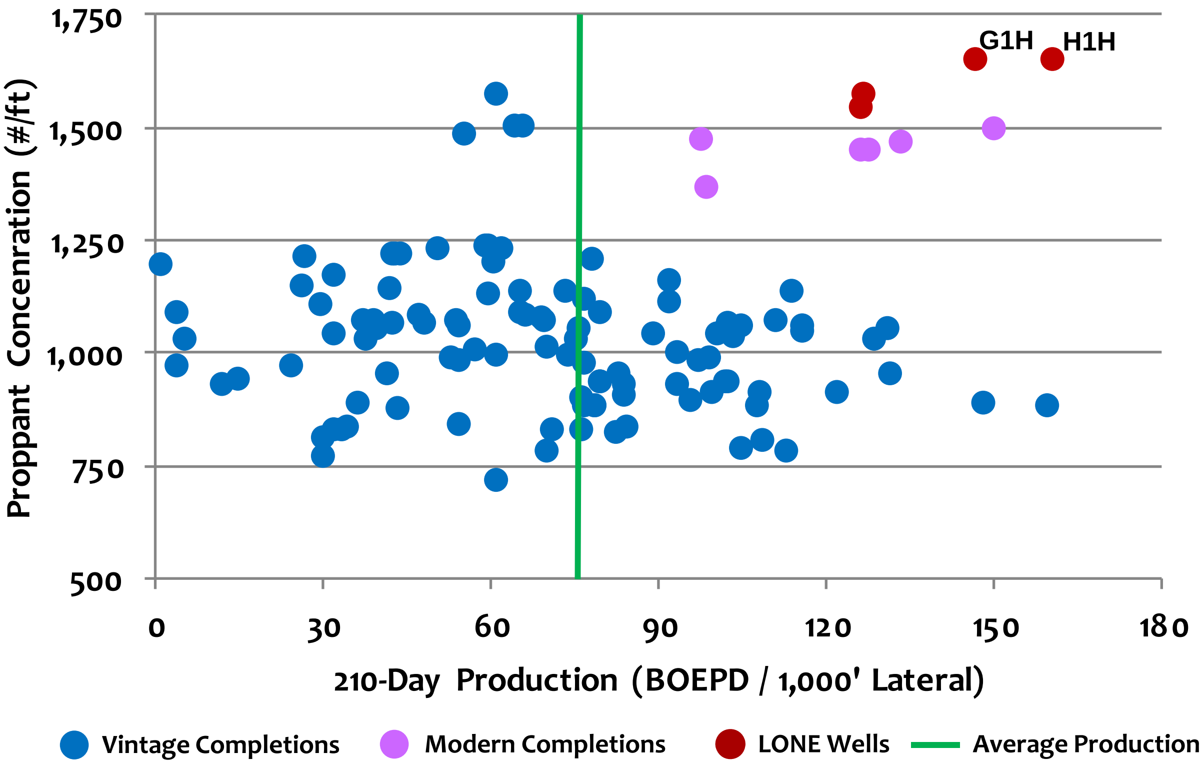
[1] *All reserves and economic data calculated using a $65 flat oil price and $2.75 flat gas deck for the purposes of illustrating the potential impact to reserves and PV-10 for the company.*

