California Resources Corporation Announces First Quarter 2019 Results

May 2, 2019

LOS ANGELES--(BUSINESS WIRE)--California Resources Corporation (NYSE: CRC), an independent California-based oil and gas exploration and production company, today reported a net loss attributable to common stock (CRC net loss) of $67 million, or $1.38 per diluted share, for the first quarter of 2019. Adjusted net income[1] for the first quarter of 2019 was $31 million, or $0.63 per diluted share. Operational and financial highlights for the first quarter of 2019 are as follows:

Highlights

- Reported adjusted EBITDAX[1] of $301 million; an adjusted EBITDAX margin[1] of 38%; an adjusted EBITDAX per BOE[1] of $25.13, which was the highest since 2015; net cash provided by operating activities of $158 million
- First quarter 2019 average daily production of 133,000 barrels of oil equivalent (BOE) per day, an 8% increase over the prior year period; oil production increased 9% over the prior year period
- Invested $138 million of total capital, including internally funded capital of $104 million
- Drilled 42 wells with internally funded capital and 18 wells with JV capital
- Sold a 50% working interest and transferred operatorship in portions of a field for consideration in excess of $200 million, consisting of approximately $168 million in cash and a carried 200-well development program, for a valuation of $88,000 per flowing barrel including the carry

Todd Stevens, CRC's President and Chief Executive Officer, said, "CRC began 2019 with a solid first quarter that highlighted our value-driven, dynamic capital allocation. We generated strong cash flow, benefiting from the high quality, low risk and long life of CRC's resource base, as well as our ability to quickly adapt operating and capital plans to capture value across various price environments. To further accelerate value, we recently sold an interest in our shallow production in the Lost Hills field, which garnered more than $200 million consisting of $168 million in cash, in addition to a 100% carry on a 200-well development program worth at least $35 million. The sale represents a 'win-win' that provides cash to fund our ongoing balance sheet strengthening efforts, while retaining a significant upside in the future development by the new operator. We will continue to seek strategic opportunities through the drill bit and through accretive transactions using our diverse portfolio that unlock shareholder value and strengthen our balance sheet."

First Quarter 2019 Results

For the first quarter of 2019, CRC reported a net loss attributable to common stock of $67 million, or $1.38 per diluted share, compared to a loss of $2 million, or $0.05 per diluted share for the same period of 2018. Adjusted net income[1] for the first quarter of 2019 was $31 million, or $0.63 per diluted share, compared with adjusted net income[1] of $8 million, or $0.18 per diluted share for the same prior year period. First quarter of 2019 adjusted net income[1] excluded $97 million of non-cash derivative losses on commodity contracts, a $3 million non-cash derivative loss from interest-rate contracts as well as a net gain of $6 million on debt repurchases and $4 million of unusual and infrequent items.

EBITDAX for the first quarter of 2019 was $301 million and cash provided by operating activities was $158 million, which included interest payments of $72 million.

Total daily production volumes increased 8% year-over-year, from 123,000 BOE per day for the first quarter of 2018 to 133,000 BOE per day for the first quarter of 2019. Total daily production for 2019 included volumes from the Elk Hills transaction, which was completed in the second quarter of 2018. Oil volumes averaged 84,000 barrels per day, NGL volumes averaged 15,000 barrels per day and gas volumes averaged 202,000 thousand cubic feet (MCF) per day.

Realized crude oil prices, including the effect of settled hedges, increased by $2.51 per barrel from the first quarter of 2018 to $65.28 per barrel in the first quarter of 2019 primarily due to settled hedges that increased our realized crude oil prices by $1.98 per barrel. Realized NGL prices were $42.52 per barrel. Realized natural gas prices were $3.43 per MCF for the first quarter of 2019, $0.62 higher than the same prior-year period primarily due to higher winter demand.

Production costs for the first quarter of 2019 were $233 million compared to $212 million for the first quarter of 2018. The increase is attributable to the Elk Hills transaction, cash-settled stock-based compensation, energy costs and other items.

