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, 2018

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.)
27200 Tourney Road, Suite 315 **Santa Clarita, California**	**91355**
(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 every Interactive Data File required to be submitted 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 such files). ☑ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company or an emerging growth 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, 2018	48,565,905

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, 2018 and December 31, 2017
(in millions, except share data)

	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash	$ 31	$ 20
Trade receivables	293	277
Inventories	69	56
Other current assets, net	153	130
Total current assets	546	483
PROPERTY, PLANT AND EQUIPMENT	22,323	21,260
Accumulated depreciation, depletion and amortization	(15,937)	(15,564)
Total property, plant and equipment, net	6,386	5,696
OTHER ASSETS	52	28
TOTAL ASSETS	$ 6,984	$ 6,207
CURRENT LIABILITIES		
Accounts payable	349	257
Accrued liabilities	522	475
Total current liabilities	871	732
LONG-TERM DEBT	5,108	5,306
DEFERRED GAIN AND ISSUANCE COSTS, NET	253	287
OTHER LONG-TERM LIABILITIES	612	602
MEZZANINE EQUITY		
Redeemable noncontrolling interest	745	—
EQUITY		
Preferred stock (20 million shares authorized at $0.01 par value) no shares outstanding at September 30, 2018 and December 31, 2017	—	—
Common stock (200 million shares authorized at $0.01 par value) outstanding shares (September 30, 2018 - 48,565,905 and December 31, 2017 - 42,901,946)	—	—
Additional paid-in capital	4,983	4,879
Accumulated deficit	(5,688)	(5,670)
Accumulated other comprehensive loss	(20)	(23)
Total equity attributable to common stock	(725)	(814)
Noncontrolling interests	120	94
Total equity	(605)	(720)
TOTAL LIABILITIES AND EQUITY	$ 6,984	$ 6,207

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, 2018 and 2017
(in millions, except share data)

	Three months ended September 30,		Nine months ended September 30,	
	2018	**2017**	**2018**	**2017**
REVENUES AND OTHER				
Oil and gas sales	$ 700	$ 461	$ 1,932	$ 1,387
Net derivative (loss) gain from commodity contracts	(54)	(65)	(259)	51
Other revenue	182	49	313	113
Total revenues and other	828	445	1,986	1,551
COSTS AND OTHER				
Production costs	236	222	679	649
General and administrative expenses	81	61	234	183
Depreciation, depletion and amortization	128	134	372	412
Taxes other than on income	45	39	120	103
Exploration expense	4	5	18	17
Other expenses, net	149	29	259	76
Total costs and other	643	490	1,682	1,440
OPERATING INCOME (LOSS)	185	(45)	304	111
NON-OPERATING (LOSS) INCOME				
Interest and debt expense, net	(95)	(85)	(281)	(252)
Net gain on early extinguishment of debt	2	—	26	4
Gain on asset divestitures	3	—	4	21
Other non-operating expenses	(4)	(2)	(16)	(11)
INCOME (LOSS) BEFORE INCOME TAXES	91	(132)	37	(127)
Income tax	—	—	—	—
NET INCOME (LOSS)	91	(132)	37	(127)
Net income attributable to noncontrolling interests	(25)	(1)	(55)	(1)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 66	$ (133)	$ (18)	$ (128)
Net income (loss) attributable to common stock per share				
Basic	$ 1.34	$ (3.11)	$ (0.38)	$ (3.01)
Diluted	$ 1.32	$ (3.11)	$ (0.38)	$ (3.01)

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, 2018 and 2017
(in millions)

	Three months ended September 30,		Nine months ended September 30,	
	2018	**2017**	**2018**	**2017**
Net income (loss)	$ 91	$ (132)	$ 37	$ (127)
Other comprehensive income items:				
Reclassification of realized losses on pension and postretirement benefits to income[(a)]	—	1	3	4
Total other comprehensive income	—	1	3	4
Comprehensive income attributable to noncontrolling interests	(25)	(1)	$ (55)	$ (1)
Comprehensive income (loss) attributable to common stock	$ 66	$ (132)	$ (15)	$ (124)

(a) No associated tax for the three and nine months ended September 30, 2018 and 2017. See *Note 11 Pension 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, 2018 and 2017
(in millions)

	Nine months ended September 30, 2018	Nine months ended September 30, 2017
CASH FLOW FROM OPERATING ACTIVITIES		
Net income (loss)	$ 37	$ (127)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	372	412
Net derivative loss (gain) from commodity contracts	259	(51)
Net (payments) proceeds on settled commodity derivatives	(178)	15
Net gain on early extinguishment of debt	(26)	(4)
Amortization of deferred gain	(58)	(55)
Gain on asset divestitures	(4)	(21)
Other non-cash charges to income, net	78	46
Dry hole expenses	4	1
Changes in operating assets and liabilities, net	(91)	9
Net cash provided by operating activities	393	225
CASH FLOW FROM INVESTING ACTIVITIES		
Capital investments	(504)	(232)
Changes in capital investment accruals	40	26
Asset divestitures	17	33
Acquisitions	(514)	—
Other	(4)	(1)
Net cash used in investing activities	(965)	(174)
CASH FLOW FROM FINANCING ACTIVITIES		
Proceeds from 2014 Revolving Credit Facility	1,822	1,000
Repayments of 2014 Revolving Credit Facility	(1,843)	(1,010)
Payments on 2014 Term Loan	—	(91)
Debt repurchases	(149)	(24)
Debt transaction costs	(4)	(2)
Contributions from noncontrolling interest holders, net	796	98
Distributions paid to noncontrolling interest holders	(80)	(6)
Issuance of common stock	52	2
Shares canceled for taxes	(11)	(2)
Net cash provided (used) by financing activities	583	(35)
Increase in cash	11	16
Cash—beginning of period	20	12
Cash—end of period	$ 31	$ 28