La Salle County Performance Update

Horned Frog Area Lease Map

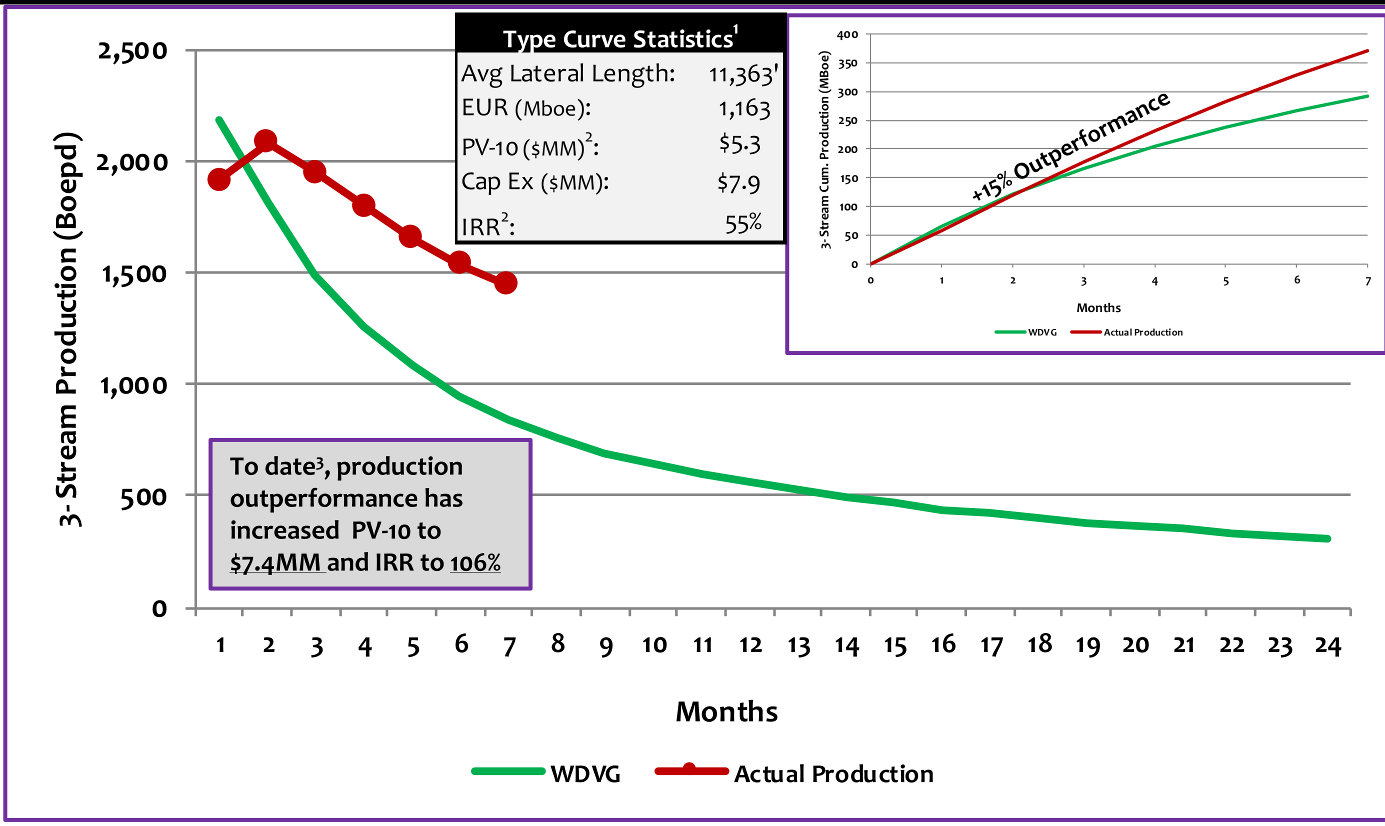


Horned Frog Wells vs. Competitor Offsets



LaSalle County Performance Update

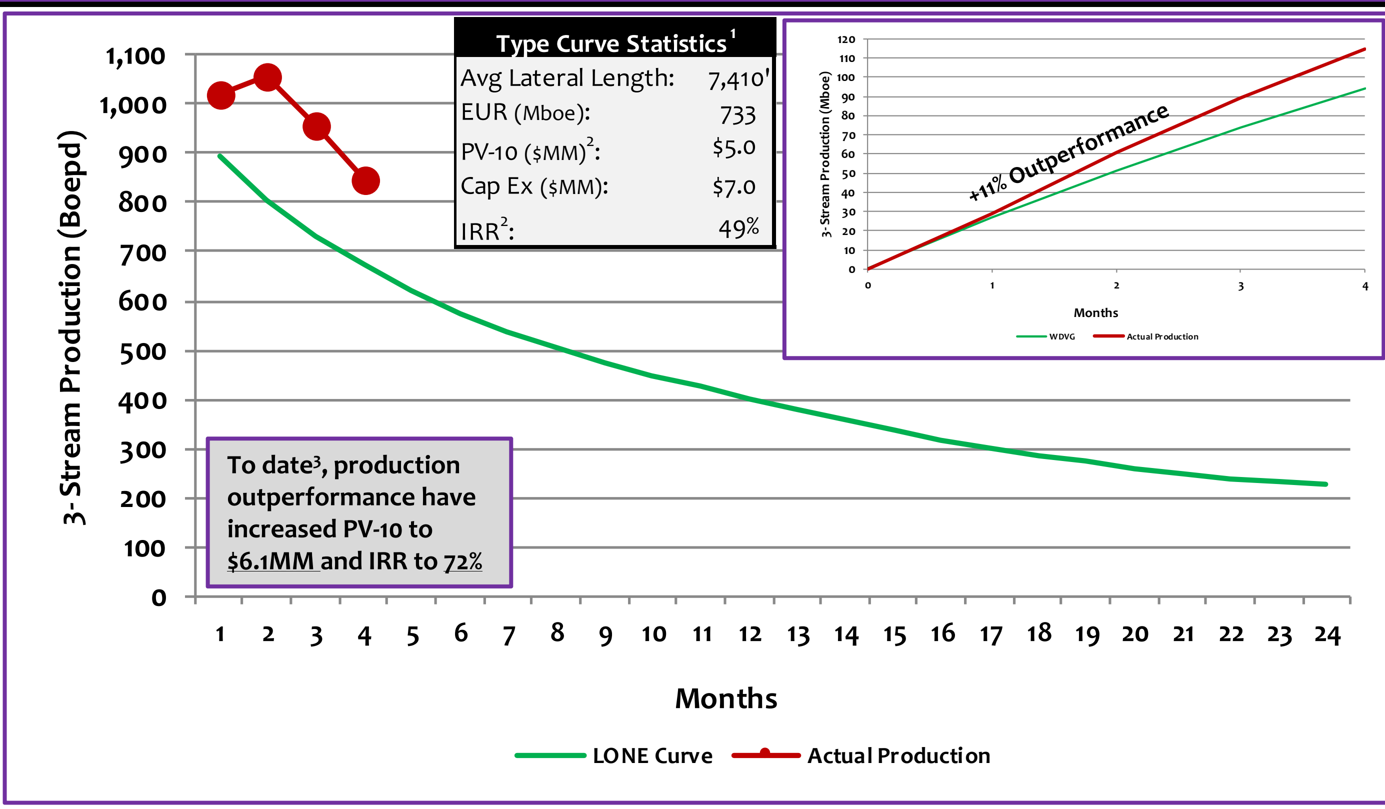
Horned Frog G#1H & H#2H vs. Type Curve



Type Curve Statistics[1]	
Avg Lateral Length:	11,363'
EUR (Mboe):	1,163
PV-10 ($MM)[2]:	$5.3
Cap Ex ($MM):	$7.9
IRR[2]:	55%

To date[3], production outperformance has increased PV-10 to $7.4MM and IRR to 106%

Horned Frog NW 2H & 3H vs. Type Curve



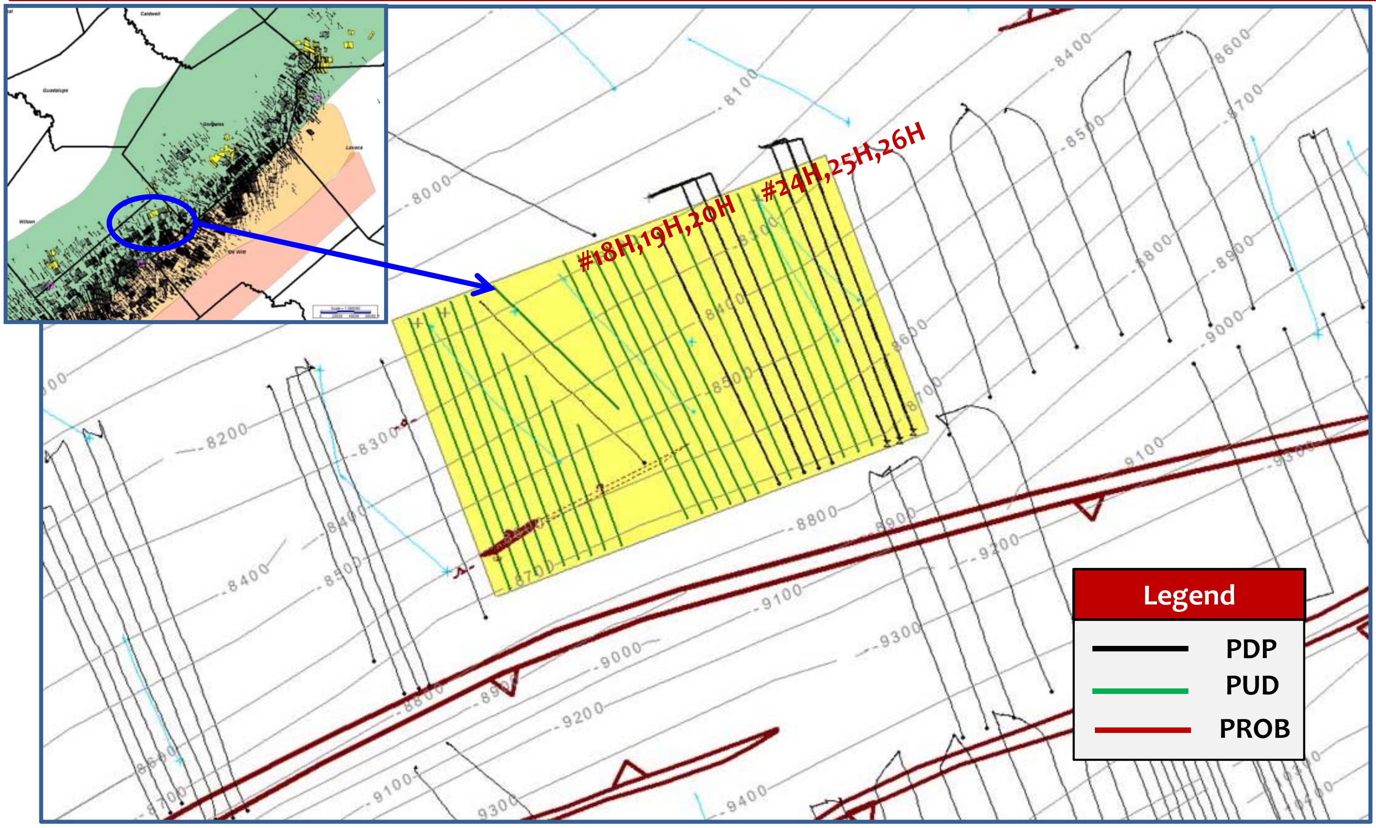
Type Curve Statistics[1]	
Avg Lateral Length:	7,410'
EUR (Mboe):	733
PV-10 ($MM)[2]:	$5.0
Cap Ex ($MM):	$7.0
IRR[2]:	49%

