NEWS RELEASE **For Immediate Release**

California Resources Corporation Announces Fourth Quarter 2018 and Full Year Results

LOS ANGELES, February 27, 2019 - California Resources Corporation (NYSE: CRC), an independent California-based oil and gas exploration and production company, today reported net income attributable to common stock (CRC net income) of $346 million, or $7.00 per diluted share, for the fourth quarter of 2018. Adjusted net income[1] for the fourth quarter of 2018 was $26 million, or $0.53 per diluted share. For the full year of 2018, CRC net income was $328 million, or $6.77 per diluted share. Adjusted net income[1] for the full year of 2018 was $61 million, or $1.27 per diluted share.

Adjusted EBITDAX[1] for the fourth quarter of 2018 was $314 million and $1,117 million for the full year of 2018. Cash provided by operating activities was $68 million for the fourth quarter of 2018 and $461 million for the full year of 2018, or an 86% increase over the full year $248 million in 2017.

Quarterly Highlights

- Produced an average of 136,000 barrels of oil equivalent (BOE) per day, an increase of 8% over the prior year period
- Produced an average of 86,000 barrels of oil per day, an increase of 8% over the prior year period
- Generated core adjusted EBITDAX[1] of $352 million, which excludes $50 million of net settlement payments on commodity derivative contracts offset by $12 million related to cash-settled stock-based compensation
- Reported adjusted EBITDAX[1] of $314 million and an adjusted EBITDAX margin[1] of 41%
- Invested $197 million of total capital, including internally funded capital of $174 million with the remainder funded by joint venture (JV) partners
- Drilled 86 wells with internally funded capital and five wells with JV capital

Full Year Highlights

- Produced an average of 132,000 BOE per day, an increase of 2% over the prior year
- Generated core adjusted EBITDAX[1] of $1,374 million, which excludes $228 million of net settlement payments on commodity derivative contracts and $29 million related to cash-settled stock-based compensation
- Reported adjusted EBITDAX[1] of $1,117 million and an adjusted EBITDAX margin[1] of 39%

- Invested $747 million of total capital, including internally funded capital of $641 million with the remainder funded by JV partners
- Drilled 237 wells with internally funded capital and 106 wells with JV capital
- Implemented $34 million of annualized synergies in the nine months following the Elk Hills acquisition, significantly exceeding the initial target of $20 million in a shorter time frame than expected

Todd A. Stevens, CRC's President and Chief Executive Officer, said, "In 2018, our strategic approach focused on capturing the full value of our portfolio, driving operational excellence, efficiently and effectively allocating capital, and strengthening the balance sheet. We made good progress on each priority, increasing the impact of our investment program and delivering 8% growth in oil production from the fourth quarter of 2017 to the fourth quarter of 2018. We invested in value-driven activity to develop our core and growth areas with the support of strategic JV capital, in addition to successfully resuming our exploration program. We also harnessed our operating expertise to generate more synergies than expected around the consolidation of our flagship Elk Hills asset. We are entering 2019 with a internally funded capital program of $300 to $385 million, which we will adjust to align our financial and operating plans to market conditions. We are also in discussions to obtain additional investments from new and existing JV partners that could increase our capital program by $100-$150 million to support a total capital budget of approximately $500 million. This will allow us to maintain activity and efficiency gains, while retaining a high degree of operational flexibility. Supported by our diverse asset base, high level of operating control and dynamic business model, we expect to continue to deliver meaningful value for our shareholders in 2019 and beyond."

Fourth Quarter 2018 Results

For the fourth quarter of 2018, CRC net income was $346 million, or $7.00 per diluted share, compared to a net loss attributable to common stock (CRC net loss) of $138 million, or $3.23 per diluted share for the same period of 2017. Adjusted net income[1] for the fourth quarter of 2018 was $26 million, or $0.53 per diluted share, compared with an adjusted net loss[1] of $14 million, or $0.33 per diluted share for the same prior year period. The 2018 results reflected increased production and higher realized commodity prices for oil and natural gas compared to 2017. The fourth quarter of 2018 adjusted net income[1] excluded $295 million of non-cash derivative gains on commodity contracts, a $6 million non-cash derivative loss from interest-rate contracts and a net gain of $31 million on debt repurchases.

Total daily production volumes averaged 136,000 BOE per day for the fourth quarter of 2018, compared to 126,000 BOE per day for the fourth quarter of 2017, an increase of 8%, largely driven by the Elk Hills acquisition in the second quarter of 2018. For the fourth quarter of 2018, oil volumes averaged 86,000 barrels per day, NGL volumes averaged 16,000 barrels per day and gas volumes averaged 204,000 thousand cubic feet (MCF) per day. Organically, oil production grew over 1,000 barrels per day from the third quarter of 2018 to the fourth quarter of 2018, excluding the effects of production sharing-type contracts (PSCs) and acquisitions.

Realized crude oil prices, including the effect of settled hedges, increased by $3.05 per barrel for the fourth quarter of 2018 to $59.97 per barrel from the same prior year period. Settled hedges decreased realized crude oil prices by $6.15 per barrel for the fourth quarter of 2018. Average realized NGL prices registered $43.56 per barrel, reflecting a realized price that was 64% of Brent prices. Realized natural gas prices were $3.77 per MCF for the fourth quarter of 2018, $1.00 higher than the same prior year period. The increase in realized gas prices resulted from the effects of limited third-party storage and pipeline constraints.

Production costs for the fourth quarter of 2018 were $233 million, or $18.61 per BOE, compared to $227 million, or $19.64 per BOE, for the fourth quarter of 2017. In line with industry practice for reporting PSCs, CRC reports gross field operating costs, but only CRC's share of production volumes, which results in higher production costs per barrel. Excluding this PSC effect, per unit production costs[1] for the fourth quarter of 2018 would have been $17.44 per BOE compared to $18.31 for the same prior year period. The decrease in production costs per BOE was primarily driven by higher production between comparative periods, largely related to the Elk Hills acquisition. Elk Hills' production costs are lower than the average CRC-wide production cost per barrel. As a result, the Elk Hills acquisition had a favorable effect on production cost per barrel. General and administrative expenses (G&A) were $65 million for the fourth quarter of 2018 compared to $66 million for the prior year period.

