CONCHO

3Q | 2018

Quarterly Update

October 30, 2018

Forward-Looking Statements and Other Disclaimers

Forward-Looking Statements and Cautionary Statements

The foregoing 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 fact, 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. Forward-looking statements contained in this presentation specifically include statements relating to benefits of the acquisition of RSP Permian, Inc. (“RSP”). The words “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “enable,” “foresee,” “plan,” “will,” “guidance,” “outlook,” “goal” or other similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements, which generally are not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. These statements are based on certain assumptions and analyses made by the Company based on management’s experience, expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Forward-looking statements are not guarantees of performance. Although the Company believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, 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 the risk factors and other information discussed or referenced in the Company’s most recent Annual Report on Form 10-K and other filings with the SEC. 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 includes financial measures that are not in accordance with generally accepted accounting principles (“GAAP”), including adjusted net income, adjusted net income per diluted share, free cash flow and EBITDAX. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For definitions of such measures and reconciliations of adjusted net income, adjusted net income per diluted share and EBITDAX to the nearest comparable measures in accordance with GAAP, please see the appendix.

The SEC requires oil and natural gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions (using the trailing 12-month average first-day-of-the-month prices), operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The SEC also permits the disclosure of separate estimates of probable or possible reserves that meet SEC definitions for such reserves; however, the Company currently does not disclose probable or possible reserves in its SEC filings.

In this presentation, proved reserves attributable to the Company at December 31, 2017 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of $47.79 per Bbl of oil and $2.98 per MMBtu of natural gas. The Company’s estimate of its total proved reserves at December 31, 2017 is based on reports prepared by Cawley, Gillespie & Associates, Inc. and Netherland, Sewell & Associates, Inc., independent petroleum engineers. The Company may use the terms “unproved reserves,” “resources” and similar phrases to describe estimates of potentially recoverable hydrocarbons that the SEC rules prohibit from being included in filings with the SEC. These are based on analogy to the Company’s existing models applied to additional acres, additional zones and tighter spacing and are the Company’s internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These quantities may not constitute “reserves” within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules. Such estimates and identified drilling locations have not been fully risked by Company management and are inherently more speculative than proved reserves estimates. Actual locations drilled and quantities that may be ultimately recovered from the Company’s interests could differ substantially from these estimates. There is no commitment by the Company to drill all of the drilling locations that have been attributed to these quantities. 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, actual drilling results, including geological and mechanical factors affecting recovery rates, and other factors. Such estimates may change significantly as development of the Company’s oil and natural gas assets provide additional data. The Company’s 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 or other factors that are beyond the Company’s control.

Cautionary Statements Regarding Resource

Concho may use the term “resource potential” and similar phrases to describe estimates of potentially recoverable hydrocarbons that SEC rules prohibit from being included in filings with the SEC. These are based on analogy to Concho’s existing models applied to additional acres, additional zones and tighter spacing and are Concho’s internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These quantities may not constitute “reserves” within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules. Such estimates and identified drilling locations have not been fully risked by Concho management and are inherently more speculative than proved reserves estimates. Actual locations drilled and quantities that may be ultimately recovered from Concho’s interests could differ substantially from these estimates. There is no commitment by Concho to drill all of the drilling locations that have been attributed to these quantities. Factors affecting ultimate recovery include the scope of Concho’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, actual drilling results, including geological and mechanical factors affecting recovery rates, and other factors. Such estimates may change significantly as development of Concho’s oil and natural gas assets provide additional data. Concho’s 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 or other factors that are beyond Concho’s control. Concho’s use of the term “premium resource” refers to assets with the capacity to produce at an internal rate of return that is greater than thirty-five percent based on fifty-five dollar oil and three dollar gas.

Key Messages

Summary

3Q 2018

- Strong results
- Successful integration of RSP
- Development projects driving efficiencies

Outlook

- Free cash flow momentum
- Strong crude oil growth
- Increasing focus on large-scale development

Focus on Returns

- Competitive production and cash flow growth per debt-adjusted share
- Improving ROCE
- Initiating quarterly dividend in 2019

Well Positioned to Deliver Sustainable, Profitable Performance

- Execution strength and scale
- Disciplined capital allocation
- Financial strength
- Strong free cash flow generation and improving corporate returns

Note: Free cash flow is a non-GAAP measure. See appendix for reconciliation to GAAP measure. Additionally, ROCE is a non-GAAP measure that is defined as net income plus after-tax interest expense divided by average stockholders equity plus average net debt.

