Resolute Energy Corporation

Investor Presentation

August 6, 2018

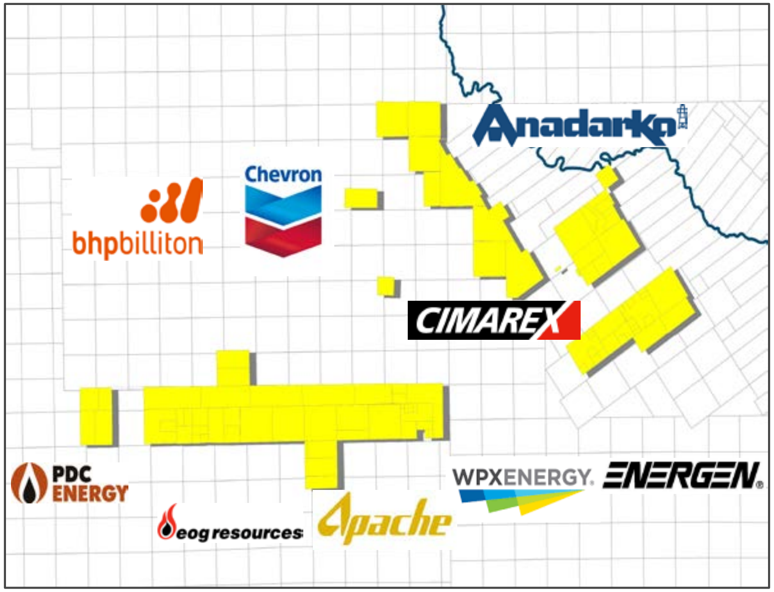
Cautionary statements

Statements in this presentation, other than statements of historical fact, are “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. Words such as “expect,” “estimate,” “project,” “budget,” “forecast,” “target”, “anticipate,” “intend,” “plan,” “may,” “will,” “could,” “should,” “poised”, “believes,” “predicts,” “potential,” “continue,” and similar expressions are intended to identify such forward-looking statements; however the absence of these words does not mean the statements are not forward-looking. Such forward looking statements include statements regarding 2018 production, lease operating expense, corporate G&A, capital expenditure and product mix guidance; anticipated 2018 production targets and oil percentage; 2018 and 2019 expected production growth; ; our plans and expectations regarding our future development activities including drilling and completing wells and the spacing of such wells; the number of such potential projects, locations and productive intervals; expected timing and location of drilling and completion of pad wells and the timing of the production contribution thereof; plans regarding future oil and gas takeaway; expected third quarter Adjusted EBITDA; anticipated additional drilling inventory; future financial, operating results and shareholder returns; future liquidity and availability of capital; future leverage ratios; 2018 capital expenditure detail, including expected cost estimates for Ranger and Sandlot nine-pack; future infrastructure plans and options; future production, reserve growth and decline rates; the impact of well interference and the effectiveness of drilling and completion adjustments in response thereto; the anticipated benefits of our 2018 development strategy; our projection of free cash flow through 2019; the prospectivity of our properties and acreage; estimated ultimate recoveries of oil and gas (EURs); performance of wells against type curves; and anticipated rates of return (IRRs), net asset values and PV-10 values of our projects and properties. Resolute will evaluate its capital expenditures in relation to its liquidity and cash flow and may adjust its activity and capital spending levels based on acquisitions, changes in commodity prices, the cost of goods and services, production results and other considerations. Forward-looking statements in this presentation include matters that involve known and unknown risks, uncertainties and other factors that may cause actual results, levels of activity, performance or achievements to differ materially from results expressed or implied by this presentation. Such risk factors include, among others: the Company’s ability to successfully implement its strategy to create long-term stockholder value; depressed commodity prices; the volatility of oil and gas prices and basis differentials, including the price realized by Resolute; disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil, NGL and gas and other processing and transportation considerations; inaccuracy in reserve estimates and expected production rates; potential write downs of the carrying value and volumes of reserves as a result of low commodity prices; the discovery, estimation, development and replacement by Resolute of oil and gas reserves; our ability to fund and develop our estimated proved undeveloped reserves; changes in our production mix of oil and gas; the future cash flow, liquidity and financial position of Resolute; Resolute’s level of indebtedness and our ability to fulfill our obligations under the senior notes, our credit facility and any additional indebtedness that we may incur; potential borrowing base reductions under our revolving credit facility; constraints imposed on our business and operations by our revolving credit facility and senior notes which may limit our ability to execute our business strategy; the risk of a transaction that could trigger a change of control under our debt agreements; the success of the business and financial strategy, hedging strategies and development and production plans of Resolute; the amount, nature and timing of capital expenditures of Resolute, including future development costs; potential operational disruption caused by the actions of stockholder activists; the availability of additional capital and financing, including the capital needed to pursue our drilling and development plans for our properties, on terms acceptable to us or at all; uncertainty surrounding timing of identifying drilling locations and necessary capital to drill such locations; the potential for downspacing, infill or multi-lateral drilling in the Permian Basin or obstacles thereto; the timing of issuance of permits and rights of way; the timing and amount of future production of oil and gas; availability of drilling, completion and production personnel, supplies and equipment; the completion and success of exploratory drilling on our properties; potential delays in the completion, commissioning and optimization schedule of Resolute’s facilities construction projects or any potential breakdown of such facilities; operating costs and other expenses of Resolute; the success of prospect development and property acquisition of Resolute; risks associated with unanticipated liabilities assumed, or title, environmental or other problems resulting from, our acquisitions; the ability to sell or otherwise monetize assets at values and on terms that are advantageous to us; Resolute’s dependence on third parties for installation of gas gathering and processing infrastructure, oil gathering facilities and water disposal facilities and potential delays and breakdowns relating thereto; risks relating to our joint interest partners’ and other counterparties’ inability to fulfill their contractual commitments; the concentration of our credit risk as the result of depending on one primary oil purchaser and one primary gas purchaser in the Delaware Basin; the concentration of our producing properties in a single geographic area; loss of senior management or key technical personnel; the impact of long-term incentive programs, including performance-based awards and stock appreciation rights; the success of Resolute in marketing oil and gas; competition in the oil and gas industry; the impact of weather and the occurrence of disasters, such as fires, floods and other events and natural disasters; environmental liabilities; potential power supply limitations or delays; operational problems or uninsured or underinsured losses affecting Resolute’s operations or financial results; adverse changes in government regulation and taxation of the oil and gas industry, including the potential for increased regulation of underground injection, fracing operations and venting/flaring; potential regulation of waste water injection intended to address seismic activity; potential climate related change regulations; risks and uncertainties associated with horizontal drilling and completion techniques; the availability of water and our ability to adequately treat and dispose of water during and after drilling and completing wells; our relationship with the local communities in which we operate; changes in derivatives regulation; risks associated with rising interest rates; the impact of any U.S. or global economic recession; losses possible from pending or future regulation; developments in oil-producing and gas-producing countries; risks of terrorist activities directed at oil and gas production; cyber security risks; and risks related to our common stock, potential declines in stock prices and potential future dilution to stockholders. Actual results may differ materially from those contained in the forward-looking statements in this presentation. Resolute undertakes no obligation and does not intend to update these forward-looking statements to reflect events or circumstances occurring after the date of this presentation. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. You are encouraged to review Item 1A. Risk Factors and all other disclosures appearing in the Company’s Form 10-K and Form 10-K/A for the year ended December 31, 2017, subsequent quarterly reports on Form 10-Qand subsequent filings with the Securities and Exchange Commission (the "SEC") for further information on risks and uncertainties that could affect the Company’s businesses, financial condition and results of operations. All forward-looking statements are qualified in their entirety by this cautionary statement. Furthermore, the SEC prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than “reserves,” as that term is defined by the SEC. In this presentation, Resolute includes estimates of quantities of oil and gas using certain terms, such as “resource,” “resource potential,” “EUR,” “oil in place,” or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC definitions of proved, probable and possible reserves, and which the SEC guidelines strictly prohibit Resolute from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by Resolute. Finally, reserve estimates mentioned in this presentation were prepared internally using price and cost assumptions and methodologies that are different from what would be required if prepared in accordance with guidelines established by the SEC for the estimation of proved reserves, and such reserve estimates do not include probable and possible reserves. Such reserve estimates have not been audited by our independent reserves auditor. Production rates, including “early time” rates, 24-hour peak IP rates, 30, 60, 90, 120 and 150 day peak IP rates, for both our wells and for those wells that are located near to our properties are limited data points in each well’s productive history and represent three stream gross production. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data becomes available. Peak production rates are not necessarily indicative or predictive of future production rates, EUR or economic rates of return from such wells and should not be relied upon for such purpose. Equally, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as leaseline offsets. Standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid-length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,000 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet. Non-GAAP financial measures: Resolute’s presentations may include certain non-GAAP financial measures. When applicable, a reconciliation of these measures to the most directly comparable GAAP measure is presented.

