Exhibit 99.1

NEWS RELEASE

For immediate release

California Resources Corporation Announces Third Quarter 2017 Results

LOS ANGELES, November 6, 2017 – 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 $133 million, or $3.11 per diluted share, for the third quarter of 2017, compared with net income attributable to common stock (CRC net income) of $546 million, or $13.04 per diluted share, for the third quarter of 2016. The adjusted net loss[1] for the third quarter of 2017 was $52 million, or $1.22 per diluted share, compared with an adjusted net loss[1] of $71 million, or $1.74 per diluted share, for the third quarter of 2016. For the first nine months of 2017, the CRC net loss was $128 million, or $3.01 per diluted share, compared with CRC net income of $356 million, or $8.79 per diluted share, for the same period in 2016. The adjusted net loss[1] for the first nine months of 2017 was $173 million, or $4.07 per diluted share, compared with an adjusted net loss[1] of $243 million, or $6.12 per diluted share, for the same period in 2016.

Adjusted EBITDAX[1] for the third quarter of 2017 was $181 million compared with $164 million for the third quarter of 2016. Adjusted EBITDAX[1] for the first nine months of 2017 was $539 million compared with $448 million for the same period in 2016. Cash provided by operations was $225 million for the first nine months of 2017. Capital investments for the third quarter of 2017 were $100 million and $232 million for the first nine months of 2017, of which $30 million was funded by CRC's joint venture (JV) partner Benefit Street Partners (BSP) in the third quarter and $82 million in the first nine months. After excluding the capital that was funded by BSP, CRC generated free cash flow[1] of $101 million for the first nine months of 2017.

Quarterly Highlights Include:

- Produced approximately 128,000 BOE per day
- Invested capital of $100 million, of which JV partner BSP funded $30 million
- Drilled 28 wells with internally funded capital and 49 wells with JV capital
- Received approval for a bank amendment, subject to certain conditions being met, which would extend the maturity of our credit facility and relax financial covenants, among other changes
- Borrowing Base reaffirmed at $2.3 billion
- Generated adjusted EBITDAX[1] of $181 million, reflecting an adjusted EBITDAX margin[1] of 35%

[1] See Attachment 2 for explanations of how we calculate and use the non–GAAP measures of Adjusted EBITDAX, Adjusted EBITDAX margin, Free Cash Flow and Adjusted Net Loss, and for reconciliations of the foregoing to their nearest GAAP measure as applicable.

Todd Stevens, President and Chief Executive Officer, said, "We have been very pleased with our team's execution as we nearly doubled the drilling activity in the third quarter of 2017 compared to the prior quarter. Our corporate strategy has always been to focus on value. One way we have delivered this is through our drilling efficiencies. Furthermore, we are particularly excited about the strong successes from the Buena Vista Nose area and our redevelopment wells in the Los Angeles Basin. We believe we will exit this year at a level of activity supported by capital from cash flows and JV partners. As the industry moves toward our long-standing philosophy of living within cash flow and not chasing production at all costs, we continue to execute against our operational and financial goals with this core principle in mind. We are also pleased to be moving forward with an amendment to address our bank credit facility maturity and covenants."

Third Quarter Results

For the third quarter of 2017, the CRC net loss was $133 million, or $3.11 per diluted share, compared with CRC net income of $546 million, or $13.04 per diluted share, for the same period of 2016. Operational results were stronger year over year due to higher oil and gas sales partially offset by higher production costs from increased downhole maintenance activity. Non-operating income reflected a gain in the third quarter of 2016 from debt-reduction actions. The third quarter 2017 adjusted net loss[2] was $52 million, or $1.22 per diluted share, compared with an adjusted net loss[2] of $71 million, or $1.74 per diluted share, for the same period of 2016. The third quarter 2017 adjusted net loss[2] excluded $72 million of non-cash derivatives losses and a net $9 million charge for other unusual and infrequent items. The third quarter 2016 adjusted net loss[2] excluded $660 million of gains related to repurchases of the Company's notes, $25 million of non-cash derivatives losses, a $12 million interest charge for the write-off of deferred debt costs, and a $6 million charge for other unusual and infrequent items.