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Condensed Consolidated Statements of Equity
For the nine months ended September 30, 2018 and 2017
(in millions)

	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interest	Total Equity
Balance, December 31, 2016	$ 4,861	$ (5,404)	$ (14)	$ (557)	$ —	$ (557)
Net (loss) income	—	(128)	—	(128)	1	(127)
Contribution from noncontrolling interest holders, net	—	—	—	—	98	98
Distributions paid to noncontrolling interest holders	—	—	—	—	(6)	(6)
Other comprehensive income	—	—	4	4	—	4
Share-based compensation, net	14	—	—	14	—	14
Balance, September 30, 2017	$ 4,875	$ (5,532)	$ (10)	$ (667)	$ 93	$ (574)

	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interest	Total Equity[(a)]
Balance, December 31, 2017	$ 4,879	$ (5,670)	$ (23)	$ (814)	$ 94	$ (720)
Net loss	—	(18)	—	(18)	(16)	(34)
Contribution from noncontrolling interest holders, net	—	—	—	—	82	82
Distributions paid to noncontrolling interest holders	—	—	—	—	(40)	(40)
Issuance of common stock[(b)]	101	—	—	101	—	101
Other comprehensive income	—	—	3	3	—	3
Share-based compensation, net	3	—	—	3	—	3
Balance, September 30, 2018	$ 4,983	$ (5,688)	$ (20)	$ (725)	$ 120	$ (605)

(a) Excludes redeemable noncontrolling interest recorded in mezzanine equity. See *Note 6 Joint Ventures* for more information.

(b) Includes 2.85 million shares of common stock (valued at $51 million at issuance) issued to Chevron in connection with our acquisition of Chevron's working interest in Elk Hills unit and 2.3 million shares of common stock (valued at $50 million at issuance) issued to an Ares-led investor group in connection with the formation of our Ares JV. See *Note 7 Acquisitions and Divestitures* for more information.

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 (the Spin-off). We became an independent, publicly traded company on December 1, 2014. Occidental initially retained approximately 18.5% of our outstanding shares of common stock, which were 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, 2018 and December 31, 2017 and the statements of operations, comprehensive income, cash flows and equity for the three and nine months ended September 30, 2018 and 2017, as applicable. We have eliminated all significant intercompany transactions and accounts. We account for our share of oil and gas exploration and production ventures in which we have a direct working interest by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on our balance sheets, statements of operations and cash flows.

We have prepared this report pursuant to the rules and regulations of the United States (U.S.) Securities and Exchange Commission (SEC) applicable to interim financial information, which permit the 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 financial statements and the notes thereto in our Annual Report on Form 10-K for the year ended December 31, 2017.

Certain prior year amounts have been reclassified to conform to the 2018 presentation. On the statements of operations, we reclassified interest cost, expected return on assets, amortization of prior service costs and settlements/curtailments, all associated with defined benefit pension plans, from general and administrative expenses to other non-operating expenses, net in accordance with new accounting rules. See *Note 2 Accounting and Disclosure Changes* for more information.

NOTE 2 ACCOUNTING AND DISCLOSURE CHANGES

Recently Issued Accounting and Disclosure Changes

In February 2016, the Financial Accounting Standards Board (FASB) issued rules requiring lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. In January 2018, the FASB issued an update to the lease standard providing an optional transition approach for land easements allowing entities to evaluate only new or modified land easements. In July 2018, the FASB provided optional transition relief allowing a prospective approach in applying the new rules by not adjusting comparative period financial information for the effects of the new rules and not requiring disclosures for periods before the effective date. These rules will be effective for us on January 1, 2019, which we expect to apply prospectively. We have identified our lease population and are currently implementing lease accounting software among other activities. We expect the adoption of these rules to increase both our assets and liabilities by the same amount, which could be significant.

Recently Adopted Accounting and Disclosure Changes

In May 2014, the FASB issued rules on the recognition of revenue that created Topic 606 (ASC 606), which superseded existing revenue recognition requirements reported in accordance with U.S. generally accepted accounting principles (GAAP), and required an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The new rules required certain sales-related costs to be reported as other expense as opposed to being netted against oil and gas sales or other revenue. We adopted ASC 606 on January 1, 2018 using the modified retrospective method with no adjustment to opening retained earnings. Results for reporting periods beginning after January 1, 2018 are presented under ASC 606, while prior period amounts are not adjusted and continue to be reported under the accounting standards in effect prior to adoption. See *Note 12 Revenue Recognition* for more information.

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 to assets. Employers are required to 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. We adopted these rules in the first quarter of 2018 with no significant impact on our financial statements. The interest cost, expected return on assets, amortization of prior service costs and settlements/curtailments have been reclassified from general and administrative expense to other non-operating expenses. We elected to use the amounts disclosed for the various components of net periodic benefit cost in the pension and postretirement benefit plans footnote as the basis of the retrospective application.

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. We adopted these rules in the first quarter of 2018 with no impact on our financial statements.

Components of accumulated other comprehensive income (AOCI) are recorded net of related taxes determined using prevailing rates when the components are initially recorded. When the U.S. federal corporate tax rates changed in December 2017, a difference arose between tax amounts recorded to AOCI as compared to the expected tax amount using the newly enacted corporate tax rates. Our accounting policy is to remove such residual tax differences from AOCI when the related components are ultimately settled. In February 2018, the FASB issued rules that give entities the option to reclassify this residual difference from AOCI to retained earnings. We early adopted this accounting standard in the first quarter of 2018 without reclassifying this residual tax difference to retained earnings.

