UNIT CORPORATION

Capital One Securities
14th Annual Energy Conference

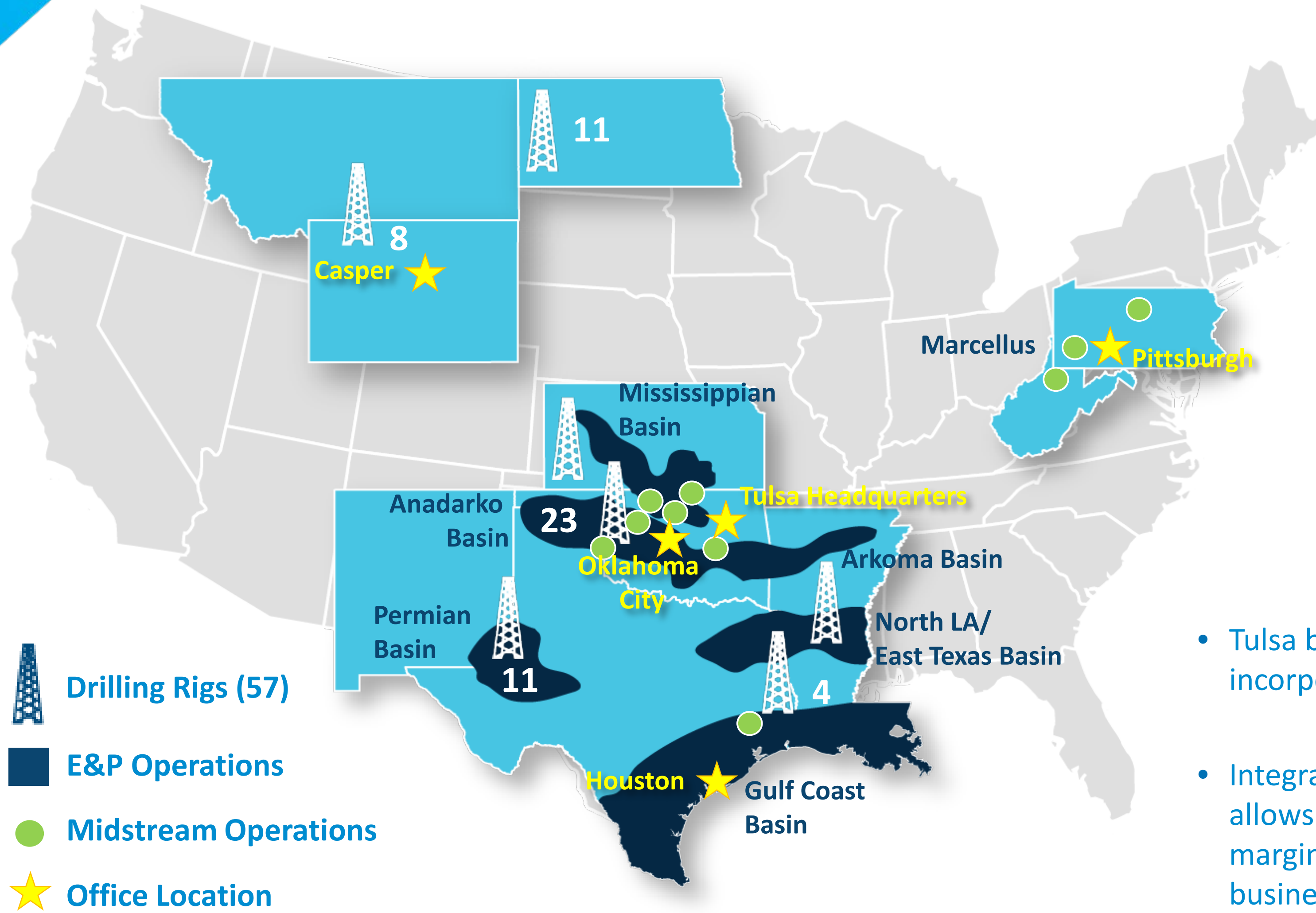
December 11, 2019

Forward Looking Statement

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. 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. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company’s drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management’s expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, risks relating to refinancing notes, prices and demand for oil and natural gas, availability of drilling equipment and personnel, availability of sufficient capital to execute the Company’s business plan, the Company’s ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected and other risks disclosed under “Risk Factors” in the Company’s most recent Form 10-K and Form 10-Q. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. This presentation may contain certain terms, such as locations and estimated ultimate recovery (“EUR”) and other similar terms that describe estimates of potential wells and potentially recoverable hydrocarbons that SEC rules prohibit from being included in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and may not constitute “reserves” within the meaning of SEC rules and accordingly, are subject to substantially greater risk of being actually realized. These estimates are based on the Company’s existing models and internal estimates. Actual quantities that may be ultimately recovered from the Company’s interests will differ substantially. Factors affecting ultimate recovery include the scope of the Company’s ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves may change significantly as development of the Company’s core assets provide additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation contains financial measures that have not been prepared in accordance with U.S. Generally Accepted Accounting Principles (“non-GAAP financial measures”) including EBITDA, adjusted EBITDA, and certain operating margins and debt ratios. The non-GAAP financial measures should not be considered a substitute for financial measures prepared in accordance with U.S. Generally Accepted Accounting Principles (“GAAP”). We urge you to review the reconciliations of the non-GAAP financial measures to GAAP financial measures in the appendix.

A Diversified Energy Company



- Tulsa based, incorporated in 1963
- Integrated approach allows Unit to capture margin from each business segment

Business Segment Overview

Upstream

- Currently running 0 rigs
- Q3 2019 Production: 47.8 Mboe/d
  - 51% gas / 28% NGL / 21% oil
- 468,315 net acres (689,521 gross)
  - ~85% operated production
  - ~81% HBP
  - 750-950 gross locations
- 2018 YE Proved Reserves:
  - 159.7 Mmboe
  - Proved PV-10: $1,106mm

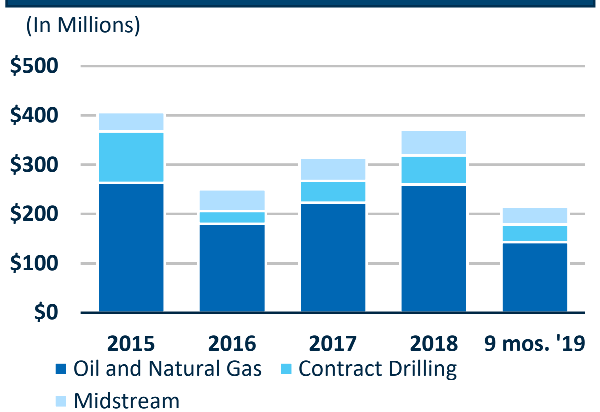
Contract Drilling

- 57 rig fleet; 18 rigs contracted
  - 32% total fleet utilization
  - 54 rigs pad capable
- 13 patented high-spec BOSS rigs optimized for pad drilling
  - 14th BOSS currently moving to first location under long-term contract
  - 100% BOSS rig utilization

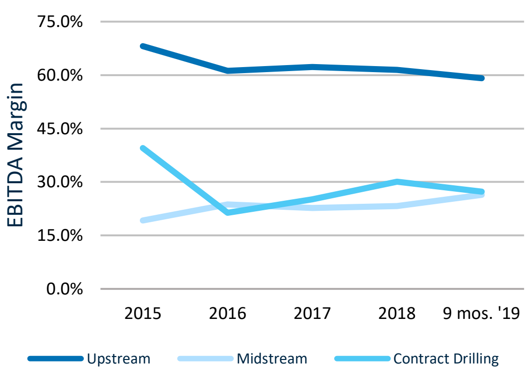
Midstream

- Conducted through Superior Pipeline Company L.L.C., a JV with SP Investor Holdings
- Operations consist of buying, selling, gathering, processing, and treating natural gas and NGLs
- 21 active gathering systems
- 12 gas processing plants
- 3 natural gas treatment plants
- ~323 MMcf/d processing capacity
- ~1,500 miles of pipeline in Texas, Oklahoma, and Appalachia

EBITDA by Segment



Margin by Business Segment

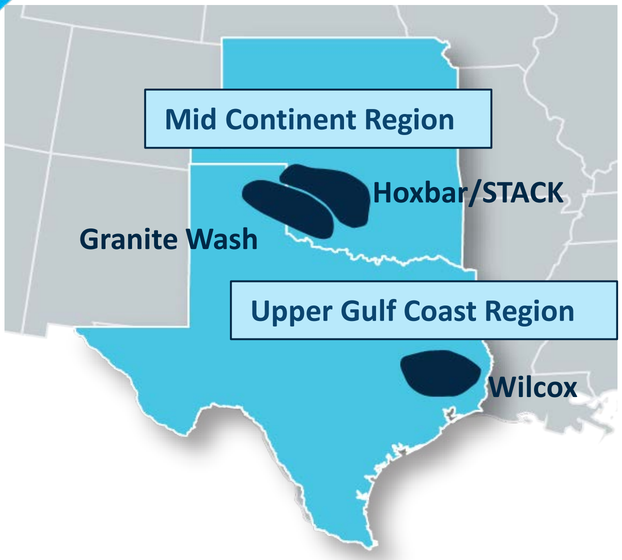


Investment Highlights

Unit offers a unique opportunity to invest in an integrated oil & gas company, capturing margin across the value chain

1. Diversified and integrated asset base across upstream, midstream, and drilling services
2. Capital stewardship with a history of capital spending in-line with cash flow
3. Upstream portfolio in the core of the Mid-Con and Gulf Coast with multiple years of inventory
4. Continuing shift to emphasize oil production
5. Midstream assets provide predictable fee-based cash flows with 66% coming from 3rd party producers
6. Top tier drilling services business with 100% utilization on high-spec, proprietary BOSS rigs
7. Experienced management team

Upstream Segment Overview



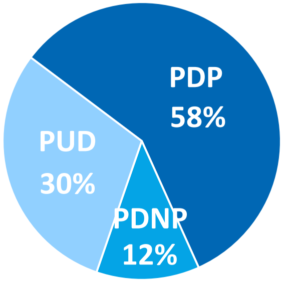
Key focus areas include:

Mid-Continent:
- Southern Oklahoma Hoxbar Oil Trend ("SOHOT") & Red Fork (Western Oklahoma)
- STACK (Western Oklahoma)
- Granite Wash (Texas Panhandle)

Upper Gulf Coast:
- Wilcox (Southeast Texas)