To date[3], production outperformance have increased PV-10 to $6.1MM and IRR to 72%

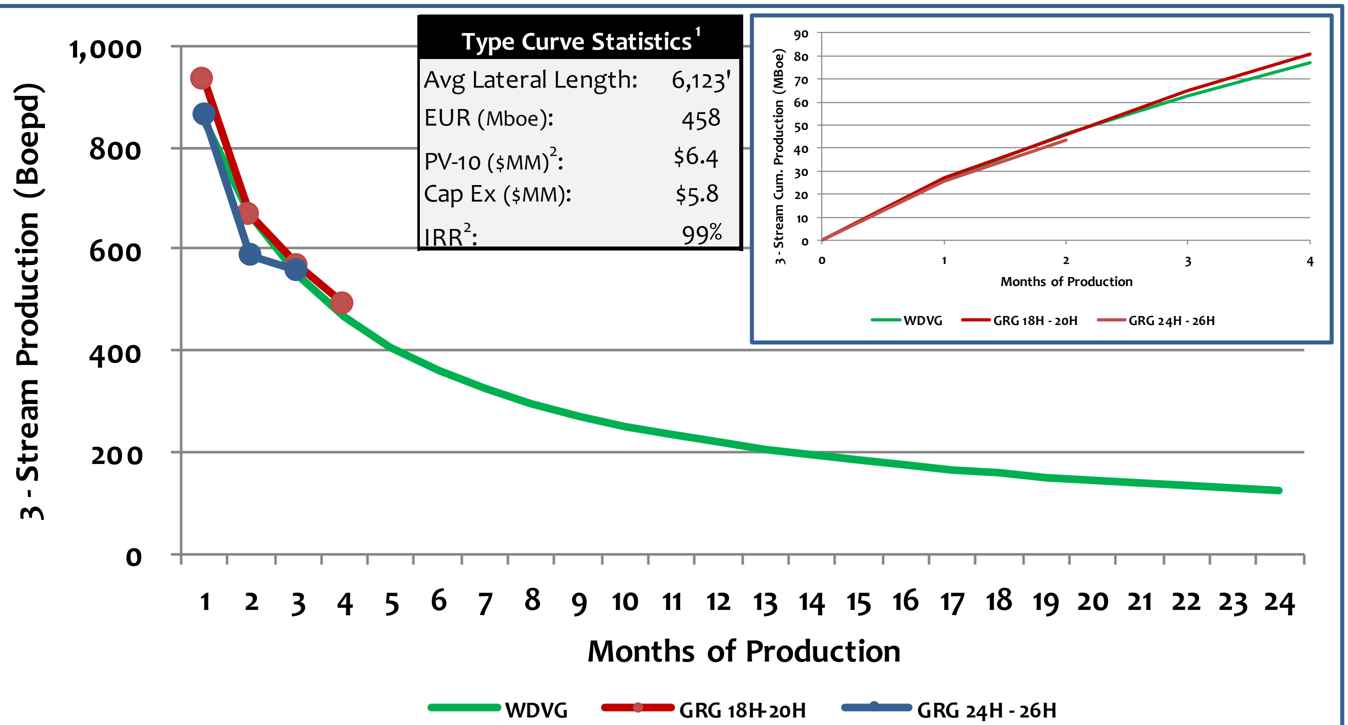
[1] Type Curve data sourced from Lonestar's 12/31/17 reserve report, independently engineered by WD Von Gonten & Co. [2] Economics assume $65 flat oil price and $2.75 flat gas deck. "LONE Curve" sourced internally. [3] Production outperformance assumes actuals to date and type curve thereafter.

Karnes County Performance Update

Karnes County Leasehold Map



Karnes County Well Results



Type Curve Statistics[1]	
Avg Lateral Length:	6,123'
EUR (Mboe):	458
PV-10 ($MM)[2]:	$6.4
Cap Ex ($MM):	$5.8
IRR[2]:	99%

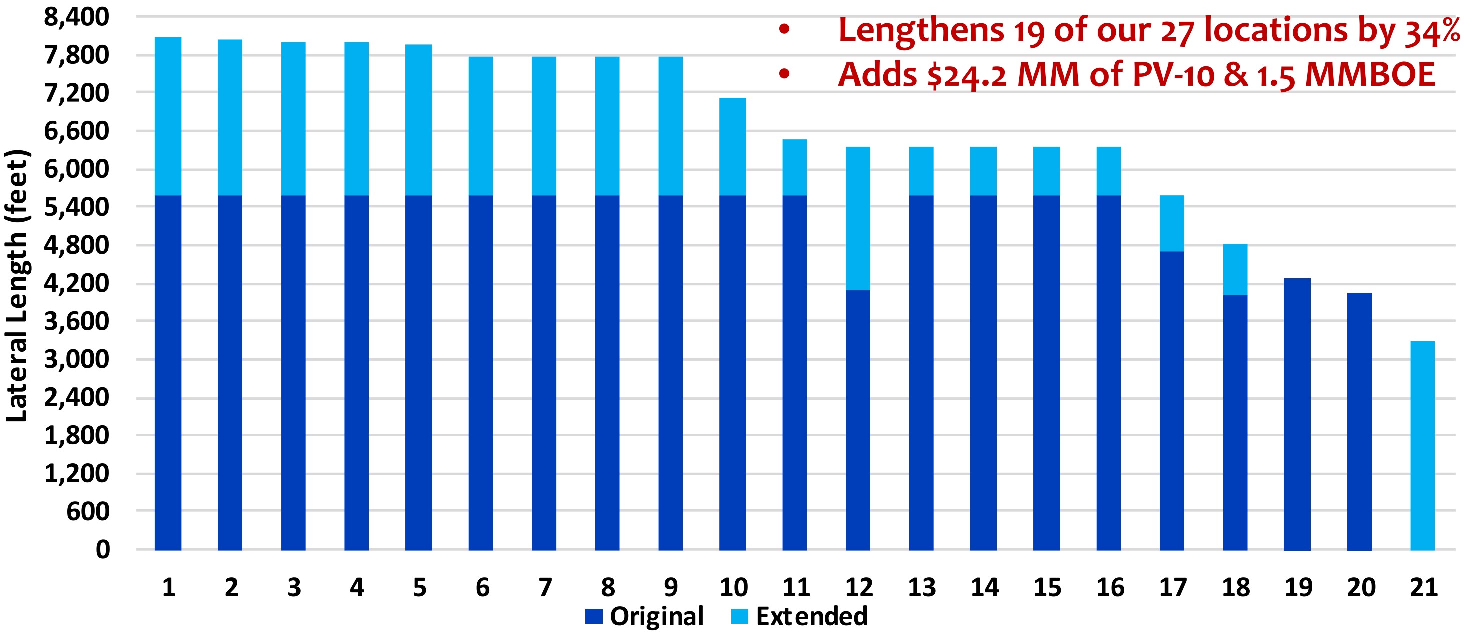
[1] Type Curve data sourced from Lonestar's 12/31/17 reserve report, independently engineered by WD Von Gonten & Co. [2] Economics assume $65 flat oil price and $2.75 flat gas deck. [3] Production outperformance assumes actuals to date and type curve thereafter.