3Q 2018 Performance

Executing Near-Term Goals, Focusing on Long-Term Returns

Highlights

Delivering Strong, Consistent Execution

- Total production of 287 MBoepd above the high end of guidance
- Oil production 185 MBopd
- Advancing large-scale projects

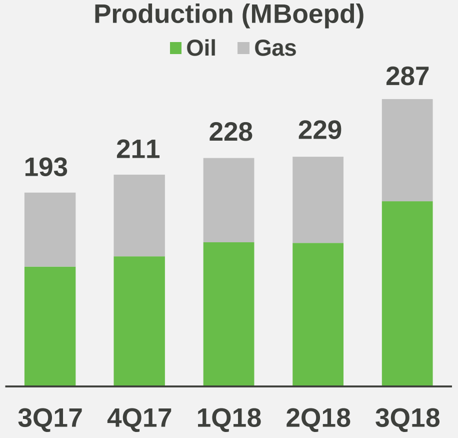
Prioritizing Capital Discipline and Financial Performance

- Strong cash margin reflects cost control
- Cash flow from operations exceeded capital investment, excluding acquisitions
- Net loss of $199mm, or $1.05 per diluted share; adjusted net income of $269mm, or $1.42 per diluted share
- EBITDAX of $829mm

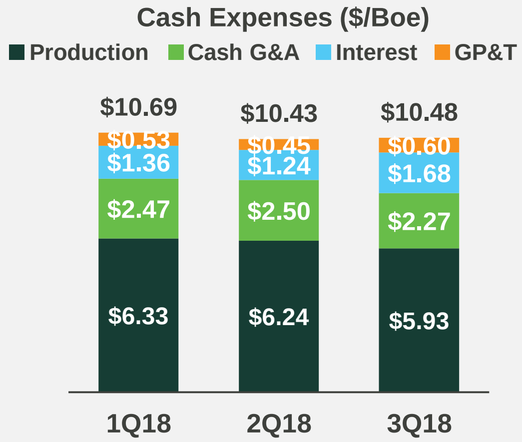
Maintaining Strong Balance Sheet

- At September 30, 2018, 1.2x debt-to-annualized EBITDAX
- Investment-grade credit ratings

High-Margin Growth



Focus on Cost Control

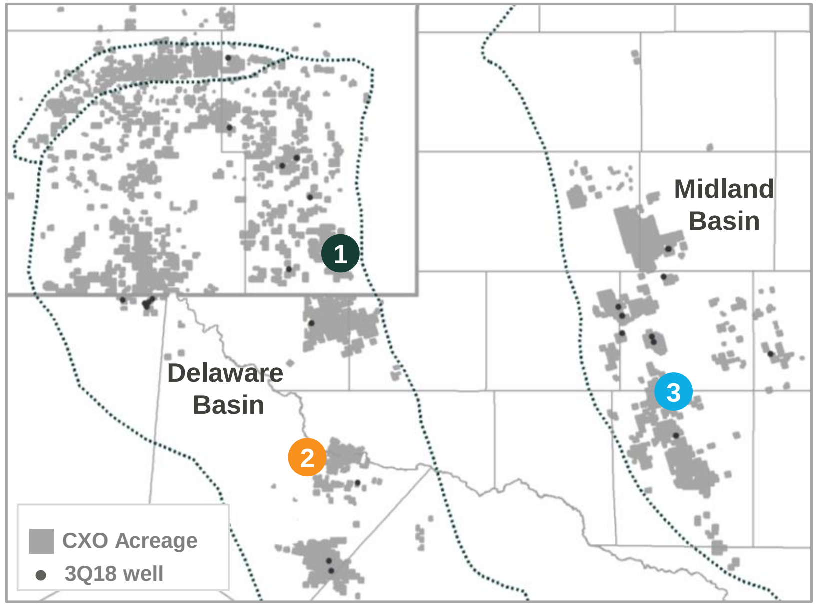


Note: Adjusted net income, adjusted net income per diluted share, EBITDAX and annualized EBITDAX are non-GAAP measures. See appendix for reconciliation to GAAP measures.

3Q 2018 Operational Highlights

Scaling Development to Maximize Recoveries and Economics

Activity Overview



Key Operating Stats

Moved to 2 Operating Areas from 4

› Delaware Basin & Midland Basin

Operated Rigs

› 3Q18 average: 31 rigs

Completion Crews

› 3Q18 average: 9 crews

Asset Performance

Delaware Basin

› Added 31 horizontal wells (avg. lateral length 6,685')
- Avg. 30-day peak rate: 1,422 Boepd (73% oil)
- Avg. 60-day peak rate: 1,269 Boepd (73% oil)

Midland Basin

› Added 34 horizontal wells (avg. lateral length 9,686')
- Avg. 30-day peak rate: 1,178 Boepd (86% oil)
- Avg. 60-day peak rate: 1,066 Boepd (85% oil)

Recent Large-Scale Projects

1 White Falcon

7 wells

› Targets: 3rd Bone Spring, Wolfcamp A

› Avg. lateral length: 8,772'

› Avg. 30-day peak rate: 1,804 Boepd per well (84% oil)

2 Iceman/Hollywood

8 wells

› Targets: 3rd Bone Spring, Wolfcamp A

› Avg. lateral length: 11,679'

