Lonestar Resources US, Inc.

Second Quarter 2019 Conference Call

August 6, 2019

Disclaimer and Forward Looking Statements

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 Annual Report on Form 10-K filed with the Securities and Exchange Commission, or the SEC, on March 13, 2019, as well as other documents that we 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.

Key Messages

Key Messages

Second Quarter 2019 Highlights
- Production rose 22% to 13,630 Boe/d, exceeding guidance of 12,400-12,800 Boe/d
- Adjusted EBITDAX rose 15% to $33.5 MM, exceeding guidance of $30 to $32 MM
- New wells onstream ahead of schedule and exceed Type Curve forecasts

Outstanding Price Realizations Continue
- Crude Oil- realizations were +$3.24/bbl vs. WTI
- Natural Gas- realizations were -$0.10/Mcf vs. Henry Hub

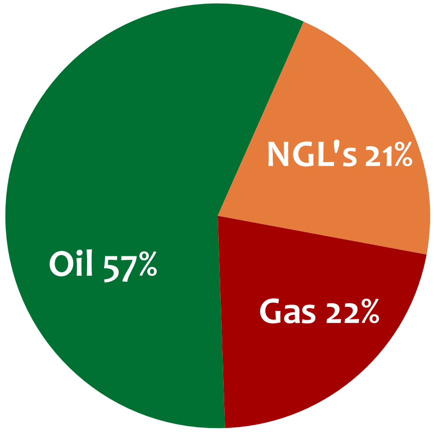
New Wells Have Ramped Production to Over 16,000 Boe/d in July
- Horned Frog NW (100% WI / LaSalle) 2 wells @ Max-30 rates of 1,482 Boe/d (avg)
- Georg (100% WI / Karnes) 4 wells @ Max-30 rates of 1,045 Boe/d (avg)
- Horned Frog South (100% WI / La Salle) 2 wells @ Max-30 rates of 2,493 Boe/d (avg)
- Sooner (100% WI / DeWitt) 3 wells @IP24 rates of 3,460 BOE/d (avg)

Third Quarter 2019 Guidance- Significant Growth
- Production guidance of 17,000-17,500 Boe/d
- Adjusted EBITDAX guidance of $36.0 to $37.5 MM
- Oil price +$1.20/bbl to WTI & gas price -$0.05 to HH

Hedge Book Provides Cash Flow Certainty
- Bal '19- 90% oil swapped @$54.58/bbl / 50% gas swapped @$2.83/MMBTU
- Cal '20- 80-90% oil swapped @ $56.95/bbl / 45-55% gas swapped @ $2.59/MMBTU
- Cal '21- 35% oil swapped @ $54.68/bbl

Two-Year Plan to Achieve High Returns & Self-Funded Growth
- 2019 Guidance- Increased to 14,800-15,000 Boe/d & $135-$140 MM EBITDAX
- 2020 Target- 19% growth of 17,000-18,300 Boe/d & $165-$185 MM EBITDAX
- 2020 Target- Can be achieved with 15-16 wells, which would generate $5-$20 MM of free cash flow

2Q19 Production By Product



Product	Volume
Crude Oil	7,795 bbl/d
NGL's	2,901 bbl/d
Natural Gas	17,601 Mcf/d
Total	**13,630 Boe/d**

Key Financial Highlights

LONESTAR RESOURCES

Financial Commentary

2Q19 Volumes Up 20% to 13,630 Boe/d

- *8 New Completion Contribute in Qtr.*
  - *Horned Frog NW #4H, #5H (La Salle County)*
    - Onstream April 2019
    - 2.0 gross / 2.0 net wells
  - *Georg #3H, #4H, #5H, #6H (Karnes County)*
    - Onstream May 2019
    - 4.0 gross / 3.2 net wells
  - *Horned Frog F #A1H, #B1H (La Salle County)*
    - Onstream June 2019
    - 2.0 gross / 2.0 net wells

Per Unit Expenses

Unit Expenses Are Declining…

- *Expect More Scale in 3Q19 Results*
- LOE- $6.35 per Boe ↓3% Q-o-Q
- G,P&T- $0.60 per Boe ↓30% Q-o-Q
- Taxes- $2.27 per Boe ↑2% Q-o-Q
- G&A- $3.02 per Boe ↓10% Q-o-Q
- Int. Exp.- $8.19 per Boe ↓16% Q-o-Q
- Total.- $20.43 per Boe ↓10% Q-O-Q

Product Pricing

Product Pricing Increased 6%…

- *Benchmark Prices Were Mixed Q-O-Q*
  - *WTI up $4.91 to $59.81/bbl in 2Q19*
  - *HH down $0.36 to $2.56/MMBTU in 2Q19*
- *Crude Oil Diffs Led The Way in 2Q19*
  - *Oil price differentials were +$3.23/bbl vs. WTI*
    - Increased 11%, or $6.12/bbl vs. 1Q19
  - *NGL price differentials were 22% of WTI*
    - Decreased 14% , or $2.16/bbl vs. 1Q19
    - 2Q19 was 22% of WTI vs. 28% of WTI in 1Q19
  - *Gas price differentials were -$0.10/Mcf vs. HH*
    - Decreased 15%, or $0.45 vs. 1Q19

Per Unit Revenues

…Cash Margins Rose 27% in 2Q19

- Revenues- $42.10 per Boe, ↑6% Q-o-Q
- Expenses- $20.43 per Boe, ↓10% Q-O-Q
- Total.- $21.67 per Boe, ↑27% Q-o-Q

Daily Production

Product	1Q19	Mix	2Q19	Mix
Crude Oil	6,557	58%	7,795	57%
NGL's	2,417	21%	2,901	21%
Natural Gas	14,391	21%	17,601	21%
Total	11,372	100%	13,630	100%

Product Pricing / Revenues

	$MM			$ / Boe		
Product	1Q19	2Q19	Chg.	1Q19	2Q19	Chg.
Crude Oil	$33.6	$44.7	+33%	$56.92	$63.04	+11%
NGL's	$3.4	$3.5	+5%	$15.60	$13.44	(14%)
Nat. Gas	$3.8	$3.9	+5%	$2.91	$2.46	(15%)
Total	$40.7	$52.2	+28%	$39.80	$42.10	+6%

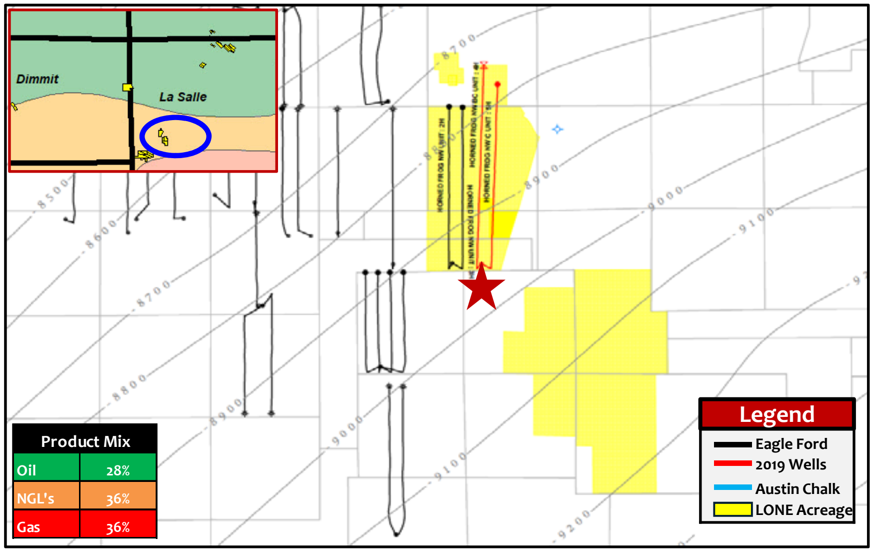
Cash Expenses[1]

	$MM			$ / Boe		
Expense	1Q19	2Q19	Chg.	1Q19	2Q19	Chg.
LOE[2]	$6.7	$7.9	+17%	$6.57	$6.35	(3%)
G,P&T[3]	$0.9	$0.7	(15%)	$0.86	$0.60	(30%)
Taxes	$2.3	$2.8	+23%	$2.24	$2.27	+2%
G&A[4]	$3.5	$3.7	+8%	$3.37	$3.02	(10%)
Int. Exp.[5]	$10.0	$10.2	+2%	$9.73	$8.19	(16%)
Total	$23.3	$25.3	+9%	$22.76	$20.43	(10%)
Cash Margin	$17.4	$26.9	+54%	$17.04	$21.67	+27%

[1] Cash Operating Costs are controllable expenses incurred by the Company
[2] LOE – Excludes $0.3 million of rig stand-by expense
[3] G,P&T – Gathering, processing and transportation expense
[4] Excludes stock-based compensation
[5] Excludes amortization of debt issuance cost, premiums & discounts

Horned Frog Northwest (La Salle County)