Karnes County Lateral Extensions

Karnes Area Development Map

Lateral Inventory

- Lengthens 19 of our 27 locations by 34%
- Adds $24.2 MM of PV-10 & 1.5 MMBOE



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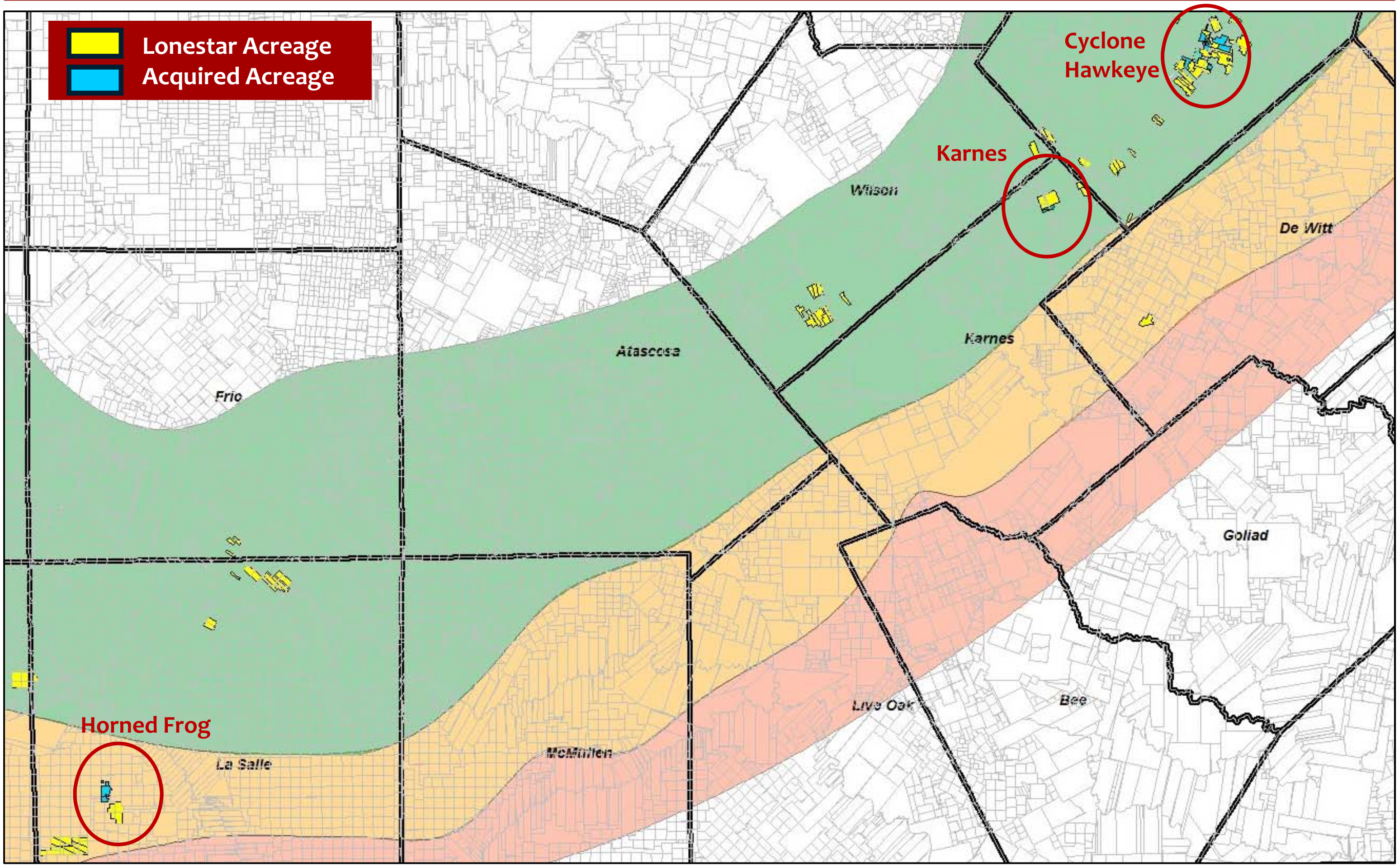
Year to Date Acreage Additions

Lonestar's Acreage Position



Impact of Acreage Additions

Property	Acres	Bonus	Payment	Net Reserves (MMBOE)	Proved PV-10	Locations Affected	Length Increased
Horned Frog NW	993	$1,250	$1.2	5.0	$38.1	7	100%
Cyclone/Hawkeye	2,727	$1,069	$2.9	1.7	$27.5	22	50%
Karnes County	275	$192	$0.1	1.5	$24.2	19	34%
Total	**3,995**	**$1,053**	**$4.2**	**8.2**	**$89.8**	**48**	**51%**

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Quarterly Highlights

	3Q18		4Q18 Guidance			
Product	Reported	Mix	Low	Mix	High	Mix
Crude Oil (bbl/d)	7,183	58%	7,700	60%	8,000	62%
NGL's (bbl/d)	2,855	23%	2,450	19%	2,400	19%
Natural Gas (Mcf/d)	14,600	19%	14,700	21%	14,400	19%
Total (boe/d)	**12,471**	**100%**	**12,600**	**100%**	**12,800**	**100%**

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Fourth Quarter Guidance- Continued Growth

- Production guidance of 12,600 to 12,800 boe/d, negatively impacted by Frio River flooding
- Equates to 10% crude oil production growth (at midpoint)
- Adjusted EBITDAX of $39.0-$41 million

2018 New Completions Are Substantially Outperforming

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Appendix

Non-GAAP Reconciliation

Reconciliation of Non-GAAP Financial Measures

Adjusted EBITDAX (Unaudited)

Adjusted EBITDAX is not a measure of net income as determined by GAAP. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of the Company's consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. The Company defines Adjusted EBITDAX as net (loss) income before depreciation, depletion, amortization and accretion, exploration costs, non-recurring costs, (gain) loss on sales of oil and natural gas properties, impairment of oil and gas properties, stock-based compensation, interest expense, income tax (benefit) expense, rig standby expense, other income (expense) and unrealized (gain) loss on derivative financial instruments and unrealized (gain) loss on warrants.

Management believes Adjusted EBITDAX provides useful information to investors because it assists investors in the evaluation of the Company's operating performance and comparison of the results of the Company's operations from period to period without regard to its financing methods or capital structure. The Company excludes the items listed above from net income in arriving at Adjusted EBITDAX to eliminate the impact of certain non-cash items or because these amounts can vary substantially from company to company within its industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Certain items excluded from Adjusted EBITDAX 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. The Company's computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table presents a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income (loss) for each of the periods indicated.

