Investor Presentation

March 2019

BRY
Nasdaq Listed

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, return of capital, improvement of recovery factors 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 us appear in Risk Factors in our current Annual Report on Form 10-K and other filings with the Securities and Exchange Commission.

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, pending or future 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.

Except as required by law, we undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made. All included forward-looking statements, expressed or implied, 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. Key assumptions underlying these projections include, but are not limited to forecasted average ICE (Brent) oil sales prices based on the average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $71.54 per Bbl ICE (Brent) for oil and NGLs and $3.10 per MMBtu NYMEX (Henry Hub) for natural gas at December 31, 2018. The volume-weighted average prices over the lives of the properties were $66.49 per Bbl of oil and condensate, $32.87 per Bbl of NGLs and $2.806 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. 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 risks and uncertainties discussed above. 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.

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 less than those contained in these projections.

Measures used in this presentation that are not presented in accordance with U.S. generally accepted accounting principles ("GAAP") are reconciled to the nearest GAAP measure. See appendix for reconciliation of Non-GAAP measures. Adjusted Net Income (Loss) and Adjusted EBITDA are not measures of net income (loss), Levered Free Cash Flow is not a measure of cash flow, and Adjusted General and Administrative Expenses is not a measure of general and administrative expenses, in all cases, as determined by GAAP. PV-10 is not the standardized measure of oil and gas prescribed by GAAP. Finding and Development cost ("F&D") and reserves replacement ratio are not GAAP measures. These measures are provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP or to the standardized measure of discounted future cash flows and should not be considered as an alternative to, or more meaningful than, the measures as determined in accordance with GAAP.

These measures are supplemental non-GAAP financial measures used by management to analyze and monitor the operating and financial performance of our business, evaluate hedging needs, allocate capital, compare the results between periods without regard to our financing methods or capital structure and measure and evaluate the cost of replacing annual production and adding proved reserves; and also by external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted Net Income (Loss) as net income (loss) adjusted for derivative gains or losses net of cash received or paid for scheduled derivative settlements, other unusual, out-of-period and infrequent items, including restructuring costs and reorganization items and the income tax expense or benefit of these adjustments using our effective tax rate. We define Adjusted EBITDA as earnings before interest expense; income taxes; depreciation, depletion, and amortization; 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 costs and reorganization items. We define Levered Free Cash Flow as Adjusted EBITDA less capital expenditures, interest expense and dividends. We define Adjusted General and Administrative Expenses as general and administrative expenses adjusted for non-recurring restructuring and other costs and non-cash stock compensation expense. PV-10 represents the present value of estimated future cash inflows from proved oil and gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and does not give effect to derivatives transactions. F&D Cost – All-In is calculated by dividing total costs incurred for the year as defined by GAAP by the sum of proved reserve extensions and discoveries, revisions of previous estimates, improved recovery and purchases of minerals in place for the year. F&D Cost – Program is calculated by dividing total costs incurred for the year as defined by GAAP by extensions and discoveries and improved recovery for the year. Reserves replacement ratio is calculated by dividing the sum of proved reserve extensions and discoveries, revisions of previous estimates, improved recovery and purchases and sales of minerals in place for the year by current year production.

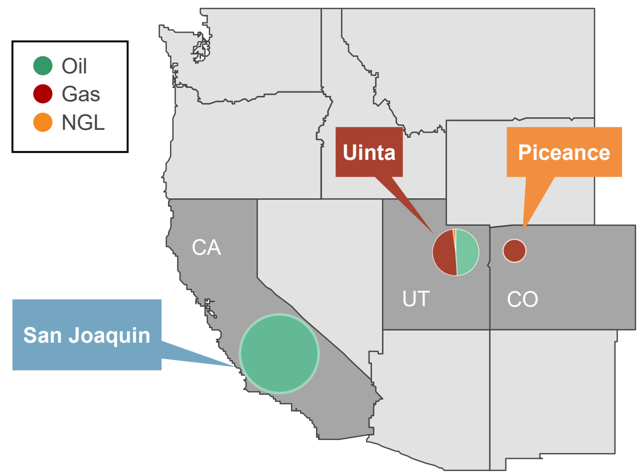
The amounts included in the calculations these measures were computed in accordance with GAAP. We exclude certain items listed above because they can vary widely and unpredictably in nature, timing, amount and frequency and stock compensation expense is non-cash in nature. Our computations may not be comparable to other similarly titled measures used by other companies and should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP. There is no guarantee that historical sources of reserves additions will continue performing as many factors fully or partially outside of management's control affect reserves additions. Management uses this measure to gauge results of its capital allocation. The F&D measures are limited in that reserves may be added and produced based on costs incurred in separate periods and other oil and gas producers may use different measures affecting comparability.

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. To generate the type curves, 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, 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 our independent reserves engineers to prepare their reports on our reserves and they have not reviewed the type curves included in this presentation. Investors are cautioned not to place undue reliance on our type curves - our actual production and ultimate recoveries may differ substantially.

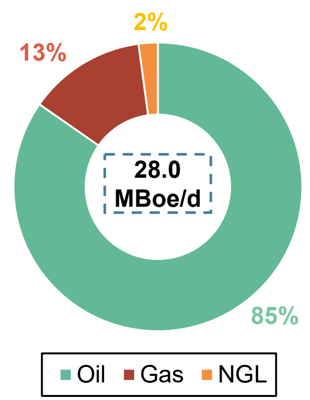
Introductory Overview of Berry Petroleum

- **Conventional properties in California, Utah and Colorado**
  - Q4 2018 Production: 85% Oil
  - Q4 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**
  - 20 years[2] of low risk, development opportunities
- **High average working interest (98%) and net revenue interest (89%) at Q4**
- **Largely held-by-production acreage (75%), including 99% of California at Q4 2018**
- **Brent-influenced oil pricing dynamics in California**

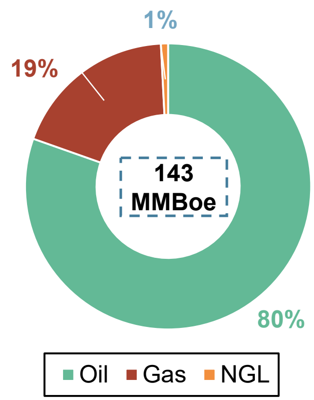
Map of Berry Assets[1]



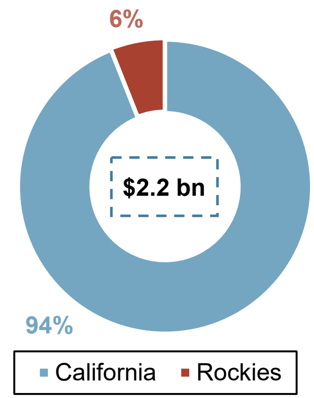
4Q18 Production by Commodity



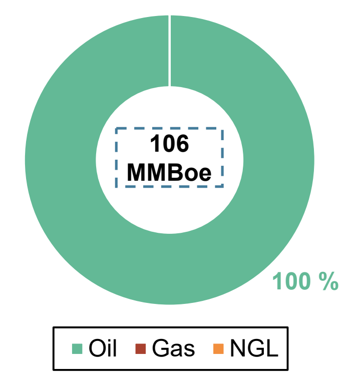
1P Reserves by Commodity



1P PV-10 Value by Area[3]



California 1P Reserves by Commodity



[1] Bubble size implies PV-10 value of reserves. | [2] Based on 2019 development pace. | [3] Please see the Appendix for non-GAAP reconciliations.

Framework for Success

Focus on Creating Long-Term Value

Committed to our Strategy

Grow Value	■ Managing to value not to production or volume growth ■ Directing capital primarily to our oil-rich and low risk development opportunities in the San Joaquin “Super” basin ■ Shifting capital away from Rockies today due to marketing issues; production profile and reservoir performance well understood
Levered Free Cash Flow	■ Capital program funded from levered free cash flow - today and into the future ■ Can maintain current production and pay financial commitments including dividends and interest through the cycle
Return of Capital	■ Returning capital to shareholders primarily via industry leading dividend and, to a lesser extent, share buyback program
Focus on Execution	■ Developed metrics that focus of improving operational efficiency, EH&S performance and improving inventory visibility ■ Plan on a two-year budget cycle to adapt to changing business conditions as they arise