Total daily production volumes averaged 128,000 barrels of oil equivalent (BOE) per day for the third quarter of 2017, a decrease of 7 percent from 138,000 BOE per day for the third quarter of 2016. Total daily production decreased 1,000 BOE per day, or less than 1 percent, from the second quarter of 2017.

In the third quarter of 2017, realized crude oil prices, including the effect of settled hedges, increased $6.99 per barrel to $50.02 per barrel from $43.03 per barrel in the prior year comparable quarter. Settled hedges increased realized crude oil prices by $1.12 per barrel in the third quarter of 2017 compared with $1.30 per barrel in the prior year comparable quarter. Realized NGL prices increased 54 percent to $34.63 per barrel from $22.45 per barrel in the third quarter of 2016 due to higher exports and low inventories. Realized natural gas prices decreased 3 percent to $2.56 per thousand cubic feet (Mcf), compared with $2.64 per Mcf in the same period of 2016.

Production costs for the third quarter of 2017 were $222 million, or $18.90 per BOE, compared with $211 million, or $16.63 per BOE, for the third quarter of 2016. The industry practice for reporting production sharing-type contracts (PSCs) can result in higher production costs per barrel as gross field operating costs are matched with net production. Excluding the PSC effects, per unit production costs would have been $17.81 and $15.63 for the third quarter of 2017 and 2016, respectively. The increase in production costs was driven by the ramp-up of downhole maintenance activity in line with stronger commodity prices. Adjusted general and administrative (G&A) expenses for the third quarter of 2017 were $62 million, compared with $57 million for the third quarter of 2016. The increase in adjusted G&A expenses was a result of higher costs of performance-based bonus and incentive compensation plans due to better than expected results.

Taxes other than on income of $39 million for the third quarter of 2017 were $2 million higher than the same period of 2016. Exploration expense of $5 million for the third quarter of 2017 was also $2 million higher than the same period of 2016.

Capital investment in the third quarter of 2017 totaled $100 million, consisting of $70 million of CRC internally funded capital and $30 million of BSP capital. Approximately $81 million was directed to drilling and capital workovers.

Cash provided by operations for the quarter of 2017 was $105 million and free cash flow[2] was $35 million after excluding capital funded by BSP.

[2] See Attachment 2 for explanations of how we calculate and use the non-GAAP measures of Adjusted Net Loss and Free Cash Flow, and for reconciliations to the nearest GAAP measurement, as applicable.

Nine-Month Results

For the first nine months of 2017, the CRC net loss was $128 million, or $3.01 per diluted share, compared with CRC net income of $356 million, or $8.79 per diluted share, for the same period of 2016. Operational results were stronger year over year due to higher revenue partially offset by an increase in production costs resulting from increased activity and higher gas and electricity costs. The first nine months of 2016 reflected a gain from our debt-reduction actions. The adjusted net loss[2] for the first nine months of 2017 was $173 million, or $4.07 per diluted share, compared with an adjusted net loss[2] of $243 million, or $6.12 per diluted share, for the same period of 2016. The 2017 adjusted net loss[2] excluded $38 million of non-cash derivative losses, $21 million of gains from asset divestitures, $4 million of gains related to retirements of the Company's notes and a net $18 million charge from other unusual and infrequent items. The 2016 adjusted net loss[2] excluded $793 million of gains related to retirements of the Company's notes, $243 million of non-cash derivatives losses, a $31 million gain from asset divestitures, a $63 million tax benefit from a partial reversal of valuation allowances against CRC's deferred tax assets, a $12 million interest charge for the write-off of deferred debt issuance costs and a net $33 million charge for other unusual and infrequent items.

Total daily production volumes averaged 130,000 BOE per day in the first nine months of 2017, compared with 142,000 BOE per day for the same period in 2016, a decrease of 8 percent.

In the first nine months of 2017, realized crude oil prices, including the effect of settled hedges, increased $8.51 per barrel to $49.42 per barrel from $40.91 per barrel for the same period in 2016. Settled hedges increased 2017 realized crude oil prices by $0.66 per barrel, compared with $3.37 per barrel for the same period in 2016. Realized NGL prices increased 62 percent to $33.00 from $20.36 per barrel in the first nine months of 2016. Realized natural gas prices increased 25 percent to $2.64 per thousand cubic feet (Mcf), compared with $2.11 per Mcf for the same period in 2016.