Stock-based compensation	1Q15	2Q15	3Q15	4Q15	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18
Net Income (Loss)	**$ (725)**	**$(20,883)**	**$ 7,381**	**$(13,106)**	**$(11,297)**	**$(12,844)**	**$(11,260)**	**$(63,300)**	**$ 3,118**	**$ (24,011)**	**$ (8,948)**	**$(17,612)**	**$ (18,425)**	**$ (23,525)**	**$(21,685)**
Income tax expense (benefit)	(1,120)	(11,028)	4,360	(7,333)	(5,795)	(6,245)	1,684	35,341	1,703	(12,601)	(4,956)	(13,165)	(3,109)	(3,103)	(282)
Interest expense (1)	5,847	5,972	6,666	6,092	6,124	6,174	7,345	9,939	5,032	9,115	7,789	8,103	11,148	11,230	12,190
Exploration expense	—	51	—	171	—	1	10	371	—	205	—	421	—	—	109
Depletion, depreciation, amortization and accretion	12,838	13,307	13,021	19,876	15,195	12,549	10,718	13,713	11,974	13,498	16,530	14,955	15,425	20,737	23,775
EBITDAX	**16,840**	**(12,581)**	**31,428**	**5,700**	**4,227**	**(365)**	**8,497**	**(3,935)**	**21,827**	**(13,794)**	**10,415**	**(7,298)**	**5,039**	**5,339**	**14,107**
Rig standby expense (2)	—	—	10	653	313	1,584	364	—	—	—	61	561	—	—	27
Non-recurring costs (3)	—	19	25	1,182	323	321	607	308	—	3,127	337	175	—	—	60
Stock-based compensation	433	433	880	839	95	95	122	135	178	461	346	644	450	2,281	924
(Gain) loss on sale of oil and gas properties	—	—	—	—	—	(1,531)	53	1,404	142	205	119	—	—	—	—
Impairment of oil and gas properties	—	19,328	—	9,295	—	1,938	29,144	4,488	—	27,081	—	6,332	—	—	12,169
Unrealized (gain) loss on derivative financial instruments	3,768	14,908	(10,668)	720	8,429	13,176	4,600	10,163	(8,339)	(3,770)	9,437	19,860	7,594	18,896	9,911
Unrealized (gain) loss on warrants	—	—	—	—	—	—	611	(1,179)	(2,270)	(613)	(402)	198	152	2,462	(509)
Office lease write-off	—	—	—	—	—	—	—	—	—	—	—	—	1,568	—	—
Loss on extinguishment of debit	—	—	—	—	—	—	—	—	—	—	—	—	8,619	—	—
Other (income) expense	663	(4)	18	389	206	819	(29,362)	1,118	(4)	(46)	(4)	(8)	(7)	232	315
Adjusted EBITDAX	**$21,704**	**$ 22,103**	**$21,693**	**$ 18,778**	**$ 13,593**	**$ 16,037**	**$ 14,636**	**$ 12,502**	**$ 11,534**	**$ 12,651**	**$ 20,309**	**$ 20,464**	**$ 23,415**	**$ 29,210**	**$ 37,004**

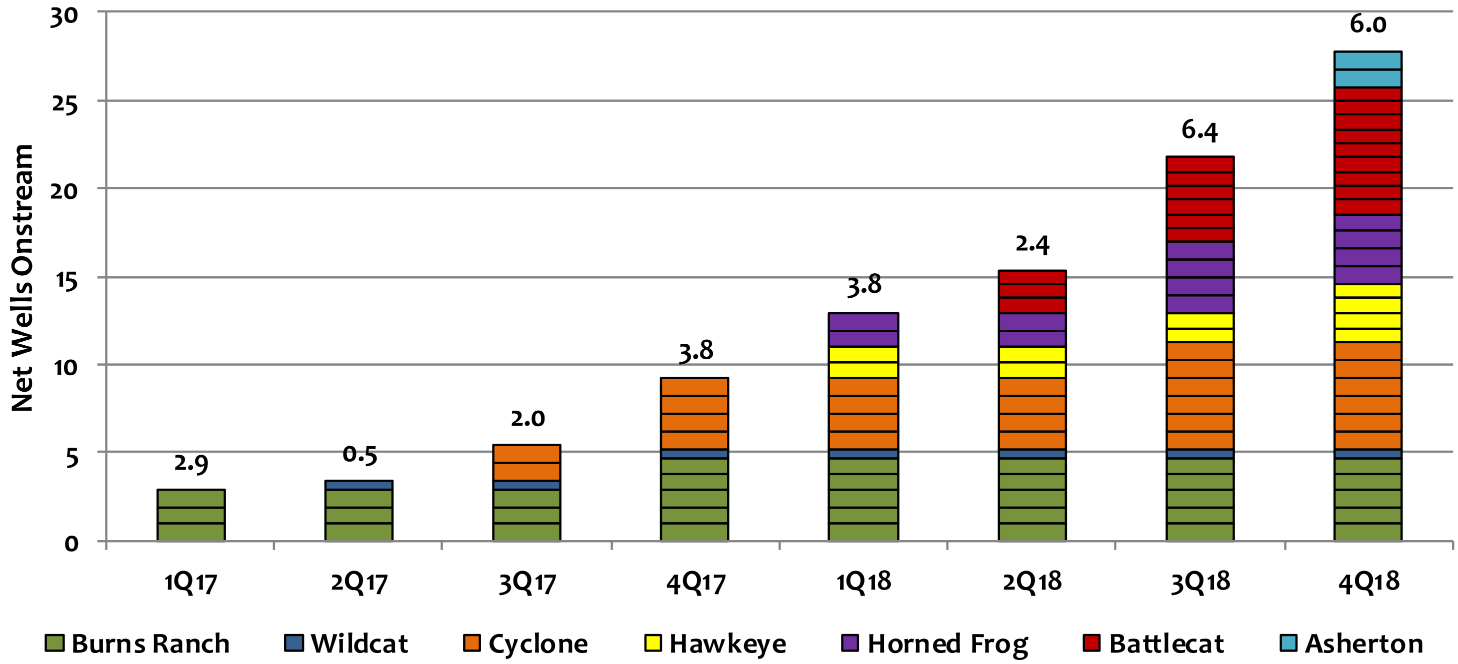
(1) Interest expense consists of Amortization of finance costs and Dividends paid on Series A Preferred Stock.

(2) Represents downtime associated with a drilling rig contract

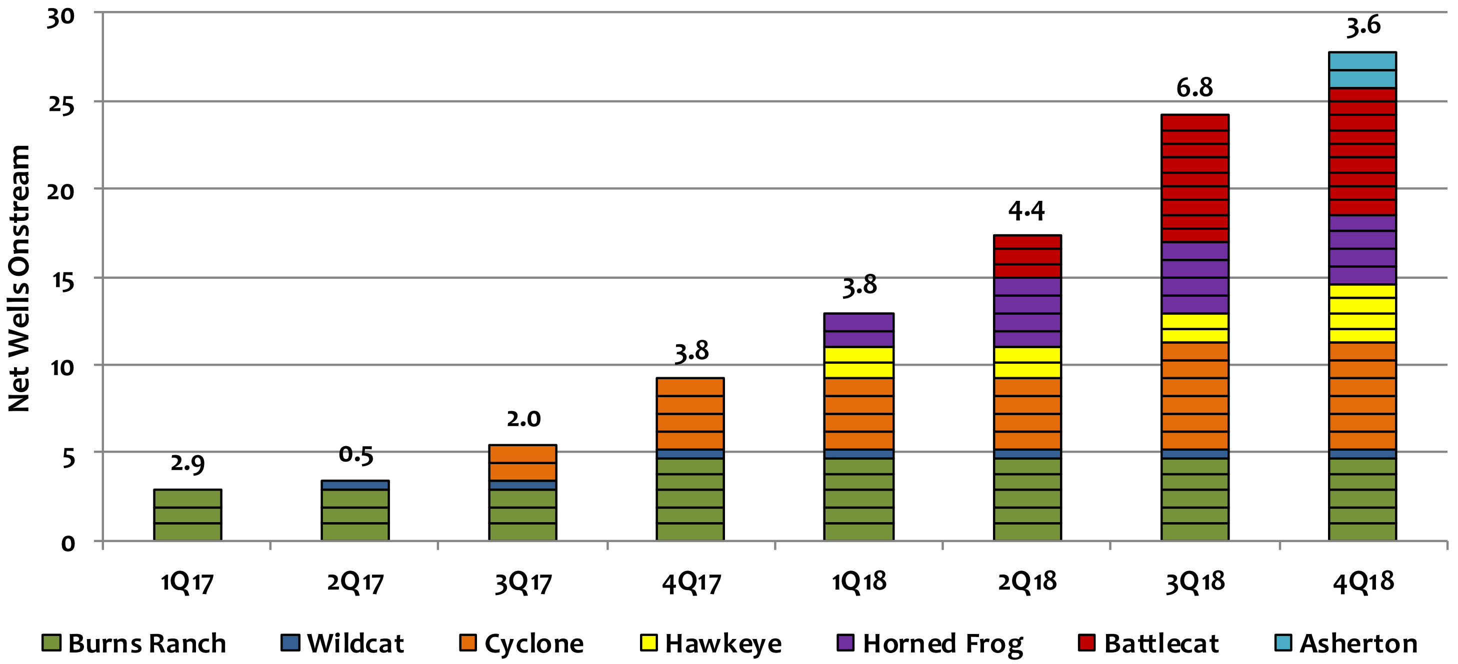
(3) Non-recurring costs consists of Acquisitions Costs and General and Administrative Expenses related to the re-domiciliation to the United States, and listing on the NASDAQ.