› Avg. 30-day peak rate: 1,765 Boepd per well (70% oil)

3 Windham B

10 wells

› Targets: Lower Spraberry, Wolfcamp A, B and C

› Avg. lateral length: 10,332'

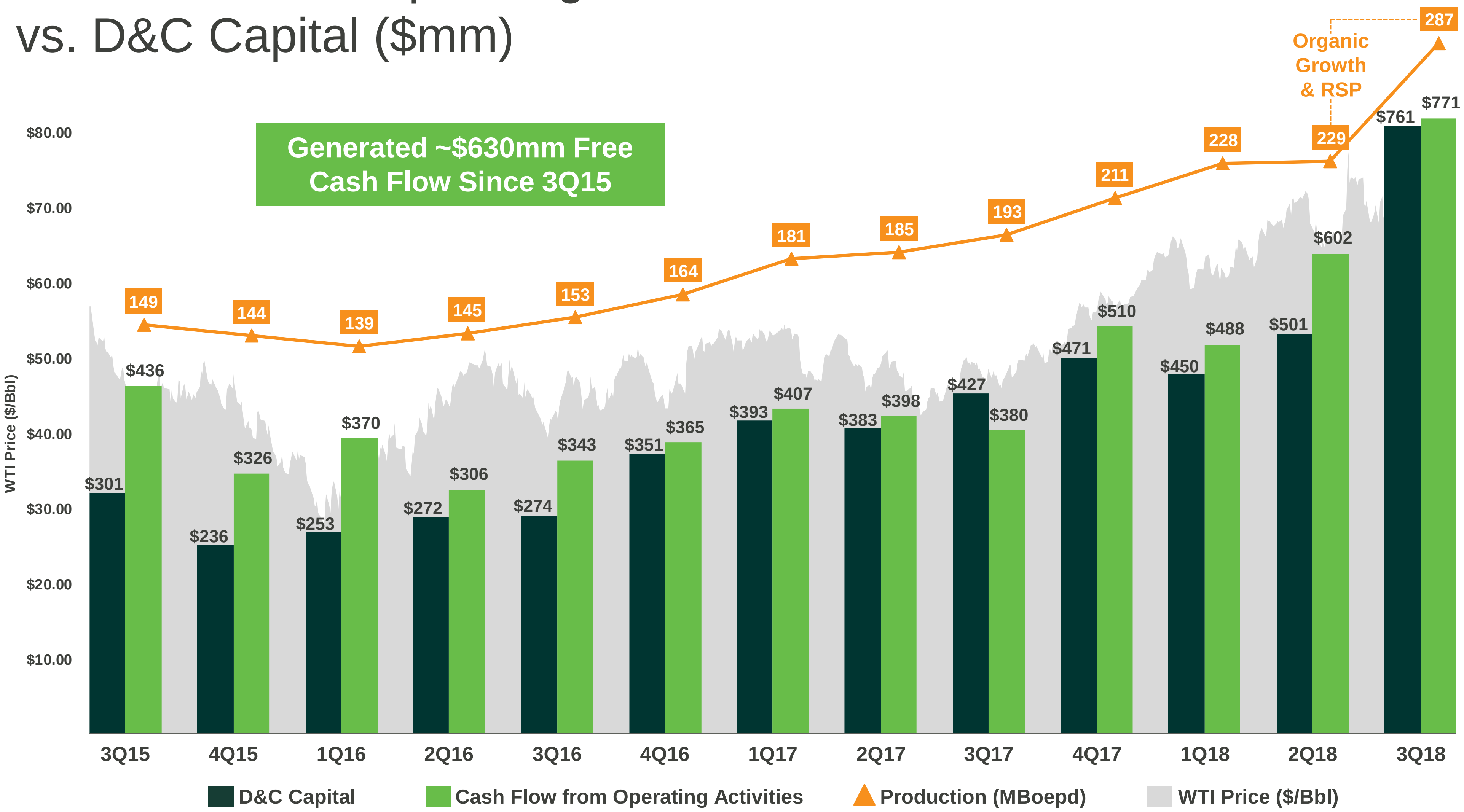
› Avg. 30-day peak rate: 1,238 Boepd per well (84% oil)

Note: Well results provided for wells with >60 days of production data in 3Q18. Concho moved from 4 operating areas to 2. Delaware Basin asset performance excludes New Mexico Shelf results. Historical data for Delaware Basin and Midland Basin is provided in the appendix.

Track Record of Delivering Production Growth & Free Cash Flow

Foundation for New Capital Allocation Framework

Cash Flow from Operating Activities vs. D&C Capital ($mm)



Takeaways

- Free cash flow generation for 12 out of past 13 quarters
- Sustained performance driven by efficient, disciplined capital allocation
- **Sets foundation for new capital allocation framework**

Note: Free cash flow is a non-GAAP measure. See appendix for reconciliation to GAAP measure. Drilling & Completion (D&C) capital represents exploration and development costs incurred for oil and natural gas producing activities for each quarter shown. See appendix for a summary of costs incurred.