Production costs for the first nine months of 2017 were $649 million, or $18.31 per BOE, compared with $583 million, or $15.01 per BOE, for the same period in 2016. Per unit production costs, excluding the effect of PSC contracts, were $17.21 and $14.18 per BOE for the first nine months of 2017 and 2016, respectively. The increase in production costs was driven by higher natural gas and power prices and the ramp-up of downhole and surface maintenance activity in line with stronger commodity prices. While higher natural gas prices increase CRC's production costs for power and steam generation, they result in a net benefit to the Company due to higher revenue generated from natural gas sales. Adjusted general and administrative expenses for the first nine months of 2017 were $187 million, compared with $167 million for the first nine months of 2016. The increase in adjusted G&A expenses was a result of higher employee-related costs due to the resumption of employee benefits and higher costs of performance-based bonus and incentive compensation plans due to better than expected results.

Taxes other than on income of $103 million for the first nine months of 2017 were $15 million lower than the same period of 2016. Exploration expense of $17 million for the first nine months of 2017 was $4 million higher than the same period of 2016.

Capital investment in the first nine months of 2017 totaled $232 million, consisting of $150 million of CRC internally funded capital and $82 million of BSP capital. Approximately $170 million was directed to drilling and capital workovers.

Cash provided by operations for the first nine months of 2017 was $225 million and free cash flow[3] was $101 million after excluding capital that was funded by BSP.

[3] See Attachment 2 for explanations of how we calculate and use the non-GAAP measures of Adjusted Net Loss and Free Cash Flow, and for reconciliations to the nearest GAAP measure, as applicable.

Hedging Update

CRC continues to opportunistically seek hedging transactions to protect its cash flow, operating margins and capital program and to maintain liquidity. During the third quarter of 2017, CRC hedged 2018 volumes of 19,000 barrels of oil per day at approximately $60.00 Brent for 2018. See attachment 8 for more details.

Operational Update and 2017 Capital Investment Plan

CRC remains on track for its full year total capital plan, which is inclusive of BSP and MIRA JV capital, of $400 million. The Company averaged eight rigs in the third quarter of 2017 and is currently operating nine rigs. Activity has primarily been focused in the San Joaquin Basin on steamfloods and waterfloods. Within the basin, CRC has two rigs on steamfloods, three rigs on conventional, one on waterfloods, and two on unconventional. Additionally, the Company has one part-time rig drilling waterflood projects in the Los Angeles Basin.

For the fourth quarter of 2017, CRC remains focused on waterflood and steamflood opportunities primarily in the San Joaquin Basin. The Company expects to continue deploying JV capital toward its focus areas and anticipates spudding several exploratory opportunities.

Credit Facility Amendment

We are working with our lender group to amend our 2014 Credit Facility. The proposed amendment has received approval from each member of the lender group, subject to federally mandated flood insurance review. The proposed amendment, if completed, would become effective upon the satisfaction of certain conditions, including the closing of a new term loan with minimum proceeds of at least $900 million and minimum liquidity at closing of $500 million. The proceeds of the new term loan would be used to repay a portion of the borrowings under the 2014 Credit Facility. The proposed amendment would, among other things, (i) extend the maturity date of the 2014 Credit Facility until 2021 (subject to a potential earlier springing maturity date consistent with our 2014 Credit Facility), (ii) permit the repurchase of up to $100 million of junior indebtedness, (iii) provide financial covenant relief and (iv) reduce commitments under the 2014 revolving facility to $1 billion and the 2014 term loan to $200 million. We can provide no assurances that the amendment will be signed or will become effective, whether as a result of flood insurance review or otherwise.