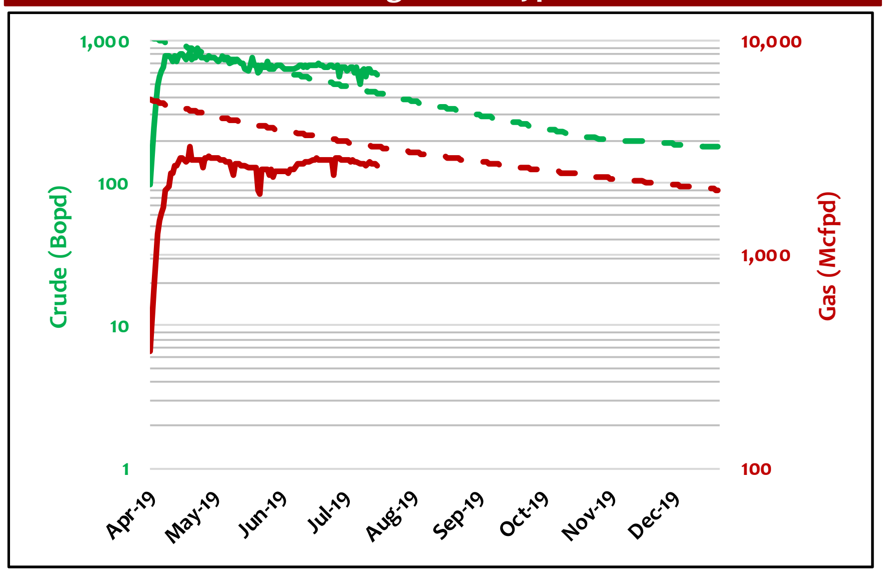
Horned Frog NW Activity Map



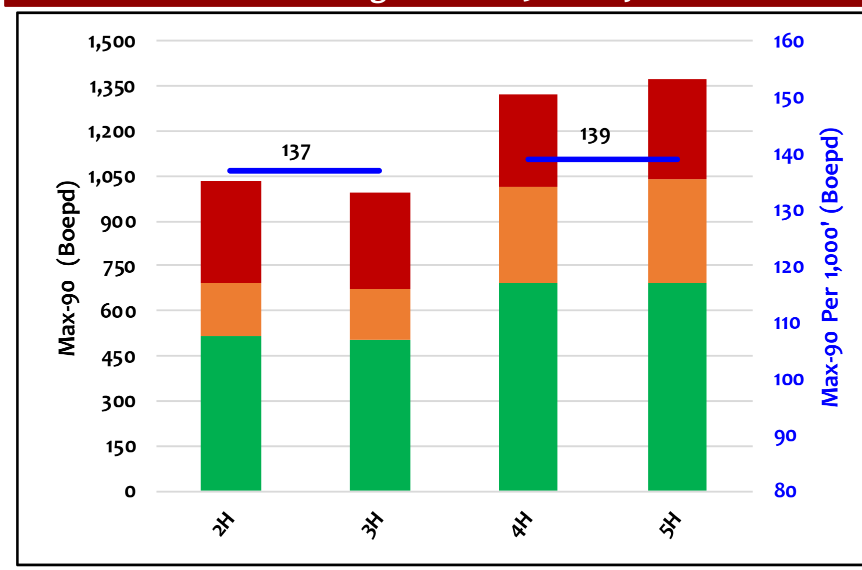
Horned Frog NW Highlights

- In 2018, LONE completed 2 wells, which averaged Max-30 rates of 1,049 Boe/d (7,400’ laterals)
- In April, 2019, HFNW #4H & #5H were placed online, yielding avg. Max-30 rates of 1,453 Boe/d (9,708’ laterals)
- Through 90 days, 2019 wells are exhibiting higher productivity per foot vs. shorter 2018 laterals
- Outpacing 1.5 MMBOE third-part reserve estimate
- Current oil rates are 35% above forecast:
  - Targeting
  - Stimulation
  - Choke Management
- Lonestar plans additional drilling here in 2020

Horned Frog NW vs Type Curve

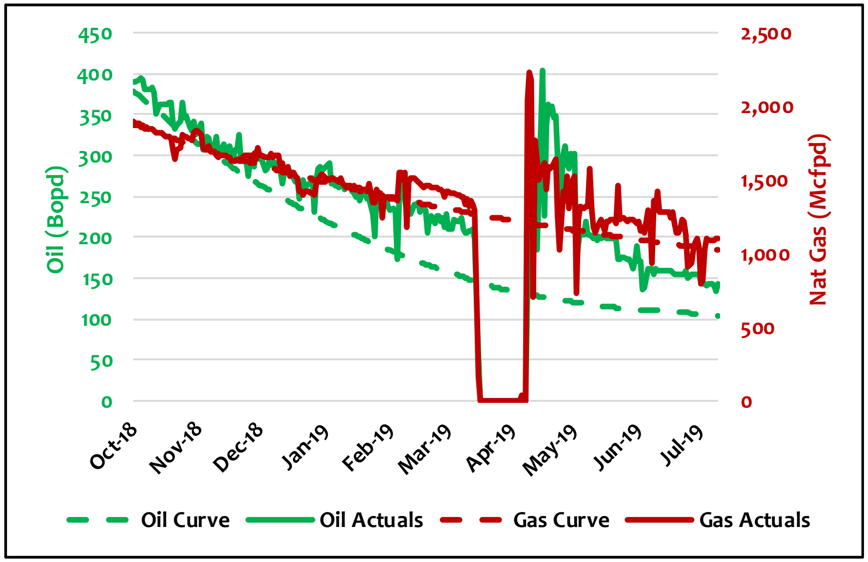


Horned Frog NW Max-90 Analysis



Horned Frog Northwest ("Parent / Child")

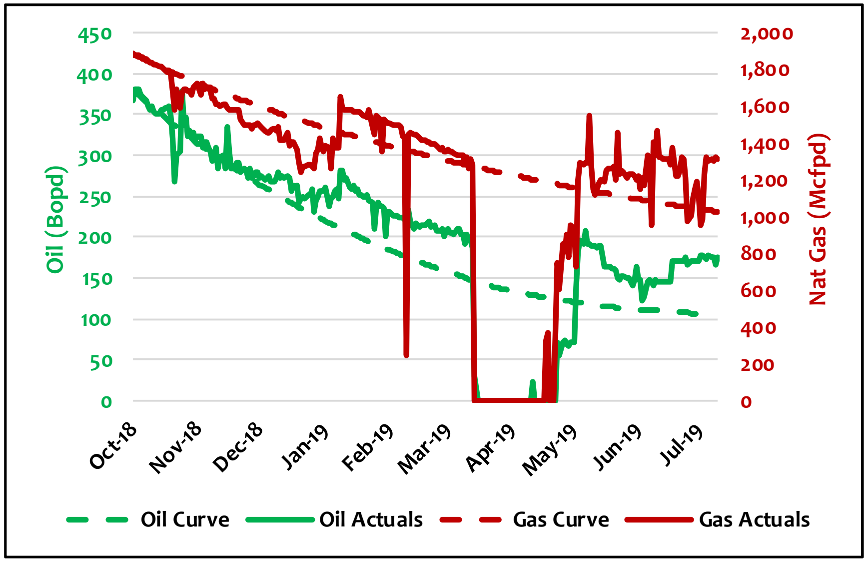
Horned Frog NW 2H – Recovery From Frac Hit



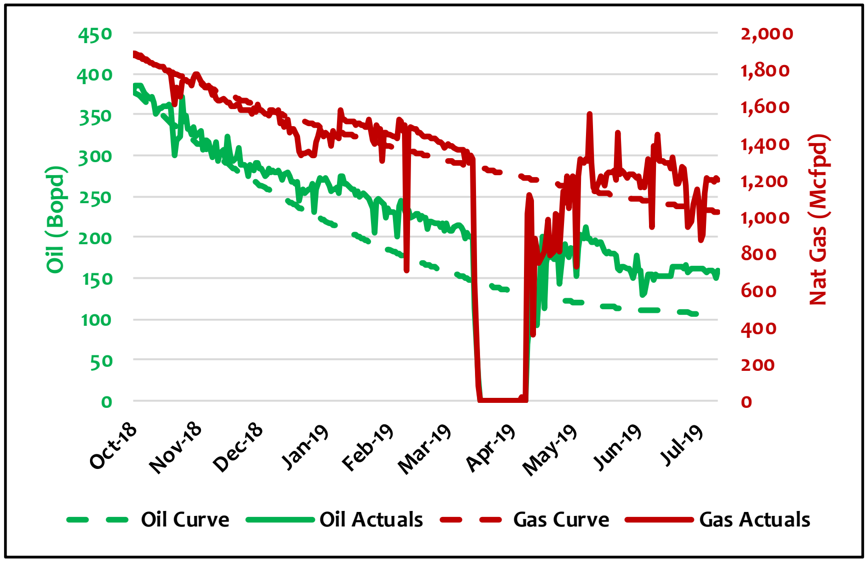
Horned Frog NW Frac Hits

- "Child" wells, the completed in 2019 (#4H-#5H) have outperformed the "Parent" wells in 2018 (#2H#3H)
- Prior to being shut-in for Child fracs, the #2H-#3H had outperformed third-party type curve by 10%
- After being placed back online, Parent wells continue to outperform Type Curve, and follow production decline trends exhibited prior to shut-in, at higher rates