CRC reported taxes other than on income of $29 million for the fourth quarter of 2018 compared to $33 million for the same prior year period. Exploration expense was $16 million for the fourth quarter of 2018, $11 million higher than the same prior year period due to exploration dry holes.

CRC's internally funded capital investment for the fourth quarter of 2018 totaled $174 million, of which $119 million was directed to drilling and capital workovers. CRC's JV partner Benefit Street Partners LLC (BSP) funded $12 million, which is included in CRC's consolidated results, while JV partner Macquarie Infrastructure and Real Assets Inc. (MIRA) funded an additional $11 million of investment, which is excluded from our consolidated results.

Cash provided by operating activities was $68 million for the fourth quarter of 2018, which included interest payments of $157 million.

Full Year 2018 Results

For the full year of 2018, CRC net income was $328 million, or $6.77 per diluted share, compared to a CRC net loss of $266 million, or $6.26 per diluted share, for the full year of 2017. Adjusted net income[1] for 2018 was $61 million, or $1.27 per diluted share, compared with an adjusted net loss[1] of $187 million, or $4.40 per diluted share, for 2017. The 2018 results reflected significantly higher realized prices and higher production, partially offset by increased production costs, as well as higher G&A and interest expense. The 2018 adjusted net income[1] excluded $224 million of non-cash derivative gains on commodity contracts, a net gain of $57 million on debt repurchases, a $6 million non-cash derivative loss from interest rate contracts, a $5 million gain on asset divestitures and a net $13 million charge related to other unusual and infrequent items. The 2017 adjusted net loss[1] excluded $78 million of non-cash derivative losses, $21 million of gains from asset divestitures, a $4 million net gain on debt repurchases and a $26 million net charge from other unusual and infrequent items.

Total daily production volumes averaged 132,000 BOE per day for the full year of 2018 compared with 129,000 BOE per day for 2017. This net increase included a 1,300 barrel per day negative PSC effect on production volumes due to higher realized prices for 2018. Oil volumes averaged 82,000 barrels per day, NGL volumes averaged 16,000 barrels per day and gas volumes averaged 202,000 MCF per day.

Realized crude oil prices, including the effect of settled hedges, increased $11.36 per barrel to $62.60 per barrel for the full year 2018 from $51.24 per barrel for 2017. Settled hedges reduced 2018 realized crude oil prices by $7.51 per barrel compared with a $0.23 decrease per barrel for 2017. Realized NGL prices increased 22% to $43.67 per barrel for 2018 from $35.76 per barrel for 2017. Realized natural gas prices increased 12% to $3.00 per MCF for 2018 compared with $2.67 per MCF for 2017.

Production costs for the full year of 2018 were $912 million, or $18.88 per BOE, compared to $876 million, or $18.64 per BOE, for 2017. The Elk Hills acquisition and cash-settled stock-based compensation added $38 million and $4 million to full year production costs for 2018, respectively. Synergies captured from the Elk Hills consolidation reduced production costs by $17 million, partially offset by an increase in energy costs. Per unit production costs, excluding the effect of PSC contracts[1], were $17.47 and $17.48 per BOE for the full year of 2018 and 2017, respectively. G&A expenses were $299 million and $249 million for the full year of 2018 and 2017, respectively, with the difference primarily related to increased equity compensation expense resulting from CRC's higher stock price, as well as additional G&A expense as a result of lower cost recovery following the Elk Hills acquisition.

Taxes other than on income of $149 million for 2018 were $13 million higher than 2017, primarily due to higher greenhouse gas (GHG) costs related to annual price increases, in addition to a reduction in the number of allowances granted to CRC between periods. CRC reported exploration expenses of $34 million for the full year of 2018, or $12 million higher than 2017, due to exploration dry holes.

CRC's internally funded capital investment for 2018 totaled $641 million, of which $445 million was directed to drilling and capital workovers. CRC's JV partner BSP funded an additional $49 million, which is included in CRC's consolidated results, while JV partner MIRA funded an additional $57 million of investment, which is excluded from our consolidated results.

Cash provided by operating activities for the full year of 2018 was $461 million, which included interest payments of $441 million and $98 million of GHG payments related to prior years' allowances.

Operational Update

CRC operated an average of 10 drilling rigs during the fourth quarter of 2018 with five rigs focused on waterfloods, three on conventional primary production, one on steamfloods and one on unconventional production. CRC drilled 90 development wells and one exploration well with CRC and JV capital (33 steamflood, 38 waterflood, 13 primary and 7 unconventional). Steamfloods and waterfloods have different production profiles and longer response times than typical conventional wells and, as a result, the full production contribution may not be experienced in the same period that the well is drilled. In the San Joaquin basin, CRC produced approximately 99,000 BOE per day and operated six rigs during the fourth quarter of 2018. The Los Angeles basin contributed 26,000 BOE per day of production and operated three rigs directed toward waterflood projects during the fourth quarter of 2018. The Ventura basin produced 6,000 BOE per day and operated one rig directed toward waterflood projects during the fourth quarter of 2018. The Sacramento basin produced 5,000 BOE per day and had no active drilling program during the fourth quarter of 2018.

2019 Capital Budget

With current oil prices slightly above $60 per barrel Brent, CRC estimates its 2019 internally funded capital program will range from $300 million to $385 million, which may be adjusted during the course of the year depending on commodity prices. CRC is also in discussion to obtain additional investments from new and existing JVs that could increase the 2019 capital program by $100 to $150 million, to support a total capital budget of approximately $500 million. CRC’s internally funded investments will be largely directed to quick payback projects, such as primary drilling and capital workovers, and low-risk projects including waterflood and steamflood investments that maintain base production.

Balance Sheet Strengthening Update

For the fourth quarter of 2018, CRC repurchased a total of $55 million in aggregate principal amount of CRC's outstanding debt for $50 million. In 2018, CRC repurchased a total of $232 million in aggregate principal amount of CRC's outstanding debt for $199 million. The majority of CRC's debt repurchases focused on CRC's Second Lien Notes.