NOTE 3 OTHER INFORMATION

Cash at September 30, 2018 and December 31, 2017 included approximately $13 million and $5 million, respectively, which is restricted under one of our joint venture agreements.

Other current assets, net as of September 30, 2018 and December 31, 2017 consisted of the following:

	September 30, 2018	December 31, 2017
	(in millions)	
Amounts due from joint interest partners	$ 87	$ 76
Derivative assets from commodities contracts	34	23
Prepaid expenses	23	19
Asset held for sale	—	12
Other	9	—
Other current assets, net	$ 153	$ 130

In the second quarter of 2018, we divested a non-core asset that was held for sale in the prior period. See *Note 7 Acquisitions and Divestitures* for more information.

Accrued liabilities as of September 30, 2018 and December 31, 2017 consisted of the following:

	September 30, 2018	December 31, 2017
	(in millions)	
Derivative liabilities from commodities contracts	$ 191	$ 154
Accrued taxes other than on income	65	130
Accrued employee-related costs	106	86
Accrued interest	60	23
Other	100	82
Accrued liabilities	$ 522	$ 475

Other long-term liabilities included asset retirement obligations of $417 million and $403 million at September 30, 2018 and December 31, 2017, 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, 2018 and 2017. Interest paid, net of capitalized amounts, totaled approximately $278 million and $249 million for the nine months ended September 30, 2018 and 2017, respectively. Non-cash financing activities in 2018 included 2.85 million shares of common stock (valued at $51 million) issued in connection with the Elk Hills transaction. See *Note 7 Acquisitions and Divestitures* for more on the Elk Hills transaction.

NOTE 4 INVENTORIES

Inventories as of September 30, 2018 and December 31, 2017 consisted of the following:

	September 30, 2018	December 31, 2017
	(in millions)	
Materials and supplies	$ 64	$ 53
Finished goods	5	3
Total	$ 69	$ 56

NOTE 5 DEBT

As of September 30, 2018 and December 31, 2017, our long-term debt consisted of the following credit agreements, second lien notes and senior notes:

	Outstanding Principal (in millions)		Interest Rate	Maturity	Security
	September 30, 2018	December 31, 2017			
Credit Agreements					
2014 Revolving Credit Facility	$ 342	$ 363	LIBOR plus 3.25%-4.00% ABR plus 2.25%-3.00%	June 30, 2021	Shared First-Priority Lien
2017 Credit Agreement	1,300	1,300	LIBOR plus 4.75% ABR plus 3.75%	December 31, 2022[(a)]	Shared First-Priority Lien
2016 Credit Agreement	1,000	1,000	LIBOR plus 10.375% ABR plus 9.375%	December 31, 2021	First-Priority Lien
Second Lien Notes					
Second Lien Notes	2,122	2,250	8%	December 15, 2022[(b)]	Second-Priority Lien
Senior Notes					
5% Senior Notes due 2020	100	100	5%	January 15, 2020	Unsecured
5½% Senior Notes due 2021	100	100	5.5%	September 15, 2021	Unsecured
6% Senior Notes due 2024	144	193	6%	November 15, 2024	Unsecured
Total	$ 5,108	$ 5,306			

Note: For a detailed description of our credit agreements, second lien notes and senior notes, please see our most recent Form 10-K for the year ended December 31, 2017.

(a) The 2017 Credit Agreement is subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million in principal of the 2016 Credit Agreement is outstanding at that time.

(b) The Second Lien Notes require principal repayments of approximately $335 million in June 2021, $67 million in December 2021 and $70 million in June 2022.

Deferred Gain and Issuance Costs

As of September 30, 2018, net deferred gain and issuance costs were $253 million, consisting of $357 million of a deferred gain offset by $104 million of deferred issuance costs and original issue discounts. The December 31, 2017 net deferred gain and issuance costs were $287 million, consisting of $415 million of a deferred gain offset by $128 million of deferred issuance costs and original issue discounts.

2014 Revolving Credit Facility

As of September 30, 2018, we had approximately $490 million of available borrowing capacity, subject to a $150 million month-end minimum liquidity requirement. The borrowing base under this facility was reaffirmed at $2.3 billion in October 2018. Our 2014 Revolving Credit Facility also includes a sub-limit of $400 million for the issuance of letters of credit. As of September 30, 2018 and December 31, 2017, we had letters of credit outstanding of approximately $167 million and $148 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

Note Repurchases

In the third quarter of 2018, we repurchased $31 million in aggregate principal amount of our 8% senior secured second lien notes due December 15, 2022 (Second Lien Notes) and $1 million of our 6% senior notes due November 15, 2024 (2024 Notes) for $30 million, resulting in a $2 million pre-tax gain, net of a reduction in deferred issuance costs. In the nine months ended September 30, 2018, we repurchased $128 million and $49 million in aggregate principal amount of our Second Lien Notes and our 2024 Notes, respectively, for $149 million in cash resulting in a pre-tax gain of $26 million, net of a reduction in deferred issuance costs.

Fair Value

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, 2018 and December 31, 2017, including the fair value of variable-rate debt, was approximately $5.0 billion and $4.8 billion, respectively, compared to a carrying value of approximately $5.1 billion and $5.3 billion, respectively.