Horned Frog NW 3H – Recovery From Frac Hit

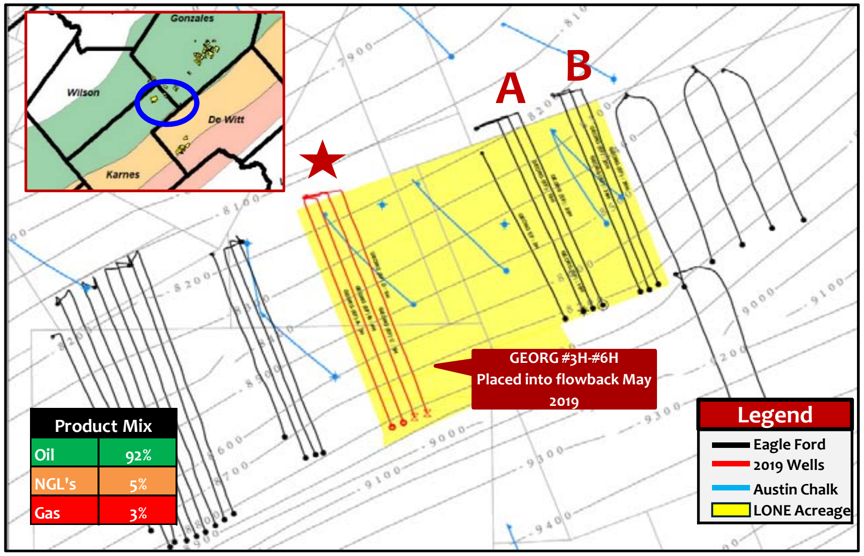


Horned Frog NW 2H & 3H Average Recovery



Karnes County

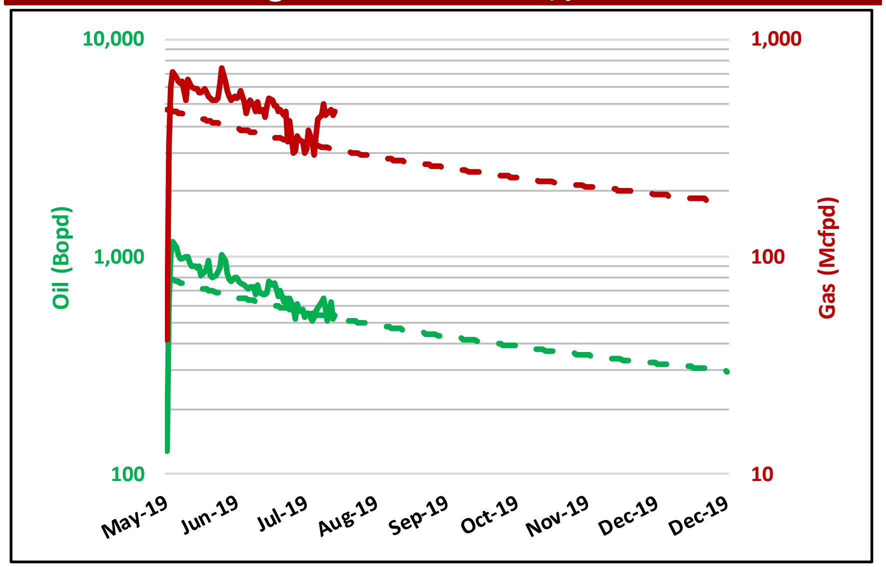
Karnes Co. Activity Map



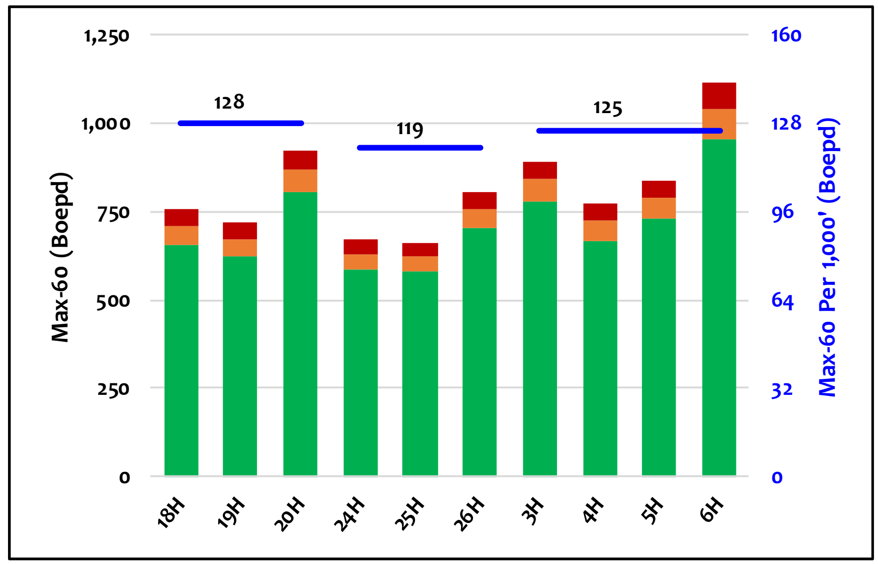
Karnes County Highlights

- In 2018, LONE completed 6 wells, which averaged Max-30 rates of 908 Boe/d (6,245' laterals)
- Lonestar added contiguous leasehold through swaps and primary term leasing, allowing for longer laterals
- In May, 2019, Georg #3H-#6H were placed into flowback, yielding avg. Max-30 rates of 1,045 Boe/d (7,231' laterals)
- Through 60 days, 2019 long laterals are exhibiting the same productivity per foot as 2018 laterals
- 2019 wells have EUR's of 0.6 MMBOE, cost $6.4 MM
- Lonestar currently plans additional drilling in 2020

Georg 3H-6H Actuals vs. Type Curve

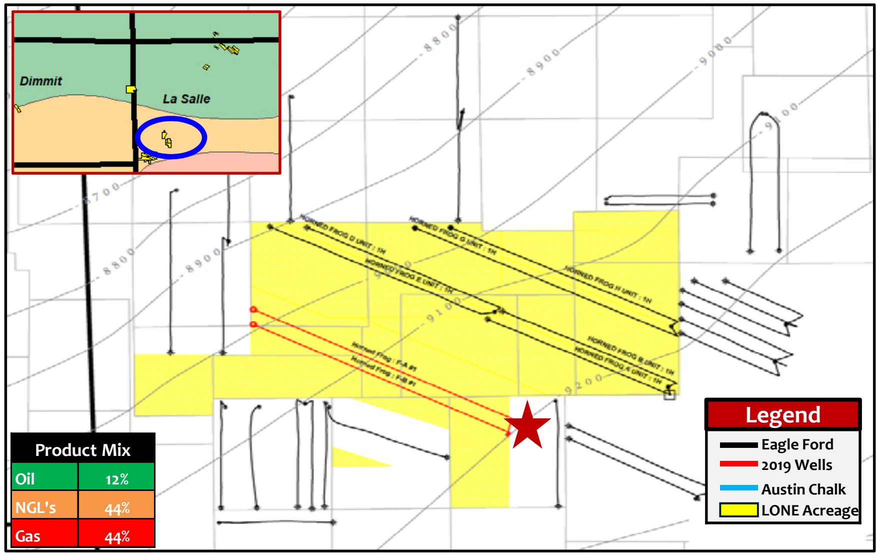


Karnes County Max-60 Analysis



Horned Frog South (La Salle County)