Year-End 2018 Reserves

CRC's proved reserves totaled 712 million barrels of oil equivalent (MMBOE), an increase from 618 MMBOE in 2017. Excluding positive price revisions, proved undeveloped reserves downgraded at management's discretion and acquisitions, CRC organically replaced 127% of proved reserves. CRC achieved this strong organic reserve replacement ratio through wellexecuted capital programs in its Buena Vista, South Valley, Huntington Beach and Long Beach areas of operations. In 2018, total additions to proved reserves from all sources were 142 MMBOE, resulting in an all-in reserve replacement ratio of 296%.

Hedging Update

CRC continues to opportunistically implement a hedging program to protect its cash flow, operating margins and capital program, while maintaining adequate liquidity. For the first and second quarters of 2019, CRC has protected the downside price risk of approximately 45,000 and 40,000 barrels per day at approximately $66 Brent and $70 Brent per barrel, respectively. For the third and fourth quarters of 2019, CRC has protected the downside price risk of approximately 40,000 and 35,000 barrels per day at approximately $73 Brent and $76 Brent per barrel, respectively. Except for a small portion primarily in the first quarter of 2019, the 2019 hedges do not contain caps, thereby providing upside to oil price movements. See Attachment 10 for more details.

[1] See Attachment 3 for how CRC calculates and uses the non-GAAP measures of adjusted EBITDAX, core adjusted EBITDAX, adjusted EBITDAX margin, free cash flow, production costs (excluding the effects of PSC-type contracts) and adjusted net income (loss), and for reconciliations of the foregoing to their nearest GAAP measure.

Conference Call Details

To participate in today's conference call scheduled for 5:00 P.M. Eastern Standard Time, either dial (877) 328-5505 (International calls please dial +1 (412) 317-5421) or access via webcast at www.crc.com, fifteen minutes prior to the scheduled start time to register. Participants may also pre-register for the conference call at http://dpregister.com/10127347. A digital replay of the conference call will be archived for approximately 30 days and supplemental slides for the conference call will be available online in the Investor Relations section of www.crc.com.

About California Resources Corporation

California Resources Corporation is the largest oil and natural gas exploration and production company in California on a gross-operated basis. CRC operates its world-class resource base exclusively within the State of California, applying complementary and integrated infrastructure to gather, process and market its production. Using advanced technology, California Resources Corporation focuses on safely and responsibly supplying affordable energy for California by Californians.

Forward-Looking Statements

This presentation contains forward-looking statements that involve risks and uncertainties that could materially affect CRC's expected results of operations, liquidity, cash flows and business prospects. Such statements include those regarding CRC's expectations as to its future:

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects

- operating costs
- Value Creation Index (VCI) metrics, which are based on certain estimates including future production rates, costs and commodity prices
- operations and operational results including production, hedging and capital investment
- budgets and maintenance capital requirements
- reserves
- type curves
- expected synergies from acquisitions and joint ventures

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While CRC believes assumptions or bases underlying its expectations are reasonable and make them in good faith, they almost always vary from actual results, sometimes materially. CRC also believes third-party statements it cites are accurate, but has not independently verified them and does not warrant their accuracy or completeness. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on CRC's financial flexibility
- insufficient cash flow to fund planned investments, debt repurchases or changes to CRC's capital plan
- inability to enter desirable transactions, including acquisitions, asset sales and joint ventures
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products
- joint ventures and acquisitions and CRC's ability to achieve expected synergies
- the recoverability of resources and unexpected geologic conditions
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves
- changes in business strategy
- PSC effects on production and unit production costs
- effect of stock price on costs associated with incentive compensation
- insufficient capital, including as a result of lender restrictions, unavailability of capital markets or inability to attract potential investors
- effects of hedging transactions
- equipment, service or labor price inflation or unavailability
- availability or timing of, or conditions imposed on, permits and approvals
- lower-than-expected production, reserves or resources from development projects, joint ventures or acquisitions, or higher-than-expected decline rates
- disruptions due to accidents, mechanical failures, transportation or storage constraints, natural disasters, labor difficulties, cyber attacks or other catastrophic events

- factors discussed in “Risk Factors” in CRC's Annual Report on Form 10-K available on its website at crc.com.

Words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "goal," "intend," "likely," "may," "might," "plan," "potential," "project," "seek," "should," "target, "will" or "would" and similar words that reflect the prospective nature of events or outcomes typically identify forward-looking statements. Any forward-looking statement speaks only as of the date on which such statement is made and CRC 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.