Company overview | Delaware Basin pure play

- Premier Delaware Basin position[1]
  - 27,100 gross (21,100 net) acres, ~90% in derisked core of Basin
- Strong execution
  - Successful transition to pad drilling
  - 2Q18 exit rate in excess of 35,000 Boe per day
- Expanding derisked inventory
  - Added ~150 Lower Wolfcamp B and Wolfcamp C locations in Mustang
  - 559 gross (502 net) operated Wolfcamp development locations[1]
  - Evaluating Bone Spring and Lower Wolfcamp in Appaloosa

Core acreage offset by high-quality operators



Market data ($ million)[2]	
Ticker symbol	REN
Market cap	$695
Total net debt	$673
Enterprise value	$1,430

1. *As of June 30, 2018. Core development area in Appaloosa, Bronco and Mustang*
2. *23.2 million shares outstanding as of July 31, 2018 and share price of $30.00 as of August 3, 2018. Enterprise value includes $62.5 million face value convertible preferred.*

2Q18 operational highlights

- Second quarter production of 24,036 Boe per day with an exit rate of more than 35,000 Boe per day
- Ranger nine-pack on line in early June with per well average peak rate of 2,300 Boe per day, approximately 60% oil
- First Sandlot nine-pack flowing back with strong initial performance; early time rate in excess of 13,000 Boe per day[1], still inclining
- South Mitre well-pack completion scheduled to begin in mid-August, first production expected late September; includes first refrac
- Mustang Lower Wolfcamp wells significantly outperforming type curve with strong oil rates; adds ~150 locations to development inventory

Resolute unlocking the full potential of its assets

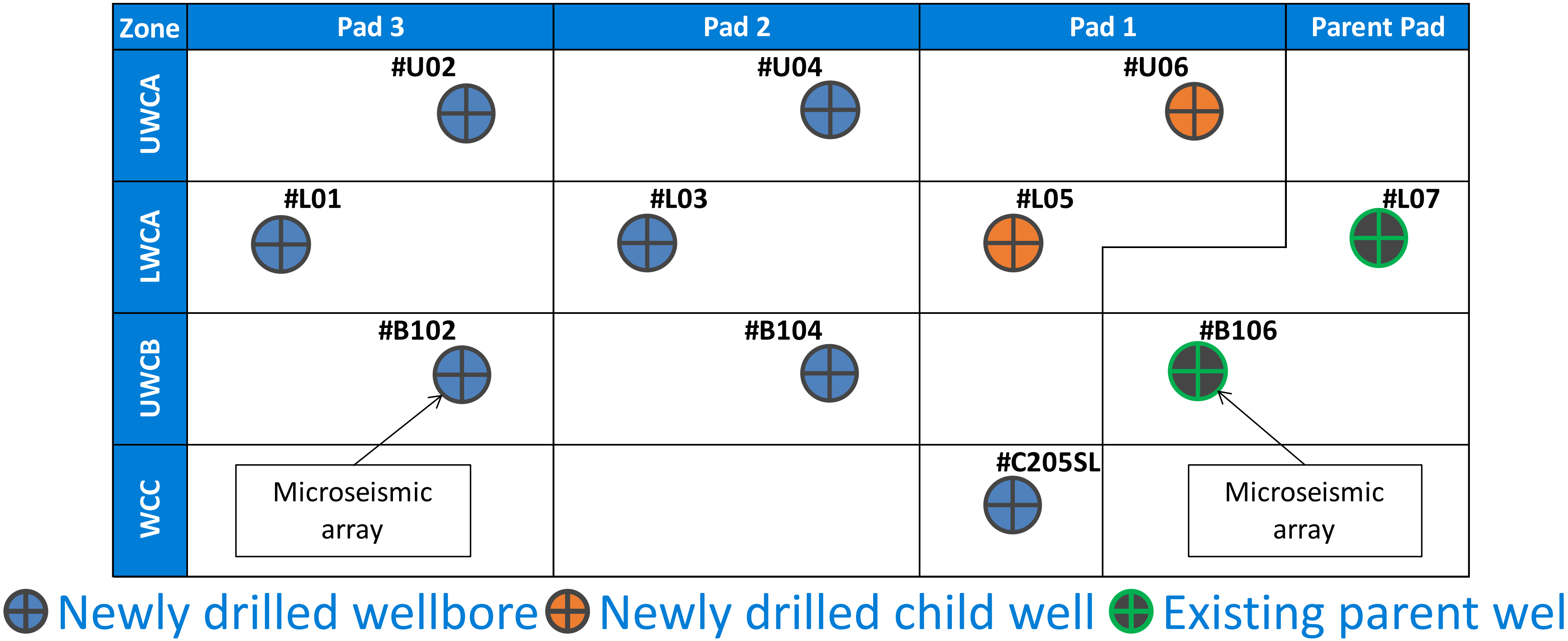
1. *Early time rates as of July 31, 2018, subject to change*

2Q18 operational achievements

Production	▪ 2Q18 exit rate production jumped to more than 35,000 Boe per day, up nearly 70% from 1Q18 exit rate ▪ Second nine-pack, located in the Sandlot unit, came online in mid-July and is currently producing more than 13,000 Boe per day[1] and still inclining
Drilling	▪ Ranger and Sandlot drilling on budget ▪ Utilizing spudder rig to preset wells; reliably reducing drill times by three days per well
Completion	▪ Added third frac spread in June to complete first Sandlot nine-pack ▪ In Sandlot unit pumped ~102 million pounds of sand and ~2.1 million barrels of fluid for nine well completions

1. *Early time rates as of July 31, 2018, subject to change*

Schematic of Ranger pads



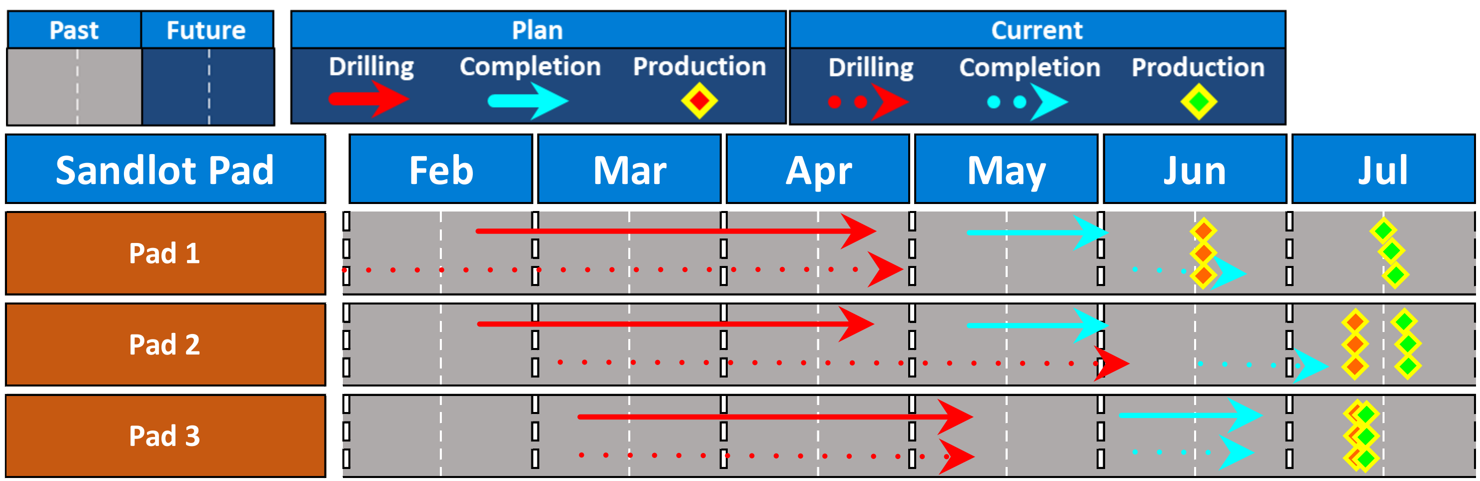
Ranger nine-pack results	Length (feet)	Average peak rate 24 hour (Boe per day)	Average cum % oil
Ranger – six parent wells	9,659	2,476	59%
Ranger – two child wells	9,601	2,034	60%
Ranger C205SL	9,721	1,990	48%

Schematic of Sandlot pads

Zone	PAD 3	PAD 2	PAD 1
UWCA	#U05	#U03	#U01
LWCA	#L06	#L04	#L02
UWCB	#B105	Microseismic array #B103	#B101