General and administrative (G&A) expenses were $83 million for the first quarter of 2019 compared to $63 million for the same prior-year period. CRC's cash-settled stock-based compensation expense increased approximately $7 million due to the increase in the Company's stock price in the first quarter of 2019. Additionally, 2019 G&A expenses increased by approximately $3 million as certain costs are no longer collected from CRC's former working interest partner following the Elk Hills transaction.

CRC reported taxes other than on income of $41 million for the first quarter of 2019 compared to $38 million for the same prior year period. Exploration expense was $10 million for the first quarter of 2019, $2 million higher in the first quarter of 2019 than the same prior-year period due to an increased exploration budget.

CRC's internally funded capital investment for the first quarter of 2019 totaled $104 million, of which $93 million was directed to drilling and capital workovers. CRC's JV partner Benefit Street Partners (BSP) also invested $27 million, which is included in CRC's consolidated results. CRC's JV partner Macquarie Infrastructure and Real Assets Inc. (MIRA) invested an additional $7 million, which is excluded from CRC's consolidated results.

Operational Update

In the first quarter of 2019, CRC operated an average of 7 drilling rigs with 2 rigs focused on conventional primary production, 2 on waterfloods, 1 on steamfloods and 2 on unconventional production. With total invested capital, we drilled 52 development wells and 8 exploration wells (40 steamflood, 9 waterflood, 5 primary and 6 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. The San Joaquin basin produced approximately 97,000 BOE per day and operated six rigs. The Los Angeles basin contributed 25,000 BOE per day of production and operated one rig directed toward waterflood projects. The Ventura and Sacramento basins, where we had no active drilling program, produced 6,000 BOE per day and 5,000 BOE per day, respectively.

2019 Capital Budget

CRC’s internally funded investments will be largely directed to short payout projects, such as primary drilling and capital workovers, and low-risk projects including waterflood and steamflood investments that maintain base production. 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 obtained an additional $50 million investment from BSP during the first quarter of 2019 and continues discussions to obtain additional investments from new and existing JVs to achieve a total capital budget of approximately $500 million.

Strategic Asset Divestiture

On May 1, 2019 CRC sold 50% of our working interest and transferred operatorship in certain zones in our Lost Hills field in the San Joaquin Basin for total consideration in excess of $200 million, consisting of approximately $168 million in cash and a carried 200 well development program to be drilled through 2023 with an estimated minimum value of $35 million. The cash proceeds were used to pay down the revolver and CRC benefits from accelerated development from the drilling carry.

Balance Sheet and Credit Facility Update

Effective May 1, 2019, CRC's borrowing base under its 2014 Credit Agreement was reaffirmed at $2.3 billion. Following the closing of the Lost Hills transaction, pro forma total debt outstanding was $5.1 billion, down $168 million from March 31, 2019, bringing total availability on the Company's revolver to over $420 million before the minimum liquidity requirement.

During the first quarter of 2019, CRC repurchased $18 million in aggregate principal amount of CRC's Second Lien Notes for $14 million.

Hedging Update

CRC continues to implement an opportunistic hedging program to protect its cash flow, operating margins and capital program, while maintaining adequate liquidity. For the second quarter of 2019, CRC has protected its downside price risk on approximately 40,000 barrels per day at approximately $70 Brent. For the third and fourth quarters of 2019, CRC has protected the downside price risk on approximately 40,000 and 35,000 barrels per day at approximately $73 Brent and $76 Brent, respectively. The underlying instruments in our 2019 hedge program are puts and put spreads that provide full upside to oil price movements. For the first and second quarters of 2020, CRC has protected the downside risk of approximately 25,000 and 15,000 barrels per day at approximately $72 Brent and $70 Brent, respectively. CRC's 2019 and 2020 put spreads provide downside price protection until Brent prices drop to between $55 and $60 per barrel, at which point we receive Brent plus approximately $15 per barrel. See Attachment 7 for more details.

[1] See Attachment 3 for non-GAAP financial measures of adjusted EBITDAX, adjusted EBITDAX margin, adjusted EBITDAX per BOE, production costs (excluding the effects of PSC-type contracts) and adjusted net income (loss), including reconciliations to their most directly comparable GAAP measure, where applicable.

