NEWS RELEASE

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California Resources Corporation Announces Second Quarter 2018 Results

LOS ANGELES, August 2, 2018 - 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 $82 million, or $1.70 per diluted share, for the second quarter of 2018. Adjusted net loss[1] for the second quarter of 2018 was $14 million, or $0.29 per diluted share.

Quarterly Highlights Include:

- Generated core adjusted EBITDAX[1] of $337 million excluding the impact of $68 million of cash hedging losses and $24 million of stock-based compensation expenses
- Reported adjusted EBITDAX[1] of $245 million including these items, and an adjusted EBITDAX margin[1] of 38%
- Produced 134,000 BOE per day, above the midpoint of the guidance range
- Internally funded capital investments of $170 million
- Drilled 48 wells with internally funded capital and 35 wells with joint venture (JV) capital
- Implemented $15 million of annualized synergies from the acquired Elk Hills interests, well ahead of anticipated pace

2018 Outlook:

- Increased 2018 capital budget to a range of $650 million to $700 million (including approximately $100 million or more of JV funding), subject to further adjustments based on commodity prices in the second half of the year and other developments
- Incremental capital directed to drilling, workover and facilities projects in the San Joaquin, Los Angeles and Ventura basins
- Third quarter 2018 production guidance of 134,000 to 138,000 BOE per day
- Third quarter 2018 production forecast reflects CRC's return to a growth profile

Todd A. Stevens, CRC's President and Chief Executive Officer, said, "CRC is building sustained momentum as our experienced and pressure tested teams continue to drive strong operational execution and as we take advantage of the breadth and diversity of our California portfolio. Our teams are driving improved efficiencies in the field and we expect to deliver value-oriented production growth through the second half of 2018. This is showcased by our ability to capture near-term synergies from the consolidation of CRC's flagship Elk Hills interests quicker than expected, in addition to solid production results we are witnessing from our drilling activity. Looking ahead, we are keenly monitoring crude oil fundamentals and commodity markets to flex our capital plans and enhance our 2019 cash flow performance. We expect our mid-cycle capital investment plan should maximize value creation through value-oriented production increases along with stronger EBITDAX growth into 2019, particularly with the modified hedging strategy."

Second Quarter 2018 Results

For the second quarter of 2018, the CRC net loss was $82 million, or $1.70 per diluted share, while adjusted net loss[1] was $14 million, or $0.29 per diluted share. Adjusted net loss[1] excluded $92 million of non-cash derivative losses and a net gain of $24 million on debt repurchases. These results compared to a net loss of $48 million, or $1.13 per diluted share, and an adjusted net loss of $78 million, or $1.83 per diluted share, in the prior year period. The 2018 results represented higher production and significantly higher realized oil and NGL prices offset by hedge results and higher production costs resulting from increased activity levels and equity compensation.

Total daily production volumes averaged 134,000 barrels of oil equivalent (BOE) per day for the second quarter of 2018, compared to 129,000 BOE per day for the same period in 2017, an increase of nearly 4 percent driven by the Elk Hills acquisition. This net increase included a 1,600 BOE per day negative effect on production volumes from our PSCs. For the second quarter of 2018, oil volumes averaged 83,000 barrels per day, NGL volumes averaged 16,000 barrels per day and gas volumes averaged 210,000 thousand cubic feet (MCF) per day.

Realized crude oil prices, including the effect of settled hedges, increased by $16.13 per barrel in the second quarter of 2018 to $64.11 per barrel from the prior year comparable period. Settled hedges decreased realized crude oil prices by $9.08 per barrel. Average realized NGL prices continued to be strong and registered $42.13 per barrel, reflecting a realized price that was 56% of Brent prices. Realized natural gas prices were $2.25 per MCF.