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Attachment 1

SUMMARY OF RESULTS

($ and shares in millions, except per share amounts)	Fourth Quarter 2018	Fourth Quarter 2017	Twelve Months 2018	Twelve Months 2017
Statement of Operations Data:				
Revenues and Other				
Oil and gas sales [(a)]	**$ 658**	$ 549	**$ 2,590**	$ 1,936
Net derivative gain (loss) from commodity contracts	**260**	(141)	**1**	(90)
Other revenue [(a)]	**160**	47	**473**	160
Total revenues and other	**1,078**	455	**3,064**	2,006
Costs and Other				
Production costs	**233**	227	**912**	876
General and administrative expenses	**65**	66	**299**	249
Depreciation, depletion and amortization	**130**	132	**502**	544
Taxes other than on income	**29**	33	**149**	136
Exploration expense	**16**	5	**34**	22
Other expenses, net [(a)]	**140**	30	**399**	106
Total costs and other	**613**	493	**2,295**	1,933
Operating Income (Loss)	**465**	(38)	**769**	73
Non-Operating (Loss) Income				
Interest and debt expense, net	**(98)**	(91)	**(379)**	(343)
Net gain on early extinguishment of debt	**31**	—	**57**	4
Gain on asset divestitures	**1**	—	**5**	21
Other non-operating expenses	**(7)**	(6)	**(23)**	(17)
Income (Loss) Before Income Taxes	**392**	(135)	**429**	(262)
Income tax	**—**	—	**—**	—
Net Income (Loss)	**392**	(135)	**429**	(262)
Net income attributable to noncontrolling interests	**(46)**	(3)	**(101)**	(4)
Net Income (Loss) Attributable to Common Stock	**$ 346**	$ (138)	**$ 328**	$ (266)
Net income (loss) attributable to common stock per share - basic [(b)]	**$ 7.00**	$ (3.23)	**$ 6.77**	$ (6.26)
Net income (loss) attributable to common stock per share - diluted	**$ 7.00**	$ (3.23)	**$ 6.77**	$ (6.26)
Adjusted net income (loss)	**$ 26**	$ (14)	**$ 61**	$ (187)
Adjusted net income (loss) per share - basic [(b)]	**$ 0.53**	$ (0.33)	**$ 1.27**	$ (4.40)
Adjusted net income (loss) per share - diluted	**$ 0.53**	$ (0.33)	**$ 1.27**	$ (4.40)
Weighted-average common shares outstanding - basic	**$ 48.6**	$ 42.7	**$ 47.4**	$ 42.5
Weighted-average common shares outstanding - diluted	**$ 48.6**	$ 42.7	**$ 47.4**	$ 42.5
Adjusted EBITDAX	**$ 314**	$ 231	**$ 1,117**	$ 779
Effective tax rate	**0%**	0%	**0%**	0%

(a) We adopted a new revenue recognition standard on January 1, 2018 which required certain sales-related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard does not affect net income. Results for reporting periods beginning January 1, 2018 are presented under the new accounting standard while prior periods are not adjusted and continue to be reported under accounting standards in effect for the applicable period. Under prior accounting standards, for the three and twelve months ended December 31, 2018, oil and gas sales would have been $653 million and $2,568 million, respectively, other revenue would have been $150 million and $392 million, respectively, and other expenses, net would have been $125 million and $296 million, respectively.

(b) In calculating Net income (loss) attributable to common stock per share - basic, income of $6 million and $7 million for the three and twelve months ended December 31, 2108, respectively, was allocated to unvested participating securities with the balance of undistributed earnings allocated to common shares. In calculating Adjusted net income (loss) per share - basic, none and $1 million for the three and twelve months ended December 31, 2018, respectively, was allocated to unvested participating securities with the balance of undistributed earnings allocated to common shares. For periods of losses no allocation is made to participating securities.

($ and shares in millions)	Fourth Quarter 2018	Fourth Quarter 2017	Twelve Months 2018	Twelve Months 2017
Cash Flow Data:				
Net cash provided by operating activities	**$ 68**	$ 23	**$ 461**	$ 248
Net cash used in investing activities	**$ (191)**	$ (139)	**$ (1,156)**	$ (313)
Net cash provided by financing activities	**$ 109**	$ 108	**$ 692**	$ 73

Selected Balance Sheet Data:	**December 31, 2018**	December 31, 2017
Total current assets	**$ 640**	$ 483
Total property, plant and equipment, net	**$ 6,455**	$ 5,696
Total current liabilities	**$ 607**	$ 732
Long-term debt	**$ 5,251**	$ 5,306
Other long-term liabilities	**$ 575**	$ 602
Mezzanine equity	**$ 756**	$ —
Equity	**$ (247)**	$ (720)
Outstanding shares as of	**48.7**	42.9

STOCK-BASED COMPENSATION

Our consolidated results of operations for the three and twelve months ended December 31, 2018 include the effects of long-term stock-based compensation plans under which we annually grant awards to executives, non-executive employees and non-employee directors that are either settled with shares of our common stock or cash. Our equity-settled awards granted to executives include stock options, restricted stock and performance stock units that either cliff vest at the end of a three-year period or vest ratably over a three-year period, some of which are partially settled in cash. Our equity-settled awards granted to non-employee directors are restricted stock units that cliff vest after one year. Our cash-settled awards granted to non-executive employees vest ratably over a three-year period.

Changes in our stock price introduces volatility in our income statement because we pay partially or fully cash-settled awards based on our stock price as of the vesting date and accounting rules require that we adjust our obligation for such awards to the amount that would be paid using our stock price as of the end of each reporting period. Cash-settled awards, including executive awards partially settled in cash, account for over 50% of our total outstanding awards. The increase in our stock price in 2018 resulted in higher cash-settled stock-based compensation expense in the second and third quarters of 2018 when a portion of these awards vested and our unvested awards were marked-to-market based on the period-end stock price. In the fourth quarter of 2018, our stock price declined and the year-end mark-to-market adjustments reduced our compensation expense. Equity-settled awards are not similarly adjusted for changes in our stock price.

Stock-based compensation is included in both general and administrative expenses and production costs as shown in the table below:

($ in millions, except per BOE amounts)	Fourth Quarter 2018	Fourth Quarter 2017	Twelve Months 2018	Twelve Months 2017
Expense (Income)				
General and administrative expenses				
Cash-settled awards	**$ (10)**	$ 6	**$ 23**	$ 9
Equity-settled awards	**2**	3	**13**	14
Total stock-based compensation in G&A	**$ (8)**	$ 9	**$ 36**	$ 23
Total stock-based compensation in G&A per Boe	**$ (0.64)**	$ 0.78	**$ 0.75**	$ 0.49
Production costs				
Cash-settled awards	**$ (2)**	$ 2	**$ 6**	$ 2
Equity-settled awards	**—**	—	**3**	4
Total stock-based compensation in production costs	**$ (2)**	$ 2	**$ 9**	$ 6
Total stock-based compensation in production costs per Boe	**$ (0.16)**	$ 0.17	**$ 0.19**	$ 0.13
Total company stock-based compensation	**$ (10)**	$ 11	**$ 45**	$ 29
Total company stock-based compensation per Boe	**$ (0.80)**	$ 0.95	**$ 0.94**	$ 0.62