Framework for Success

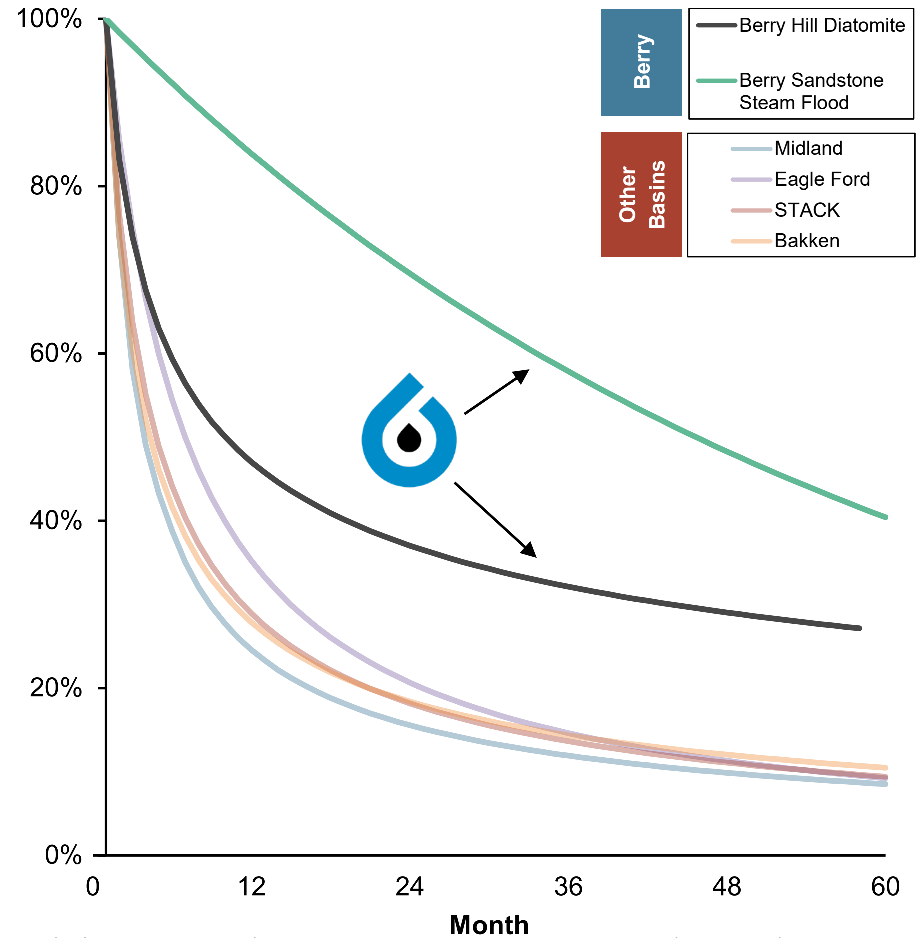
Powered by Our Principals and Assets

Highly Oil Weighted	■ Low production declines with stable operational costs influenced by Brent pricing creates high margins ■ Mix for 2019 will average 87% oil
Substantial Inventory	■ Management believes we have over 20 years of high returning inventory ■ 2018 third party reserve report shows our R/P ratio is 14.5 years and our reserve replacement ratio in California is 275%
Operational Control and Stable Cost Structure	■ Well results are generally predictable, repeatable and present lower risk than unconventional resource plays - decades of historical data ■ Largest cost is steam at 40-45% of OPEX. We hedge purchased gas and gain efficiencies from our cogeneration facilities
Focused on Geography, Skill Sets and HSE	■ In California, three large fields on westside of the San Joaquin Basin ■ Thermal recovery from heavy oil in shallow reservoirs ■ Generations of knowledge and experienced employees ■ Built a culture of "Safety First"
Balance Sheet Strength	■ Committed to maintain low leverage through the price cycle ■ Fund all organic growth with levered free cash flow ■ Committed to return capital to shareholders

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)

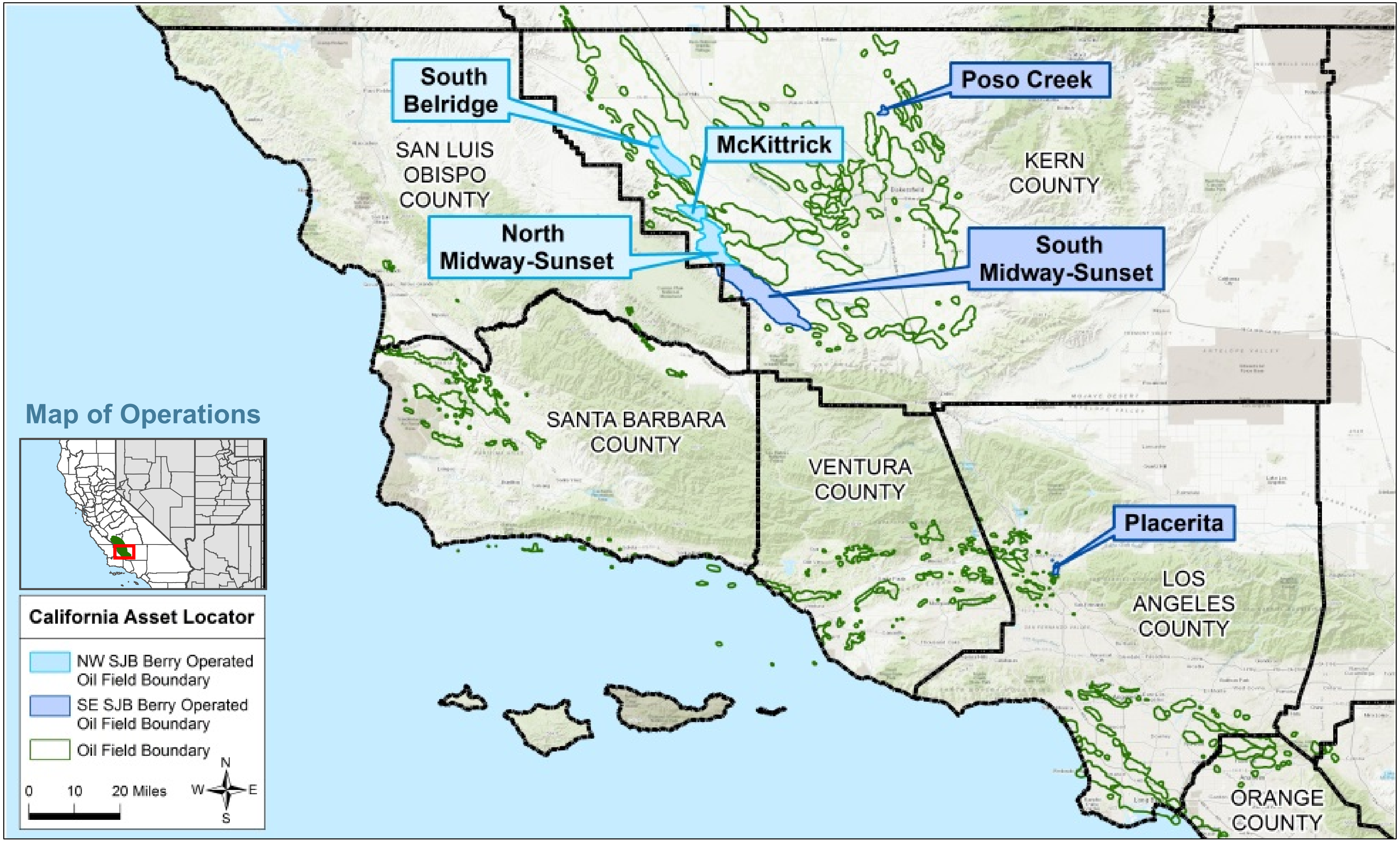


Source: Berry internal database, Third-party Company Presentations
Note: Berry Sandstone Steam Flood reaches peak production after approximately 12 months. Time period shown for Sandstone is shown from peak production and onward. The initial rate of production from peak production is determined using 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.

We Are Broadly Advantaged vs. Unconventional Resource Players

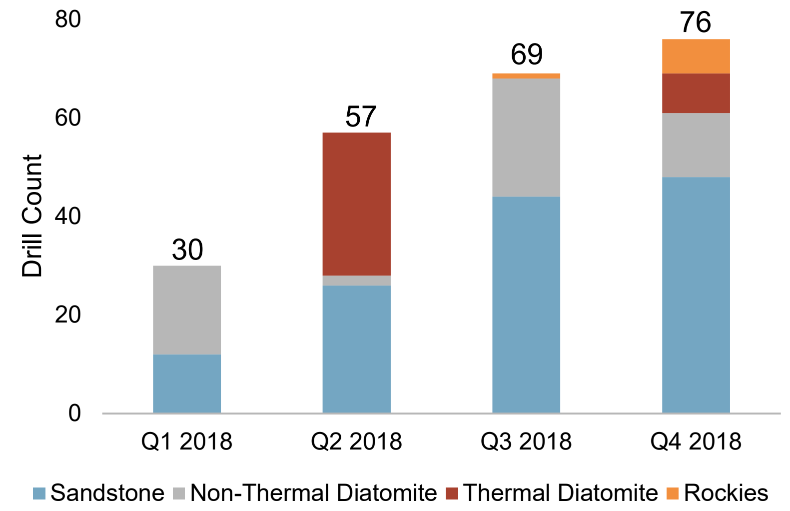
	Berry	Resource / Shale Players	*The Berry Benefit*
Production History	Decades of History	Still Learning	✓
Production Declines	Low	High	✓
IP Rates	Lower	Higher	✗
Capital and Service Cost Intensity	Low	Higher (i.e. "Big fracs")	✓
Operating Cost Stability/ Predictability	Stable	Experiencing Inflation	✓
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	✓

