NEWS RELEASE

For immediate release

California Resources Corporation Announces Second Quarter 2019 Results

LOS ANGELES, August 1, 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 of $12 million, or $0.24 per diluted share, for the second quarter of 2019. Adjusted net loss[1] was $14 million, or $0.29 per diluted share. Operational and financial highlights for the second quarter of 2019 were as follows:

Highlights

- Reported adjusted EBITDAX[1] of $255 million; adjusted EBITDAX margin[1] of 39%; net cash provided by operating activities of $114 million
- Second quarter 2019 average daily production of 129,000 barrels of oil equivalent (BOE) per day, and oil production of 79,000 barrels per day
- CRC invested $124 million of internally funded capital and $140 million including JV capital
- Drilled 33 wells in the San Joaquin basin and 6 wells in the Los Angeles basin including JV wells
- Entered into a joint venture with subsidiaries of Colony Capital, Inc. to invest up to $500 million to further develop our flagship Elk Hills field, with an initial commitment of $320 million

Todd Stevens, CRC's President and Chief Executive Officer, said, "Our portfolio of quality assets continues to attract outside capital seeking reliable returns. Our three largest development joint ventures potentially provide for over $1 billion from our partners to drill our broad project inventory. We remain disciplined in utilizing our internal VCI metric to dynamically allocate our capital to maximize value in our portfolio. Strengthening our balance sheet remains a top focus and we're continuing to target 10 to 15 percent of our discretionary cash flow towards balance sheet strengthening. We continue to pursue other transactions that will enhance these efforts. Our capital plan calls for CRC's investments to be modestly lower in the second half of the year, while JV capital will increase with our new partner's investment. This will result in a slight increase in production through the end of the year."

Second Quarter 2019 Results

For the second quarter of 2019, CRC reported net income attributable to common stock of $12 million, or $0.24 per diluted share, compared to a loss of $82 million, or $1.70 per diluted share, for the same period of 2018. Adjusted net loss[1] for both the second quarter of 2019 and 2018 was $14 million, or $0.29 per diluted share. Second quarter 2019 adjusted net loss[1] excluded a net gain of $20 million on debt repurchases, $4 million of non-cash derivative gains on commodity derivatives and income of $2 million, net, for unusual and infrequent items.

Adjusted EBITDAX[1] for the second quarter of 2019 was $255 million and cash provided by operating activities was $114 million.

Total daily production volumes decreased 4% year-over-year, from 134,000 BOE per day for the second quarter of 2018 to 129,000 BOE per day for the second quarter of 2019. Total daily production for the second quarter of 2019 was lower partially due to a strategic divestiture which was completed in the second quarter of 2019. The divestiture, together with PSC effects, reduced our second quarter 2019 production by over 2,000 BOE per day. Non-recurring events including power and plant outages lowered quarterly production by 1,000 BOE per day. Oil volumes averaged 79,000 barrels per day, NGL volumes averaged 16,000 barrels per day and gas volumes averaged 203,000 thousand cubic feet (Mcf) per day.

Despite lower Brent index prices, our realized crude oil prices, including the effect of settled hedges, increased by $6.55 per barrel from $64.11 in the second quarter of 2018 to $70.66 per barrel in the second quarter of 2019. In the second quarter of 2019, hedge settlements increased our realized crude oil prices by $1.89 per barrel compared to a reduction of $9.08 per barrel in the prior year period. Realized NGL prices were $27.82 per barrel, down $14.31 over the prior year period as local and national markets experienced excess supply resulting from Canadian imports coupled with weaker demand. Realized natural gas prices were $2.33 per Mcf for the second quarter of 2019, $0.08 higher than the same prior year period due to stronger California demand.

Production costs for the second quarter of 2019 were $230 million compared to $231 million for the second quarter of 2018.

General and administrative (G&A) expenses were $79 million for the second quarter of 2019 compared to $90 million for the same prior-year period. CRC's obligation for cash-settled stock-based compensation awards is adjusted for changes in our stock price at the end of each quarter and the related expense decreased approximately $16 million due to a lower stock price in the second quarter of 2019. This decrease was partially offset by higher overhead expenses in 2019.