Amendments

On August 20, 2018, we entered into an amendment to the 2014 Credit Agreement. The 2014 Credit Agreement was amended to, among other things:

- permit us to draw on our revolver to repurchase our Second Lien Notes and Senior Notes at a discount to par in an amount up to $300 million;
- permit us to draw on our revolver to repurchase our Second Lien Notes and Senior Notes at a discount to par, without regard to time limit, in an amount not to exceed a specified portion of proceeds from future dispositions of certain assets;
- in connection with any repurchase of certain of our indebtedness, increase the minimum liquidity required to make such repurchase (calculated on a pro forma basis after giving effect to the repurchase) from $250 million to $300 million; and
- enhance our ability to refinance our outstanding term loans under our 2017 Credit Agreement and 2016 Credit Agreement, Second Lien Notes and Senior Notes, in each case by allowing the use of permitted refinancing indebtedness for such refinancing so long as certain conditions are met.

On September 18, 2018, we entered into an amendment to the 2017 Credit Agreement. The 2017 Credit Agreement was amended to, among other things:

- permit us to repurchase our Second Lien Notes and Senior Notes at a discount to par, without regard to time limit, in an amount not to exceed a specified portion of proceeds from dispositions of certain assets; and
- enhance our ability to refinance our outstanding Second Lien Notes, Senior Notes and 2016 Credit Agreement, in each case by allowing the use of permitted refinancing indebtedness for such refinancing so long as certain conditions are met.

Other

At September 30, 2018, we were in compliance with all financial and other debt covenants.

All obligations under our 2014 Revolving Credit Facility, 2017 Credit Agreement and 2016 Credit Agreement (collectively, Credit Facilities) as well as our Second Lien Notes and Senior Notes are guaranteed both fully and unconditionally and jointly and severally by all of our material wholly owned subsidiaries.

A one-eighth percent change in the variable interest rates on the borrowings under our Credit Facilities on September 30, 2018 would result in a $3 million change in annual interest expense.

NOTE 6 JOINT VENTURES

Noncontrolling Interests

The following table presents the changes in noncontrolling interests by joint venture partners (described in greater detail below), reported in equity and mezzanine equity on the condensed consolidated balance sheets, for the nine months ended September 30, 2018 (in millions):

			Equity Attributable to Noncontrolling Interest	Mezzanine Equity - Redeemable Noncontrolling Interest
	Ares JV	**BSP JV**	**Total**	**Ares JV**
Balance, December 31, 2017	$ —	$ 94	$ 94	$ —
Net (loss) income attributable to noncontrolling interests	(8)	(8)	(16)	71
Contributions from noncontrolling interest holders, net	33	49	82	714
Distributions to noncontrolling interest holders	(5)	(35)	(40)	(40)
Balance, September 30, 2018	$ 20	$ 100	$ 120	$ 745

Ares Management L.P. (Ares)

In February 2018, we entered into a midstream JV with ECR Corporate Holdings L.P. (ECR), a portfolio company of Ares Management L.P. (Ares). This JV (Ares JV) holds the Elk Hills power plant (a 550-megawatt natural gas fired power plant) and a 200 million cubic foot per day cryogenic gas processing plant. We hold 50% of the Class A common interest and 95.25% of the Class C common interest in the Ares JV. ECR holds 50% of the Class A common interest, 100% of the Class B preferred interest and 4.75% of the Class C common interest. We received $750 million in proceeds upon entering into the Ares JV, before $3 million for transaction costs.

The Class A common and Class B preferred interests held by ECR are reported as redeemable noncontrolling interest in mezzanine equity due to an embedded optional redemption feature. The Class C common interest held by ECR is reported in equity on our condensed consolidated balance sheets.

The Ares JV is required to make monthly distributions to the Class B holders. The Class B preferred interest has a deferred payment feature whereby a portion of the monthly distributions may be deferred for the first three years to the fourth and fifth year. The deferred amounts accrue an additional return. Distributions to the Class B preferred interest holders are reported as a reduction to mezzanine equity on our condensed consolidated balance sheets. Monthly, the Ares JV is also required to distribute its excess cash flow over its working capital requirements to the Class C common interests, on a pro-rata basis.

We can cause the Ares JV to redeem ECR's Class A and Class B interests, in whole, but not in part, at any time by paying $750 million for the Class B interest and $60 million for the Class A interest, plus any previously accrued but unpaid preferred distributions and a make-whole payment if the redemption happens prior to five years from inception. We have the option to extend the redemption period for up to an additional two and one-half years, in which case the interests can be redeemed for $750 million for the Class B interest and $80 million for the Class A interest, plus any previously accrued but unpaid preferred distributions and a make-whole payment if the redemption happens prior to seven and one-half years from inception. If we do not cause a redemption at the end of the seven and one-half year period, ECR can either sell its Class A and Class B interests or cause the sale or lease of the Ares JV assets.

Our condensed consolidated statements of operations reflect the full operations of our Ares JV, with ECR's share of net income reported in net income attributable to noncontrolling interests.

Additionally, in the first quarter of 2018, an Ares-led investor group purchased approximately 2.3 million shares of our common stock in a private placement for an aggregate purchase price of $50 million.

Benefit Street Partners (BSP)

In February 2017, we entered into a joint venture with BSP (BSP JV) where BSP will contribute up to $250 million, subject to agreement of the parties, in exchange for a preferred interest in the BSP 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 $150 million in three equal tranches, before transaction costs, in March 2017, July 2017 and June 2018. The funds contributed by BSP are used to develop certain of our oil and gas properties.