Focused on Our California San Joaquin Basin Assets

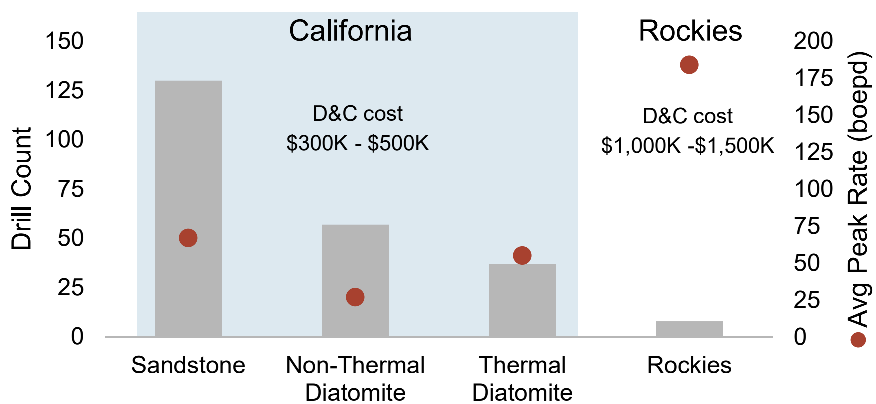


2018 Drilling Results & California Production

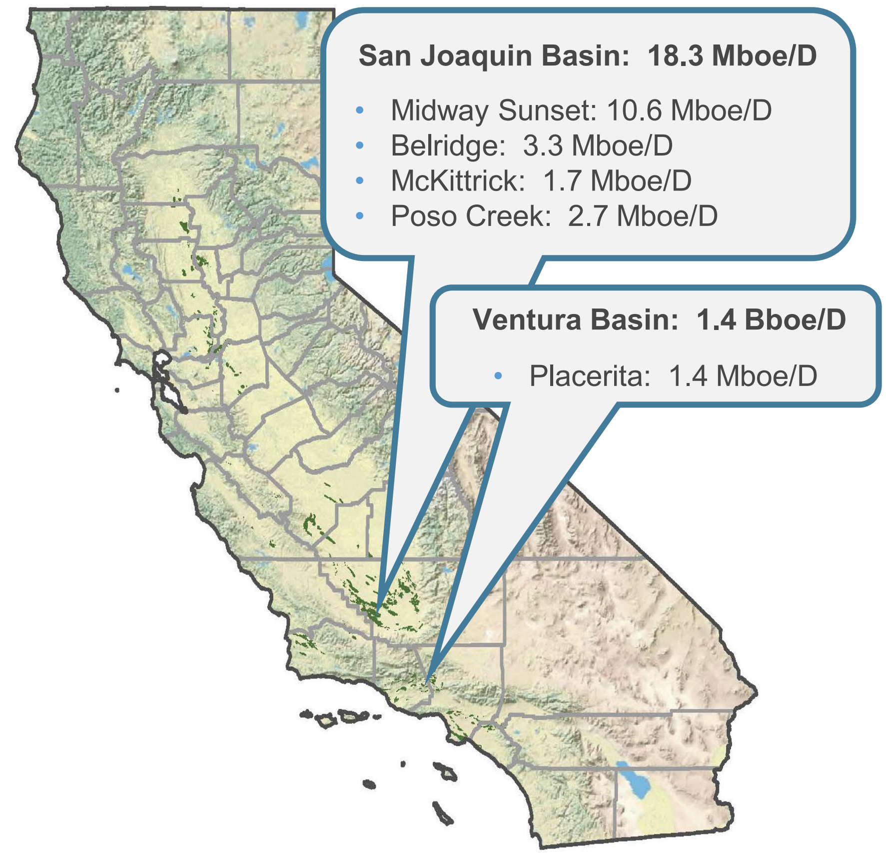
2018 Drilling Program



2018 Drilling Results



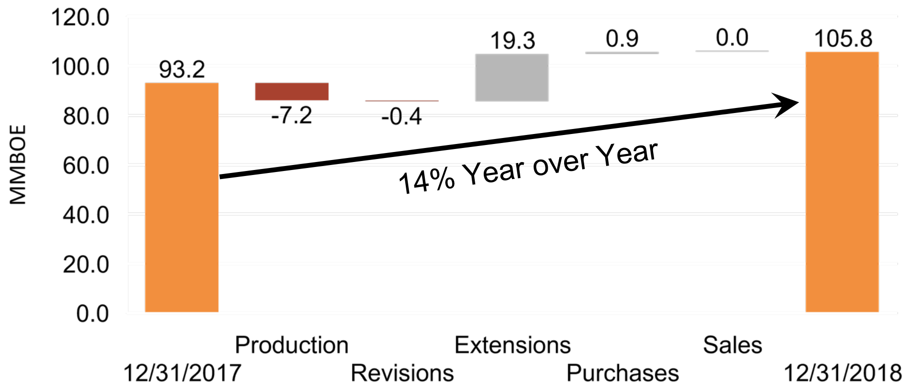
California Asset Map



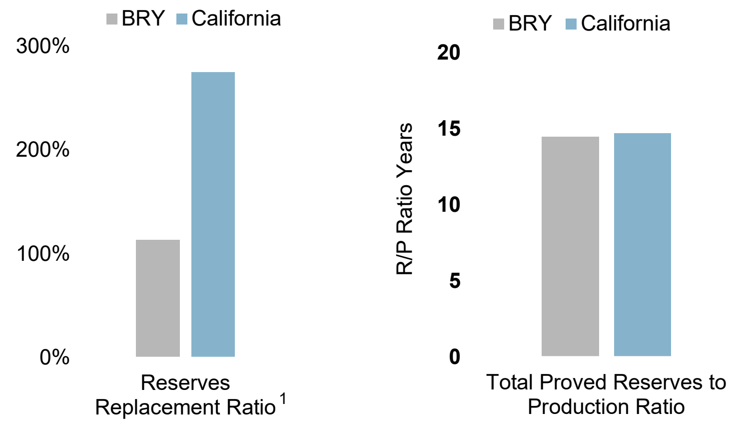
Proved Reserves

YE 2018 Results – D&M View of Assets

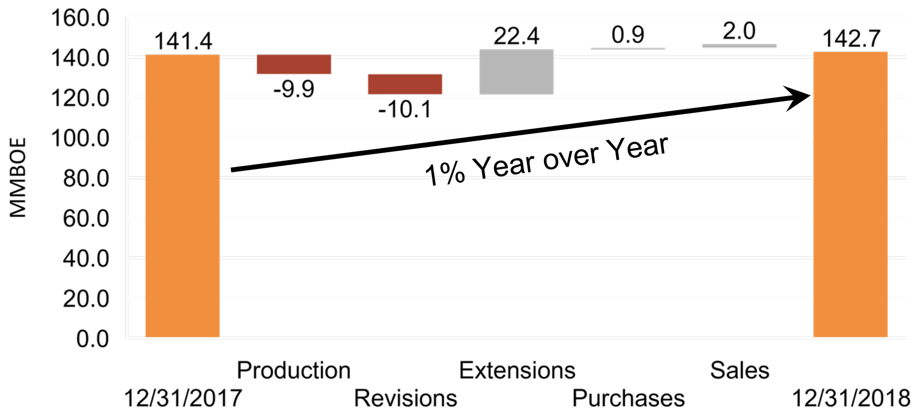
California Reserve Reconciliation



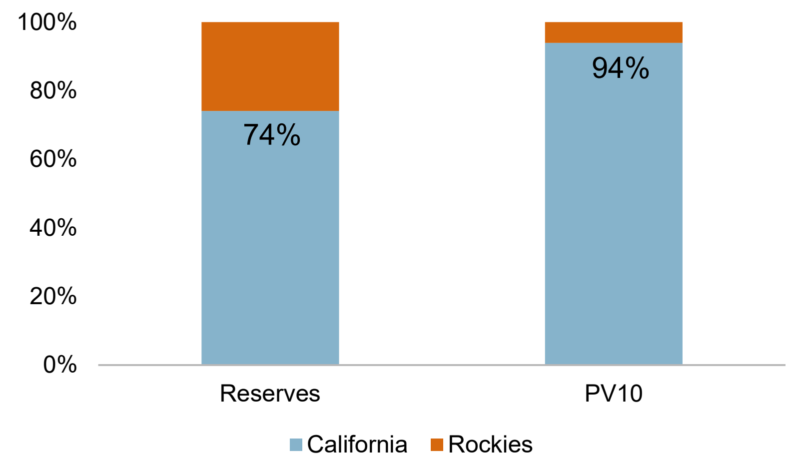
Replacement Metrics



Total Berry Reserve Reconciliation