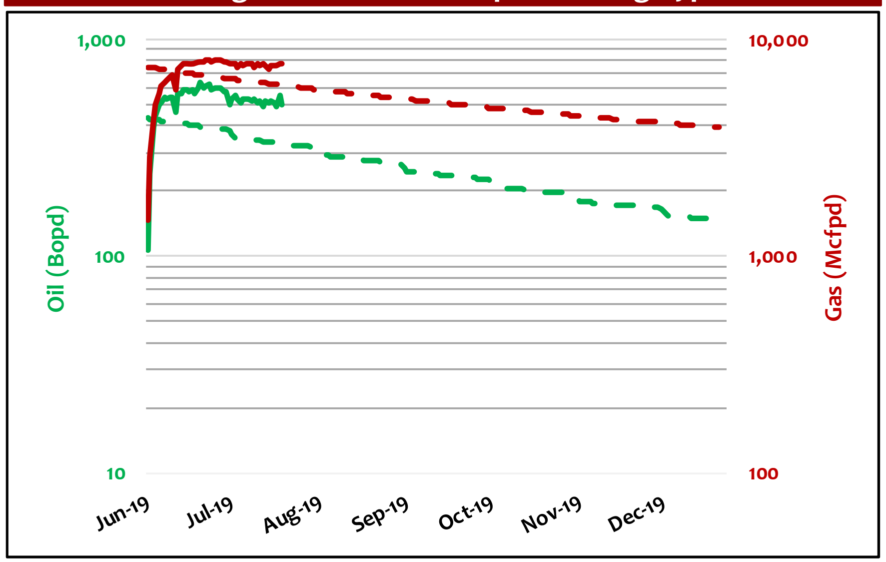
Horned Frog South Activity Map



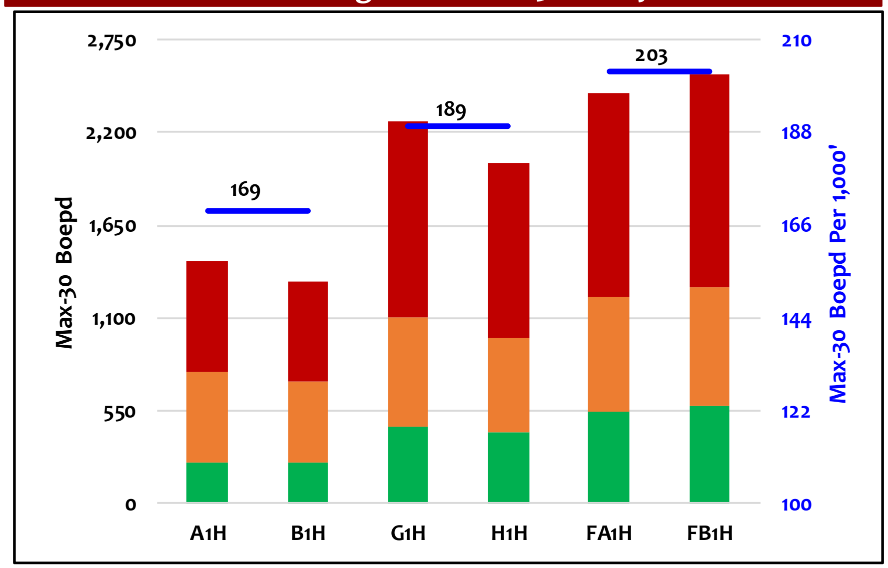
Horned Frog South Highlights

- In 2018, LONE completed 2 wells, which averaged Max-30 rates of 2,148 Boe/d (11,300' laterals)
- In June 2019, F A#1H & F B#1H were placed into flowback, with avg. Max-30 rates of 2,493 Boe/d (12,300' laterals)
- Acquisition of contiguous leasehold allowed for extension of laterals (cost- $0.3 MM)
- Through 30 days, 2019 wells are exhibiting higher productivity per foot than 2018 laterals (+8%)
- 2019 wells have produced 17% more oil-per-ft than 2018 wells
- Lonestar currently plans additional activity here in 2020

Horned Frog F A & B Wells Outperforming Type Curve

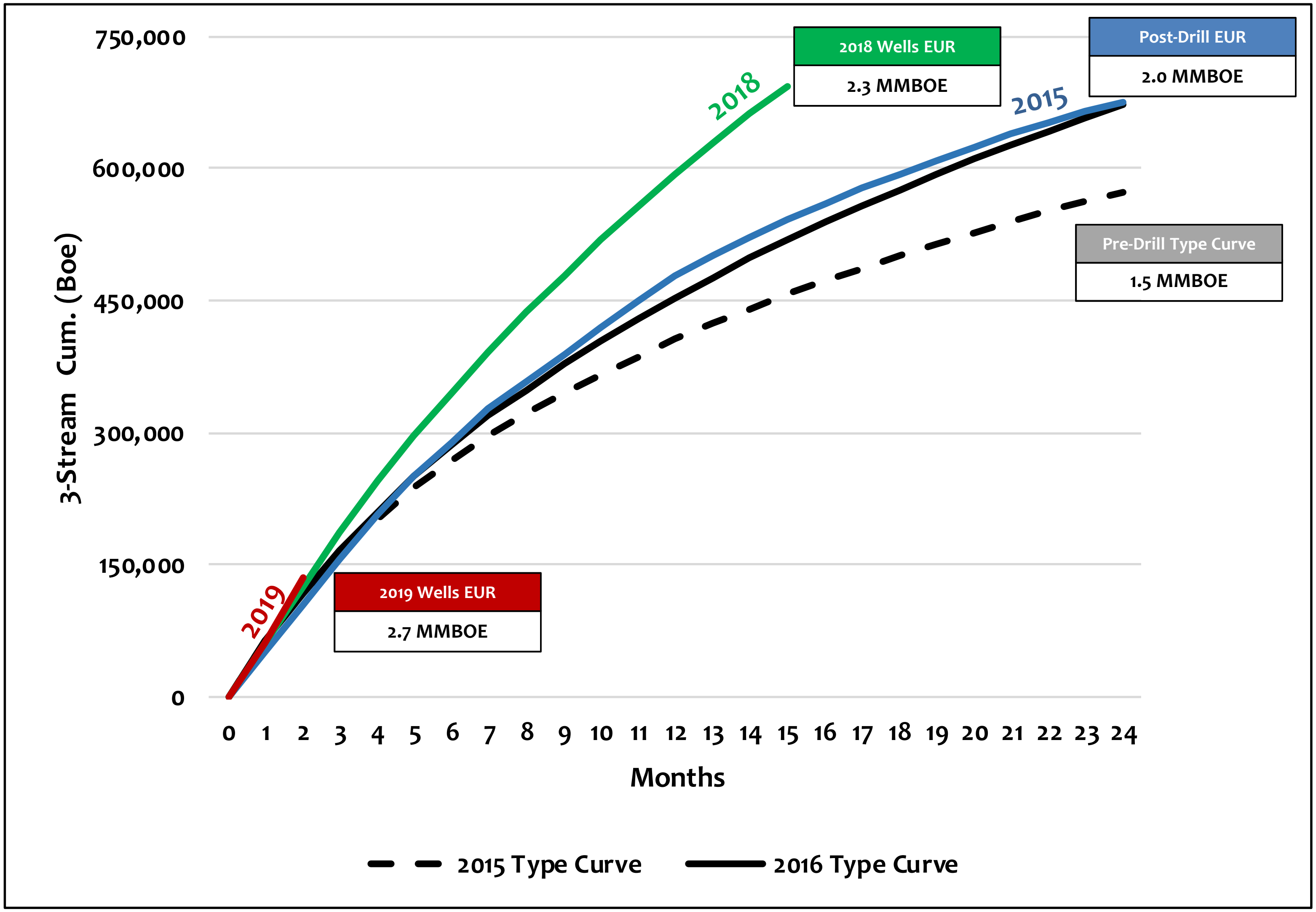


Horned Frog South Max-30 Analysis



Horned Frog South- EUR Progress

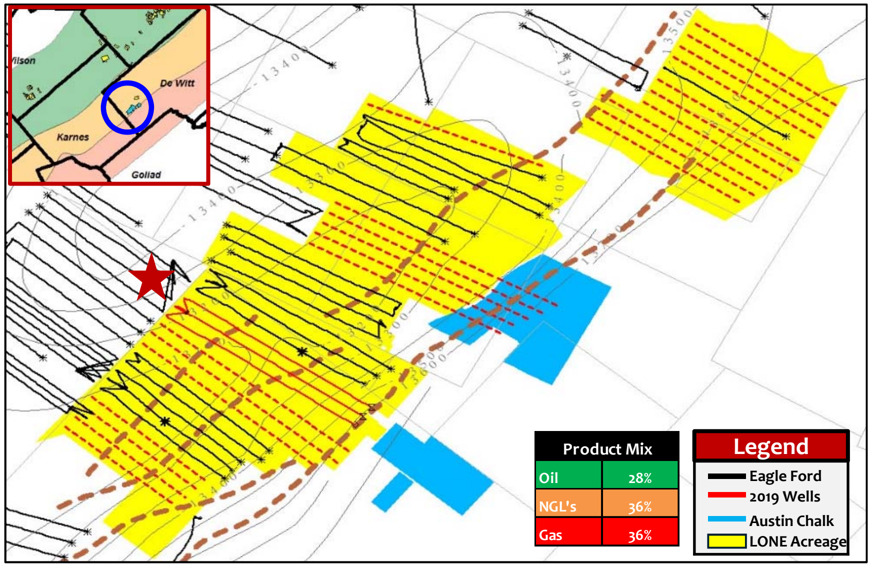
Horned Frog South Cum vs Time Plot [1]



[1] *All reserves figures are normalized to 12,000' laterals*

Sooner (De Witt County)