Conference Call Details

To participate in today’s conference call scheduled for 5:00 P.M. Eastern Daylight 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/DiamondPassRegistration/register?linkSecurityString=78449&confirmationNumber=10129738. 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, distributions to JV partners or changes to CRC's capital plan
- inability to enter into 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 CRC's 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.

Attachment 1

SUMMARY OF RESULTS

	First Quarter	
($ and shares in millions, except per share amounts)	**2019**	2018
Statements of Operations:		
Revenues and Other		
Oil and gas sales	**$ 601**	$ 575
Net derivative loss from commodity contracts	**(89)**	(38)
Other revenue	**178**	72
Total revenues and other	**690**	609
Costs and Other		
Production costs	**233**	212
General and administrative expenses	**83**	63
Depreciation, depletion and amortization	**118**	119
Taxes other than on income	**41**	38
Exploration expense	**10**	8
Other expenses, net	**148**	61
Total costs and other	**633**	501
Operating Income	**57**	108
Non-Operating (Loss) Income		
Interest and debt expense, net	**(100)**	(92)
Net gain on early extinguishment of debt	**6**	—
Gain on asset divestitures	**—**	—
Other non-operating expenses	**(7)**	(7)
(Loss) Income Before Income Taxes	**(44)**	9
Income tax	**—**	—
Net (Loss) Income	**(44)**	9
Net income attributable to noncontrolling interests	**(23)**	(11)
Net Loss Attributable to Common Stock	**$ (67)**	$ (2)
Net loss attributable to common stock per share - basic	**$ (1.38)**	$ (0.05)
Net loss attributable to common stock per share - diluted	**$ (1.38)**	$ (0.05)
Adjusted net income	**$ 31**	$ 8
Adjusted net income per share - basic	**$ 0.64**	$ 0.18
Adjusted net income per share - diluted	**$ 0.63**	$ 0.18
Weighted-average common shares outstanding - basic	**48.7**	44.2
Weighted-average common shares outstanding - diluted	**48.7**	44.2

Adjusted EBITDAX	**$ 301**	$ 250
Effective tax rate	**0%**	0%

	First Quarter	
($ and shares in millions)	**2019**	2018
Cash Flow Data:		
Net cash provided by operating activities	**$ 158**	$ 200
Net cash used in investing activities	**$ (182)**	$ (138)
Net cash provided by financing activities	**$ 50**	$ 412

($ in millions)	**March 31, 2019**	December 31, 2018
Selected Balance Sheet Data:		
Total current assets	**$ 577**	$ 640
Total property, plant and equipment, net	**$ 6,548**	$ 6,455
Total current liabilities	**$ 689**	$ 607
Long-term debt	**$ 5,169**	$ 5,251
Other long-term liabilities	**$ 692**	$ 575
Mezzanine equity	**$ 766**	$ 756
Equity	**$ (289)**	$ (247)
Outstanding shares as of	**48.8**	48.7

STOCK-BASED COMPENSATION

Our consolidated results of operations for the three months ended March 31, 2019 and 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 introduce volatility in our results of operations 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 unvested 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 approximately 50% of our total outstanding awards. Our stock price increased $8.67 or 51% from $17.04 as of December 31, 2018 to $25.71 as of March 31, 2019. The increase in our stock price resulted in higher cash-settled stock-based 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:

	First Quarter	
($ in millions, except per BOE amounts)	**2019**	2018
General and administrative expenses		
Cash-settled awards	**$ 10**	$ 3
Equity-settled awards	**3**	3
Total stock-based compensation in G&A	**$ 13**	$ 6

Total stock-based compensation in G&A per Boe	**$1.09**	$0.54
Production costs		
Cash-settled awards	**$ 3**	$ 1
Equity-settled awards	**1**	1
Total stock-based compensation in production costs	**$ 4**	$ 2
Total stock-based compensation in production costs per Boe	**$0.33**	$0.18
Total company stock-based compensation	**$ 17**	$ 8
Total company stock-based compensation per Boe	**$1.42**	$0.72

DERIVATIVE GAINS AND LOSSES

The following table presents the components of our net derivative loss from commodity contracts and our non-cash derivative loss from interest-rate contracts. Our non-cash derivative loss from interest-rate contracts is reported in other non-operating expenses.