Production costs for the second quarter of 2018 were $231 million, compared to $216 million in the second quarter of 2017, an increase of $15 million primarily due to higher production from the Elk Hills acquisition of $12 million, and increased equity compensation expense of $5 million resulting from the stock price increase. On a per unit basis, second quarter production costs were $18.93 per BOE, compared to $18.34 per BOE in the prior year comparable period. Second quarter unit production costs were within the previously disclosed guidance levels, and would have been $18.52 excluding higher equity compensation expense or $0.56 per BOE lower on a sequential basis from first quarter 2018 unit production costs of $19.08. In line with industry practice for companies operating under PSCs, CRC reports gross field operating costs and only the Company's share of production volumes, which can result in higher production costs per barrel. Excluding this PSC effect, per unit production costs[1] for the second quarter of 2018 would have been $17.41. General and administrative (G&A) expenses were $90 million for the second quarter of 2018, compared to $63 million in the first quarter of 2018 and $31 million higher than the prior year comparable period primarily related to higher equity compensation expense as a result of CRC's increased stock price. CRC's increased stock price added $19 million to the current year expense compared to the prior year period. The Elk Hills acquisition added another $3 million to second quarter 2018 G&A expense. The rest of the increase was mostly related to the timing of certain expenses.

CRC reported taxes other than on income of $37 million, $6 million higher than the prior year period largely due to higher property taxes as a result of commodity price increases. Exploration expense of $6 million for the second quarter of 2018 remained flat to the prior year comparable period.

Capital investment in the second quarter of 2018 totaled $170 million, excluding JV capital. Approximately $115 million was directed to drilling and capital workovers.

Cash provided by operating activities was $34 million, which included interest payments of $154 million. CRC's working capital use is larger in the second and fourth quarters of the year due to the timing of interest and property tax payments. CRC's free cash flow[1] was $(136) million in the second quarter of 2018 after taking into account capital that was funded by BSP.

Six-Month Results

For the first six months of 2018, CRC net loss was $84 million, or $1.81 per diluted share, compared to net income of $5 million, or $0.12 per diluted share, for the same period of 2017. The 2018 results reflected significantly higher realized oil and NGL prices offset by hedge results and higher production costs resulting from higher activity levels, energy costs and equity compensation. The adjusted net loss[1] for the first six months of 2018 was $6 million, or $0.13 per diluted share, compared with an adjusted net loss of $121 million, or $2.85 per diluted share, for the same period of 2017. The 2018 adjusted net loss excluded $99 million of non-cash derivative losses, a gain of $24 million on debt repurchases and a net $3 million charge related to other unusual and infrequent items. The 2017 adjusted net loss excluded $110 million of non-cash derivative gains, $21 million of gains from asset divestitures, a $4 million gain on debt repurchases and a $9 million charge from other unusual and infrequent items.

Total daily production volumes averaged 129,000 BOE per day in the first six months of 2018, compared with 131,000 BOE per day for the same period in 2017, a decrease of 2 percent. This decrease included a negative effect on production volumes from our PSCs of 2,000 BOE per day. Excluding production from the Elk Hills acquisition and the effect of PSC contracts, the decline from the first half of 2017 to the first half of 2018 was 4%, which is below CRC's previously reported base production decline range.

In the first six months of 2018, realized crude oil prices, including the effect of settled hedges, increased $14.35 per barrel to $63.47 per barrel from $49.12 per barrel for the same period in 2017. Settled hedges reduced 2018 realized crude oil prices by $6.88 per barrel, compared with an increase of $0.42 per barrel for the same period in 2017. Realized NGL prices increased 32 percent to $42.63 from $32.20 per barrel in the first six months of 2017. Realized natural gas prices decreased 6 percent to $2.51 per Mcf, compared with $2.68 per Mcf for the same period in 2017.

Production costs for the first six months of 2018 were $443 million, or $19.01 per BOE, compared to $427 million, or $18.02 per BOE, for the same period in 2017. The Elk Hills transaction added $12 million to the first six months' production costs, and the increase in equity compensation expense added $6 million, or $0.25 per BOE. Excluding these items, production costs were slightly lower in the current year period compared to the prior year due to efficiencies delivered. Per unit production costs, excluding the effect of PSC contracts, were $17.44 and $16.92 per BOE for the first six months of 2018 and 2017, respectively. G&A expenses for the first six months of 2018 were $153 million and for the first six months of 2017 were $122 million, with the difference almost entirely related to the increased equity compensation expense resulting from the stock price increase.

