Investor Presentation

November 2018

Disclaimer

The information in this document includes forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements specifically include our expectations as to our future financial position, liquidity, cash flows, results of operations and business strategy, potential acquisition opportunities, other plans and objectives for operations, maintenance capital requirements, expected production and costs, reserves, hedging activities, capital investments and other guidance. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. You can typically identify forward-looking statements by words such as aim, anticipate, achievable, believe, budget, continue, could, effort, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially. Material risks that may affect our results of operations and financial position appear in Risk Factors in our final prospectus dated July 25, 2018 as filed with the SEC pursuant to Rule 424(b)(4) of the Securities Act of 1933, as amended, on July 27, 2018 (the "prospectus").

Factors (but not necessarily all the factors) that could cause results to differ include among others:

* volatility of oil, natural gas and NGL prices;
* inability to generate sufficient cash flow from operations or to obtain adequate financing to fund capital expenditures and meet working capital requirements;
* price and availability of natural gas;
* our ability to use derivative instruments to manage commodity price risk;
* impact of environmental, health and safety, and other governmental regulations, and of current or pending legislation;
* uncertainties associated with estimating proved reserves and related future cash flows;
* our inability to replace our reserves through exploration and development activities;
* our ability to obtain permits and otherwise to meet our proposed drilling schedule and to successfully drill wells that produce oil and natural gas in commercially viable quantities;
* effects of competition;
* our ability to make acquisitions and successfully integrate any acquired businesses;
* market fluctuations in electricity prices and the cost of steam;
* asset impairments from commodity price declines;
* large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
* geographical concentration of our operations;
* our ability to improve our financial results and profitability following our emergence from bankruptcy and other risks and uncertainties related to our emergence from bankruptcy;
* changes in tax laws;
* impact of derivatives legislation affecting our ability to hedge;
* ineffectiveness of internal controls;
* concerns about climate change and other air quality issues;
* catastrophic events;
* litigation;
* our ability to retain key members of our senior management and key technical employees; and
* information technology failures or cyber attacks.

We undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made. All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

This presentation includes management's projections of certain key operating and financial metrics for the year ending December 31, 2018. Key assumptions underlying these projections include, but are not limited to, (i) averaging three drilling rigs in California continuously through 2018, (ii) drilling and completion cost for PUD wells in California in 2018 will average less than $450,000 per well, (iii) forecasted average ICE (Brent) oil sales prices based on strip pricing as of May 31, 2018 of $74.59, $72.98 and $69.15 per Bbl for 2018, 2019, and 2020, respectively, and flat pricing assumption for 2021 onward of $66.49 per Bbl, and (iv) forecasted average NYMEX Henry Hub natural gas sales prices based on strip pricing as of May 31, 2018 of $2.94, $2.75 and $2.68 per Bbl for 2018, 2019, and 2020 respectively and flat pricing assumption for 2021 onward of $2.66 per Mcf.

Disclaimer (Cont.)

Material assumptions also include a consistent and stable regulatory environment; timely and available drilling and completion equipment and crew availability and access to necessary resources for drilling, completing and operating wells; availability of capital; and accessibility to transport and sell oil and natural gas product to available markets. These projections reflect the consistent application of Berry's accounting policies. While Berry believes that these assumptions are reasonable in light of management's current expectations concerning future events, the estimates underlying these assumptions are inherently uncertain and speculative and are subject to significant business, economic, regulatory, environmental and competitive risks and uncertainties that could cause actual results to differ materially from those Berry anticipates and many of which are beyond Berry's control. Any of the risks discussed in the prospectus would cause Berry's actual operating and financial results to vary significantly from the estimates provided herein.

While Berry currently expects that its actual results will be within the ranges described herein, there will be differences between actual and projected results, and actual results may be materially greater or materially less than those contained in these projections. Inclusion of these projections in this presentation should not be regarded as a representation by any person that the projected operating and financial results will be achieved. In addition, the projected results set forth below are not necessarily indicative of results Berry may achieve in any other period.

This presentation has been prepared by Berry and includes market data and other statistical information from sources believed by it to be reliable, including independent industry publications, government publications or other published independent sources. Some data is also based on Berry's good faith estimates, which are derived from its review of internal sources as well as the independent sources described above. Although Berry believes these sources are reliable, it has not independently verified the information and cannot guarantee its accuracy and completeness.

Proved reserve data included in this presentation is based on a proved reserve report prepared by DeGoyler and MacNaughton ("D&M") as of December 31, 2017 and addendum prepared as of June 28, 2018 (the "D&M Report"). Unless otherwise noted or suggested by context, reserve estimates were prepared in accordance with current SEC rules and regulations regarding oil, natural gas and NGL reserve reporting.

Berry uses PV-10, a supplemental financial measure that is not presented in accordance with U.S. generally accepted accounting principles ("GAAP"), in this presentation, which reflects the present value of its estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization expense, exploration expenses and hedging activities, discounted at 10% per year before income taxes. Please see slide 26 for a reconciliation to the standardized measure of discounted future net cash flows.

Berry uses Adjusted EBITDA and Levered Free Cash Flow, financial measures that are not presented in accordance with GAAP, in this presentation. Adjusted EBITDA and Levered Free Cash Flow are used as supplemental non-GAAP financial measures by Berry's management and by external users of Berry's financial statements, such as industry analysts, investors, lenders and rating agencies. Berry believes Adjusted EBITDA is useful because it allows management to more effectively evaluate Berry's operating performance and compare the results of its operations period to period without regard to Berry's financing methods or capital structure. Levered Free Cash Flow is used by management as a primary metric to plan capital allocation for maintenance and internal growth opportunities, as well as hedging needs. It also serves as a measure for assessing our financial performance and our ability to generate excess cash from operations to service debt and pay dividends.

Berry defines Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, amortization and accretion; exploration expense; derivative gains or losses, net of cash received or paid for scheduled derivative settlements; impairments; stock compensation expense and other unusual out-of-period and infrequent items, including restructuring and reorganization costs. Berry defines Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense, and dividends. While Adjusted EBITDA and Levered Free Cash Flow are non-GAAP measures, the amounts included in these calculations were computed in accordance with GAAP. These measures are provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. Our computations of Adjusted EBITDA and Levered Free Cash Flow may not be comparable to other similarly titled measures used by other companies. Adjusted EBITDA and Levered Free Cash Flow should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP. Please see slide 25 and 26 for a reconciliations of Adjusted EBITDA and Levered Free Cash Flow to GAAP amounts.

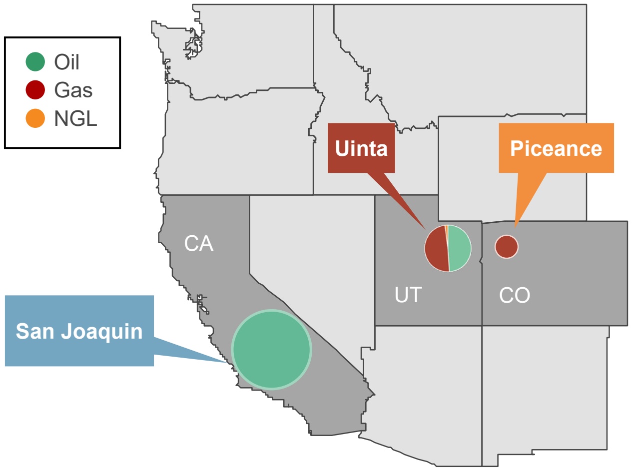
Berry uses Adjusted General and Administrative Expenses ("Adjusted G&A"), a supplemental financial measure that is not presented in accordance with GAAP, in this presentation. We define Adjusted G&A as general and administrative expenses adjusted for non-recurring restructuring and other costs and non-cash stock compensation expense. Management believes Adjusted G&A is a useful measure because it allows management to more effectively compare our performance from period to period. We exclude the items listed because these amounts can vary widely and unpredictably in nature, timing, amount and frequency and stock compensation expense is non-cash in nature. Adjusted G&A should not be considered as an alternative to, or more meaningful than, general and administrative expenses as determined in accordance with GAAP. Adjusted G&A may not be comparable to other similarly titled measures for other companies. Please see slide 27 for a reconciliation of Adjusted G&A to general and administrative expenses.

The type curves provided in this presentation are prepared by Berry's internal reserves engineers by conducting a decline curve analysis of production results from Berry's wells to generate an arithmetic mean of historical production for each project. Berry relied on the production results through February 1, 2018 for its own wells that it submitted to the Division of Oil, Gas and Geothermal Resources of the California Department of Conservation ("DOGGR"), which results are publicly available at maps.conservation.ca.gov/doggr/wellfinder/#openModal, to generate the type curves, and these wells are listed on slides 42-44 of Berry's July 2018 Investor presentation (available at berrypetroleum.com/Investors). These type curves were not relied upon by D&M in preparing the D&M Report, and D&M has not reviewed the type curves included in this presentation. Investors are cautioned not to place undue reliance on Berry's type curves and Berry's actual production and ultimate recoveries may differ substantially.