New Capital Allocation Framework

Driving Shareholder Returns

Historically guided by growth within cash flow

Enhance free cash flow generation and corporate returns

- Disciplined approach to growth
- Capital returns to shareholders
- Maintain a strong balance sheet

Cash Flow Priorities		Free Cash Flow Opportunities		
Capital Program	Dividend	Strengthen Balance Sheet	Additional Returns to Shareholders	Portfolio Enhancement

Our Mindset

- Reflects evolution of the E&P business model
- Substantial free cash flow momentum following RSP combination
- **Underscores outlook for sustainable, profitable growth and returns**

Note: Free cash flow is a non-GAAP measure. See appendix for reconciliation to GAAP measure.

Well Positioned to Deliver on New Capital Allocation Framework

Building on Our Advantages to Deliver Growth *and* Value

Execution Strength & Scale

Leading Large-Scale Development in the Permian

Resource Capture → Resource Delineation → Development Optimization

Development Optimization:

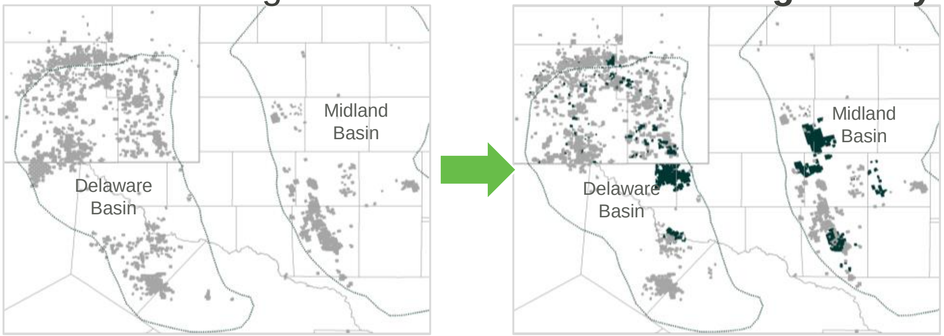
- Maximizes resource recovery and economics
- Helps mitigate parent/child well degradation
- Captures supply chain and logistics advantages
- Accelerates learning and adaptation

High-Quality Portfolio

Balanced Portfolio within the Permian

Concho Acreage: 2016

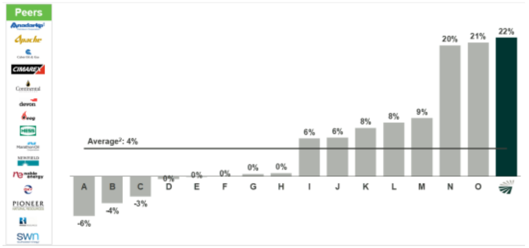
Concho Acreage Today



Superior Capital Efficiency

Asset Quality + Low Breakeven

10-Year Production Growth / DAS[1]

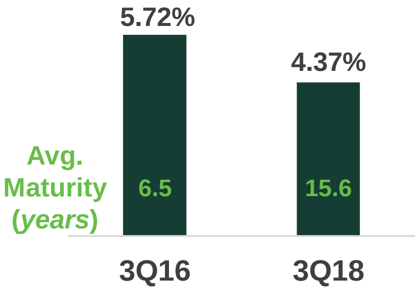


- Delivering free cash flow *and* production growth
- Peer-leading production growth per debt-adjusted share (DAS)
- Strong cash margins

Financial Strength

Low Leverage Provides Substantial Flexibility

Avg. Coupon



- Investment grade ratings
- Reducing cost of capital
- Lower interest expense supporting margin expansion

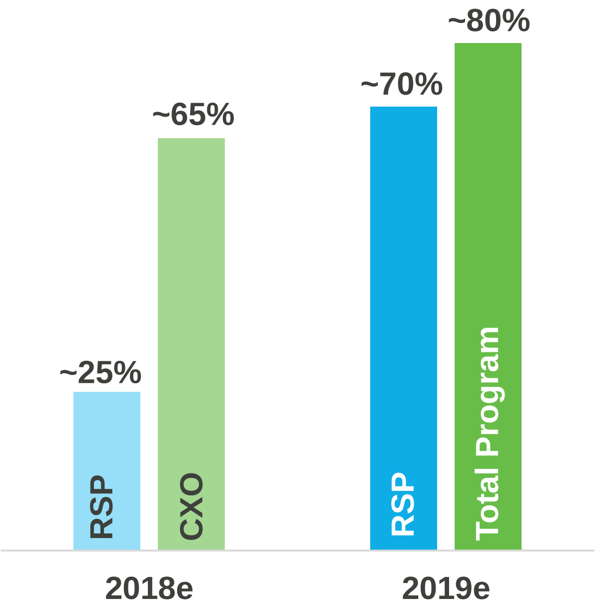
Note: Free cash flow is a non-GAAP measure. See appendix for reconciliation to GAAP measure. Concho acreage is as of December 31, 2017, pro forma for transactions announced to date.
[1]Source: Bloomberg. Reflects 10-year production growth per debt-adjusted share CAGR ended June 30, 2018. Debt-adjusted share is defined as ending debt divided by ending share price plus ending shares outstanding.