Current Completion Schedule

2Q18 Conference Call - 2018 Schedule

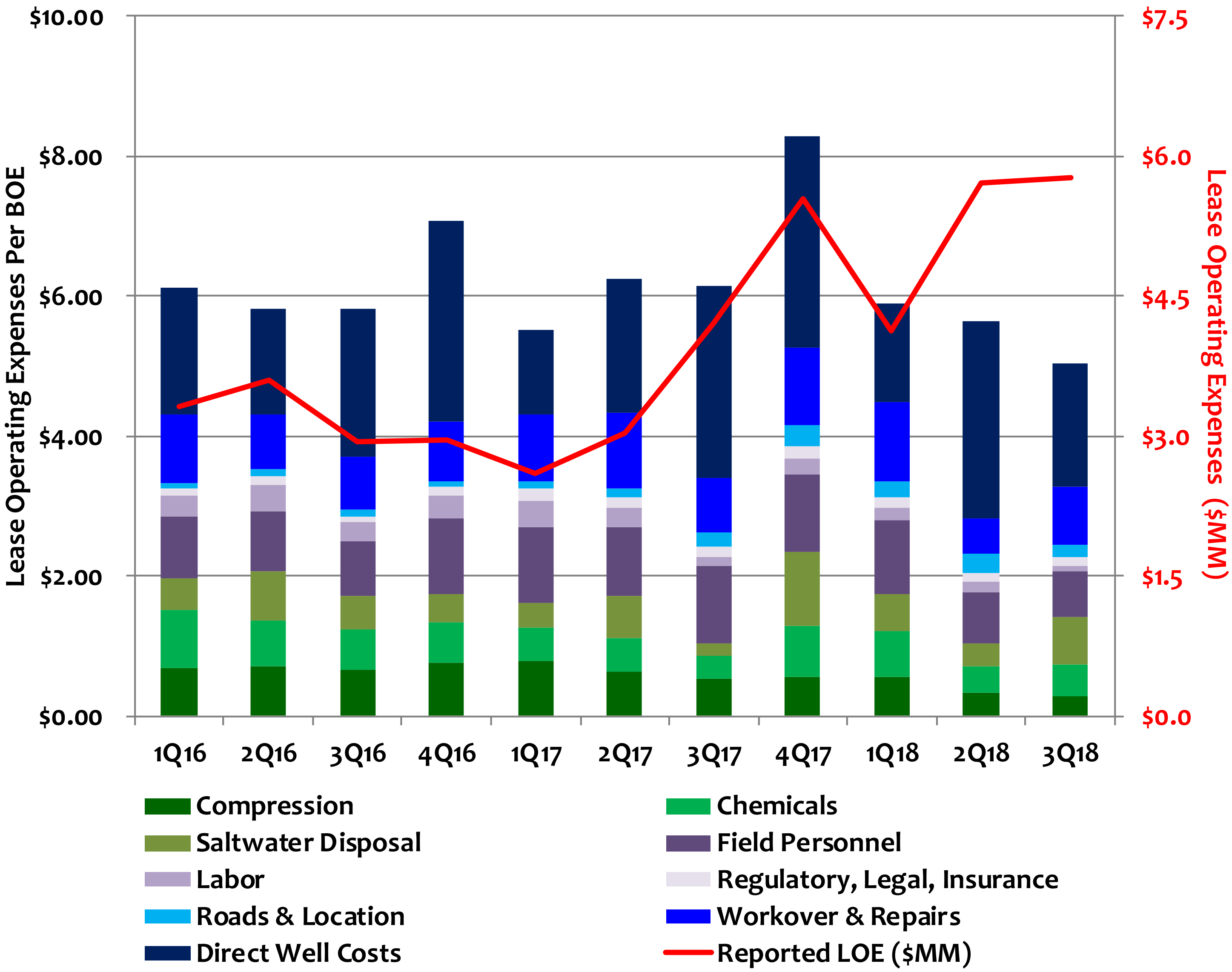


Current 2018 Schedule

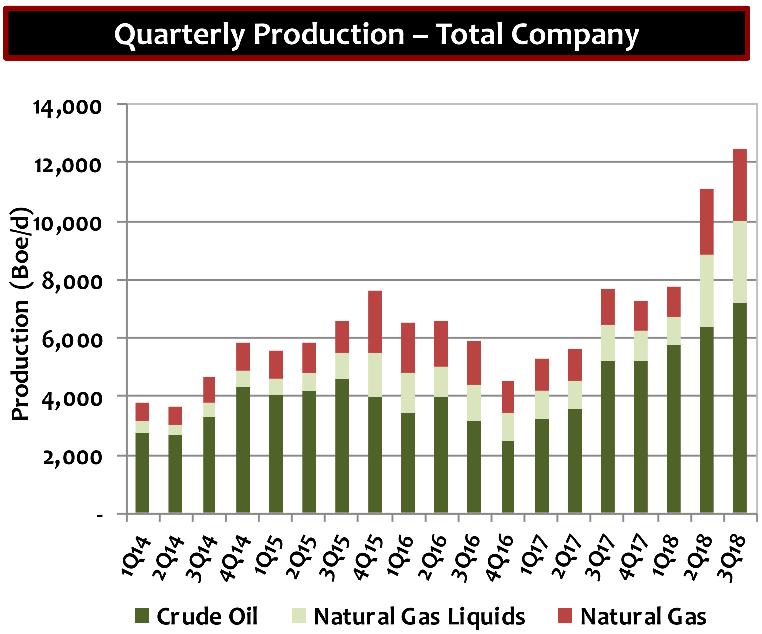


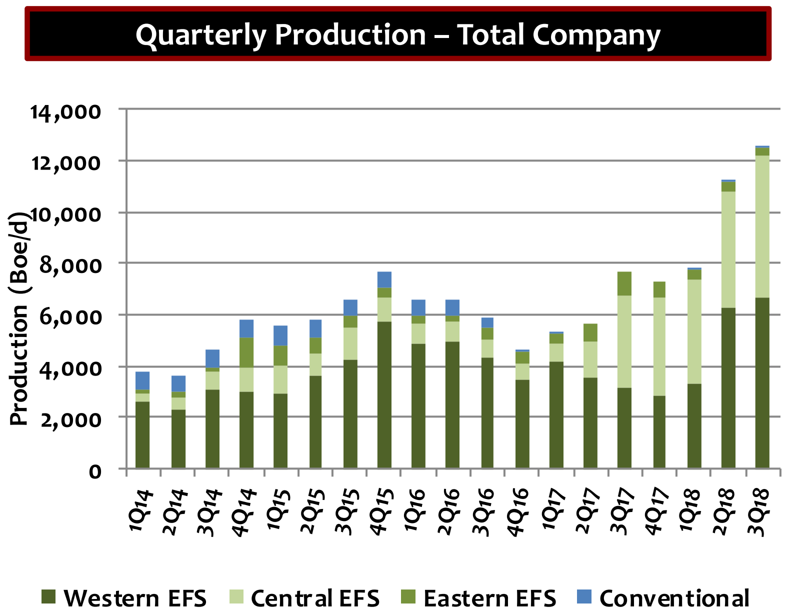
[1] *Two Horned Frog NW wells added in 2Q18 contributed approximately 14 days in June 2018*