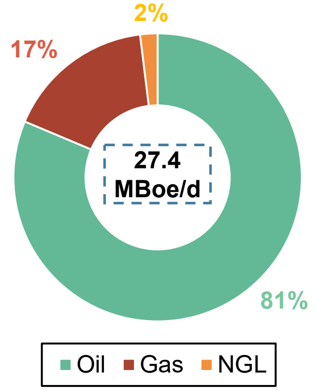
Introductory Overview of Berry Petroleum

- **Conventional properties in California, Utah, Colorado, and Texas**
  - Q3 2018 Production: 81% Oil
  - Q3 2018 California Production: 100% Oil
- **Proven management team**
  - Established track record of leading public companies
- **Long production history and operational control**
  - Shallow decline curves with highly predictable production profiles
  - Low-risk development opportunities
- **Extensive inventory of high-return drilling locations**
  - 18+ years[2] of low risk, development opportunities
  - High average working interest (97%) and net revenue interest (88%) at Q3
- **Largely held-by-production acreage (75%), including 99% of California at Q3 2018**
- **Brent-influenced oil pricing dynamics in California**

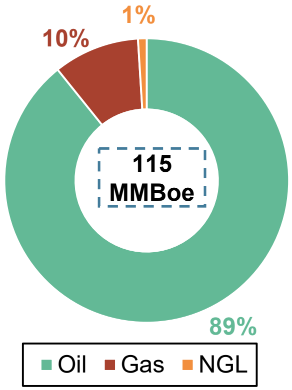
Map of Berry Assets[1]



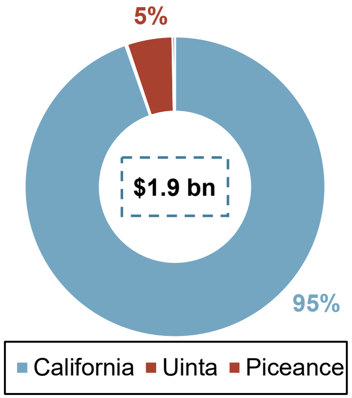
3Q18 Production by Commodity[4]



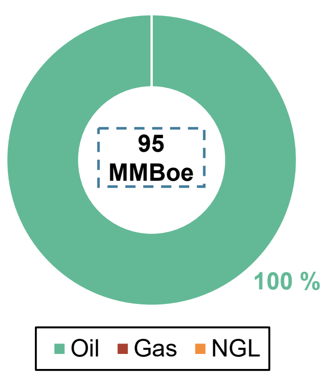
1P Reserves by Commodity[3]



1P PV-10 Value by Area[3]



California 1P Reserves by Commodity[3]

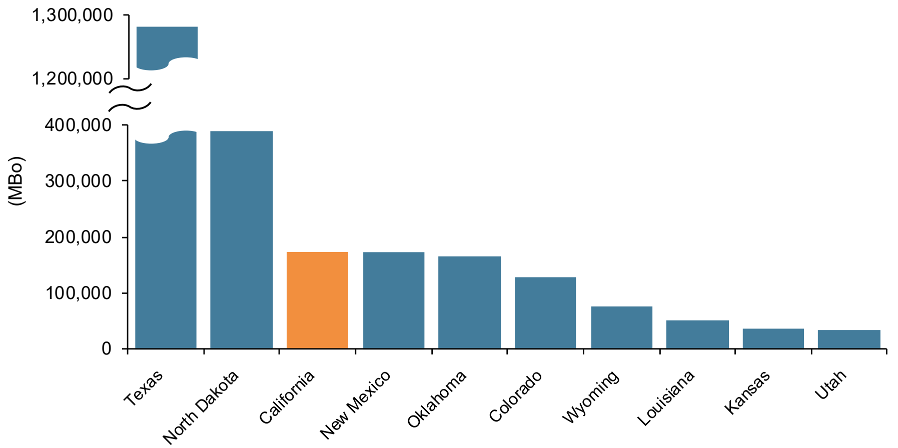


[1] Excludes East Texas Assets and bubble size implies PV-10 value of reserves. | [2] Based on 2018 development pace. | [3] Prepared based on D&M Report using closing monthly futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (Henry Hub) for natural gas on May 31, 2018. Please see slides 48-49 of Berry's July 2018 Investor Presentation (available at berrypetroleum.com/Investors) for a comparison to SEC Pricing. Please see slide 2 for a note regarding the non-GAAP financial measure PV-10. | [4] Includes 300 Boe/d of Utah inventory sales

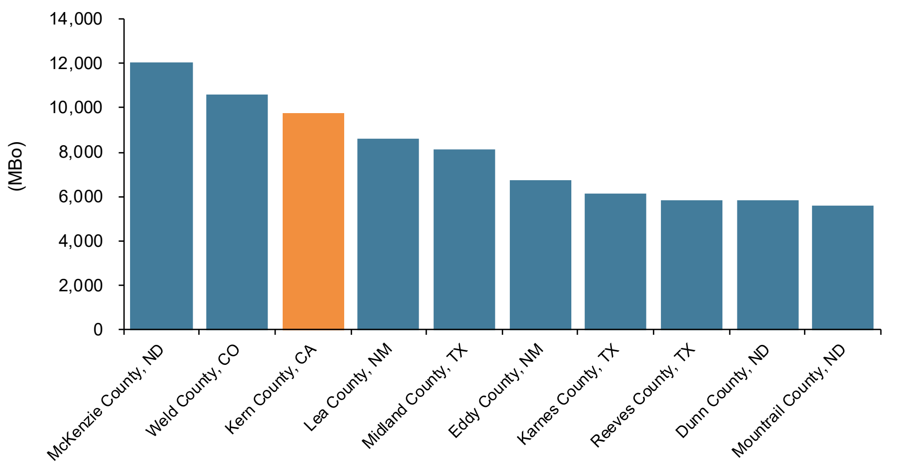
California and U.S. Energy Industry are Intertwined

- **California overview**
  - California is the third largest crude oil producer in the U.S. Lower 48, after Texas and North Dakota[1]
    - Kern County is the third largest oil producing county in the U.S. Lower 48[2]
  - Energy consumption ranks among the highest in the nation creating an inherent incentive to maintain and grow a diverse energy production base
  - Several major oil and gas companies maintain significant operations in the region including: Chevron, Exxon and Shell
  - Chevron is California's largest producer and keeps its Global Headquarters there[3]
- **Total annual economic contribution by oil and gas[4]**
  - Oil and gas extraction represents sizeable portion of contribution
  - 368,100 direct, indirect and induced jobs
  - $33 billion in total labor income
  - $148 billion in total output
- **Over $26 billion in annual state and local tax revenue contributed by oil and gas overall[4]**

Top Crude Oil Producing States in Lower 48 (2017)[1]



Top Crude Oil Producing Counties in Lower 48 (Feb 2018)[2]



[1] *EIA 2017 Total Crude Oil Production.*
[2] *DrillingEdge.*
[3] *Chevron; 2017 Supplement to the Annual Report, p. 13.*
[4] *Los Angeles County Economic Development Corporation; YE 2015.*

The Berry Advantage

Our Key Asset, Operational and Financial Advantages…

- *Oil dominated, low-risk conventional asset base*
- *Focused on San Joaquin Basin assets on west side*
- *Long-lived reserves with low and predictable production decline rates*
- *Stable development and production cost structures*
- *18+ years[1] of identified high return oil drilling locations*
- *Abundant potential strategic opportunities in-basin*
- *Brent-influenced crude oil pricing dynamics*
- *Strong balance sheet and liquidity*