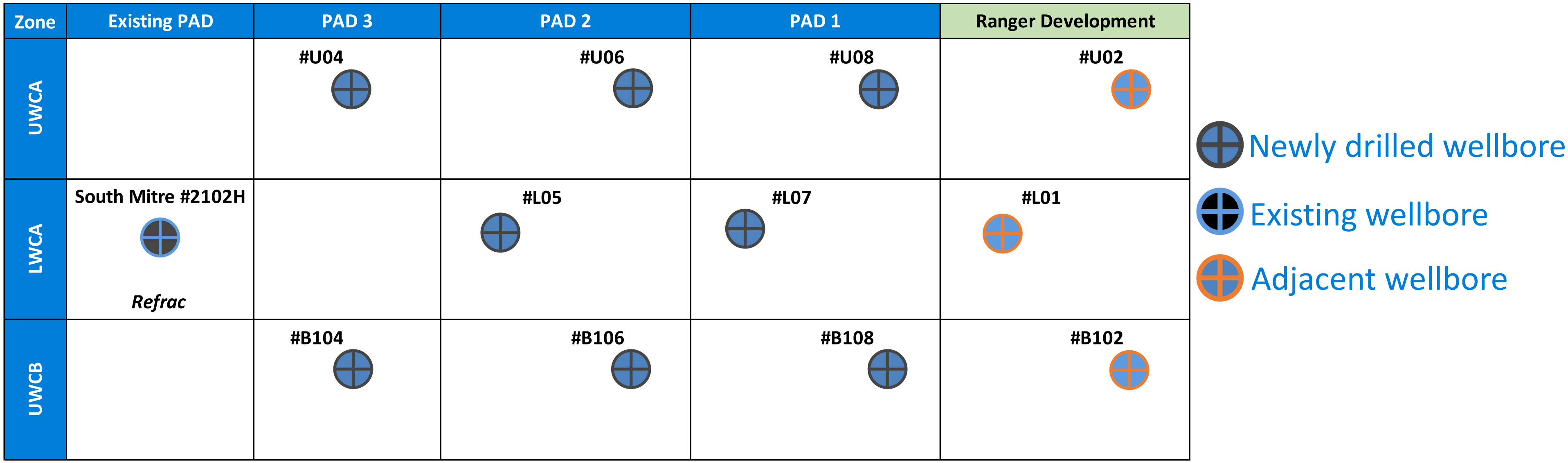
Newly drilled wellbore

- Early time rate in excess of 13,000 Boe per day[1] (44% cumulative oil), production rate still inclining

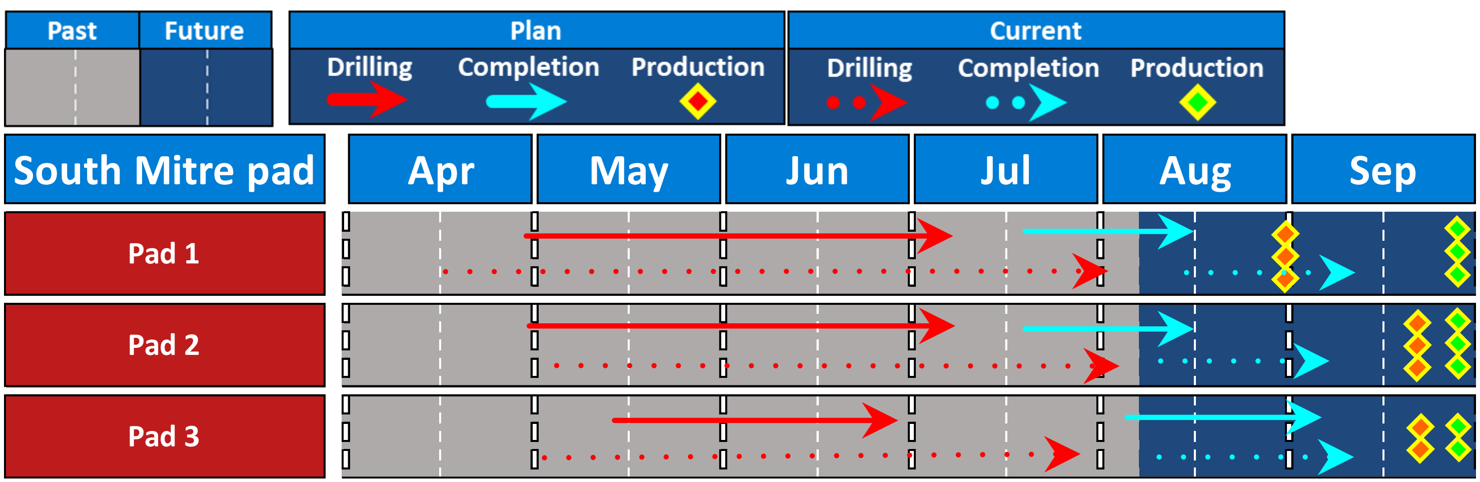


1. *Early time rates as of July 31, 2018, subject to change*

Schematic of South Mitre pads



- South Mitre 2102H was drilled in August 2016 and is scheduled to be refraced as part of this well-pack completion



Financial highlights

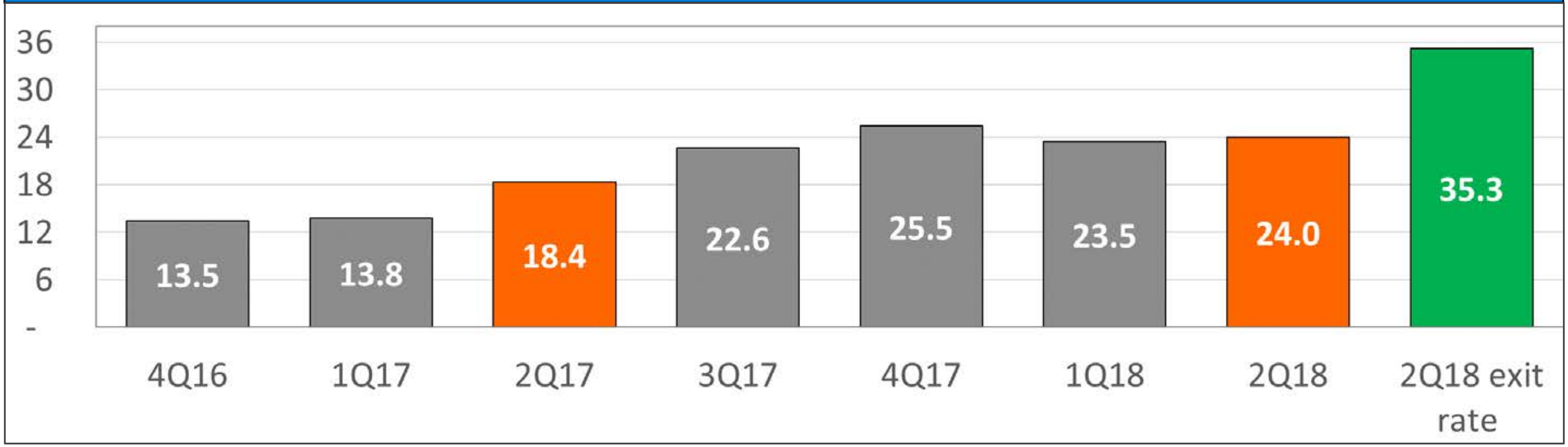
- Expect capital expenditures, LOE and cash-based G&A[1] to be within previously announced guidance range
- Preliminary cost estimates for Ranger and Sandlot nine-packs indicate aggregate drilling, completion and well facility expenditures in line with original budget
- LOE of $15.4 million, or $7.02 per Boe; expect 3Q18 LOE costs per Boe to be similar to 1Q18
- Hedged 63% of estimated oil production at $56.51 per Bbl NYMEX and 46% of Mid-Cush basis at $8.08 per Bbl for September to December 2018[2]
- 3Q18 Adjusted EBITDA expected to significantly increase based on results from pad development program

Resolute unlocking the full potential of its assets

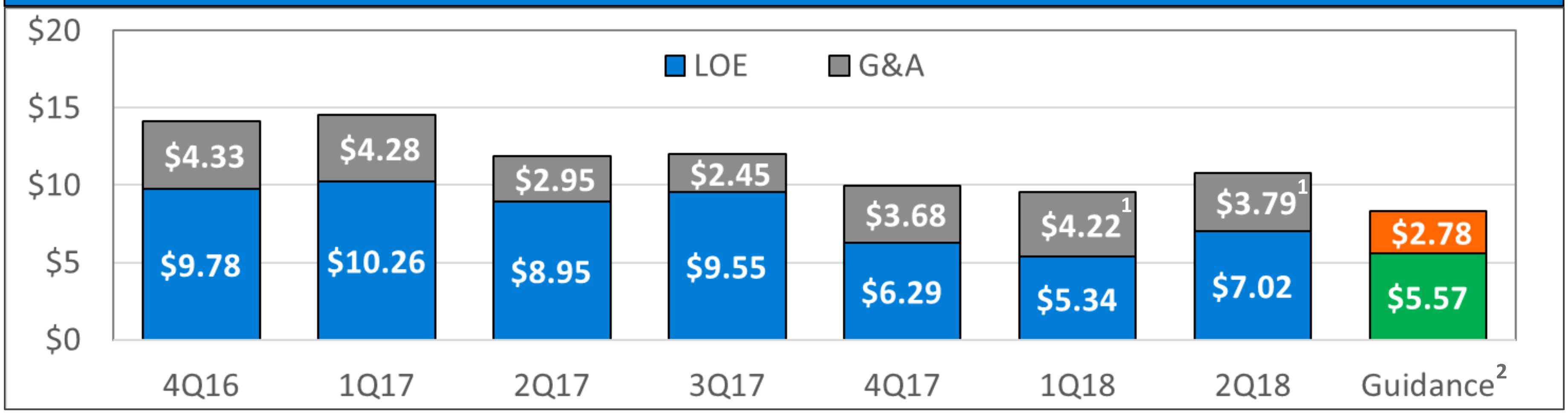
1. *A non-GAAP measure defined as consolidated general and administrative expense adjusted to exclude non-cash stock-based compensation and one-time, non-recurring, transaction related expenses (transaction costs or fees)*
2. *Based on midpoint of guidance*