Taxes other than on income of $75 million for the first six months of 2018 were $11 million higher than the same period of 2017 primarily due to higher property taxes as a result of commodity price increases. Exploration expense of $14 million for the first six months of 2018 was $2 million higher than the same period of 2017.

Capital investment in the first six months of 2018 totaled $309 million excluding JV capital, of which $209 million was directed to drilling and capital workovers.

Cash provided by operating activities for the first six months of 2018 was $234 million and free cash flow was $(75) million after taking into account capital that was funded by BSP.

Operational Update

CRC operated an average of ten rigs during the second quarter of 2018 and drilled 83 development wells with CRC and JV capital (51 steamflood, 18 waterflood, three primary and 11 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 year that the well is drilled. In the San Joaquin basin, CRC operated seven rigs and produced approximately 98,000 BOE per day for the second quarter of 2018. The Los Angeles basin had three rigs directed toward waterflood projects, and contributed 25,000 BOE per day of production in the second quarter. Production for the Ventura basin was 6,000 BOE per day and the Sacramento basin produced 5,000 BOE per day. Neither of these areas had active drilling programs in the period.

2018 Capital Budget

With stronger expected cash flows from commodity price improvements and increased production from the Elk Hills transaction, combined with synergies resulting from the transaction, CRC increased its 2018 capital program to a range from $650 million to $700 million, which includes approximately $100 million or more of JV capital, subject to further adjustments based on commodity prices in the second half of the year and other developments. This is an increase from its previously stated range of $550 million to $600 million. The incremental investment builds on the momentum created to increase second half 2018 production with a more substantial effect in 2019. The additional capital will primarily be deployed to drilling, workovers and facilities in the San Joaquin, Los Angeles and Ventura basins. As expected, CRC received funding of a third tranche of the BSP capital in the second quarter of 2018.

Debt Reduction Update

CRC continued to validate its commitment to strengthening the balance sheet. In the second quarter of 2018, CRC repurchased a total of $143 million in aggregate principal amount of the Company's outstanding debt for $118 million in cash.

Borrowing Base Redetermination

As previously disclosed, effective May 1, 2018, CRC's borrowing base under its 2014 Credit Agreement was reaffirmed at $2.3 billion.

Hedging Update

CRC continues to opportunistically seek hedging transactions to protect its cash flow, operating margins and capital program while maintaining adequate liquidity. For the first and second quarters of 2019, CRC has hedged approximately 42,000 and 37,000 barrels per day, at approximately $64 Brent and $67 Brent, respectively. In the third and fourth quarters of 2019, the Company hedged approximately 32,000 and 22,000 barrels per day, at approximately $71 and $73 Brent, respectively. A significant majority of the 2019 hedges do not contain caps, thereby providing upside to oil price movements. See Attachment 8 for more details.

CRC also purchased LIBOR interest rate caps in the second quarter of 2018 which cap the interest rate on a notional $1.3 billion at one-month LIBOR of 2.75% through May 2021.

[1] See Attachment 3 for explanations of 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 as 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/10120726. 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. The Company 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 the Company's expectations as to future:

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects
- operating costs
- operations and operational results including production, hedging, capital investment and expected value creation index (VCI)
- capital budgets and maintenance capital requirements
- reserves
- type curves
- expected synergies from acquisitions

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While CRC believes the assumptions or bases underlying its expectations are reasonable and makes them in good faith, they almost always vary from actual results, sometimes materially. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on its financial flexibility
- insufficient cash flow to fund planned investment or changes to our capital plan
- inability to enter desirable transactions including 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 its products
- PSC effects on production and unit production costs
- effect of stock price on costs associated with incentive compensation
- competition with larger, better funded competitors for and costs of oilfield equipment, services, qualified personnel and acquisitions
- incorrect estimates of reserves and related future net cash flows
- joint venture and acquisition activities and our ability to achieve expected synergies
- the recoverability of resources
- unexpected geologic conditions
- changes in business strategy
- inability to replace reserves
- insufficient capital, including as a result of lender restrictions, unavailability of capital markets or inability to attract potential investors
- effects of hedging transactions and inability to enter efficient hedges
- 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 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 www.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 the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