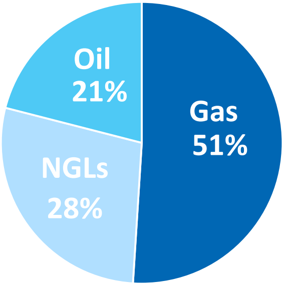
Proved Reserves

YE 2018 Proved Reserves (Mboe):
- PDP: 91,743
- PDNP: 19,833
- PUD: 48,105



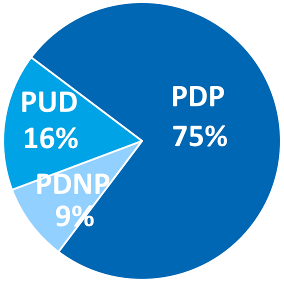
Q3 2019 Daily Production

Q3 2019 Daily Production:
- 47.8 MBoe/d



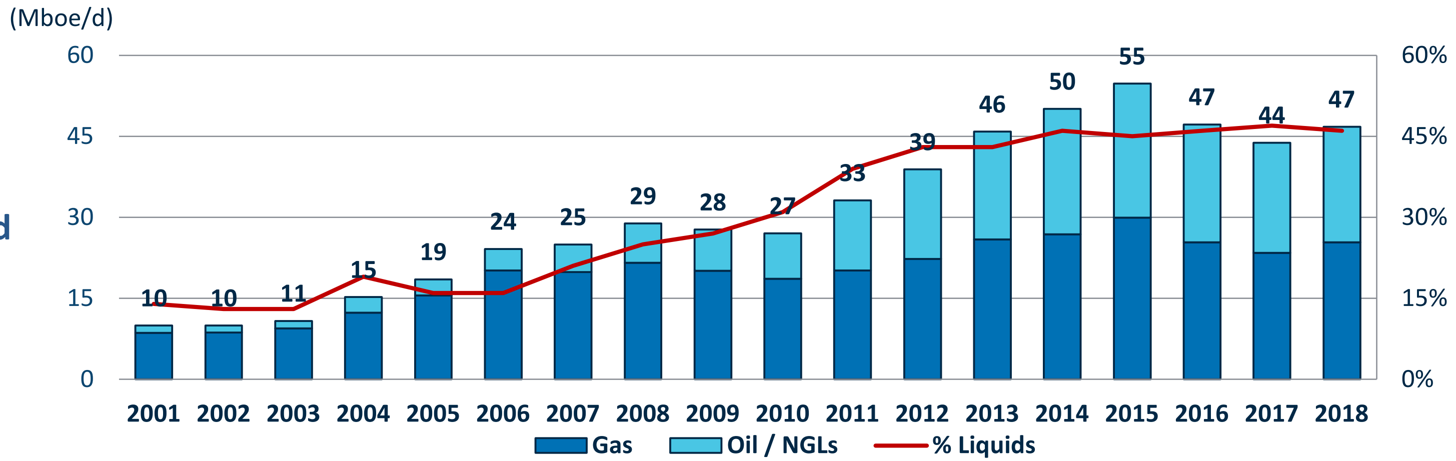
PV-10

Total YE 2018 PV-10:
- PDP: $831
- PDNP: $102
- PUD: $173

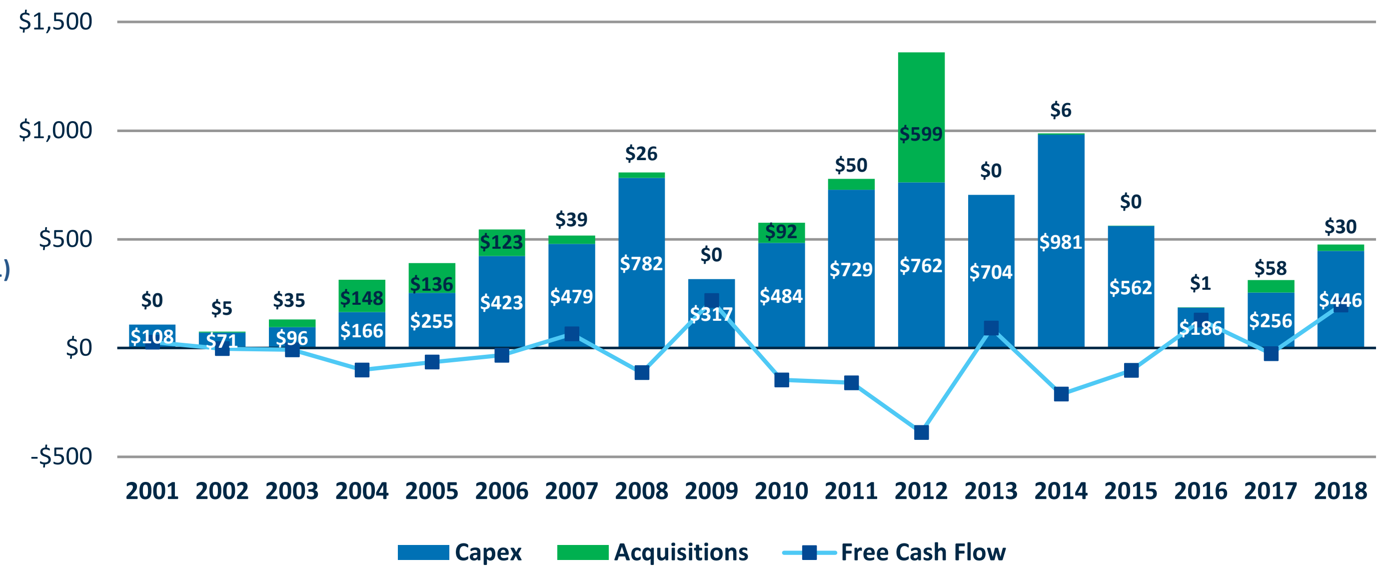


Track Record of Disciplined Growth

History of Production Growth with Increased Liquids Content



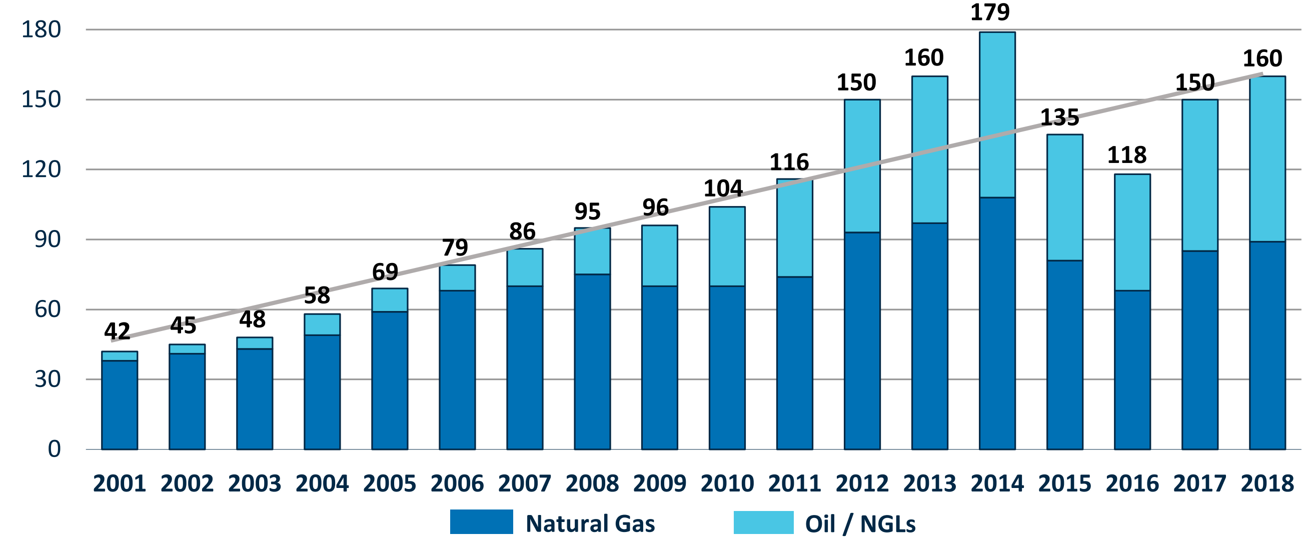
Capex & Free Cash Flow[1] ($ in millions)



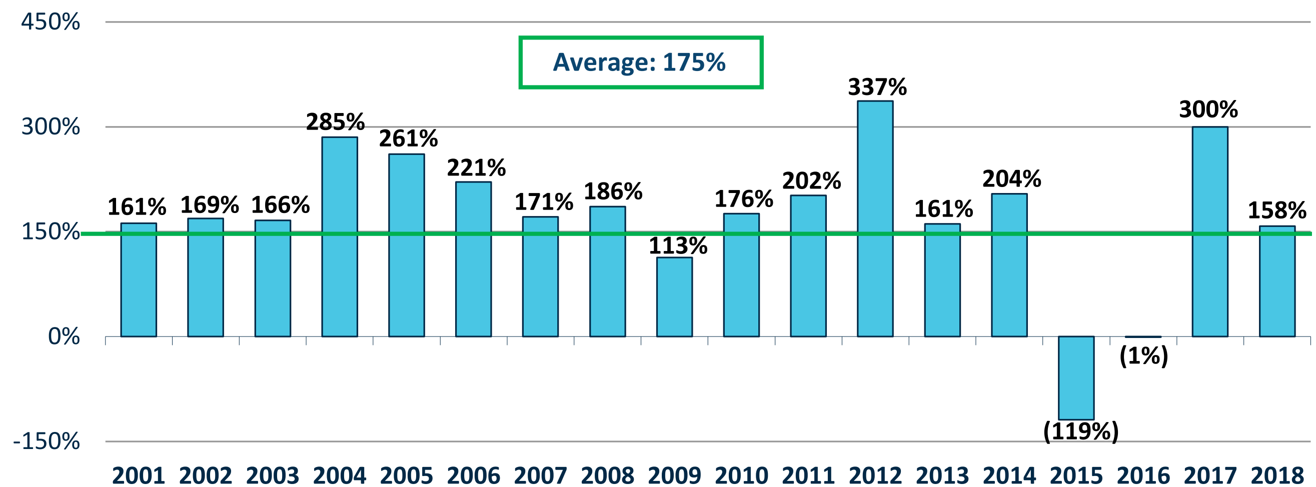
(1) Free cash flow defined as cash flow from operating activities plus proceeds from divestitures less capital expenditures, including acquisitions.

Track Record of Reserve Growth

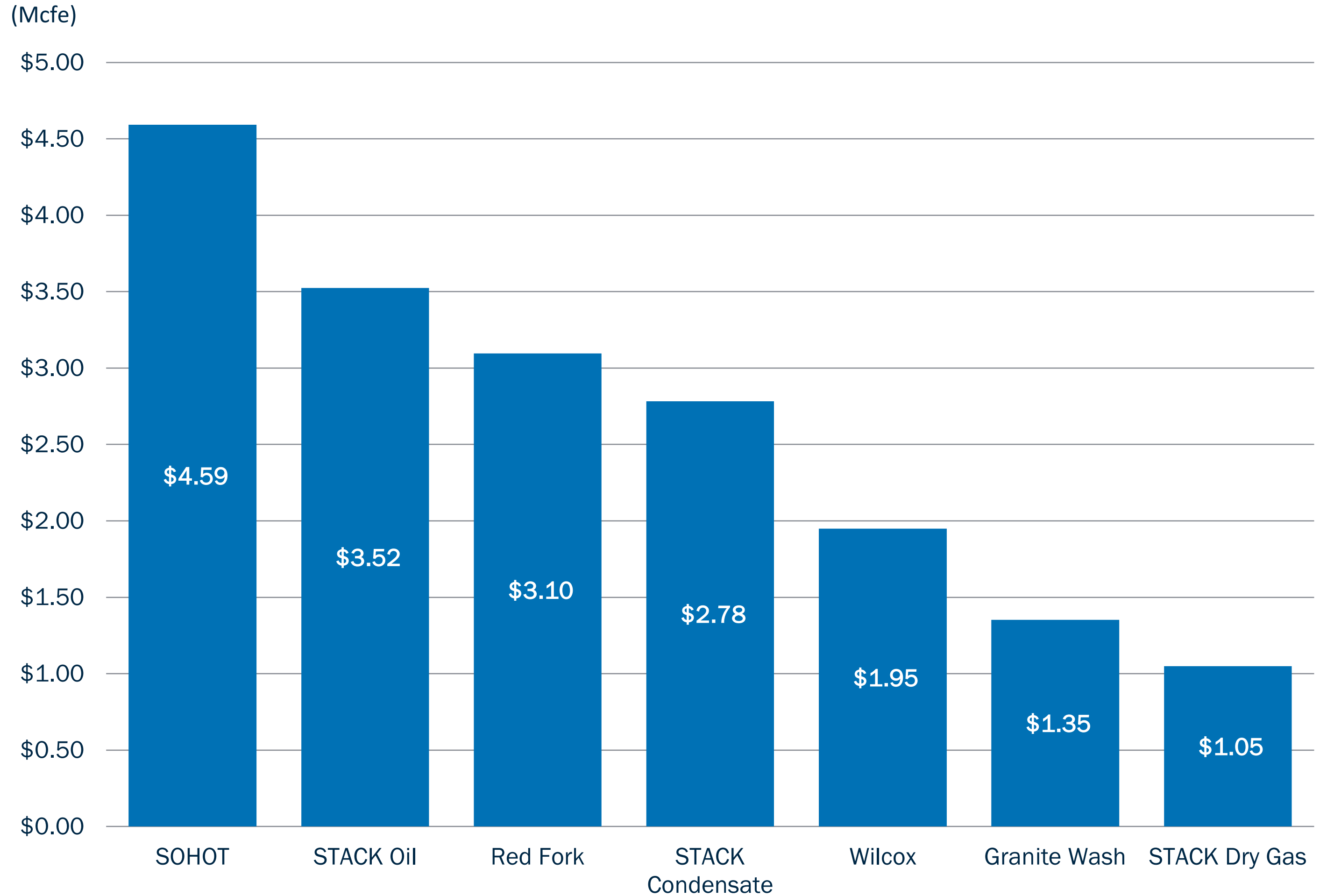
Proved Reserves (MMBoe)



Annual Reserve Replacement



Core Area Cash Margins per Mcfe



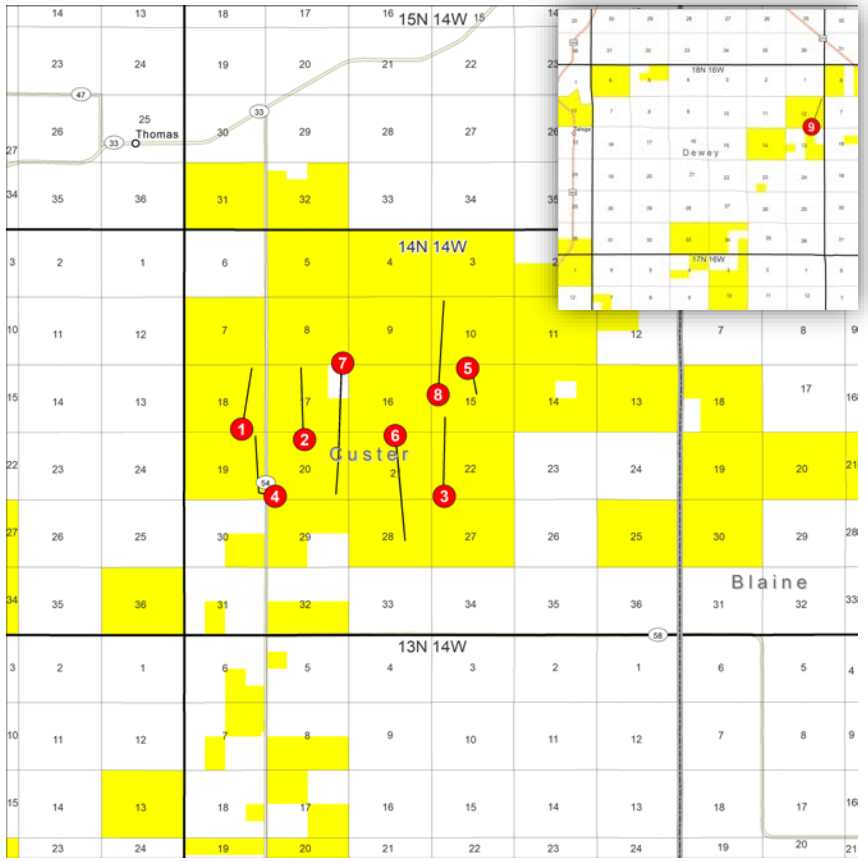
% Gas	23%	35%	39%	42%	61%	62%	99%

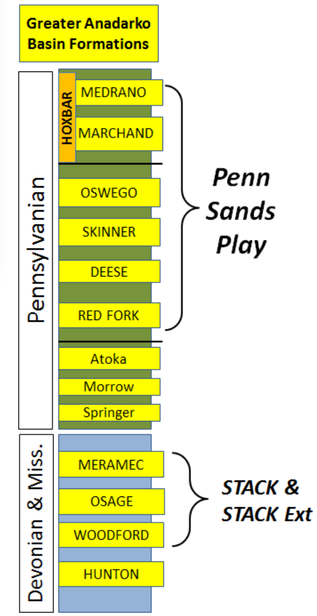
See Core Area Cash Margins in Appendix. Based on 2020 average from 11/1/19 strip price deck.