Consistent production growth, improving cost structure

Permian production growth (MBoe per day)



Company cash costs per Boe



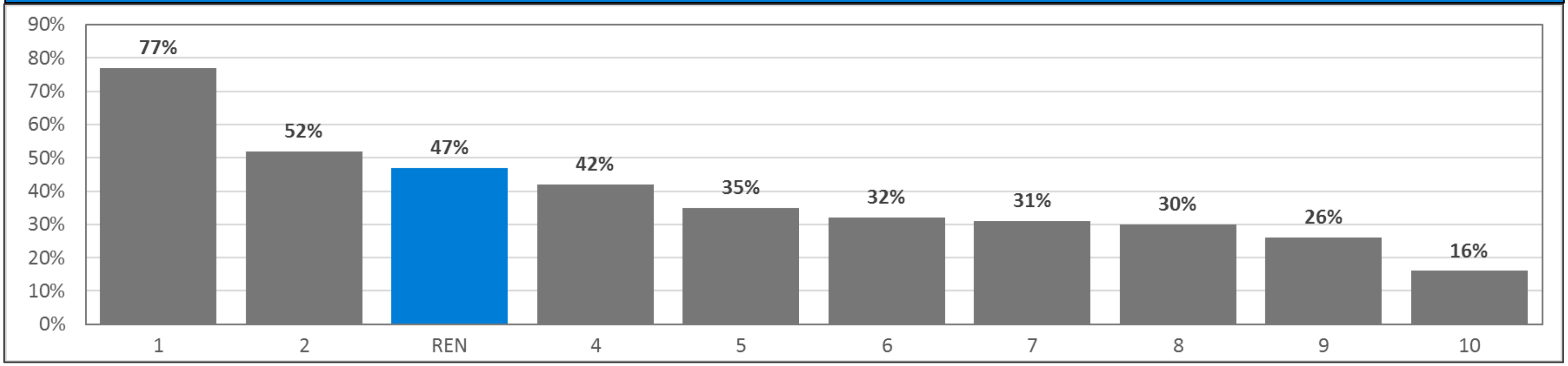
1. *Excludes stockholder activism expenses*
2. *Based on midpoint of guidance.*

Note: LOE is net of Copas reimbursements and excludes non-cash charges

Premier Delaware Basin operator

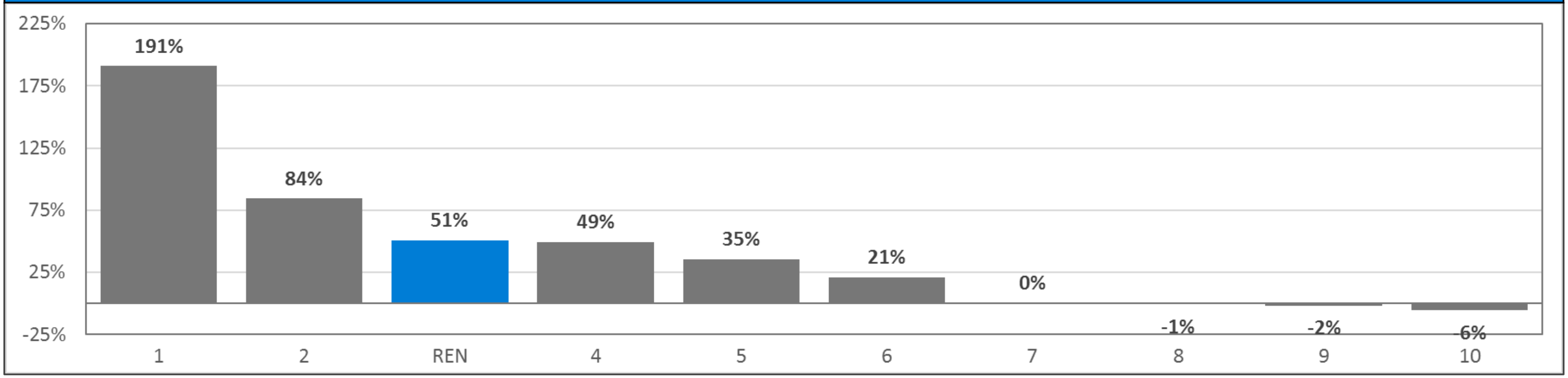
Top tier production growth

2018E to 2019E Permian pureplay production growth[1]



Strong cash flow per share

CAGR – 2017A to 2019E growth in cash flow per share[2]



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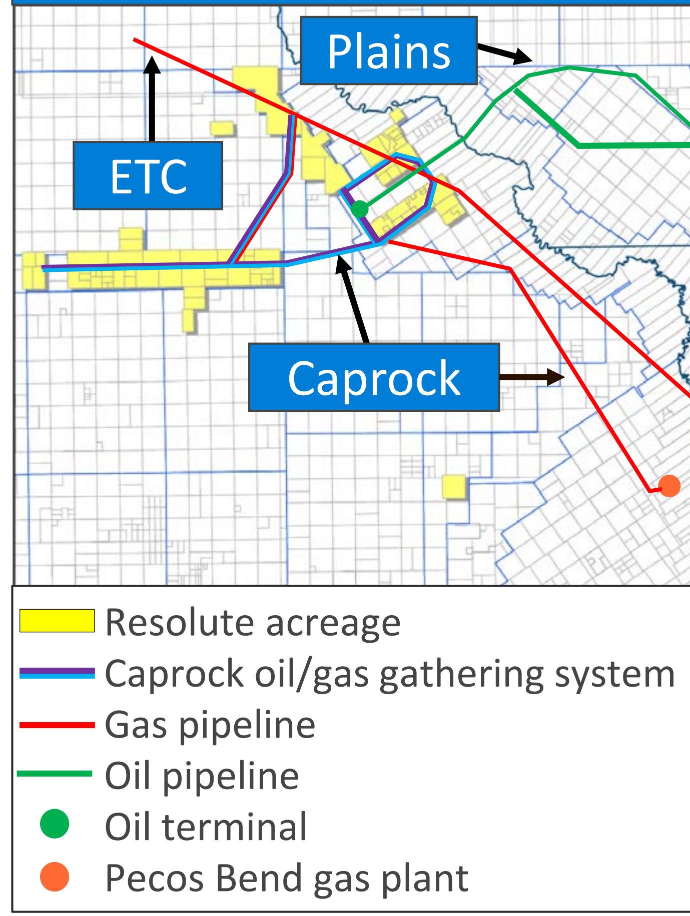
1. *Market data per FactSet as of July 27, 2018. Companies included are CDEV, CPE, EGN, FANG, HK, JAG, LPI, PE, REN, ROSE (alphabetical order). Source: Petrie Partners LLC*
2. *Companies included are AXAS, DNR, ECR, EPE, ESTE, HK, PVAC, REN, SBOW and SNDE (alphabetical order). Source: Johnson Rice & Company LLC as of June 15, 2018.*

Takeaway and realized prices

- No material production curtailed
- Plains has provided assurances of reliable oil takeaway
- ETC and Caprock provide multiple options for transporting residue gas and NGL
- 2Q18 realized pricing:
  - Oil – $59.96 per Bbl
  - Gas - $1.50 per MMBtu
  - NGL - $15.92 per Bbl
- The Company continues active review of multiple options in the financial and physical markets to further mitigate basis differential risk