PRODUCTION STATISTICS

Net Oil, NGLs and Natural Gas Production Per Day	Fourth Quarter 2018	Fourth Quarter 2017	Twelve Months 2018	Twelve Months 2017
Oil (MBbl/d)				
San Joaquin Basin	**56**	50	**53**	52
Los Angeles Basin	**26**	26	**25**	27
Ventura Basin	**4**	4	**4**	4
Total	**86**	80	**82**	83
NGLs (MBbl/d)				
San Joaquin Basin	**15**	15	**15**	15
Ventura Basin	**1**	1	**1**	1
Total	**16**	16	**16**	16
Natural Gas (MMcf/d)				
San Joaquin Basin	**168**	138	**165**	140
Los Angeles Basin	**2**	1	**1**	1
Ventura Basin	**7**	7	**7**	8
Sacramento Basin	**27**	33	**29**	33
Total	**204**	179	**202**	182
Total Production (MBoe/d) [(a)]	**136**	126	**132**	129

Note: MBbl/d refers to thousands of barrels per day; MMcf/d refers to millions of cubic feet per day; MBoe/d refers to thousands of barrels of oil equivalent per day.

(a) Natural gas volumes have been converted to BOE based on the equivalence of energy content between six Mcf of natural gas and one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

Our results of operations can include the effects of unusual, out-of-period and infrequent transactions and events affecting earnings that vary widely and unpredictably (in particular certain non-cash items such as derivative gains and losses) in nature, timing, amount and frequency. Therefore, management uses a measure called adjusted net income (loss) which excludes those items. This measure is not meant to disassociate items from management's performance, but rather is meant to provide useful information to investors interested in comparing our performance between periods. Reported earnings are considered representative of management's performance over the long term. Adjusted net income (loss) is not considered to be an alternative to net income (loss) reported in accordance with U.S. generally accepted accounting principles (GAAP).

We define certain of our non-GAAP financial measures as follows:

(1) Adjusted EBITDAX is calculated as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; other unusual, out-of-period and infrequent items; and other non-cash items.

(2) Core Adjusted EBITDAX removes the transitory effects of settled hedges and cash-settled stock-based compensation expense from Adjusted EBITDAX.

(3) Free Cash Flow is net cash provided by operating activities after our internal capital investment.

(4) Discretionary Cash Flow is the cash available after payments to our noncontrolling interest holders and cash interest, excluding the effect of working capital changes but before our internal capital investment.

We believe these measures provide useful information in assessing our financial condition, results of operations and cash flows and are widely used by the industry, the investment community and our lenders. Although these are non-GAAP measures, the amounts included in the calculations were computed in accordance with GAAP. Certain items excluded from these non-GAAP measures are significant components in understanding and assessing our financial performance, such as our cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. These measures should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP. A version of Adjusted EBITDAX is a material component of certain of our financial covenants under our 2014 Revolving Credit Facility and is provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP.

ADJUSTED NET INCOME (LOSS)

The following table presents a reconciliation of the GAAP financial measure of net income (loss) attributable to common stock to the non-GAAP financial measure of adjusted net income (loss) and presents the GAAP financial measure of net income (loss) attributable to common stock per diluted share and the non-GAAP financial measure of adjusted net income (loss) per diluted share:

	Fourth Quarter		Twelve Months	
($ millions, except per share amounts)	**2018**	2017	**2018**	2017
Net income (loss)	**$ 392**	$ (135)	**$ 429**	$ (262)
Net income attributable to noncontrolling interests	**(46)**	(3)	**(101)**	(4)
Net income (loss) attributable to common stock	**346**	(138)	**328**	(266)
Unusual, infrequent and other items:				
Non-cash derivative (gain) loss from commodities excluding noncontrolling interest	**(295)**	116	**(224)**	78
Non-cash derivative loss from interest-rate contracts	**6**	—	**6**	—
Early retirement and severance costs	**—**	1	**4**	5
Gain on asset divestitures	**(1)**	—	**(5)**	(21)
Net gain on early extinguishment of debt	**(31)**	—	**(57)**	(4)
Other, net	**1**	7	**9**	21
Total unusual, infrequent and other items	**(320)**	124	**(267)**	79
Adjusted net income (loss)	**$ 26**	$ (14)	**$ 61**	$ (187)
Net income (loss) attributable to common stock per share - diluted	**$ 7.00**	$ (3.23)	**$ 6.77**	$ (6.26)
Adjusted net income (loss) per share - diluted	**$ 0.53**	$ (0.33)	**$ 1.27**	$ (4.40)

DERIVATIVE GAINS AND LOSSES

($ millions)	Fourth Quarter 2018	Fourth Quarter 2017	Twelve Months 2018	Twelve Months 2017
Commodity Contracts:				
Non-cash derivative gain (loss) excluding noncontrolling interest	**$ 295**	$ (116)	**$ 224**	$ (78)
Non-cash derivative gain (loss) included in noncontrolling interest	**15**	(3)	**5**	(5)
Net payments on settled commodity derivatives	**(50)**	(22)	**(228)**	(7)
Net derivative gain (loss) from commodity contracts	**$ 260**	$ (141)	**$ 1**	$ (90)
Interest Rate Contracts:				
Non-cash derivative loss	**$ (6)**	$ —	**$ (6)**	$ —

FREE CASH FLOW

($ millions)	Fourth Quarter 2018	Fourth Quarter 2017	Twelve Months 2018	Twelve Months 2017
Net cash provided by operating activities	**$ 68**	$ 23	**$ 461**	$ 248
Capital investment	**(186)**	(139)	**(690)**	(371)
Free cash flow	**(118)**	(116)	**(229)**	(123)
BSP funded capital investment	**12**	14	**49**	96
Free cash flow excluding BSP funded capital	**$ (106)**	$ (102)	**$ (180)**	$ (27)

DISCRETIONARY CASH FLOW

($ millions)	Fourth Quarter 2018	Fourth Quarter 2017	Twelve Months 2018	Twelve Months 2017
Adjusted EBITDAX	**$ 314**	$ 231	**$ 1,117**	$ 779
Cash Interest	**(157)**	(145)	**(441)**	(396)
Distributions to noncontrolling interest holders:				
BSP joint venture	**(21)**	(2)	**(56)**	(8)
Ares joint venture	**(20)**	—	**(65)**	—
Discretionary Cash Flow	**$ 116**	$ 84	**$ 555**	$ 375

ADJUSTED EBITDAX AND CORE ADJUSTED EBITDAX

The following tables present a reconciliation of the GAAP financial measures of net income (loss) and net cash provided (used) by operating activities to the non-GAAP financial measures of adjusted and core adjusted EBITDAX.