Berry Petroleum Corporation

…Result in…

…A Differentiated Opportunity in E&P

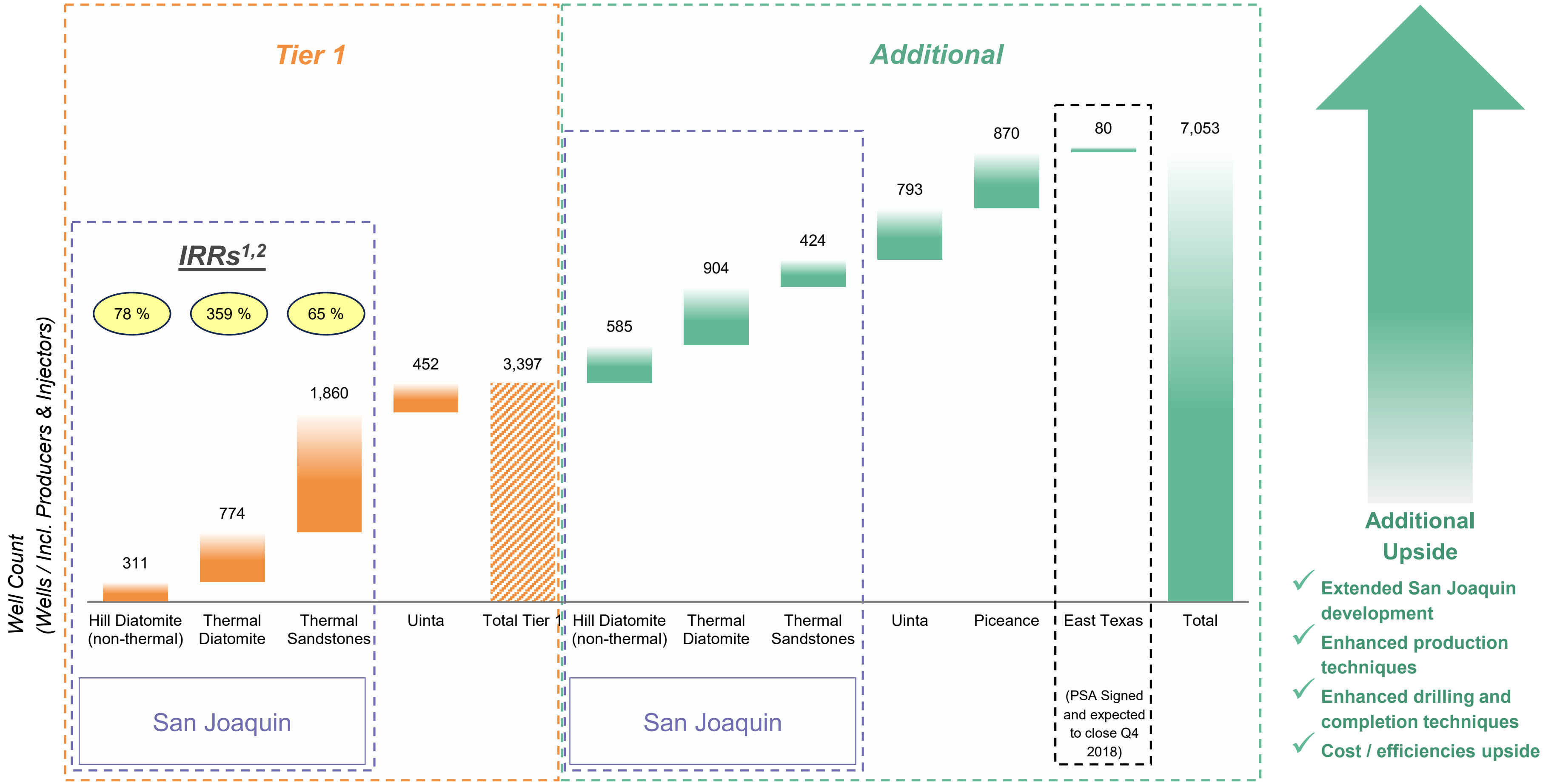
- Top-tier corporate level returns
- Long-term capital efficient growth
- High degree of capital flexibility with low breakeven oil prices
- Positive levered free cash flow through commodity price cycles
- Ability and intention to return capital to shareholders

[1] *Based on 2018 development pace.*

We Are Broadly Advantaged vs. Unconventional Resource Players

	Berry	Resource / Shale Players	*The Berry Benefit*
Production History	Decades of History	Still Learning	✓
Production Declines	Low	High	✓
IP Rates	Lower	Higher	✗
Capital and Service Cost Intensity	Low	Higher (i.e. "Big fracs")	✓
Operating Cost Stability/ Predictability	Stable	Experiencing Inflation	✓
Potential GOR Issues	No (CA ~100% oil)	Yes	✓
Takeaway and Service Capacity Constraints	No (We service CA demand)	Yes	✓
Ability to Generate and Return Capital for Shareholders	Yes	Recurring returns of capital uncommon historically and today	✓

Significant Inventory of High Return Development Opportunities

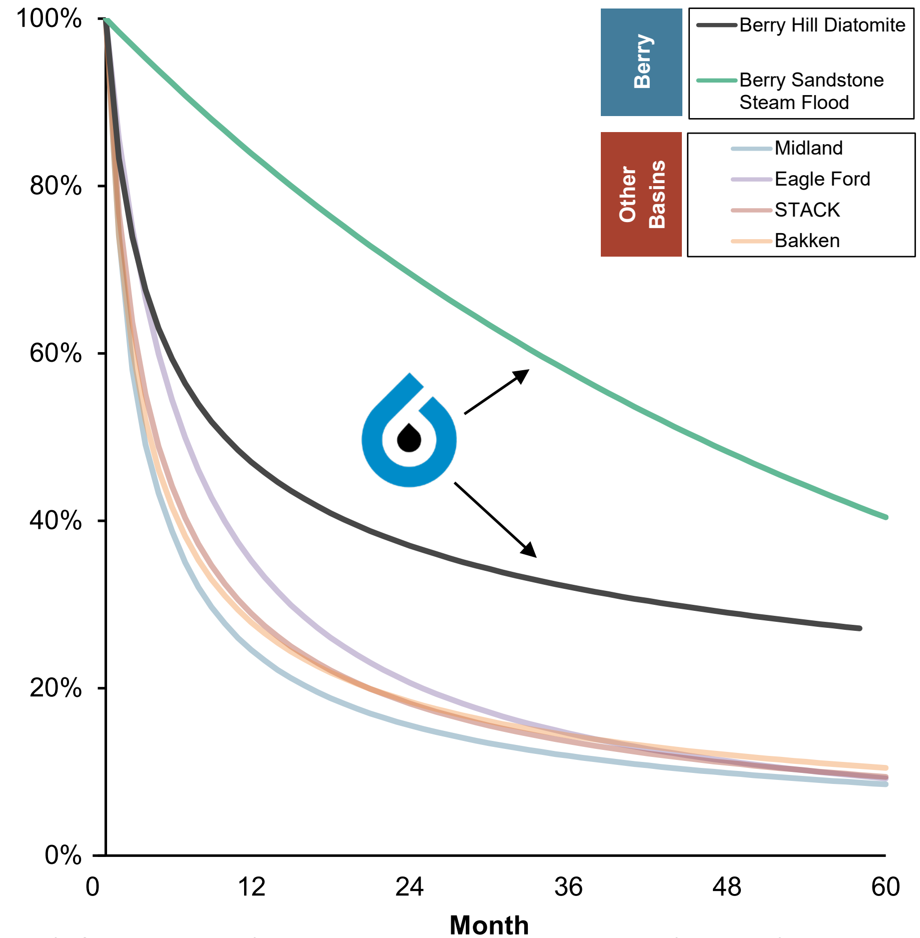


[1] IRRs based on Strip Pricing. Berry's Strip Pricing oil, natural gas and NGL reserves were determined using index prices for natural gas and oil, respectively, as of May 31, 2018 without giving effect to derivative transactions. The average future prices for benchmark commodities used in determining Berry's Strip Pricing reserves were $74.59 per Bbl for oil and NGLs for 2018, $72.98 for 2019, $69.15 for 2020 and $66.49 for 2021 thereafter, on the ICE (Brent), and $2.94 per MMBtu for natural gas for 2018, $2.75 for 2019, $2.68 for 2020 and $2.66 for 2021 thereafter, on the NYMEX Henry Hub. For a comparison to SEC Pricing, please see slides 48-49 in Berry's July 2018 Investor Presentation (available at berrypetroleum.com/Investors). | [2] IRRs calculated based on Berry's type curves and management's assumptions. Please see slide 2 for a note regarding Berry's type curves and slides 37-38 of Berry's July 2018 Investor Presentation (available at berrypetroleum.com/Investors) for more detailed information related to those curves.

Our Low Declining Wells and Production Base Mitigate "Treadmill" Conundrum Experienced in Unconventional Shale Plays

- The decline rates from our new conventional oil wells in California are materially lower than those experienced in the top-tier U.S. oily shale plays
- The extensive history of development and production in our California fields provides a high degree of confidence and predictability
- Our California wells produce little to no gas
- With shale well, there is limited visibility around long-term production profiles, including EURs and GORs
- The low declining nature of our development wells and PDPs result in a high degree of capital flexibility

% of Initial Rate From Peak Production (New Wells)