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SUMMARY OF RESULTS

($ and shares in millions, except per share amounts)	Second Quarter 2018	Second Quarter 2017	Six Months 2018	Six Months 2017
Statement of Operations Data:				
Revenues and Other				
Oil and gas sales	**$ 657**	$ 439	**$ 1,232**	$ 926
Net derivative (loss) gain from commodity contracts	**(167)**	43	**(205)**	116
Other revenue	**59**	34	**131**	64
Total revenues and other [(a)]	**549**	516	**1,158**	1,106
Costs and Other				
Production costs	**231**	216	**443**	427
General and administrative expenses	**90**	59	**153**	122
Depreciation, depletion and amortization	**125**	138	**244**	278
Taxes other than on income	**37**	31	**75**	64
Exploration expense	**6**	6	**14**	12
Other expenses, net [(a)]	**49**	25	**110**	47
Total costs and other	**538**	475	**1,039**	950
Operating Income	**11**	41	**119**	156
Non-Operating (Loss) Income				
Interest and debt expense, net	**(94)**	(83)	**(186)**	(167)
Net gain on early extinguishment of debt	**24**	—	**24**	4
Gain on asset divestitures	**1**	—	**1**	21
Other non-operating expenses	**(5)**	(5)	**(12)**	(9)
(Loss) Income Before Income Taxes	**(63)**	(47)	**(54)**	5
Income tax	**—**	—	**—**	—
Net (Loss) Income	**(63)**	(47)	**(54)**	5
Net income attributable to noncontrolling interests	**(19)**	(1)	**(30)**	—
Net (Loss) Income Attributable to Common Stock	**$ (82)**	$ (48)	**$ (84)**	$ 5
Net (loss) income attributable to common stock per share - basic	**$ (1.70)**	$ (1.13)	**$ (1.81)**	$ 0.12
Net (loss) income attributable to common stock per share - diluted	**$ (1.70)**	$ (1.13)	**$ (1.81)**	$ 0.12
Adjusted net loss	**$ (14)**	$ (78)	**$ (6)**	$ (121)
Adjusted net loss per diluted share	**$ (0.29)**	$ (1.83)	**$ (0.13)**	$ (2.85)
Weighted-average common shares outstanding - basic	**48.2**	42.4	**46.3**	42.4
Weighted-average common shares outstanding - diluted	**48.2**	42.4	**46.3**	42.7
Adjusted EBITDAX	**$ 245**	$ 161	**$ 495**	$ 361
Effective tax rate	**0%**	0%	**0%**	0%

(a) We adopted the 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 after 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 prior period. Under prior accounting standards total revenues and other for the three months and the six months ended June 30, 2018 would have been $513 million and $1,080 million, respectively, and other expenses, net for the three months and the six months ended June 30, 2018 would have been $13 million and $32 million, respectively.

Cash Flow Data:	Second Quarter 2018	Second Quarter 2017	Six Months 2018	Six Months 2017
Net cash provided (used) by operating activities	**$ 34**	$ (13)	**$ 234**	$ 120
Net cash used in investing activities	**$ (669)**	$ (74)	**$ (807)**	$ (74)
Net cash provided (used) by financing activities	**$ 183**	$ 46	**$ 595**	$ (49)

Balance Sheet Data:		June 30, 2018		December 31, 2017
Total current assets	**$**	**559**	$	483
Total property, plant and equipment, net	**$**	**6,334**	$	5,696
Total current liabilities	**$**	**893**	$	732
Long-term debt	**$**	**5,075**	$	5,306
Mezzanine equity	**$**	**735**	$	—
Equity	**$**	**(645)**	$	(720)
Outstanding shares as of		**48.4**		42.9

STOCK-BASED COMPENSATION

Our stock price increased $36.89 or over 430% from $8.55 as of June 30, 2017 to $45.44 as of June 30, 2018. Due to our stock price increase, we recognized a significant increase in stock-based compensation expense that is included in both general and administrative expenses and production costs as shown in the following table:

	Second Quarter				Six Months			
($ in millions)		**2018**		2017		**2018**		2017
General and administrative expenses								
Cash-settled awards	**$**	**19**	$	—	**$**	**22**	$	1
Equity-settled awards		**4**		4		**7**		7
Total stock-based compensation in G&A	**$**	**23**	$	4	**$**	**29**	$	8
Total stock-based compensation in G&A per Boe	**$**	**1.89**	$	0.34	**$**	**1.24**	$	0.34
Production costs								
Cash-settled awards	**$**	**5**	$	—	**$**	**6**	$	—
Equity-settled awards		**1**		1		**2**		2
Total stock-based compensation in production costs	**$**	**6**	$	1	**$**	**8**	$	2
Total stock-based compensation in production costs per Boe	**$**	**0.49**	$	0.08	**$**	**0.34**	$	0.08
Total company stock-based compensation	**$**	**29**	$	5	**$**	**37**	$	10
Total company stock-based compensation per Boe	**$**	**2.38**	$	0.42	**$**	**1.58**	$	0.42

PRODUCTION STATISTICS

Net Oil, NGLs and Natural Gas Production Per Day	Second Quarter		Six Months	
	2018	2017	**2018**	2017
Oil (MBbl/d)				
San Joaquin Basin	**54**	52	**52**	52
Los Angeles Basin	**25**	26	**24**	27
Ventura Basin	**4**	5	**4**	5
Sacramento Basin	**—**	—	**—**	—
Total	**83**	83	**80**	84
NGLs (MBbl/d)				
San Joaquin Basin	**15**	15	**15**	15
Los Angeles Basin	**—**	—	**—**	—
Ventura Basin	**1**	1	**1**	1
Sacramento Basin	**—**	—	**—**	—
Total	**16**	16	**16**	16
Natural Gas (MMcf/d)				
San Joaquin Basin	**172**	141	**157**	141
Los Angeles Basin	**1**	—	**1**	1
Ventura Basin	**8**	8	**7**	8
Sacramento Basin	**29**	33	**31**	33
Total	**210**	182	**196**	183
Total Production (MBoe/d) [(a)]	**134**	129	**129**	131

(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 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. We believe adjusted EBITDAX provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry, the investment community and our lenders. While adjusted EBITDAX is a non-GAAP measure, the amounts included in the calculation of adjusted EBITDAX were computed in accordance with GAAP. A version of this measure 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. Certain items excluded from adjusted EBITDAX 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. Adjusted EBITDAX should be read in conjunction with the information contained in our financial statements prepared 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 loss and presents the GAAP financial measure of net (loss) income attributable to common stock per diluted share and the non-GAAP financial measure of Adjusted net loss per diluted share:

	Second Quarter		Six Months	
($ millions, except per share amounts)	**2018**	2017	**2018**	2017
Net (loss) income attributable to common stock	**$ (82)**	$ (48)	**$ (84)**	$ 5
Unusual, infrequent and other items:				
Non-cash derivative loss (gain), excluding noncontrolling interest	**92**	(35)	**99**	(110)
Early retirement and severance costs	**2**	—	**4**	3
Gain on asset divestitures	**(1)**	—	**(1)**	(21)
Net gain on early extinguishment of debt	**(24)**	—	**(24)**	(4)
Other, net	**(1)**	5	**—**	6
Total unusual, infrequent and other items	**68**	(30)	**78**	(126)
Adjusted net loss	**$ (14)**	$ (78)	**$ (6)**	$ (121)
Net (loss) income attributable to common stock per diluted share	**$ (1.70)**	$ (1.13)	**$ (1.81)**	$ 0.12
Adjusted net loss per diluted share	**$ (0.29)**	$ (1.83)	**$ (0.13)**	$ (2.85)