CRC reported taxes other than on income of $36 million for the second quarter of 2019 compared to $37 million for the same prior-year period. Exploration expense was $10 million for the second quarter of 2019, $4 million higher than the same prior-year period.

CRC's internally funded capital investment for the second quarter of 2019 totaled $124 million, of which $89 million was directed to drilling and capital workovers. CRC's JV partner Benefit Street Partners (BSP) also invested $16 million, which is included in CRC's consolidated results.

Six-Month Results

For the first six months of 2019, CRC net loss attributable to common stock was $55 million, or $1.13 per diluted share, compared to a loss of $84 million, or $1.81 per diluted share, for the same period of 2018. Including hedge settlements, the 2019 results reflected higher year-over-year revenue despite a lower oil price environment. Adjusted net income[1] for the first six months of 2019 was $17 million, or $0.35 per diluted share, compared with an adjusted net loss[1] of $6 million, or $0.13 per diluted share, for the same period of 2018. The 2019 adjusted net income[1] excluded $93 million of non-cash derivative losses, a net gain of $26 million from debt repurchases and a net $5 million charge related to other unusual and infrequent items.

Total daily production volumes averaged 131,000 BOE per day for the first six months of 2019, compared with 129,000 BOE per day for the same period in 2018, an increase of 2 percent. The 2018 volumes reflected only one quarter of production from the Elk Hills acquisition. The 2019 volumes reflected the effect of a strategic divestiture and non-recurring events in the second quarter.

In the first six months of 2019, realized crude oil prices, including the effect of settled hedges, increased $4.43 per barrel to $67.90 per barrel from $63.47 per barrel for the same period in 2018. Settled hedges increased 2019 realized crude oil prices by $1.93 per barrel, compared with a reduction of $6.88 per barrel for the same period in 2018. Realized NGL prices decreased 18 percent, or $7.66 per barrel to $34.97 per barrel in the first six months of 2019 from $42.63 per barrel for the same period of 2018. Realized natural gas prices increased to $2.87 per Mcf, compared with $2.51 per Mcf for the same period in 2018.

Production costs for the first six months of 2019 were $463 million, or $19.54 per BOE, compared to $443 million, or $19.01 per BOE, for the same period in 2018. The increase is primarily attributable to the Elk Hills transaction, higher surface operations and maintenance costs and other items, partially offset by lower downhole maintenance activity and lower costs resulting from the Lost Hills divestiture. Per unit production costs, excluding the effect of PSCs, were $17.99 and $17.44 per BOE for the first six months of 2019 and 2018, respectively.

G&A expenses for the first six months of 2019 were $162 million and for the first six months of 2018 were $153 million, with the increase largely due to higher expenses across a number of functions, partially offset by lower equity compensation expense in the first half of 2019.

Taxes other than on income of $77 million for the first six months of 2019 were comparable to the same period of 2018, when taxes were $75 million. Exploration expense of $20 million for the first six months of 2019 was $6 million higher than the same period of 2018.

Capital investment in the first six months of 2019 totaled $228 million excluding JV capital, of which $158 million was directed to drilling and capital workovers. BSP also invested $43 million, which is included in CRC's consolidated results.

Cash provided by operating activities for the first six months of 2019 was $272 million and free cash flow was $44 million after taking into account capital investment that was funded by BSP.

Operational Update

In the second quarter of 2019, CRC operated an average of seven drilling rigs, with two rigs focused on conventional primary production, two on waterfloods, one on steamfloods and two on unconventional production. With total invested capital, we drilled 39 development wells and no exploration wells (5 steamflood, 20 waterflood, 4 primary and 10 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 94,000 BOE per day and operated six rigs. The Los Angeles basin contributed 24,000 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 of both vertical and lateral wells 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 $350 million to $385 million. CRC entered into a JV with subsidiaries of Colony Capital, Inc. (collectively, "Colony") in July 2019. As a result, CRC will increase its JV investment contributions to a range of $175 to $225 million for 2019. CRC anticipates a total capital program of approximately $525 to $610 million for the year.