2019 Development Sets Up Strong 2020+

2019 Development Outlook

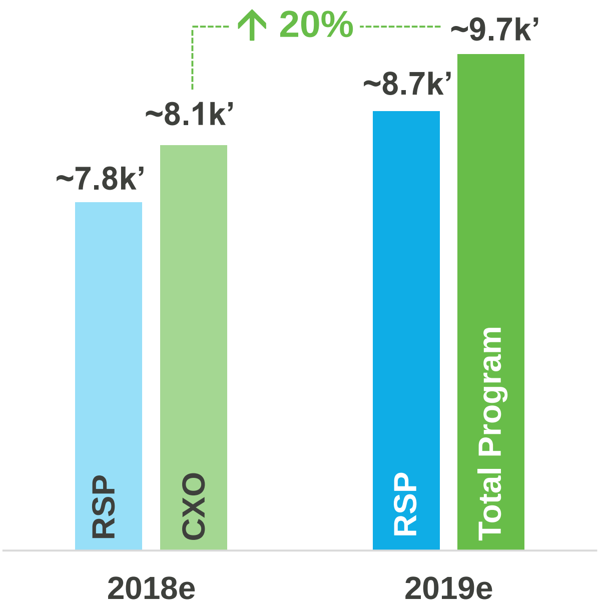
More Capital to Large-Scale Projects

Capital Allocated to Large-Scale Projects



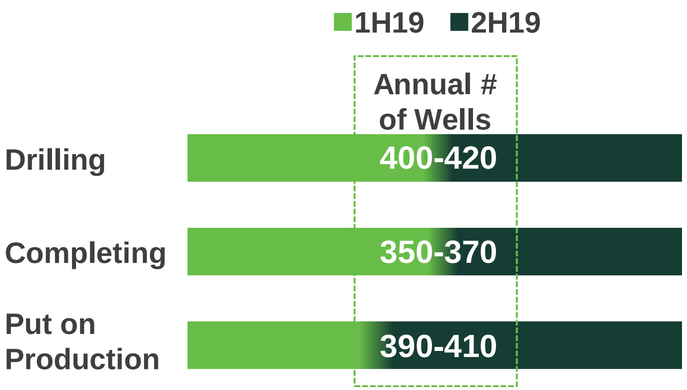
Significant Increase in Lateral Length

Average Lateral Length



Production Starts 2H19-Weighted

Gross Operated Activity



Note: A large-scale project includes 4 wells or more. 2018e RSP activity reflects RSP's standalone plan. Gross operated activity represents the wells the Company expects to start drilling, completing and/or put on production.

2019 Development Sets Up Strong 2020+

2019-2020 Financial Outlook

	2019e	2019e-2020e
Capital Program	$3.4-$3.6bn	Run ~34 rigs in ‘19; ~38 rigs in ‘20
Free Cash Flow (FCF)	FCF+	FCF+
Crude Oil Growth	35%-40%	30% 2-YR CAGR
Total Production Growth	25%-30%	25% 2-YR CAGR
ROCE	>Cost of Capital	2020+ >10%

Exit Rate Outlook

4Q 2018 → 4Q 2019

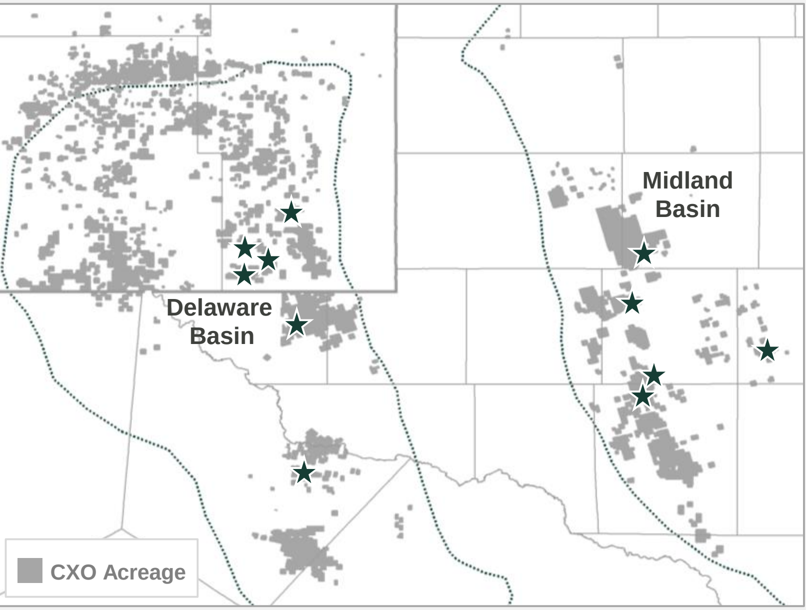
- +25% crude oil growth
- +18% total production growth

Notes: Capital program excludes acquisitions. 2019e crude oil growth and total production growth guidance equates to 16%-20% and 12%-16%, respectively, on a pro forma basis. The two-year crude oil and total production CAGR guidance equates to 20% and 17%, respectively, on a pro forma basis from 2018 to 2020. Free cash flow is a non-GAAP measure. See appendix for reconciliation to GAAP measure. Additionally, ROCE is a non-GAAP measure that is defined as net income plus after-tax interest expense divided by average stockholders equity plus average net debt.