DERIVATIVE GAINS AND LOSSES

	Second Quarter		Six Months	
($ millions)	**2018**	2017	**2018**	2017
Non-cash derivative (loss) gain, excluding noncontrolling interest	**$ (92)**	$ 35	**$ (99)**	$ 110
Non-cash derivative loss included in noncontrolling interest	**(7)**	—	**(7)**	(1)
Net (payments) proceeds on settled commodity derivatives	**(68)**	8	**(99)**	7
Net derivative (loss) gain from commodity contracts	**$ (167)**	$ 43	**$ (205)**	$ 116

FREE CASH FLOW

($ millions)	Second Quarter 2018	Second Quarter 2017	Six Months 2018	Six Months 2017
Net cash provided (used) by operating activities	**$ 34**	$ (13)	**$ 234**	$ 120
Capital investment	**(188)**	(82)	**(327)**	(132)
Free cash flow	**(154)**	(95)	**(93)**	(12)
BSP funded capital investment	**18**	28	**18**	43
Free cash flow excluding BSP funded capital	**$ (136)**	$ (67)	**$ (75)**	$ 31

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.

($ millions)	Second Quarter 2018	Second Quarter 2017	Six Months 2018	Six Months 2017
Net (loss) income	**$ (63)**	$ (47)	**$ (54)**	$ 5
Interest and debt expense, net	**94**	83	**186**	167
Interest income	**(1)**	—	**(1)**	—
Depreciation, depletion and amortization	**125**	138	**244**	278
Exploration expense	**6**	6	**14**	12
Unusual, infrequent and other items (a)	**68**	(30)	**78**	(126)
Other non-cash items	**16**	11	**28**	25
Adjusted EBITDAX (A)	**$ 245**	$ 161	**$ 495**	$ 361
Net payments (proceeds) on settled commodity derivatives	**68**	(8)	**99**	(7)
Cash-settled stock-based compensation	**24**	—	**28**	1
Core Adjusted EBITDAX (b)	**$ 337**	$ 153	**$ 662**	$ 355
Net cash provided (used) by operating activities	**$ 34**	$ (13)	**$ 234**	$ 120
Cash interest	**154**	151	**215**	195
Exploration expenditures	**4**	6	**10**	11
Changes in operating assets and liabilities	**55**	12	**37**	29
Other, net	**(2)**	5	**(1)**	6
Adjusted EBITDAX (A)	**$ 245**	$ 161	**$ 495**	$ 361
Net payments (proceeds) on settled commodity derivatives	**68**	(8)	**99**	(7)
Cash-settled stock-based compensation	**24**	—	**28**	1
Core Adjusted EBITDAX (b)	**$ 337**	$ 153	**$ 662**	$ 355

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

(b) Core Adjusted EBITDAX removes the transitory effects of settled hedges, which in 2018 limited CRC's full price realization. Our hedging strategy for 2019 has changed and we are not putting caps on price. Similarly, the significant run-up in our stock price has had a significant effect on our equity compensation costs due to a cumulative catch-up effect. The 2018 Core Adjusted EBITDAX demonstrates our cash generation capacity, taking into account our new hedging strategy going into 2019.

ADJUSTED EBITDAX MARGIN

($ millions)	Second Quarter 2018	Second Quarter 2017	Six Months 2018	Six Months 2017
Total revenues and other	**$ 549**	$ 516	**$ 1,158**	$ 1,106
Non-cash derivative loss (gain)	**99**	(35)	**106**	(109)
Adjusted revenues (B)	**$ 648**	$ 481	**$ 1,264**	$ 997
Adjusted EBITDAX Margin (A)/(B)	**38%**	33%	**39%**	36%

PRODUCTION COSTS PER BOE

($ per Boe)	Second Quarter 2018	Second Quarter 2017	Six Months 2018	Six Months 2017
Production costs	**$ 18.93**	$ 18.34	**$ 19.01**	$ 18.02
Costs attributable to PSC-type contracts	**(1.52)**	(1.16)	**(1.57)**	(1.10)
Production costs, excluding effects of PSC-type contracts	**$ 17.41**	$ 17.18	**$ 17.44**	$ 16.92

ADJUSTED NET LOSS VARIANCE ANALYSIS

($ millions)