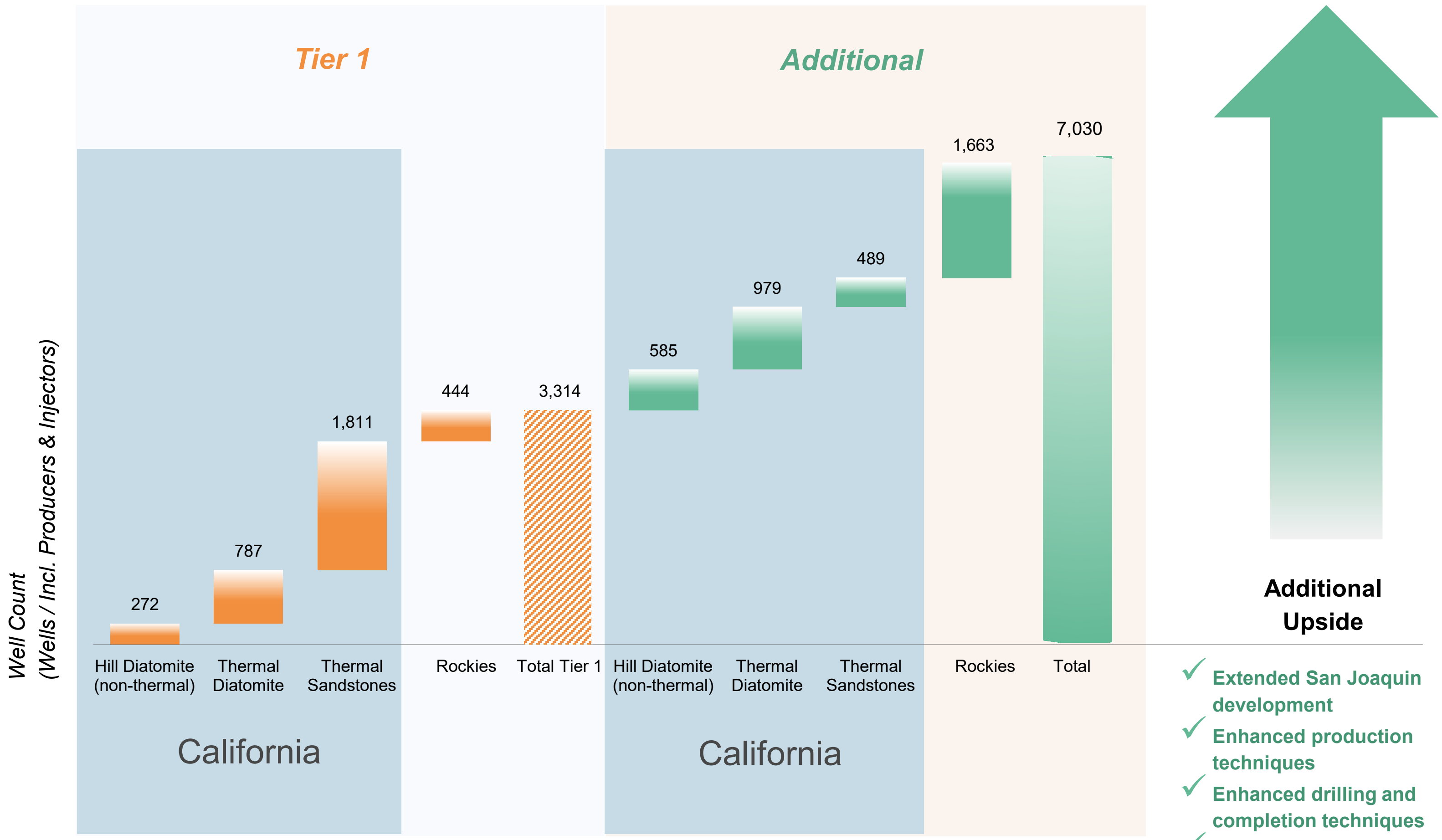


Reserves & Value



[1]See Appendix for Non-GAAP reconciliations

Significant California Inventory

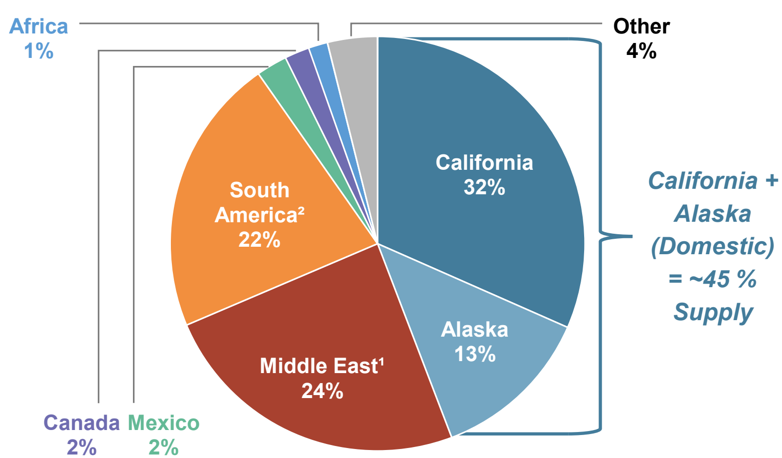


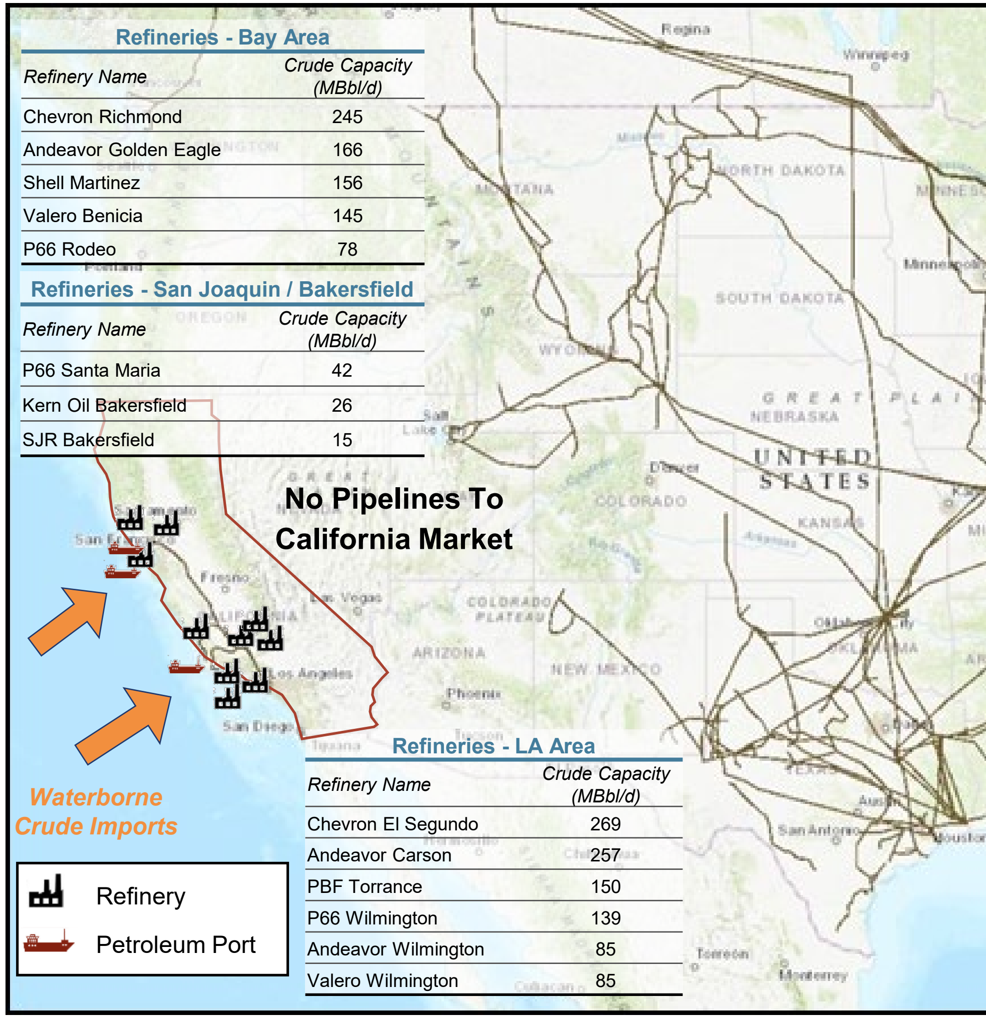
- ✓ Extended San Joaquin development
- ✓ Enhanced production techniques
- ✓ Enhanced drilling and completion techniques
- ✓ Cost / efficiencies upside

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

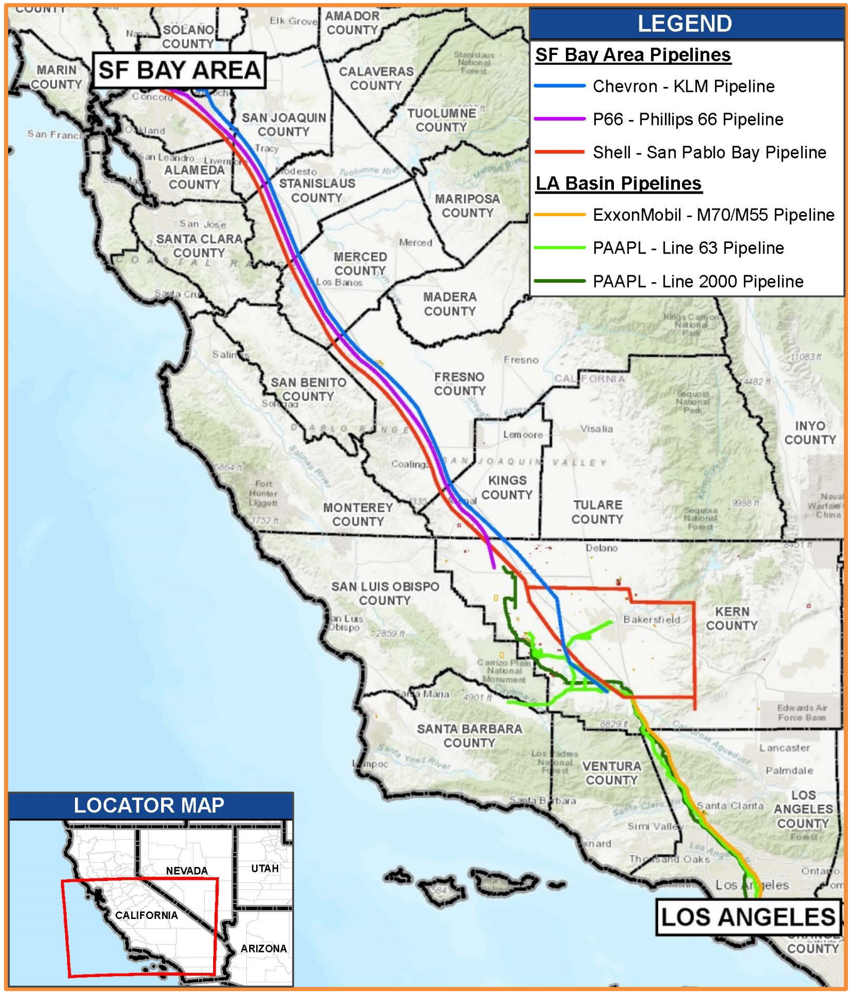
Source: California Almanac

[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.

