SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ___________ to ___________

Commission file number 001-36478

California Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	**46-5670947**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
9200 Oakdale Avenue, Suite 900 **Los Angeles, California**	**91311**
(Address of principal executive offices)	(Zip Code)

(888) 848-4754
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☑ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☑ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. (See definition of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act):
Large Accelerated Filer ☐ Accelerated Filer ☑ Non-Accelerated Filer ☐ Smaller Reporting Company ☐
Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act) ☐ Yes ☑ No

Shares of common stock outstanding as of September 30, 2017	42,868,072

California Resources Corporation and Subsidiaries

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Condensed Consolidated Balance Sheets
As of September 30, 2017 and December 31, 2016
(in millions, except share data)

	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and cash equivalents	$ 28	$ 12
Trade receivables	221	232
Inventories	58	58
Other current assets, net	145	123
Total current assets	452	425
PROPERTY, PLANT AND EQUIPMENT	21,124	20,915
Accumulated depreciation, depletion and amortization	(15,432)	(15,030)
Total property, plant and equipment, net	5,692	5,885
OTHER ASSETS	39	44
TOTAL ASSETS	$ 6,183	$ 6,354
CURRENT LIABILITIES		
Current maturities of long-term debt	$ 100	$ 100
Accounts payable	263	219
Accrued liabilities	383	407
Total current liabilities	746	726
LONG-TERM DEBT - PRINCIPAL AMOUNT	5,039	5,168
DEFERRED GAIN AND ISSUANCE COSTS, NET	356	397
OTHER LONG-TERM LIABILITIES	616	620
EQUITY		
Preferred stock (20 million shares authorized at $0.01 par value) no shares outstanding at September 30, 2017 and December 31, 2016	—	—
Common stock (200 million shares authorized at $0.01 par value) outstanding shares (September 30, 2017 - 42,868,072 and December 31, 2016 - 42,542,637)	—	—
Additional paid-in capital	4,875	4,861
Accumulated deficit	(5,532)	(5,404)
Accumulated other comprehensive loss	(10)	(14)
Total equity attributable to common stock	(667)	(557)
Noncontrolling interest	93	—
Total equity	(574)	(557)
TOTAL LIABILITIES AND EQUITY	$ 6,183	$ 6,354

The accompanying notes are an integral part of these condensed consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Condensed Consolidated Statements of Operations
For the three and nine months ended September 30, 2017 and 2016
(in millions, except share data)

	Three months ended September 30,		Nine months ended September 30,	
	2017	**2016**	**2017**	**2016**
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				
Basic	$ (3.11)	$ 13.04	$ (3.01)	$ 8.79
Diluted	$ (3.11)	$ 13.04	$ (3.01)	$ 8.79

The accompanying notes are an integral part of these condensed consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Condensed Consolidated Statements of Comprehensive Income
For the three and nine months ended September 30, 2017 and 2016
(in millions)

	Three months ended September 30,		Nine months ended September 30,	
	2017	**2016**	**2017**	**2016**
Net (loss) income	$ (132)	$ 546	$ (127)	$ 356
Net income attributable to noncontrolling interest	(1)	—	(1)	—
Other comprehensive income items:				
Reclassification to income of realized losses on pension and postretirement[(a)]	1	2	4	8
Total other comprehensive income, net of tax	1	2	4	8
Comprehensive (loss) income attributable to common stock	$ (132)	$ 548	$ (124)	$ 364

(a) No associated tax for the three and nine months ended September 30, 2017 and 2016. See *Note 10 Retirement and Postretirement Benefit Plans*, for additional information.

The accompanying notes are an integral part of these condensed consolidated financial statements.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Condensed Consolidated Statements of Cash Flows
For the nine months ended September 30, 2017 and 2016
(in millions)

	Nine months ended September 30, 2017	Nine months ended September 30, 2016
CASH FLOW FROM OPERATING ACTIVITIES		
Net (loss) income	$ (127)	$ 356
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation, depletion and amortization	412	422
Deferred income tax benefit	—	(78)
Net derivative (gains) losses	(51)	157
Net proceeds on settled derivatives	15	86
Net gains on early extinguishment of debt	(4)	(793)
Amortization of deferred gain	(55)	(53)
Gains on asset divestitures	(21)	(31)
Other non-cash charges to income, net	46	84
Dry hole expenses	1	—
Changes in operating assets and liabilities, net	9	(5)
Net cash provided by operating activities	225	145
CASH FLOW FROM INVESTING ACTIVITIES		
Capital investments	(232)	(45)
Changes in capital investment accruals	26	(5)
Asset divestitures	33	19
Other	(1)	—
Net cash used by investing activities	(174)	(31)
CASH FLOW FROM FINANCING ACTIVITIES		
Proceeds from 2014 Revolving Credit Facility	1,000	1,761
Repayments of 2014 Revolving Credit Facility	(1,010)	(1,728)
Proceeds from 2016 Credit Agreement	—	990
Payments on 2014 Term Loan	(91)	(329)
Debt repurchases	(24)	(770)
Debt transaction costs	(2)	(44)
Contribution from noncontrolling interest, net	98	—
Distributions paid to noncontrolling interest holders	(6)	—
Employee stock purchases and other	2	4
Shares canceled for taxes	(2)	—
Net cash used by financing activities	(35)	(116)
Increase (decrease) in cash and cash equivalents	16	(2)
Cash and cash equivalents—beginning of period	12	12
Cash and cash equivalents—end of period	$ 28	$ 10

The accompanying notes are an integral part of these condensed consolidated financial statements.

NOTE 1 THE SPIN-OFF AND BASIS OF PRESENTATION

The Separation and Spin-off

We are an independent oil and natural gas exploration and production company operating properties within California. We were incorporated in Delaware as a wholly owned subsidiary of Occidental Petroleum Corporation (Occidental) on April 23, 2014, and remained a wholly owned subsidiary of Occidental until November 30, 2014. On November 30, 2014, Occidental distributed shares of our common stock on a pro-rata basis to Occidental stockholders and we became an independent, publicly traded company (the Spin-off). Occidental initially retained approximately 18.5% of our outstanding shares of common stock, which it distributed to Occidental stockholders on March 24, 2016.

Except when the context otherwise requires or where otherwise indicated, all references to ‘‘CRC,’’ the ‘‘company,’’ ‘‘we,’’ ‘‘us’’ and ‘‘our’’ refer to California Resources Corporation and its subsidiaries, and all references to ‘‘Occidental’’ refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

Basis of Presentation

In the opinion of our management, the accompanying financial statements contain all adjustments (consisting of normal recurring adjustments) necessary to fairly present our financial position as of September 30, 2017 and the statements of operations, comprehensive income, and cash flows for the three and nine months ended September 30, 2017 and 2016, as applicable. We have eliminated all of our significant intercompany transactions and accounts.

We have prepared this report pursuant to the rules and regulations of the United States (U.S.) Securities and Exchange Commission applicable to interim financial information, which permit omission of certain disclosures to the extent they have not changed materially since the latest annual financial statements. We believe our disclosures are adequate to make the information not misleading. This Form 10-Q should be read in conjunction with the consolidated and combined financial statements and the notes thereto in our Annual Report on Form 10-K for the year ended December 31, 2016.

Certain prior year amounts have been reclassified to conform to the 2017 presentation. On the statements of operations, we reclassified gains on asset divestitures out of other expenses, net. We also moved interest and debt expense, net out of operating income (loss) and into non-operating income (loss).

NOTE 2 ACCOUNTING AND DISCLOSURE CHANGES

Recently Issued Accounting and Disclosure Changes

In 2016, the Financial Accounting Standards Board (FASB) issued rules clarifying the revenue recognition standard issued in 2014. Under the new rules, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. The new rules also require more detailed disclosures related to the nature, timing, amount and uncertainty of revenue and cash flows arising from contracts with customers. We have substantially completed our assessment of these new rules. Based on our assessment to date, we have not identified any changes to the timing of revenue recognition based on the requirements of the new rules. We will adopt these rules in the first quarter of 2018 and expect to apply the modified retrospective approach upon adoption with the cumulative effect of applying the rules, if any, recognized as of the date of initial application.

In January 2017, the FASB issued rules that changed the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. The rules are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. We do not expect the adoption of these rules to have a significant impact on our financial statements.

In March 2017, the FASB issued rules requiring employers that sponsor defined benefit plans for pensions and postretirement benefits to present the service cost component of net periodic benefit cost in the same income statement line item as other employee compensation costs arising from services rendered during the period. Only the service cost component will be eligible for capitalization in assets. Employers will present the other components of the net periodic benefit cost separately from the line item that includes the service cost and outside of any subtotal of operating income. The rules are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. We do not expect the adoption of these rules to have a significant impact on our financial statements.

In May 2017, the FASB issued rules to simplify the guidance on the modification of share-based payment awards. The amendments provide clarity on which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting prospectively. The rules are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. The new rules will be applied prospectively to any awards modified on or after the adoption date.

Recently Adopted Accounting and Disclosure Changes

In July 2015, the FASB issued rules requiring entities to measure inventory at the lower of cost or net realizable value. We adopted these rules in the first quarter of 2017 with no changes to our financial statements.

NOTE 3 OTHER INFORMATION

Cash and cash equivalents at September 30, 2017 included approximately $17 million that is restricted for capital investment under our joint venture agreements.

Other current assets, net at September 30, 2017 and December 31, 2016 included amounts due from joint interest partners of approximately $71 million and $51 million and derivative assets from commodities contracts of $46 million and $39 million, respectively. Also included in other current assets, net at September 30, 2017 and December 31, 2016 are assets held for sale of $12 million and $19 million, respectively.

Accrued liabilities at September 30, 2017 and December 31, 2016 reflected net greenhouse gas obligations of $104 million and $89 million, accrued interest of $66 million and $25 million, accrued employee-related costs of $63 million and $91 million, derivative liabilities from commodities contracts of $60 million and $103 million and liabilities held for sale of $0 and $7, respectively.

Other long-term liabilities included asset retirement obligations of $410 million and $397 million at September 30, 2017 and December 31, 2016, respectively.

Fair Value of Financial Instruments

The carrying amounts of cash and other on-balance sheet financial instruments, other than debt, approximate fair value.

Supplemental Cash Flow Information

We did not make U.S. federal and state income tax payments during the nine months ended September 30, 2017 and 2016. Interest paid totaled approximately $251 million and $244 million for the nine months ended September 30, 2017 and 2016, respectively.

NOTE 4 INVENTORIES

Inventories as of September 30, 2017 and December 31, 2016 consisted of the following:

	September 30, 2017	December 31, 2016
	(in millions)	
Materials and supplies	$ 54	$ 55
Finished goods	4	3
Total	$ 58	$ 58

NOTE 5 DEBT

Debt as of September 30, 2017 and December 31, 2016 consisted of the following:

	September 30, 2017	December 31, 2016
	(in millions)	
2014 Credit Facilities (Secured First Lien)		
Revolving Credit Facility	$ 837	$ 847
Term Loan Facility	559	650
2016 Credit Agreement (Secured First Lien)	1,000	1,000
Second Lien Notes		
8% Notes Due 2022	2,250	2,250
Senior Notes (Unsecured)		
5% Notes Due 2020	165	193
5 ½% Notes Due 2021	135	135
6% Notes Due 2024	193	193
Total Debt - Principal Amount	5,139	5,268
Less Current Maturities of Long-Term Debt	(100)	(100)
Long-Term Debt - Principal Amount	$ 5,039	$ 5,168

At September 30, 2017, deferred gain and issuance costs were $356 million net, consisting of $434 million of deferred gains offset by $78 million of deferred issuance costs and original issue discounts. The December 31, 2016 deferred gain and issuance costs were $397 million net, consisting of $489 million of deferred gains offset by $92 million of deferred issuance costs and original issue discounts.

Credit Facilities

2014 Credit Facilities

Our credit facilities from 2014 (2014 Credit Facilities) comprise (i) a $559 million senior term loan facility (2014 Term Loan) and (ii) a $1.4 billion senior revolving loan facility (2014 Revolving Credit Facility). We are permitted to increase the size of our 2014 Revolving Credit Facility by up to $245 million if we obtain additional commitments from new or existing lenders. Our 2014 Revolving Credit Facility includes a sub-limit of $400 million for the issuance of letters of credit. Our credit limit under our 2014 Credit Facilities is approximately $2.0 billion. Borrowings under these facilities are also subject to a borrowing base, which was reaffirmed at $2.3 billion as of November 1, 2017.