Red Fork – Adds Oily Drilling Inventory

Red Fork Summary

- 19,100 net acres
- 86% HBP
- 64% average WI
- 9 horizontal wells drilled
- 20-30 operated locations
- 15-25 non-op locations
- Well costs:
  - 4,500’ $5.7 MM
  - 7,500’ $7.1 MM





Unit Petroleum

1 — Unit Petroleum, Frymire 1-18H, IP30: 755 Boe/d (9% Oil)

2 — Unit Petroleum, Hamar 3H-17, IP30: 1,080 Boe/d (72% Oil)

3 — Unit Petroleum, Schrock 2215 1HX, IP30: 1,910 Boe/d (54% Oil)

4 — Unit Petroleum, Schrock 1H-19, IP30: 300 Boe/d (70% Oil)

5 — Unit Petroleum, Wingard 1522 #2HX, IP30: 480 Boe/d (16% Oil)

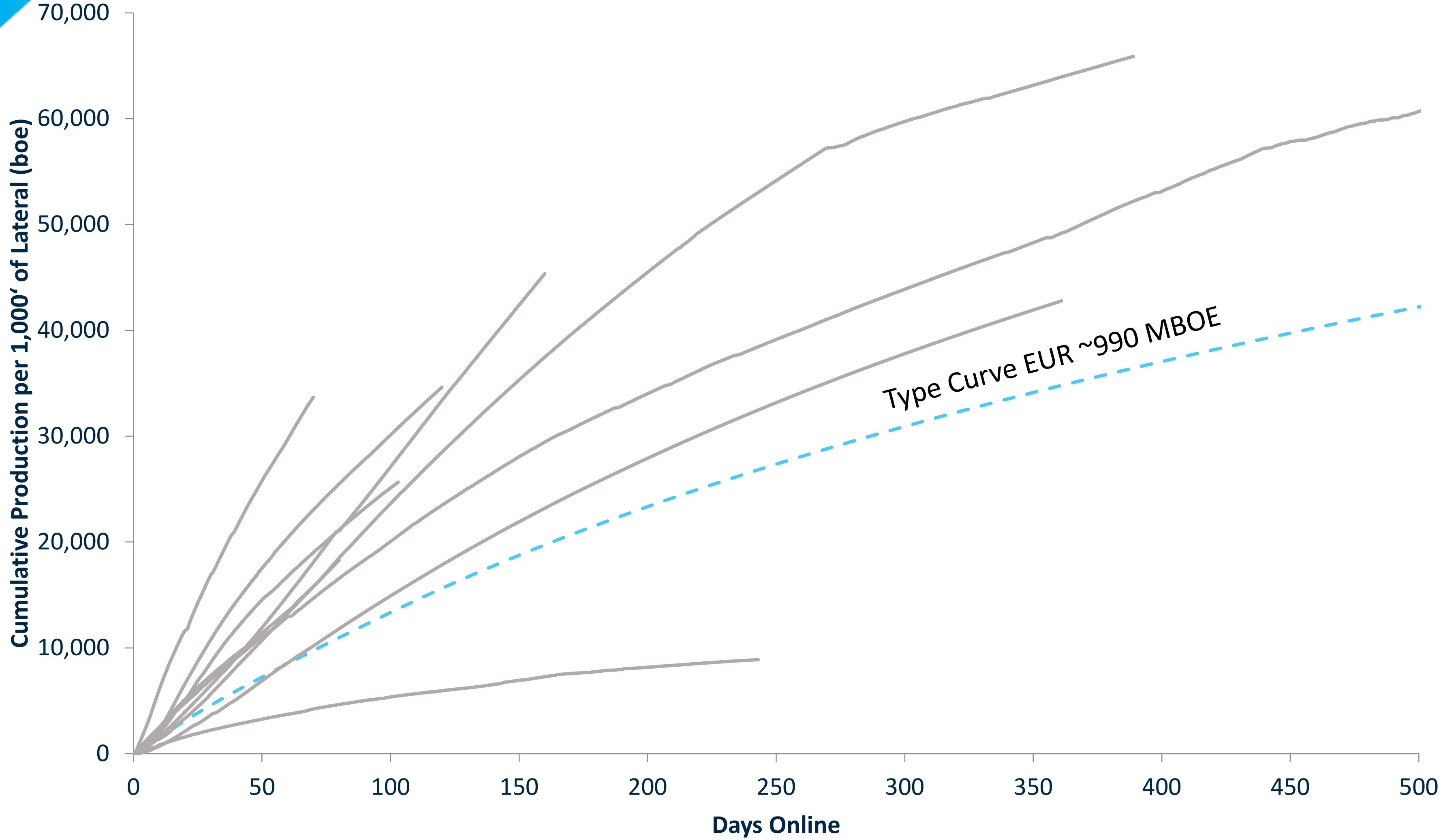
6 — Unit Petroleum, Wingard Farms 2128 1 HX, IP30: 2,775 Boe/d (75% Oil)

7 — Unit Petroleum, Saratoga 1720 1 HX, IP30: 3,020 Boe/d (75% Oil)

8 — Unit Petroleum, Wingard 1510 #1HX, IP30: 1215 Boe/d (53% Oil)

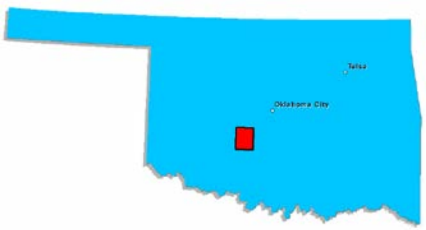
9 — Unit Petroleum, Hayes Trust 1 H-12, IP30: 1,615 Boe/d (81% Oil)

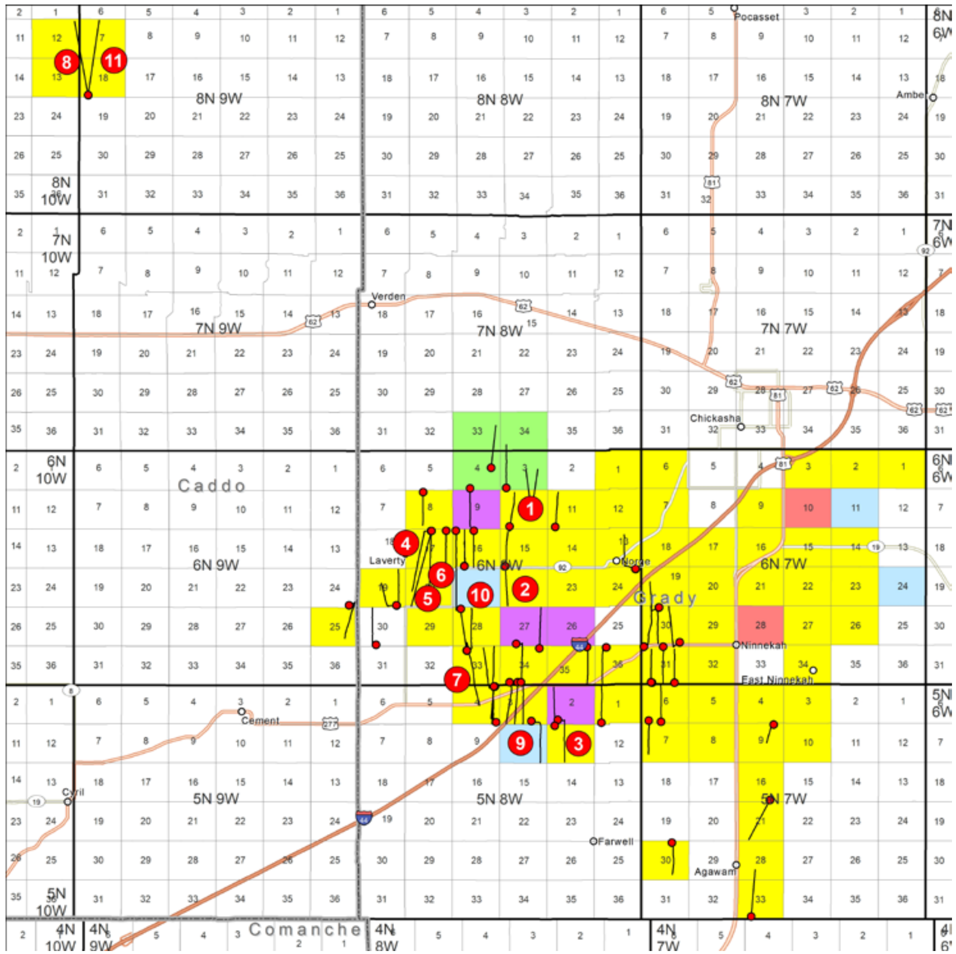
Red Fork Production Performance



Red Fork Type Curve assumes 7,500' lateral

SOHOT – Low Cost, High ROR Oil Play





- Unit Petroleum
- Camino
- Echo E&P LLC
- Kaiser- Francis
- Limerock Resources

Denotes Unit Non-Op working interest

Marchand Horizontal

11 Unit Petroleum
5D "A" 18/7 1HXL
IP30: 497 Boe/d 98% Oil

10 Kaiser Francis
Amanda 21-6-8 1H
IP30: 540 Boe/d 71% Oil

9 Kaiser Francis
Torralba 10-5-8 1H
IP30: 578 Boe/d 70% Oil

8 Unit Petroleum
5D 13/12 1HXL
IP30: 520 Boe/d 88% Oil

7 Unit Petroleum
Livingston Land 1HXL
IP30: 565 Boe/d 72% Oil

6 Unit Petroleum
Schenk Trust 3-17HXL
IP30: 1,470 Boe/d 75% Oil

1 Unit Petroleum
Schmidt 1-10H
IP30: 687 Boe/d 80% Oil

2 Unit Petroleum
Nina 1-22H
IP30: 1,124 Boe/d 76% Oil

3 Unit Petroleum
McConnell 1-11H
IP30: 1,271 Boe/d 63% Oil

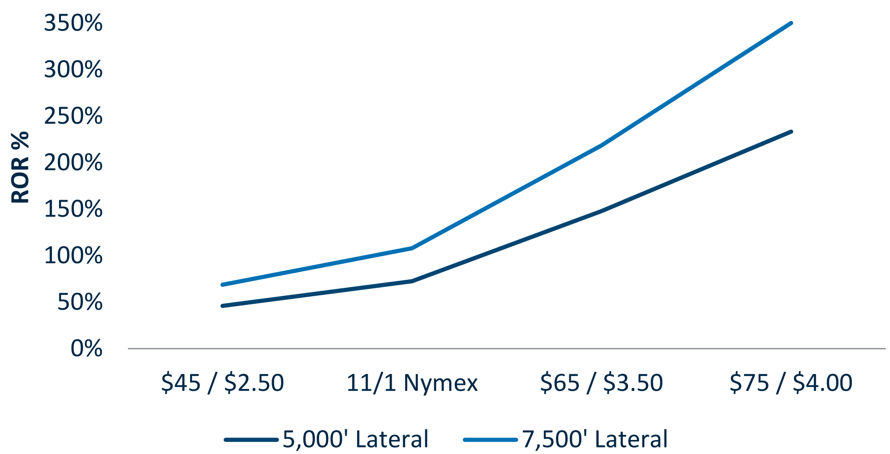
4 Unit Petroleum
Schenk Trust 1-17HXL
IP30: 2,349 Boe/d 79% Oil

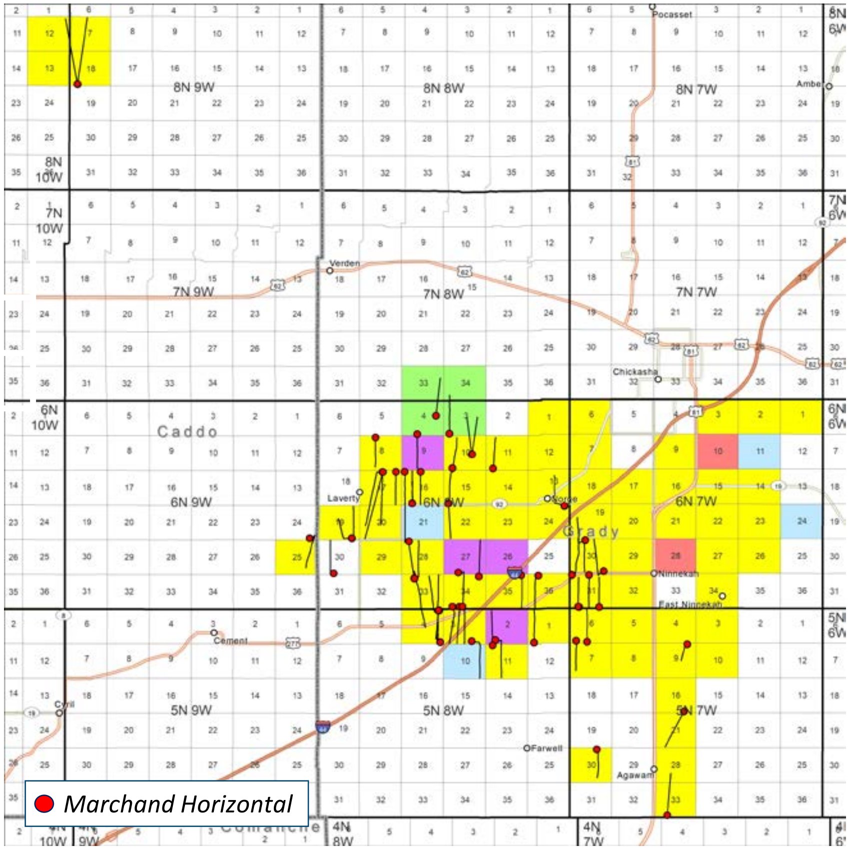
5 Unit Petroleum
Schenk Trust 2-17HXL
IP30: 1,463 Boe/d 79% Oil

SOHOT – Low Cost, High ROR Oil Play

Type Curve	Marchand 5,000’	Marchand 7,500’
IP - 30 (Boe/d)	720	1,006
ROR [1]	73%	108%
EUR (Mboe)	568	812
% Liquids	76%	76%
Well Cost ($mm)	$4.7	$5.9

Single Well Economics





[1] 11/1/2019 Strip Price Deck with 1st Production Starting 1/1/2020.
See Q4 2019 Economic Prices in Appendix (also available at www.unitcorp.com/investor/reports/html)

SOHOT – Predictable Oil Production and Improving Capital Efficiency

Geology

- Marchand stacked lenses provide multiple oil drilling targets
- Medrano proved gas potential