We Have Significant Financial Flexibility Across Oil Price Scenarios

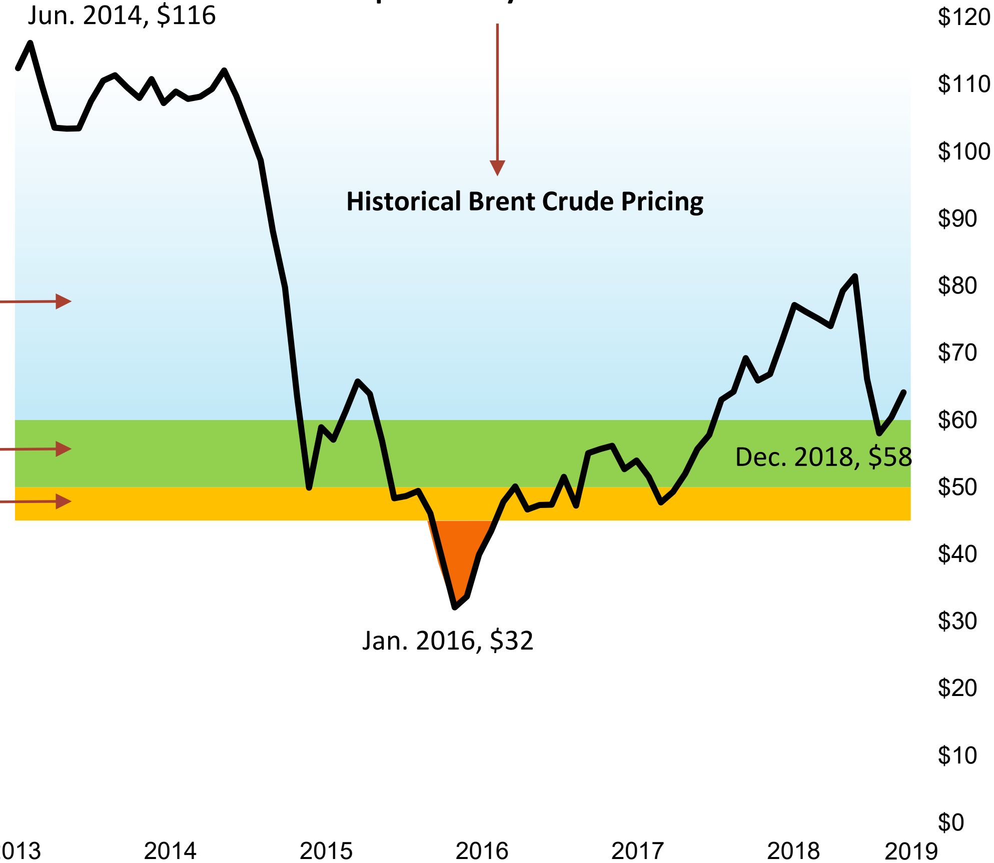
Simple financial principles and planned allocations...

Applied rationally across the price cycle

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*

Key Company Highlights

	Q4 2018		Full-year 2018	
79% directed to development capital in California	$53 MM	Capital Expenditures	$148 MM	88% directed to development capital in California
	76	Wells Drilled	232	
85% Oil 78% in California	28.0	Production Mboe/D	27.0	82% Oil 73% in California
	$82 MM	Adjusted EBITDA[1]	$258 MM	

[1] See Appendix for Non-GAAP reconciliations

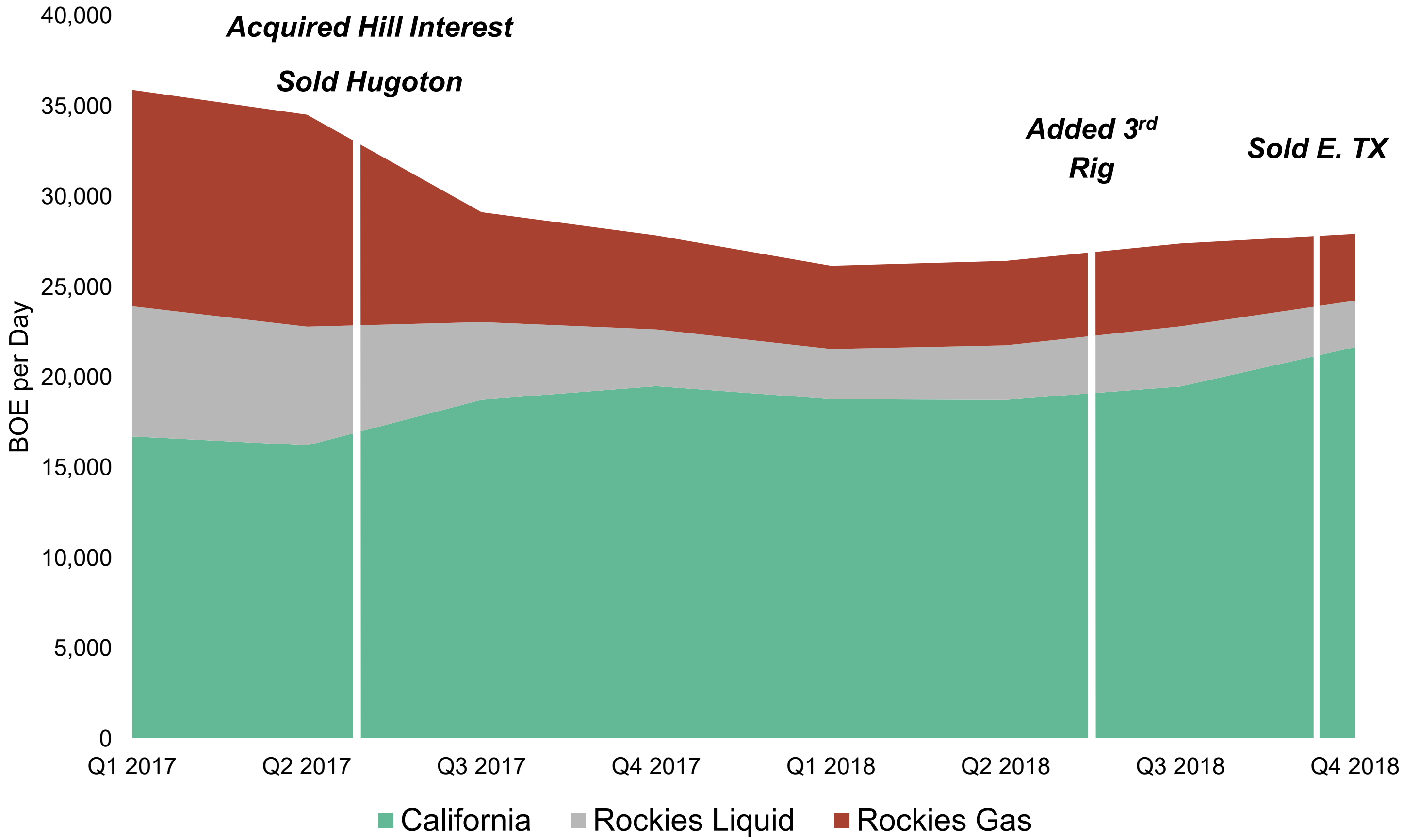
Key Area Highlights (Excludes E. Texas)

	2018 California		2018 Rockies[1]
93% from California	$227 MM	Operating Income[2]	$19 MM
100% Oil	19.7	Daily Production	6.7
88% in California	$126	Capital Expenditures	$17
74% in California	106	Proved Reserves	37
94% in California	$2,027 MM	PV-10[3]	$125 MM

[1] Excludes E. Texas [2]Operating income includes oil, natural gas and NGL sales, offset by operating expenses, general and administrative expenses, DD&A, and taxes, other than income taxes. [3]See Appendix for Non-GAAP reconciliations