Our 2014 Credit Facilities mature at the earlier of November 2019 and the 182nd day prior to the maturity of our 2020 Notes or the 2021 Notes if the outstanding principal amount of either series exceeds $100 million prior to its respective maturity date.

In 2016 and through the nine months ended September 30, 2017, we made scheduled quarterly payments of $25 million on our 2014 Term Loan for an aggregate amount of $175 million. In August 2016, we made a $250 million prepayment on our 2014 Term Loan from the proceeds of our 2016 Credit Agreement. In February 2017, we made a $16 million prepayment on our 2014 Term Loan from the proceeds of non-core asset sales.

The lenders under our 2014 Credit Facilities have a first-priority lien on a substantial majority of our assets, including our Elk Hills power plant and midstream assets. We also granted a lien on the same assets to the lenders under our 2016 Credit Agreement and the holders of our Second Lien Notes.

Borrowings under our 2014 Credit Facilities bear interest, at our election, at either a LIBOR rate or an alternate base rate (ABR) (equal to the highest of (i) the federal funds effective rate plus 0.50%, (ii) the administrative agent's prime rate and (iii) the one-month LIBOR rate plus 1.00%), in each case plus an applicable margin. This applicable margin is based, while our total leverage ratio exceeds 3.00 to 1.00, on our borrowing base utilization and will vary from (i) in the case of LIBOR loans, 2.50% to 3.50% and (ii) in the case of ABR loans, 1.50% to 2.50%. The unused portion of our 2014 Revolving Credit Facility commitments is subject to a commitment fee equal to 0.50% per annum. We also pay customary fees and expenses under our 2014 Credit Facilities. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period, but not less than quarterly.

As of September 30, 2017, the financial performance covenants under our 2014 Credit Facilities were as follows:

	2017		**2018 and beyond**			
	9/30	12/31	3/31	6/30	9/30	12/31
Maximum leverage ratio[a]	3.25 to 1.00	3.25 to 1.00	2.25 to 1.00	2.25 to 1.00	2.25 to 1.00	2.25 to 1.00
Minimum interest coverage ratio[b]	1.20 to 1.00	1.20 to 1.00	2.00 to 1.00	2.00 to 1.00	2.00 to 1.00	2.00 to 1.00
Minimum asset coverage ratio[c]	N/A	1.20 to 1.00	N/A	1.20 to 1.00	N/A	1.20 to 1.00
Minimum monthly liquidity[d]	$250 million					

(a) The ratio of indebtedness under our 2014 Credit Facilities to trailing four-quarter Adjusted EBITDAX
(b) The ratio of Adjusted EBITDAX to consolidated interest charges, adjusted for deferred gain amortization
(c) The ratio of PV-10 to total indebtedness under our 2014 Credit Facilities and our 2016 Credit Agreement
(d) Measured as of the last day of each calendar month

The required ratios for 2018 and beyond were last amended in February 2016 and were not changed in subsequent modifications when the ratios through the end of 2017 were amended. As of September 30, 2017, we had approximately $431 million of available borrowing capacity under our 2014 Revolving Credit Facility, subject to the month-end minimum liquidity requirement.

We must generally apply 100% of the net cash proceeds from asset sales (other than de minimis sales and sales to permitted development joint ventures) to repay loans outstanding under our 2014 Credit Facilities, except that we are permitted to use up to 50% of net cash proceeds from non-borrowing base asset sales or monetizations (i) to repurchase our Senior Notes to the extent available at a significant minimum discount to par, (ii) to purchase up to $140 million of certain of our Senior Notes at a discount to par, (iii) for general corporate purposes or (iv) for oil and gas expenditures, including expenditures for the maintenance, repair or improvement of existing properties and assets, and the acquisition of leasehold, seismic or other assets used in an oil and gas business. At least 75% of asset sale proceeds must be in cash (50% for sales of non-borrowing base assets unless our leverage ratio is less than 4:00 to 1:00 at which time the requirement falls to 40%), other than permitted development joint ventures and certain other transactions. Our 2014 Credit Facilities also permit us to incur up to an additional $50 million of non-facility indebtedness, which may be secured by non-borrowing base assets, subject to compliance with our financial covenants, the proceeds of which must be applied to repay our 2014 Term Loan. We must apply cash on hand in excess of $150 million daily to repay amounts outstanding under our 2014 Revolving Credit Facility. Further, we are restricted from paying dividends or making other distributions to common stockholders.

Our borrowing base under our 2014 Credit Facilities is redetermined each May 1 and November 1. Our borrowing base is based upon a number of factors, including commodity prices and reserves, declines in which could cause our borrowing base to be reduced. Increases in our borrowing base require approval of at least 80% of our revolving lenders, as measured by exposure, while decreases or affirmations require a two-thirds approval. We and the lenders (requiring a request from the lenders holding two-thirds of the revolving commitments and outstanding loans) each may request a special redetermination once in any period between three consecutive scheduled redeterminations. We will be permitted to have collateral released when both (i) our credit ratings are at least Baa3 from Moody's and BBB- from S&P, in each case with a stable or better outlook, and (ii) certain permitted liens securing other debt are released.

We are working with our lender group to amend our 2014 Credit Facilities. 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, will 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 our 2014 Credit Facilities. If the proposed amendment is completed and becomes effective, our 2014 Credit Facilities would be amended to:

- extend the maturity date until June 30, 2021, subject to a springing maturity of (i) 273 days prior to the maturity of our 2020 Notes to the extent that more than $100 million of such notes remain outstanding at such date and (ii) 273 days prior to the maturity of our 2021 Notes, to the extent that more than $100 million of such notes remain outstanding on such date;
- reset the financial performance covenants as follows:
  - maximum leverage ratio of indebtedness under our 2014 Credit Facilities and the new term loan to EBITDAX to be less than 1.90 to 1.00 through 2019 and less than 1.50 to 1.00 thereafter and
  - minimum interest coverage ratio to be greater than 1.20 to 1.00;
- defer quarterly payments on our 2014 Term Loan until September 30, 2019, which would be reduced to $12.5 million per quarter thereafter;
- reduce our 2014 Revolving Credit Facility commitment to $1 billion and reduce our minimum liquidity requirement to $150 million;
- increase the applicable margin on LIBOR-based loans to a range of 3.25% to 4.00% and on ABR-based loans to a range of 2.25% to 3.00%;
- permit us to use 50% of the proceeds from an Elk Hills power plant monetization to prepay our 2016 Credit Agreement, Second Lien Notes and Senior Notes;
- permit us to use the proceeds from other non-borrowing base asset sales to prepay our 2016 Credit Agreement, Second Lien Notes and Senior Notes as follows:
  - 75% of such proceeds for all aggregate proceeds received up to $500 million
  - 50% of such proceeds for all aggregate proceeds received between $500 million and $1 billion
  - 25% of such proceeds for all aggregate proceeds received in excess of $1 billion
- permit us to incur certain other first-lien indebtedness for deleveraging activities.

2016 Credit Agreement

In August 2016, we entered into a $1 billion first-lien term loan (2016 Credit Agreement), the net proceeds of which were used to (i) prepay $250 million of our 2014 Term Loan and (ii) reduce our 2014 Revolving Credit Facility by $740 million. The proceeds received were net of a $10 million original issue discount. The loan under our 2016 Credit Agreement bears interest at a floating rate per annum equal to LIBOR plus 10.375%, subject to a 1.00% LIBOR floor, determined for the applicable interest period (or ABR rates plus 9.375% in certain circumstances). Interest on LIBOR loans is payable at the end of each LIBOR period, but not less than quarterly. Interest on ABR loans is payable quarterly in arrears.

Our 2016 Credit Agreement matures at the earlier of December 2021 and the 91st day prior to maturity of our 2020 Notes or our 2021 Notes if the outstanding principal amount of either series exceeds $100 million prior to its respective maturity date. As of September 30, 2017, we had $165 million and $135 million in aggregate principal amount of outstanding 2020 Notes and 2021 Notes, respectively.

Our 2016 Credit Agreement is secured by the same collateral used to secure our 2014 Credit Facilities but is second in collateral recovery to the lenders under our 2014 Credit Facilities. Prepayment of our 2016 Credit Agreement is subject to an adjustable make-whole amount prior to the fourth anniversary. Following the fourth anniversary, we may redeem at par. At both September 30, 2017 and December 31, 2016, we had $1 billion outstanding under our 2016 Credit Agreement.

Our 2016 Credit Agreement provides for customary covenants and events of default consistent with, or generally less restrictive than, the covenants in our 2014 Credit Facilities, including limitations on additional indebtedness, liens, asset dispositions, investments and restricted payments and other negative covenants, in each case subject to certain limitations and exceptions. Additionally, our 2016 Credit Agreement requires us to maintain a first-lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31, consistent with our 2014 Credit Facilities.

Second Lien Notes

In December 2015, we issued $2.25 billion in aggregate principal amount of 8% senior secured second-lien notes due December 15, 2022 (Second Lien Notes), which we exchanged for $2.8 billion of our outstanding Senior Notes. We recorded a deferred gain of approximately $560 million on the debt exchange, which will be amortized using the effective interest rate method over the term of our Second Lien Notes. Our Second Lien Notes are secured on a lower-priority basis than the lenders of our 2014 Credit Facilities and 2016 Credit Agreement.

We pay interest on our Second Lien Notes semiannually in cash in arrears on June 15 and December 15.

The indenture governing our Second Lien Notes includes covenants that, among other things, limit our ability to incur debt secured by liens subject to certain exceptions and restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a “change of control triggering event” (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Second Lien Notes, to offer to purchase our Second Lien Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest. The indenture also restricts our ability to sell certain assets and to release collateral from liens securing our Second Lien Notes, unless the collateral is released in compliance with our 2014 Credit Facilities.

We may redeem our Second Lien Notes (i) prior to December 15, 2017 from the proceeds of certain equity offerings, in an amount up to 35% of the initial aggregate principal amount of the notes issued plus any additional notes issued, at a redemption price equal to 108% of the principal amount redeemed, plus accrued and unpaid interest, (ii) prior to December 15, 2018, in whole or in part at a redemption price equal to 100% of the principal amount redeemed plus a make-whole amount and accrued and unpaid interest and (iii) on or after December 15, 2018, in whole or in part at a fixed redemption price ranging from 104% to 102% of the principal amount redeemed plus accrued and unpaid interest prior to 2019 and 100% thereafter.

Senior Notes

In October 2014, we issued $5 billion in aggregate principal amount of our senior unsecured notes, including $1 billion of 5% notes due January 15, 2020 (2020 Notes), $1.75 billion of 5 ½% notes due September 15, 2021 (2021 Notes) and $2.25 billion of 6% notes due November 15, 2024 (2024 Notes and, collectively, Senior Notes). We used the net proceeds from the issuance of our Senior Notes to make a $4.95 billion cash distribution to Occidental in October 2014.

In 2015, we repurchased approximately $33 million in principal amount of our 2020 Notes for $13 million in cash. We also exchanged a substantial majority of our Senior Notes for our Second Lien Notes in December 2015 as described above. In 2016, we repurchased over $1.5 billion in principal amount of our outstanding Senior Notes, primarily using drawings of $750 million on our 2014 Revolving Credit Facility and cash from operations. We also exchanged approximately 3.4 million shares of our common stock for $100 million in aggregate principal amount of our Senior Notes. In the first quarter of 2017, we purchased $28 million in aggregate principal amount of our 2020 Notes for $24 million in cash.

The following table summarizes the material terms of our Senior Notes outstanding at September 30, 2017:

	2020 Notes	2021 Notes	2024 Notes
Outstanding principal	$165 million	$135 million	$193 million
Interest rate	5%	5.5%	6%
Maturity date	January 15, 2020	September 15, 2021	November 15, 2024
Interest payment dates	January 15 July 15	March 15 September 15	May 15 November 15

The indenture governing our Senior Notes includes covenants that, among other things, limits our ability to grant liens securing borrowed money subject to certain exceptions and restricts our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a “change of control triggering event” (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Senior Notes, to offer to purchase our Senior Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest.