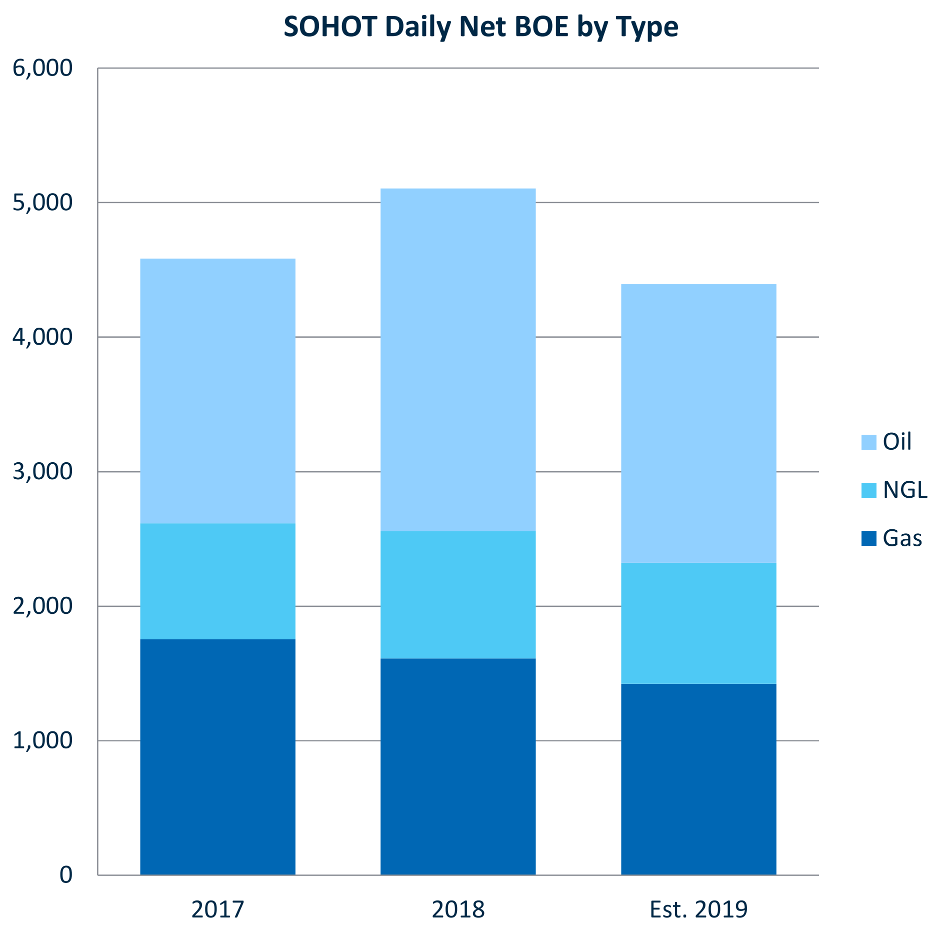
Land

- 31,500 net acres
- 84% HBP
- Majority operated
- Average working interest ~ 89%
- Potential locations:

	Marchand	Medrano	Total
Operated	15-20	10-15	25-35
Non-operated	35-40	15-20	50-60

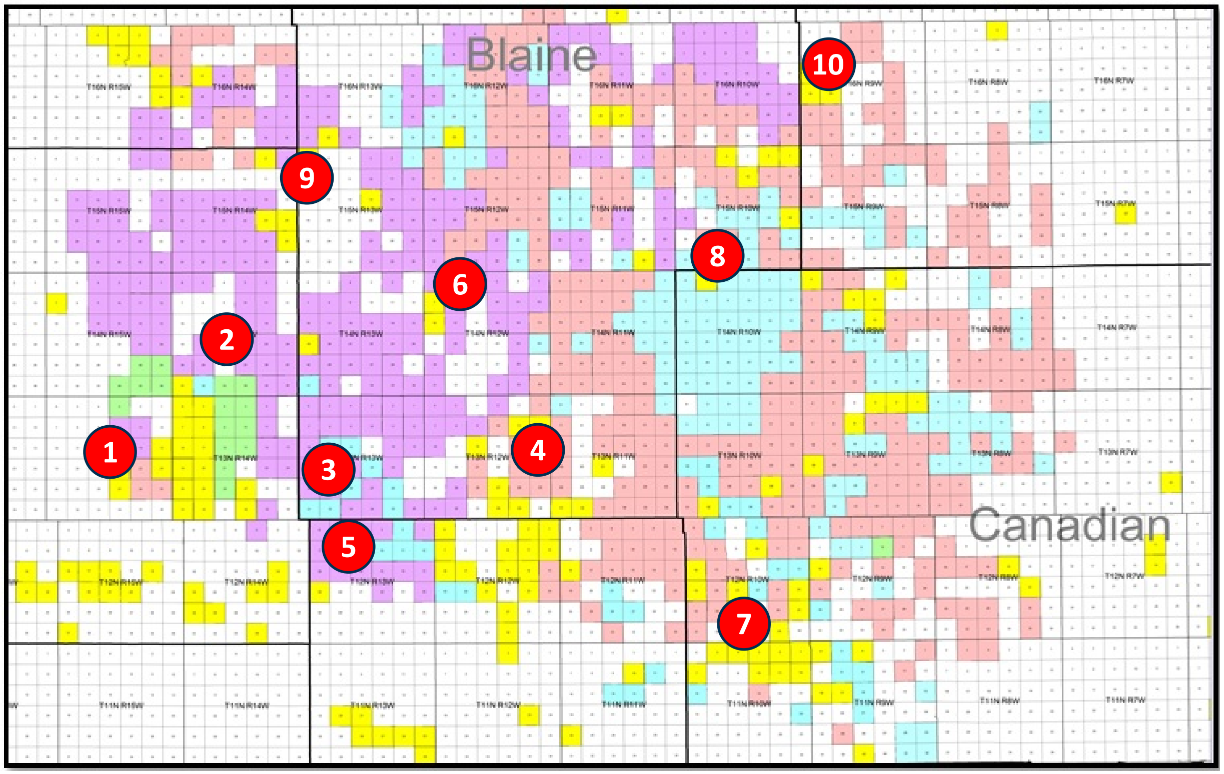
Operations

- Incremental optimization of drilling and completion process has kept cost low without sacrificing EUR
- Extended laterals (XL) improving capital efficiency



STACK Core – Provides Good ROR Oil/Wet Gas with Dry Gas Optionality

- Unit Petroleum
- Cont'l Resources
- Devon Energy
- Cimarex
- Citizen Energy II



* *Denotes IP Per Public Data*

Denotes Unit Non-Op working interest

Meramec Horizontal

10 Continental Resources
Privott 17_20-16N-9 1HX
IP30: 4,308 Boe/d 30% Oil

9 Devon Energy
Tiger Swallowtail 1HX
IP30: 18.4 MMcfe/d 81% Gas

8 Devon Energy
Cheetah 32_29-15N-101XH
IP30: 3,730 Boe/d 41% Oil

7 Citizen Energy
Braveheart 1H-21-28
IP30: 7.4 MMcfe/d 100% Gas

6 Continental Resources
Lorene 1-8-5XH
IP30: 5,483 Boe/d 30% Oil

5 Continental Resources
Mol 1-7-8XH *
IP30: 25.0 MMcfe/d 100% Gas

1 Continental Resources
Eagle 1R-15-10XH *
IP30: 18.0 MMcfe/d 100% Gas

2 MEP Operating
Spanish Castle Magic 1HX*
IP30: 22.2 MMcfe/d 99% Gas

3 Continental Resources
Heckenberg 2-30-19XH
IP30: 32.2 MMcfe/d 100% Gas

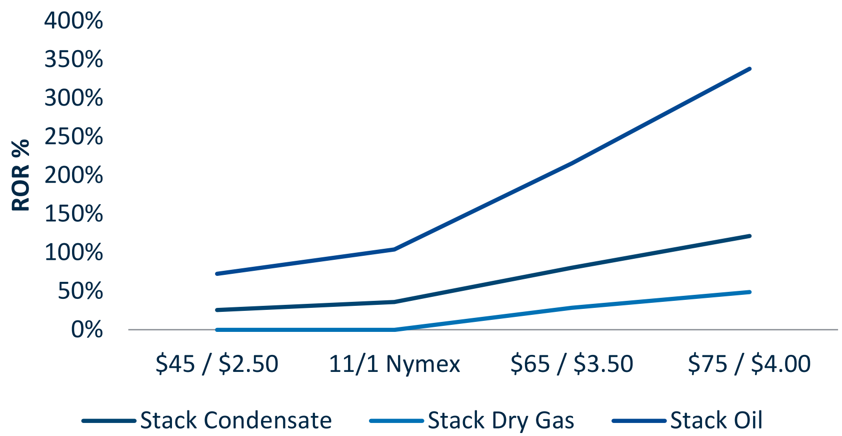
4 Marathon
Hicks BIA 1-13-12XH
IP30: 14.8 MMcfe/d 99% Gas

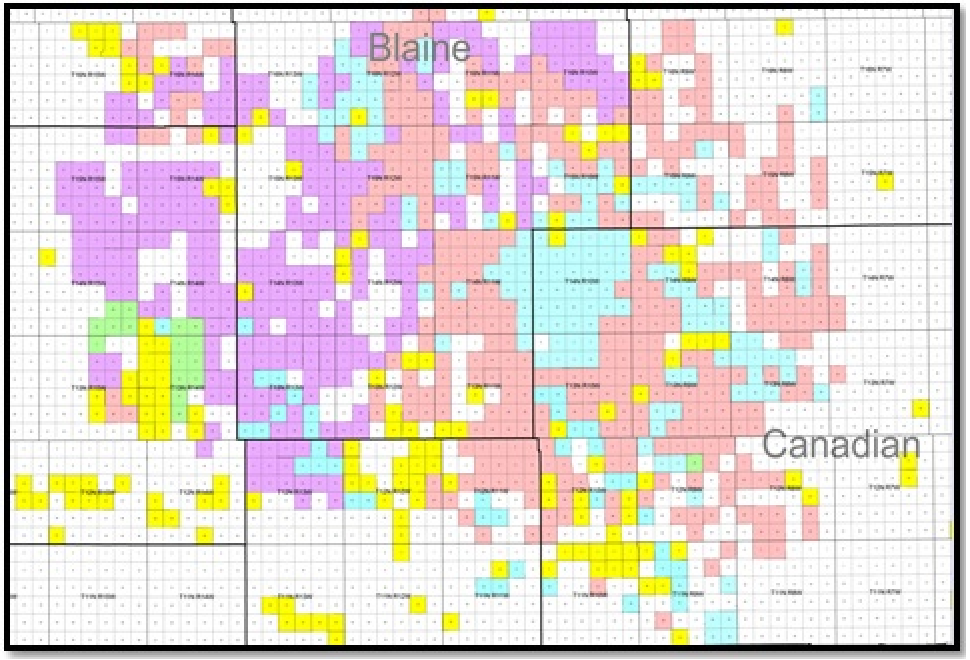
STACK Core – Provides Good ROR Oil/Wet Gas with Dry Gas Optionality

Type Curve	Oil Window	Condensate Window	Dry Gas* Window
IP - 30 (Boe/d, Mcfe/d*)	1,671	1,727	12,212*
ROR [1]	104%	36%	0%
EUR (Mboe/Bcfe*)	1,890	1,914	13.2*
% Liquids/Gas*	63%	55%	99%*
Lateral Length	10,000	10,000	10,000
Well Cost ($mm)	$8.0	$10.0	$10.9

*Natural gas/equivalent metrics

Single Well Economics





[1] 11/1/2019 Strip Price Deck with 1st Production Starting 1/1/2020. Dry Gas 1st Production Starting 4/1/2020. See Q4 2019 Economic Prices in Appendix (also available at www.unitcorp.com/investor/reports/html)

STACK – Growing into Core Production Growth Area for Unit Petroleum

Geology

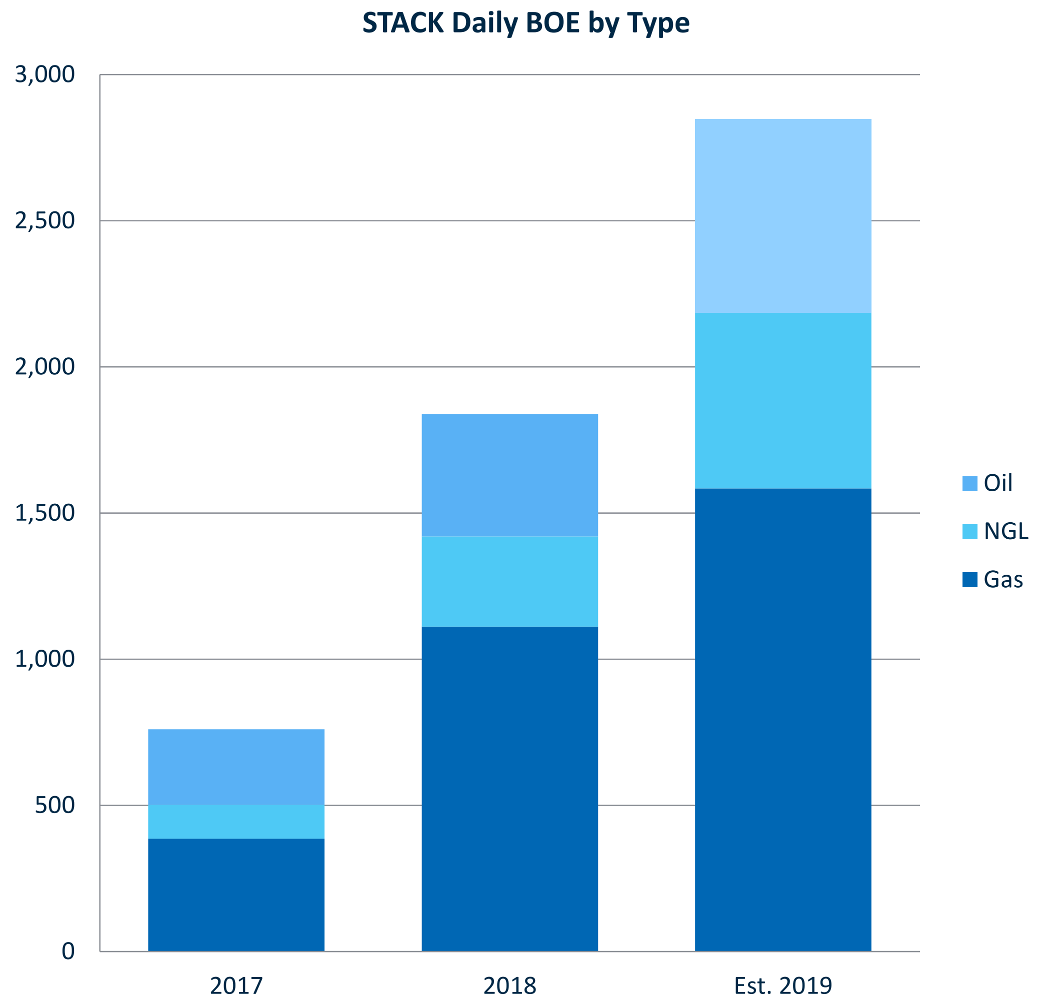
- Stacked drilling targets in Osage, Meramec, and Woodford
- Red Fork Potential in some areas
- Sands consistently present across play