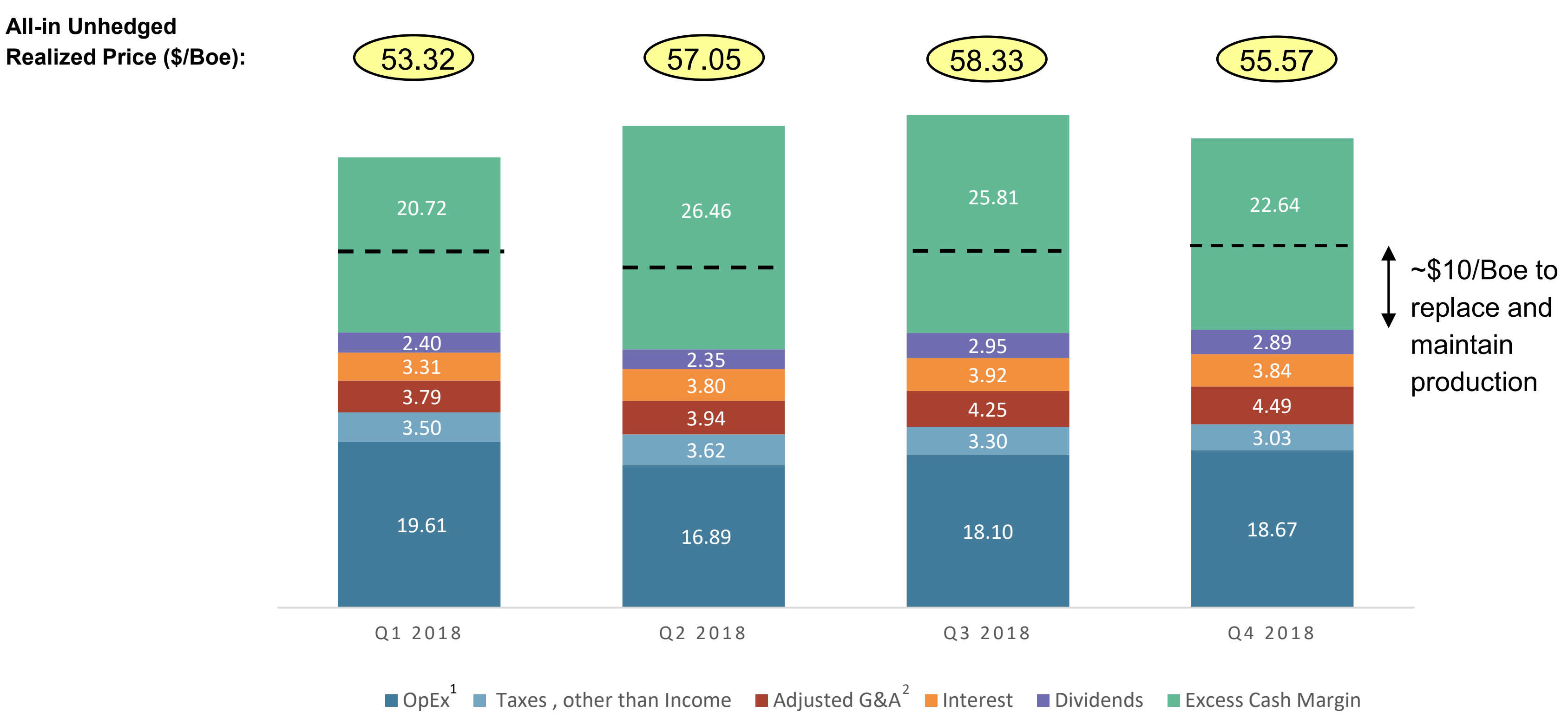
Berry Total Production

- California continues to be our focus with investment of 88% of 2018 development capital
  - California grew 11% year over year and 15% January to December 2018
  - 2018 Total company production is 27.0 Mboe/D



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

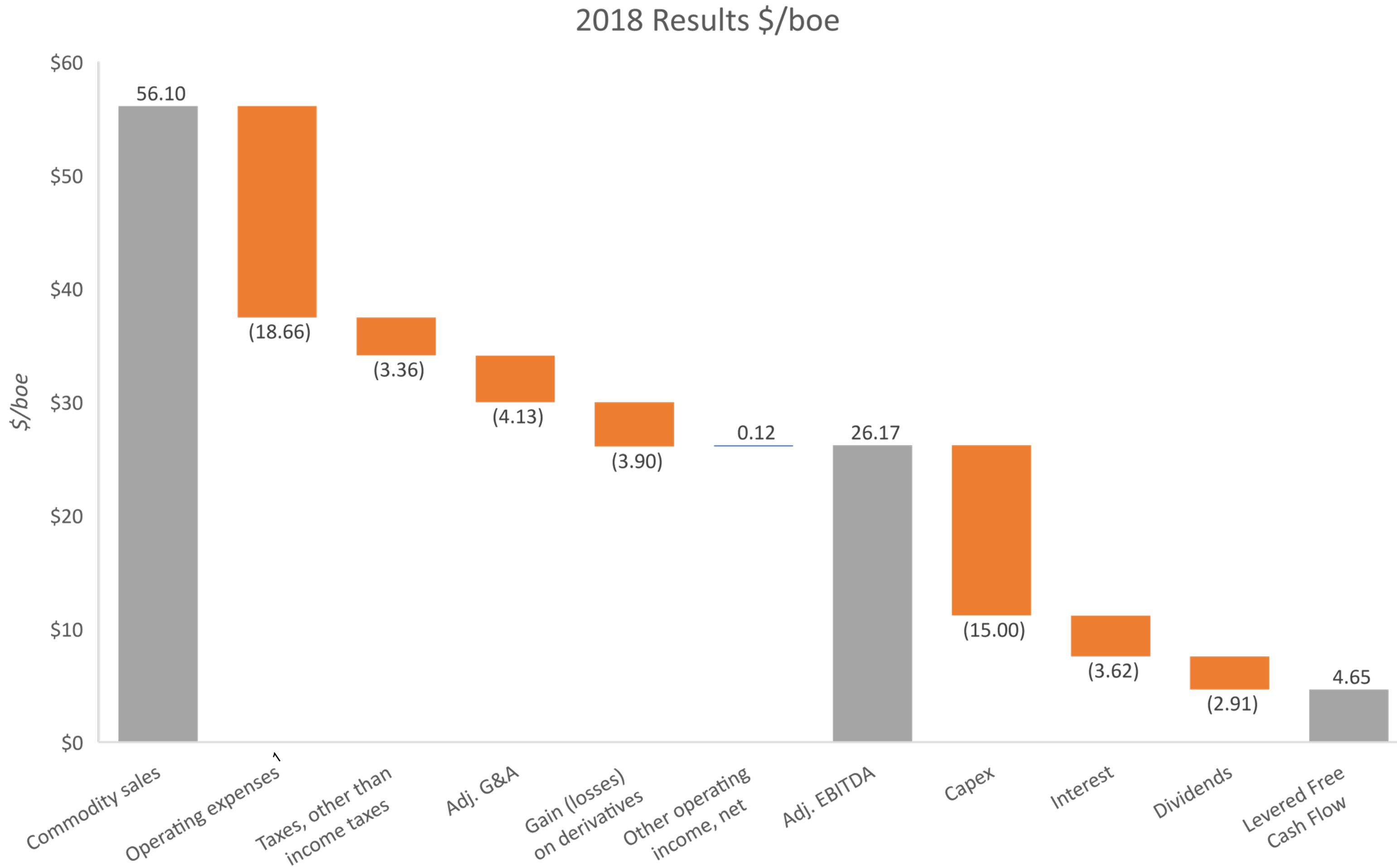
Total Company Margin



[1] *We define Operating Expenses as LOE, electricity expense, transportation expense, and marketing expense, net of electricity, transportation and marketing sales, as well as derivative settlements (received or paid) for gas purchases.*

[2] *See Appendix for the reconciliation of the Non-GAAP financial measure Adjusted G&A.*

Our calculation of Levered Free Cash Flow (Hedged)



[1] *We define Operating Expenses as LOE, electricity expense, transportation expense, and marketing expense, net of electricity, transportation and marketing sales, as well as derivative settlements (received or paid) for gas purchases.*

See Appendix for a reconciliation to GAAP for Adjusted EBITDA, Adjusted G&A, and Levered Free Cash Flow

Key 2018 Financial Metrics

Leverage	Interest Coverage	PV-10/Debt	Debt/Proved Reserves ($/Boe)	CROIC
1.5x	7.2x	5.5x	$2.75	20%

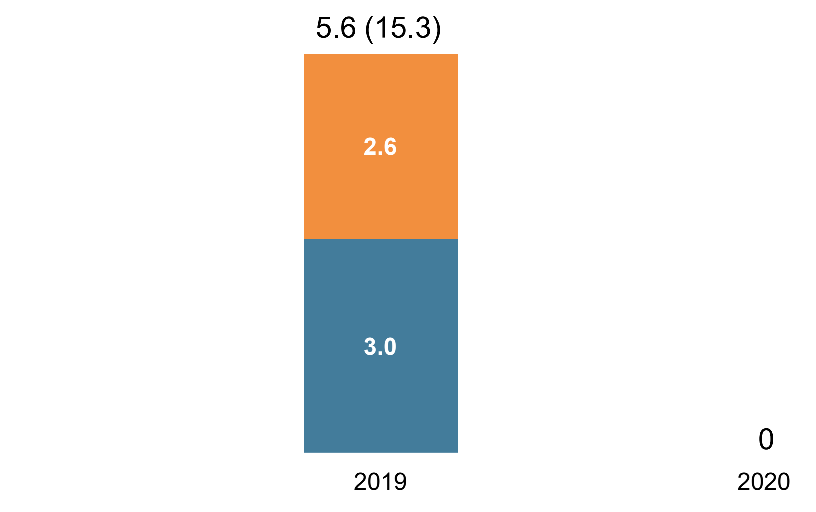
Leverage ratio = Long-term Debt / Adj. EBITDA
Interest coverage = Adj. EBITDA / Interest expense
Proved Reserves and PV-10 estimates are based on SEC'18 prices of $71.50 Brent / $3.10 Henry Hub
CROIC: Cash Returned on Invested Capital = (Net cash provided by operating activities before working capital + Interest + non-recurring items) divided by (Average Stockholder's Equity + Average Debt)
(See Appendix for a reconciliation to GAAP for Adjusted EBITDA, PV-10, and CROIC)