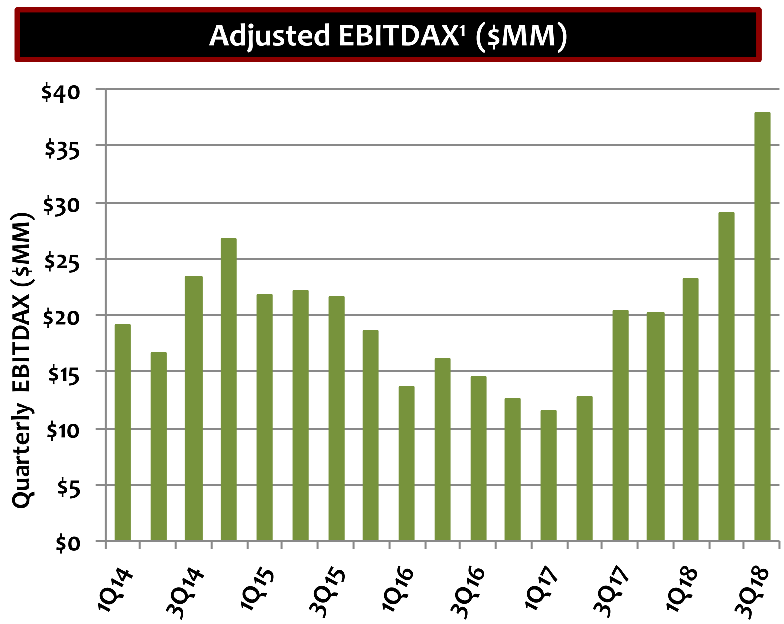
Lease Operating Expenses

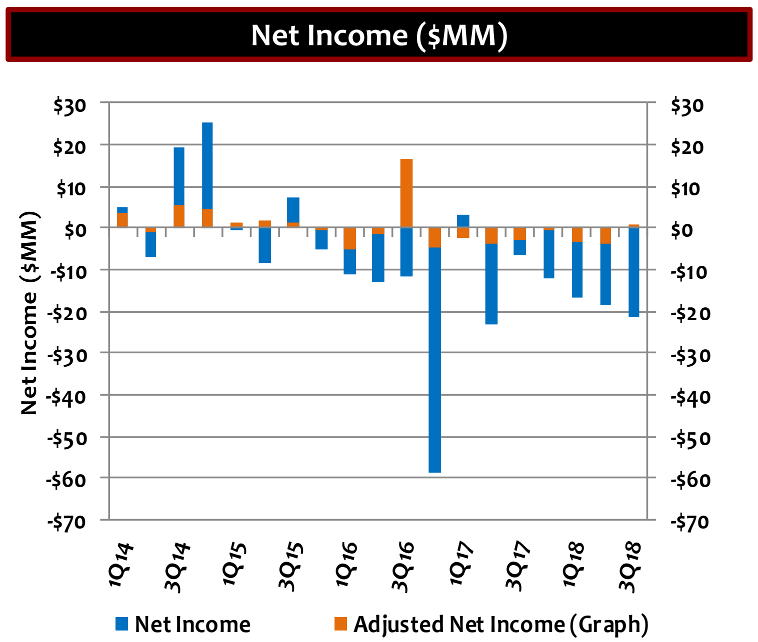


Financial Statistics & Guidance









Note- All 2014 , 2015, 2016, 2017 and 2018 figures are unaudited

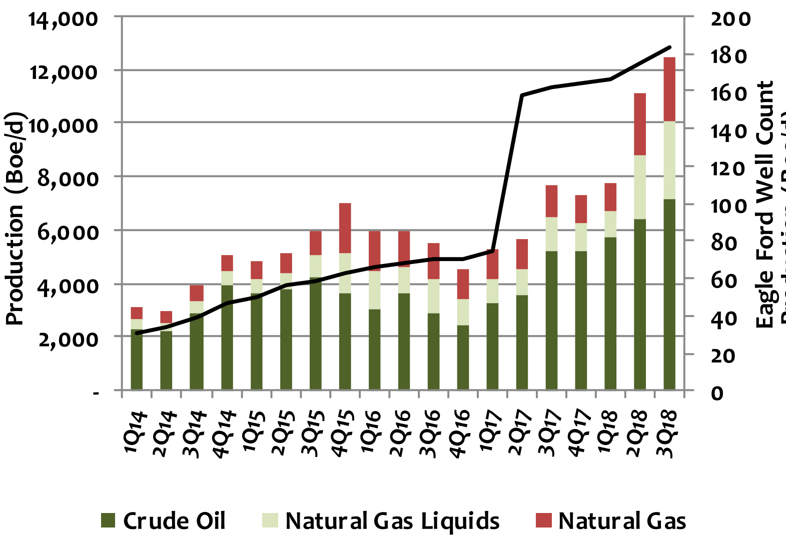
[1] Please see "Non-GAAP Financial Reconciliation" in the Appendix for the definition of Adjusted EBITDAX, a reconciliation of Net Income (loss) to Adjusted EBITDAX, and the reasons for its use.

[2]One-time charges totaling $34.0 million; 27.1 million impairment for Poplar Leasehold, $2.7 million one time expense related to acquisition, $2.0 warrant discount recognition due to early payment on second lien, $1.1 million prepayment premium on second lien, $0.6 million non-recurring general and administrative costs, $0.5 stock based compensation, offset by $0.5 million previously recognized income tax benefits