Land

- 12,000 net acres in STACK Core
- 5,000 net acres in STACK Extension
- 85% HBP
- 100 - 150 potential operated locations with working interest of 40 - 60%
- 400 - 800 potential non-operated locations with working interest of ~ 5%

Operations

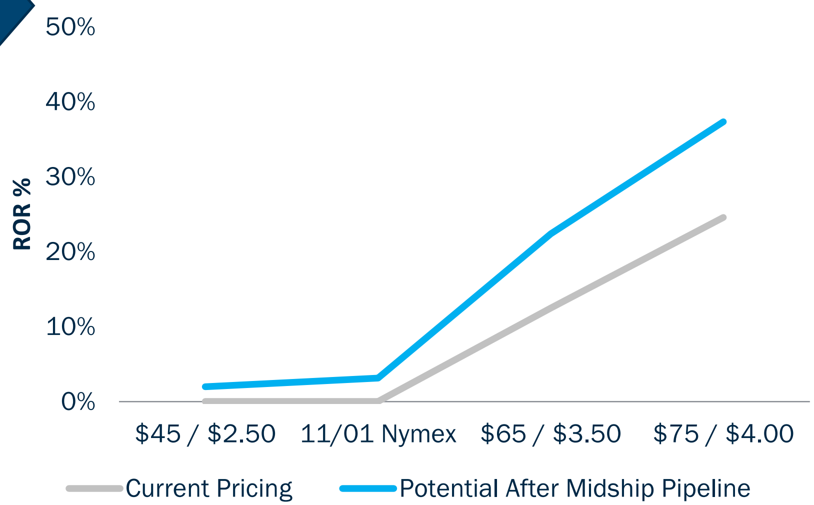
- Participating in ~ 60 non-op wells in 2019
- Dry gas delayed until gas margins and takeaway capacity improve

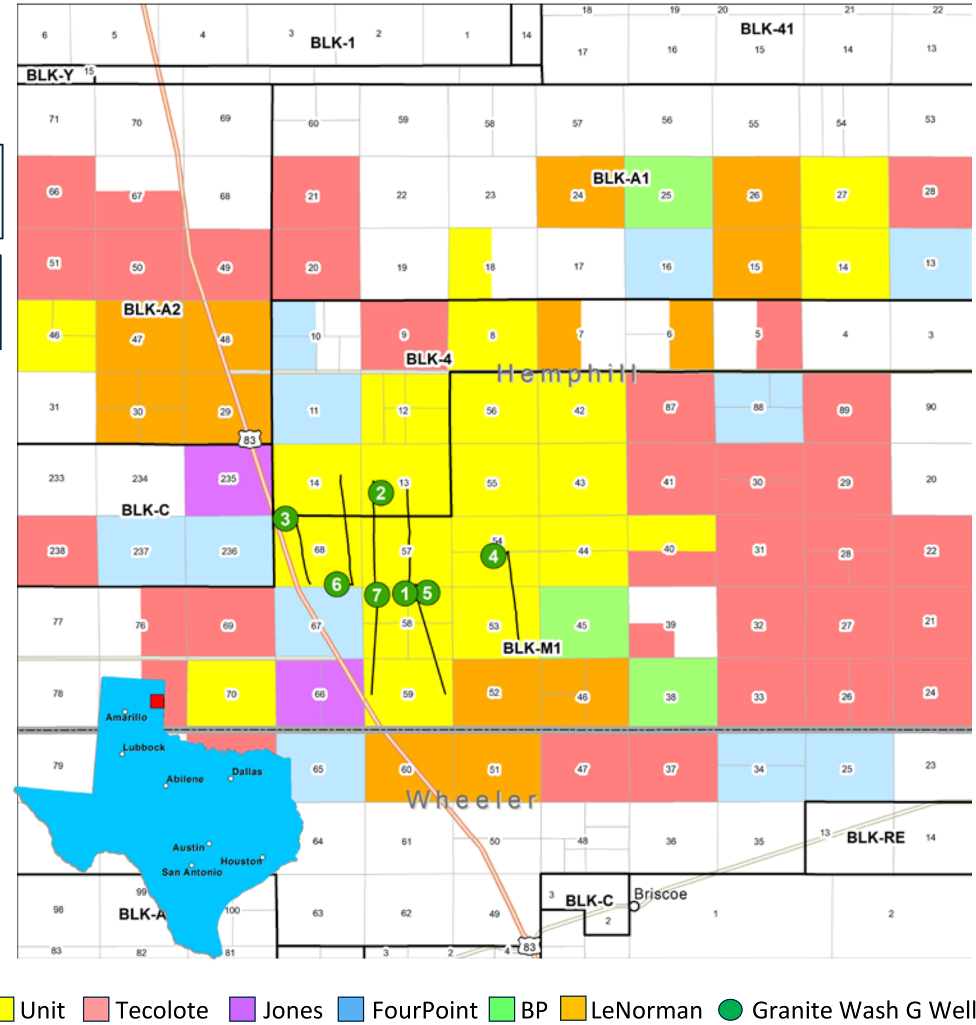


Granite Wash – Low Risk Wet Gas Condensate Play with NGL Price Upside

1 Francis 5713 EXL #3H IP30: 9.5 MMcfe/d (78% Gas)	
2 Carr 1357 WXL #4H IP30: 10.0 MMcfe/d (84% Gas)	5 Francis 5859 EXL #5H IP30: 5.5 Mmcfe/d (63% Gas)
3 Meek #6836H IP30: 5.8 MMcfe/d (76% Gas)	6 Meek 6814 #2H IP30: 9.3 Mmcfe/d (82% Gas)
4 Meek 5453 CXL #2H IP30: 4.1 MMcfe/d (73% Gas)	7 Francis 5859 WXL #4H IP30: 6.5 Mmcfe/d (64% Gas)

Single Well Economics[1] – Granite Wash G





[1] 11/1/2019 Strip Price Deck with 1st Production Starting 4/1/2020
See Q4 2019 Economic Prices in Appendix (also available at www.unitcorp.com/investor/reports/html)

Granite Wash – Competitive Advantages Drive Differentiated Value

Geology

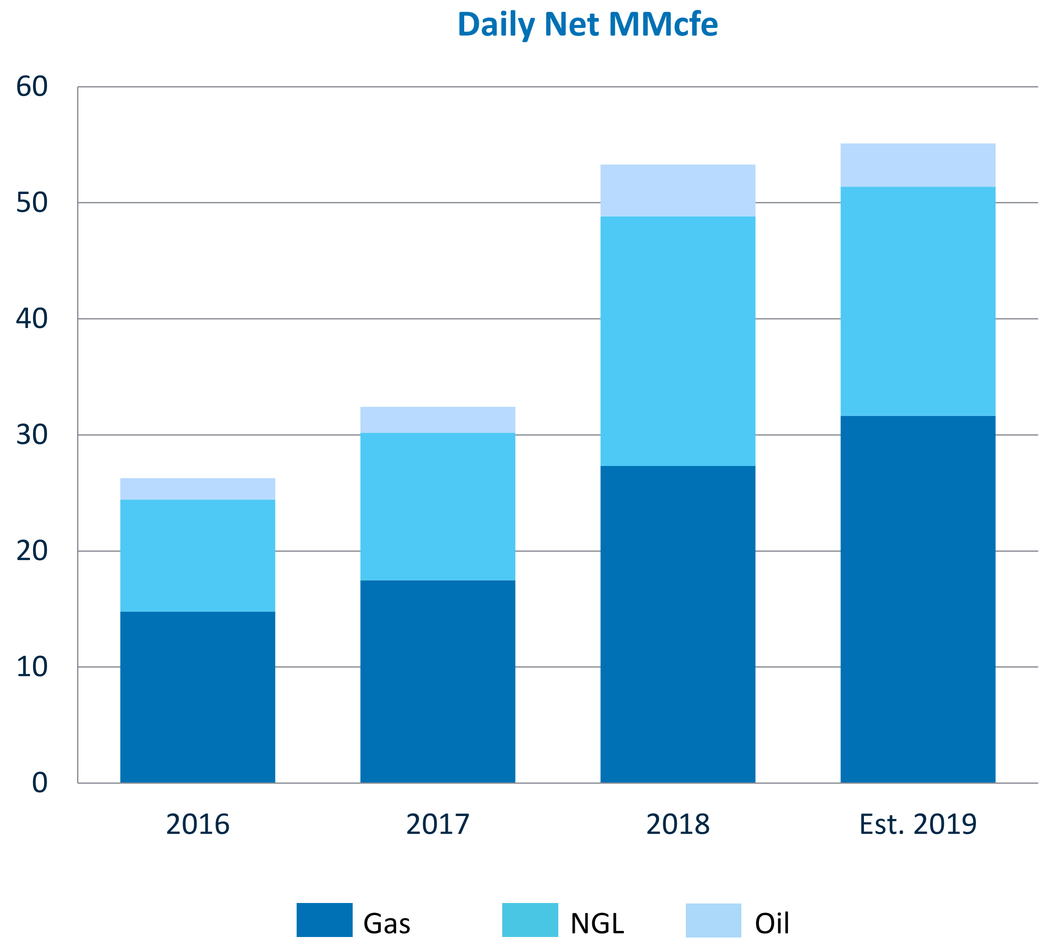
- 11 stacked Granite Wash sands significantly improves capital efficiency
- Sands present across acreage

Land

- 9,000 net largely contiguous acres allow for extended lateral (XL) drilling
- 90% HBP and operated
- Average working interest ~ 90%
- 100-150 potential XL locations

Operations/Infrastructure/Processing

- Incremental process improvements continue to decrease drilling days
- SWD network lowers disposal costs 80%
- Water recycling pits lower frack costs
- Electricity across field lowers lifting costs
- Superior processes the gas improving cash margin



Wilcox – Conventional Stacked Over-Pressured Intervals Provide Low Cost High Potential

Overall Wilcox Drilling Program Results

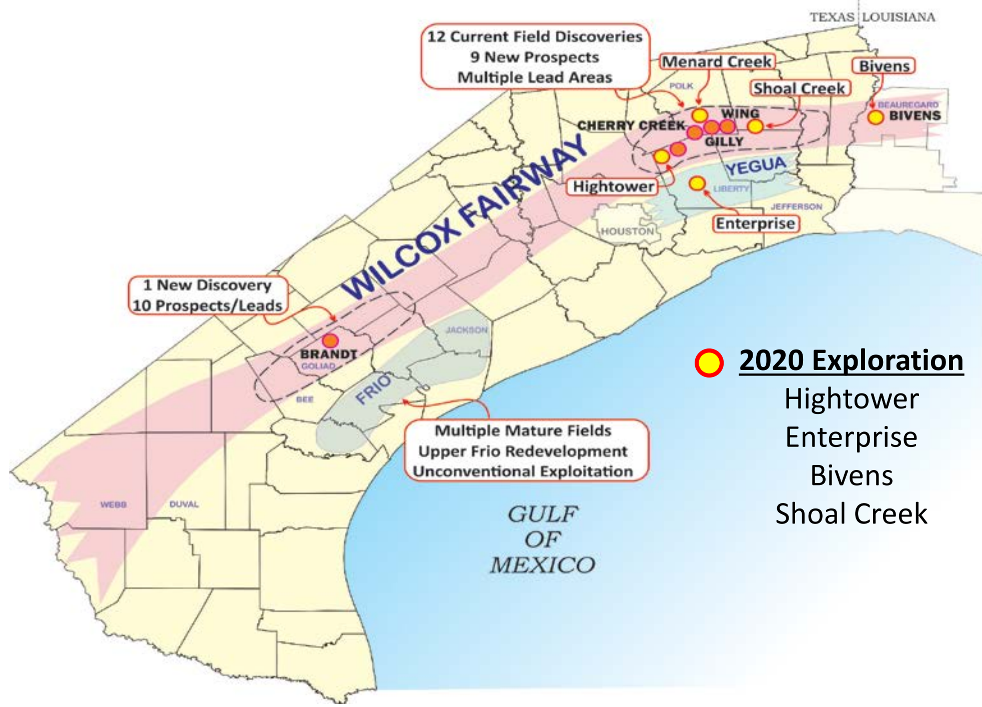
- Drilled 177 operated wells since 2003 (166 vertical, 11 horizontal)
- Program ROR > 81%
- Operated with working interest ~ 91%
- Production: ~ 80 MMcfe/d (36% liquids)

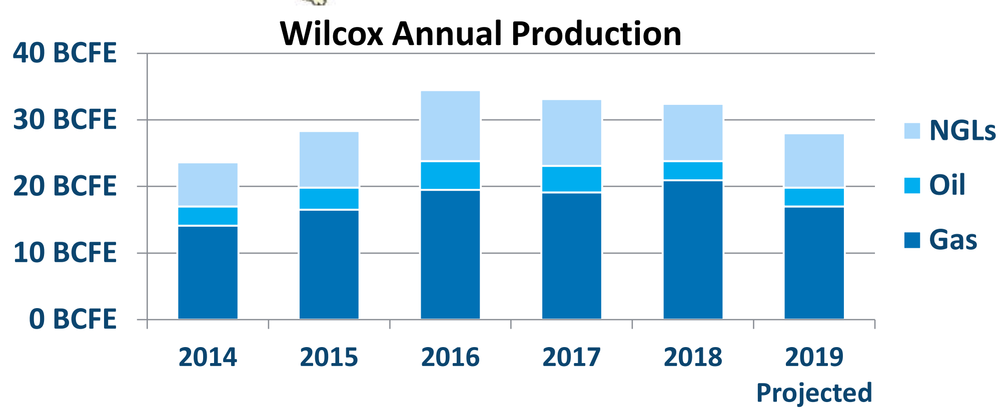
Gilly Field – Wet Gas Reservoir

- 400 Bcfe stacked pay gas resource
- Cumulative production ~ 135 Bcfe
- Average EUR of 10-20 Bcfe per well
- Typical well ~ $5 MM cost, ROR > 100%