2017 2nd Quarter Adjusted Net Loss	**$**	**(78)**
Price - Oil		121 [a]
Price - NGLs		18
Price - Natural Gas		(3)
Volume		3
Production cost		(15)
Taxes other than on income		(6)
DD&A rate		15
Interest expense		(11)
Adjusted general & administrative expenses		(30)
Net income attributable to noncontrolling interests		(18)
All others		(10)
2018 2nd Quarter Adjusted Net Loss	**$**	**(14)**

2017 Six-Month Adjusted Net Loss	**$**	**(121)**
Price - Oil		224 [a]
Price - NGLs		31
Price - Natural Gas		(6)
Volume		(45)
Production cost		(16)
Taxes other than on income		(11)
DD&A rate		29
Exploration expense		(2)
Interest expense		(19)
Adjusted general & administrative expenses		(30)
Net income attributable to noncontrolling interests		(30)
All others		(10)
2018 Six-Month Adjusted Net Loss	**$**	**(6)**

(a) Includes cash settlement payments on commodity derivatives

CAPITAL INVESTMENTS

($ millions)	Second Quarter 2018	Second Quarter 2017	Six Months 2018	Six Months 2017
Internally Funded Capital	**$ 170**	$ 45	**$ 309**	$ 80
BSP Funded Capital	**18**	37	**18**	52
Consolidated Reported Capital Investments	**$ 188**	$ 82	**$ 327**	$ 132
MIRA Funded Capital	**6**	8	**28**	8
Total Capital Program	**$ 194**	$ 90	**$ 355**	$ 140

NONCONTROLLING INTEREST DETAIL

($ millions)	Second Quarter 2018	Second Quarter 2017	Six Months 2018	Six Months 2017
Distributions to noncontrolling interest holders				
BSP Joint Venture	**$ 4**	$ 1	**$ 17**	$ 1
Ares Joint Venture	**19**	—	**24**	—
Total	**$ 23**	$ 1	**$ 41**	$ 1

PRICE STATISTICS

	Second Quarter		Six Months	
	2018	2017	**2018**	2017
Realized Prices				
Oil with hedge ($/Bbl)	**$ 64.11**	$ 47.98	**$ 63.47**	$ 49.12
Oil without hedge ($/Bbl)	**$ 73.19**	$ 46.95	**$ 70.35**	$ 48.70
NGLs ($/Bbl)	**$ 42.13**	$ 30.08	**$ 42.63**	$ 32.20
Natural gas ($/Mcf) [(a)]	**$ 2.25**	$ 2.47	**$ 2.51**	$ 2.68
Index Prices				
Brent oil ($/Bbl)	**$ 74.90**	$ 50.92	**$ 71.04**	$ 52.79
WTI oil ($/Bbl)	**$ 67.88**	$ 48.29	**$ 65.37**	$ 50.10
NYMEX gas ($/MMBtu)	**$ 2.75**	$ 3.14	**$ 2.81**	$ 3.20
Realized Prices as Percentage of Index Prices				
Oil with hedge as a percentage of Brent	**86%**	94%	**89%**	93%
Oil without hedge as a percentage of Brent	**98%**	92%	**99%**	92%
Oil with hedge as a percentage of WTI	**94%**	99%	**97%**	98%
Oil without hedge as a percentage of WTI	**108%**	97%	**108%**	97%
NGLs as a percentage of Brent	**56%**	59%	**60%**	61%
NGLs as a percentage of WTI	**62%**	62%	**65%**	64%
Natural gas as a percentage of NYMEX [(a)]	**82%**	79%	**89%**	84%

(a) See Note (a) on Attachment 1 related to our adoption of the new accounting standard related to the reporting of certain sales related costs. For the three months and six months ended June 30, 2018, the realized gas price would have been $2.06 per Mcf and $2.28 per Mcf, respectively, and the realized gas price as a percentage of NYMEX would have been 75% and 81%, respectively.