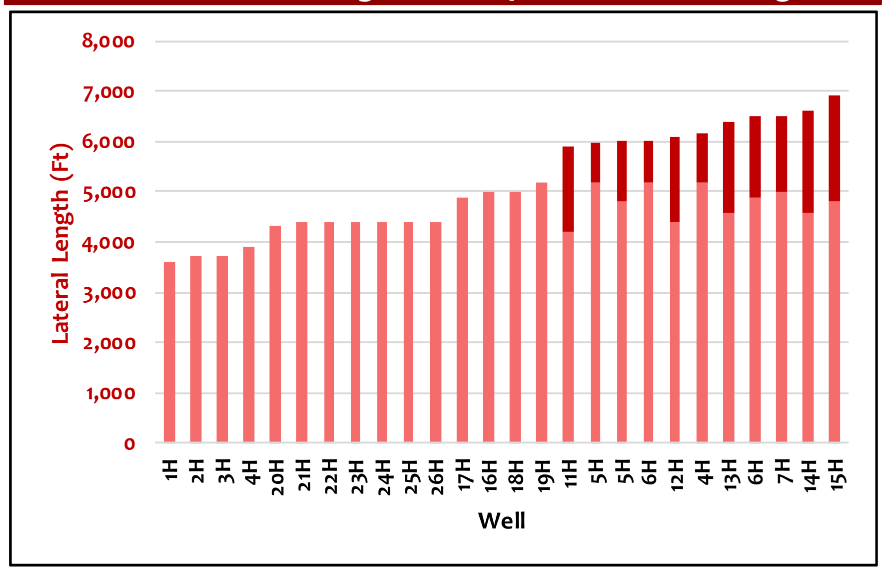
Sooner Activity Map



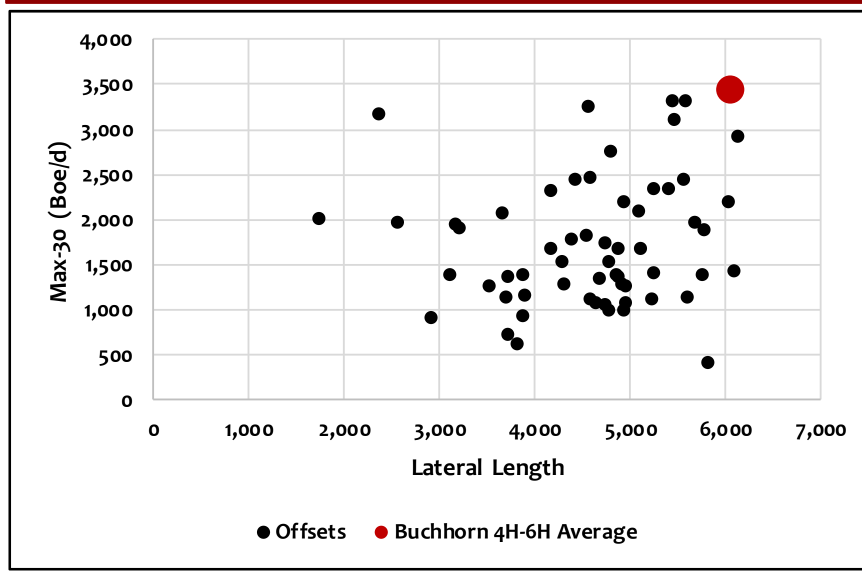
Sooner Highlights

- Buchhorn#4H-#6H went into flowback mid-July.
- Seismic Interpretation allowed for extending laterals through previously mapped faults
- Added leasehold to further extend laterals by ~1,000'
  - Added $1.7 MM to pad cost
  - Proppant / Ft. ~2,000#
  - Initial Flowing Tubing Pressures @7,900 psi
- Current test rates are an average of 3,460 Boe/d
  - 531 bbl/d oil
  - 1,299 bbl/d NGL's
  - 9,762 Mcf/d natural gas
- Lonestar currently plans activity here in 2020

Geoscience and Leasing Extend Operated Lateral Lengths

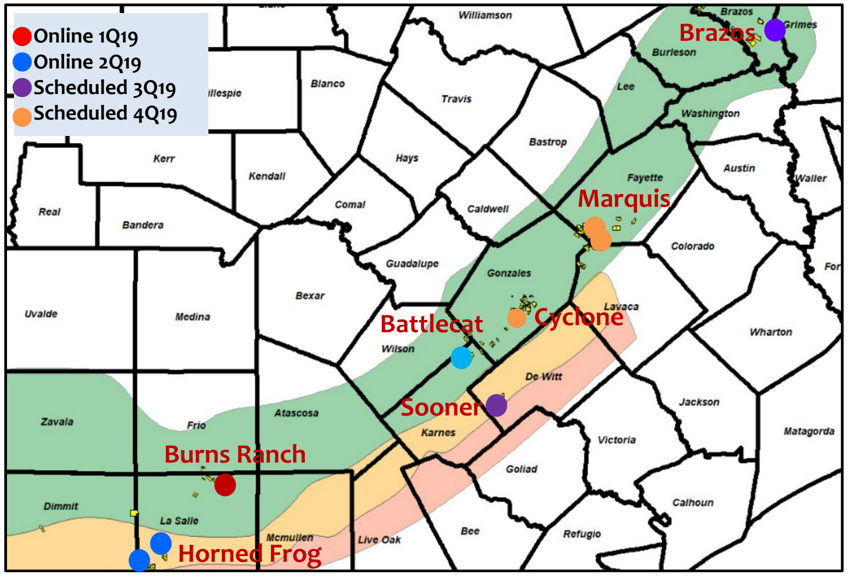


Sooner Buchhorn #4H-#6H vs. Offsets



2019 Schedule

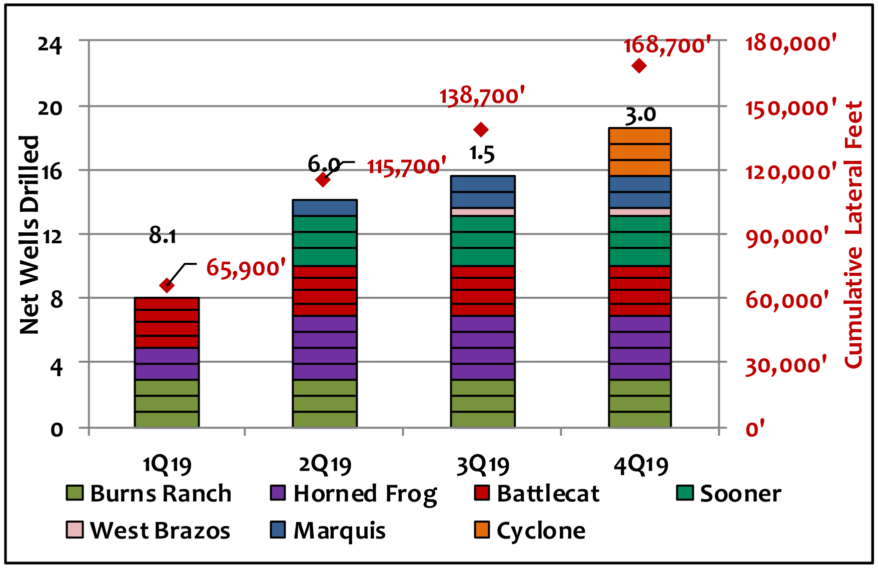
2019 Activity Map (onstream)



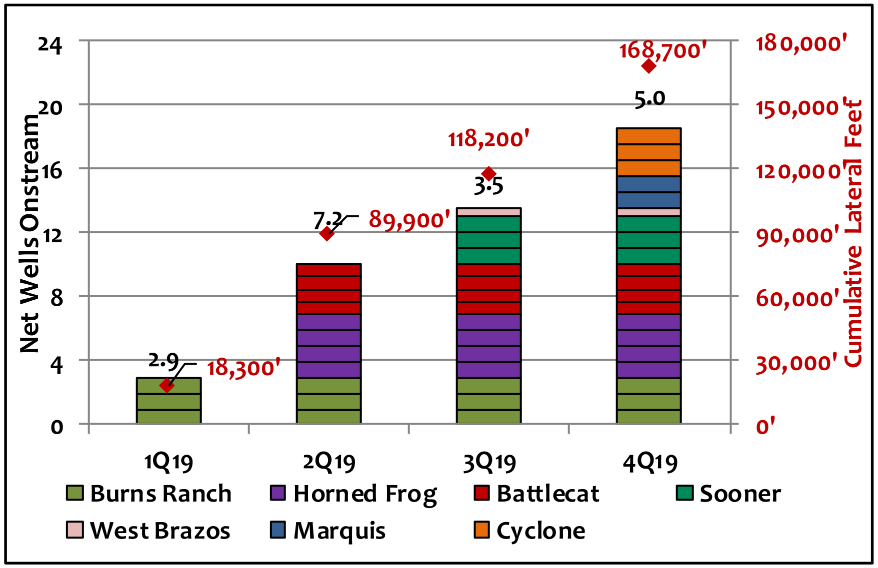
Drilling & Completion Stats

- To date, Lonestar has drilled 17 gross / 15.6 net wells with a total of 138,700' of perforated lateral, representing 82% of the planned wells drilled in 2019 – leaving 3 wells to drill for the remainder of 2019
- To date, Lonestar has completed stimulation on 14 wells with a total of 365 stages, while averaging over 4 stages per day – putting us ahead of schedule

Drilling Schedule



Completion Schedule



Quarterly Highlights

Guidance

	2Q19		3Q19 Guidance		
Product	**Reported**	**Mix**	**Low**	**High**	**Mix**
Crude Oil (bbl/d)	7,786	57%	7, 700	7,800	45%
NGL's (bbl/d)	2,907	21%	4,380	4,550	26%
Nat. Gas (Mcf/d)	17,599	22%	29,500	31,000	29%
Total (boe/d)	**13,626**	**100%**	**17,000**	**17,500**	**100%**
Adj. EBITDAX ($MM)	**$33.5**	---	**$36.0**	**$37.5**	---

Outstanding Well Results

- **Horned Frog NW (100% WI / LaSalle) 2 wells @ Max-30 rates of 1,482 Boe/d**
- **Georg (100% WI / Karnes) 4 wells @ Max-30 rates of 1,045 Boe/d**
- **Horned Frog South (100% WI / La Salle) 2 wells @ Max-30 rates of 2,493 Boe/d**
- **Sooner (100% WI / DeWitt) 3 wells recently tested at rates of 3,460 Boe/d**

Third Quarter 2019 Guidance

Third Quarter 2019 Guidance

- **Production guidance- 17,000 Boe/d to 17,500 Boe/d, up 25-28% sequentially**
- **Adjusted EBITDAX guidance- to $36.0-$37.5 MM, or 8-11% sequentially**

Outstanding Price Differentials Continue

- **Crude Oil- guided to +$2.00-$2.50/bbl vs. WTI**
- **NGL's- guided to 25% of WTI**
- **Natural Gas- guided to -$0.10/Mcf vs. HH**

Scale Continues to Drive Down Unit Operating Costs

- **Lease Operating Expense- $8.3-$8.5 MM, or $5.35-$5.45/ Boe**
- **G&A Expense- $3.3-$3.4 MM, or $2.10-$2.20/ Boe**

Going Forward…

2019 Results Exceeding Guidance

- **Well performance has been excellent**
- **17 of 20 wells have been drilled, 3 awaiting completion**
- **Increased guidance from 13,700-14,700 Boe/d to 14,800-15,000 Boe/d**

2020 Targets Can Be Achieved With Less Capital[1]

- **Production Target- 17,000-18,300 Boe/d**
- **EBITDAX Target- $165-$185 MM**
- **Can be achieved with 15-16 wells**
- **Can be achieved with $115-$120 MM of D&C Capital**

[1] The Lonestar Board of Directors has not approved a 2020 budget. All Targets subject to approval of a capital program

Lonestar Resources US, Inc.