Unit's Wilcox Competitive Advantages

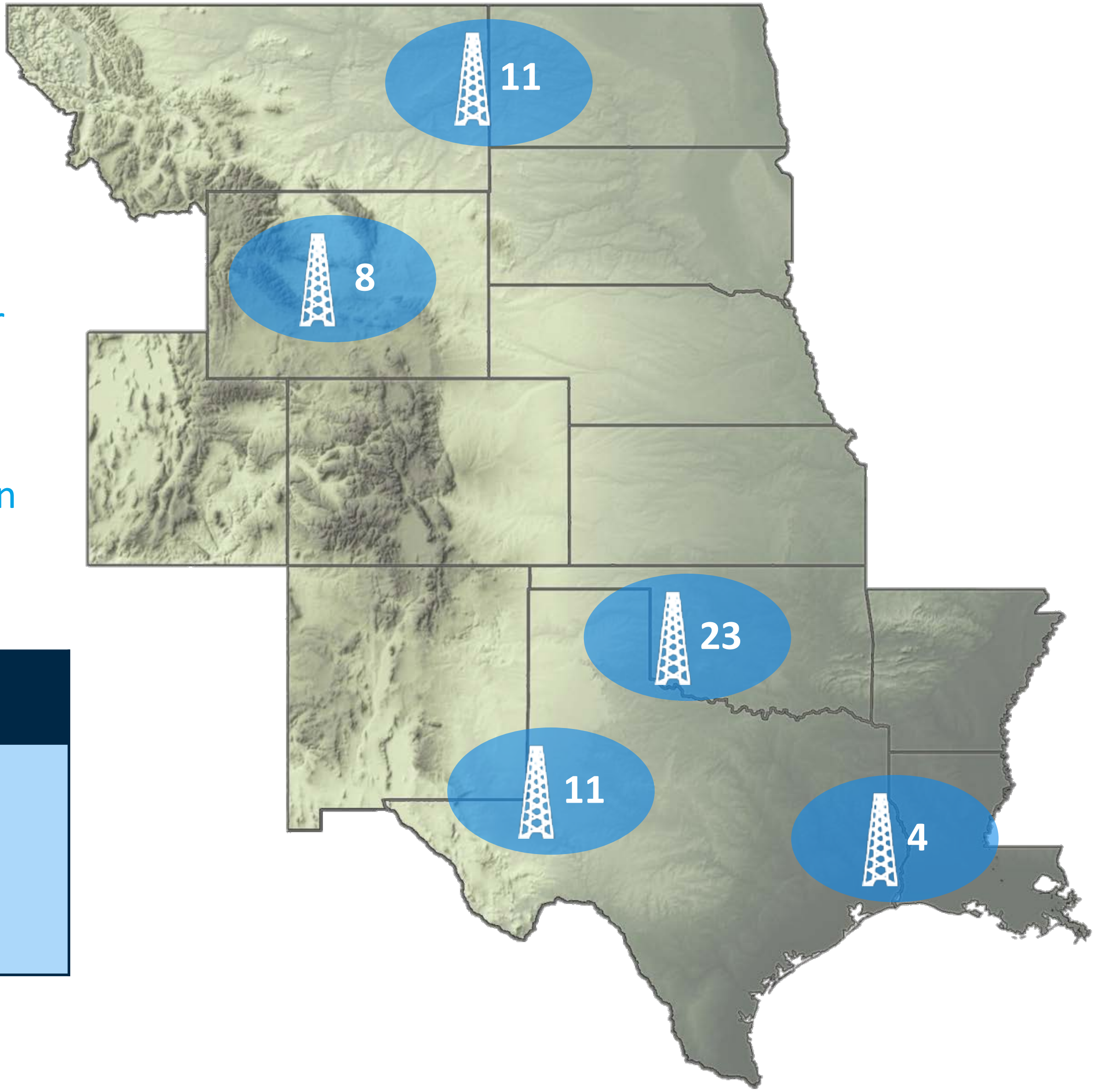
- Premium Gulf Coast pricing for oil and gas
- Wet Gas/Condensate provides margin uplift
- Large 3D seismic database provides consistent stream of exploratory prospect ideas
- Conventional over-pressured reservoirs provide high potential at low acreage costs
- Proven stacked play concept yielding significant return (ROR 81%)
- Low cost play (.85/Mcfe)





Rig Fleet Presence in Key Regions

- 57 rig fleet
- 32% total fleet utilization
- 54 rigs pad capable
- SCR rigs modified to meet customer requirements
- All 13 BOSS rigs operating
- 14th BOSS rig moving to first location under long-term contract

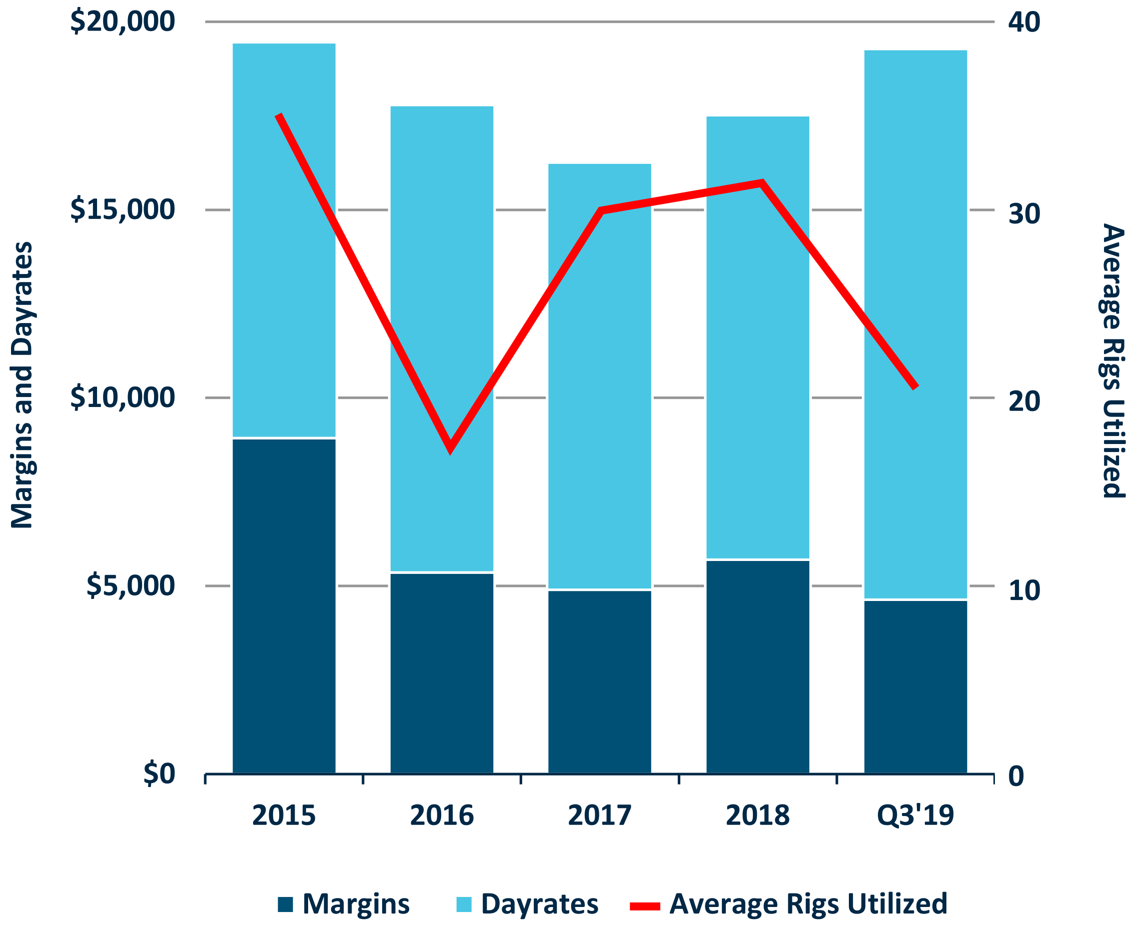


Current Rigs Operating(1)	
Area	# of Rigs
Mid-Continent	3
Bakken	5
Niobrara	2
Permian	8
Total	18

(1) As of December 9, 2019.

Average Dayrates and Margins (1)

- Average dayrates increased 4% quarter-over-quarter



(1) See Reconciliation of Average Daily Operating Margin Before Elimination of Intercompany Rig Profit and Bad Debt Expense in Appendix.

The BOSS Drilling Rig

Optimized for Pad Drilling

- Multi-direction walking system
- Racking & setback capacity for additional tubulars

Faster Between Locations

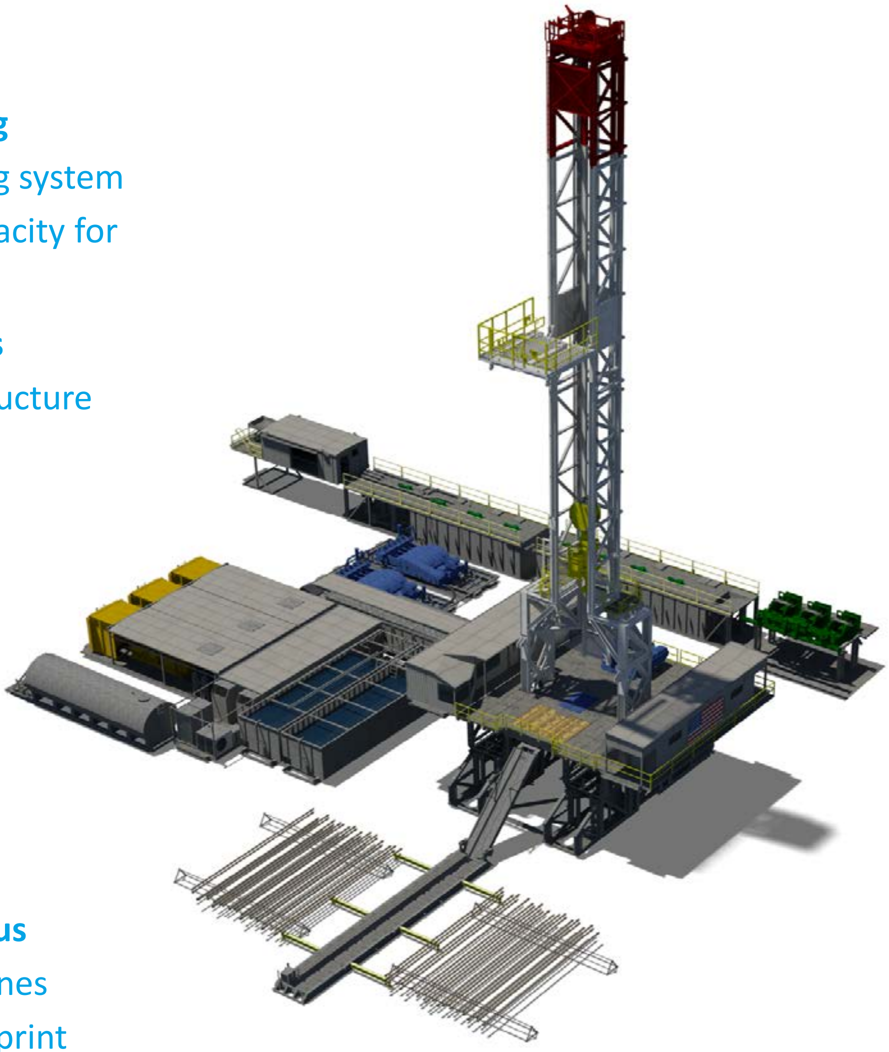
- Quick assembly substructure
- 32-34 truck loads

More Hydraulic Horsepower

- (2) 2,200 horsepower mud pumps
- 1,500 gpm available with one pump

Environmentally Conscious

- Dual-fuel capable engines
- Compact location footprint



All 13 BOSS rigs currently operating or under contract

14th BOSS rig moving to first location under long-term contract

Midstream Core Operations

Key Metrics

- 21 active gathering systems
- 12 gas processing plants
- Three natural gas treatment plants
- 323 MMcf/d processing capacity
- Q3'19 average processing volume of 168 MMcf/d
- Q3'19 average throughput volume of 429 MMcf/d
- Approx. 1,500 miles of pipeline

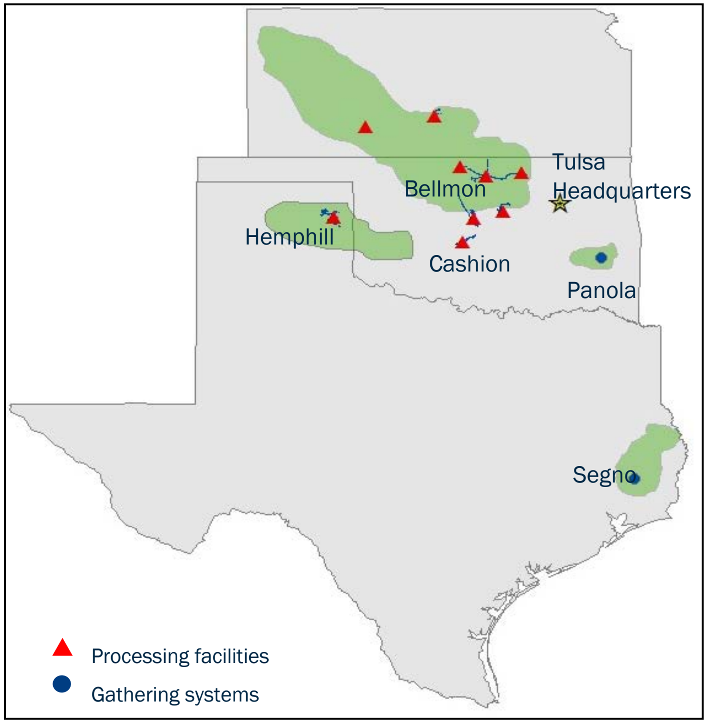
Northern Oklahoma and Kansas
- Approx. 1.9 million dedicated acres
- 176 MMcf/d processing capacity
- 658 miles of gathering pipeline

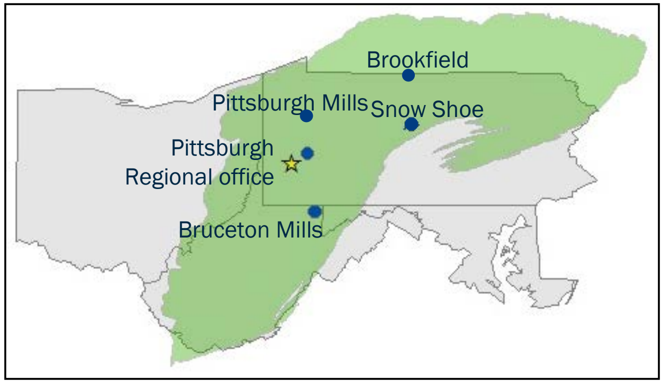
Texas Panhandle
- Approx. 47,000 dedicated acres
- 135 MMcf/d processing capacity
- 331 miles of gathering pipeline

Central & Eastern OK
- Approx. 70,000 dedicated acres
- 12 MMcf/d processing capacity
- 404 miles of gathering pipeline

East Texas
- 62 miles of gathering pipeline
- 120 MMcf/d gathering capacity
- Q3'19 average gathered volume of 63 MMcf/d

Appalachia
- Approx. 71,000 dedicated acres
- 56 miles of gathering pipeline
- Connected 7 new wells in 2019





Superior Joint Venture Overview

OPTrust | Partners Group — REALIZING POTENTIAL IN PRIVATE MARKETS

SP Investor Holdings, LLC

50%

UNIT.