	Fourth Quarter		Twelve Months	
($ millions)	**2018**	2017	**2018**	2017
Net income (loss)	**$ 392**	$ (135)	**$ 429**	$ (262)
Interest and debt expense, net	**98**	91	**379**	343
Depreciation, depletion and amortization	**130**	132	**502**	544
Exploration expense	**16**	5	**34**	22
Unusual, infrequent and other items [(a)]	**(320)**	124	**(267)**	79
Other non-cash items	**(2)**	14	**40**	53
Adjusted EBITDAX	**$ 314**	$ 231	**$ 1,117**	$ 779
Net payments on settled commodity derivatives	**50**	22	**228**	7
Cash-settled stock-based compensation	**(12)**	8	**29**	11
Core Adjusted EBITDAX	**$ 352**	$ 261	**$ 1,374**	$ 797
Net cash provided by operating activities	**$ 68**	$ 23	**$ 461**	$ 248
Cash interest	**157**	145	**441**	396
Exploration expenditures	**3**	4	**17**	20
Working capital changes	**86**	52	**199**	94
Other, net	**—**	7	**(1)**	21
Adjusted EBITDAX	**$ 314**	$ 231	**$ 1,117**	$ 779
Net payments on settled commodity derivatives	**50**	22	**228**	7
Cash-settled stock-based compensation	**(12)**	8	**29**	11
Core Adjusted EBITDAX	**$ 352**	$ 261	**$ 1,374**	$ 797

(a) See Adjusted Net Income (Loss) reconciliation.

ADJUSTED EBITDAX MARGIN

	Fourth Quarter		Twelve Months	
($ millions)	**2018**	2017	**2018**	2017
Total revenues and other	**$ 1,078**	$ 455	**$ 3,064**	$ 2,006
Non-cash derivative (gain) loss	**(310)**	119	**(229)**	83
Adjusted revenues	**$ 768**	$ 574	**$ 2,835**	$ 2,089
Adjusted EBITDAX Margin [(b)]	**41%**	40%	**39%**	37%

(b) See Note (a) on Attachment 1 related to our adoption of a new revenue recognition standard for the reporting of certain sales-related costs. Under prior accounting standards, for the three and twelve months ended December 31, 2018, the adjusted EBITDAX margin would have been 42% and 41% respectively.

PRODUCTION COSTS PER BOE

	Fourth Quarter		Twelve Months	
($ per Boe)	**2018**	2017	**2018**	2017
Production costs	**$ 18.61**	$ 19.64	**$ 18.88**	$ 18.64
Excess costs attributable to PSC-type contracts	**(1.17)**	(1.33)	**(1.41)**	(1.16)
Production costs, excluding effects of PSC-type contracts	**$ 17.44**	$ 18.31	**$ 17.47**	$ 17.48

PV-10 AND STANDARDIZED MEASURE

The following table presents a reconciliation of the GAAP financial measure of standardized measure of discounted future net cash flows to the non-GAAP financial measure of PV-10:

($ millions)	2018
Standardized measure of discounted future net cash flows	$ 7,275
Present value of future income taxes discounted at 10%	2,136
PV-10 of proved reserves [(1)]	$ 9,411

(1) PV-10 is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC prescribed pricing assumptions for the period. PV-10 differs from Standardized Measure because Standardized Measure includes the effects of future income taxes on future net cash flows. Neither PV-10 nor Standardized Measure should be construed as the fair value of our oil and natural gas reserves. Standard Measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.

Reserve Replacement Ratios [1]	**2018**
Organic Reserve Replacement Ratio [2]	
Extensions and discoveries	**30**
Improved recovery	**4**
Revisions related to performance (excluding discretionary PUD downgrades)	**27**
Organic proved reserves added - MMBOE (A)	**61**
Production in 2018 - MMBOE (B)	**48**
Organic reserve replacement ratio (A)/(B)	**127%**
All-in Reserve Replacement Ratio [3]	
Extensions and discoveries	**30**
Improved recovery	**4**
Purchases of proved reserves	**64**
Revisions related to performance	**6**
Revisions related to price	**38**
All-in proved reserves added - MMBOE (C)	**142**
Production in 2018 - MMBOE (D)	**48**
All-in reserve replacement ratio (C)/(D)	**296%**

(1) The reserve replacement ratio is a non-GAAP measure that management uses to gauge the results of its capital program. There is no guarantee that historical sources of reserve additions will continue as many factors fully or partially outside management's control, including commodity prices, availability of capital and the underlying geology, affect reserves additions. Other oil and gas producers may use different methods to calculate replacement ratios, which may affect comparability.

(2) The organic reserve replacement ratio is calculated for a specified period using the proved oil-equivalent additions from extensions and discoveries, improved recovery and performance-related revisions (excluding 21 MMBOE of proved undeveloped reserves downgraded at management's discretion), divided by oil-equivalent production.

(3) The all-in reserve replacement ratio is calculated for a specified period using the proved oil-equivalent additions from extensions and discoveries, improved recovery, revisions and purchases, divided by oil-equivalent production.