We may redeem our Senior Notes prior to their maturity dates, in whole or in part, at a redemption price equal to 100% of the principal amount redeemed plus a make-whole amount and accrued and unpaid interest.

Other

At September 30, 2017, we were in compliance with all financial and other debt covenants.

All obligations under our 2014 Credit Facilities and 2016 Credit Agreement (collectively, Credit Facilities) as well as our Second Lien Notes are guaranteed both fully and unconditionally and jointly and severally by all of our material wholly owned subsidiaries.

The terms and conditions of all of our indebtedness are subject to additional qualifications and limitations that are set forth in the relevant governing documents.

We estimate the fair value of fixed-rate debt, which is classified as Level 1, based on prices from known market transactions for our instruments. The estimated fair value of our debt at September 30, 2017 and December 31, 2016, including the fair value of the variable-rate portion, was approximately $4.1 billion and $4.9 billion, respectively, compared to a carrying value of approximately $5.1 billion and $5.3 billion. A one-eighth percent change in the variable interest rates on the borrowings under our Credit Facilities on September 30, 2017 would result in a $3 million change in annual interest expense.

As of September 30, 2017 and December 31, 2016, we had letters of credit of approximately $137 million and $130 million, respectively, under our 2014 Revolving Credit Facility. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

NOTE 6 ACQUISITIONS, DIVESTITURES AND OTHER

In February 2017, we divested non-core assets resulting in $32 million of proceeds and a $21 million gain.

In February 2017, we entered into a joint venture with Benefit Street Partners (BSP) where BSP will contribute up to $250 million, subject to agreement of the parties, in exchange for a preferred interest in the JV (BSP JV). The funds contributed by BSP are designated to be used to develop certain of our oil and gas properties. We contributed a net profits interest in existing and future cash flow from such properties in exchange for a common interest in the JV. BSP is entitled to preferential distributions and, if BSP receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. BSP funded two $50 million commitments in March and July 2017. As of September 30, 2017, the noncontrolling interest in our BSP JV is comprised of contributions from BSP of $98 million (net of $2 million in issuance discounts), distributions to BSP of $6 million and BSP's share of net income of $1 million.

In April 2017, we entered into a joint venture with Macquarie Infrastructure and Real Assets Inc. (MIRA) under which MIRA will invest up to $300 million, subject to agreement of the parties, to develop certain of our oil and gas properties in exchange for a 90% working interest in the related properties (MIRA JV). MIRA will fund 100% of the development cost of such properties. Our 10% working interest reverts to 75% if MIRA receives cash distributions equal to a predetermined threshold return. MIRA initially committed $160 million, which is intended to be invested over two years. Of the committed amount, MIRA contributed $38 million for drilling projects through September 30, 2017, with additional funding expected during the course of the year and in 2018.

Our consolidated results reflect the full operations of our BSP JV, with BSP's share of net income being reported as a noncontrolling interest. Our consolidated results reflect only our working interest share in our MIRA JV.

NOTE 7 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

We, or certain of our subsidiaries, are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at September 30, 2017 and December 31, 2016 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, our subsidiaries, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with the Spin-off, purchases and other transactions that they have entered into with us. These indemnities include indemnities made to Occidental against certain tax-related liabilities that may be incurred by Occidental relating to the Spin-off and liabilities related to operation of our business while it was still owned by Occidental. As of September 30, 2017, we are not aware of material indemnity claims pending or threatened against the company.

We are currently under examination by the Internal Revenue Service for our U.S. federal income tax return for the post-Spin-off period in 2014 and calendar year 2015. No significant issues have been raised to date. State returns for these years remain subject to examination.

NOTE 8 DERIVATIVES

General

We use a variety of derivative instruments to protect our cash flows, margins and capital investment program from the cyclical nature of commodity prices and to improve our ability to comply with the covenants of our Credit Facilities in case of price deterioration. We will continue to be strategic and opportunistic in implementing our hedging program as market conditions permit. Derivatives are carried at fair value and on a net basis when a legal right of offset exists with the same counterparty.

As of September 30, 2017, we did not have any derivatives designated as hedges. Unless otherwise indicated, we use the term "hedge" to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not necessarily accounted for as cash-flow or fair-value hedges. As part of our hedging program, we entered into a number of derivative transactions that resulted in the following Brent-based crude oil contracts as of September 30, 2017:

	Q4 2017	Q1 2018	Q2 2018	Q3 2018	Q4 2018	FY 2019	FY 2020
Sold Calls:							
Barrels per day	6,300	16,800	16,200	16,100	16,100	1,000	900
Weighted-average price per barrel	$ 57.80	$ 58.86	$ 58.92	$ 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 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 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 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 our BSP JV, including all of the 2019 and 2020 positions. Our 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 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.

Additional hedges for 2018 were put in place after September 30, 2017 that are not included in the table above.

Fair Value of Derivatives

Our commodity derivatives are measured at fair value using industry-standard models with various inputs, including quoted forward prices, and are all classified as Level 2 in the required fair value hierarchy for the periods presented. The following table presents the fair values (at gross and net) of our outstanding derivatives as of September 30, 2017 and December 31, 2016 (in millions):

	September 30, 2017			
	Balance Sheet Classification	**Gross Amounts Recognized at Fair Value**	**Gross Amounts Offset in the Balance Sheet**	**Net Fair Value Presented in the Balance Sheet**
Assets				
Commodity Contracts	Other current assets	$ 52	$ (6)	$ 46
Commodity Contracts	Other assets	13	—	13
Liabilities				
Commodity Contracts	Accrued liabilities	(66)	6	(60)
Commodity Contracts	Other long-term liabilities	(19)	—	(19)
Total derivatives		$ (20)	$ —	$ (20)

	December 31, 2016			
	Balance Sheet Classification	**Gross Amounts Recognized at Fair Value**	**Gross Amounts Offset in the Balance Sheet**	**Net Fair Value Presented in the Balance Sheet**
Assets				
Commodity Contracts	Other current assets	$ 88	$ (49)	$ 39
Commodity Contracts	Other assets	25	(6)	19
Liabilities				
Commodity Contracts	Accrued liabilities	(152)	49	(103)
Commodity Contracts	Other long-term liabilities	(58)	6	(52)
Total derivatives		$ (97)	$ —	$ (97)

NOTE 9 EARNINGS PER SHARE

We compute basic and diluted earnings per share (EPS) using the two-class method required for participating securities. Certain restricted and performance stock awards are considered participating securities when such shares have non-forfeitable dividend rights at the same rate as common stock.

Under the two-class method, undistributed earnings allocated to participating securities are subtracted from net income attributable to common stock in determining net income available to common stockholders. In loss periods, no allocation is made to participating securities because the participating securities do not share in losses. For basic EPS, the weighted-average number of common shares outstanding excludes outstanding shares related to unvested restricted stock awards. For diluted EPS, the basic shares outstanding are adjusted by adding potentially dilutive securities.

For the three and nine months ended September 30, 2017, we issued approximately 51,000 shares and 154,000 shares, respectively, of common stock in connection with our employee stock purchase plan. For the three and nine months ended September 30, 2016, we issued approximately 53,000 shares and 237,000 shares, respectively, of common stock in connection with our employee stock purchase plan.

The following table presents the calculation of basic and diluted EPS for the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016[(a)]	2017	2016[(a)]
	(in millions, except per-share amounts)			
Basic EPS calculation				
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
Less: net income (loss) allocated to participating securities	—	(14)	—	(7)
Net (loss) income available to common stockholders	$ (133)	$ 532	$ (128)	$ 349
Weighted-average common shares outstanding - basic	42.7	40.8	42.5	39.7
Basic EPS	$ (3.11)	$ 13.04	$ (3.01)	$ 8.79
Diluted EPS calculation				
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
Less: net income (loss) allocated to participating securities	—	(14)	—	(7)
Net (loss) income available to common stockholders	$ (133)	$ 532	$ (128)	$ 349
Weighted-average common shares outstanding - basic	42.7	40.8	42.5	39.7
Dilutive effect of potentially dilutive securities	—	—	—	—
Weighted-average common shares outstanding - diluted	42.7	40.8	42.5	39.7
Diluted EPS	$ (3.11)	$ 13.04	$ (3.01)	$ 8.79

(a) Our previously reported basic and diluted earnings per share for the three months ended September 30, 2016 changed from $13.45 to $13.04 and $13.06 to $13.04, respectively. Our previously reported basic earnings per share for the nine months ended September 30, 2016 also changed from $8.97 to $8.79. These changes occurred because of the application of the two-class method of earnings allocation in a period with net income. Unlike other periods in 2016, the third quarter of 2016 resulted in net income because of the non-recurring gain generated from the extinguishment of debt. This represents a 3% and 2% change for the three and nine months ended September 30, 2016, respectively, from the previously reported basic earnings per share amount, which we believe is immaterial based on the absolute amount as well as the non-recurring nature of the third quarter gain, which did not affect any trends embedded in operating results.

NOTE 10 RETIREMENT AND POSTRETIREMENT BENEFIT PLANS

The following table sets forth the components of the net periodic benefit costs for our defined benefit pension and postretirement benefit plans:

	Three months ended September 30,			
	2017		2016	
	Pension Benefit	Postretirement Benefit	Pension Benefit	Postretirement Benefit
	(in millions)			
Service cost	$ —	$ 1	$ —	$ 1
Interest cost	1	1	1	1
Expected return on plan assets	(1)	—	(1)	—
Recognized actuarial loss	—	—	1	—
Settlement loss	1	—	1	—
Total	$ 1	$ 2	$ 2	$ 2

	Nine months ended September 30,			
	2017		2016	
	Pension Benefit	Postretirement Benefit	Pension Benefit	Postretirement Benefit
	(in millions)			
Service cost	$ 1	$ 3	$ 1	$ 3
Interest cost	2	3	2	3
Expected return on plan assets	(2)	—	(2)	—
Recognized actuarial loss	1	—	1	—
Settlement loss	4	—	6	—
Total	$ 6	$ 6	$ 8	$ 6

During each quarter ended September 30, 2017 and 2016, we contributed $1 million to our defined benefit pension plans. During the nine months ended September 30, 2017 and 2016, we contributed $6 million and $7 million, respectively, to our defined benefit pension plans. We expect to satisfy minimum funding requirements with contributions of $1 million to our defined benefit pension plans during the remainder of 2017. The 2017 and 2016 settlements were associated with early retirements.

NOTE 11 INCOME TAXES

For the three and nine months ended September 30, 2017, we did not provide any current or deferred tax provision or benefit. The difference between our statutory tax rate and our effective tax rate for the periods is primarily related to an increase in our valuation allowance based on the expectation of a tax loss for the year. Given our recent and anticipated future earnings trends, we have recorded a full valuation allowance against our net deferred tax asset and do not believe any of our valuation allowance as of September 30, 2017 will be released within the next 12 months. The amount of the net deferred tax assets considered realizable could however be adjusted if estimates change. In the first quarter of 2016, we had a deferred tax benefit of $78 million resulting from a change in valuation allowance.

NOTE 12 CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Our Credit Facilities and Second Lien Notes are guaranteed both fully and unconditionally and jointly and severally by our material wholly owned subsidiaries (Guarantor Subsidiaries). Certain of our subsidiaries do not guarantee our Credit Facilities and Second Lien Notes (Non-Guarantor Subsidiaries). The following condensed consolidating balance sheets at September 30, 2017 and December 31, 2016, condensed consolidating statements of operations and statements of cash flows for the nine months ended September 30, 2017 and 2016 reflect the condensed consolidating financial information of our parent company, CRC (Parent), our combined Guarantor Subsidiaries, our combined Non-Guarantor Subsidiaries and the consolidation and elimination entries necessary to arrive at the information for CRC on a consolidated basis.

The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities.