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.

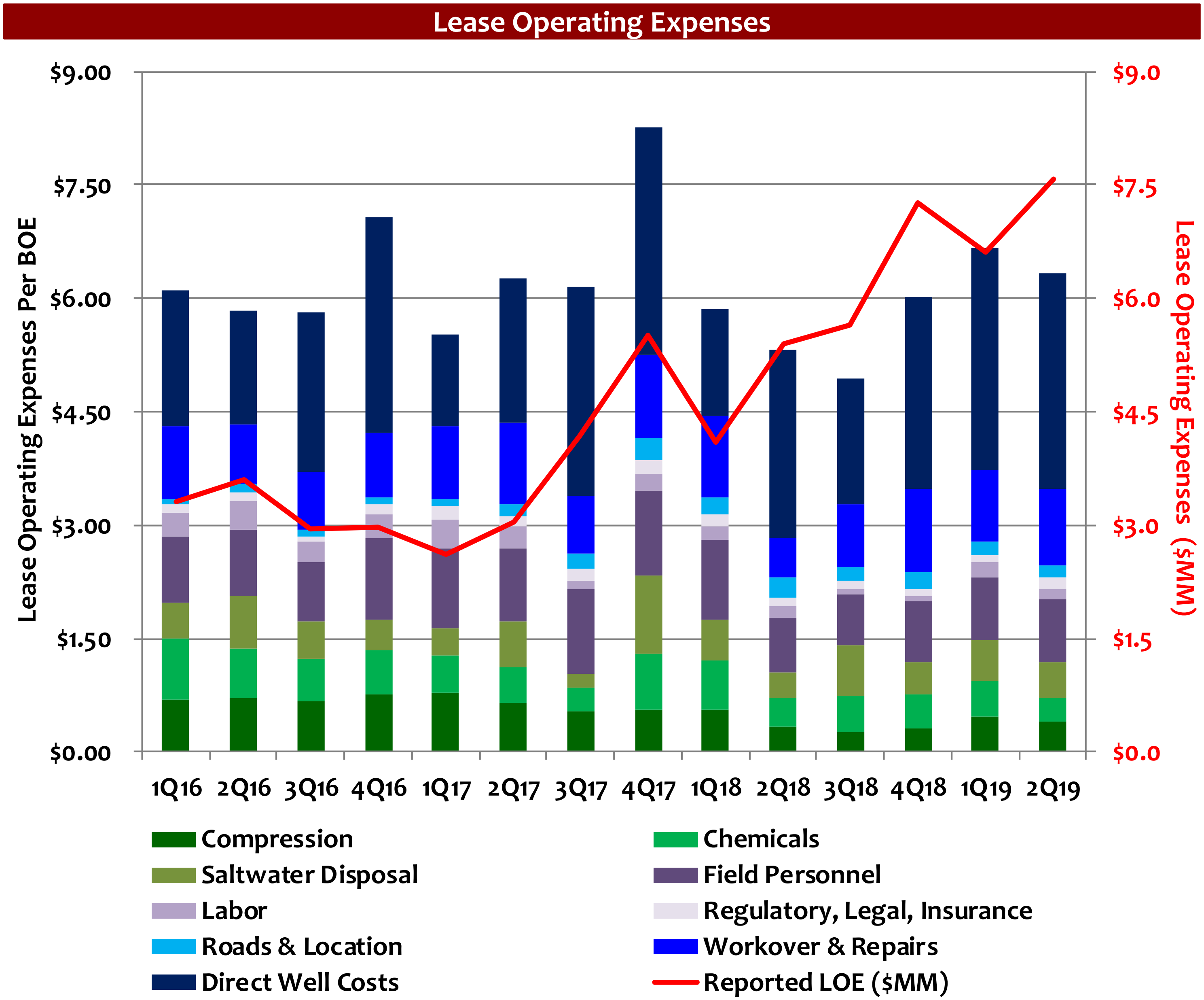
Stock-based compensation	1Q15	2Q15	3Q15	4Q15	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18	4Q18	1Q19	2Q19
Net Income (Loss)	**$ (725)**	**$(20,883)**	**$ 7,381**	**$(13,106)**	**$(11,297)**	**$(12,844)**	**$(11,260)**	**$(63,300)**	**$ 3,118**	**$ (24,011)**	**$ (8,948)**	**$(17,611)**	**$ (18,425)**	**$ (23,525)**	**$(21,685)**	**$ 75,170**	**$(60,629)**	**$11,177**
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)	13,283	(12,933)	1,200
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	8,102	11,148	11,230	12,190	12,192	12,721	12,890
Exploration expense	—	51	—	171	—	1	10	371	—	205	—	416	—	—	109	—	190	—
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	14,954	15,425	20,737	23,775	23,645	17,970	21,515
EBITDAX	**16,840**	**(12,581)**	**31,428**	**5,700**	**4,227**	**(365)**	**8,497**	**(3,935)**	**21,827**	**(13,794)**	**10,415**	**(7,304)**	**5,039**	**5,339**	**14,107**	**124,290**	**(42,681)**	**46,782**
Rig standby expense (2)	—	—	10	653	313	1,584	364	—	—	—	61	561	—	—	27	—	107	310
Non-recurring costs (3)	—	19	25	1,182	323	321	607	308	—	3,127	337	173	—	—	60	436	—	—
Stock-based compensation	433	433	880	839	95	95	122	135	178	461	346	644	450	2,281	924	(1,746)	929	98
(Gain) loss on sale of oil and gas properties	—	—	—	—	—	(1,531)	53	1,404	142	205	119	—	—	—	—	—	32,894	155
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	(79,776)	35,509	(13,760)
Unrealized (gain) loss on warrants	—	—	—	—	—	—	611	(1,179)	(2,270)	(613)	(402)	198	152	2,463	(509)	(2,522)	102	(796)
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)	—	(7)	231	315	(31)	183	678
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**	**$ 40,651**	**$ 27,043**	**$33,467**

(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

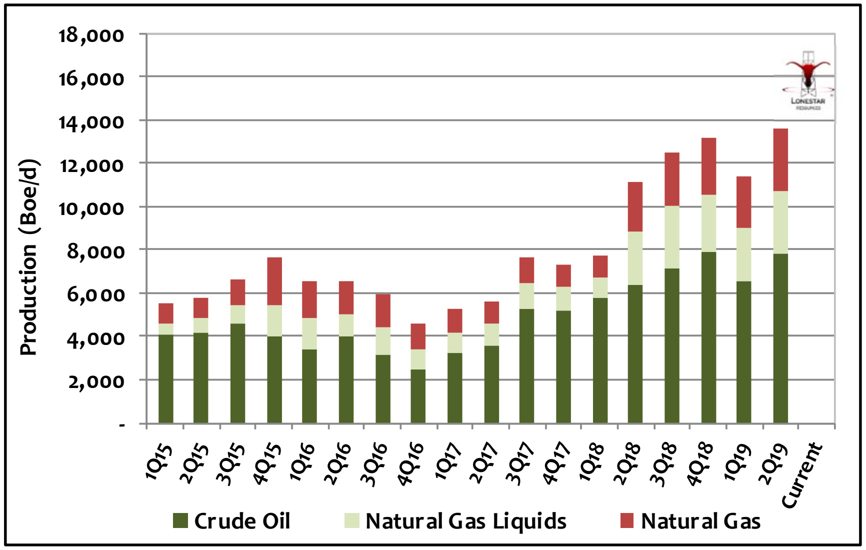
(3) Non-recurring costs consists of Acquisitions Costs and General and Administrative Expenses related to the re-domiciliation to the United States, and listing on the NASDAQ.