Conference Call Details

To participate in today's conference call scheduled for 5:00 P.M. Eastern Standard Time, either dial (877) 328-5505 (International calls please dial +1 (412) 317-5421) or access via webcast at www.crc.com, fifteen minutes prior to the scheduled start time to register. Participants may also pre-register for the conference call at http://dpregister.com/10111633. 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 Investor Relations at 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 our expected results of operations, liquidity, cash flows and business prospects. Such statements include those regarding our 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)
- budgets and maintenance capital requirements
- reserves
- type curves

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While we believe the assumptions or bases underlying our expectations are reasonable and make 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 our financial flexibility
- insufficient cash flow to fund planned investment
- 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 our products
- 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
- 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 our Annual Report on Form 10-K available on our 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)	Third Quarter 2017	Third Quarter 2016	Nine Months 2017	Nine Months 2016
Statement of Operations Data:				
Revenues and Other				
Oil and gas net sales	**$ 461**	$ 424	**$ 1,387**	$ 1,157
Net derivative (losses) gains	**(65)**	(14)	**51**	(157)
Other revenue	**49**	46	**113**	95
Total revenues and other	**445**	456	**1,551**	1,095
Costs and Other				
Production costs	**222**	211	**649**	583
General and administrative expenses	**63**	58	**191**	186
Depreciation, depletion and amortization	**134**	137	**412**	422
Taxes other than on income	**39**	37	**103**	118
Exploration expense	**5**	3	**17**	13
Other expenses, net	**29**	29	**76**	76
Total costs and other	**492**	475	**1,448**	1,398
Operating (Loss) Income	**(47)**	(19)	**103**	(303)
Non-Operating (Loss) Income				
Interest and debt expense, net	**(85)**	(95)	**(252)**	(243)
Net gains on early extinguishment of debt	**—**	660	**4**	793
Gains on asset divestitures	**—**	—	**21**	31
Other non-operating expense	**—**	—	**(3)**	—
(Loss) Income Before Income Taxes	**(132)**	546	**(127)**	278
Income tax benefit	**—**	—	**—**	78
Net (Loss) Income	**(132)**	546	**(127)**	356
Net income attributable to noncontrolling interest	**(1)**	—	**(1)**	—
Net (Loss) Income Attributable to Common Stock	**$ (133)**	$ 546	**$ (128)**	$ 356
(Loss) Earnings per share attributable to common stock - diluted	**$ (3.11)**	$ 13.04	**$ (3.01)**	$ 8.79
Adjusted Net Loss	**$ (52)**	$ (71)	**$ (173)**	$ (243)
Adjusted EPS - diluted	**$ (1.22)**	$ (1.74)	**$ (4.07)**	$ (6.12)
Weighted-average common shares outstanding - diluted	**42.7**	40.8	**42.5**	39.7
Adjusted EBITDAX	**$ 181**	$ 164	**$ 539**	$ 448
Effective tax rate	**0%**	0%	**0%**	(28)%
Cash Flow Data:				
Net cash provided by operating activities	**$ 105**	$ 101	**$ 225**	$ 145
Net cash used by investing activities	**$ (100)**	$ (13)	**$ (174)**	$ (31)
Net cash provided (used) by financing activities	**$ 14**	$ (80)	**$ (35)**	$ (116)

Balance Sheet Data:	**September 30, 2017**	December 31, 2016
Total current assets	**$ 452**	$ 425
Property, plant and equipment, net	**$ 5,692**	$ 5,885
Current maturities of long-term debt	**$ 100**	$ 100
Other current liabilities	**$ 646**	$ 626
Long-term debt, principal amount	**$ 5,039**	$ 5,168
Total equity	**$ (574)**	$ (557)
Outstanding shares as of	**42.9**	42.5

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 nature, timing, amount and frequency. Therefore, management uses measures called adjusted net income (loss) and adjusted general and administrative expenses which exclude those items. These measures are not meant to disassociate items from management's performance, but rather are 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) and adjusted general and administrative expenses are not considered to be alternatives to net income (loss) or general and administrative expenses, respectively, 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; and other unusual, out-of-period and infrequent items and other non-cash items. Our management believes 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. This measure is a material component of certain of our financial covenants under our 2014 credit facilities 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 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:

	Third Quarter		Nine Months	
($ millions, except per share amounts)	**2017**	2016	**2017**	2016
Net (loss) income attributable to common stock	**$ (133)**	$ 546	**$ (128)**	$ 356
Unusual and infrequent items:				
Non-cash derivative losses (gains), excluding noncontrolling interest	**72**	25	**(38)**	243
Early retirement, severance and other costs	**1**	1	**4**	19
Gains on asset divestitures	**—**	—	**(21)**	(31)
Net gains on early extinguishment of debt	**—**	(660)	**(4)**	(793)
Other	**8**	5	**14**	14
Adjusted income items before interest and taxes	**81**	(629)	**(45)**	(548)
Deferred debt issuance costs write-off	**—**	12	**—**	12
Reversal of valuation allowance for deferred tax assets [(a)]	**—**	—	**—**	(63)
Total	**$ 81**	$ (617)	**$ (45)**	$ (599)
Adjusted net loss	**$ (52)**	$ (71)	**$ (173)**	$ (243)
Net (loss) income attributable to common stock per diluted share	**$ (3.11)**	$ 13.04	**$ (3.01)**	$ 8.79
Adjusted net loss per diluted share	**$ (1.22)**	$ (1.74)	**$ (4.07)**	$ (6.12)

(a) Amount represents the out-of-period portion of the valuation allowance reversal.

DERIVATIVES GAINS AND LOSSES

	Third Quarter		Nine Months	
($ millions)	**2017**	2016	**2017**	2016
Non-cash derivative losses (gains), excluding noncontrolling interest	**$ 72**	$ 25	**$ (38)**	$ 243
Non-cash derivative losses for noncontrolling interest	**1**	—	**2**	—
Cash proceeds from settled derivatives	**(8)**	(11)	**(15)**	(86)
Net derivative losses (gains)	**$ 65**	$ 14	**$ (51)**	$ 157

FREE CASH FLOW

($ millions)	Third Quarter 2017	Third Quarter 2016	Nine Months 2017	Nine Months 2016
Net cash provided by operating activities	**$ 105**	$ 101	**$ 225**	$ 145
Capital investment	**(100)**	(19)	**(232)**	(45)
Changes in capital accruals	**—**	6	**26**	(5)
Free cash flow, after working capital	**5**	88	**19**	95
BSP capital investment	**30**	—	**82**	—
Free cash flow, excluding BSP capital	**$ 35**	$ 88	**$ 101**	$ 95

ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

($ millions)	Third Quarter 2017	Third Quarter 2016	Nine Months 2017	Nine Months 2016
General and administrative expenses	**$ 63**	$ 58	**$ 191**	$ 186
Early retirement and severance costs	**(1)**	(1)	**(4)**	(19)
Adjusted general and administrative expenses	**$ 62**	$ 57	**$ 187**	$ 167

ADJUSTED EBITDAX

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

($ millions)	Third Quarter 2017	Third Quarter 2016	Nine Months 2017	Nine Months 2016
Net (loss) income attributable to common stock	**$ (133)**	$ 546	**$ (128)**	$ 356
Interest and debt expense, net	**85**	95	**252**	243
Income tax benefit	**—**	—	**—**	(78)
Depreciation, depletion and amortization, excluding noncontrolling interest	**132**	137	**406**	422
Exploration expense	**5**	3	**17**	13
Adjusted income items before interest and taxes[c]	**81**	(629)	**(45)**	(548)
Other non-cash items	**11**	12	**37**	40
Adjusted EBITDAX (A)	**$ 181**	$ 164	**$ 539**	$ 448
Net cash provided by operating activities	**$ 105**	$ 101	**$ 225**	$ 145
Cash interest	**56**	64	**251**	244
Exploration expenditures	**5**	3	**16**	13
Other changes in operating assets and liabilities	**7**	(9)	**33**	32
Other, net	**8**	5	**14**	14
Adjusted EBITDAX (A)	**$ 181**	$ 164	**$ 539**	$ 448

(c) See Adjusted Net Loss reconciliation.

ADJUSTED EBITDAX MARGIN

($ millions)	Third Quarter 2017	Third Quarter 2016	Nine Months 2017	Nine Months 2016
Total Revenues	**$ 445**	$ 456	**$ 1,551**	$ 1,095
Non-cash derivative losses (gains)	**73**	25	**(36)**	243
Adjusted revenues (B)	**$ 518**	**$ 481**	**$ 1,515**	**$ 1,338**
Adjusted EBITDAX Margin (A)/(B)	**35%**	**34%**	**36%**	**33%**

PV-10 of Proved Reserves

PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future cash outflows for development and production costs, discounted at 10% per annum. PV-10 at October 31, 2017 (October PV-10) differs from our standardized measure of discounted future net cash flows (Standardized Measure) because: (i) Standardized Measure includes the effects of future income taxes on future pre-tax cash flows; and (ii) October PV-10 uses the forward curves as opposed to SEC prescribed pricing. It is not practicable to calculate the Standardized Measure as of October 31, 2017 using the SEC prescribed pricing assumptions and the present value of income taxes at this time. Neither PV-10 nor Standardized Measure should be construed as the fair value of our oil and natural gas reserves.