The BSP JV holds net profits interests (NPI) in existing and future cash flow from certain of our properties and the proceeds from the NPI are used by the BSP JV to (1) pay quarterly minimum distributions to BSP, (2) pay for development costs within the project area, upon mutual agreement between members, and (3) make distributions to BSP until the predetermined threshold is achieved.

Our consolidated results reflect the full operations of our BSP JV, with BSP's share of net income being reported in net income attributable to noncontrolling interests on our condensed consolidated statements of operations.

Other

Macquarie Infrastructure and Real Assets Inc. (MIRA)

Our consolidated results include our working interest share in a joint venture we entered into with Macquarie Infrastructure and Real Assets Inc. (MIRA) in April 2017. Subject to the agreement of the parties, MIRA will invest up to $300 million to develop certain of our oil and gas properties in exchange for a 90% working interest in the related properties. MIRA will fund 100% of the development cost of such properties. Our 10% working interest increases to 75% if MIRA receives cash distributions equal to a predetermined threshold return. MIRA initially committed $160 million. In June 2018, the parties amended the initial joint development program to $140 million. The agreement provides for a commitment of up to 110% of the program amount. MIRA invested $58 million in 2017 and $46 million in the nine months ended September 30, 2018. MIRA expects to contribute $11 million for drilling projects in the fourth quarter of 2018 and the balance of the committed amount in 2019.

Subsequent Events

In October 2018, we entered into three joint ventures where our partners carry a portion of our costs. The JV partners have committed capital of approximately $35 million and could provide additional capital if certain milestones are met. We have committed $13 million over a three-year period in connection with these joint ventures.

NOTE 7 ACQUISITIONS AND DIVESTITURES

Acquisitions

On April 9, 2018, we acquired the remaining working, surface and mineral interests in the 47,000-acre Elk Hills unit from Chevron U.S.A., Inc. (Chevron) (the Elk Hills transaction) for approximately $518 million, including $7 million of liabilities assumed relating to asset retirement obligations and favorable customary purchase price adjustments of $2 million. We accounted for the Elk Hills transaction as a business combination. After the transaction, we hold all of the working, surface and mineral interests in the Elk Hills unit. The effective date of the transaction was April 1, 2018.

As part of the Elk Hills transaction, Chevron reduced its royalty interest in one of our oil and gas properties by half and extended the time frame to invest the remainder of our capital commitment on that property by two years, to the end of 2020. As of September 30, 2018, the remaining commitment was approximately $18 million. Any deficiency in meeting this capital investment obligation will be paid in cash. We expect to fulfill the capital investment requirement within the extended period. In addition, the parties mutually agreed to release each other from pending claims with respect to the Elk Hills unit.

The following table summarizes the total consideration, including customary closing adjustments, and the allocation of the consideration based on the fair value of the assets acquired as of the acquisition date (in millions):

Consideration:		
Cash	$	462
Purchase price adjustments		(2)
Common stock issued (2.85 million shares)		51
Liabilities assumed		7
	$	518
Identifiable assets acquired:		
Proved properties	$	435
Other property and equipment		77
Materials and supplies		6
	$	518

The results of operations for the Elk Hills transaction were included in our condensed consolidated financial statements subsequent to the closing date.

On April 2, 2018, we acquired an office building in Bakersfield, California for $48.4 million, which we believe is significantly less than the estimated replacement value of the property and the land. We currently have approximately 500 employees using eight different locations in Bakersfield across multiple leases. We expect that the new building will create significant value by bringing our Bakersfield employees together into a single location over the next 12 to 15 months, which will increase the efficiency, effectiveness and collaboration of these employees. This building was the only available office space in the Bakersfield area large enough to allow us to consolidate our workforce into a single location. For the initial eight months, a former owner of the building will occupy most of the space as a tenant, from which we expect to generate rental income of approximately $4 million in 2018. In December 2018, this tenant will downsize the space they are leasing, with a corresponding reduction in rent, until December 2022. The vacated space will be available to lease to other tenants to generate additional income. In addition, the unimproved land may be monetized in the future. Approximately $6 million of the purchase price was allocated to the in-place leases, which is included in other assets and is being amortized into other expenses, net.

Divestitures

During the nine months ended September 30, 2018, we divested non-core assets resulting in $17 million of proceeds and a $4 million gain. During the nine months ended September 30, 2017, we divested non-core assets resulting in $33 million of proceeds and a $21 million gain.

NOTE 8 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, 2018 and December 31, 2017 were not material to our condensed consolidated 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 would not be material to our consolidated financial position or results of operations.

We 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, 2018, we are not aware of material indemnity claims pending or threatened against the company.

In October 2018, we settled the examination by the Internal Revenue Service (IRS) of our U.S. federal income tax returns for the post-Spin-off period in 2014 and calendar year 2015. There were no changes to our tax filings as a result of the examination. We remain subject to examination by the IRS for calendar years 2016 and 2017 as well as for all periods subsequent to the Spin-off by the state of California.

NOTE 9 DERIVATIVES

General

We use a variety of derivative instruments to protect our cash flow, operating margin and capital program from the cyclical nature of commodity prices. These derivatives are intended to help us maintain adequate liquidity and 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.