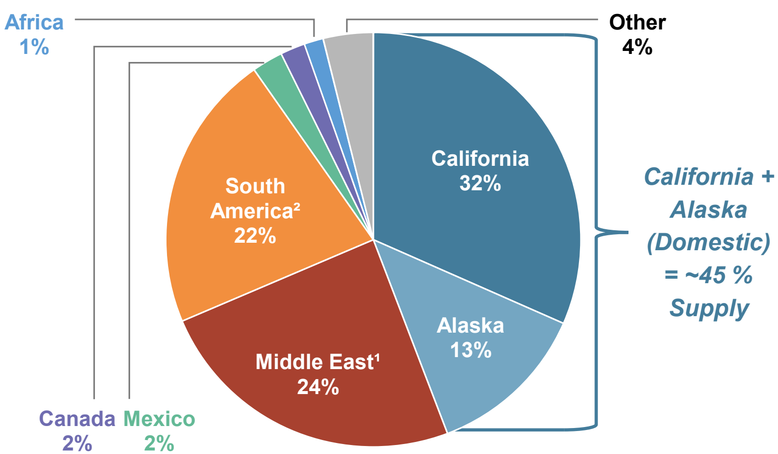


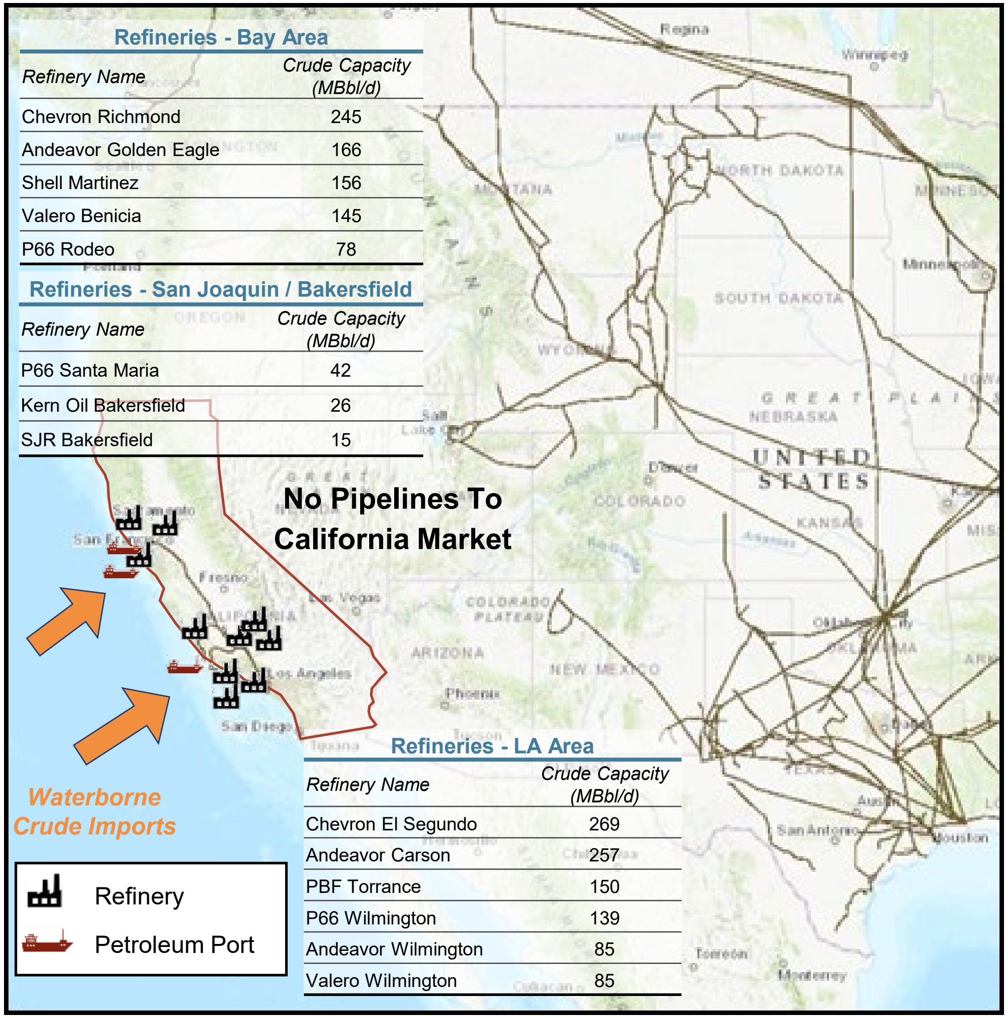
Source: Berry internal database, Third-party Company Presentations
Note: Berry Sandstone Steam Flood reaches peak production after approximately 12 months. Time period shown for Sandstone is shown from peak production and onward. The initial rate of production from peak production is determined using Berry's type curves, Please see slide 2 for a note regarding Berry's type curves and slides 37-38 of Berry's July 2018 Investor Presentation (available at berrypetroleum.com/Investors) for more detailed information related to those curves.

California's Oil Market is Isolated From Rest of Lower 48

- There are no major crude oil pipelines connecting California to the rest of the US.
- California refiners import ~67% of supplies from waterborne sources, including >50% from non-US sources driving prices to track closely to Brent (ICE)
- In 2017, ~46% of supply came from the Middle East[1] and South America[2]

2017 Sources of Feedstock for California





Refineries - Bay Area

Refinery Name	Crude Capacity (MBbl/d)
Chevron Richmond	245
Andeavor Golden Eagle	166
Shell Martinez	156
Valero Benicia	145
P66 Rodeo	78

Refineries - San Joaquin / Bakersfield

Refinery Name	Crude Capacity (MBbl/d)
P66 Santa Maria	42
Kern Oil Bakersfield	26
SJR Bakersfield	15

Refineries - LA Area

Refinery Name	Crude Capacity (MBbl/d)
Chevron El Segundo	269
Andeavor Carson	257
PBF Torrance	150
P66 Wilmington	139
Andeavor Wilmington	85
Valero Wilmington	85

Source: California Almanac

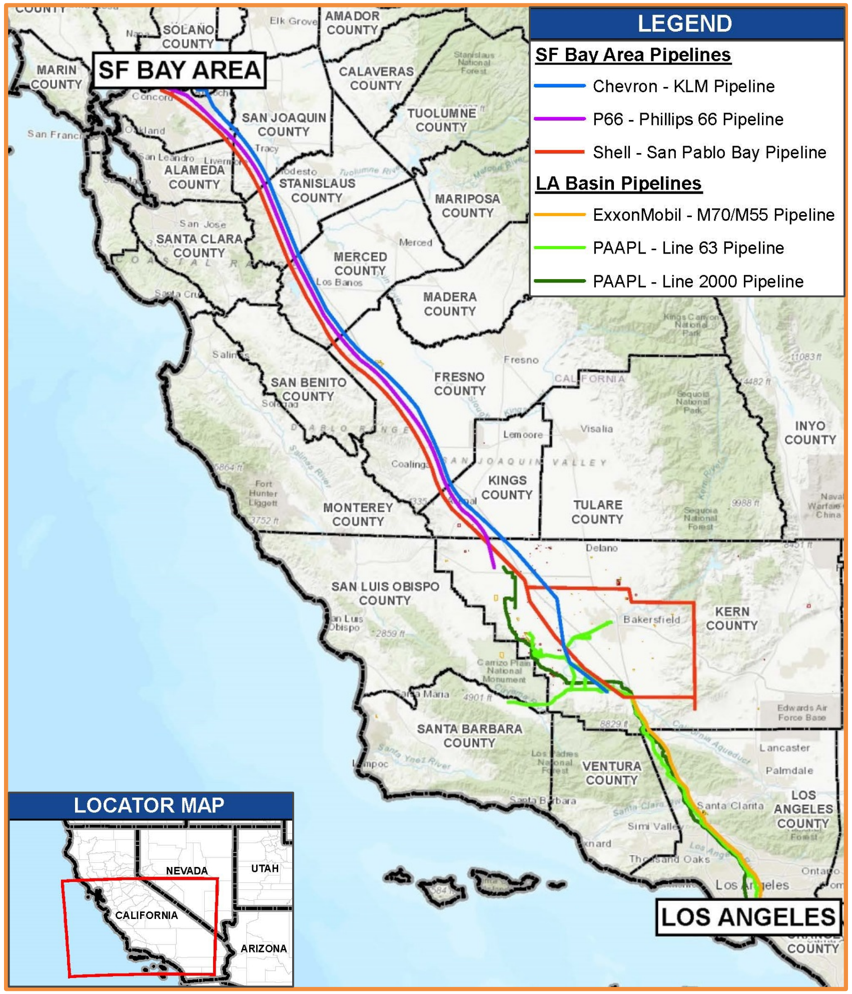
[1] Largest Middle Eastern importers are Saudi Arabia, Iraq and Kuwait. | [2] Largest South American importers are Ecuador, Colombia and Brazil.

California Runs on California Crude, With Plenty of Takeaway Capacity

- Kern County oil production benefits from access to multiple, intra-state pipelines connecting Kern County producers to refineries in Kern County, the Bay Area and L.A.
  - 3 run north to the Bay Area and all are common carriers
  - 2 of the 3 pipelines that run south to L.A. are common carriers
  - Crude by rail is a permanent feature of supply, but volumes have been limited to date
  - The California oil market is insulated from the infrastructure bottlenecks in the rest of the North America (Permian, Canada)

	Pipeline	Owner	Approx. Capacity (MBbl/d)	Description
Bay Area	KLM	CPL	90	Common Carrier
	San Pablo	Shell	210	Common Carrier
	Philips 66	P66	75	Common Carrier
LA	Line 2000[1]	Plains	130 / 75	Common Carrier
	Line 63[1]			Common Carrier
	M70/55	PBF	95	Proprietary

[1] *Plains Line 2000 and 63 currently operate as one line.*



Our Senior Executive Team

Core Values

- Leadership
- Entrepreneurship
- Accountability
- Communication
- Ownership

Highlights

- Broad, diversified and cross-functional experience
- Focused on long-term value creation
- Culture of trust, honesty and fair-dealing
- Employing extensive experience to our basins, which generally lack innovation
- Added key individuals to instill a positive, entrepreneurial spirit
- Encouraging staff to "think outside the lease" and take an innovative approach to developing our core assets
- Implemented initiatives to reverse decline and ramp up production

Experienced Management Team

Trem Smith *CEO*	Chevron; Hillwood Energy, A Perot Company
Cary Baetz *EVP & CFO*	Seventy Seven Energy; Atrium Windows and Doors; Boots & Coots International Well Control
Gary Grove *EVP & COO*	Bonanza Creek; Unocal 76
Kurt Neher *EVP, Business Development*	California Resources Corporation; OXY
Ken Royer *EVP, General Counsel*	California Resources Corporation; OXY