Strategic Asset Divestiture

As previously disclosed, CRC sold 50% of its working interest and transferred operatorship in certain zones in our Lost Hills field in the San Joaquin Basin on May 1, 2019. The total consideration was in excess of $200 million, including approximately $168 million in cash before transaction costs and a carried 200-well development program to be drilled through 2023 with an estimated value of $35 million. The cash proceeds of $165 million, net of transaction costs and purchase price adjustments, were used to pay down the revolver. CRC also benefits from accelerated development from the drilling carry.

Recent Joint Venture

In July 2019, CRC entered into a JV with Colony, under which Colony has committed to invest $320 million for the development of portions of our flagship Elk Hills field, located in the San Joaquin basin. Colony's total investment may be increased to $500 million, subject to the mutual agreement of the parties. The initial commitment will cover multiple development opportunities in portions of the Elk Hills field and is intended to be invested over approximately three years in accordance with a development plan that has been agreed to by the parties consisting of 275 wells. Colony will fund 100% of the development wells and will earn a 90% working interest in those wells. If Colony receives an agreed upon return, CRC's working interest will increase from 10% to 82.5%.

Colony also received a warrant to purchase up to 1.25 million shares of our common stock, at an exercise price of $40 per share.

Repurchases and Balance Sheet Update

During the second quarter of 2019, CRC repurchased $58 million in face value of CRC's Second Lien Notes for $45 million, bringing the aggregate face value of Second Lien Notes repurchased since issuance to approximately $260 million. Total net debt outstanding at the end of the second quarter was $5.1 billion.

Hedging Update

CRC continues to execute an opportunistic hedging program to protect its cash flow, operating margins and capital program, while maintaining adequate liquidity. For the third and fourth quarters of 2019, CRC has protected the downside price risk on 40,000 and 35,000 barrels per day at approximately $73 Brent and $76 Brent, respectively. These put spreads provide full upside to oil price movements and downside protection until Brent prices drop below approximately $58 and $60 per barrel in the third and fourth quarters, respectively, at which point we receive Brent plus approximately $15 per barrel. For the first and second quarters of 2020, CRC has protected the downside risk of 25,000 and 10,000 barrels per day at approximately $72 Brent and $70 Brent, respectively. These put spreads provide downside price protection until Brent prices drop below $57 and $55 per barrel in the first and second quarters, respectively, at which point we receive Brent plus $15 per barrel. CRC also entered into a swap for 5,000 barrels per day in the second quarter of 2020 at approximately $70 Brent, which is subject to another 5,000 barrel per day at the same price at the option of the counterparties. See Attachment 8 for more details.

[1] See Attachment 3 for non-GAAP financial measures of adjusted EBITDAX, adjusted EBITDAX margin, 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/10132315. 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 makes 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 “Item 1A - 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)	Second Quarter 2019	Second Quarter 2018	Six Months 2019	Six Months 2018
Statements of Operations:				
Revenues and Other				
Oil and gas sales	**$ 578**	$ 657	**$ 1,179**	$ 1,232
Net derivative gain (loss) from commodity contracts	**21**	(167)	**(68)**	(205)
Other revenue	**54**	59	**232**	131
Total revenues and other	**653**	549	**1,343**	1,158
Costs and Other				
Production costs	**230**	231	**463**	443
General and administrative expenses	**79**	90	**162**	153
Depreciation, depletion and amortization	**121**	125	**239**	244
Taxes other than on income	**36**	37	**77**	75
Exploration expense	**10**	6	**20**	14
Other expenses, net	**55**	49	**203**	110
Total costs and other	**531**	538	**1,164**	1,039
Operating Income	**122**	11	**179**	119
Non-Operating (Loss) Income				
Interest and debt expense, net	**(98)**	(94)	**(198)**	(186)
Net gain on early extinguishment of debt	**20**	24	**26**	24
Gain on asset divestitures	**—**	1	**—**	1
Other non-operating expenses	**(3)**	(5)	**(10)**	(12)
Income (Loss) Before Income Taxes	**41**	(63)	**(3)**	(54)
Income tax	**—**	—	**—**	—
Net Income (Loss)	**41**	(63)	**(3)**	(54)
Net income attributable to noncontrolling interests	**(29)**	(19)	**(52)**	(30)
Net Income (Loss) Attributable to Common Stock	**$ 12**	$ (82)	**$ (55)**	$ (84)
Net income (loss) attributable to common stock per share - basic	**$ 0.25**	$ (1.70)	**$ (1.13)**	$ (1.81)
Net income (loss) attributable to common stock per share - diluted	**$ 0.24**	$ (1.70)	**$ (1.13)**	$ (1.81)
Adjusted net (loss) income	**$ (14)**	$ (14)	**$ 17**	$ (6)
Adjusted net (loss) income per share - basic	**$ (0.29)**	$ (0.29)	**$ 0.35**	$ (0.13)
Adjusted net (loss) income per share - diluted	**$ (0.29)**	$ (0.29)	**$ 0.35**	$ (0.13)
Weighted-average common shares outstanding - basic	**48.9**	48.2	**$ 48.8**	$ 46.3
Weighted-average common shares outstanding - diluted	**49.2**	48.2	**$ 48.8**	$ 46.3
Adjusted EBITDAX	**$ 255**	$ 245	**$ 556**	$ 495
Effective tax rate	**0%**	0%	**0%**	0%
Cash Flow Data:				
Net cash provided by operating activities	**$ 114**	$ 34	**$ 272**	$ 234
Net cash provided (used) in investing activities	**$ 12**	$ (669)	**$ (170)**	$ (807)
Net cash (used) provided by financing activities	**$ (142)**	$ 183	**$ (92)**	$ 595