	First Quarter	
($ millions)	**2019**	2018
Commodity Contracts:		
Non-cash derivative loss excluding noncontrolling interest	**$(97)**	$ (7)
Non-cash derivative loss - noncontrolling interest	**(6)**	—
Net proceeds (payments) on settled commodity derivatives	**14**	(31)
Net derivative loss from commodity contracts	**$(89)**	$(38)
Interest-Rate Contracts:		
Non-cash derivative loss	**$ (3)**	$ —

Attachment 2

PRODUCTION STATISTICS

	First Quarter	
Net Oil, NGLs and Natural Gas Production Per Day	**2019**	2018
Oil (MBbl/d)		
San Joaquin Basin	**55**	49
Los Angeles Basin	**25**	24
Ventura Basin	**4**	4
Total	**84**	77
NGLs (MBbl/d)		
San Joaquin Basin	**14**	15
Ventura Basin	**1**	1
Total	**15**	16
Natural Gas (MMcf/d)		
San Joaquin Basin	**165**	143
Los Angeles Basin	**2**	1
Ventura Basin	**7**	7
Sacramento Basin	**28**	31
Total	**202**	182
Total Production (MBoe/d)	**133**	123

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 (Boe) per day. Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

Attachment 3

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

Our results of operations, which are presented in accordance with generally accepted accounting principles (GAAP), 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 certain non-GAAP measures to assess our financial condition, results of operations and cash flows. These measures 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.

Below are additional disclosures regarding each of the non-GAAP measures reported in this press release, including reconciliations to their most directly comparable GAAP measure where applicable.

ADJUSTED NET INCOME (LOSS)

Management uses a measure called adjusted net income (loss) to provide useful information to investors interested in comparing our core operations between periods and our performance to our peers. This measure is not meant to disassociate the effects of unusual, out-of-period and infrequent items affecting earnings from management's performance but rather to provide useful information to investors in comparing our financial performance with the financial performance of other companies. Adjusted net income (loss) is not considered to be an alternative to net income (loss) reported in accordance with GAAP. The following table presents a reconciliation of the GAAP financial measure of net (loss) income attributable to common stock to the non-GAAP financial measure of adjusted net income (loss) and presents the GAAP financial measure of net (loss) attributable to common stock per diluted share and the non-GAAP financial measure of adjusted net income per diluted share.

	First Quarter	
($ millions, except per share amounts)	**2019**	2018
Net (loss) income	**$ (44)**	$ 9
Net income attributable to noncontrolling interests	**(23)**	(11)
Net loss attributable to common stock	**(67)**	(2)
Unusual, infrequent and other items:		
Non-cash derivative loss from commodities excluding noncontrolling interest	**97**	7
Non-cash derivative loss from interest-rate contracts	**3**	—
Early retirement costs	**—**	2
Net gain on early extinguishment of debt	**(6)**	—
Other, net	**4**	1
Total unusual, infrequent and other items	**98**	10
Adjusted net income	**$ 31**	$ 8
Net loss attributable to common stock per share - diluted	**$(1.38)**	$(0.05)
Adjusted net income per share - diluted	**$ 0.63**	$ 0.18

FREE CASH FLOW

Management uses free cash flow, which is defined by us as net cash provided by operating activities after our internal capital investment, as a measure of liquidity. The following table presents a reconciliation of net cash provided by operating activities to free cash flow after internally funded capital investment.

	First Quarter	
($ millions)	**2019**	2018
Net cash provided by operating activities	**$158**	$200

Capital investment	**(131)**	(139)
Free cash flow	**27**	61
BSP funded capital investment	**27**	—
Free cash flow excluding BSP funded capital	**$ 54**	$ 61

DISCRETIONARY CASH FLOW

We define discretionary cash flow as the cash available after distributions to noncontrolling interests and cash interest, excluding the effect of working capital changes but before our internal capital investment. Management uses discretionary cash flow as a measure of the availability of cash to reduce debt or fund investments.