Appendix

Large-Scale Project Update

Status of 2Q18 Announced Projects



Key Projects on RSP Acreage

Delaware Basin

- Taylor – 8 wells

Midland Basin

- Calverley – 6 wells
- Spanish Trail – 5 wells
- Ted Johnson – 13 wells

Delaware Basin

Project	Well Count	Drilling	Completion	Production
Tiger Cat	4	✓	✓	✓
Gettysburg	5	✓	✓	4Q18
Dominator	23	✓	In progress	1H19
Eider	12	✓	In progress	1H19
Jack	6	In progress	1H19	1H19
Taylor	8	1H19	2H19	2H19

Midland Basin

Project	Well Count	Drilling	Completion	Production
Calverley	6	✓	✓	✓
Windham TXL	11	✓	In progress	4Q18
Pegasus	6	✓	4Q18	1H19
Spanish Trail	5	✓	4Q18	1H19
Ted Johnson	13	4Q18	1H19	2H19

Historical Well Performance

Historical Activity Tables & Well Results

Horizontal Wells Added	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18
Delaware Basin	25	20	23	27	33	21	31
Midland Basin	21	31	13	10	20	21	34

Avg. 30-Day Peak Rates (MBoepd)	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18
Delaware Basin	1,530	1,532	1,392	1,787	2,042	1,863	1,422
Midland Basin	1,164	923	1,272	1,102	1,156	1,294	1,178

Avg. Lateral Length (ft.)	1Q17	2Q17	3Q17	4Q17	1Q18	2Q18	3Q18
Delaware Basin	6,200	7,168	7,171	7,093	8,964	7,358	6,685
Midland Basin	9,910	9,995	10,198	11,620	10,156	9,800	9,686

Note: Horizontal wells added include wells that had at least 60 days of production in each respective quarter; excludes RSP activity prior to closing date of July 19, 2018. Delaware Basin asset performance excludes New Mexico Shelf results.

Reconciliation of Net Loss to Adjusted Net Income and Adjusted Net Income Per Diluted Share

(Unaudited)

The Company's presentation of adjusted net income and adjusted net income per diluted share that exclude the effect of certain items are non-GAAP financial measures. Adjusted net income and adjusted net income per diluted share represent net income and diluted net income per share determined under GAAP without regard to certain non-cash and unusual items. The Company believes these measures provide useful information to analysts and investors for analysis of its operating results on a recurring, comparable basis from period to period. Adjusted net income and adjusted net income per diluted share should not be considered in isolation or as a substitute for net income or diluted net income per share as determined in accordance with GAAP and may not be comparable to other similarly titled measures of other companies.

The following table provides a reconciliation from the GAAP measure of net loss to adjusted net income (non-GAAP), both in total and on a per diluted share basis, for the periods indicated:

	Three Months Ended September 30,	
(in millions, except per share amounts)	2018	2017
Net loss - as reported	**$ (199)**	**$ (113)**
Adjustments for certain non-cash and unusual items:		
Loss on derivatives	625	206
Net cash receipts from (payments on) derivatives	(44)	30
Leasehold abandonments	6	-
Loss on extinguishment of debt	-	65
(Gain) loss on disposition of assets and other	5	(15)
RSP transaction costs	23	-
Tax impact	(140)	(106)
Change in state statutory effective income tax rate	(7)	-
Adjusted net income	**$ 269**	**$ 67**
Net loss per diluted share - as reported	$ (1.05)	$ (0.77)
Adjustments for certain non-cash and unusual items per diluted share:		
Loss on derivatives	3.29	1.40
Net cash receipts from (payments on) derivatives	(0.23)	0.20
Leasehold abandonments	0.03	-
Loss on extinguishment of debt	-	0.44
(Gain) loss on disposition of assets and other	0.03	(0.10)
RSP transaction costs	0.12	-
Tax impact	(0.73)	(0.72)
Change in state statutory effective income tax rate	(0.04)	-
Adjusted net income per diluted share	**$ 1.42**	**$ 0.45**
Adjusted earnings per share:		
Basic net income	$ 1.42	$ 0.45
Diluted net income	$ 1.42	$ 0.45

Reconciliation of Net Loss to EBITDAX

(Unaudited)

EBITDAX (as defined below) is presented herein and reconciled from the GAAP measure of net loss because of its wide acceptance by the investment community as a financial indicator.