Finding and Development Costs[4]	**2018**	
Exploration and development costs - in millions (A)	**$ 690**	
Property acquisition costs - in millions	**554**	
Total costs incurred - in millions (B)	**$ 1,244**	
Organic proved reserves added - MMBOE (C)	**61**	
Organic finding and development costs - $/BOE (A)/(C)	**$ 11.31**	(5)
Total reserve replacements - MMBOE (D)	**142**	
All-in finding and development costs - $/BOE (B)/(D)	**$ 8.76**	(6)

(4) We believe that reporting our finding and development costs can aid investors in their evaluation of our ability to add proved reserves at a reasonable cost but is not a substitute for required GAAP disclosures. Various factors, primarily timing differences and effects of commodity price changes, can cause finding and development costs associated with a particular period's reserves additions to be imprecise. For example, we will need to make more investments in order to develop the proved undeveloped reserves added during the year and any future revisions may change the actual measure from that presented above. In addition, part of the 2018 costs were incurred to convert proved undeveloped reserves from prior years to proved developed reserves. In our calculations, we have not estimated future costs to develop proved undeveloped reserves added in 2018 or removed costs related to proved undeveloped reserves added in prior periods. Our calculations of finding and development costs may not be comparable to similar measures provided by other companies.

(5) We calculate organic finding and development costs by dividing the costs incurred for the year from the capital program by the amount of oil-equivalent proved reserves added in the same year from improved recovery, extensions and discoveries and performance-related revisions (excluding 21 MMBOE of proved undeveloped reserves downgraded at management's discretion).

(6) We calculate all-in finding and development costs by dividing the costs incurred for the year by the amount of oil-equivalent proved reserves added in the same year from improved recovery, extensions and discoveries, revisions and purchases.

ADJUSTED NET INCOME (LOSS) VARIANCE ANALYSIS
($ millions)

2017 4th Quarter Adjusted Net Loss	**$**	**(14)**	
Price - Oil		19	(a)
Price - NGLs		(1)	
Price - Natural Gas		15	(a)
Volume		37	
Production costs		(6)	
Taxes other than on income		4	
DD&A rate		11	
Interest expense		(7)	
Adjusted general & administrative expenses		1	
Net income attributable to noncontrolling interests		(43)	
Other		10	
2018 4th Quarter Adjusted Net Income	**$**	**26**	

2017 Twelve-Month Adjusted Net Loss	**$**	**(187)**	
Price - Oil		342	(a)
Price - NGLs		47	
Price - Natural Gas		19	(a)
Volume		13	
Production costs		(36)	
Taxes other than on income		(13)	
DD&A rate		53	
Interest expense		(36)	
Adjusted general & administrative expenses		(49)	
Net income attributable to noncontrolling interests		(97)	
Other		5	
2018 Twelve-Month Adjusted Net Income	**$**	**61**	

(a) Includes cash settlements on commodity derivatives.

CAPITAL INVESTMENTS

($ millions)	Fourth Quarter **2018**	Fourth Quarter 2017	Twelve Months **2018**	Twelve Months 2017
Internally Funded Capital	**$ 174**	$ 125	**$ 641**	$ 275
BSP Funded Capital	**12**	14	**49**	96
Consolidated Reported Capital Investments	**$ 186**	$ 139	**$ 690**	$ 371
MIRA Funded Capital	**11**	20	**57**	58
Total Capital Program	**$ 197**	$ 159	**$ 747**	$ 429

PRICE STATISTICS

	Fourth Quarter		Twelve Months	
	2018	2017	**2018**	2017
Realized Prices				
Oil with hedge ($/Bbl)	**$ 59.97**	$ 56.92	**$ 62.60**	$ 51.24
Oil without hedge ($/Bbl)	**$ 66.12**	$ 59.87	**$ 70.11**	$ 51.47
NGLs ($/Bbl)	**$ 43.56**	$ 44.03	**$ 43.67**	$ 35.76
Natural gas ($/Mcf) [(a)]	**$ 3.77**	$ 2.77	**$ 3.00**	$ 2.67
Index Prices				
Brent oil ($/Bbl)	**$ 68.08**	$ 61.54	**$ 71.53**	$ 54.82
WTI oil ($/Bbl)	**$ 58.81**	$ 55.40	**$ 64.77**	$ 50.95
NYMEX gas ($/MMBtu)	**$ 3.40**	$ 3.00	**$ 2.97**	$ 3.09
Realized Prices as Percentage of Index Prices				
Oil with hedge as a percentage of Brent	**88%**	92%	**88%**	93%
Oil without hedge as a percentage of Brent	**97%**	97%	**98%**	94%
Oil with hedge as a percentage of WTI	**102%**	103%	**97%**	101%
Oil without hedge as a percentage of WTI	**112%**	108%	**108%**	101%
NGLs as a percentage of Brent	**64%**	72%	**61%**	65%
NGLs as a percentage of WTI	**74%**	79%	**67%**	70%
Natural gas as a percentage of NYMEX [(a)]	**111%**	92%	**101%**	86%

(a) See Note (a) on Attachment 1 related to our adoption of a new accounting standard regarding the reporting of certain sales related costs. For the three months and twelve months ended December 31, 2018, the realized gas price would have been $3.59 per Mcf and $2.79 per Mcf, respectively, and the realized gas price as a percentage of NYMEX would have been 106% and 94%, respectively.

FOURTH QUARTER DRILLING ACTIVITY

Wells Drilled (Gross)	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	12	—	—	—	12
Waterflood	19	16	3	—	38
Steamflood	33	—	—	—	33
Unconventional	7	—	—	—	7
Total	71	16	3	—	90
Exploration Wells					
Primary	—	—	1	—	1
Waterflood	—	—	—	—	—
Steamflood	—	—	—	—	—
Unconventional	—	—	—	—	—
Total	—	—	1	—	1
Total Wells [(a)]	71	16	4	—	91
CRC Wells Drilled	69	13	4	—	86
BSP Wells Drilled	—	3	—	—	3
MIRA Wells Drilled	2	—	—	—	2

[(a)] Includes steam injectors and drilled but uncompleted wells, which would not be included in the SEC definition of wells drilled.