Commodity Contracts

As of September 30, 2018, 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, 2018:

	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Q4 2019
Sold Calls:					
Barrels per day	15,000	15,000	5,000	—	—
Weighted-average price per barrel	$ 58.83	$ 66.15	$ 68.45	$ —	$ —
Purchased Calls:					
Barrels per day	—	2,000	—	—	—
Weighted-average price per barrel	$ —	$ 71.00	$ —	$ —	$ —
Purchased Puts:					
Barrels per day	—	33,000	35,000	30,000	20,000
Weighted-average price per barrel	$ —	$ 63.48	$ 68.29	$ 71.67	$ 75.00
Sold Puts:					
Barrels per day	19,000	35,000	30,000	30,000	20,000
Weighted-average price per barrel	$ 45.00	$ 50.71	$ 55.00	$ 56.67	$ 60.00
Swaps:					
Barrels per day	48,000	7,000(1)	—	—	—
Weighted-average price per barrel	$ 60.35	$ 67.71	$ —	$ —	$ —

Note: Additional hedges for 2019 and 2020 were put in place after September 30, 2018 that are not included in the table above.

(1) 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 $70.00 for the first quarter of 2019.

The BSP JV entered into crude oil derivatives that are included in our consolidated results but not in the above table. The hedges entered into by the BSP JV could affect the timing of the redemption of the JV interest. The BSP JV sold calls for up to approximately 1,000 barrels per day at a weighted-average price per barrel of $60.00 per barrel for 2018 through 2020. The BSP JV purchased puts for up to approximately 2,000 barrels per day at a weighted-average price per barrel of approximately $50.00 for 2018 through 2021. This joint venture also entered into natural gas swaps for insignificant volumes for periods through May 2021.

The outcomes of the derivative instruments are as follows:

- Sold calls – we make settlement payments for prices above the indicated weighted-average price per barrel.
- Purchased calls – we receive settlement payments for prices above the indicated weighted-average price per barrel.
- Purchased puts – we receive settlement payments for prices below the indicated weighted-average price per barrel.
- Sold puts – we make settlement payments for prices below the indicated weighted-average price per barrel.

From time to time, we may use combinations of these and other derivative instruments to increase the efficacy of our commodity hedging program.

Interest-Rate Contracts

In May 2018, we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. These interest-rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021.

Fair Value of Derivatives

Our derivative contracts are measured at fair value using industry-standard models with various inputs, including quoted forward prices, and are classified as Level 2 in the required fair value hierarchy for the periods presented. We recognize fair value changes on derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that occurred during the period, as well as the relationship between contract prices or interest rates and the associated forward curves.

Commodity Contracts

The following table presents the fair values (at gross and net) of our outstanding commodity derivatives as of September 30, 2018 and December 31, 2017 (in millions):

September 30, 2018

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:			
Other current assets	$ 34	$ —	$ 34
Other assets	13	—	13
Liabilities:			
Accrued liabilities	(191)	—	(191)
Other long-term liabilities	(9)	—	(9)
Total derivatives	$ (153)	$ —	$ (153)

December 31, 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:			
Other current assets	$ 39	$ (16)	$ 23
Other assets	1	—	1
Liabilities:			
Accrued liabilities	(170)	16	(154)
Other long-term liabilities	(3)	—	(3)
Total derivatives	$ (133)	$ —	$ (133)

Interest-Rate Contracts

As of September 30, 2018, we reported the fair value of our interest rate derivatives of $9 million in other assets on our condensed consolidated balance sheets. For the three months ended September 30, 2018, we reported a $1 million gain on these contracts in other non-operating expense on our condensed consolidated statements of operations.

NOTE 10 EARNINGS PER SHARE

We compute basic and diluted earnings per share (EPS) using the two-class method required for participating securities. Certain of our restricted and performance stock awards are considered participating securities because they have non-forfeitable dividend rights at the same rate as our 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 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 all potentially dilutive securities.

The following table presents the calculation of basic and diluted EPS for the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,	
	2018	**2017**	**2018**	**2017**
	(in millions, except per-share amounts)			
Net income (loss)	$ 91	$ (132)	$ 37	$ (127)
Net income attributable to noncontrolling interest	(25)	(1)	(55)	(1)
Net income (loss) attributable to common stock	66	(133)	(18)	(128)
Less: net income allocated to participating securities	(1)	—	—	—
Net income (loss) available to common stockholders	$ 65	$ (133)	$ (18)	$ (128)
Weighted-average common shares outstanding - basic	48.5	42.7	47	42.5
Basic EPS	$ 1.34	$ (3.11)	$ (0.38)	$ (3.01)
Net income (loss)	$ 91	$ (132)	$ 37	$ (127)
Net income attributable to noncontrolling interest	(25)	(1)	(55)	(1)
Net income (loss) attributable to common stock	66	(133)	(18)	(128)
Less: net income allocated to participating securities	(1)	—	—	—
Net income (loss) available to common stockholders	$ 65	$ (133)	$ (18)	$ (128)
Weighted-average common shares outstanding - basic	48.5	42.7	47	42.5
Dilutive effect of potentially dilutive securities	0.6	—	—	—
Weighted-average common shares outstanding - diluted	49.1	42.7	47	42.5
Diluted EPS	$ 1.32	$ (3.11)	$ (0.38)	$ (3.01)
Weighted-average anti-dilutive shares[a]	1.1	2.5	2.8	2.6

(a) Anti-dilutive shares represent potentially dilutive securities that are excluded from the computation of diluted EPS. In periods of income, anti-dilutive shares primarily include the effect of out-of-the-money stock options. In periods of loss, anti-dilutive shares include stock options and unvested awards.