The realized prices used to calculate future cash flows for the October PV-10 were based on the WTI forward curve for oil and the Henry Hub forward curve for natural gas as of September 29, 2017 adjusted to reflect realizations that we receive for our products, which for oil is Brent based. Future operating and capital costs were forecast based on these commodity price curves applied to expectations of future operating and development activities. The October PV-10 is based on an internal mid-year reserves estimate. Other valid assumptions would give rise to substantially different results. The timing of capital investment to develop proved undeveloped reserves, pricing and cost estimates may differ from year-end Standardized Measure and PV-10, which are prepared in accordance with SEC rules.

PV-10 and Standardized Measure are used by the industry and by CRC's management as an asset value measure to compare against our past reserves base and the reserves base of other business entities because the pricing, cost environment and discount assumptions are prescribed by the SEC and are comparable. PV-10 further facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity. The October PV-10 and other asset values presented in the table below were used by participants in the 2014 Credit Facility to reaffirm the borrowing base as of November 1, 2017.

($ millions)		
Standardized measure of discounted future net cash flows, as of December 31, 2016	$	2,667
Present value of future income taxes discounted at 10%		181
PV-10 of Proved Reserves, as of December 31, 2016		2,848
Sales of oil and natural gas produced, net of production costs and other operating expenses		(724)
Net change in prices, production costs and other operating expenses		2,187
Revisions of quantity estimates[a]		657
October PV-10[b]	$	4,968
PV-10 of Proved Developed Producing Reserves	$	3,388
PV-10 of Proved Developed Nonproducing Reserves		883
PV-10 of Proved Undeveloped Reserves		697
October PV-10[b]		4,968
Elk Hills Power PV-10		43
Other[c]		72
October PV-10, including other assets	$	5,083

(a) This amount is the result of a full mid-year reserves estimate. Includes changes in reserves quantities since December 31, 2016 due to: (i) addition of previously uneconomic reserves at December 31, 2016 as a result of higher prices used in the October PV-10; (ii) technical adjustments; (iii) reserves added from the 2017 capital program to date; and (iv) effect of the JVs, among other effects.

(b) PV-10 as of October 31, 2017 was calculated using the forward curve for WTI and Henry Hub as of September 29, 2017. The WTI prices were adjusted to reflect CRC's realized prices, which are Brent based. The average WTI forward curve was $51.23 per barrel through 2024 and was held flat thereafter. The average Henry Hub forward curve was $2.89 per MMBtu through 2024 and was held flat thereafter.

(c) Includes the PV-10 of hedges outstanding at October 31, 2017 and the PV-10 of other assets partially offset by October PV-10 attributable to noncontrolling interest.

ADJUSTED NET INCOME / (LOSS) VARIANCE ANALYSIS

($ millions)

2016 3rd Quarter Adjusted Net Loss	**$ (71)**
Price - Oil	56
Price - NGLs	18
Price - Natural Gas	(1)
Volume	(27)
Production cost	(11)
DD&A	(8)
Exploration expense	(2)
Interest expense	(2)
Adjusted general & administrative expenses	(5)
All others	1
2017 3rd Quarter Adjusted Net Loss	**$ (52)**

2016 Nine-Month Adjusted Net Loss	**$ (243)**
Price - Oil	213
Price - NGLs	57
Price - Natural Gas	29
Volume	(101)
Production cost	(66)
DD&A	(26)
Exploration expense	(4)
Interest expense	(21)
Adjusted general & administrative expenses	(20)
Income tax	(15)
All others	24
2017 Nine-Month Adjusted Net Loss	**$ (173)**