Condensed Consolidating Balance Sheet

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
As of September 30, 2017			(in millions)		
Total current assets	$ 9	$ 425	$ 20	$ (2)	$ 452
Total property, plant and equipment, net	24	5,589	79	—	5,692
Investments in consolidated subsidiaries	5,981	582	—	(6,563)	—
Other assets	—	37	2	—	39
TOTAL ASSETS	$ 6,014	$ 6,633	$ 101	$ (6,565)	$ 6,183
Total current liabilities	234	513	1	(2)	746
Long-term debt - principal amount	5,039	—	—	—	5,039
Deferred gain and issuance costs, net	356	—	—	—	356
Other long-term liabilities	138	475	3	—	616
Amounts due to (from) affiliates	914	(914)	—	—	—
Total equity	(667)	6,559	97	(6,563)	(574)
TOTAL LIABILITIES AND EQUITY	$ 6,014	$ 6,633	$ 101	$ (6,565)	$ 6,183
As of December 31, 2016					
Total current assets	$ 7	$ 418	$ —	$ —	$ 425
Total property, plant and equipment, net	25	5,856	4	—	5,885
Investments in consolidated subsidiaries	5,713	537	—	(6,250)	—
Other assets	—	44	—	—	44
TOTAL ASSETS	$ 5,745	$ 6,855	$ 4	$ (6,250)	$ 6,354
Total current liabilities	221	505	—	—	726
Long-term debt - principal amount	5,168	—	—	—	5,168
Deferred gain and issuance costs, net	397	—	—	—	397
Other long-term liabilities	132	487	1	—	620
Amounts due to (from) affiliates	384	(384)	—	—	—
Total equity	(557)	6,247	3	(6,250)	(557)
TOTAL LIABILITIES AND EQUITY	$ 5,745	$ 6,855	$ 4	$ (6,250)	$ 6,354

Condensed Consolidating Statement of Operations

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions)		
For the nine months ended September 30, 2017					
Total revenues and other	$ 22	$ 1,551	$ 10	$ (32)	$ 1,551
Total costs and other	168	1,303	9	(32)	1,448
Non-operating (loss) income	(253)	23	—	—	(230)
Income tax benefit	—	—	—	—	—
NET (LOSS) INCOME	(399)	271	1	—	(127)
Net income attributable to noncontrolling interest	—	—	(1)	—	(1)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (399)	$ 271	$ —	$ —	$ (128)
For the nine months ended September 30, 2016					
Total revenues and other	$ —	$ 1,093	$ 2	$ —	$ 1,095
Total costs and other	153	1,243	2	—	1,398
Non-operating income (loss)	547	34	—	—	581
Income tax benefit	78	—	—	—	78
NET INCOME (LOSS)	$ 472	$ (116)	$ —	$ —	$ 356

Condensed Consolidating Statement of Cash Flows

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions)		
For the nine months ended September 30, 2017					
Net cash (used) provided by operating activities	$ (403)	$ 621	$ 7	$ —	$ 225
Net cash used by investing activities	(2)	(90)	(82)	—	(174)
Net cash provided (used) by financing activities	409	(536)	92	—	(35)
Increase (decrease) in cash and cash equivalents	4	(5)	17	—	16
Cash and cash equivalents—beginning of period	—	12	—	—	12
Cash and cash equivalents—end of period	$ 4	$ 7	$ 17	$ —	$ 28
For the nine months ended September 30, 2016					
Net cash (used) provided by operating activities	$ (419)	$ 563	$ 1	$ —	$ 145
Net cash used by investing activities	(1)	(30)	—	—	(31)
Net cash provided (used) by financing activities	420	(535)	(1)	—	(116)
Decrease in cash and cash equivalents	—	(2)	—	—	(2)
Cash and cash equivalents—beginning of period	—	12	—	—	12
Cash and cash equivalents—end of period	$ —	$ 10	$ —	$ —	$ 10

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

Except when the context otherwise requires or where otherwise indicated, all references to ‘‘CRC,’’ the ‘‘company,’’ ‘‘we,’’ ‘‘us’’ and ‘‘our’’ refer to California Resources Corporation and its subsidiaries, and all references to ‘‘Occidental’’ refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

General

We are an independent oil and natural gas exploration and production company operating properties within California. We were incorporated in Delaware as a wholly owned subsidiary of Occidental on April 23, 2014, and remained a wholly owned subsidiary of Occidental until November 30, 2014. On November 30, 2014, Occidental distributed shares of our common stock on a pro-rata basis to Occidental stockholders and we became an independent, publicly traded company (the Spin-off). Occidental initially retained approximately 18.5% of our outstanding shares of common stock, which it distributed to Occidental stockholders on March 24, 2016.

Business Environment and Industry Outlook

Our operating results and those of the oil and gas industry as a whole are heavily influenced by commodity prices. Oil and gas prices and differentials may fluctuate significantly, generally as a result of changes in supply and demand and other market-related variables. These and other factors make it impossible to predict realized prices reliably.

Much of the global exploration and production industry has been challenged at prevailing price levels in recent years, putting pressure on the industry's ability to generate positive cash flow and access capital. Global oil prices were higher in the third quarter and first nine months of 2017 compared to the same periods of 2016. Natural gas liquids (NGLs) prices have improved relative to crude oil prices since early 2016 due to tighter domestic supplies, the strength of exports and higher contract prices on natural gasoline. Natural gas prices in the U.S. were higher in the three and nine months ended September 30, 2017 than the comparable periods in 2016 due to lower production and higher demand.

The following table presents the average daily Brent, WTI and NYMEX prices for the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
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

Oil prices and differentials will continue to be affected by a variety of factors including consumption patterns; inventory levels; global and local economic conditions; the actions of OPEC and other producers and governments; actual or threatened disruptions in production, refining and processing; currency exchange rates; worldwide drilling and exploration activities; the effects of conservation, weather, geophysical and technical limitations; transportation and storage limitations; technological advances; and regional market conditions and costs in producing areas; as well as the effect of changes in these variables on market perceptions.

We currently sell all of our crude oil into the California refining markets, which we believe have offered relatively favorable pricing compared to other U.S. regions for similar grades. California is heavily reliant on imported sources of energy, with approximately 67% of the oil consumed in 2016 imported from outside the state. A vast majority of the imported oil arrives via supertanker, mostly from foreign locations. As a result, California refiners have typically purchased crude oil at international waterborne-based prices. We believe that the limited crude transportation infrastructure from other parts of the country to California will continue to contribute to higher realizations than most other U.S. oil markets for comparable grades.

Prices and differentials for NGLs are related to the supply and demand for the products making up these liquids. Some of them more typically correlate to the price of oil while others are affected by natural gas prices as well as the demand for certain chemical products for which they are used as feedstock. In addition, infrastructure constraints magnify pricing volatility.

Natural gas prices and differentials are strongly affected by local market fundamentals, as well as availability of transportation capacity from producing areas. Capacity influences prices because California imports about 90% of its natural gas from other states and Canada. As a result, we typically enjoy favorable pricing relative to out-of-state producers since we can deliver our gas for lower transportation costs. Due to our much lower natural gas production compared to our oil production, the changes in natural gas prices have a smaller impact on our operating results.

In addition to selling natural gas, we also use gas for our steamfloods and power generation. As a result, the positive impact of higher prices is partially offset by higher operating costs. Higher natural gas prices have a net positive effect on our operating results. Conversely, lower natural gas prices generally have a net negative effect on our results, but lower the cost of our steamflood projects and power generation. In 2017, greater availability of hydro electricity in California due to higher-than-normal rainfalls has caused downward pressure on natural gas prices and gas storage capacity disruptions have caused seasonal price volatility.

Our earnings are also affected by the performance of our processing and power generation assets. We process our wet gas to extract NGLs and other natural gas byproducts. We then deliver dry gas to pipelines and separately sell the NGLs. The efficiency with which we extract liquids from the wet gas stream affects our operating results. Additionally, we use part of the electricity from our Elk Hills power plant to reduce operating costs at Elk Hills and nearby fields and increase reliability. The remaining electricity is sold to the grid and a utility under a power purchase and sales agreement that includes a capacity payment. The price we obtain for our excess power impacts our earnings but generally by an insignificant amount.

We opportunistically seek strategic hedging transactions to protect our cash flows, margins and capital investment programs from the cyclical nature of commodity prices and to improve our ability to comply with the covenants under our Credit Facilities. We can give no assurances that our hedges will be adequate to accomplish our objectives. Unless otherwise indicated, we use the term "hedge" to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not necessarily accounted for as cash-flow or fair-value hedges.

We respond to economic conditions by adjusting the amount and allocation of our capital program, aligning the size of our workforce with our level of activity and continuing to improve efficiencies and finding cost savings. The reductions in our capital program in 2015 and 2016 negatively impacted our 2017 production levels. With our increased capital program in 2017 our production decline rate has slowed which sets us up for future growth. Sustained low prices may materially affect the quantities of oil and gas reserves we can economically produce over the longer term.

Seasonality

While certain aspects of our operations are affected by seasonal factors, such as electricity costs, overall, seasonality is not a material driver of changes in our quarterly results during the year.

Exploration and Development Joint Ventures

We have entered into a number of joint ventures where our partners carry all or substantially all of our exploration and development costs. These joint ventures allow us to continue to develop our assets while providing us with financial flexibility and immediate production benefit.

In February 2017, we entered into a joint venture with Benefit Street Partners (BSP) where BSP will contribute up to $250 million, subject to agreement of the parties, in exchange for a preferred interest in the JV (BSP JV). The funds contributed by BSP are designated to be used to develop certain of our oil and gas properties. We contributed a net profits interest in existing and future cash flow from such properties in exchange for a common interest in the JV. BSP is entitled to preferential distributions and, if BSP receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. BSP funded two $50 million commitments in March and July 2017. As of September 30, 2017, the noncontrolling interest in our BSP JV is comprised of contributions from BSP of $98 million (net of $2 million in issuance discounts), distributions to BSP of $6 million and BSP's share of net income of $1 million.

In April 2017, we entered into a joint venture with Macquarie Infrastructure and Real Assets Inc. (MIRA) under which MIRA will invest up to $300 million, subject to agreement of the parties, to develop certain of our oil and gas properties in exchange for a 90% working interest in the related properties (MIRA JV). MIRA will fund 100% of the development cost of such properties. Our 10% working interest reverts to 75% if MIRA receives cash distributions equal to a predetermined threshold return. MIRA initially committed $160 million, which is intended to be invested over two years. Of the committed amount, MIRA contributed $38 million for drilling projects through September 30, 2017, with additional funding expected during the course of the year and in 2018.

Our consolidated results reflect the full operations of our BSP JV, with BSP's share of net income being reported as a noncontrolling interest. Our consolidated results reflect only our working interest share in our MIRA JV.

We also entered into several other development and exploration joint ventures in which our joint venture partners have committed capital of approximately $30 million. These joint ventures could provide more than $75 million in capital if certain milestones are met.

Operations

We conduct our operations through fee interests, mineral leases and other contractual arrangements. We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.3 million net acres, approximately 60% of which we hold in fee. Our oil and gas leases have a primary term ranging from one to ten years, which is extended through the end of production once it commences. We also own a network of strategically placed infrastructure that is integrated with, and complementary to, our operations, including gas plants, oil and gas gathering systems, power plants and other related assets, which we use to maximize the value generated from our production.

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to production-sharing contracts (PSCs) that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and production costs. We record a share of production and reserves to recover a portion of such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners' share of capital and production costs that we incur on their behalf, (ii) for our share of contractually defined base production and (iii) for our share of remaining production thereafter. We recover our share of capital and production costs, and generate returns, through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline assuming comparable capital investment and production costs; however, our net economic benefit is greater when product prices are higher. The contracts represented slightly less than 20% of our production for the quarter ended September 30, 2017.

In addition, in line with industry practice for reporting PSC-type contracts, we report 100% of operating costs under the PSCs in our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery. The total volumes we report represent less than 100% of the volumes produced under the PSCs. This difference in reporting full operating costs but only our net share of production inflates our operating costs per barrel, with an equal corresponding increase in revenues, with no effect on our net results.