FULL YEAR DRILLING ACTIVITY

Wells Drilled (Gross)	**San Joaquin Basin**	**Los Angeles Basin**	**Ventura Basin**	**Sacramento Basin**	**Total**
Development Wells					
Primary	33	—	—	—	33
Waterflood	36	52	3	—	91
Steamflood	182	—	—	—	182
Unconventional	33	—	—	—	33
Total	284	52	3	—	339
Exploration Wells					
Primary	2	—	2	—	4
Waterflood	—	—	—	—	—
Steamflood	—	—	—	—	—
Unconventional	—	—	—	—	—
Total	2	—	2	—	4
Total Wells [a]	286	52	5	—	343
CRC Wells Drilled	190	42	5	—	237
BSP Wells Drilled	5	10	—	—	15
MIRA Wells Drilled	91	—	—	—	91

[a] Includes steam injectors and drilled but uncompleted wells, which would not be included in the SEC definition of wells drilled.

HEDGES - CURRENT

	1Q 2019	2Q 2019	3Q 2019	4Q 2019	1Q 2020
CRUDE OIL					
Sold Calls:					
Barrels per day	15,000	5,000	—	—	—
Weighted-average Brent price per barrel	$66.15	$68.45	$—	$—	$—
Purchased Calls:					
Barrels per day	2,000	—	—	—	—
Weighted-average Brent price per barrel	$71.00	$—	$—	$—	$—
Purchased Puts:					
Barrels per day	38,000	40,000	40,000	35,000	10,000
Weighted-average Brent price per barrel	$65.66	$69.75	$73.13	$75.71	$75.00
Sold Puts:					
Barrels per day	40,000	35,000	40,000	35,000	10,000
Weighted-average Brent price per barrel	$51.88	$55.71	$57.50	$60.00	$60.00
Swaps:					
Barrels per day	7,000	—	—	—	—
Weighted-average Brent price per barrel	$67.71	$—	$—	$—	$—

The BSP JV entered into crude oil derivatives that are included in our consolidated results but not in the above table. The hedges entered into by the BSP JV could affect the timing of the redemption of the JV interest. The BSP JV sold calls for up to approximately 1,000 barrels per day at a weighted-average price per barrel of $60.00 for 2019 through 2020. The BSP JV purchased puts for up to approximately 2,000 barrels per day at a weighted-average price per barrel of approximately $50.00 for 2019 through 2021. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021.

In May 2018 we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. The interest rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021.

RESERVES

As of December 31, 2018	**San Joaquin Basin**	**Los Angeles Basin**	**Ventura Basin**	**Sacramento Basin**	**Total**
Oil Reserves (MMBbl)					
Proved Developed Reserves	231	131	27	—	389
Proved Undeveloped Reserves	86	42	13	—	141
Total	317	173	40	—	530
NGLs Reserves (MMBbl)					
Proved Developed Reserves	45	—	2	—	47
Proved Undeveloped Reserves	12	—	1	—	13
Total	57	—	3	—	60
Natural Gas Reserves (Bcf)					
Proved Developed Reserves	473	9	23	60	565
Proved Undeveloped Reserves	148	4	9	8	169
Total	621	13	32	68	734
Total Reserves (MMBoe)[(a)]					
Proved Developed Reserves	355	132	33	10	530
Proved Undeveloped Reserves	123	43	15	1	182
Total	478	175	48	11	712

Note: MMBbl refers to millions of barrels; Bcf refers to billions of cubic feet; MMBoe refers to millions of barrels of oil equivalent.

(a) Natural gas volumes have been converted to BOE based on the equivalence of energy content between six Mcf of natural gas and one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

Attachment 12

2019 FIRST QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q1 2019 [(a)]

Oil	94% to 99% of Brent
NGLs	55% to 60% of Brent
Natural Gas	100% to 110% of NYMEX

2019 First Quarter Production, Capital and Income Statement Guidance

Production [(b) & (c)]	132 to 137 MBOE per day
Capital [(d)]	$110 million to $140 million
Production costs [(b) & (c)]	$18.25 to $19.75 per BOE
Adjusted general and administrative expenses [(b) & (e)]	$6.55 to $6.95 per BOE
Depreciation, depletion and amortization [(b)]	$9.85 to $10.15 per BOE
Taxes other than on income	$41 million to $45 million
Exploration expense	$9 million to $14 million
Interest expense [(f)]	$98 million to $103 million
Cash interest [(f)]	$70 million to $75 million
Income tax expense rate	0%
Cash tax rate	0%

Pre-tax 2019 First Quarter Price Sensitivities [(g)]

$1 change in Brent index - Oil [(h)]	$4.6 million
$1 change in Brent index - NGLs	$0.9 million
$0.50 change in NYMEX - Gas	$4.7 million

(a) Realizations exclude hedge effects.

(b) Based on an average assumed Q1 2019 Brent price of $60 per barrel.

(c) Based on an average assumed Brent price of $65 per barrel, Q1 2019 production would be 131 to 136 MBOE per day and production costs would be $18.40 to $19.90 per BOE. Based on an average assumed Brent price of $70 per barrel, Q1 2019 production would be 130 to 135 MBOE per day and production costs would be $18.50 to $20.00 per BOE.

(d) Capital guidance includes CRC, BSP and MIRA capital.

(e) Our long-term incentive compensation programs for employees are stock based but payable in cash. Accounting rules require that we adjust the cumulative liability for all vested but unpaid awards under these programs to the amount that would be paid using our stock price as of the end of each reporting period. Therefore, in addition to the normal pro-rata vesting expense associated with these programs, our quarterly G&A expense could include this cumulative adjustment depending on movement in our stock price. Our stock price used to set first quarter 2019 guidance was $20.00 per share. This results in an upward cumulative stock compensation adjustment due to the higher stock price compared to year-end. Only about 1/3 of such cumulative adjustment would result in a cash liability in the same year as the adjustment because of the pro-rata three-year vesting of our incentive compensation programs.

(f) Interest expense includes cash interest, original issue discount and amortization of deferred financing costs as well as the deferred gain that resulted from the December 2015 debt exchange. Cash interest for the quarter is lower than interest expense due to the timing of interest payments.

(g) Due to our tax position there is no difference between the impact on our income and cash flows.

(h) Amount reflects the sensitivity with respect to unhedged barrels which have no upside limitation. We have downside protection on approximately 53% of our oil production, at a weighted average Brent floor price of $66 per barrel below which we receive Brent plus approximately $14 per barrel.