PRODUCTION COSTS PER BOE

	Third Quarter		Nine Months	
($ per Boe)	**2017**	2016	**2017**	2016
Production Costs	**$ 18.90**	$ 16.63	**$ 18.31**	$ 15.01
Costs attributable to PSC contracts	**(1.09)**	(1.00)	**(1.10)**	(0.83)
Production Costs, excluding the effects of PSC contracts	**$ 17.81**	$ 15.63	**$ 17.21**	$ 14.18

CAPITAL INVESTMENTS

($ millions)	Third Quarter 2017	Third Quarter 2016	Nine Months 2017	Nine Months 2016
Internally Funded Capital Investments	**$ 70**	$ 19	**$ 150**	$ 45 (a)
BSP Capital	**30**	—	**82**	—
Consolidated Capital - CRC & BSP	**$ 100**	$ 19	**$ 232**	$ 45
MIRA Capital	**30**	—	**38**	—
Total Capital - CRC and Partner	**$ 130**	$ 19	**$ 270**	$ 45

(a) Amount includes $18 million of capital incurred for the turnaround at the Elk Hills Power Plant.

PRODUCTION STATISTICS

Net Oil, NGLs and Natural Gas Production Per Day	Third Quarter 2017	Third Quarter 2016	Nine Months 2017	Nine Months 2016
Oil (MBbl/d)				
San Joaquin Basin	**51**	56	**52**	58
Los Angeles Basin	**27**	29	**27**	30
Ventura Basin	**4**	5	**5**	5
Sacramento Basin	**—**	—	**—**	—
Total	**82**	90	**84**	93
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	**139**	149	**140**	150
Los Angeles Basin	**2**	2	**1**	3
Ventura Basin	**8**	8	**8**	8
Sacramento Basin	**33**	34	**32**	36
Total	**182**	193	**181**	197
Total Production (MBoe/d) [(a)]	**128**	138	**130**	142

(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. The price of natural gas on a BOE basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, for the nine months ended September 30, 2017, the average prices of Brent oil and NYMEX natural gas were $52.59 per Bbl and $3.12 per MMBtu, respectively, resulting in an oil-to-gas price ratio of approximately 17 to 1.

PRICE STATISTICS

	Third Quarter		Nine Months	
	2017	2016	**2017**	2016
Realized Prices				
Oil with hedge ($/Bbl)	**$ 50.02**	$ 43.03	**$ 49.42**	$ 40.91
Oil without hedge ($/Bbl)	**$ 48.90**	$ 41.73	**$ 48.76**	$ 37.54
NGLs ($/Bbl)	**$ 34.63**	$ 22.45	**$ 33.00**	$ 20.36
Natural gas ($/Mcf)	**$ 2.56**	$ 2.64	**$ 2.64**	$ 2.11
Index Prices				
Brent oil ($/Bbl)	**$ 52.18**	$ 46.98	**$ 52.59**	$ 43.01
WTI oil ($/Bbl)	**$ 48.21**	$ 44.94	**$ 49.47**	$ 41.33
NYMEX gas ($/MMBtu)	**$ 2.95**	$ 2.70	**$ 3.12**	$ 2.24
Realized Prices as Percentage of Index Prices				
Oil with hedge as a percentage of Brent	**96%**	92%	**94%**	95%
Oil without hedge as a percentage of Brent	**94%**	89%	**93%**	87%
Oil with hedge as a percentage of WTI	**104%**	96%	**100%**	99%
Oil without hedge as a percentage of WTI	**101%**	93%	**99%**	91%
NGLs as a percentage of Brent	**66%**	48%	**63%**	47%
NGLs as a percentage of WTI	**72%**	50%	**67%**	49%
Natural gas as a percentage of NYMEX	**87%**	98%	**85%**	94%

THIRD QUARTER DRILLING ACTIVITY

Wells Drilled (Net)	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	6	—	—	—	6
Waterflood	17	4	—	—	21
Steamflood	46	—	—	—	46
Unconventional	4	—	—	—	4
Total	73	4	—	—	77
Exploration Wells					
Primary	—	—	—	—	—
Waterflood	—	—	—	—	—
Steamflood	—	—	—	—	—
Unconventional	—	—	—	—	—
Total	—	—	—	—	—
Total Wells [(a)]	73	4	—	—	77
CRC Wells Drilled	24	4	—	—	28
BSP Wells Drilled	14	—	—	—	14
MIRA Wells Drilled - Net	35	—	—	—	35
Development Drilling Capital - CRC & BSP ($ millions)	$43	$6	$4	$—	$53
Development Drilling Capital - MIRA ($ millions)	$30	$—	$—	$—	$30