($ and shares in millions)	June 30, 2019	December 31, 2018
Selected Balance Sheet Data:		
Total current assets	**$ 522**	$ 640
Total property, plant and equipment, net	**$ 6,409**	$ 6,455
Total current liabilities	**$ 610**	$ 607
Long-term debt	**$ 5,060**	$ 5,251
Other long-term liabilities	**$ 679**	$ 575
Mezzanine equity	**$ 777**	$ 756
Equity	**$ (279)**	$ (247)
Outstanding shares as of	**49.0**	48.7

STOCK-BASED COMPENSATION

Our consolidated results of operations for the three months and six months ended June 30, 2019 and 2018 include the effects of long-term stock-based compensation plans under which awards are granted annually 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 units 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 either vest at the grant date or 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 cash-settled awards based on our stock price on 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 at 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. 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:

	Second Quarter		Six Months	
($ in millions, except per BOE amounts)	**2019**	2018	**2019**	2018
General and administrative expenses				
Cash-settled awards	**$ 3**	$ 19	**$ 13**	$ 22
Equity-settled awards	**4**	4	**7**	7
Total stock-based compensation in G&A	**$ 7**	$ 23	**$ 20**	$ 29
Total stock-based compensation in G&A per Boe	**$ 0.60**	$ 1.89	**$ 0.84**	$ 1.24
Production costs				
Cash-settled awards	**$ 1**	$ 5	**$ 4**	$ 6
Equity-settled awards	**1**	1	**2**	2
Total stock-based compensation in production costs	**$ 2**	$ 6	**$ 6**	$ 8
Total stock-based compensation in production costs per Boe	**$ 0.17**	$ 0.49	**$ 0.25**	$ 0.34
Total company stock-based compensation	**$ 9**	$ 29	**$ 26**	$ 37
Total company stock-based compensation per Boe	**$ 0.77**	$ 2.38	**$ 1.09**	$ 1.58

DERIVATIVE GAINS AND LOSSES

The following table presents the components of our net derivative gains and losses 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.

	Second Quarter		Six Months	
($ millions)	**2019**	2018	**2019**	2018
Commodity Contracts:				
Non-cash derivative gain (loss) excluding noncontrolling interest	**$ 4**	$ (92)	**$ (93)**	$ (99)
Non-cash derivative gain (loss) - noncontrolling interest	**3**	(7)	**(3)**	(7)
Total non-cash changes	**7**	(99)	**(96)**	(106)
Net proceeds (payments) on settled commodity derivatives	**14**	(68)	**28**	(99)
Net derivative gain (loss) from commodity contracts	**$ 21**	$ (167)	**$ (68)**	$ (205)
Interest-Rate Contracts:				
Non-cash derivative loss	**$ (1)**	$ (1)	**$ (4)**	$ (1)