Lease Operating Expenses

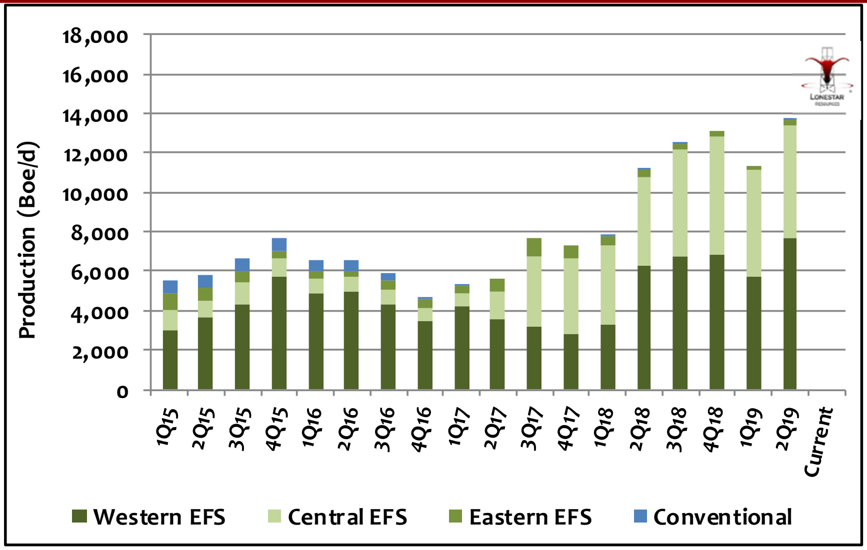


Financial Statistics

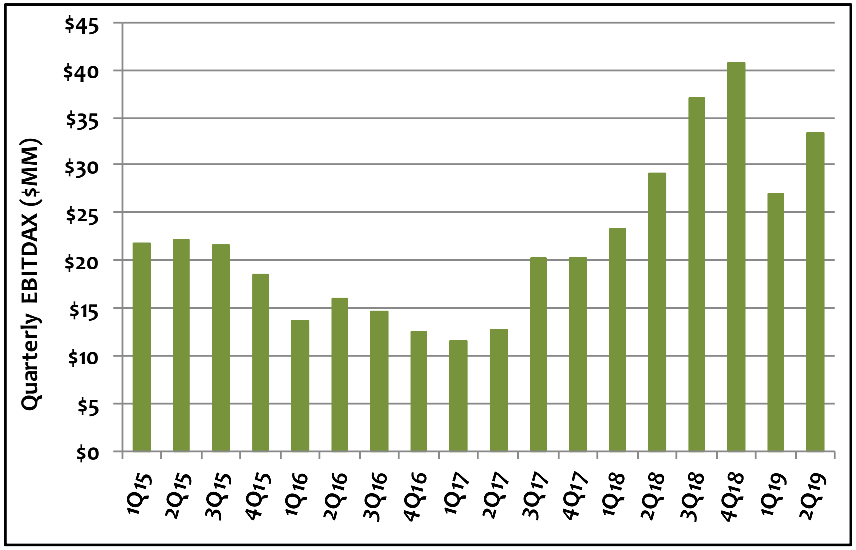
Quarterly Production – By Product



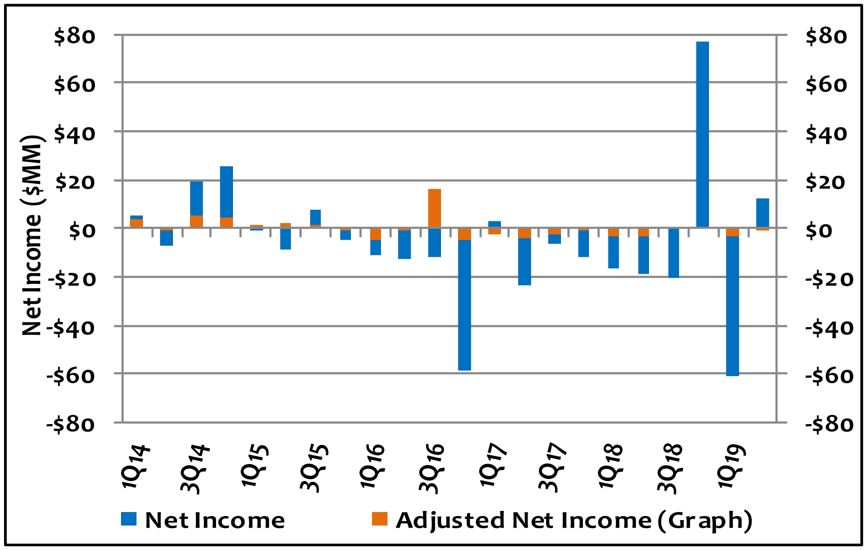
Quarterly Production- By Region



EBITDAX[1] ($MM)



Net Income ($MM)

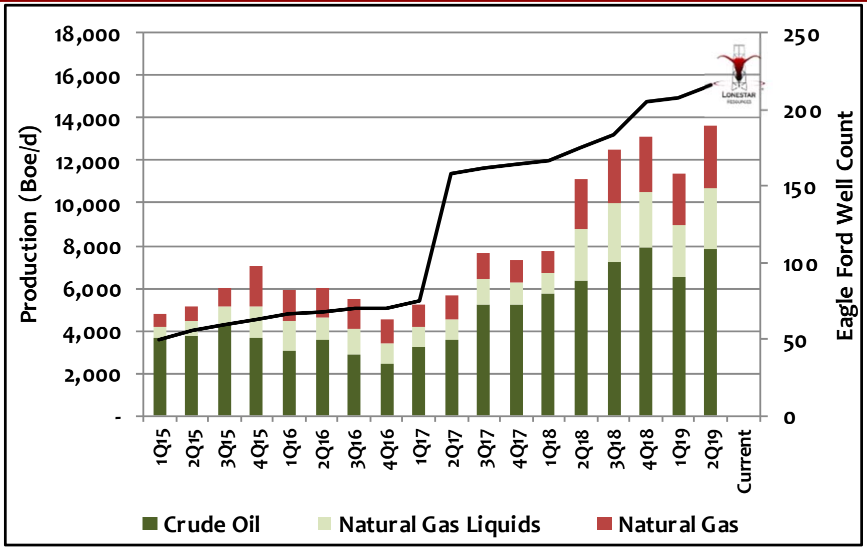


Note- All 2015, 2016, 2017, 2018 and 2019 figures are unaudited

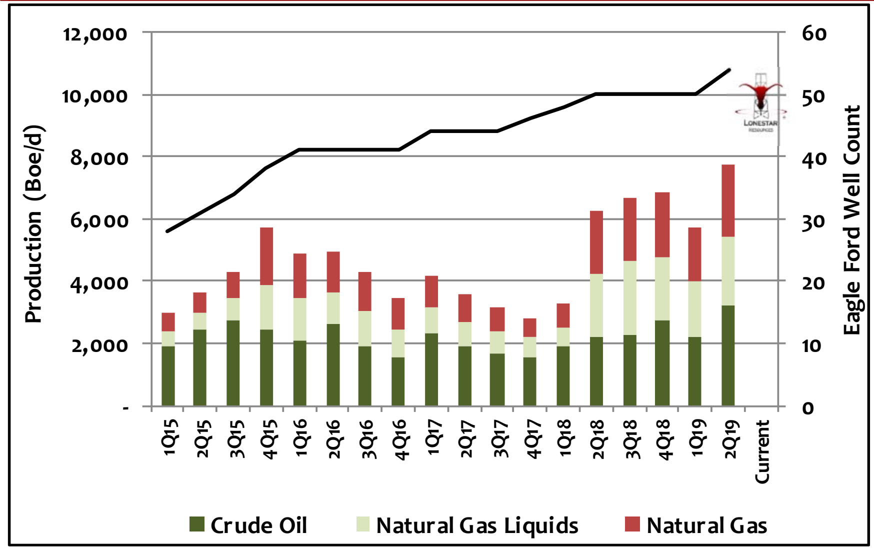
[1] Please see "Non-GAAP Financial Reconciliation" in the Appendix for the definition of Adjusted EBITDAX, a reconciliation of Net Income (loss) to Adjusted EBITDAX, and the reasons for its use.