We Have Significant Financial Flexibility Across Oil Price Scenarios

Simple financial principles and planned allocations…

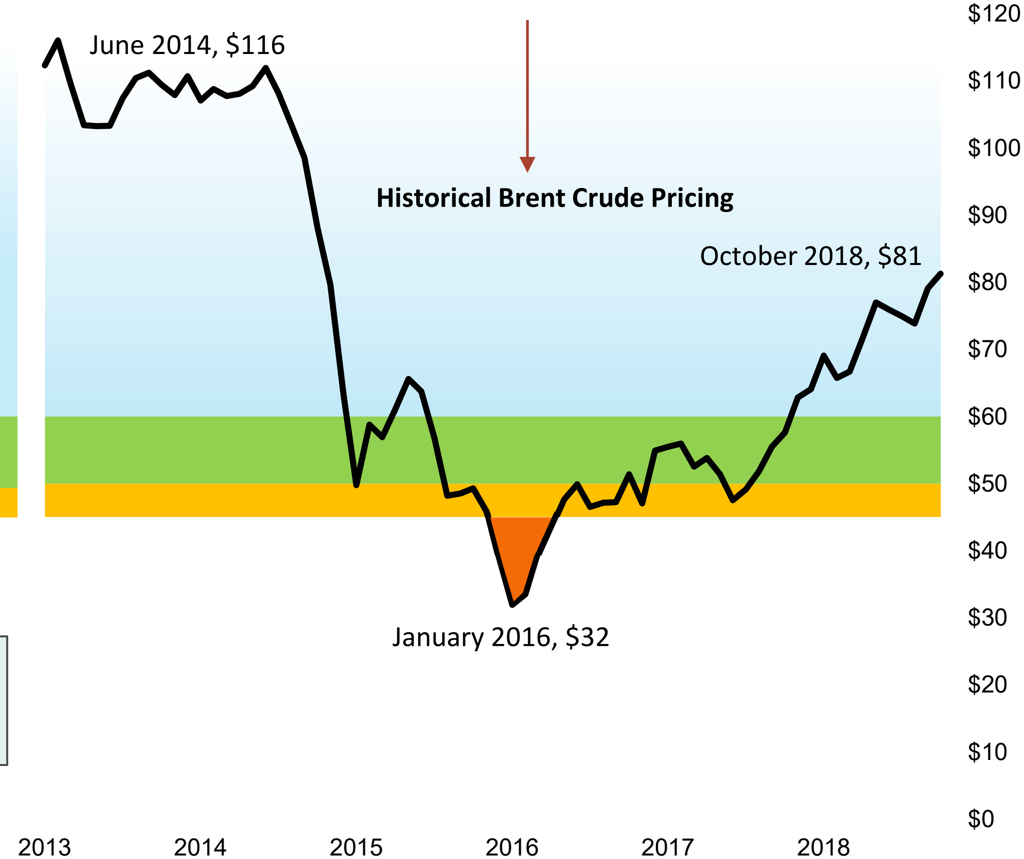
Accelerate development program, pursue accretive acquisitions and bolt-ons, purchase debt in the open market, explore returning capital to shareholders

Fund planned development program

Sustain production*, Pay interest, pay current dividend

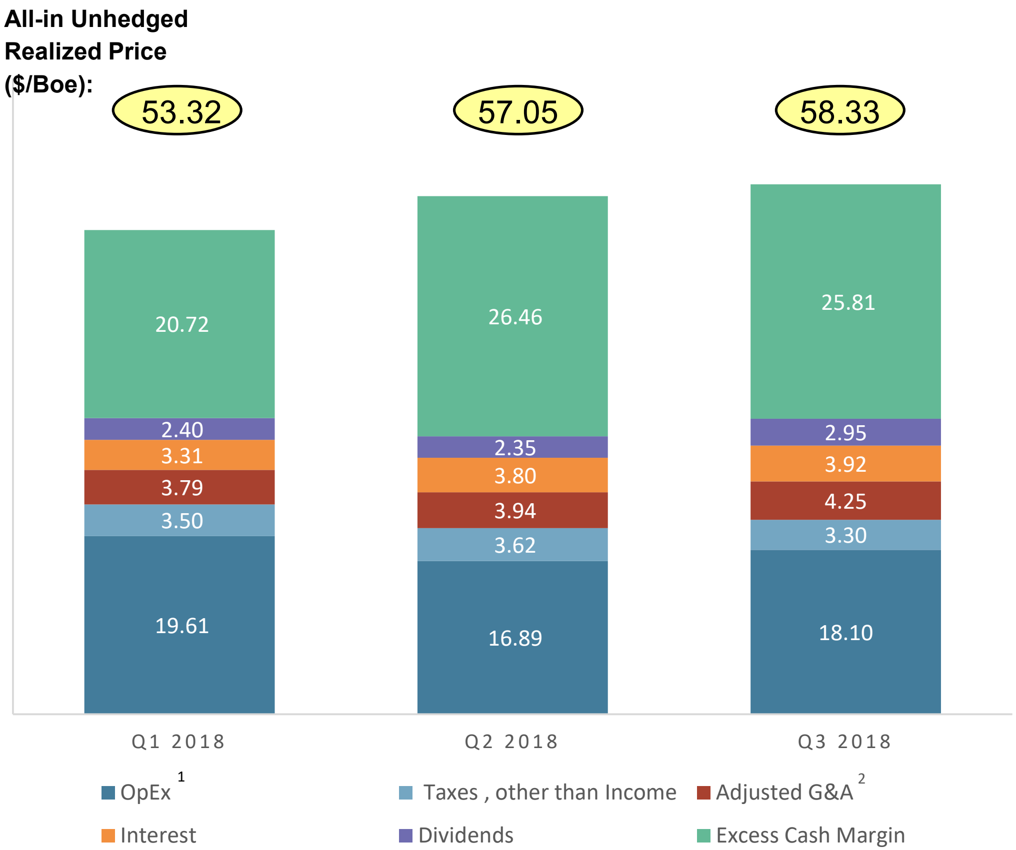
**We estimate ~$10 per Boe in annual capital to keep production volumes flat over the next three years*

Applied rationally across the price cycle

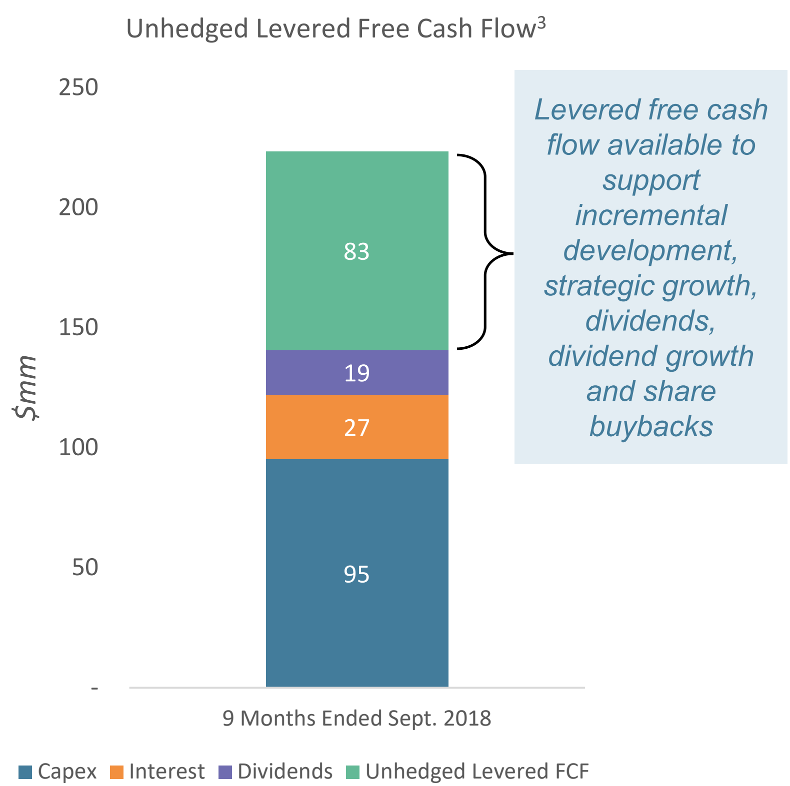


Strong Oil-Driven Cash Margins are Backed by a Stable Cost Structure

Total Company Margin



Levered Free Cash Flow Generation ($mm)[1]