PRODUCTION STATISTICS

Net Oil, NGLs and Natural Gas Production Per Day	Second Quarter 2019	Second Quarter 2018	Six Months 2019	Six Months 2018
Oil (MBbl/d)				
San Joaquin Basin	**52**	54	**54**	52
Los Angeles Basin	**23**	25	**24**	24
Ventura Basin	**4**	4	**4**	4
Total	**79**	83	**82**	80
NGLs (MBbl/d)				
San Joaquin Basin	**15**	15	**14**	15
Ventura Basin	**1**	1	**1**	1
Total	**16**	16	**15**	16
Natural Gas (MMcf/d)				
San Joaquin Basin	**164**	172	**164**	157
Los Angeles Basin	**3**	1	**3**	1
Ventura Basin	**6**	8	**6**	7
Sacramento Basin	**30**	29	**29**	31
Total	**203**	210	**202**	196
Total Production (MBoe/d)	**129**	134	**131**	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 (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.

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 is meant to provide useful information to investors interested in comparing our financial 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 GAAP. 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.

	Second Quarter		Six Months	
($ millions, except per share amounts)	**2019**	2018	**2019**	2018
Net income (loss)	**$ 41**	$ (63)	**$ (3)**	$ (54)
Net income attributable to noncontrolling interests	**(29)**	(19)	**(52)**	(30)
Net income (loss) attributable to common stock	**12**	(82)	**(55)**	(84)
Unusual, infrequent and other items:				
Non-cash derivative (gain) loss from commodities, excluding noncontrolling interest	**(4)**	92	**93**	99
Early retirement and severance costs	**2**	2	**2**	4
Net gain on early extinguishment of debt	**(20)**	(24)	**(26)**	(24)
Other, net	**(4)**	(2)	**3**	(1)
Total unusual, infrequent and other items	**(26)**	68	**72**	78
Adjusted net (loss) income	**$ (14)**	$ (14)	**$ 17**	$ (6)
Net income (loss) attributable to common stock per share - diluted	**$ 0.24**	$ (1.70)	**$ (1.13)**	$ (1.81)
Adjusted net (loss) income per share - diluted	**$ (0.29)**	$ (0.29)	**$ 0.35**	$ (0.13)

FREE CASH FLOW

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

	Second Quarter		Six Months	
($ millions)	**2019**	2018	**2019**	2018
Net cash provided by operating activities	**$ 114**	$ 34	**$ 272**	$ 234
Capital investments	**(140)**	(188)	**(271)**	(327)
Free cash flow	**(26)**	(154)	**1**	(93)
BSP funded capital	**16**	18	**43**	18
Free cash flow, excluding BSP funded capital	**$ (10)**	$ (136)	**$ 44**	$ (75)

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 income (loss) and net cash provided by operating activities to the non-GAAP financial measure of adjusted EBITDAX.

	Second Quarter		Six Months	
($ millions, except per BOE amounts)	**2019**	2018	**2019**	2018
Net income (loss)	**$ 41**	$ (63)	**$ (3)**	$ (54)
Interest and debt expense, net	**98**	94	**198**	186
Depreciation, depletion and amortization	**121**	125	**239**	244
Exploration expense	**10**	6	**20**	14
Unusual, infrequent and other items [(a)]	**(26)**	68	**72**	78
Other non-cash items	**11**	15	**30**	27
Adjusted EBITDAX	**$ 255**	$ 245	**$ 556**	$ 495
Net cash provided by operating activities	**$ 114**	$ 34	**$ 272**	$ 234
Cash interest	**153**	154	**225**	215
Exploration expenditures	**6**	4	**10**	10
Working capital changes	**(18)**	55	**49**	37
Other, net	**—**	(2)	**—**	(1)
Adjusted EBITDAX	**$ 255**	$ 245	**$ 556**	$ 495
Adjusted EBITDAX per Boe	**$ 21.75**	$ 20.08	**$ 23.46**	$ 21.24

(a) See Adjusted Net Income reconciliation.

DISCRETIONARY CASH FLOW

We define discretionary cash flow as the cash available after distributions to noncontrolling interest holders 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.