Gathering infrastructure



Current derivative position

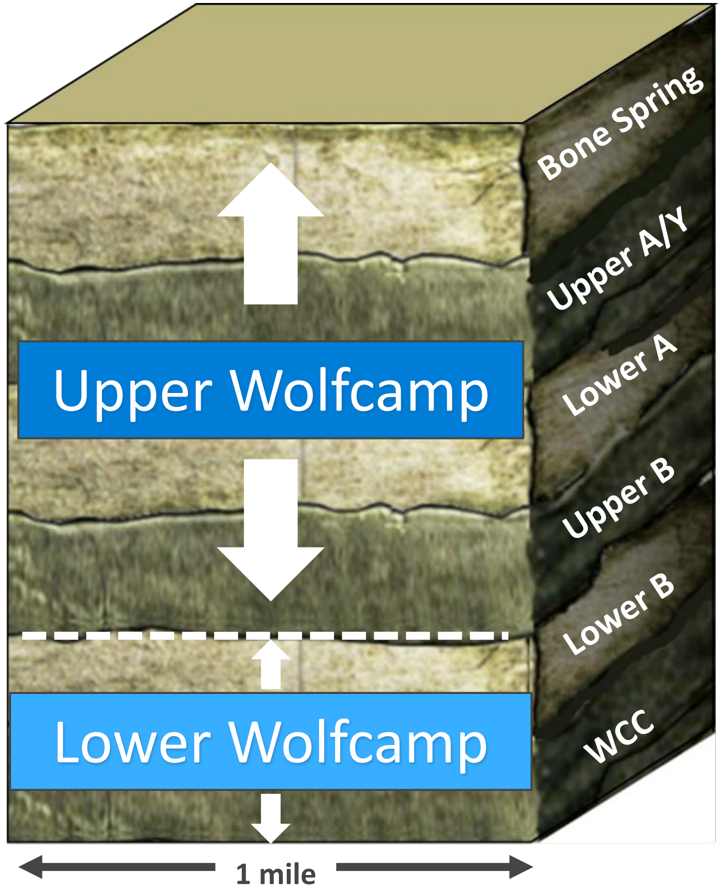
- September through December 2018:
  - NYMEX hedges in place for approximately 63% of estimated oil production[1]
  - Basis swaps covering approximately 46% of estimated oil production[1]

Period	Product	Type of contract	Oil volume (Bbl per day)	Gas volume (MMBtu per day)	Weighted average floor price	Weighted average ceiling price
Aug 18[2]	Oil	Swaps	3,000	-	$ 50.56	$ -
	Oil	Collars[4]	5,500	-	$ 52.45	$ 57.93
	Oil	Basis swaps[5]	6,000	-	$ 5.61	$ -
	Gas	Swaps	-	20,000	$ 2.77	$ -
	Gas	Basis swaps[6]	-	18,000	$ 0.69	$ -
Sep - Dec 18[2]	Oil	Swaps[4]	8,000	-	$ 59.29	$ -
	Oil	Collars	5,500	-	$ 52.45	$ 57.93
	Oil	Basis swaps[5]	9,869	-	$ 8.08	$ -
	Gas	Swaps	-	10,000	$ 2.77	$ -
	Gas	Basis swaps[6]	-	18,000	$ 0.69	$ -
2019[3]	Oil	Swaps	5,000	-	$ 64.54	$ -
	Oil	Basis swaps[5]	5,000	-	$ 10.37	$ -

1. *Based on midpoint of guidance*
2. *The Company has sold call options of 2,200 Bbl per day at $60.00 per Bbl and bought call options of 1,100 Bbl per day at $55.00 per Bbl.*
3. *The Company has sold call options of 3,670 Bbl per day at $64.36 per Bbl.*
4. *Each of the Company's three-way collars has a sub-floor price of $40.00 per Bbl.*
5. *The Company has entered into oil basis swaps in order to hedge the Midland Cushing differential.*
6. *The Company has entered into gas basis swaps in order to hedge the Permian Basin El Paso differential.*

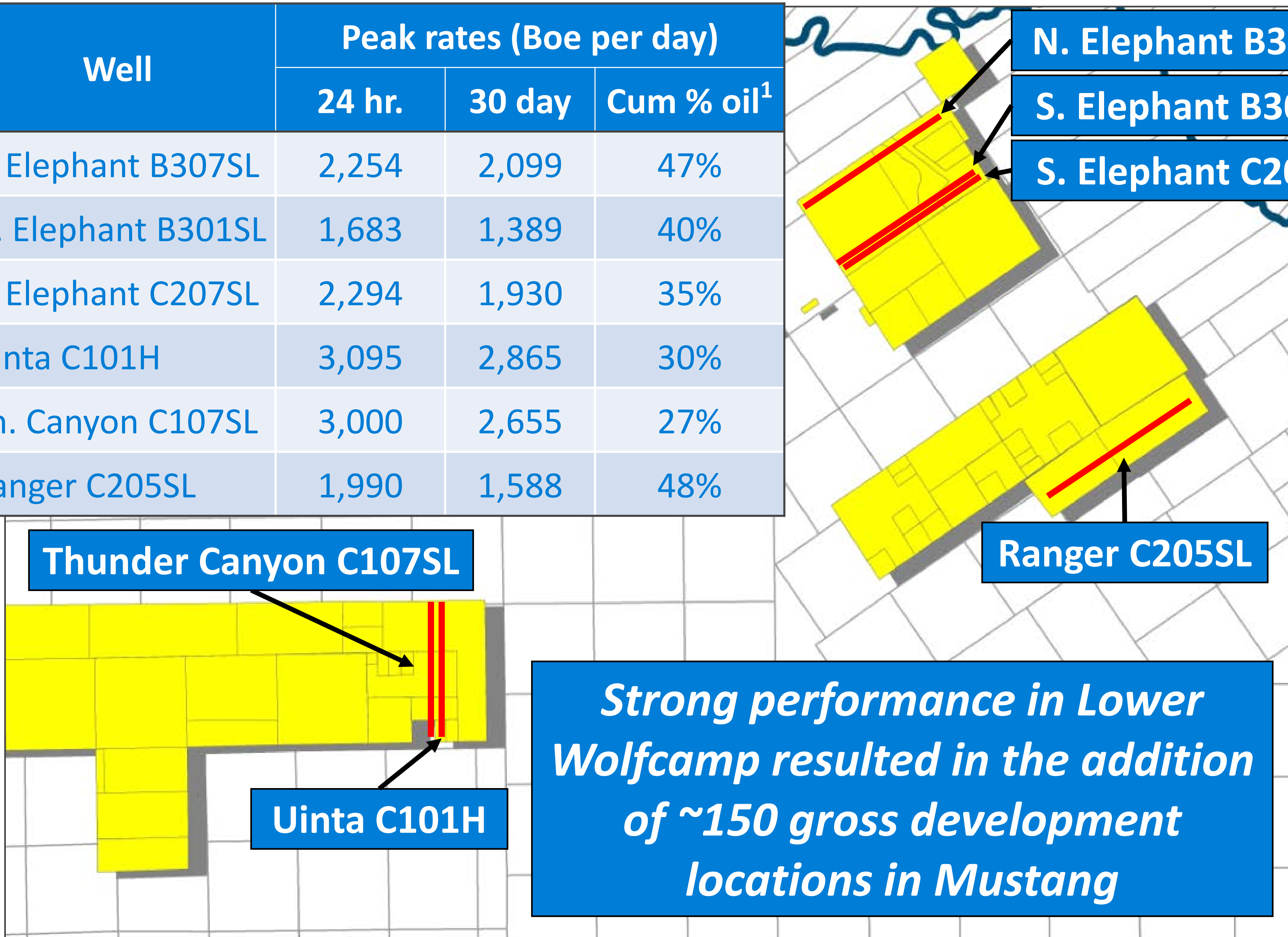
Significantly expanding development inventory

- Lower Wolfcamp wells in Mustang have shown strong initial rates
  - Two wells had peak 24-hour rates in excess of 3,000 Boe per day, 800 Bbl oil, 1,100 Bbl NGL
  - Added ~150 development locations in Mustang
- Testing Lower Wolfcamp in Appaloosa
  - Four wells on production
  - Strong oil rates in Ranger WCC well
  - Higher water rates than Mustang
- Evaluating Bone Spring across acreage
  - Expect 3rd Bone Spring to be prospective in Appaloosa
  - Anticipate higher oil cuts



Positive results in Lower Wolfcamp | All wells on line

	Well	Peak rates (Boe per day)		
		24 hr.	30 day	Cum % oil[1]
LWCB	S. Elephant B307SL	2,254	2,099	47%
LWCB	N. Elephant B301SL	1,683	1,389	40%
WCC	S. Elephant C207SL	2,294	1,930	35%
WCC	Uinta C101H	3,095	2,865	30%
WCC	Th. Canyon C107SL	3,000	2,655	27%
WCC	Ranger C205SL	1,990	1,588	48%

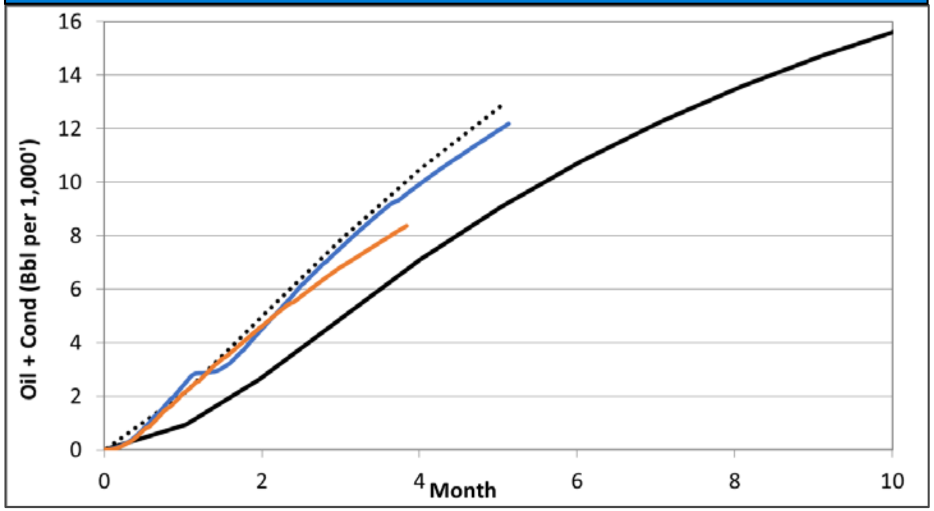


Strong performance in Lower Wolfcamp resulted in the addition of ~150 gross development locations in Mustang