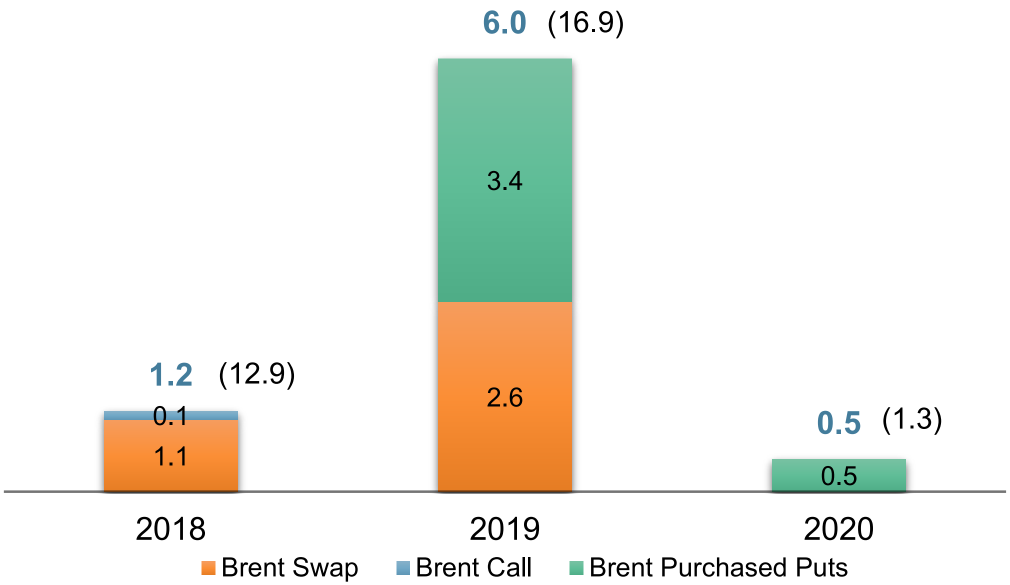


[1] We define Operating Expenses as LOE, electricity expense, transportation expense, and marketing expense, net of electricity, transportation and marketing sales. [2] See slide 2 for a note regarding the Non-GAAP financial measure Adjusted G&A. [3] Please see slide 2 for a note regarding the Non-GAAP measure of levered free cash flow.

Prudent & Proactive Commodity Price Risk Management

High degree of margin visibility via proactive hedging program and cost stability

Hedge Volumes in MMBbls (MBbl/d) **as of 09/30/2018**



	2018	2019	2020
Brent Swap	$74.82	$75.40	
Brent Purchased Put		$65.00	$65.00
Brent Call	$80.00		
Weighted Average	$75.36	$69.56	$65.00

$70.18 Weighted Average

Note: Prices are weighted average.
** Excludes Basis Swaps*
[1] Excludes deferred premiums.
[2] Through March 31, 2020 but averaged over 366 days.
Note: In the second quarter 2018 we restructured our hedge position to reflect market pricing at that time.

Our Financial Policy

Prudent Balance Sheet Management	■ Target Net Debt to EBITDA of 1.5 – 2.0x or lower through commodity price cycles ■ Deleveraging will be achieved through organic growth and excess free cash flow
Return Capital to Shareholders via Meaningful Quarterly Dividend	■ Intend to return capital to shareholders quarterly in meaningful quantities ■ Targeting an attractive dividend payout ratio
Long-Term Hedging	■ Strategy is to secure revenue stream to fund capital needs ■ Hedge target is to cover operating expenses and fixed charges 2 years out ■ Fixing physical gas supply and pricing to correlate to the top line hedging program
Capital Spend	■ Use levered free cash flow from operations to fund maintenance and organic growth opportunities ■ Use other sources of capital for acquisitions that support the long-term leverage profile ■ Maintain capital flexibility; we can and will cut capex in a downturn

I. Asset Overview

A view of Berry's Homebase acreage in South Midway Sunset

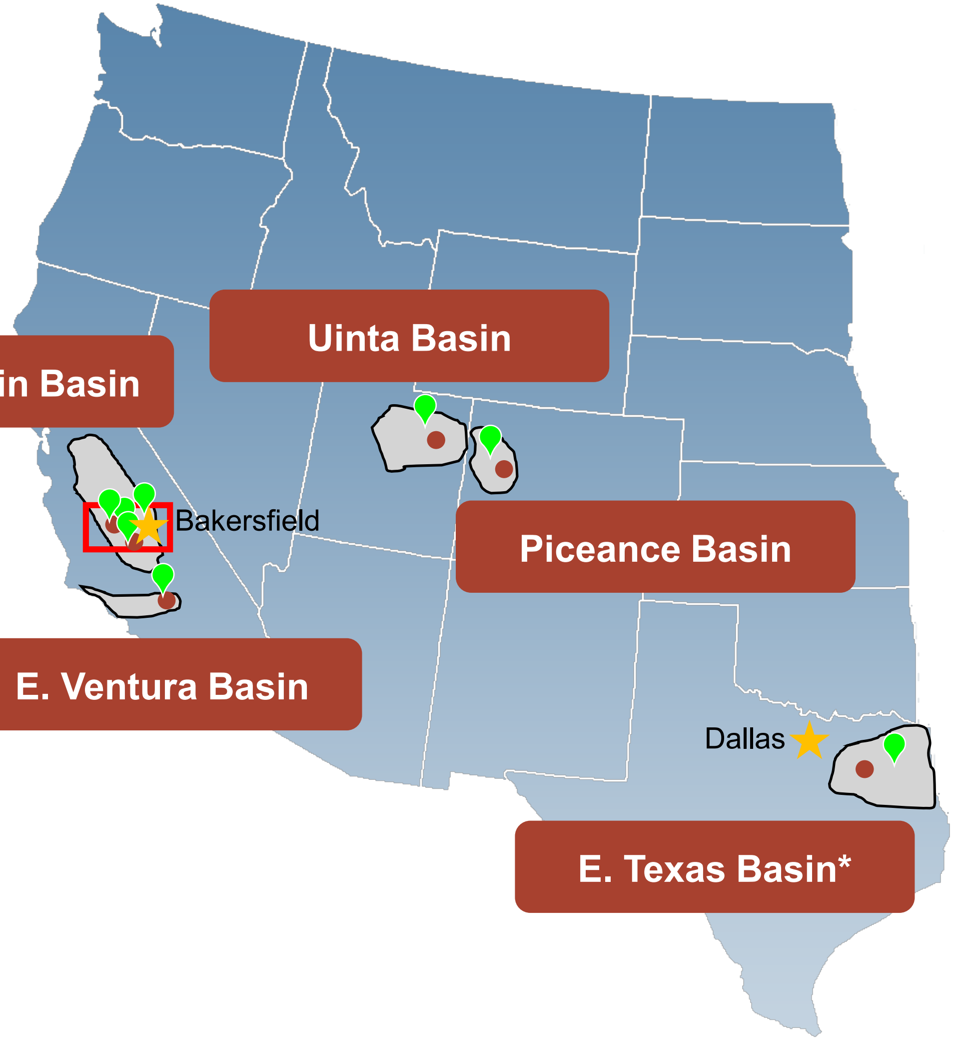
Our Large, Conventional and Diversified Asset Base is Oil-Weighted and Valuable

Basin	May 2018 Strip Net Proved Reserves[1] (MMBoe) / % PD	3Q18 Avg. Net Production[6] (MBoe/d)	3Q18 % Oil Production	May 2018 Strip 1P PV-10[1,2] ($mm) / % of Total	Avg. WI / NRI[3,4]	Gross Drilling Inventory (Identified)	June 2018 Producing Wells, Gross[4,5]	2Q18 Net Acreage
	115 / 71 %	27.4	81 %	$ 1,862	95 % / 88 %	7,053	3,911	116,927
California	95 / 66 %	19.5	100 %	$ 1,762 / 95 %	99 % / 94 %	4,858	2,704	7,945
Uinta	15 / 100 %	5.1	44 %	$ 91 / 5 %	85 % / 78 %	1,245	920	96,441
Piceance	3 / 100 %	2.0	3 %	$ 4 / 0 %	72 % / 63 %	870	170	8,008
East Texas	2 / 100 %	0.7	1 %	$ 5 / 0 %	99 % / 74 %	80	117	4,533

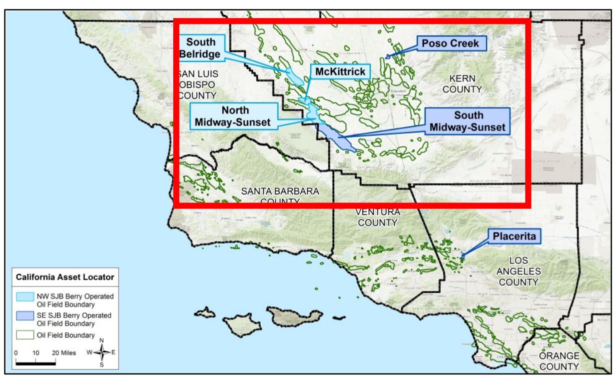
[1] Prepared based on D&M Report using closing monthly futures prices as reported on the ICE (Brent) for oil and NGLs and NYMEX (Henry Hub) for natural gas on May 31, 2018. Please see slide 2 for a note regarding Berry's type curves and slides 37-38 of Berry's July 2018 Investor Presentation (available at berrypetroleum.com/Investors) for more detailed information related to those curves and slides 48-49 for a comparison to SEC Pricing. | [2] Please see slide 2 for a note regarding the non-GAAP financial measure PV-10. | [3] Weighted average WI across active wells as of June, 2018 and weighted average NRI for through June 2018. | [4] Excludes 91 wells in the Piceance basin each with a 5% working interest and eleven wells in the Permian basin all with less than 0.1% working interest. | [5] Includes steam flood and water flood injection wells in California. | [6] Includes 300 Boe/d of Utah inventory sales