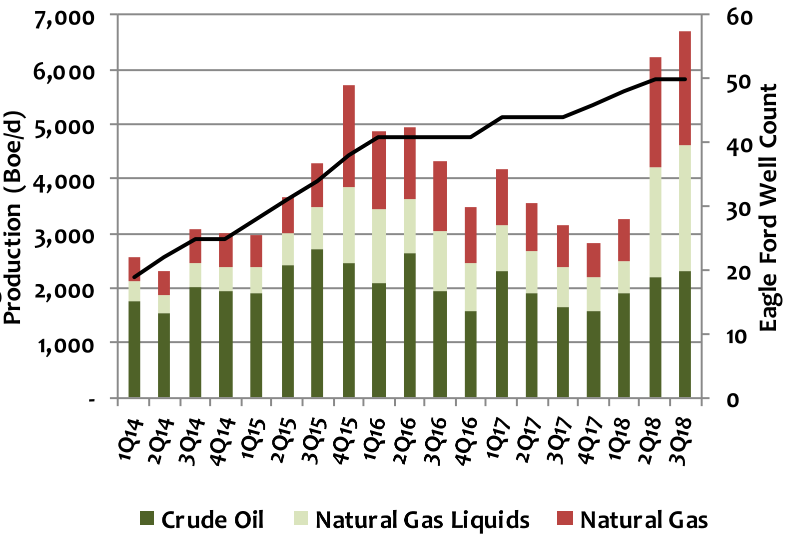
2QFP – 2Q17 Proforma Acquisition

Quarterly Production Summary

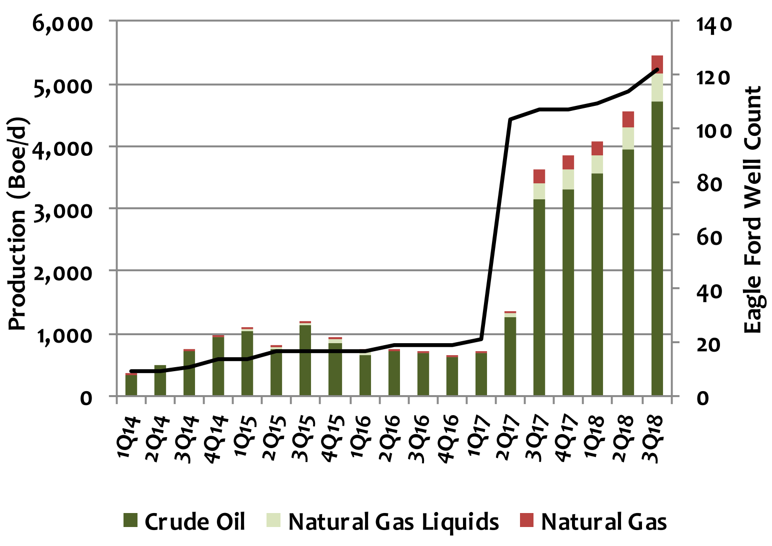
Quarterly Production – Total Eagle Ford



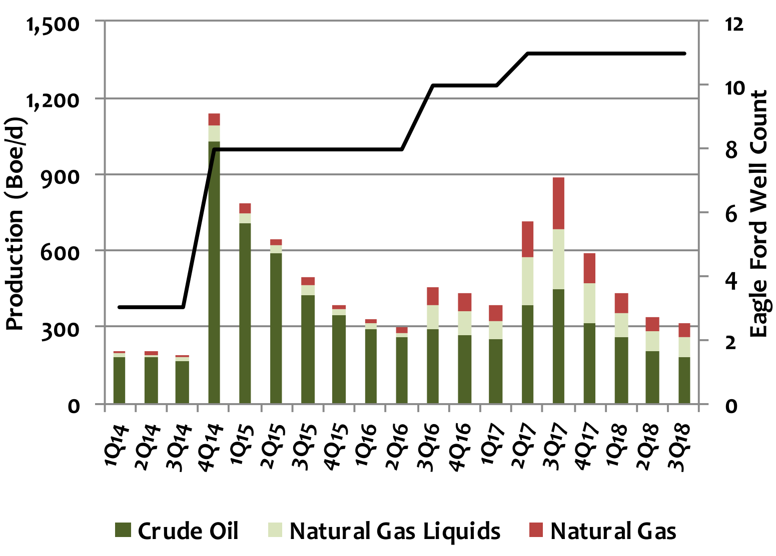
Quarterly Production – Western Eagle Ford



Quarterly Production – Central Eagle Ford



Quarterly Production – Eastern Eagle Ford



** Well count reflects unconventional Eagle Ford Shale wells*

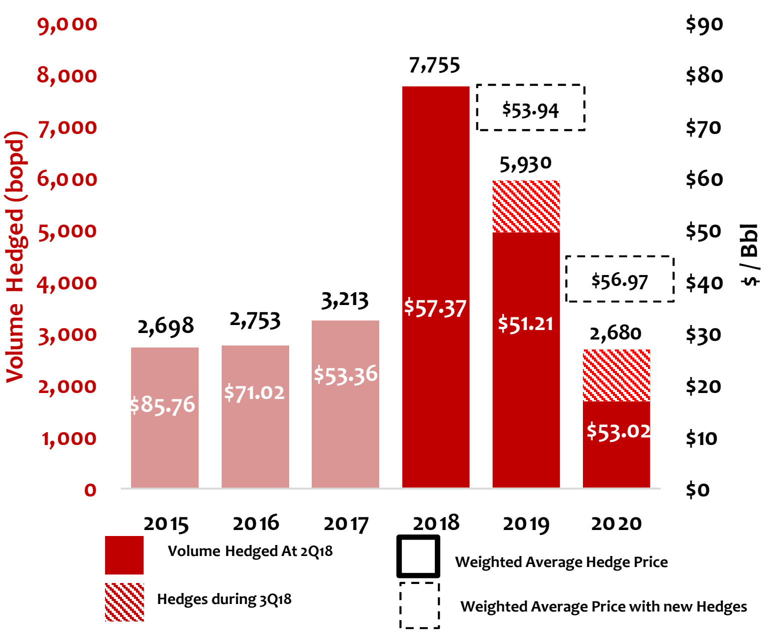
Current Hedge Book

LONESTAR RESOURCES

- Since inception, Lonestar has implemented a strategy to reduce the effects of volatility of oil and natural gas prices on the Company's results of operations by securing fixed price contracts for a portion of its expected sales volumes
- Hedging Program focuses on Crude Oil
- In recent months, Lonestar has entered into additional swap agreements, increasing hedges to 98% of Bal ' 18 and 69% of Cal '19 analysts' consensus forecast oil production.
- During the third quarter, Lonestar bolstered its 2019 hedge book by adding 2.2 MMBbls or 5,930 Bbls/day at a weighted average price of $5.05 of Louisiana Light Sweet (LLS) basis swaps to lock in a premium to WTI.

Crude Oil- WTI Hedge Summary

% of Production Hedged	64%	85%	~69%	~98%[1]	~69%[1]	~29%[1]



2018 Hedging Volumes from October – December 2018

LLS Basis Swaps

Period	Instrument	Volume	Fixed Price
Cal '19	WTI – LLS Swap	5,930 bbls/day	$5.05

Crude Hedge Book at September 30, 2018

Period	Instrument	Volume	Fixed Price
Bal '18	Oil – WTI Swap	7,755 bbls/day	$57.37
Cal '19	Oil- WTI Swap	1,536 bbls/day	$48.04
Cal '19	Oil –WTI Swap	1,394 bbls/day	$50.40
Cal '19	Oil-WTI Swap	1,100 bbls/day	$50.90
Cal '19	Oil-WTI Swap	900 bbls/day	$58.25
Cal '19	Oil-WTI Swap	500 bbls/day	$65.20
Cal '19	Oil-WTI Swap	500 bbls/day	$69.57
Cal '20	Oil-WTI Swap	556 bbls/day	$48.90
Cal '20	Oil-WTI Swap	1,124 bbls/day	$55.06
Cal '20	Oil-WTI Swap	500 bbls/day	$61.65
Cal '20	Oil-WTI Swap	500 bbls/days	$65.56

[1]*Based on analysts' consensus estimates*

Glossary

- "bbl" means barrel of oil.
- bbls/d means the number of one stock tank barrel, or 42 US gallons liquid volume of oil or other liquid hydrocarbons per day.
- "Boe" means barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.
- Boe/d means barrels of oil equivalent per day.
- "scf" means standard cubic feet.
- "btu" means British thermal units.
- "M" prefix means thousand.
- "MM" prefix means million.
- "B" prefix means billion.
- "NGL" means Natural Gas Liquids– these products are stripped from the gas stream at 3rd party facilities remote to the field.
- "TEV" means total enterprise value
- "LTM" means last twelve months
- "NTM" means next twelve months
- "HBP" means held by production
- "EPS" means earnings per share
- "Mcf/d" means thousand cubic feet of natural gas per day
- "IRR" means our internal rate of return, calculates the interest rate at which the net present value of all the cash flows (both positive and negative) from a project or investment equal zero
- "EUR" means gross estimated ultimate recoveries for a single well

Note: One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an industry-standard approximate energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.