Quarterly Production Summary

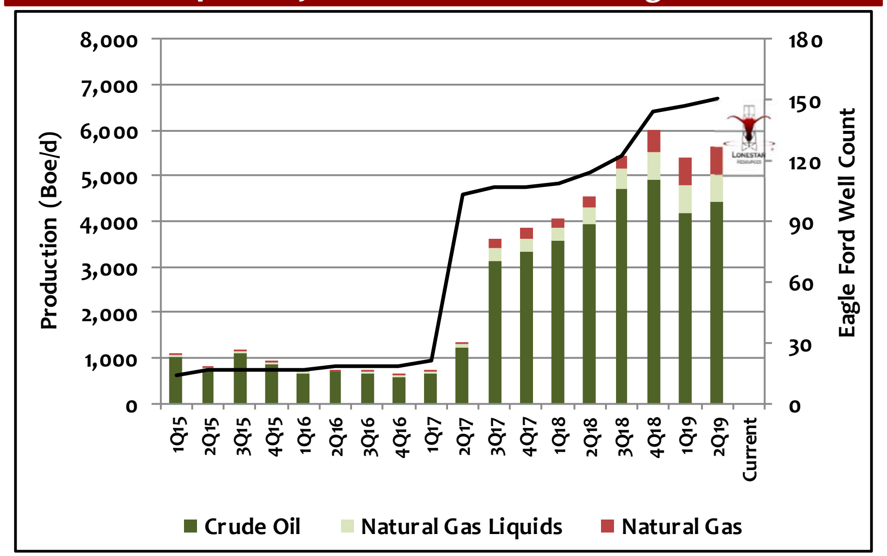
Quarterly Production – Total Company



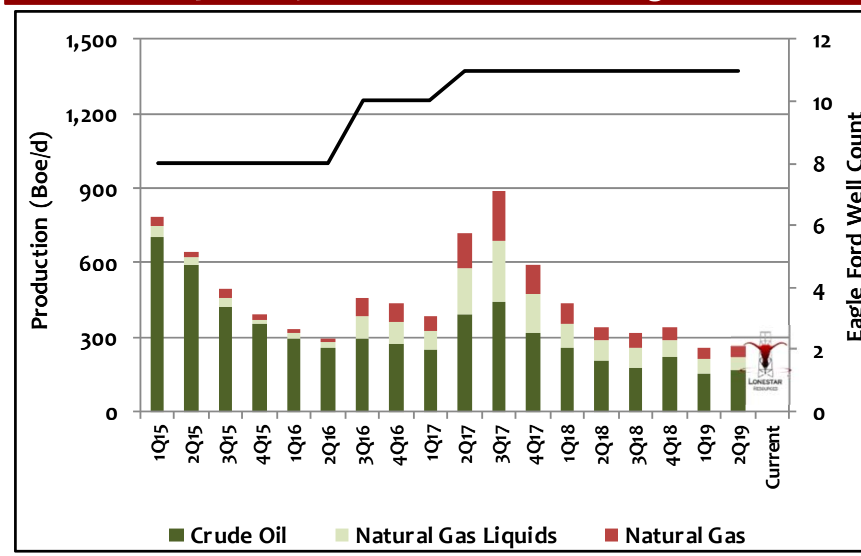
Quarterly Production – Western Region



Quarterly Production – Central Region



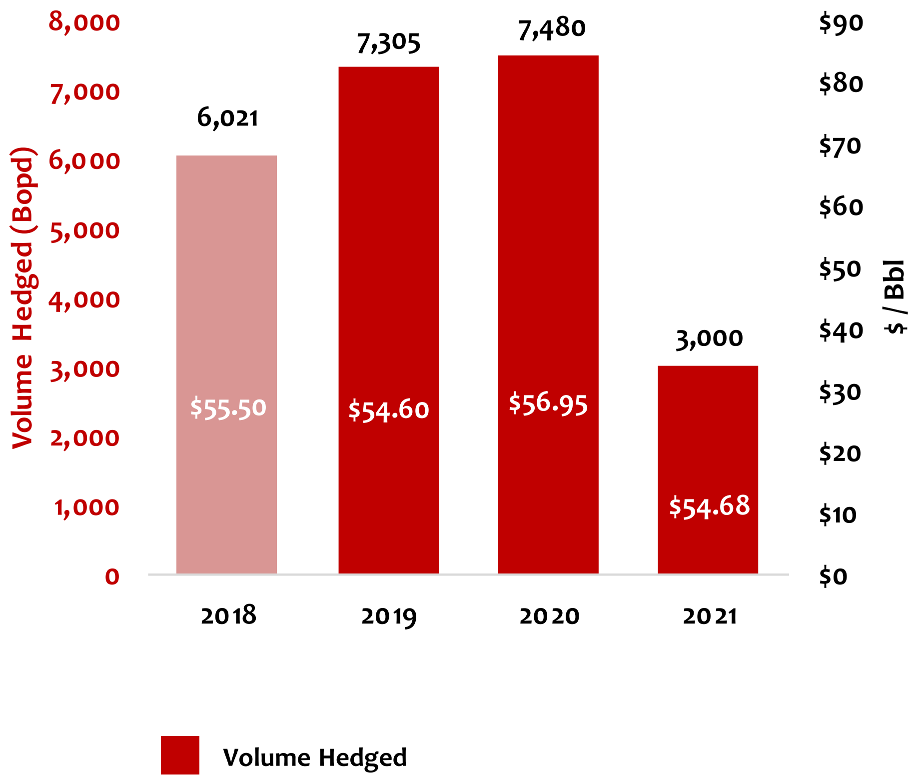
Quarterly Production – Eastern Region



Hedging Summary – Crude Oil

Crude Oil Contracts

% of Production Hedged[1]	88%	90%	80-90%	35%



LLS Basis Swaps

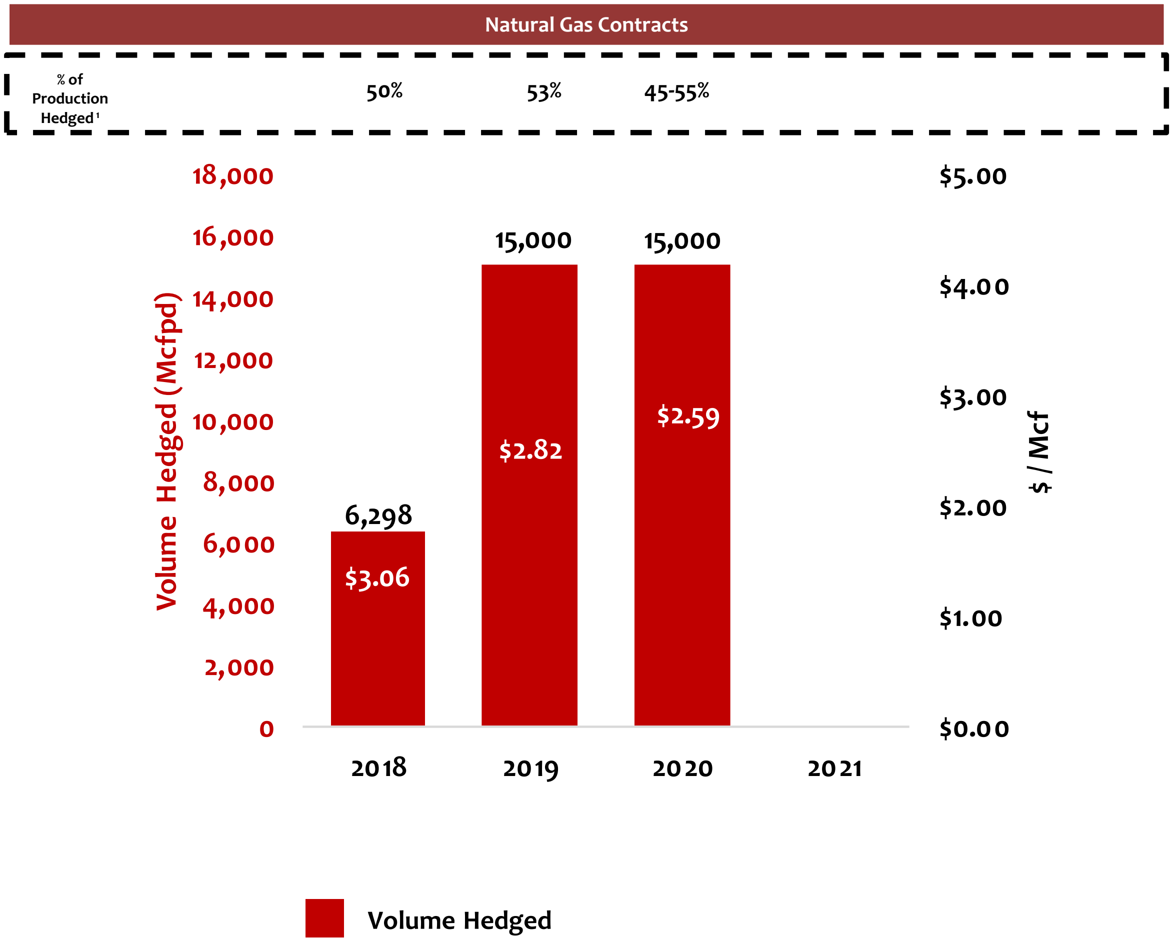
Period	Instrument	Volume	Fixed Price
Bal '19	LLS-Basis Swap	6,000 bbls/day	$5.05

Crude Oil Contracts

Period	Instrument	Volume	Fixed Price
Bal '19	Oil- WTI Swap	1,213 bbls/day	$48.04
Bal '19	Oil –WTI Swap	1,930 bbls/day	$50.40
Bal '19	Oil-WTI Swap	1,100 bbls/day	$50.90
Bal '19	Oil-WTI Swap	993 bbls/day	$58.25
Bal '19	Oil-WTI Swap	500 bbls/day	$65.20
Bal '19	Oil-WTI Swap	500 bbls/day	$69.57
Bal '19	Oil-WTI Swap	70 bbls/day	$48.97
Bal '19	Oil-WTI Swap	500 bbls/day	$58.72
Bal '19	Oil-WTI Swap	500 bbls/day	$58.77
Cal '20	Oil-WTI Swap	556 bbls/day	$48.90
Cal '20	Oil-WTI Swap	1,123 bbls/day	$55.06
Cal '20	Oil-WTI Swap	500 bbls/day	$61.65
Cal '20	Oil-WTI Swap	500 bbls/day	$65.56
Cal '20	Oil-WTI Swap	500 bbls/day	$58.03
Cal '20	Oil-WTI Swap	500 bbls/day	$57.70
Cal '20	Oil-WTI Swap	500 bbls/day	$57.94
Cal '20	Oil-WTI Swap	500 bbls/day	$57.71
Cal '20	Oil-WTI Swap	1,000 bbls/day	$60.00
Cal '20	Oil-WTI Swap	800 bbls/day	$51.60
Cal '20	Oil-WTI Swap	500 bbls/day	$56.45
Cal '20	Oil-WTI Swap	500 bbls/day	$56.25
Cal '21	Oil-WTI Swap	2,000 bbls/day	$56.50
Cal '21	Oil-WTI Swap	1,000 bbls/day	$51.05

[1]% hedged values based off mid-point of guidance. Note- 2019 Bbl/d represent Jul Forward

Hedging Summary – Natural Gas



Natural Gas Contracts

Period	Instrument	Volume	Fixed Price
Bal '19	Natural Gas – NYMEX Swap	6,449 MMBTU/day	$2.87
Bal '19	Natural Gas – NYMEX Swap	8,551 MMBTU/day	$2.77
Cal '20	Natural Gas – NYMEX Swap	15,000 MMBTU/day	$2.59

[1]% hedged values off mid-point of guidance. Note- 2019 Mcf/d represent Jul Forward