Operational Areas – Focused in California Super Basin

- Corporate & Executive Office
- Division Offices
- Producing Assets
- Basin Boundary

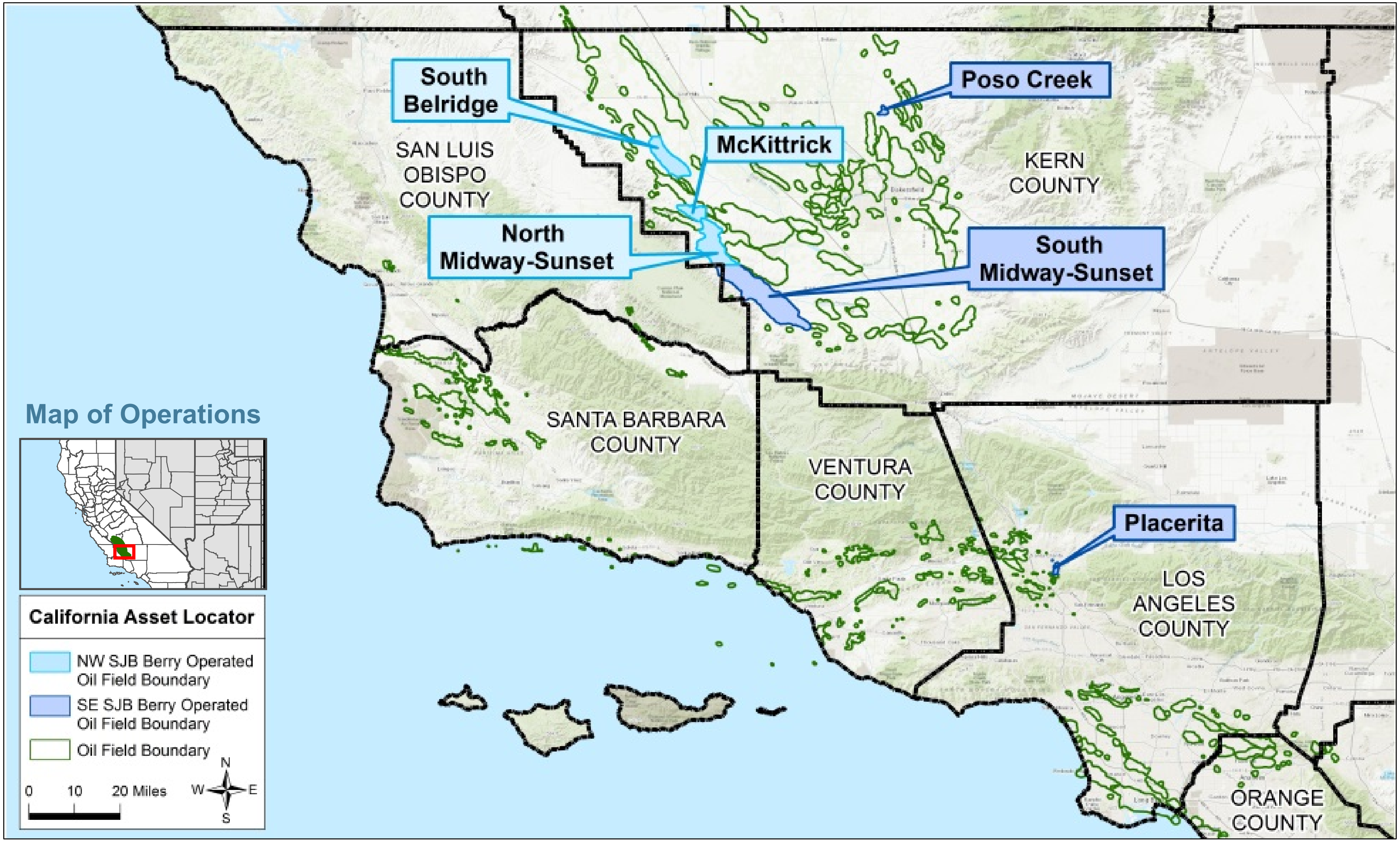


Southern San Joaquin Basin



*PSA signed and expected to close in Q4 2018

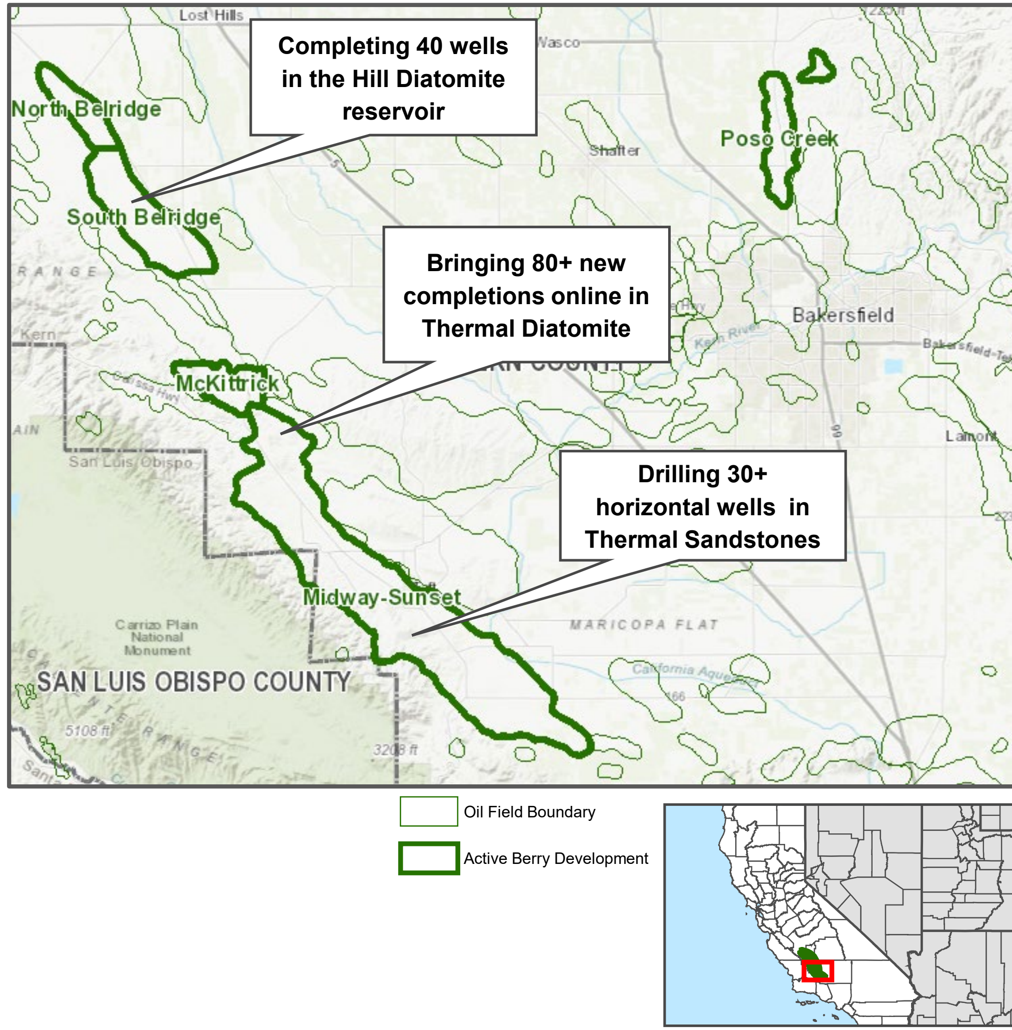
Focused on Our California San Joaquin Basin Assets



Key Operational Activities

- Development is primarily in the San Joaquin Basin
- Added a third rig in California in April and expect three rigs through 2018 and an average of four rigs in 2019
- Select Second quarter activity:
  - Drilled 16 horizontal wells in the thermal sandstone reservoirs in Midway-Sunset including one in North Midway Sunset
  - Drilled 29 and recompleted 23 thermal Diatomite wells in Midway Sunset resulting in over 80 new separate completions
  - Drilled 1 Green River/Wasatch producer in Utah
- Select Third quarter activity:
  - Began bringing the new thermal Diatomite wells online in Midway Sunset
  - Completed 15 Hill Diatomite wells in South Belridge (8 producers, 7 injectors)
  - Drilled 12 horizontal wells in the thermal sandstone in Midway Sunset, including 7 in North Midway
- Select Fourth quarter planned activity:
  - Complete an additional 25 Hill Diatomite producers in South Belridge (22 producers, 3 injectors)
  - Continue drilling in thermal sandstone reservoirs at Midway Sunset, McKittrick, Poso and S. Belridge, including additional horizontal producers in Midway Sunset
  - Drilling and recompleting additional thermal Diatomite wells in Midway Sunset
  - Drill an additional 7 Green River/Wasatch producers in Utah