	Second Quarter		Six Months	
($ millions)	**2019**	2018	**2019**	2018
Adjusted EBITDAX	**$ 255**	$ 245	**$ 556**	$ 495
Cash interest	**(153)**	(154)	**(225)**	(215)
Distributions paid to noncontrolling interest holders:				
BSP JV	**(6)**	(4)	**(25)**	(17)
Ares JV	**(20)**	(19)	**(40)**	(24)
Discretionary cash flow	**$ 76**	$ 68	**$ 266**	$ 239

ADJUSTED EBITDAX MARGIN

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

($ millions)	Second Quarter 2019	Second Quarter 2018	Six Months 2019	Six Months 2018
Total revenues and other	**$ 653**	$ 549	**$ 1,343**	$ 1,158
Non-cash derivative (gain) loss	**(7)**	99	**96**	106
Revenues, excluding non-cash derivative gains and losses	**$ 646**	$ 648	**$ 1,439**	$ 1,264
Adjusted EBITDAX Margin	**39%**	38%	**39%**	39%

ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

Management uses a measure called adjusted general and administrative expenses to provide useful information to investors interested in comparing our costs between periods and our performance to our peers. The following table presents a reconciliation of the GAAP financial measure of general and administrative expenses to the non-GAAP financial measure of adjusted general and administrative expenses.

	Second Quarter 2019	Second Quarter 2018	Six Months 2019	Six Months 2018
General and administrative expenses	**$ 79**	$ 90	**$ 162**	$ 153
Severance	**(1)**	—	**(1)**	—
Office consolidation	**(1)**	—	**(1)**	—
Transaction costs	**—**	(1)	**—**	(1)
Adjusted general and administrative expenses	**$ 77**	$ 89	**$ 160**	$ 152

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)	Second Quarter 2019	Second Quarter 2018	Six Months 2019	Six Months 2018
Production costs	**$ 19.62**	$ 18.93	**$ 19.54**	$ 19.01
Excess costs attributable to PSC-type contracts	**(1.64)**	(1.52)	**(1.55)**	(1.57)
Production costs, excluding effects of PSC-type contracts	**$ 17.98**	$ 17.41	**$ 17.99**	$ 17.44

CAPITAL INVESTMENTS

($ millions)	Second Quarter 2019	Second Quarter 2018	Six Months 2019	Six Months 2018
Internally funded capital	**$ 124**	$ 170	**$ 228**	$ 309
BSP funded capital	**16**	18	**43**	18
Capital investments - as reported	**$ 140**	$ 188	**$ 271**	$ 327
MIRA funded capital	**—**	5	**7**	27
Total capital program	**$ 140**	$ 193	**$ 278**	$ 354

PRICE STATISTICS

	Second Quarter		Six Months	
	2019	2018	**2019**	2018
Realized Prices				
Oil with hedge ($/Bbl)	**$ 70.66**	$ 64.11	**$ 67.90**	$ 63.47
Oil without hedge ($/Bbl)	**$ 68.77**	$ 73.19	**$ 65.97**	$ 70.35
NGLs ($/Bbl)	**$ 27.82**	$ 42.13	**$ 34.97**	$ 42.63
Natural gas ($/Mcf)	**$ 2.33**	$ 2.25	**$ 2.87**	$ 2.51
Index Prices				
Brent oil ($/Bbl)	**$ 68.32**	$ 74.90	**$ 66.11**	$ 71.04
WTI oil ($/Bbl)	**$ 59.82**	$ 67.88	**$ 57.36**	$ 65.37
NYMEX gas ($/MMBtu)	**$ 2.66**	$ 2.75	**$ 2.95**	$ 2.81
Realized Prices as Percentage of Index Prices				
Oil with hedge as a percentage of Brent	**103%**	86%	**103%**	89%
Oil without hedge as a percentage of Brent	**101%**	98%	**100%**	99%
Oil with hedge as a percentage of WTI	**118%**	94%	**118%**	97%
Oil without hedge as a percentage of WTI	**115%**	108%	**115%**	108%
NGLs as a percentage of Brent	**41%**	56%	**53%**	60%
NGLs as a percentage of WTI	**47%**	62%	**61%**	65%
Natural gas as a percentage of NYMEX	**88%**	82%	**97%**	89%