Fixed and Variable Costs

Our total production costs consist of variable costs that tend to vary depending on production levels, and fixed costs that typically do not vary with changes in production levels or well counts, especially in the short term. The substantial majority of our near-term fixed costs become variable over the longer term because we manage them based on the field’s stage of life and operating characteristics. For example, portions of labor and material costs, energy, workovers and maintenance expenditures correlate to well count, production and activity levels. Portions of these same costs can be relatively fixed over the near term; however, they are managed down as fields mature in a manner that correlates to production and commodity price levels. While a certain amount of costs for facilities, surface support, surveillance and related maintenance can be regarded as fixed in the early phases of a program, as the production from a certain area matures, well count increases and daily per well production drops, such support costs can be reduced and consolidated over a larger number of wells, reducing costs per operating well. Further, many of our other costs, such as property taxes and oilfield services, are variable and will respond to activity levels and tend to correlate with commodity prices. Overall, we believe approximately one-third of our operating costs are fixed over the life cycle of our fields. We actively manage our fields to optimize production and costs. When we see growth in a field we increase capacities, and similarly when a field nears the end of its economic life we manage the costs while it remains economically viable to produce.

Production and Prices

The following table sets forth our average production volumes of oil, NGLs and natural gas per day for the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	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

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

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent 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 barrel and $3.12 per MMBtu, respectively, resulting in an oil-to-gas ratio of approximately 17 to 1.

The following table sets forth the average realized prices for our products for the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Oil prices with hedge ($ per Bbl)	$ 50.02	$ 43.03	$ 49.42	$ 40.91
Oil prices without hedge ($ per Bbl)	$ 48.90	$ 41.73	$ 48.76	$ 37.54
NGLs prices ($ per Bbl)	$ 34.63	$ 22.45	$ 33.00	$ 20.36
Gas prices ($ per Mcf)	$ 2.56	$ 2.64	$ 2.64	$ 2.11

The following table presents our average realized prices as a percentage of Brent, WTI and NYMEX for the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Oil with hedge as a percentage of Brent	96%	92%	94%	95%
Oil with hedge as a percentage of WTI	104%	96%	100%	99%
Oil without hedge as a percentage of Brent	94%	89%	93%	87%
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%
Gas as a percentage of NYMEX	87%	98%	85%	94%

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2016 to September 30, 2017 are discussed below:

	September 30, 2017	December 31, 2016
	(in millions)	
Cash and cash equivalents	$ 28	$ 12
Trade receivables	$ 221	$ 232
Inventories	$ 58	$ 58
Other current assets, net	$ 145	$ 123
Property, plant and equipment, net	$ 5,692	$ 5,885
Other assets	$ 39	$ 44
Current maturities of long-term debt	$ 100	$ 100
Accounts payable	$ 263	$ 219
Accrued liabilities	$ 383	$ 407
Long-term debt - principal amount	$ 5,039	$ 5,168
Deferred gain and issuance costs, net	$ 356	$ 397
Other long-term liabilities	$ 616	$ 620
Equity attributable to common stock	$ (667)	$ (557)
Equity attributable to noncontrolling interest	$ 93	$ —

Cash and cash equivalents at September 30, 2017 included approximately $17 million of cash that is restricted for capital investment under our joint venture agreements. See *Liquidity and Capital Resources* for additional discussion of changes in cash and cash equivalents.

The decrease in trade receivables was largely the result of lower production in the third quarter of 2017 compared to the fourth quarter of 2016. The decrease in property, plant and equipment reflected depreciation, depletion and amortization (DD&A) for the period, partially offset by capital investments. The increase in other current assets, net was primarily due to changes in derivative assets and amounts due from joint interest partners, partially offset by a decrease in non-core assets held for sale.

The increase in accounts payable reflected higher capital investments in the quarter ended September 30, 2017, compared to the quarter ended December 31, 2016. The decrease in accrued liabilities was primarily due to lower derivative obligations, the effect of employee bonus payments in the first quarter of 2017 and the reduction in liabilities related to the sale of non-core property in the first quarter of 2017, partially offset by higher net greenhouse gas obligations as well as accrued interest and property taxes primarily due to the timing of payments. The decrease in long-term debt primarily reflected payments on our 2014 Term Loan. The decrease in deferred gain and issuance costs, net, reflected the amortization of deferred gains, partially offset by the amortization of deferred issuance costs. The decrease in other long-term liabilities reflected lower derivative liabilities, primarily due to mark-to-market effects, partially offset by an increase in asset retirement obligations largely caused by accretion and a deposit from our joint interest partner MIRA. The decrease in equity attributable to common stock primarily reflected the net loss for the period. Equity attributable to noncontrolling interest primarily reflected contributions from BSP, partially offset by distributions to BSP through September 30, 2017.

Statement of Operations Analysis

For the three months ended September 30, 2017 and 2016, we had a pre-tax loss of $132 million and pre-tax income of $546 million, respectively. For the nine months ended September 30, 2017 and 2016, we had a pre-tax loss of $127 million and pre-tax income of $278 million, respectively. The following table presents the results of our operations:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
	(in millions)			
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
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)
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
Adjusted net loss	$ (52)	$ (71)	$ (173)	$ (243)
Adjusted EBITDAX	$ 181	$ 164	$ 539	$ 448
Effective tax rate	—%	—%	—%	(28)%

Non-GAAP Financial Measures

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 (loss) income and adjusted general and administrative expenses, both of 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; 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.

The following table reconciles net (loss) income attributable to common stock to adjusted net loss and presents net (loss) income attributable to common stock and adjusted net loss per diluted share:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
	(in millions)			
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
Net gains on early extinguishment of debt	—	(660)	(4)	(793)
Gains on asset divestitures	—	—	(21)	(31)
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.

The following table presents a reconciliation of the GAAP financial measure of net (loss) income attributable to common stock to the non-GAAP financial measure of Adjusted EBITDAX:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
	(in millions)			
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	81	(629)	(45)	(548)
Other non-cash items	11	12	37	40
Adjusted EBITDAX	$ 181	$ 164	$ 539	$ 448

The following table presents the components of our net derivative losses (gains):

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
	(in millions)			
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

The following table presents the reconciliation of our company-wide general and administrative expenses to adjusted general and administrative expenses:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
	(in millions)			
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

Results of Oil and Gas Operations

The following represents key operating data for our oil and gas operations, excluding certain corporate items, on a per Boe basis:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Production costs	$ 18.90	$ 16.63	$ 18.31	$ 15.01
Production costs, excluding effects of PSC contracts[(a)]	$ 17.81	$ 15.63	$ 17.21	$ 14.18
General and administrative expenses	$ 0.85	$ 0.71	$ 0.88	$ 0.85
Adjusted general and administrative expenses[(b)]	$ 0.77	$ 0.63	$ 0.76	$ 0.69
Depreciation, depletion and amortization	$ 10.73	$ 10.15	$ 10.92	$ 10.24
Taxes other than on income	$ 2.64	$ 2.44	$ 2.34	$ 2.63

(a) As described in the Operations section, the reporting of our PSC contracts creates a difference between reported production costs and reported volumes, inflating the per barrel production costs. The amounts represent the production costs for the company after adjustments for this difference.

(b) For each quarter ended September 30, 2017 and 2016, the amount excludes unusual and infrequent charges related to early retirement and severance costs associated with field personnel totaling $0.08 per Boe. For the nine months ended September 30, 2017 and 2016, the amount excludes unusual and infrequent charges related to early retirement and severance costs associated with field personnel totaling $0.12 per Boe and $0.16 per Boe, respectively.

Three months ended September 30, 2017 vs. 2016

Oil and gas net sales increased 9%, or $37 million, for the three months ended September 30, 2017, compared to the same period of 2016, due to increases of approximately $59 million and $18 million from higher oil and NGL realized prices, respectively, partially offset by the effects of lower oil and natural gas production of $36 million and $3 million, respectively. The higher realized oil prices reflected an increase in global oil prices and improved differentials. Daily oil and gas production volumes averaged 128,000 Boe in the third quarter of 2017, compared with 138,000 Boe in the third quarter of 2016, representing a year-over-year decline rate of 7%. Average oil production decreased by 9%, or 8,000 barrels per day, to 82,000 barrels per day in the three months ended September 30, 2017, compared to the same period of the prior year. NGL production of 16,000 barrels per day was comparable for both periods. Natural gas production decreased by 6% to 182 MMcf per day.

Net derivative losses were $65 million and $14 million for the three months ended September 30, 2017 and 2016, respectively, representing an overall change of $51 million. The 2017 amount included a non-cash derivative loss of $73 million compared to $25 million in the prior year, representing a $48 million change in addition to lower income from cash settlements of $3 million. The non-cash loss reflected changes in the commodity price curves at the end of each of the respective periods.

Other revenue increased 7%, or $3 million, for the three months ended September 30, 2017, compared to the same period of 2016, due to increased third-party power sales from our Elk Hills power plant.

Production costs for the three months ended September 30, 2017 increased $11 million to $222 million or $18.90 per Boe, compared to $211 million or $16.63 per Boe for the same period of 2016, representing a 5% increase on an absolute dollar basis. Total production costs in the third quarter of 2016 reflected the continued effect of management's decision to selectively defer workovers and downhole maintenance activity in light of low commodity prices. Production costs in the third quarter of 2017 reflected higher downhole maintenance activity in line with the current price environment.

Our general and administrative expenses for the three months ended September 30, 2017 increased $5 million to $63 million, compared to the same period of 2016. Our adjusted general and administrative expenses were $62 million and $57 million for the three months ended September 30, 2017 and 2016, respectively, which excluded early retirement and severance costs. The non-cash portion of general and administrative expenses, comprising equity compensation and pension settlement costs, was approximately $5 million and $6 million for the three months ended September 30, 2017 and 2016, respectively.

DD&A expense decreased by $3 million for the three months ended September 30, 2017, compared to the same period of 2016. Of this decrease, approximately $10 million was attributable to lower volumes, partially offset by an increase in the DD&A rate of approximately $7 million.

Taxes other than on income, which include property and production taxes and greenhouse gas emissions costs, increased for the three months ended September 30, 2017, compared to the same period of 2016, largely due to higher property and production-related taxes assessed, partially offset by lower greenhouse gas emission costs.

Interest and debt expense, net, decreased to $85 million for the three months ended September 30, 2017, compared to $95 million in the same period of 2016. The 2016 period reflected the write off of deferred financing costs related to the tender of our Senior Notes.

Net gains on early extinguishment of debt for the three months ended September 30, 2016 consisted of gains on the tender of our Senior Notes.

For the three months ended September 30, 2017 and 2016, we did not provide any current or deferred tax benefit on pre-tax loss of $132 million or any tax provision on pre-tax income of $546 million, respectively. The difference between our 35% statutory tax rate and our 0% effective tax rate for 2017 is primarily related to an increase in our valuation allowance based on the expectation of a tax loss for the year. For 2016, our 0% effective tax rate primarily relates to the exclusion of gains related to our debt-reduction actions.

Nine months ended September 30, 2017 vs. 2016

Oil and gas net sales increased 20%, or $230 million, for the nine months ended September 30, 2017, compared to the same period of 2016, due to increases of approximately $284 million, $57 million and $29 million from higher oil, NGL and natural gas realized prices, respectively, partially offset by the effects of lower oil, NGL and natural gas production of $125 million, $3 million and $12 million, respectively. The higher realized oil prices reflected a significant increase in global oil prices and improved differentials. Daily oil and gas production volumes averaged 130,000 Boe in the nine months ended September 30, 2017, compared with 142,000 Boe in the same period of 2016, representing a year-over-year decline rate of 8%. Average oil production decreased by 10%, or 9,000 barrels per day, compared to the same period of the prior year, to 84,000 barrels per day in the nine months ended September 30, 2017. NGL production was 16,000 barrels per day for the nine months ended September 30, 2017 and 2016. Natural gas production decreased by 8% to 181 MMcf per day.

Net derivative gains were $51 million for the nine months ended September 30, 2017, compared to a loss of $157 million in the comparable period of 2016, representing an overall change of $208 million. The 2017 amount included a non-cash derivative gain compared to a loss in the prior year, representing a $279 million change, partially offset by lower gains from cash settlements of $71 million. The non-cash change reflected changes in the commodity price curves at the end of each of the respective periods.

Other revenue increased 19%, or $18 million, for the nine months ended September 30, 2017, compared to the same period of 2016, due to increased third-party power sales from our Elk Hills power plant, which was offline for about half of the first quarter of 2016 for a planned turnaround.