NOTE 11 PENSION 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,			
	2018		2017	
	Pension Benefit	Postretirement Benefit	Pension Benefit	Postretirement Benefit
	(in millions)			
Service cost	$ —	$ 1	$ —	$ 1
Interest cost	—	1	1	1
Expected return on plan assets	(1)	—	(1)	—
Recognized actuarial loss	1	—	—	—
Settlement loss	—	—	1	—
Total	$ —	$ 2	$ 1	$ 2

	Nine months ended September 30,			
	2018		2017	
	Pension Benefit	Postretirement Benefit	Pension Benefit	Postretirement Benefit
	(in millions)			
Service cost	$ 1	$ 3	$ 1	$ 3
Interest cost	1	3	2	3
Expected return on plan assets	(2)	—	(2)	—
Recognized actuarial loss	1	—	1	—
Settlement loss	4	—	4	—
Total	$ 5	$ 6	$ 6	$ 6

We contributed $6 million and $1, respectively, to our defined benefit pension plans in the three months ended September 30, 2018 and 2017. We contributed $8 million and $6 million, respectively, to our defined benefit pension plans in the nine months ended September 30, 2018 and 2017. We do not expect to make any additional contributions to our defined benefit plans during the remainder of 2018. The 2018 and 2017 settlement losses were associated with early retirements.

NOTE 12 REVENUE RECOGNITION

We account for revenue in accordance with ASC 606, Revenue from Contracts with Customers, which we adopted on January 1, 2018, using the modified retrospective method, which was applied to all contracts that were not completed as of that date. Prior period results were not adjusted and continue to be reported under the accounting standards in effect for the prior period. The new standard did not affect the timing of our revenue recognition and did not impact net income; accordingly, we did not record an adjustment to the opening balance of retained earnings.

We derive substantially all of our revenue from sales of oil, natural gas and natural gas liquids (NGLs), with the remaining revenue generated from sales of electricity and marketing activities related to storage and managing excess pipeline capacity.

The following is a description of our principal activities from which we generate revenue. Revenues are recognized when control of promised goods is transferred to our customers, in an amount that reflects the consideration we expect to receive in exchange for those goods.

Commodity Sales Contracts

We recognize revenue from the sale of our oil, natural gas and NGL production when delivery has occurred and control passes to the customer. Our commodity contracts are short term, typically less than a year. We consider our performance obligations to be satisfied upon transfer of control of the commodity. In certain instances, transportation and processing fees are incurred by us prior to control being transferred to customers. These costs were previously offset against oil and gas sales. Upon adoption of ASC 606, we are recording these costs as a component of other expenses, net on our condensed consolidated statements of operations.

Our commodity sales contracts are indexed to a market price or an average index price. We recognize revenue in the amount that we have a right to invoice once we are able to adequately estimate the consideration (i.e., when market prices are known). Our contracts with customers typically require payment within 30 days following invoicing.

Electricity

The electrical output of the Elk Hills power plant that is not used in our operations is sold to the wholesale power market and to a utility under a power purchase and sales agreement, which includes a capacity payment. Revenue is recognized when obligations under the terms of a contract with our customer are satisfied; generally, this occurs upon delivery of the electricity. We report electricity sales as other revenue on our condensed consolidated statements of operations. Revenue is measured as the amount of consideration we expect to receive based on average index pricing with payment due the month following delivery. Capacity payments are based on a fixed annual amount per kilowatt hour and monthly rates vary based on seasonality, which is consistent with how we earn the capacity payment. Capacity payments are settled monthly. We consider our performance obligations to be satisfied upon delivery of electricity or as the contracted amount of energy is made available to the customer in the case of capacity payments.

Marketing, Trading and Other

Marketing, trading and other revenue primarily includes our activities associated with storing, transporting and marketing our production as well as third-party volumes.

To transport our natural gas as well as third-party volumes, we have entered into firm pipeline commitments. Depending on market conditions, we may have excess capacity, in which case we may enter into natural gas purchase and sale agreements with third parties. We consider our performance obligations to be satisfied upon transfer of control of the commodity. We have not incurred any significant fees or penalties related to excess capacity on these commitments.

We report our marketing and trading activities on a gross basis with purchases and costs reported in other expenses, net and sales recorded in other revenue on our condensed consolidated statements of operations.

Disaggregation of Revenue

The following table provides disaggregated revenue for the three and nine months ended September 30, 2018 (in millions):

	Three months ended September 30, 2018	Nine months ended September 30, 2018
Oil and gas sales:		
Oil	$ 568	$ 1,587
NGLs	71	195
Natural gas	61	150
	700	1,932
Other revenue:		
Electricity	42	87
Marketing, trading and other	140	225
Interest income	—	1
	182	313
Net derivative loss from commodity contracts	(54)	(259)
Total revenues and other	$ 828	$ 1,986

The impact of the adoption of ASC 606 on our condensed consolidated statements of operations for the three and nine months ended September 30, 2018 was as follows (in millions):

	Three months ended September 30, 2018			Nine months ended September 30, 2018		
	As Reported ASC 606	Previous GAAP	Change	As Reported ASC 606	Previous GAAP	Change
REVENUES AND OTHER						
Oil and gas sales	$ 700	$ 695	$ 5	$ 1,932	$ 1,915	$ 17
Net derivative loss from commodity contracts	(54)	(54)	—	(259)	(259)	—
Other revenue	182	177	5	313	242	71
Total revenues and other	828	818	10	1,986	1,898	88
COSTS AND OTHER						
Production costs	236	236	—	679	679	—
General and administrative expenses	81	81	—	234	234	—
Depreciation, depletion and amortization	128	128	—	372	372	—
Taxes other than on income	45	45	—	120	120	—
Exploration expenses	4	4	—	18	18	—
Other expenses, net	149	139	10	259	171	88
Total costs and other	643	633	10	1,682	1,594	88
OPERATING INCOME	185	185	—	304	304	—
NON-OPERATING (LOSS) INCOME						
Interest and debt expense, net	(95)	(95)	—	(281)	(281)	—
Net gain on early extinguishment of debt	2	2	—	26	26	—
Gain on asset divestitures	3	3	—	4	4	—
Other non-operating expenses	(4)	(4)	—	(16)	(16)	—
INCOME BEFORE INCOME TAXES	91	91	—	37	37	—
Income tax	—	—	—	—	—	—
NET INCOME	91	91	—	37	37	—
Net income attributable to noncontrolling interests	(25)	(25)	—	(55)	(55)	—
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 66	$ 66	$ —	$ (18)	$ (18)	$ —

The adoption of ASC 606 did not have an impact on our condensed consolidated balance sheets as of September 30, 2018 and December 31, 2017.