SECOND QUARTER DRILLING ACTIVITY

Wells Drilled	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	4	—	—	—	4
Waterflood	14	6	—	—	20
Steamflood	5	—	—	—	5
Unconventional	10	—	—	—	10
Total	33	6	—	—	39
Exploration Wells					
Primary	—	—	—	—	—
Waterflood	—	—	—	—	—
Steamflood	—	—	—	—	—
Unconventional	—	—	—	—	—
Total	—	—	—	—	—
Total Wells [(a)]	33	6	—	—	39
CRC wells drilled	31	6	—	—	37
BSP wells drilled	2	—	—	—	2
MIRA wells drilled	—	—	—	—	—

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

SIX MONTHS 2019 DRILLING ACTIVITY

Wells Drilled	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	6	—	—	—	6
Waterflood	15	14	—	—	29
Steamflood	40	—	—	—	40
Unconventional	16	—	—	—	16
Total	77	14	—	—	91
Exploration Wells					
Primary	2	—	1	—	3
Waterflood	—	—	—	—	—
Steamflood	5	—	—	—	5
Unconventional	—	—	—	—	—
Total	7	—	1	—	8
Total Wells [a]	84	14	1	—	99
CRC wells drilled	69	9	1	—	79
BSP wells drilled	14	5	—	—	19
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.

HEDGES - CURRENT

	Q3 2019	Q4 2019	Q1 2020	Q2 2020
CRUDE OIL				
Purchased Puts:				
Barrels per day	40,000	35,000	25,000	10,000
Weighted-average Brent price per barrel	$73.13	$75.71	$72.00	$70.00
Sold Puts:				
Barrels per day	40,000	35,000	25,000	10,000
Weighted-average Brent price per barrel	$57.50	$60.00	$57.00	$55.00
Swaps:				
Barrels per day	—	—	—	5,000 (a)
Weighted-average Brent price per barrel	$—	$—	$—	$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 BSP's noncontrolling 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 2021.

(a) Counterparties have the option to increase swap volumes by up to 5,000 barrels per day at a weighted-average Brent price of $70.05 for the second quarter of 2020.

2019 THIRD QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q3 2019 [(a)]	
Oil	95% to 100% of Brent
NGLs	36% to 41% of Brent
Natural Gas	105% to 115% of NYMEX
2019 Third Quarter Production, Capital and Income Statement Guidance	
Production (assumed Q3 average Brent price of $65/Bbl)	127 to 132 MBOE per day
Production (assumed Q3 average Brent price of $70/Bbl)	126 to 131 MBOE per day
Capital [(b)]	$165 million to $195 million
Production costs (assumed Q3 average Brent price of $65/Bbl)	$18.25 to $19.75 per BOE
Production costs (assumed Q3 average Brent price of $70/Bbl)	$18.45 to $19.95 per BOE
Adjusted general and administrative expenses [(c) & (d)]	$6.30 to $6.70 per BOE
Depreciation, depletion and amortization [(c)]	$9.85 to $10.15 per BOE
Taxes other than on income	$41 million to $45 million
Exploration expense	$3 million to $8 million
Interest expense [(e)]	$92 million to $97 million
Cash interest [(e)]	$70 million to $75 million
Effective tax rate	0%
Cash tax rate	0%
Pre-tax 2019 Third Quarter Price Sensitivities [(f)]	
$1 change in Brent index - Oil [(g)]	$6.6 million
$1 change in Brent index - NGLs	$0.5 million
$0.50 change in NYMEX - Gas	$7.0 million

(a) Realizations exclude hedge effects.

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

(c) Production based on assumed Q3 average Brent price of $65/Bbl. This reflects the additional reduction of close to 1,000 barrels of oil per day compared to the second quarter of 2019 due to the divestiture of 50% interest in our Lost Hills operation that closed on May 1, 2019.

(d) A portion of our long-term incentive compensation programs are stock based but payable in cash. Accounting rules require that we adjust our obligation 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 a cumulative adjustment depending on movement in our stock price. Our stock price used to set Q3 2019 guidance was $19.68 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 lower 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 limitation to upside price movements. We have downside price protection on approximately 49% of our Q3 2019 oil production, at a weighted average Brent floor price of approximately $73 per barrel below which we receive Brent plus $15 per barrel.