Production costs for the nine months ended September 30, 2017 increased $66 million to $649 million or $18.31 per Boe, compared to $583 million or $15.01 per Boe for the same period of 2016, resulting in an 11% increase on an absolute dollar basis. The year-over-year increase was driven by increased activity in line with the stronger commodity prices and higher gas and electricity costs. Total production costs in the nine months ended 2016 reflected management's decision to selectively defer workovers and downhole maintenance activity in light of low commodity prices. Production costs in the nine months ended 2017 reflected higher downhole maintenance activity in line with the current price environment.

Our general and administrative expenses for the nine months ended September 30, 2017 increased $5 million to $191 million, compared to the same period of 2016. Our adjusted general and administrative expenses were $187 million and $167 million for the nine months ended September 30, 2017 and 2016, respectively, each of which excluded early retirement and severance costs. The 2016 period reflected temporary employee benefit reductions. The 2017 period primarily reflected higher performance-related bonus and incentive compensation largely due to better-than-expected performance. The non-cash portion of general and administrative expenses, comprising equity compensation and pension settlement costs, was approximately $16 million and $20 million for the nine months ended September 30, 2017 and 2016, respectively.

DD&A expense decreased by $10 million for the nine months ended September 30, 2017, compared to the same period of 2016. Of this decrease, approximately $37 million was attributable to lower volumes, partially offset by an increase in the DD&A rate of approximately $27 million.

Taxes other than on income, which include property and production taxes and greenhouse gas emissions costs, decreased for the nine months ended September 30, 2017, compared to the same period of 2016, largely due to lower property taxes assessed.

Interest and debt expense, net, increased to $252 million for the nine months ended September 30, 2017, compared to $243 million in the same period of 2016, due to higher blended interest rates in 2017 resulting from the $1 billion credit facility that we entered into in the third quarter of 2016, partially offset by lower debt balances resulting from our debt-reduction actions. The 2016 period also reflected the write off of deferred financing costs related to the tender of our Senior Notes.

Net gains on early extinguishment of debt consisted of the gains on debt repurchases for the nine months ended September 30, 2017. Net gains on early extinguishment of debt for the nine months ended September 30, 2016 consisted of open-market purchases, a debt-for-equity exchange and a cash tender for our Senior Notes.

Gains on asset divestitures reflected non-core asset sales during each of the respective periods.

Other non-operating expense for the nine months ended September 30, 2017 reflected transaction costs related to our joint ventures.

For the nine months ended September 30, 2017, we did not provide any current or deferred tax provision on pre-tax loss of $127 million. The difference between our 35% statutory tax rate and our 0% effective tax rate for the period is primarily related to increases in our valuation allowance based on an expectation of a tax loss for the year. For the same period of 2016, we had a deferred tax benefit of $78 million resulting from a change in valuation allowance. For 2016, we did not provide a tax provision on our pre-tax income due to the exclusion of gains related to our debt-reduction actions.

Liquidity and Capital Resources

The primary source of liquidity and capital resources to fund our capital program and other obligations has been cash flow from operations. Operating cash flows are largely dependent on oil and natural gas prices, sales volumes and costs. Significant changes in oil and natural gas prices have a material impact on our liquidity.

Lower commodity prices in recent years have put pressure on the oil and gas industry's ability to generate positive cash flow and access capital. If commodity prices were to prevail through 2017 at about current levels, we would expect to be able to fund our operations and capital budget with our operating cash flows and would not anticipate a net draw down on our 2014 Revolving Credit Facility. Our ability to borrow funds under our 2014 Revolving Credit Facility is limited by the size of our lenders' commitments, our ability to comply with covenants, our borrowing base and a $250 million minimum monthly liquidity requirement. Effective November 1, 2017, the borrowing base under our 2014 Credit Facilities was reaffirmed at $2.3 billion. Our credit limit under our 2014 Credit Facilities is $2.0 billion. As of September 30, 2017, we had approximately $431 million of available borrowing capacity under these facilities, subject to the minimum liquidity requirement.

We expect to be in compliance with the covenants under our 2014 Credit Facilities through 2017, but at current product prices, we expect that we would not be in compliance with the minimum interest coverage ratio when it increases to 2.00 to 1.00 and the maximum leverage ratio when it decreases to 2.25 to 1.00 in March 2018. If the proposed amendment to our 2014 Credit Facilities described elsewhere in this Quarterly Report on Form 10-Q is not completed, or if it is completed but does not become effective, we would need to seek a separate amendment for covenant relief from our lenders. Since the Spin-off, the lenders under or 2014 Credit Facilities have been supportive in granting multiple amendments to facilitate our efforts to strengthen our balance sheet, including covenant amendments. However, we can make no assurances that they will continue to grant covenant amendments. Our inability to amend our covenants in the event the proposed amendment to our 2014 Credit Facilities is not completed, or if it is completed but does not become effective, would have a material adverse effect on our liquidity. If we were to breach any of the covenants under our 2014 Credit Facilities, our lenders could accelerate the principal amount due under such facilities and foreclose against the assets securing them. If payments were accelerated, or we failed to make certain payments, under these facilities, it would result in a default under our 2016 Credit Agreement and outstanding notes and permit acceleration and foreclosure against the assets securing our 2016 Credit Agreement and Second Lien Notes.

Our 2014 Credit Facilities mature at the earlier of November 2019 and the182nd day prior to the maturity of our 2020 Notes or our 2021 Notes if the outstanding principal amount of either series exceeds $100 million prior to its respective maturity date. Our 2016 Credit Agreement matures at the earlier of December 2021 and the 91st day prior to maturity of the 2020 Notes or of our 2021 Notes if the outstanding principal amount of either series exceeds $100 million prior to its respective maturity date. As of September 30, 2017, we had $165 million and $135 million in aggregate principal amount of outstanding 2020 Notes and 2021 Notes, respectively.

For continued financial flexibility in a lower price environment, we expect to rely on operating cash flows, settlements from our derivatives contracts, joint ventures, our available borrowing capacity and our ability to manage the pace of development activities to keep the internally funded portion of the aggregate capital program within our operating cash flow.

We cannot guarantee our planned increase in investments in 2017 will result in a rapid reversal of, or a significant increase in, production trends. If commodity prices fall below current levels for a sustained period, we may need to reduce the size of our capital program and, as a result, may experience declines in our production and reserves. Such declines may reduce our liquidity and ability to satisfy our debt obligations by negatively impacting our cash flow from operations, the value of our assets and the amount of our borrowing base.

We will continue to evaluate opportunities to strengthen our balance sheet. We expect our main source of deleveraging, as measured by a lower leverage ratio, will come from our future production growth through reinvesting substantially all of our operating cash flow into our business. However, we may also from time to time seek to further reduce our outstanding debt using cash from asset sales, other monetizations or other sources. Such activities, if any, will depend on available funds, prevailing market conditions, our liquidity requirements, contractual restrictions in our credit facilities, perceived credit risk by counterparties and other factors. The amounts involved may be material. We can give no assurances that any of these efforts will be successful.

Our strategy for protecting our cash flows and liquidity also includes our hedging program. We currently have the following Brent-based crude oil contracts, which includes activity subsequent to September 30, 2017:

	Q4 2017	Q1 2018	Q2 2018	Q3 2018	Q4 2018	FY 2019	FY 2020
Sold Calls:							
Barrels per day	6,300	10,400	10,400	16,100	16,100	1,000	900
Weighted-average 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 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 price per barrel	$ —	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ —	$ —
Swaps:							
Barrels per day	30,300	29,300	29,000	19,000	19,000	—	—
Weighted-average price per barrel	$ 55.09	$ 60.04	$ 60.00	$ 60.13	$ 60.13	$ —	$ —

A small portion of the derivatives in the table above were entered into by our BSP JV, including all of the 2019 and 2020 positions. Our 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 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.

Credit Facilities

2014 Credit Facilities

Our credit facilities from 2014 (2014 Credit Facilities) currently comprise (i) a $559 million senior term loan facility (2014 Term Loan) and (ii) a $1.4 billion senior revolving loan facility (2014 Revolving Credit Facility). We are permitted to increase the size of our 2014 Revolving Credit Facility by up to $245 million if we obtain additional commitments from new or existing lenders. Our 2014 Revolving Credit Facility includes a sub-limit of $400 million for the issuance of letters of credit. Our credit limit under our 2014 Credit Facilities is approximately $2.0 billion. Borrowings under these facilities are also subject to a borrowing base, which was reaffirmed at $2.3 billion as of November 1, 2017.

In 2016 and through the nine months ended September 30, 2017, we made scheduled quarterly payments of $25 million on our 2014 Term Loan for an aggregate amount of $175 million. In August 2016, we made a $250 million prepayment on our 2014 Term Loan from the proceeds of our 2016 Credit Agreement. In February 2017, we made a $16 million prepayment on our 2014 Term Loan from the proceeds of non-core asset sales.

The lenders under our 2014 Credit Facilities have a first-priority lien on a substantial majority of our assets, including our Elk Hills power plant and midstream assets. We also granted a lien on the same assets to the lenders under our 2016 Credit Agreement and the holders of our Second Lien Notes.

Borrowings under our 2014 Credit Facilities bear interest, at our election, at either a LIBOR rate or an alternate base rate (ABR) (equal to the highest of (i) the federal funds effective rate plus 0.50%, (ii) the administrative agent's prime rate and (iii) the one-month LIBOR rate plus 1.00%), in each case plus an applicable margin. This applicable margin is based, while our total leverage ratio exceeds 3.00 to 1.00, on our borrowing base utilization and will vary from (a) in the case of LIBOR loans, 2.50% to 3.50% and (b) in the case of ABR loans, 1.50% to 2.50%. The unused portion of our 2014 Revolving Credit Facility commitments is subject to a commitment fee equal to 0.50% per annum. We also pay customary fees and expenses under our 2014 Credit Facilities. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period, but not less than quarterly.

As of September 30, 2017, the financial performance covenants under our 2014 Credit Facilities were as follows:

	2017		**2018 and beyond**			
	9/30	12/31	3/31	6/30	9/30	12/31
Maximum leverage ratio[(a)]	3.25 to 1.00	3.25 to 1.00	2.25 to 1.00	2.25 to 1.00	2.25 to 1.00	2.25 to 1.00
Minimum interest coverage ratio[(b)]	1.20 to 1.00	1.20 to 1.00	2.00 to 1.00	2.00 to 1.00	2.00 to 1.00	2.00 to 1.00
Minimum asset coverage ratio[(c)]	N/A	1.20 to 1.00	N/A	1.20 to 1.00	N/A	1.20 to 1.00
Minimum monthly liquidity[(d)]			$250 million			

(a) The ratio of indebtedness under our 2014 Credit Facilities to trailing four-quarter Adjusted EBITDAX
(b) The ratio of Adjusted EBITDAX to consolidated interest charges, adjusted for deferred gain amortization
(c) The ratio of PV-10 to total indebtedness under our 2014 Credit Facilities and our 2016 Credit Agreement
(d) Measured as of the last day of each calendar month

The required ratios for 2018 and beyond were last amended in February 2016 and were not changed in subsequent modifications when the ratios through the end of 2017 were amended. As of September 30, 2017, we had approximately $431 million of available borrowing capacity under our 2014 Revolving Credit Facility, subject to the month-end minimum liquidity requirement.

We must generally apply 100% of the net cash proceeds from asset sales (other than de minimis sales and sales to permitted development joint ventures) to repay loans outstanding under our 2014 Credit Facilities, except that we are permitted to use up to 50% of net cash proceeds from non-borrowing base asset sales or monetizations (i) to repurchase our Senior Notes to the extent available at a significant minimum discount to par, (ii) to purchase up to $140 million of certain of our Senior Notes at any discount at par, (iii) for general corporate purposes or (iv) for oil and gas expenditures, including expenditures for the maintenance, repair or improvement of existing properties and assets, and the acquisition of leasehold, seismic or other assets used in an oil and gas business. At least 75% of asset sale proceeds must be in cash (50% for sales of non-borrowing base assets unless our leverage ratio is less than 4:00 to 1:00 at which time the requirement falls to 40%), other than permitted development joint ventures and certain other transactions. Our 2014 Credit Facilities also permit us to incur up to an additional $50 million of non-facility indebtedness, which may be secured by non-borrowing base assets, subject to compliance with our financial covenants, the proceeds of which must be applied to repay our 2014 Term Loan. We must apply cash on hand in excess of $150 million daily to repay amounts outstanding under our 2014 Revolving Credit Facility. Further, we are restricted from paying dividends or making other distributions to common stockholders.