SECOND QUARTER DRILLING ACTIVITY

Wells Drilled (Gross)	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	3	—	—	—	3
Waterflood	3	15	—	—	18
Steamflood	51	—	—	—	51
Unconventional	11	—	—	—	11
Total	68	15	—	—	83
Exploration Wells					
Primary	—	—	—	—	—
Waterflood	—	—	—	—	—
Steamflood	—	—	—	—	—
Unconventional	—	—	—	—	—
Total	—	—	—	—	—
Total Wells [a]	68	15	—	—	83
CRC Wells Drilled	36	12	—	—	48
BSP Wells Drilled	2	3	—	—	5
MIRA Wells Drilled	30	—	—	—	30

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

HEDGES - CURRENT

	3Q 2018	4Q 2018	1Q 2019	2Q 2019	3Q 2019	4Q 2019	FY 2020	FY 2021
Crude Oil								
Sold Calls:								
Barrels per day	6,127	16,086	16,057	6,023	991	961	503	—
Weighted-average Brent price per barrel	$60.24	$58.91	$65.75	$67.01	$60.00	$60.00	$60.00	$—
Purchased Calls:								
Barrels per day	—	—	2,000	—	—	—	—	—
Weighted-average Brent price per barrel	$—	$—	$71.00	$—	$—	$—	$—	$—
Purchased Puts:								
Barrels per day	6,922	1,851	34,793	36,733	31,676	21,623	1,506	574
Weighted-average Brent price per barrel	$61.31	$51.70	$62.77	$67.40	$70.50	$73.09	$47.97	$45.00
Sold Puts:								
Barrels per day	24,000	19,000	35,000	30,000	30,000	20,000	—	—
Weighted-average Brent price per barrel	$46.04	$45.00	$50.71	$55.00	$56.67	$60.00	$—	$—
Swaps:								
Barrels per day	48,000	29,000	7,000	—	—	—	—	—
Weighted-average Brent price per barrel	$60.35	$60.50	$67.71	$—	$—	$—	$—	$—

A small portion of the crude oil derivatives in the table above were entered into by the BSP JV, including all of the 2020 and 2021 hedges. This joint venture also entered into natural gas swaps for insignificant volumes for periods through May 2021.

Certain of our counterparties have options to increase swap volumes by up to:
- 19,000 barrels per day at a weighted-average Brent price of $60.13 for the fourth quarter of 2018 and
- 5,000 barrels per day at a weighted-average Brent price of $70.00 for the first quarter of 2019.

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.

2018 THIRD QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q3 2018 [a]

Oil	95% to 100% of Brent
NGLs	55% to 60% of Brent
Natural Gas	100% to 110% of NYMEX

2018 Third Quarter Production, Capital and Income Statement Guidance

Production [b]	134 to 138 MBOE per day
Capital	$180 million to $200 million
Production costs [b]	$18.60 to $20.10 per BOE
Adjusted general and administrative expenses [b] & [c]	$6.60 to $6.90 per BOE
Depreciation, depletion and amortization [b]	$10.05 to $10.35 per BOE
Taxes other than on income	$42 million to $46 million
Exploration expense	$6 million to $10 million
Interest expense [d]	$94 million to $98 million
Cash interest [d]	$66 million to $70 million
Income tax expense rate	0%
Cash tax rate	0%

Pre-tax 2018 Third Quarter Price Sensitivities [e]

$1 change in Brent index - Oil [f]	$1.6 million
$1 change in Brent index - NGLs	$0.9 million
$0.50 change in NYMEX - Gas	$4.9 million

(a) Realizations exclude hedge effects.

(b) Based on average Q2 2018 Brent of $75.

(c) Our long-term incentive compensation programs for non-executive employees are stock based but payable in cash. Accounting rules require that we adjust the cumulative liability for all vested but yet unpaid awards under these programs to the amount that would be paid using our stock price as of the end of each quarter. 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 at June 30, 2018 was $45.44 per share, which was used for third quarter guidance. 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.

(d) 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.

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

(f) Amount reflects the sensitivity with respect to unhedged barrels at a Brent index price exceeding $60.00 per barrel and includes the effect of production sharing type contracts at our Wilmington field operations in Long Beach.