50%

- Retains 50% equity interest
- Received $300 million
- Retains operational control of Superior

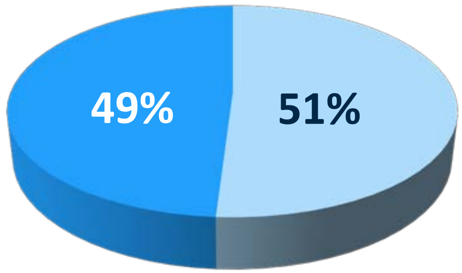
- Acquired 50% equity interest
- $300 million consideration
- Non-managing member

SUPERIOR PIPELINE COMPANY

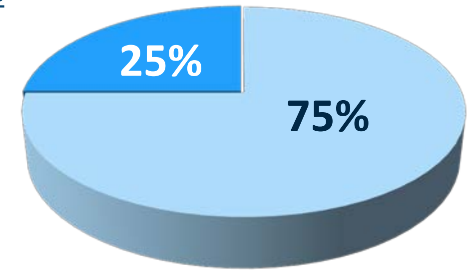
Midstream Segment Contract Mix

2010 | **Q3 2019**

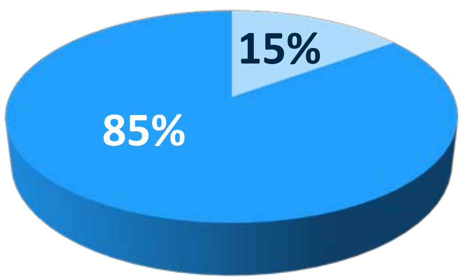
Contract Mix Based on Volume



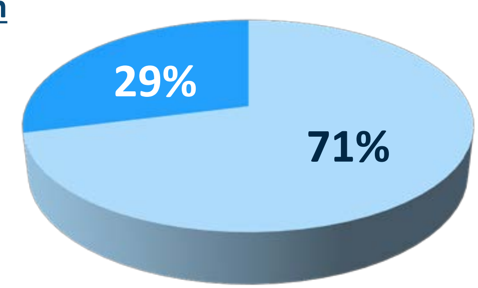
Fee Based
Commodity Based



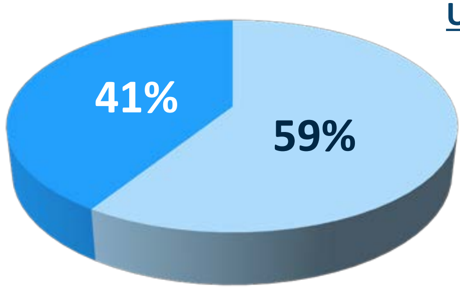
Contract Mix Based on Margin



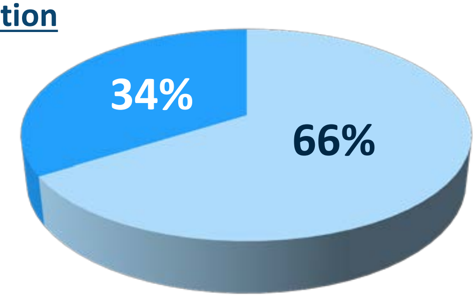
Fee Based
Commodity Based



Unit vs. 3rd Party Margin Contribution



3rd Party
Unit



Debt Structure

Senior Subordinated Notes

- **$650 million, 6.625% coupon**
- **Maturity of May 15, 2021**
- **Standard high yield incurrence covenants only, no financial maintenance tests**

Unit Secured Credit Facility (Re-determined September 26, 2019) *

• Borrowing Base and			
• Elected Commitment		$275 million	
• Outstanding(2)		$134.1	
• Maturity		October 2023	
			9/30/2019
• Key Covenants	Current ratio ≥ 1.0 to 1.0(1)		1.59x(1,2)
	Leverage ratio ≤ 4.00(1)		3.07x(1,2)

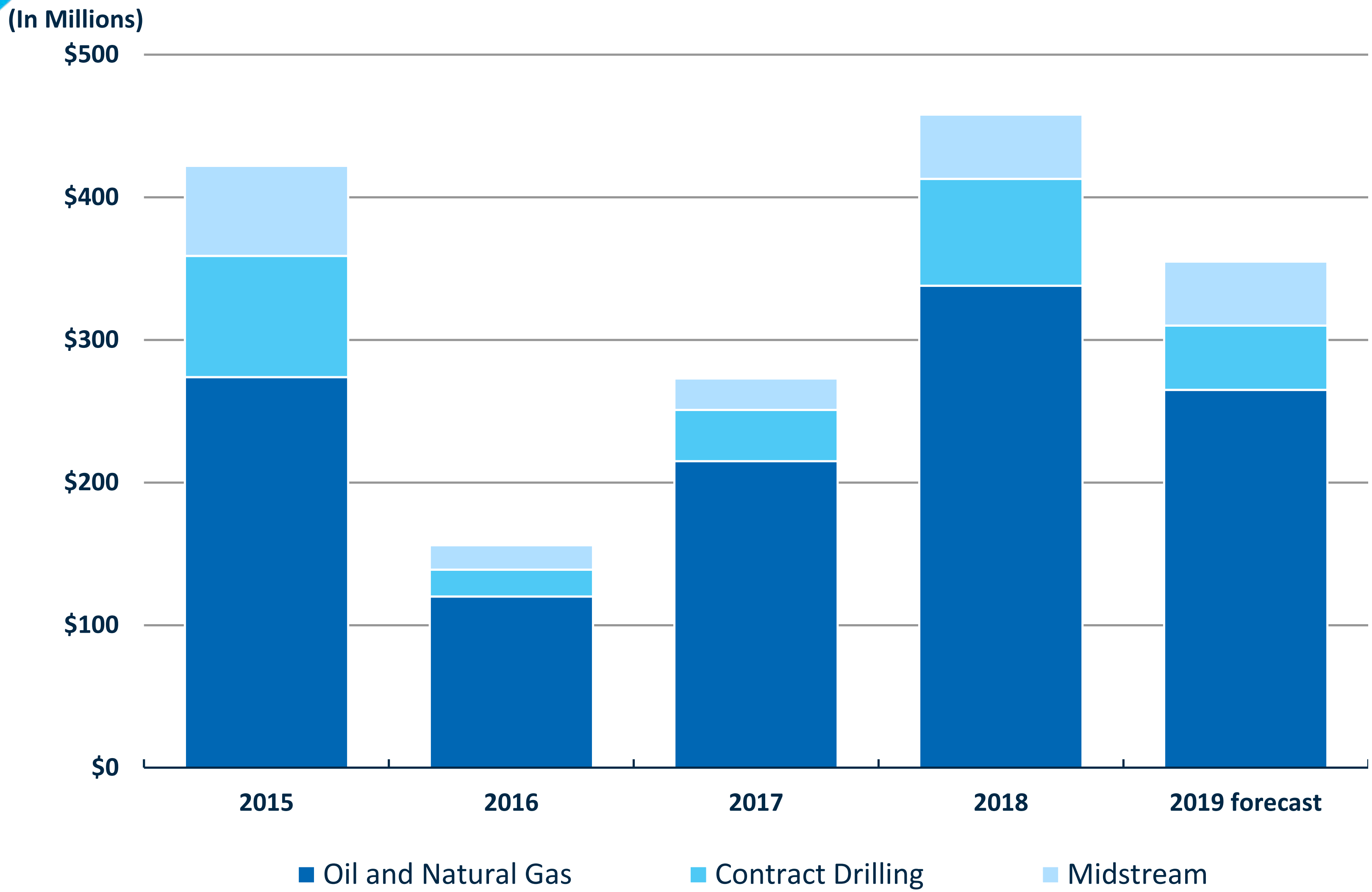
* Drilling rigs are not included in borrowing base.

Superior Secured Credit Facility

• Elected Commitment		$200 million	
• Outstanding(2)		$4.1	
• Maturity		May 2023	
			9/30/2019
• Key Covenants	Interest coverage ratio > 2.5(1)		35.38x(2)
	Leverage ratio < 4.00(1)		0.32x(2)

(1) As defined in Indenture/Credit Agreement. (2) As of September 30, 2019.

Operating Segment Capital Expenditures [1]



[1] Net of acquisitions and plugging liability revisions.

Investment Highlights

Unit offers a unique opportunity to invest in an integrated oil & gas company, capturing margin across the value chain

1. Diversified and integrated asset base across upstream, midstream, and drilling services
2. Capital stewardship with a history of capital spending in-line with cash flow
3. Upstream portfolio in the core of the Mid-Con and Gulf Coast with multiple years of inventory
4. Continuing shift to emphasize oil production
5. Midstream assets provide predictable fee-based cash flows with 66% coming from 3rd party producers
6. Top tier drilling services business with 100% utilization on high-spec, proprietary BOSS rigs
7. Experienced management team

Appendix

Reconciliation of Free Cash Flow

($ in thousands)	2001	2002	2003	2004	2005	2006	2007	2008	2009
Net cash provided by operating activities:	$ 133,021	$ 70,547	$ 121,712	$ 203,210	$ 317,771	$ 506,702	$ 577,571	$ 689,913	$ 490,475
Proceeds from disposition of property and equipment:	$ 2,631	$ 1,949	$ 1,625	$ 9,975	$ 8,722	$ 6,796	$ 5,309	$ 4,735	$ 44,733
Proceeds from Superior Equity Sale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Producing property and other acquisitions:	$ (17)	$ (4,500)	$ (35,000)	$ (148,076)	$ (136,413)	$ (122,915)	$ (38,500)	$ (25,727)	$ -
Total	$ 135,635	$ 67,996	$ 88,337	$ 65,109	$ 190,080	$ 390,583	$ 544,380	$ 668,921	$ 535,208
Capital Expenditures:	$ 108,339	$ 70,725	$ 96,162	$ 165,950	$ 254,450	$ 423,428	$ 478,950	$ 782,434	$ 316,660
Free Cash Flow [1]	**$ 27,296**	**$ (2,729)**	**$ (7,825)**	**$ (100,841)**	**$ (64,370)**	**$ (32,845)**	**$ 65,430**	**$ (113,513)**	**$ 218,548**

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Net cash provided by operating activities:	$ 390,072	$ 608,455	$ 690,911	$ 674,331	$ 708,993	$ 446,944	$ 240,130	$ 265,956	$ 347,759
Proceeds from disposition of property and equipment:	$ 40,048	$ 10,328	$ 281,824	$ 120,910	$ 66,197	$ 11,854	$ 74,823	$ 21,713	$ 25,910
Proceeds from Superior Equity Sale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 300,000
Producing property and other acquisitions:	$ (92,229)	$ (50,013)	$ (598,485)	$ -	$ (5,723)	$ (179)	$ (564)	$ (58,026)	$ (29,970)
Total	$ 337,891	$ 568,770	$ 374,250	$ 795,241	$ 769,467	$ 458,619	$ 314,389	$ 229,643	$ 643,699
Capital Expenditures:	$ 484,080	$ 728,551	$ 762,381	$ 703,984	$ 981,374	$ 561,453	$ 186,149	$ 255,553	$ 446,282
Free Cash Flow [1]	**$ (146,189)**	**$ (159,781)**	**$ (388,131)**	**$ 91,257**	**$ (211,907)**	**$ (102,834)**	**$ 128,240**	**$ (25,910)**	**$ 197,417**

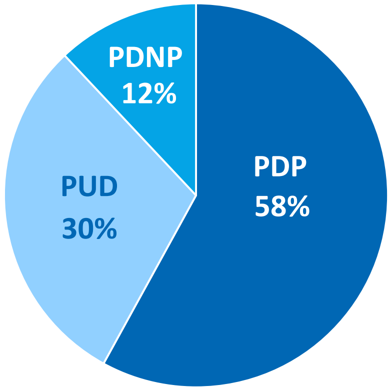
[1] Free cash flow defined as cash flow from operating activities plus proceeds from divestitures less acquisitions less capital expenditures. Data from Schedule 10-K Consolidated Statements of Cash Flows.