The borrowing base under our 2014 Credit Facilities is redetermined each May 1 and November 1. The borrowing base is based upon a number of factors, including commodity prices and reserves, declines in which could cause our borrowing base to be reduced. Increases in our borrowing base require approval of at least 80% of our revolving lenders, as measured by exposure, while decreases or affirmations require a two-thirds approval. We and the lenders (requiring a request from the lenders holding two-thirds of the revolving commitments and outstanding loans) each may request a special redetermination once in any period between three consecutive scheduled redeterminations. We will be permitted to have collateral released when both (i) our credit ratings are at least Baa3 from Moody's and BBB- from S&P, in each case with a stable or better outlook, and (ii) certain permitted liens securing other debt are released.

We are working with our lender group to amend our 2014 Credit Facilities. Although not yet executed, 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, will 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 liquidity at closing of $500 million. The proceeds of the new term loan would be used to repay a portion of the borrowings under our 2014 Credit Facilities. If the proposed amendment is completed and becomes effective, our 2014 Credit Facilities would be amended to:

- extend the maturity date until June 30, 2021, subject to a springing maturity of (i) 273 days prior to the maturity of our 2020 Notes to the extent that more than $100 million of such notes remain outstanding at such date and (ii) 273 days prior to the maturity of our 2021 Notes, to the extent that more than $100 million of such notes remain outstanding on such date;
- reset the financial performance covenants as follows:
    - maximum leverage ratio of indebtedness under our 2014 Credit Facilities and the new term loan to EBITDAX to be less than 1.90 to 1.00 through 2019 and less than 1.50 to 1.00 thereafter and
    - minimum interest coverage ratio to be greater than 1.20 to 1.00
- defer quarterly payments on our 2014 Term Loan until September 30, 2019, which would be reduced to $12.5 million per quarter thereafter;
- reduce our 2014 Revolving Credit Facility commitment to $1 billion and reduce our minimum liquidity requirement to $150 million;
- increase the applicable margin on LIBOR-based loans to a range of 3.25% to 4.00% and on ABR-based loans to a range of 2.25% to 3.00%;
- permit us to use 50% of the proceeds from an Elk Hills power plant monetization to prepay our 2016 Credit Agreement, Second Lien Notes and Senior Notes;
- permit us to use the proceeds from other non-borrowing base asset sales to prepay our 2016 Credit Agreement, Second Lien Notes and Senior Notes as follows:
    - 75% of such proceeds for all aggregate proceeds received up to $500 million
    - 50% of such proceeds for all aggregate proceeds received between $500 million and $1 billion
    - 25% of such proceeds for all aggregate proceeds received in excess of $1 billion
- permit us to incur certain other first-lien indebtedness for deleveraging activities

We can provide no assurances that the amendment will be completed or, if it is completed, that it will become effective, whether as a result of flood insurance review or otherwise.

2016 Credit Agreement

In August 2016, we entered into a $1 billion first-lien term loan (2016 Credit Agreement), the net proceeds of which were used to (i) prepay $250 million of our 2014 Term Loan and (ii) reduce our 2014 Revolving Credit Facility by $740 million. The proceeds received were net of a $10 million original issue discount. The loan under our 2016 Credit Agreement bears interest at a floating rate per annum equal to LIBOR plus 10.375%, subject to a 1.00% LIBOR floor, determined for the applicable interest period (or ABR rates plus 9.375% in certain circumstances). Interest on LIBOR loans is payable at the end of each LIBOR period, but not less than quarterly. Interest on ABR loans is payable quarterly in arrears.

Our 2016 Credit Agreement is secured by the same collateral used to secure our 2014 Credit Facilities but is second in collateral recovery to the lenders under our 2014 Credit Facilities. Prepayment of our 2016 Credit Agreement is subject to an adjustable make-whole amount prior to the fourth anniversary. Following the fourth anniversary, we may redeem at par. At both September 30, 2017 and December 31, 2016, we had $1 billion outstanding under our 2016 Credit Agreement.

Our 2016 Credit Agreement provides for customary covenants and events of default consistent with, or generally less restrictive than, the covenants in our 2014 Credit Facilities, including limitations on additional indebtedness, liens, asset dispositions, investments and restricted payments and other negative covenants, in each case subject to certain limitations and exceptions. Additionally, our 2016 Credit Agreement requires us to maintain a first-lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31, consistent with our 2014 Credit Facilities.

Second Lien Notes

In December 2015, we issued $2.25 billion in aggregate principal amount of our 8% senior secured second-lien notes due December 15, 2022 (Second Lien Notes), which we exchanged for $2.8 billion of our outstanding Senior Notes. We recorded a deferred gain of approximately $560 million on the debt exchange, which will be amortized using the effective interest rate method over the term of our Second Lien Notes. Our Second Lien Notes are secured on a lower-priority basis than the lenders of our 2014 Credit Facilities and 2016 Credit Agreement.

We pay interest on our Second Lien Notes semiannually in cash in arrears on June 15 and December 15.

The indenture governing our Second Lien Notes includes covenants that, among other things, limit our ability to incur debt secured by liens subject to certain exceptions and restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a “change of control triggering event” (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Second Lien Notes, to offer to purchase our Second Lien Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest. The indenture also restricts our ability to sell certain assets and to release collateral from liens securing our Second Lien Notes, unless the collateral is released in compliance with our 2014 Credit Facilities.

We may redeem our Second Lien Notes (i) prior to December 15, 2017 from the proceeds of certain equity offerings, in an amount up to 35% of the initial aggregate principal amount of the notes issued plus any additional notes issued, at a redemption price equal to 108% of the principal amount redeemed, plus accrued and unpaid interest, (ii) prior to December 15, 2018, in whole or in part at a redemption price equal to 100% of the principal amount redeemed plus a make-whole amount and accrued and unpaid interest and (iii) on or after December 15, 2018, in whole or in part at a fixed redemption price ranging from 104% to 102% of the principal amount redeemed plus accrued and unpaid interest prior to 2019 and 100% thereafter.

Senior Notes

In October 2014, we issued $5 billion in aggregate principal amount of our senior unsecured notes, including $1 billion of 5% notes due January 15, 2020 (2020 Notes), $1.75 billion of 5 ½% notes due September 15, 2021 (2021 Notes) and $2.25 billion of 6% notes due November 15, 2024 (2024 Notes and, collectively, Senior Notes). We used the net proceeds from the issuance of our Senior Notes to make a $4.95 billion cash distribution to Occidental in October 2014.

In 2015, we repurchased approximately $33 million in principal amount of our 2020 Notes for $13 million in cash. We also exchanged a substantial majority of our Senior Notes for our Second Lien Notes in December 2015 as described above. In 2016, we repurchased over $1.5 billion in principal amount of our outstanding Senior Notes, primarily using drawings of $750 million on our 2014 Revolving Credit Facility and cash from operations. We also exchanged approximately 3.4 million shares of our common stock for $100 million in aggregate principal amount of our Senior Notes. In the first quarter of 2017, we purchased $28 million in aggregate principal amount of our 2020 Notes for $24 million in cash.

The following table summarizes the material terms of our Senior Notes outstanding at September 30, 2017:

	2020 Notes	2021 Notes	2024 Notes
Outstanding principal	$165 million	$135 million	$193 million
Interest rate	5%	5.5%	6%
Maturity date	January 15, 2020	September 15, 2021	November 15, 2024
Interest payment dates	January 15 July 15	March 15 September 15	May 15 November 15

The indenture governing our Senior Notes includes covenants that, among other things, limits our ability to grant liens securing borrowed money subject to certain exceptions and restricts our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a “change of control triggering event” (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Senior Notes, to offer to purchase our Senior Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest.

We may redeem our Senior Notes prior to their maturity dates, in whole or in part, at a redemption price equal to 100% of the principal amount redeemed plus a make-whole amount and accrued and unpaid interest.

Other

At September 30, 2017, we were in compliance with all financial and other debt covenants.

All obligations under our 2014 Credit Facilities and 2016 Credit Agreement (collectively, Credit Facilities) as well as our Second Lien Notes are guaranteed both fully and unconditionally and jointly and severally by all of our material wholly owned subsidiaries.

The terms and conditions of all of our indebtedness are subject to additional qualifications and limitations that are set forth in the relevant governing documents.

A one-eighth percent change in the variable interest rates on the borrowings under our Credit Facilities on September 30, 2017 would result in a $3 million change in annual interest expense.

As of September 30, 2017 and December 31, 2016, we had letters of credit of approximately $137 million and $130 million, respectively, under our 2014 Revolving Credit Facility. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

Cash Flow Analysis

	Nine months ended September 30,	
	2017	2016
	(in millions)	
Net cash flows provided by operating activities	$ 225	$ 145
Net cash flows used by investing activities	$ (174)	$ (31)
Net cash flows used by financing activities	$ (35)	$ (116)
Adjusted EBITDAX	$ 539	$ 448

Our net cash provided by operating activities for the nine months ended September 30, 2017 increased by $80 million to $225 million from $145 million in the same period of 2016. The increase primarily reflected higher revenues of approximately $177 million and lower taxes other than on income of $15 million, partially offset by higher production costs of $66 million, higher cash general and administrative expenses of $20 million, higher interest payments of $17 million and higher cash exploration expense of $3 million. Additionally, our operating cash flows benefited from a positive $9 million change in working capital in the nine months ended September 30, 2017, compared to a negative $5 million change for the same period in 2016.

Our net cash flow used by investing activities of $174 million for the nine months ended September 30, 2017 included approximately $206 million of capital investments (net of changes in capital-related accruals), partially offset by proceeds from asset divestitures of $33 million. Our net cash flow used by investing activities of $31 million for the nine months ended September 30, 2016 primarily included $50 million of capital investments (net of changes in capital-related accruals), partially offset by $19 million from asset divestitures.

Our net cash flow used by financing activities of $35 million for the nine months ended September 30, 2017 included $91 million of payments on our 2014 Term Loan, $26 million of debt repurchases and transaction costs, $10 million of net payments on our 2014 Revolving Credit Facility and $6 million of distributions paid to the noncontrolling interest, partially offset by net contributions from the noncontrolling interest of $98 million. Our net cash flow used by financing activities of $116 million for the nine months ended September 30, 2016 primarily included approximately $329 million of payments on our 2014 Term Loan and debt repurchases and transaction costs of $814 million, partially offset by the issuance of our 2016 Credit Agreement for $990 million and $33 million of net proceeds from our 2014 Revolving Credit Facility.

The following table sets forth a reconciliation of the GAAP measure of net cash provided by operating activities to the non-GAAP financial measure of Adjusted EBITDAX:

	Nine months ended September 30,	
	2017	2016
	(in millions)	
Net cash provided by operating activities	$ 225	$ 145
Cash interest	251	244
Exploration expenditures	16	13
Other changes in operating assets and liabilities	33	32
Other, net	14	14
Adjusted EBITDAX	$ 539	$ 448

The increase in Adjusted EBITDAX resulted from higher revenues and lower taxes other than on income, partially offset by higher production costs, reflecting increased activity and higher gas and electricity costs.

2017 Capital Program

We create value by investing our operating cash flows back into our business. We are focusing our internally funded capital on oil projects, which provide higher margins and low decline rates that we believe will generate growing cash flow to fund increasing capital budgets that will grow production in a higher price environment.

Our low decline rates compared to our industry peers plus our high level of operational control give us the flexibility to adjust the level of such capital investments as circumstances warrant. As a result, we have developed a dynamic plan that can be scaled up or down depending on the price environment.