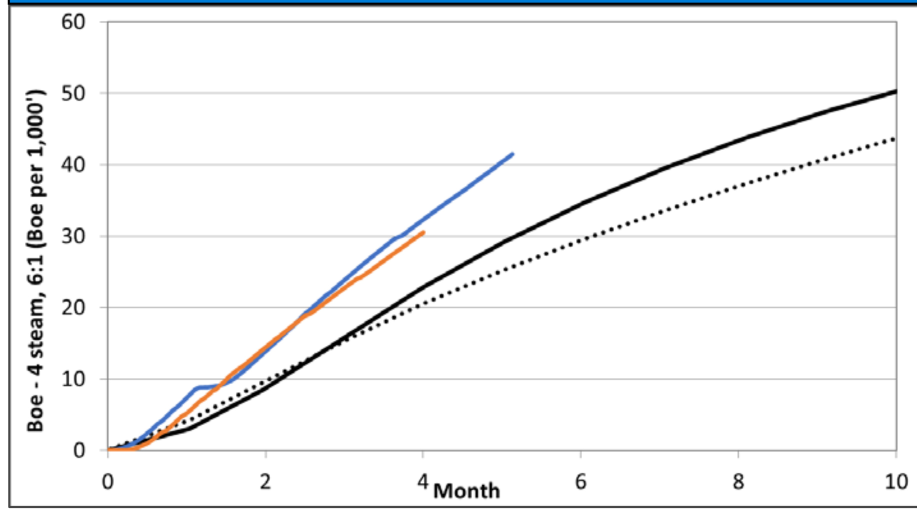
1. *Cumulative % oil as of July 15, 2018*

Mustang Wolfcamp C | Uinta and Thunder Canyon WCC

Oil



Boe



Uinta C101H — Thunder Canyon C107SL — WCC type curve — WCA type curve

Thunder Canyon / Uinta forecasted economics[1]	
Gross EUR	2,076 MBoe
% oil	32%
PV_{10}	\$8.7 million
IRR	59%
Discounted payout	1 year, 10 months

1. *Assumes July 31, 2018 strip pricing.*

Note: Type curves based on normalized 7,500 foot lateral lengths

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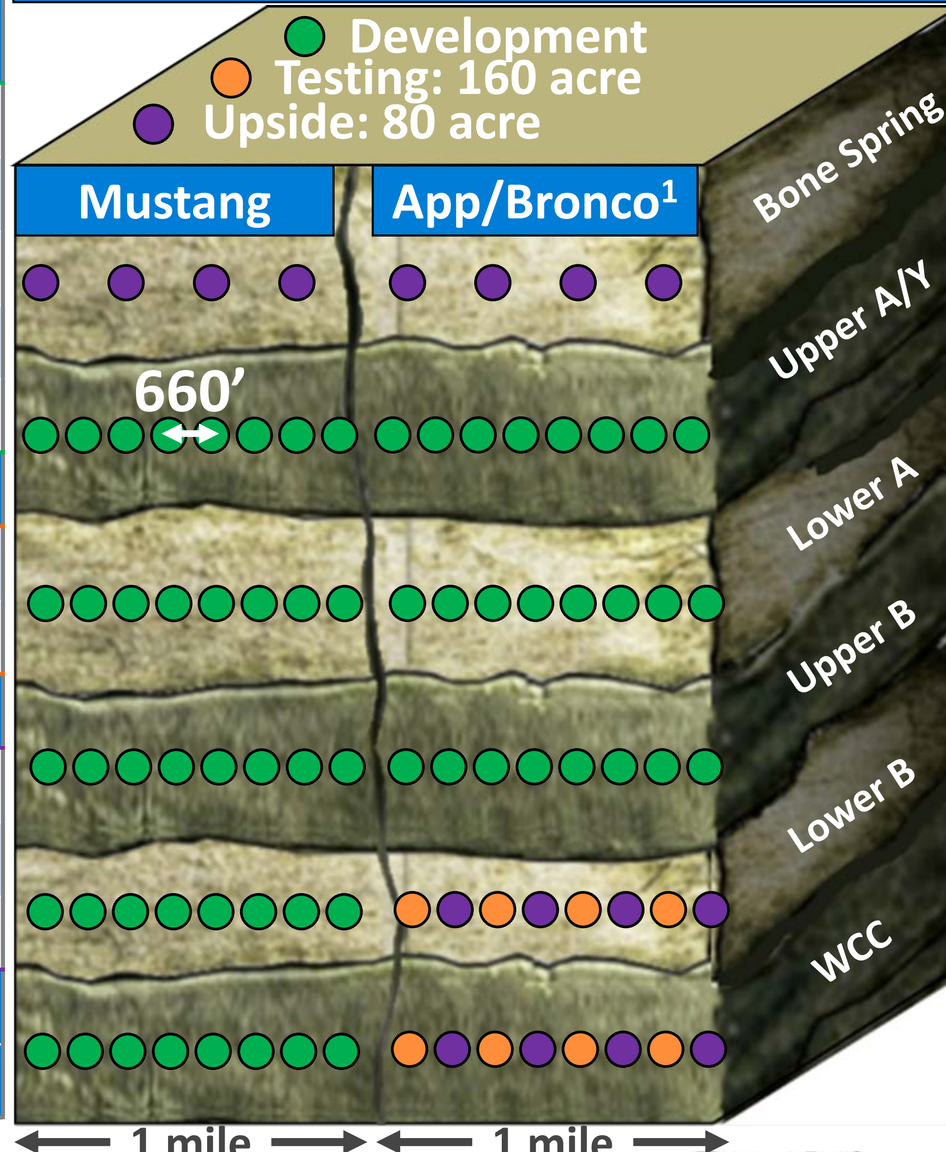
Expanding development inventory with extensive upside

	Wolfcamp zone	Wells per zone	Gross well inventory
Development	Upper A/Y	8	133
	Lower A	8	129
	Upper B	8	139
	Mustang LWCB	8	78
	Mustang WCC	8	80
	Development total		559
Testing	App/Bron LWCB[1]	4	41
	App/Bron WCC[1]	4	39
	Testing total		80
Upside	App Bone Spring	4	50
	App/Bron DS LWCB[1]	4	37
	App/Bron DS WCC[1]	4	36
	Upside total		123
	Total inventory		762