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

HEDGES - CURRENT

	4Q 2017	1Q 2018	2Q 2018	3Q 2018	4Q 2018	FY 2019	FY 2020
Crude Oil							
Sold Calls:							
Barrels per day	6,300	10,400	10,400	16,100	16,100	1,000	900
Weighted-average Brent price per barrel	$57.80	$59.38	$59.37	$58.91	$58.91	$60.00	$60.00
Purchased Puts:							
Barrels per day	11,300	1,200	1,200	1,100	1,100	1,000	900
Weighted-average Brent price per barrel	$47.75	$45.82	$45.83	$45.83	$45.85	$45.84	$43.91
Sold Puts:							
Barrels per day	—	29,000	29,000	19,000	19,000	—	—
Weighted-average Brent price per barrel	$—	$45.00	$45.00	$45.00	$45.00	$—	$—
Swaps:							
Barrels per day	30,000	29,000	29,000	19,000	19,000	—	—
Weighted-average Brent price per barrel	$55.00	$60.00	$60.00	$60.13	$60.13	$—	$—

A small portion of the derivatives in the table above were entered into by the BSP JV, including all of the 2019 and 2020 positions. The BSP JV also entered into natural gas swaps for insignificant volumes for the period of October 2017 to July 2020.

For purchased puts, we would receive settlement payments for prices below the indicated weighted-average Brent price per barrel. For sold puts, we would make settlement payments for prices below the indicated weighted-average price per barrel. From time to time, we use puts in conjunction with other derivatives to increase the efficacy of our hedging activities.

Certain of our counterparties have options to increase swap volumes by up to:

- 5,000 barrels per day at a weighted-average Brent price of $55.03 for December 2017;
- 19,000 barrels per day at a weighted-average Brent price of $60.00 for each quarter of the first half of 2018;
- 19,000 barrels per day at a weighted-average Brent price of $60.13 for each quarter of the second half of 2018;
- 10,000 barrels per day at a weighted-average Brent price of $60.00 for the first half of 2018 and
- 5,000 barrels per day at a weighted-average Brent price of $60.15 for the second half of 2018.

2017 FOURTH QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q4 2017 [(a)]	
Oil	90% to 94% of Brent
NGLs	69% to 73% of Brent
Natural Gas	96% to 100% of NYMEX

2017 Fourth Quarter Production, Capital and Income Statement Guidance	
Production	125 to 130 MBOE per day
Capital	$110 million to $130 million
Production costs	$18.75 to $19.75 per BOE
Adjusted general and administrative expenses	$5.35 to $5.65 per BOE
Depreciation, depletion and amortization	$11.60 to $11.90 per BOE
Taxes other than on income	$33 million to $37 million
Exploration expense	$6 million to $10 million
Interest expense [(b)]	$82 million to $86 million
Cash Interest [(b)]	$141 million to $145 million
Income tax expense rate	0%
Cash tax rate	0%

	On Income	On Cash
Pre-tax Fourth Quarter Price Sensitivities		
$1 change in Brent index - Oil (above $55.00 Brent) [(c)]	$3.2 million	$3.2 million
$1 change in Brent index - NGLs	$1.1 million	$1.1 million
$0.50 change in NYMEX - Gas	$2.5 million	$2.5 million

Fourth Quarter Volumes Sensitivities	
$1 change in the Brent index [(d)]	200 Bbl/d

(a) Realizations exclude hedge effects.

(b) Interest expense includes the amortization of 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. Both interest expense and cash interest do not reflect the effect of the Credit Facility amendment.

(c) At a Brent index price between $50.00 and $55.00, the sensitivity goes up to approximately $3.6 million. Below $50.00 Brent, the sensitivity drops to approximately $2.8 million.

(d) Reflects the effect of production sharing type contracts in our Wilmington field operations.