Reserve Detail

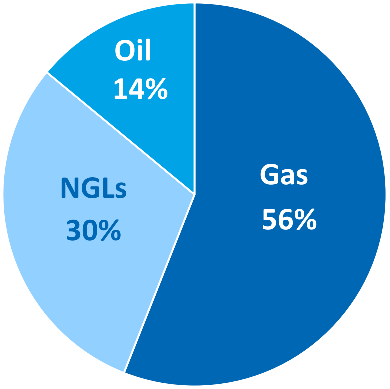
- Reserve summary, as of 12/31/2018, audited by Ryder Scott Company, L.P.
- Reserves up 7% Y/Y
- PDP up 2% Y/Y
- PV-10 up 23% Y/Y

	Oil (Mbbls)	Nat Gas (MMcf)	NGL (Mbbls)	Total (Mboe)	PV-10 ($MM)
PDP	13,248	301,948	28,171	91,743	$831
PDNP	1,944	75,268	5,344	19,833	$102
PUD	7,366	158,747	14,281	48,105	$173
Total Proved	22,558	535,963	47,796	159,681	$1,106

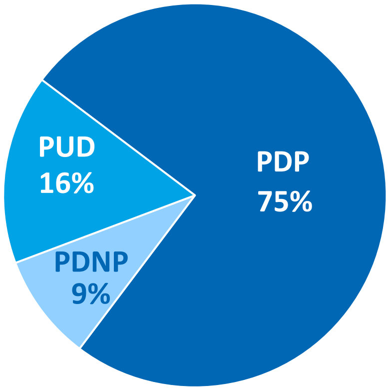
Net Proved Reserves



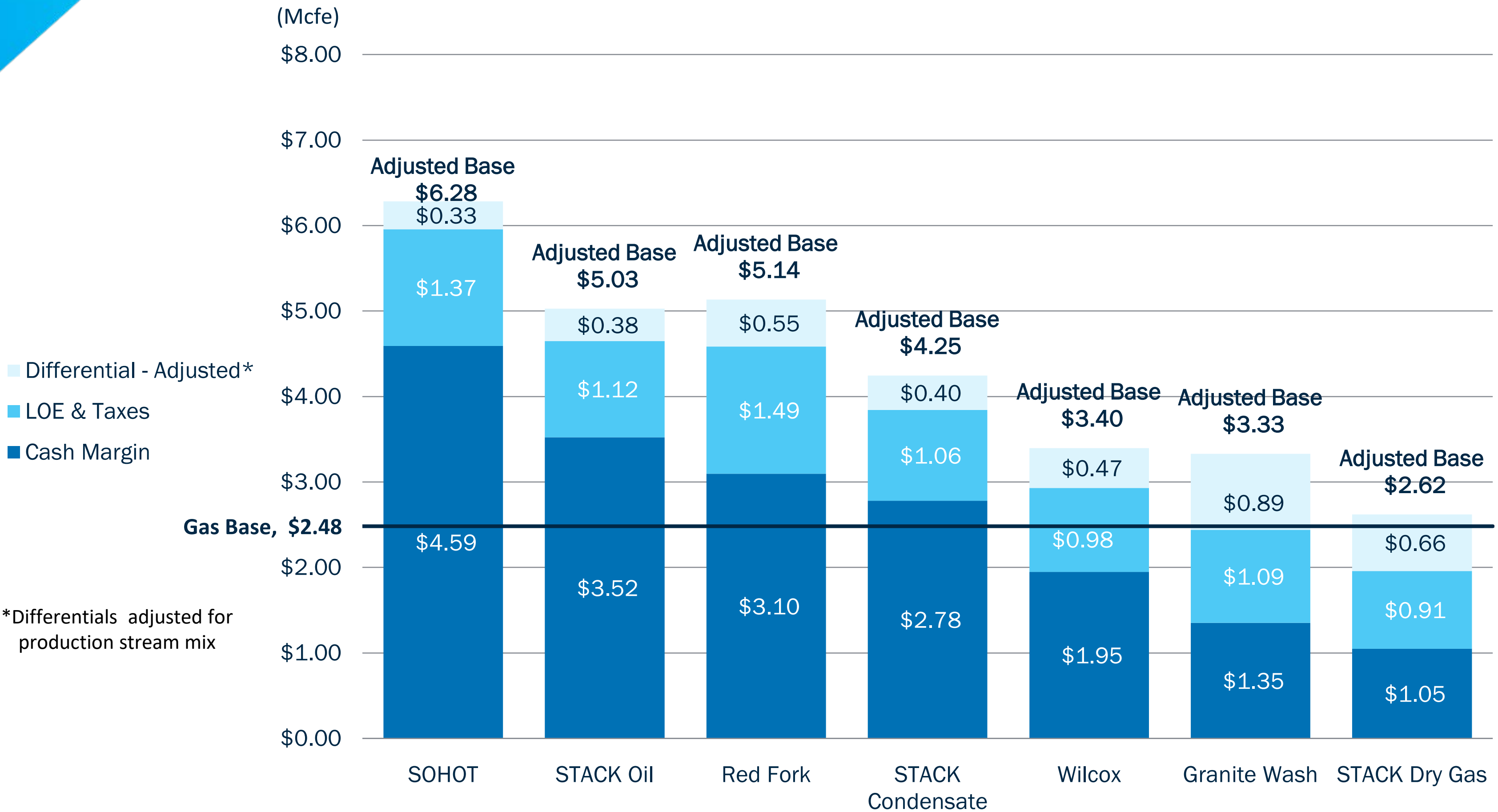
Proved Reserves Allocation



PV-10



Core Area Cash Margins



*Differentials adjusted for production stream mix

% Gas	23%	35%	39%	42%	61%	62%	99%

Note: assumes 6:1 gas to oil ratio. Production is based on actual (Jan 2019 through Sept 2019) or average type curves for the respective plays. The adjusted base prices represent the weighted average commodity price per Mcfe for each area's production (using WTI, Henry Hub and Mont Belvieu propane as a proxy for NGL prices) and are based on the November 1, 2019 strip. Differentials are adjusted to each area's production mix as of November 5, 2019. Differentials for the STACK Dry Gas and Granite Wash are estimated from basis futures and index pricing as of May 28, 2019 and assume a 75% reduction of marketing fees after the commissioning of the Midship Pipeline. Lease operating expenses are based on area specific operating cost models used in preparation of the 2019 2nd Quarter Proved Reserve Report and include gas transportation costs updated as November 5, 2019. Taxes are calculated using production and pricing described in the reserve report with Texas severance taxes adjusted for high cost tax rates. The adjusted base also includes 50% of the applicable midstream margin for Granite Wash and Wilcox.

Non-GAAP Financial Measures - Corporate

Adjusted EBITDA

($ In millions)	Nine months ended September 30, 2018	Nine months ended September 30, 2019	Years ended December 31, 2015	Years ended December 31, 2016	Years ended December 31, 2017	Years ended December 31, 2018*
Net Income (Loss)	**$37**	**($218)**	**($1,037)**	**($136)**	**$118**	**($40)**
Income Taxes	12	(53)	(627)	(71)	(58)	(14)
Depreciation, Depletion and Amortization	179	199	352	208	209	244
Impairments	—	235	1,635	162	—	148
Interest Expense	26	27	32	40	38	34
(Gain) loss on derivatives	25	(5)	(26)	23	(15)	3
Settlements during the period of matured derivative contracts	(18)	12	47	10	—	(23)
Stock compensation plans	17	17	21	14	18	23
Other non-cash items	(2)	—	3	3	3	(3)
(Gain) loss on disposition of assets	1	1	7	(3)	—	(1)
Adjusted EBITDA	**$277**	**$215**	**$407**	**$250**	**$313**	**$371**
Adjusted EBITDA attributable to non-controlling interest	15	20	—	—	—	**21**
Adjusted EBITDA attributable to Unit	**$262**	**$195**	**$407**	**$250**	**$313**	**$350**

*Reflects the sale of 50% equity interest of Superior effective 4/1/2018.

Non-GAAP Financial Measures - Segments

Segment Adjusted EBITDA (with G&A allocated)

($ In millions)	Nine months ended Sept. 30, 2018	Nine months ended Sept. 30, 2019	Years ended December 31, 2015	2016	2017	2018	LTM Q3'19
Unit Petroleum							
Income (Loss) Before Income Taxes (1)	$ 82	$ (157)	$(1,622)	$ (138)	$ 126	$ 139	$ (100)
Depreciation, Depletion and Amortization	98	118	252	114	102	134	154
Impairment of Oil & Natural Gas Properties	---	170	1,599	162	---	---	170
Other Adjustments (2)	13	12	34	42	(5)	(13)	(14)
Adjusted EBITDA	$ 193	$ 143	$ 263	$ 180	$ 223	$ 260	$ 210
Unit Drilling							
Income (Loss) Before Income Taxes (1)	$ (1)	$ (68)	$ 31	$ (20)	$ (15)	$ (151)	$ (218)
Depreciation and Impairment	42	39	64	47	56	58	55
Impairment of drilling equipment	---	63	---	---	---	148	211
Other Adjustments (2)	3	2	10	(1)	3	4	3
Adjusted EBITDA	$ 44	$ 36	$ 105	$ 26	$ 44	$ 59	$ 51
Superior Pipeline							
Income (Loss) Before Income Taxes (1)	$ 8	$ (3)	$ (33)	$ (4)	$ 1	$ 8	$ (3)
Depreciation, Amortization and Impairment	33	38	71	46	44	45	50
Other Adjustments (2)	(1)	1	1	2	2	(1)	1
Adjusted EBITDA	$ 40	$ 36	$ 39	$ 44	$ 47	$ 52	$ 48

(1) After intercompany eliminations.
(2) Adjustments per non-GAAP financial measures – corporate schedule (previous slide).
Note: Corporate G&A is allocated to the segments based on a weighted average percentage of total segment identifiable assets plus budget segment cap-x, segment depreciation, segment revenues and direct segment G&A minus budgeted divestitures. Superior Pipeline was excluded from the allocation starting in April 2018 since they are directly billed for Corporate G&A per the JV contract and the billed amount is reduced from the Corporate G&A amount allocated to the drilling and oil and gas segments.

Non-GAAP Financial Measures

Reconciliation of Average Contract Drilling Daily Operating Margin Before Elimination of Intercompany Rig Profit and Bad Debt Expense

(In thousands except for operating days and operating margins)	Nine months ended September 30, 2018	Nine months ended September 30, 2019	Years ended December 31, 2015	Years ended December 31, 2016	Years ended December 31, 2017	Years ended December 31, 2018
Contract drilling revenue	$143,527	$131,788	$265,668	$122,086	$174,720	$196,492
Contract drilling operating cost	95,593	89,505	156,408	88,154	122,600	131,385
Operating profit from contract drilling	$47,934	$42,283	$109,260	$33,932	$52,120	$65,107
Add:						
Elimination of intercompany rig profit and bad debt expense	2,434	1,627	3,991	235	1,620	3,078
Operating profit from contract drilling before elimination of intercompany rig profit and bad debt expense	50,368	43,910	113,251	34,167	53,740	68,185
Contract drilling operating days	8,919	7,305	12,681	6,374	10,964	11,960
Average daily operating margin before elimination of intercompany rig profit and bad debt expense	$5,647	$6,011	$8,931	$5,360	$4,901	$5,701

Derivative Summary

	2019	2020				2021			
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude									
Collars									
Volume (Bbl)	--	--	--	--	--	--	--	--	--
Weighted Avg Floor	--	--	--	--	--	--	--	--	--
Weighted Avg Ceiling	--	--	--	--	--	--	--	--	--
3-Way Collars									
Volume (Bbl)	368,000	--	--	--	--	--	--	--	--
Weighted Avg Floor	$61.25	--	--	--	--	--	--	--	--
Weighted Avg Subfloor	$51.25	--	--	--	--	--	--	--	--
Weighted Avg Ceiling	$72.93	--	--	--	--	--	--	--	--
Swaps									
Volume (Bbl)	184,000	--	--	--	--	--	--	--	--
Weighted Avg Swap	$59.80	--	--	--	--	--	--	--	--
Natural Gas									
Collars									
Volume (MMBtu)	1,840,000	--	--	--	--	--	--	--	--
Weighted Avg Floor	$2.63	--	--	--	--	--	--	--	--
Weighted Avg Ceiling	$3.03	--	--	--	--	--	--	--	--
3-Way Collars									
Volume (MMBtu)	--	2,730,000	2,730,000	2,760,000	2,760,000	--	--	--	--
Weighted Avg Floor	--	$2.50	$2.50	$2.50	$2.50	--	--	--	--
Weighted Avg Subfloor	--	$2.20	$2.20	$2.20	$2.20	--	--	--	--
Weighted Avg Ceiling	--	$2.80	$2.80	$2.80	$2.80	--	--	--	--
Swaps									
Volume (MMBtu)	4,300,000	--	--	--	--	--	--	--	--
Weighted Avg Swap	$2.90	--	--	--	--	--	--	--	--
Basis Swaps									
Volume (MMBtu)	5,520,000	4,550,000	4,550,000	4,600,000	4,600,000	2,700,000	2,730,000	2,760,000	2,760,000
Weighted Avg Swap	($0.46)	($0.35)	($0.35)	($0.35)	($0.35)	($0.22)	($0.22)	($0.22)	($0.22)

Q4 2019 Economic Prices

Strip Case*

	Crude	Natural Gas	PEPL Basis	NGPL-Midcon Basis	MB C2	MB C3	MB C3 $ per barrel	MB NC4	MB iC4	MB C5+	CW C2	CW C3	CW NC4	CW iC4	CW C5+
2019	$54.857	$2.640	($0.390)	($0.320)	$0.199	$0.505	$21.213	$0.644	$0.825	$1.170	$0.132	$0.475	$0.590	$0.700	$1.190
2020	$52.925	$2.484	($0.481)	($0.447)	$0.187	$0.487	$20.466	$0.621	$0.796	$1.129	$0.124	$0.458	$0.569	$0.675	$1.148
2021	$50.703	$2.468	($0.413)	($0.384)	$0.186	$0.467	$19.606	$0.595	$0.763	$1.082	$0.123	$0.439	$0.545	$0.647	$1.100
2022	$50.316	$2.494	($0.413)	($0.384)	$0.188	$0.463	$19.457	$0.591	$0.757	$1.073	$0.124	$0.436	$0.541	$0.642	$1.092
Thereafter	$50.316	$2.494	($0.413)	($0.384)	$0.188	$0.463	$19.457	$0.591	$0.757	$1.073	$0.124	$0.436	$0.541	$0.642	$1.092

*Strip prices as of 11/1/2019.