Notable CA Planned Development Programs in 2018



II. Upside Opportunities

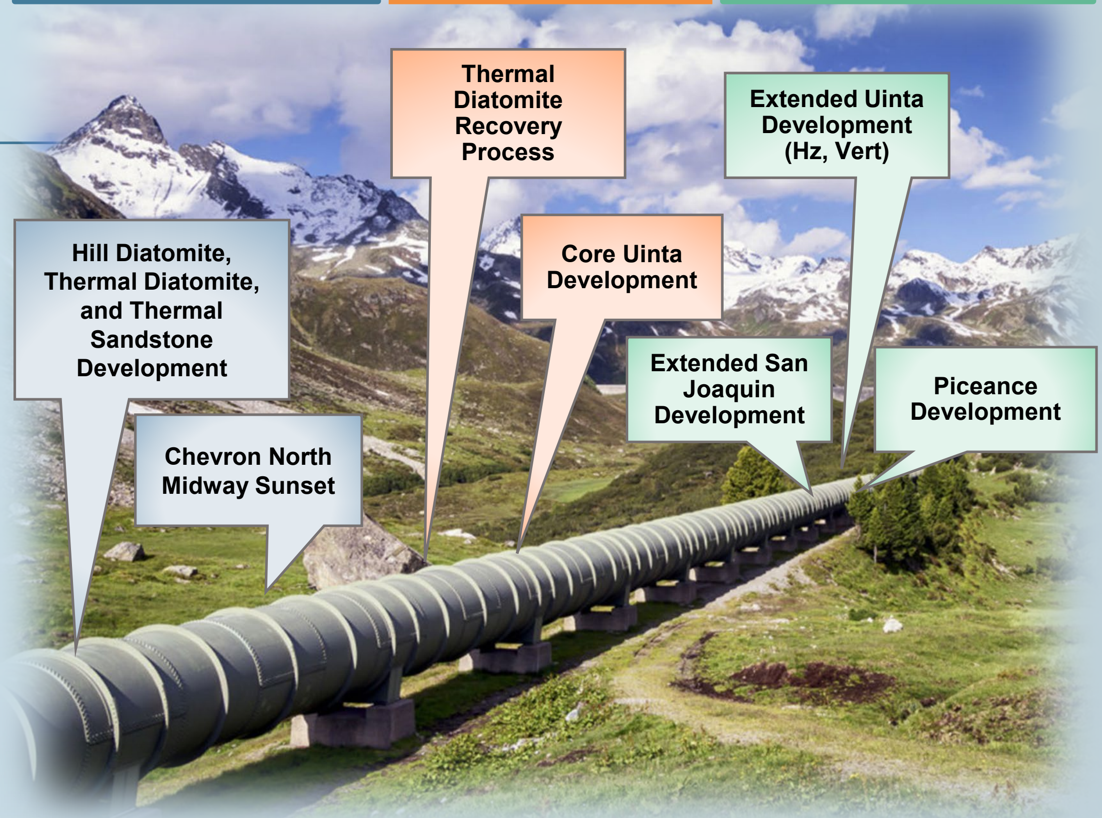
- Thermal Diatomite Recovery Process
- Uinta Opportunity
  - Vertical Development
  - Horizontal Development
- Piceance Opportunities
- Infrastructure Value and OpEx Reductions

Low Risk, High Return Locations

Near-Term Upside

California *Uinta*

Mid-Term Upside



Concluding Remarks

- ***Berry*** **is a highly differentiated E&P company with a clear strategic, operational and financial vision**

Highly Differentiated from Public Conventional and Shale E&P Companies	✓
Positive Levered Free Cash Flow Through the Cycle	✓
Stable Oil-Weighted Asset Base	✓
Long Inventory Life of Highly Economic Oil Locations	✓
Predictable Cost Structure	✓
Strategic and Organic Growth Opportunities	✓
Benefit from Favorable West Coast Crude Pricing Dynamics	✓
Strong Balance Sheet	✓
Capable of Consistent Capital Return to Investors	✓

III. Appendix

Berry's Poso Creek field, California

Updated 2018E Guidance(1)

Category	2018E Guidance	
	Low	High
Average Daily Production (MBoe/d)	27	30
% Oil	~ 80%	
Operating Expenses ($/Boe)	$ 17.00 .	$ 18.75 .
Taxes, Other than Income Taxes ($/Boe)	$ 3.25 .	$ 3.50 .
Adjusted General & Administrative Expenses ($/Boe)	$ 3.75 .	$ 4.00 .
Capital Expenditures ($ millions)	$ 140 .	$ 160 .

1. See Slide 2 for disclosures regarding the risks related to forward-looking statements and an explanation of Adjusted General and Administrative Expenses. The GAAP financial measure, General and Administrative Expense is not accessible for Adjusted General and Administrative Expense on a forward-looking basis. Berry cannot reasonably predict the non-recurring items in General and Administrative Expenses. Because of the uncertainty and variability of the nature and amount of future adjustments, which could be significant, Berry is unable to provide a reconciliation of these measures without unreasonable effort.

2019E Guidance[1]

Category	2018E Guidance	
	Low	High
Average Daily Production (MBoe/d)	29	32
% Oil	~ 86%	
Operating Expenses ($/Boe)	$ 17.00	$ 18.50
Taxes, Other than Income Taxes ($/Boe)	$ 4.25	$ 4.75
Adjusted General & Administrative Expenses ($/Boe)	$ 4.00	$ 4.50
Capital Expenditures ($ millions)	$ 230	$ 260

1. See Slide 2 for disclosures regarding the risks related to forward-looking statements and an explanation of Adjusted General and Administrative Expenses. The GAAP financial measure, General and Administrative Expense is not accessible for Adjusted General and Administrative Expense on a forward-looking basis. Berry cannot reasonably predict the non-recurring items in General and Administrative Expenses. Because of the uncertainty and variability of the nature and amount of future adjustments, which could be significant, Berry is unable to provide a reconciliation of these measures without unreasonable effort.

Non-GAAP Reconciliation
Adjusted EBITDA & Adjusted EBITDA Unhedged

The following tables present a reconciliation of the GAAP financial measures of net income (loss) and net cash (used in) provided by operating activities to the non-GAAP financial measures of Adjusted EBITDA and Adjusted EBITDA Unhedged.

(in thousands)	Nine Months Ended September 30, 2018
Adjusted EBITDA reconciliation to net income (loss):	
Net income (loss)	$15,334
Add (Subtract):	
Interest expense	26,828
Income tax expense (benefit)	3,145
Depreciation, depletion, amortization and accretion	62,017
Derivative (gain) loss	129,902
Net cash received (paid) for scheduled derivative settlements	(47,161)
(Gain) loss on sale of assets and other	522
Stock compensation expense	3,502
Non-recurring restructuring and other costs	5,359
Reorganization items, net	(23,192)
Adjusted EBITDA	$176,256

(in thousands)	Nine Months Ended September 30, 2018
Adjusted EBITDA and Levered Free Cash Flow reconciliation	
to net cash provided (used) by operating activities:	
Net cash provided (used) by operating activities	$7,334
Add (Subtract):	
Cash interest payments	19,199
Cash income tax payments	-
Cash reorganization item (receipts) payments	1,007
Non-recurring restructuring and other costs	5,359
Derivative early termination payment	126,949
Other changes in operating assets and liabilities	16,408
Other, net	-
Adjusted EBITDA	$176,256

Non-GAAP Reconciliation - Levered Free Cash Flow

Levered free cash flow reflects our financial flexibility; and we use it to plan our internal growth capital expenditures. We define levered free cash flow as Adjusted EBITDA less capital expenditures, interest expense, and dividends. Levered free cash flow is our primary metric used in planning capital allocation for maintenance and internal growth opportunities as well as hedging needs and serves as a measure for assessing our financial performance and measuring our ability to generate excess cash from our operations after servicing indebtedness.

(in thousands)	Nine Months Ended September 30, 2018
Adjusted EBITDA and Levered Free Cash Flow reconciliation to net cash provided (used) by operating activities:	
Adjusted EBITDA	$176,256
Subtract:	
Capital expenditures - accrual basis	(94,505)
Interest expense	(26,828)
Cash dividends declared	(18,732)
Levered Free Cash Flow	$36,191
Net cash received (paid) for scheduled derivative settlements	47,161
Levered Free Cash Flow unhedged	$83,352

Non-GAAP Reconciliation - Adjusted General & Administrative Expenses

The following table presents a reconciliation of the GAAP financial measure of general and administrative expenses to the non-GAAP financial measures of Adjusted general and administrative expenses.

(in thousands except MBoe amounts)	Three Months Ended September 30, 2018	Three Months Ended June 30, 2018	Three Months Ended March 31, 2018
Adjusted General and Administrative Expense reconciliation to general and administrative expenses:			
General and administrative expenses	$13,429	$12,482	$11,985
Subtract:			
Non-recurring restructuring and other costs	(1,598)	(1,714)	(2,047)
Non-cash stock compensation expense	(1,125)	(1,260)	(1,019)
Adjusted General and Administrative Expenses	$10,706	$9,508	$8,919
Adjusted General and Administrative Expenses ($/MBoe)	$4.25	$3.94	$3.79
Total MBOE	2,520	2,408	2,356

Reconciliation for PV-10

PV-10 Reconciliation ($ in millions)	At December 31, 2017
PV-10	$ 1,114
(-) Present value of future income taxes discounted at 10 %	(137)
Standardized measure of discounted future net cash flows	$ 977

Thank you!

Berry Petroleum Corporation

berrypetroleum.com