	First Quarter	
($ millions)	**2019**	2018
Adjusted EBITDAX	**$ 301**	$ 250
Cash Interest	**(72)**	(61)
Distributions to noncontrolling interests:		
BSP joint venture [(a)]	**(19)**	(13)
Ares joint venture	**(20)**	(5)
Discretionary Cash Flow	**$ 190**	$ 171

(a) The first quarter 2019 distribution of $19 million was paid in April 2019.

ADJUSTED EBITDAX

We define adjusted EBITDAX 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. Management uses adjusted EBITDAX as a measure of operating cash flow without working capital adjustments. 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, performance and liquidity measures calculated in accordance with GAAP. The following table presents a reconciliation of the GAAP financial measures of net (loss) income and net cash provided by operating activities to the non-GAAP financial measure of adjusted EBITDAX.

	First Quarter	
($ millions, except per BOE amounts)	**2019**	2018
Net (loss) income	**$ (44)**	$ 9
Interest and debt expense, net	**100**	92
Depreciation, depletion and amortization	**118**	119
Exploration expense	**10**	8
Unusual, infrequent and other items [(a)]	**98**	10
Other non-cash items	**19**	12
Adjusted EBITDAX	**$ 301**	$ 250
Net cash provided by operating activities	**$ 158**	$ 200
Cash interest	**72**	61
Exploration expenditures	**4**	6
Working capital changes	**67**	(18)
Other, net	**—**	1
Adjusted EBITDAX	**$ 301**	$ 250
Adjusted EBITDAX per Boe	**$25.13**	$22.51

(a) See Adjusted Net Income reconciliation.

ADJUSTED EBITDAX MARGIN

Management uses adjusted EBITDAX margin as a measure of profitability between periods and this measure is used by analysts for comparative purposes within the industry.

($ millions)	First Quarter 2019	2018
Total revenues and other	**$690**	$609
Non-cash derivative loss	**103**	7
Revenues, excluding non-cash derivative loss	**$793**	$616
Adjusted EBITDAX Margin	**38%**	41%

PRODUCTION COSTS PER BOE

The reporting of our PSC-type contracts creates a difference between reported production costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel production costs. The following table presents production costs after adjusting for the excess costs attributable to PSC-type contracts.

($ per Boe)	First Quarter 2019	2018
Production costs	**$19.46**	$19.08
Excess costs attributable to PSC-type contracts	**(1.45)**	(1.61)
Production costs, excluding effects of PSC-type contracts	**$18.01**	$17.47

Attachment 4

CAPITAL INVESTMENTS

($ millions)	First Quarter 2019	2018
Internally Funded Capital	**$ 104**	$ 139
BSP Funded Capital	**27**	—
Capital Investments - Consolidated	**$ 131**	$ 139
MIRA Funded Capital	**7**	22
Total Capital Program	**$ 138**	$ 161

Attachment 5

PRICE STATISTICS

	First Quarter 2019	2018
Realized Prices		
Oil with hedge ($/Bbl)	**$65.28**	$62.77
Oil without hedge ($/Bbl)	**$63.30**	$67.26
NGLs ($/Bbl)	**$42.52**	$43.13
Natural gas ($/Mcf)	**$ 3.43**	$ 2.81

Index Prices		
Brent oil ($/Bbl)	**$63.90**	$67.18
WTI oil ($/Bbl)	**$54.90**	$62.87
NYMEX gas ($/MMBtu)	**$ 3.24**	$ 2.87
Realized Prices as Percentage of Index Prices		
Oil with hedge as a percentage of Brent	**102%**	93%
Oil without hedge as a percentage of Brent	**99%**	100%
Oil with hedge as a percentage of WTI	**119%**	100%
Oil without hedge as a percentage of WTI	**115%**	107%
NGLs as a percentage of Brent	**67%**	64%
NGLs as a percentage of WTI	**77%**	69%
Natural gas as a percentage of NYMEX	**106%**	98%