Prudent & Proactive Commodity Price Risk Management

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

Hedging Volumes in MMBls (MBbl/d)

As of Feb 28, 2019



Brent Swaps*	$76.09
Brent Puts	$57.90

2019 Gas hedging: 17.5 mmbtu/day at $2.68 on a weighted-average basis

** Excludes Basis Swaps*

Revised 2019E Guidance[1]

- Reduced capital spending by $35 million or 14% with a little more than a 3% decrease in production
- Eliminated spending in the Rockies, adjusted CA capital
- Included CROIC ranges

Category	2019E Guidance		
	Low		High
Average Daily Production (MBoe/d)	28		31
% Oil		~ 87%	
Operating Expenses ($/Boe)	$ 18.00	.	$ 19.50
Taxes, Other than Income Taxes ($/Boe)	$ 4.25	.	$ 4.75
Adjusted General & Administrative Expenses ($/Boe)	$ 4.25	.	$ 4.75
Capital Expenditures ($ millions)	$ 195	.	$ 225
CROIC	18%	.	24%

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.

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 amounts ■ Targeting an attractive dividend payout ratio
Capital Spend	■ Fund maintenance & organic growth opportunities while producing positive Levered Free Cash Flow ■ 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

Concluding Remarks

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

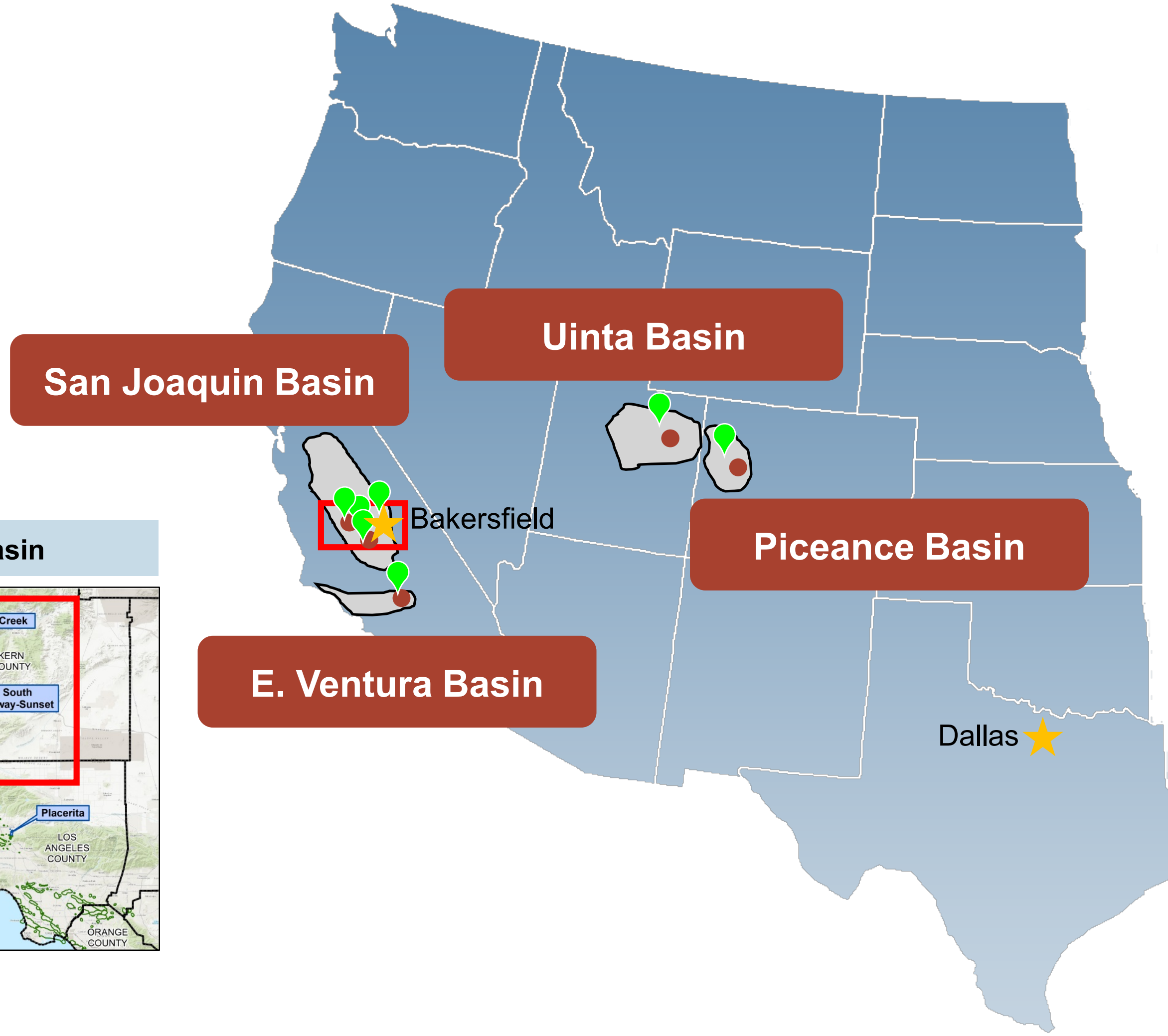
Highly Differentiated from Public Conventional and Shale E&P Companies	✓
Positive Levered Free Cash Flow Through the Cycle	✓
Stable Oil-Weighted Asset Base	✓
Long Inventory Life of Highly Economic Oil Locations	✓
Predictable Cost Structure	✓
Strategic and Organic Growth Opportunities	✓
Benefit from Favorable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

Appendix

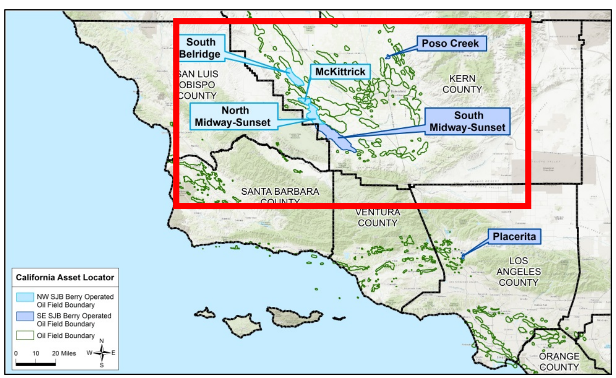
Berry's Poso Creek field, California

Operational Areas – Focused in California Super Basin

★ Corporate & Executive Office
● Division Offices
Producing Assets
☐ Basin Boundary