Inventory spacing schematic



1. "App" – Appaloosa; "Bron" – Bronco; "DS" – Downspaced

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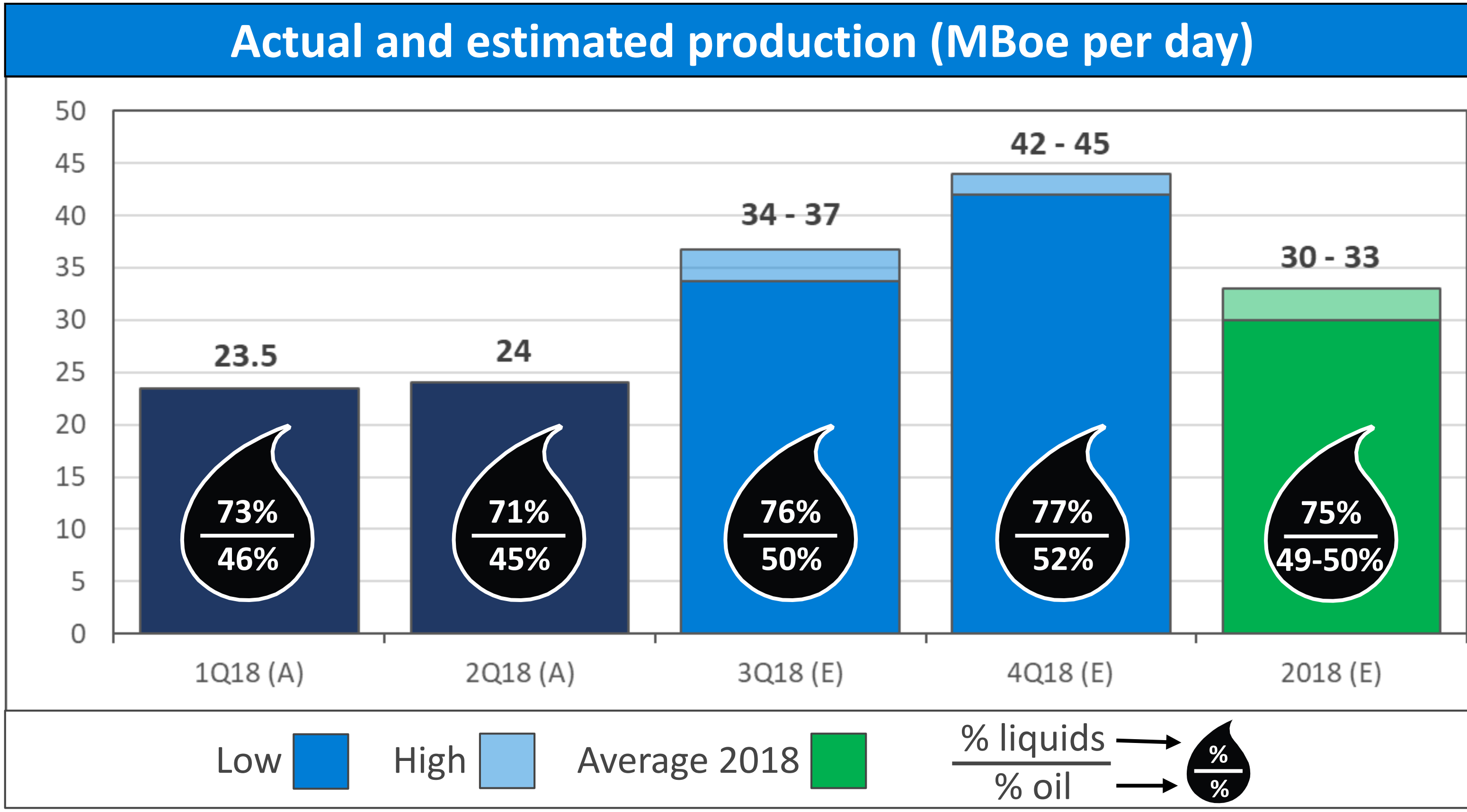
2018 production targets



- Oil component of 2Q18 production below long term run-rate
- Expect oil mix to increase through remainder of 2018; overall 2018 product mix guidance of 49% to 50% oil
  - Expect 5.6 MMBbl of oil production at midpoint of guidance; up 50% from 2017 Permian oil production

Positioned for significant value creation

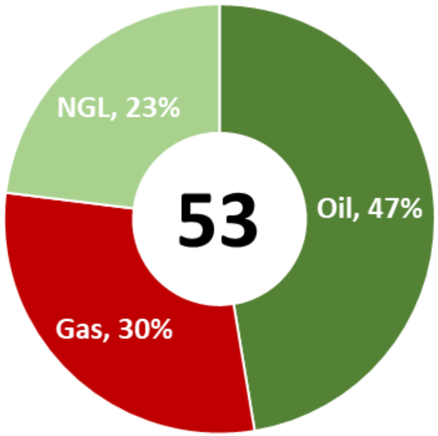
- Top-tier acreage position, employing efficient full field development to drive significant production growth
- Successful Lower Wolfcamp tests in Mustang has added ~150 development locations to inventory
- Costs: Significantly improved cost structure
- 3Q18 Adjusted EBITDA expected to increase significantly based on results from pad development program
- CF/share: Substantial growth in per share financial metrics expected to translate into stronger trading multiples

Resolute unlocking the full potential of its assets

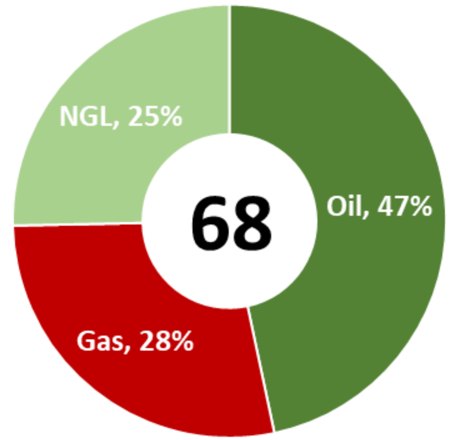
Appendix

Company reserves | SEC methodology

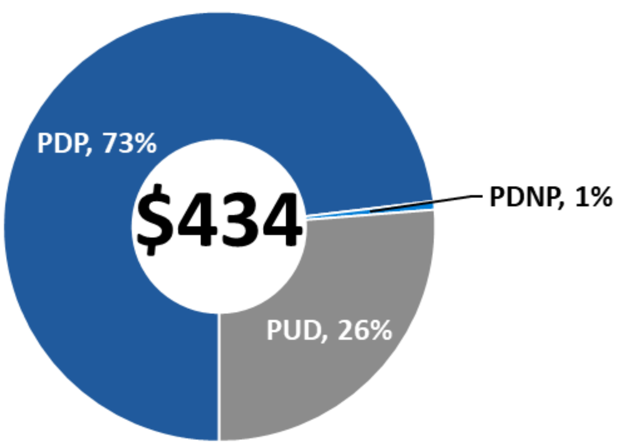
MMBoe – YE17[1]



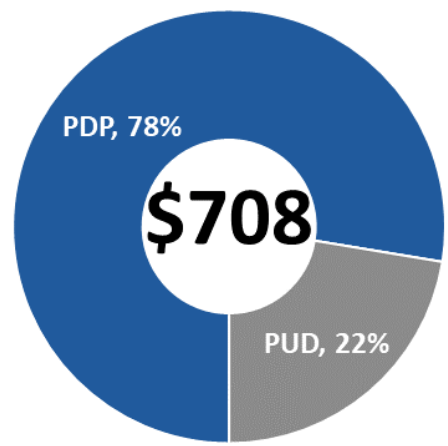
MMBoe – MY18[2]



PV10 ($ million) – YE17[1]



PV10 ($ million) – MY18[2]



1. Oil price of $51.34 per Bbl; gas price of $2.98 per MMBtu 2. Oil price of $57.67 per Bbl; gas price of $2.92 per MMBtu

Note: Prices reflect the arithmetic average of first-day-of-month oil and natural gas prices for the 12-month periods January 1 to December 31, 2017 and July 1, 2017 to June 30, 2018, respectively, as per SEC guidelines for reserves estimation.

Extensive midstream infrastructure

Oil	▪ Mustang and Appaloosa oil production gathered via Caprock system and shipped via Plains pipelines ▪ Plains Marketing buys oil at the battery under five-year contract at index minus $1.75 per barrel ▪ Plains-dedicated volumes are first to move on their system, significantly reducing curtailment risk ▪ Bronco oil volumes currently trucked; expect to connect Bronco acreage to Caprock system and Plains contract
Gas/ NGL	▪ Mustang and Appaloosa dedicated to ETC through December 2018; dedicated to Caprock thereafter ▪ Interconnects to both ETC and Caprock systems allow gas to move on Caprock system in case of curtailments on ETC system ▪ ETC and Caprock have multiple connections to residue gas pipelines ensuring that gas can move out of field
Water	▪ All batteries connected by pipeline to in-field disposal facilities ▪ Caprock developing incremental disposal capacity ▪ Disposal charge of ~$0.51 per barrel for all water produced

2018 guidance | Updated oil percentage

2018 guidance	Range	
	Low	High
Projected 2018 production		
Annual MBoe	10,950	12,045
Annual average Boe per day	30,000	33,000
4Q average Boe per day	42,000	44,000
On a volume-weighted basis:		
Oil (updated)	*49% - 50%*	
Oil and NGL	75%	
Projected 2018 costs ($ million):		
Lease operating expense	$60	$68
General and administrative	$30	$34
Projected 2018 net capital expenditures ($ million)	$365	$395

2018 capital guidance detail

2018 capital guidance ($ million)	Range	
	Low	High
Projected 2018 net capital expenditures		
Drilling, completion and well facilities	$350	$375
Field facilities and other	23	27
Other corporate capital	19	22
Total capital before earnout payments	392	424
Less: anticipated earnout payments	(27)	(29)
Total capital expenditures net of earnouts	$365	$395

Drilling and completions activity

Drilling activity						
Well name / Pad	Area	Wolfcamp zone	Lateral length (heel - toe)[1]	Status	TD date	Rig days over hole[1]
Ranger - 6 parent wells	A	UA/LA/UB	9,781	Producing	3/13/2018	25
Ranger - 2 child wells	A	UA/LA	9,701	Producing	11/23/2017	26
Ranger C205SL	A	C	9,579	Producing	12/11/2017	30
Sandlot Pad 1	M	UA/LA/UB	6,417	Flowing back	4/27/2018	21
Sandlot Pad 2	M	UA/LA/UB	6,351	Flowing back	6/2/2018	27
Sandlot Pad 3	M	UA/LA/UB	6,351	Flowing back	5/6/2018	20
Sandlot Pad 4	M	UA/LA/UB	6,300	Drilling	-	-
South Mitre Pad 1	A	UA/LA/UB	10,000	Drilling	-	-
South Mitre Pad 2	A	UA/LA/UB	10,000	Drilling	-	-
South Mitre Pad 3	A	UA/LA/UB	10,000	Drilling	-	-
Sandlot Pad 5	M	UA/LA/UB	6,300	Drilling	-	-
Sandlot Pad 6	M	UA/LA/UB	6,300	Drilling	-	-