Attachment 6

FIRST QUARTER DRILLING ACTIVITY

Wells Drilled	**San Joaquin Basin**	**Los Angeles Basin**	**Ventura Basin**	**Sacramento Basin**	**Total**
Development Wells					
Primary	2	—	—	—	2
Waterflood	1	8	—	—	9
Steamflood	35	—	—	—	35
Unconventional	6	—	—	—	6
Total	44	8	—	—	52
Exploration Wells					
Primary	2	—	1	—	3
Waterflood	—	—	—	—	—
Steamflood	5	—	—	—	5
Unconventional	—	—	—	—	—
Total	7	—	1	—	8
Total Wells [a]	51	8	1	—	60
CRC Wells Drilled	38	3	1	—	42
BSP Wells Drilled	12	5	—	—	17
MIRA Wells Drilled	1	—	—	—	1

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

Attachment 7

HEDGES - CURRENT

	2Q 2019	**3Q 2019**	**4Q 2019**	**1Q 2020**	**2Q 2020**
CRUDE OIL					
Sold Calls:					
Barrels per day	5,000	—	—	—	—

Weighted-average Brent price per barrel	$68.45	$ —	$ —	$ —	$ —
Purchased Puts:					
Barrels per day	40,000	40,000	35,000	20,000	10,000
Weighted-average Brent price per barrel	$69.75	$73.13	$75.71	$72.50	$70.00
Sold Puts:					
Barrels per day	35,000	40,000	35,000	20,000	10,000
Weighted-average Brent price per barrel	$55.71	$57.50	$60.00	$57.50	$55.00
Swaps:					
Barrels per day	—	—	—	5,000 (a)	5,000 (a)
Weighted-average Brent price per barrel	$ —	$ —	$ —	$70.29	$70.05

The BSP JV entered into crude oil derivatives for insignificant volumes through 2021 that are included in our consolidated results but not in the above table. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021. The hedges entered into by the BSP JV could affect the timing of the redemption of the JV interest.

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.

(a) A counterparty has options to increase swap volumes by up to:
- 5,000 barrels per day at a weighted-average Brent price of $70.29 for the first quarter of 2020
- 5,000 barrels per day at a weighted-average Brent price of $70.05 for the second quarter of 2020

Attachment 8

2019 SECOND QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q2 2019 (a)

Oil	95% to 100% of Brent
NGLs	41% to 46% of Brent
Natural Gas	85% to 95% of NYMEX

2019 Second Quarter Production, Capital and Income Statement Guidance

Production (assumed Q2 average Brent price of $68/Bbl)	127 to 133 MBOE per day
Production (assumed Q2 average Brent price of $73/Bbl)	126 to 132 MBOE per day
Capital (b)	$115 million to $145 million
Production costs (assumed Q2 average Brent price of $68/Bbl)	$17.75 to $19.25 per BOE
Production costs (assumed Q2 average Brent price of $73/Bbl)	$17.90 to $19.40 per BOE
Adjusted general and administrative expenses (c) & (d)	$6.55 to $6.95 per BOE
Depreciation, depletion and amortization (c)	$10.15 to $10.45 per BOE
Taxes other than on income	$36 million to $40 million
Exploration expense	$9 million to $14 million
Interest expense (e)	$96 million to $101 million
Cash interest (e)	$151 million to $156 million
Income tax expense rate	0%
Cash tax rate	0%

Pre-tax 2019 Second Quarter Price Sensitivities (f)

$1 change in Brent index - Oil (g)	$6.0 million
$1 change in Brent index - NGLs	$0.6 million

$0.50 change in NYMEX - Gas	$4.6 million

(a) Realizations exclude hedge effects.

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

(c) Production based on assumed Q2 average Brent price of $68/Bbl.

(d) A portion of 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 cash-settled 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 expense could include this cumulative adjustment depending on movement in our stock price. Our stock price used to set second quarter 2019 guidance was $25.70 per share.

(e) 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 higher than interest expense due to the timing of interest payments.

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

(g) Amount reflects the sensitivity with respect to unhedged barrels which have no upside limitation. We have downside protection on approximately 49% of our oil production, at a weighted average Brent floor price of $68 per barrel below which we receive Brent plus approximately $12 per barrel.