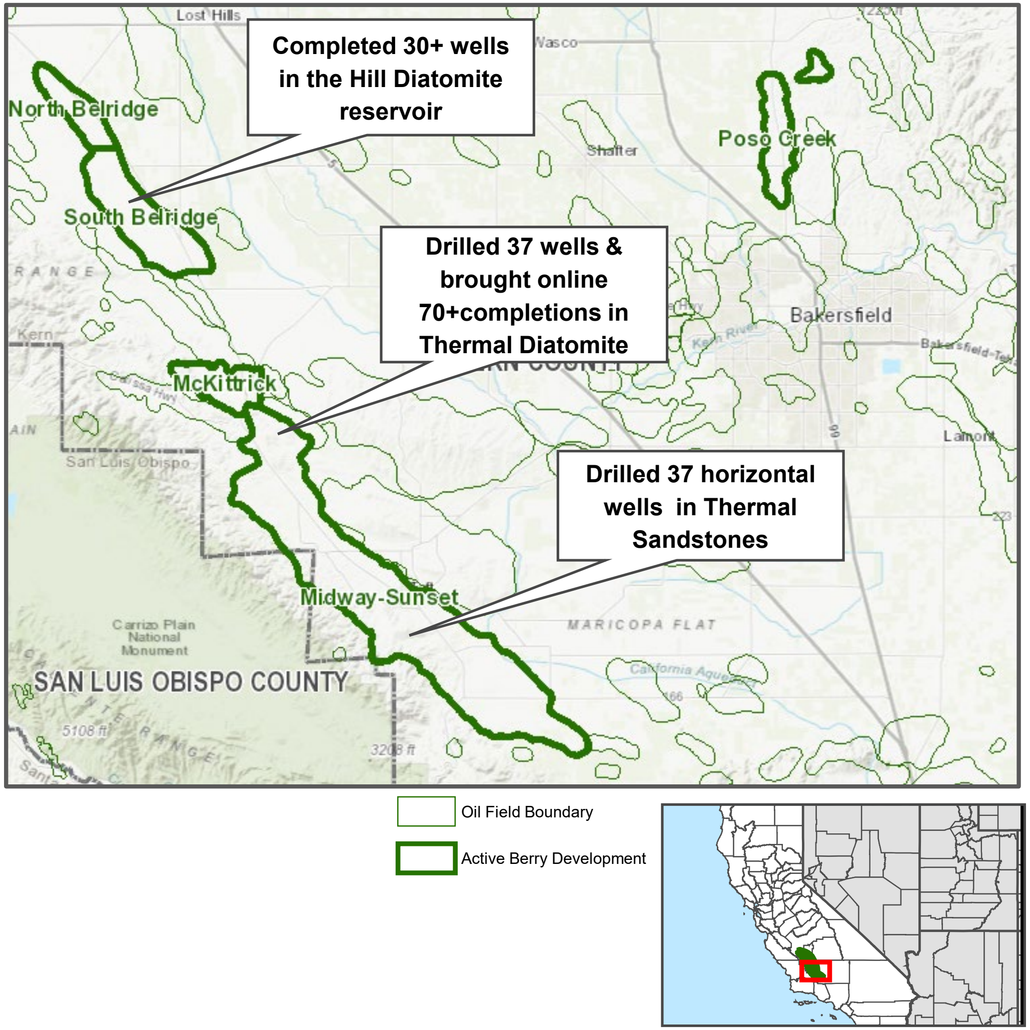
Southern San Joaquin Basin



Key Operational Activities

- Development is primarily in the San Joaquin Basin
- 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:
  - Brought the 2nd quarter 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 activity:
  - Completed an additional 18 Hill Diatomite producers in South Belridge (14 producers, 4 injectors)
  - Drilled 48 wells in thermal sandstone reservoirs at Midway Sunset, McKittrick, Poso and S. Belridge, including 9 additional horizontal producers in Midway Sunset
  - Drilled 8 and recompleted 13 thermal Diatomite wells in Midway Sunset
  - Drilled an additional 7 Green River/Wasatch producers in Utah

Notable California Development Programs in 2018



Non-GAAP Reconciliation
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 Unhedged.

Adjusted EBITDA (in thousands)	**Twelve Months Ended December 31, 2018**	**Three Months Ended December 31, 2018**	**Three Months Ended September 30, 2018**	**Three Months Ended June 30, 2018**	**Three Months Ended March 31, 2018**
Net income (loss)	$ 147,102	$ 131,768	$ 36,985	$ (28,061)	$ 6,410
Add (Subtract):					
Interest expense	$ 35,648	$ 8,820	$ 9,877	$ 9,155	$ 7,796
Income tax expense (benefit)	$ 43,035	$ 39,890	$ 7,683	$ (5,476)	$ 939
DD&A and Accretion	$ 86,271	$ 24,253	$ 21,729	$ 21,859	$ 18,429
Derivative (gains) losses	$ (1,735)	$ (131,637)	$ 17,115	$ 78,143	$ 34,644
Net cash received (paid) for scheduled derivative settlements	$ (38,482)	$ 8,679	$ (1,052)	$ 28,261	$ (17,849)
Gains (losses) on sale of assets and other	$ (2,747)	$ (3,269)	$ 400	$ 123	$ -
Stock Compensation Expense	$ 6,750	$ 3,249	$ 1,182	$ 1,278	$ 1,042
Restructuring/non-recurring costs	$ 6,773	$ 1,414	$ 1,598	$ 1,714	$ 2,047
Reorganization items	$ (24,690)	$ (1,498)	$ (13,781)	$ (456)	$ (8,955)
Adjusted EBITDA	$ 257,925	$ 81,669	$ 81,736	$ 50,018	$ 44,503
MBOE	9,855	2,571	2,520	2,407	2,356
Adjusted EBITDA per BOE	$ 26.17	$ 31.76	$ 32.43	$ 20.78	$ 18.89

Non-GAAP Reconciliation
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 Unhedged.

	Year Ended December 31, 2018	
Net cash provided (used) by operating activities	$	103,100
Add (Subtract):		
Cash interest payments		19,761
Cash income tax (receipts) payments		(1,901)
Cash reorganization item (receipts) payments		832
Non-recurring restructuring and other costs		6,773
Derivative early termination payment		126,949
Other changes in operating assets and liabilities		2,410
Other, net		—
Adjusted EBITDA	$	257,924
Net cash (received) paid for scheduled derivative settlements		38,482
Adjusted EBITDA unhedged	$	296,406

Non-GAAP Reconciliation - Levered Free Cash Flow

($ thousands)	Quarter Ended December 31, 2018	Year Ended December 31, 2018
Adjusted EBITDA	$ 81,669	$ 257,924
Subtract:		
Capital expenditures - accrual basis	(53,326)	(147,831)
Interest expense	(8,820)	(35,648)
Dividends	(9,992)	(28,658)
Levered free cash flow	$9,531	$45,787
Net cash (received) paid for scheduled derivative settlements	(8,679)	38,482
Levered free cash flow unhedged	$ 852	$ 84,269
Total Mboe	2,571	9,855
Per BOE	$ 3.71	$ 4.65

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.

Berry Petroleum Corporation
Adjusted G&A calculation
(Unaudited)

(in thousands, except per BOE amounts)	Twelve Months Ended December 31, 2018	Three Months Ended December 31, 2018	Three Months Ended September 30, 2018	Three Months Ended June 30, 2018	Three Months Ended March 31, 2018
G&A expense	$ 54,026	$ 16,130	$ 13,429	$ 12,482	$ 11,985
less: Non-recurring restructuring costs	$ (6,773)	$ (1,414)	$ (1,598)	$ (1,714)	$ (2,047)
less: Stock compensation expense (G&A portion)	$ (6,585)	$ (3,183)	$ (1,125)	$ (1,260)	$ (1,019)
Adjusted G&A	$ 40,668	$ 11,533	$ 10,706	$ 9,508	$ 8,919
MBOE	9,855	2,571	2,520	2,408	2,356
Adjusted G&A per BOE	$ 4.13	$ 4.49	$ 4.25	$ 3.94	$ 3.79

Non-GAAP Reconciliation - Cash Return on Invested Capital

(in thousands)	Twelve Months Ended December 31, 2018
Cash Return on Invested Capital:	
Net cash provided by operating activities	$ 103,100
Subtract:	
Changes in working capital	(8,658)
Add:	
Interest expense	35,648
Cash payments on early-terminated derivatives	126,949
Non-recurring restructuring and other costs	6,773
Cash return	$ 263,812
Divided by: Avg. Stockholder's Equity + Avg. Debt	1,318,271
CROIC	20%

Note: Stockholder's Equity plus Debt is an average of the current and prior periods

Non GAAP Reconciliation for PV-10

	At December 31, 2018
	(in millions)
California PV-10	$ 2,027
Rockies PV-10	125
Total Company PV-10	2,152
Less: present value of future income taxes discounted at 10%	(390)
Standardized measure of discounted future net cash flows	$ 1,762

Non-GAAP Reconciliation - Reserve Replacement and Costs

	Total Company	California
	(in MMBoe, except ratio and cost amounts)	
Extensions and discoveries (B)	22.4	19.3
Revisions of previous estimates	(10.1)	(0.4)
Purchases of minerals	0.9	0.9
Organic changes (C)	13.2	19.8
Sales of minerals	(2.0)	—
Total reserves changes	11.2	19.8
Production	9.9	7.2
Reserve replacement ratio	114%	275%
Costs incurred (development costs)(A) ($ millions)	$143.0	
Finding & Development costs per Boe		
All-In (A)/(C)	$10.83	
Program (A)/(B)	$6.38	

(a) All costs incurred in 2018 were development costs.

Non-GAAP Reconciliation - Reserves and PV-10

	December 31, 2018		
	California (San Joaquin and Ventura basins)	Rockies (Uinta and Piceance basins)	Total
Proved developed reserves:			
Oil (MMBbl)	66	7	73
Natural Gas (Bcf)	—	76	76
NGLs (MMBbl)	—	1	1
Total (MMBoe)(a)	66	21	87
Proved undeveloped reserves:			
Oil (MMBbl)	40	2	42
Natural Gas (Bcf)	—	85	85
NGLs (MMBbl)	—	—	—
Total (MMBoe)(a)	40	16	56
Tot**al proved reserves:**			
Oil (MMBbl)	106	9	115
Natural Gas (Bcf)	—	161	161
NGLs (MMBbl)	—	1	1
Total (MMBoe)(a)	106	37	143
PV-10 ($MM)(b)	$2,027	$125	$2,152

(a) Natural gas volumes have been converted to Boe based on energy content of six Mcf of gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in the year ended December 31, 2018, the average prices of ICE (Brent) oil and NYMEX (Henry Hub) natural gas were $71.53 per Bbl and $3.09 per Mcf, respectively, resulting in an oil-to-gas ratio of over 4 to 1 on an energy equivalent basis.(b) For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flows, please see "Non-GAAP Financial Measures and Reconciliations—PV-10." PV-10 does not give effect to derivatives transactions.

Thank you!

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