Our 2017 base capital budget was initially set at approximately $300 million. We entered into two joint ventures during the year in which our partners are providing capital of approximately $160 million during 2017 for the development of certain of our oil and gas properties. As a result, we reduced our internally funded portion of the capital program to approximately $240 million, partly due to $22 million in efficiencies and cost savings identified year to date. Our total capital program of approximately $400 million, which includes the portion funded by MIRA that will not be reported in our consolidated results, includes up to $160 million in joint venture drilling and completions as well as internally funded amounts of $105 million for drilling and completions, $60 million for capital workovers, $45 million for facilities, $20 million primarily for mechanical integrity projects and $10 million for exploration.

Our capital investment for the nine months ended September 30, 2017 was $232 million, of which $82 million was funded by BSP. The joint ventures afford an additional layer of optionality. We closed our second $50 million tranche of funding with BSP in July 2017 and expect the JVs to allow us to maintain at least an eight-rig program for the remainder of the year. In a higher price environment, the resulting acceleration of activity from the JVs should help compound the efficiencies and cost savings that we are implementing.

We began 2017 with two rigs and had an average of eight rigs for the three months ended September 30, 2017 and five rigs for the nine months ended September 30, 2017. At the end of the third quarter, we were operating nine rigs. By the end of the year, we expect to be operating eight rigs, with two focused on steamfloods, one each on shales, unconventional and waterfloods and three on conventional reservoirs including one for exploration. Our 2017 development program focuses on our core fields - Elk Hills, Wilmington, Kern Front, Buena Vista, Mt. Poso, Pleito Ranch, Wheeler Ridge and the delineation of Kettleman North Dome.

Lawsuits, Claims, Contingencies and Commitments

We are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief.

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at September 30, 2017 and December 31, 2016 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, our subsidiaries, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with the Spin-off, purchases and other transactions that they have entered into with us. These indemnities include indemnities made to Occidental against certain tax-related liabilities that may be incurred by Occidental relating to the Spin-off and liabilities related to operation of our business while it was still owned by Occidental. As of September 30, 2017, we are not aware of material indemnity claims pending or threatened against us.

We are currently under examination by the Internal Revenue Service for our U.S. federal income tax return for the post-Spin-off period in 2014 and calendar year 2015. No significant issues have been raised to date. State returns for these years remain subject to examination.

Significant Accounting and Disclosure Changes

See *Note 2 Accounting and Disclosure Changes* under Part I Item1 of this report for a discussion of new accounting matters.

Safe Harbor Statement Regarding Outlook and Forward-Looking Information

The information in this document includes 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 specifically include our expectations as to our future financial position, liquidity, cash flows, results of operations and business prospects, budgets, drilling and workover program, maintenance capital requirements, production, costs, operations, reserves, hedging activities, transactions and capital investments and other guidance. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. You can typically identify forward-looking statements by words such as aim, anticipate, believe, budget, continue, could, effort, estimate, expect, forecast, goal, guidance, intend, likely, may, might, objective, outlook, plan, potential, predict, project, seek, should, target, will or would and other similar words that reflect the prospective nature of events or outcomes. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, sometimes materially. Material risks that may affect our results of operations and financial position appear in Part I, Item 1A, *Risk Factors* of the 2016 Form 10-K.

Factors (but not necessarily all the factors) that could cause results to differ include: commodity price fluctuations; the effect of our debt on our financial flexibility; insufficient capital, including as a result of lender restrictions or reductions in our borrowing base, lower-than-expected operating cash flow, unavailability of capital markets or inability to attract investors; our ability to complete the proposed amendment of our 2014 Credit Facilities and, if completed, satisfy the conditions to the effectiveness of such amendment, including the closing of a new term loan facility; equipment, service or labor price inflation or unavailability; inability to replace reserves; inability to timely obtain government permits and approvals; inability to monetize selected assets or enter into favorable joint ventures; restrictions imposed by regulations 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; risks of drilling; unexpected geologic conditions; tax law changes; changes in business strategy; 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; risks related to our disposition, joint venture and acquisition activities; the recoverability of resources; limitations on our ability to enter into efficient hedging transactions; steeper than expected production decline rates; lower-than-expected production, reserves or resources from development projects or acquisitions; the effects of litigation; disruptions due to, insufficient insurance against and concentration of exposure in California to accidents, mechanical failures, transportation or storage constraints, labor difficulties, cyber attacks or other catastrophic events. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made.

All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For the three and nine months ended September 30, 2017, there were no material changes in the information required to be provided under Item 305 of Regulation S-K included under the caption *Management's Discussion and Analysis of Financial Condition and Results of Operations (Incorporating Item 7A) - Quantitative and Qualitative Disclosures About Market Risk* in the 2016 Form 10-K, except as discussed below.

Commodity Price Risk

As of September 30, 2017, we had a net derivative liability of $20 million carried at fair value, as determined from prices provided by external sources that are not actively quoted, which predominantly mature in 2017 and 2018. See additional hedging information in *Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources.*

Credit Risk

Our credit risk relates primarily to trade receivables and derivative financial instruments. Credit exposure for each customer is monitored for outstanding balances and current activity. For derivative instruments entered into as part of our hedging program, we are subject to counterparty credit risk to the extent the counterparty is unable to meet its settlement commitments. We actively manage this credit risk by selecting counterparties that we believe to be financially strong and continuing to monitor their financial health. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

As of September 30, 2017, the substantial majority of the credit exposures related to our business was with investment-grade counterparties. We believe exposure to credit-related losses related to our business at September 30, 2017 was not material and losses associated with credit risk have been insignificant for all years presented.

Item 4. Controls and Procedures

Our President and Chief Executive Officer and our Senior Executive Vice President and Chief Financial Officer supervised and participated in our evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based upon that evaluation, our President and Chief Executive Officer and our Senior Executive Vice President and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2017.

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the third quarter of 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 7 to the condensed consolidated financial statements in Part I of this Form 10-Q and Part I, Item 3, *Legal Proceedings* in the Form 10-K for the year ended December 31, 2016.

Chevron recently initiated a contractual dispute resolution process regarding audit claims alleging that it has been underallocated NGLs by approximately $200 million and overcharged for power by $50 million at the Elk Hills field. Under the applicable dispute resolution procedures, the parties are to engage in negotiations, mediation, and, if necessary, binding arbitration. After an extensive review of these claims during the audit review process, including review by a third-party accounting expert with respect to the NGL claim, we concluded and continue to believe these claims are without merit. Based on our review, we believe that we have in fact overallocated NGLs and gas to Chevron and intend to take action to seek an adjustment in our favor.

The South Coast Air Quality Management District has issued notices of violation to a subsidiary of the company and its predecessor alleging that emissions at a facility in Huntington Beach, California exceeded permit conditions over certain periods in the past three years. The subsidiary is cooperating with the District to address the matter, which is expected to include monetary sanctions in excess of $100,000 but is not expected to be material to our financial statements.

Item 1.A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. A discussion of such risks and uncertainties may be found below and under the heading *Risk Factors* in our Form 10-K for the year ended December 31, 2016.

Certain U.S. federal income tax deductions currently available to us may be eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Item 5. Other Disclosures

None.

Item 6. Exhibits

12	Computation of Ratios of Earnings to Fixed Charges.
31.1	Certification of CEO Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of CFO Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certifications of CEO and CFO Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CALIFORNIA RESOURCES CORPORATION

DATE: November 8, 2017	/s/ Roy Pineci
	Roy Pineci
	Executive Vice President - Finance
	(Principal Accounting Officer)

EXHIBIT INDEX

EXHIBITS

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CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(Amounts in millions, except ratios)

The following table sets forth our historical ratios of earnings to fixed charges for the periods indicated. You should read these ratios of earnings to fixed charges in connection with our consolidated and combined financial statements, including the notes to those statements.

	Nine months ended September 30,	Year ended December 31,				
	2017	**2016**	**2015**	**2014[a]**	**2013**	**2012**
(Loss) income before income taxes [b][c]	$ (127)	$ 201	$ (5,476)	$ (2,421)	$ 1,447	$ 1,181
Add (deduct):						
Net income attributable to noncontrolling interest	(1)	—	—	—	—	—
Interest and debt expense, net	252	328	326	72	—	—
Portion of lease rentals representative of the interest factor	3	4	4	3	4	4
Earnings (loss) before fixed charges	$ 127	$ 533	$ (5,146)	$ (2,346)	$ 1,451	$ 1,185
Fixed charges:						
Interest and debt expense, net, including capitalized interest	$ 254	$ 330	$ 335	$ 76	$ —	$ —
Portion of lease rentals representative of the interest factor	3	4	4	3	4	4
Total fixed charges	$ 257	$ 334	$ 339	$ 79	$ 4	$ 4
Ratio of earnings to fixed charges	n/a	1.6	n/a	n/a	363	296
Insufficient coverage	$ 130	$ —	$ 5,485	$ 2,425	$ —	$ —

(a) Note: Had we been a stand-alone company for the full year 2014, and had the same level of debt throughout the year as we did on December 31, 2014, of approximately $6.4 billion, we would have incurred $314 million of pre-tax interest expense, on a pro-forma basis, for the year ended December 31, 2014, compared to the $72 million pre-tax interest expense reported on our statement of operations for the year then ended. Therefore, the insufficient coverage on a pro-forma basis would have been approximately $2,667 million.

(b) The nine months ended September 30, 2017 amount includes unusual, out-of-period and infrequent items consisting of $38 million of non-cash derivative gains on outstanding hedges, $21 million of gains from asset divestitures, $4 million of net gains on the early extinguishment of debt and $18 million of other unusual, out-of-period and infrequent charges. Excluding these items, our earnings before fixed charges for the nine months ended September 30, 2017 would have been approximately $82 million. Therefore, the insufficient coverage would have been approximately $175 million.

(c) The year ended December 31, 2016 amount includes unusual and infrequent items consisting of $805 million of net gains on the early extinguishment of debt, $283 million of non-cash derivative losses on outstanding hedges, $30 million of gains from asset divestitures and $12 million deferred debt issuance cost write-off and $7 million, net, of other unusual and infrequent charges. Excluding these items, our loss before fixed charges for the year ended December 31, 2016 would have been approximately $0. Therefore, the insufficient coverage would have been approximately $334 million.

The year ended December 31, 2015 amount includes unusual and infrequent items consisting of $4.9 billion of asset impairments, $71 million of write-down of certain assets, $67 million of early retirement and severance costs, $11 million of rig termination and other costs and $8 million of debt transactions costs, partially offset by $52 million of non-cash derivative gains. Excluding these items, our loss before fixed charges for the year ended December 31, 2015 would have been approximately $189 million. Therefore, the insufficient coverage would have been approximately $528 million.

The December 31, 2014 amount includes non-cash, unusual and infrequent items consisting of $3.4 billion of asset impairments, $52 million of rig termination and other price-related costs, and $55 million of Spin-off and transition related costs. Excluding these items, our earnings before fixed charges for the year ended December 31, 2014 would have been approximately $1.2 billion, and the ratio of earnings to fixed charges would have been 14.7.

EXHIBIT 31.1

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Todd A. Stevens, certify that:

1. I have reviewed this quarterly report on Form 10-Q of California Resources Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2017

/s/ Todd A. Stevens

Todd A. Stevens
President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

RULE 13a – 14(a) / 15d – 14(a)
CERTIFICATION
PURSUANT TO §302 OF THE SARBANES-OXLEY ACT OF 2002

I, Marshall D. Smith, certify that:

1. I have reviewed this quarterly report on Form 10-Q of California Resources Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 8, 2017

/s/ Marshall D. Smith

Marshall D. Smith
Senior Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION OF CEO AND CFO PURSUANT TO
18 U.S.C. § 1350,
AS ADOPTED PURSUANT TO
§ 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of California Resources Corporation (the “Company”) for the fiscal period ended September 30, 2017, as filed with the Securities and Exchange Commission on November 8, 2017 (the “Report”), Todd A. Stevens, as Chief Executive Officer of the Company, and Marshall D. Smith, as Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that, to the best of his or her knowledge, respectively:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Todd A. Stevens

Name:	Todd A. Stevens
Title:	President and Chief Executive Officer
Date:	November 8, 2017

/s/ Marshall D. Smith

Name:	Marshall D. Smith
Title:	Senior Executive Vice President and Chief Financial Officer
Date:	November 8, 2017

A signed original of this written statement required by Section 906 has been provided to California Resources Corporation and will be retained by California Resources Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.