Note: For wells that are currently drilling the lateral length is what is planned

Completions activity						
Well name / Pad	Area	Wolfcamp zone	Lateral length (perf - perf)[1]	First production	Frac stages[1]	Proppant per foot (lbs)[1]
Ranger - 6 parent wells	A	UA/LA/UB	9,659	5/28/18 - 6/8/18	34	1,788
Ranger - 2 child wells	A	UA/LA	9,601	5/25/18 - 5/30/18	27	1,778
Ranger C205SL	A	C	9,721	5/24/2018	28	1,750
Sandlot Pad 1	M	UA/LA/UB	6,314	-	23	1,757
Sandlot Pad 2	M	UA/LA/UB	5,949	-	22	1,833
Sandlot Pad 3	M	UA/LA/UB	6,250	-	23	1,926

Resolute

1. *Averages are used for all lateral length, rig days over hole, frac stages and proppant per foot pad data*

Production activity

Production activity						
Well name / Pad	Area	Wolfcamp zone	Lateral length (perf - perf)[1]	Peak rates (Boe per day)		
				24 hour	30 day	60 day
North Elephant B301H	A	LB	7,283	1,683	1,389	1,241
Ranger - 6 parent wells	A	UA/LA/UB	9,659	2,476	2,280	-
Ranger - 2 child wells	A	UA/LA	9,601	2,034	1,758	1,588
Ranger C205SL	A	C	9,721	1,990	1,588	1,494
Sandlot Pad 1	M	UA/LA/UB	6,314	Flowing back		
Sandlot Pad 2	M	UA/LA/UB	5,949	Flowing back		
Sandlot Pad 3	M	UA/LA/UB	6,250	Flowing back		

1. *Averages are used for all lateral length, rig days over hole, frac stages and proppant per foot pad data*

Quarterly prices and volume

Prices and volume	2017					2018		
	Q1	Q2	Q3	Q4	FY	Q1	Q2	YTD
Average prices:								
Oil ($ per Bbl)	$ 47.52	$ 43.36	$ 43.53	$ 51.51	$ 46.30	$ 61.06	$ 59.96	$ 60.51
NGL ($ per Bbl)	10.77	9.19	9.50	22.34	14.20	15.50	15.92	15.71
Gas ($ per Mcf)	2.26	2.24	2.01	2.04	2.11	1.85	1.50	1.66
Production volumes:								
Oil (MBbl)	1,213	1,400	1,554	1,331	5,499	977	974	1,951
NGL (MBbl)	240	336	480	585	1,641	562	585	1,147
Gas (MMcf)	1,922	2,881	3,562	3,735	12,101	3,456	3,769	7,226
MBoe	1,773	2,216	2,628	2,539	9,156	2,115	2,187	4,302

Margin and cost structure

Summary	2017					2018		
($ in millions, except as noted)	Q1	Q2	Q3	Q4	FY	Q1	Q2	YTD
Sales volume								
Total MBoe	1,773	2,216	2,628	2,539	9,156	2,115	2,187	4,302
Revenue	$ 64.6	$ 70.2	$ 79.4	$ 89.3	$ 303.5	$ 74.7	$ 73.4	$ 148.1
Realized derivative gains (losses)	(0.3)	1.7	2.4	-	3.8	(7.3)	(9.3)	(16.6)
Adjusted revenue	$ 64.3	$ 71.9	$ 81.8	$ 89.3	$ 307.3	$ 67.4	$ 64.1	$ 131.5
Expenses								
Operating expenses[1]	18.2	19.7	25.1	16.0	79.0	11.3	15.4	26.7
Taxes	6.0	5.6	6.6	5.2	23.4	5.5	5.6	11.1
G&A[2]	7.6	6.5	6.5	9.3	29.9	8.9	8.3	17.2
Cash-settled incentive awards[3]	-	1.4	0.6	0.1	2.1	0.6	1.2	1.8
Other expense	-	-	-	0.1	0.1	-	(0.1)	-
Total expenses	31.8	33.2	38.8	30.7	134.5	26.3	30.4	56.8
Adjusted EBITDA	**$ 32.5**	**$ 38.7**	**$ 43.0**	**$ 58.6**	**$ 172.8**	**$ 41.1**	**$ 33.7**	**$ 74.7**
Capital expenditures								
Non-CO_2 capital	$ 54.9	$ 96.2	$ 101.2	$ 63.8	$ 316.1	$ 69.5	$ 150.3	$ 219.8
CO_2 purchases	1.0	1.1	0.9	0.3	3.3	-	-	-
Total	55.9	97.3	102.1	64.1	319.4	69.5	150.3	219.8
Acquisitions	-	161.3	-	-	161.3	-	-	-
Divestitures	(19.2)	(10.6)	(6.3)	(172.4)	(208.5)	(2.1)	(5.2)	(7.3)
Total capital expenditures	$ 36.7	$ 248.0	$ 95.8	$ (108.3)	$ 272.2	$ 67.4	$ 145.1	$ 212.5

Note: See appendix for EBITDA reconciliation

1. *Includes workover and excludes non-cash charges*
2. *Net of Copas reimbursements. Excludes non-cash charges*
3. *Excludes non-cash accruals; represents time- and performance-based incentive cash paid out*

Margin and cost structure per Boe

Margins	2017					2018		
($ per Boe)	Q1	Q2	Q3	Q4	FY	Q1	Q2	YTD
Revenue	$ 36.43	$ 31.70	$ 30.20	$ 35.16	$ 33.14	$ 35.33	$ 33.55	$ 34.42
Realized derivative gains (losses)	(0.14)	0.75	0.90	(0.01)	0.41	(3.44)	(4.27)	(3.86)
Adjusted revenue	$ 36.29	$ 32.45	$ 31.10	$ 35.15	$ 33.55	$ 31.89	$ 29.28	$ 30.56
Expenses								
Operating expenses[1]	10.35	8.97	9.55	6.29	8.66	5.34	7.02	6.20
Taxes	3.37	2.51	2.51	2.06	2.55	2.62	2.52	2.57
G&A[2]	4.28	2.95	2.45	3.68	3.27	4.22	3.79	4.00
Restricted cash awards[3]	-	0.62	0.25	0.05	0.24	2.89	3.77	3.35
Other expense	0.03	(0.06)	0.00	(0.01)	(0.01)	(2.61)	(3.22)	(2.93)
Total expenses	18.04	15.00	14.76	12.07	14.71	12.47	13.89	13.19
Adjusted EBITDA	**$ 18.25**	**$ 17.45**	**$ 16.33**	**$ 23.08**	**$ 18.85**	**$ 19.42**	**$ 15.39**	**$ 17.37**

Note: See appendix for EBITDA reconciliation

1. *Includes workover and excludes non-cash charges*
2. *Net of Copas reimbursements. Excludes non-cash charges*
3. *Excludes non-cash accruals; represents time- and performance-based incentive cash paid out*

Non-GAAP reconciliations

Adjusted EBITDA	2017					2018		
($ in millions)	Q1	Q2	Q3	Q4	FY	Q1	Q2	YTD
Net income (loss)	$ 1.5	$ 13.2	$ (14.6)	$ (1.3)	$ (1.2)	$ (12.8)	$ (3.7)	$ (16.6)
Adjustments:								
Interest expense, net	$ 17.7	$ 8.8	$ 8.5	$ 8.4	$ 43.4	$ 7.6	$ 8.5	$ 16.1
Income tax benefit	-	-	-	(0.3)	(0.3)	-	-	-
Depletion, depreciation and amortization	16.0	22.3	25.5	28.3	92.1	23.5	23.5	47.0
Stockholder activism	-	-	-	-	-	3.3	3.1	6.4
Aneth transaction costs	-	-	-	6.5	6.5	-	-	-
Stock-based compensation	3.0	3.0	3.1	3.2	12.3	9.2	4.5	13.7
Cash-settled incentive awards	5.4	(1.4)	5.0	7.2	16.2	11.4	(0.1)	11.3
Cash-settled incentive awards paid	-	(1.4)	(0.6)	(0.1)	(2.1)	(0.6)	(1.2)	(1.8)
Mark-to-market (gain) loss	(11.1)	(5.8)	16.1	10.2	9.4	2.1	2.8	4.9
Contingent consideration gain	-	-	-	(3.5)	(3.5)	(2.6)	(3.7)	(6.3)
Total adjustments	$ 31.0	$ 25.5	$ 57.6	$ 59.9	$ 174.0	$ 53.9	$ 37.4	$ 91.3
Adjusted EBITDA	**$ 32.5**	**$ 38.7**	**$ 43.0**	**$ 58.6**	**$ 172.8**	**$ 41.1**	**$ 33.7**	**$ 74.7**