The Company defines EBITDAX as net loss, plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion of discount on asset retirement obligations expense, (4) non-cash stock-based compensation expense, (5) loss on derivatives, (6) net cash receipts from (payments on) derivatives, (7) (gain) loss on disposition of assets, net, (8) interest expense, (9) loss on extinguishment of debt, (10) RSP transaction costs and (11) income tax benefit. EBITDAX is not a measure of net loss or cash flows as determined by GAAP. Annualized EBITDAX as used in this presentation is equal to EBITDAX for the three months ended September 30, 2018, multiplied by four.

The Company's EBITDAX measure provides additional information which may be used to better understand the Company's operations. EBITDAX is one of several metrics that the Company uses as a supplemental financial measurement in the evaluation of its business and should not be considered as an alternative to, or more meaningful than, net loss as an indicator of operating performance. Certain items excluded from 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 cost of depreciable and depletable assets. EBITDAX, as used by the Company, may not be comparable to similarly titled measures reported by other companies. The Company believes that EBITDAX is a widely followed measure of operating performance and is one of many metrics used by the Company's management team and by other users of the Company's consolidated financial statements. For example, EBITDAX can be used to assess the Company's operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of the Company's assets and the Company without regard to capital structure or historical cost basis.

The following table provides a reconciliation of the GAAP measure of net loss to EBITDAX (non-GAAP) for the periods indicated:

	Three Months Ended September 30,	
(in millions)	2018	2017
Net loss	**$ (199)**	**$ (113)**
Exploration and abandonments	10	7
Depreciation, depletion and amortization	406	284
Accretion of discount on asset retirement obligations	3	2
Non-cash stock-based compensation	23	17
Loss on derivatives	625	206
Net cash receipts from (payments on) derivatives	(44)	30
(Gain) loss on disposition of assets, net	5	(13)
Interest expense	46	39
Loss on extinguishment of debt	-	65
RSP transaction costs	23	-
Income tax benefit	(69)	(66)
EBITDAX	**$ 829**	**$ 458**

Reconciliation of Net Cash Provided by Operating Activities to EBITDAX

(Unaudited)

EBITDAX is presented herein and reconciled to the GAAP measure of net cash provided by operating activities because the Company believes EBITDAX is a widely accepted financial indicator of a company's ability to internally fund exploration and development activities and to service or incur debt without regard to financial or capital structure. EBITDAX should not be considered an alternative to net cash provided by operating activities, as defined by GAAP.

The following table provides a reconciliation of the GAAP measure of net cash provided by operating activities to EBITDAX (non-GAAP) for the period presented:

(in millions)	Three Months Ended September 30, 2018
Net cash provided by operating activities	**$ 771**
Exploration and abandonments, including dry holes	4
Interest expense	46
RSP transaction costs	23
Changes in working capital	(14)
Other	(1)
EBITDAX	**$ 829**

Reconciliation of Net Cash Provided by Operating Activities to Free Cash Flow

(Unaudited)

The Company's presentation of free cash flow is a non-GAAP financial measure. Free cash flow is defined as net cash provided by operating activities less exploration and development costs incurred. Free cash flow is presented herein and reconciled from the GAAP measure of net cash provided by operating activities because the Company believes that it provides useful information to analysts and investors. For example, free cash flow can be used to assess the Company's ability to internally fund its capital expenditures and service or incur debt. Free cash flow should not be considered in isolation or as a measure of net income or net cash provided by operating activities, as defined by GAAP, and may not be comparable to other similarly titled measures of other companies.

The following table provides a reconciliation from the GAAP measure of net cash provided by operating activities to free cash flow (non-GAAP), for the periods indicated:

	Three Months Ended												
(in millions)	September 30, 2018	June 30, 2018	March 31, 2018	December 31, 2017	September 30, 2017	June 30, 2017	March 31, 2017	December 31, 2016	September 30, 2016	June 30, 2016	March 31, 2016	December 31, 2015	September 30, 2015
Net cash provided by operating activities	$ 771	$ 602	$ 488	$ 510	$ 380	$ 398	$ 407	$ 365	$ 343	$ 306	$ 370	$ 326	$ 436
Less: Exploration and development costs incurred	(761)	(501)	(450)	(471)	(427)	(383)	(393)	(351)	(274)	(272)	(253)	(236)	(301)
Free Cash Flow	**$ 10**	**$ 101**	**$ 38**	**$ 39**	**$ (47)**	**$ 15**	**$ 14**	**$ 14**	**$ 69**	**$ 34**	**$ 117**	**$ 90**	**$ 135**

Costs Incurred

(Unaudited)

The table below provides the costs incurred for oil and natural gas producing activities for the periods indicated:

	Three Months Ended												
(in millions)	September 30, 2018	June 30, 2018	March 31, 2018	December 31, 2017	September 30, 2017	June 30, 2017	March 31, 2017	December 31, 2016	September 30, 2016	June 30, 2016	March 31, 2016	December 31, 2015	September 30, 2015
Property Acquisition Costs:													
Proved	$ 4,126	$ -	$ -	$ 2	$ 162	$ 12	$ 127	$ 725	$ 1	$ 4	$ 252	$ (2)	$ 57
Unproved	3,578	5	13	40	472	87	306	982	14	19	139	10	162
Exploration	481	335	243	296	252	238	235	189	177	165	170	149	202
Development	280	166	207	175	175	145	158	162	97	107	83	87	99
Total Costs Incurred	**$ 8,465**	**$ 506**	**$ 463**	**$ 513**	**$ 1,061**	**$ 482**	**$ 826**	**$ 2,058**	**$ 289**	**$ 295**	**$ 644**	**$ 244**	**$ 520**

2018 Operational & Financial Outlook

Updated as of October 30, 2018

4Q18 PRODUCTION

305-310 MBoepd (65% oil)

	2018 Guidance
Production	
Production (MBoepd)	260 - 263
Crude oil production mix	64%
Price realizations, excluding commodity derivatives	
Crude oil differential (per Bbl) (Relative to NYMEX - WTI; excludes Midland-Cushing basis differential)	(\$1.50) - (\$2.00)
Natural gas (per Mcf) (% of NYMEX - Henry Hub)	110% - 120%
Operating costs and expenses (\$ per Boe, unless noted)	
Lease operating expense and workover costs	\$6.00 - \$6.50
Gathering, processing and transportation	\$0.55 - \$0.65
Oil and natural gas taxes (% of oil & natural gas revenues)	7.75%
General and administrative ("G&A") expense:	
Cash G&A expense	\$2.30 - \$2.50
Non-cash stock-based compensation	\$0.80 - \$1.00
DD&A	\$15.00 - \$16.00
Exploration and other	\$0.25 - \$0.75
Interest expense (\$mm):	
Cash	\$150 - \$160
Non-cash	\$6
Income tax rate (%)	24%
Capital program (\$bn)[1]	\$2.5 - \$2.6

Updated items

Note: FY18 guidance includes production (on a 2-stream basis) and capital from RSP beginning on the acquisition closing date of July 19, 2018. The Company's capital program guidance excludes acquisitions and is subject to change without notice depending upon a number of factors, including commodity prices and industry conditions.

Hedge Position

Updated as of October 30, 2018

	2018	2019					2020
	4Q	1Q	2Q	3Q	4Q	Total	Total
Oil Price Swaps[1]:							
Volume (Bbl)	11,902,007	11,992,250	10,835,750	10,066,000	9,484,000	42,378,000	26,534,000
Price per Bbl	$ 56.86	$ 56.80	$ 56.40	$ 56.24	$ 56.12	$ 56.41	$ 58.44
Oil Three-Way Collars[1]:							
Volume (Bbl)	1,227,000	-	-	-	-	-	-
Ceiling price per Bbl	$ 60.96	$ -	$ -	$ -	$ -	$ -	$ -
Floor price per Bbl	$ 48.00	$ -	$ -	$ -	$ -	$ -	$ -
Short put price per Bbl	$ 38.00	$ -	$ -	$ -	$ -	$ -	$ -
Oil Costless Collars[1]:							
Volume (Bbl)	1,058,000	1,335,250	1,213,250	1,135,000	1,058,000	4,741,500	-
Ceiling price per Bbl	$ 60.11	$ 64.67	$ 64.00	$ 63.47	$ 62.95	$ 63.83	$ -
Floor price per Bbl	$ 46.52	$ 56.46	$ 56.06	$ 55.74	$ 55.43	$ 55.96	$ -
Oil Basis Swaps[2]:							
Volume (Bbl)	10,517,000	11,730,000	11,419,500	10,994,000	10,533,000	44,676,500	34,770,000
Price per Bbl	$ (0.77)	$ (2.93)	$ (3.02)	$ (2.97)	$ (3.07)	$ (2.99)	$ (0.82)
Natural Gas Price Swaps[3]:							
Volume (MMBtu)	18,458,000	7,291,533	7,231,387	7,178,537	7,089,535	28,790,992	12,808,000
Price per MMBtu	$ 3.00	$ 2.82	$ 2.81	$ 2.81	$ 2.81	$ 2.81	$ 2.70

[1]The oil derivative contracts are settled based on the New York Mercantile Exchange ("NYMEX") – West Texas Intermediate ("WTI") monthly average futures price.
[2]The basis differential price is between Midland – WTI and Cushing – WTI. The majority of these contracts are settled on a calendar-month basis, while certain contracts assumed in connection with the RSP acquisition are settled on a trading-month basis.
[3]The natural gas derivative contracts are settled based on the NYMEX – Henry Hub last trading day futures price.