NOTE 13 INCOME TAXES

For the three and nine months ended September 30, 2018 and 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 of zero for the periods presented includes changes to maintain our full valuation allowance against our net deferred tax assets given our recent and anticipated future earnings trends. We believe that there is a reasonable possibility that some or all of this allowance could be released in the foreseeable future. However, the amount of the net deferred tax assets considered realizable depends on the level of profitability that we are able to actually achieve.

The Tax Cuts and Jobs Act was signed into law on December 22, 2017 and included significant changes to corporate tax provisions such as a reduction in the corporate tax rate, limitations on certain corporate deductions and favorable capital recovery provisions. The California Franchise Tax Board released its summary of Federal Income Tax Changes for 2017 on April 19, 2018, which identified how these U.S. federal changes interact with California law. California law was not conformed to the corporate provisions that are the most significant to our business.

NOTE 14 CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Our Credit Facilities, Second Lien Notes and Senior 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, Second Lien Notes and Senior Notes (Non-Guarantor Subsidiaries) either because they hold assets that are less than 1% of our total consolidated assets or because they are not considered a "subsidiary" under the applicable financing agreement. The following condensed consolidating balance sheets as of September 30, 2018 and December 31, 2017 and the condensed consolidating statements of operations and statements of cash flows for the three and nine months ended September 30, 2018 and 2017, as applicable, reflect the condensed consolidating financial information of our parent company, CRC (Parent), our combined Guarantor Subsidiaries, our combined Non-Guarantor Subsidiaries and the 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 Sheets

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
As of September 30, 2018			(in millions)		
Total current assets	$ 5	$ 475	$ 81	$ (15)	$ 546
Total property, plant and equipment, net	32	5,823	531	—	6,386
Investments in consolidated subsidiaries	5,858	178	—	(6,036)	—
Other assets	10	29	13	—	52
TOTAL ASSETS	$ 5,905	$ 6,505	$ 625	$ (6,051)	$ 6,984
Total current liabilities	187	682	17	(15)	871
Long-term debt	5,108	—	—	—	5,108
Deferred gain and issuance costs, net	253	—	—	—	253
Other long-term liabilities	152	451	9	—	612
Amounts due to (from) affiliates	929	(929)	—	—	—
Mezzanine equity	—	—	745	—	745
Total equity	(724)	6,301	(146)	(6,036)	(605)
TOTAL LIABILITIES AND EQUITY	$ 5,905	$ 6,505	$ 625	$ (6,051)	$ 6,984
As of December 31, 2017					
Total current assets	$ 13	$ 464	$ 12	$ (6)	$ 483
Total property, plant and equipment, net	24	5,580	92	—	5,696
Investments in consolidated subsidiaries	5,105	606	—	(5,711)	—
Other assets	—	27	1	—	28
TOTAL ASSETS	$ 5,142	$ 6,677	$ 105	$ (5,717)	$ 6,207
Total current liabilities	122	613	3	(6)	732
Long-term debt	5,306	—	—	—	5,306
Deferred gain and issuance costs, net	287	—	—	—	287
Other long-term liabilities	154	445	3	—	602
Amounts due to (from) affiliates	87	(87)	—	—	—
Total equity	(814)	5,706	99	(5,711)	(720)
TOTAL LIABILITIES AND EQUITY	$ 5,142	$ 6,677	$ 105	$ (5,717)	$ 6,207

Condensed Consolidating Statements of Operations

For the three months ended September 30, 2018	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total revenues and other	$ —	$ 766	$ 135	$ (73)	$ 828
Total costs and other	62	582	72	(73)	643
Non-operating (loss) income	(99)	5	—	—	(94)
NET INCOME (LOSS)	(161)	189	63	—	91
Net income attributable to noncontrolling interests	—	—	(25)	—	(25)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ (161)	$ 189	$ 38	$ —	$ 66
For the three months ended September 30, 2017					
Total revenues and other	$ 5	$ 446	$ 5	$ (11)	$ 445
Total costs and other	58	439	4	(11)	490
Non-operating (loss) income	(87)	—	—	—	(87)
NET (LOSS) INCOME	(140)	7	1	—	(132)
Net income attributable to noncontrolling interest	—	—	(1)	—	(1)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (140)	$ 7	$ —	$ —	$ (133)

Condensed Consolidating Statements of Operations

For the nine months ended September 30, 2018	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions)		
Total revenues and other	$ 1	$ 1,878	$ 293	$ (186)	$ 1,986
Total costs and other	169	1,542	157	(186)	1,682
Non-operating (loss) income	(272)	5	—	—	(267)
NET INCOME (LOSS)	(440)	341	136	—	37
Net income attributable to noncontrolling interests	—	—	(55)	—	(55)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ (440)	$ 341	$ 81	$ —	$ (18)
For the nine months ended September 30, 2017					
Total revenues and other	$ 22	$ 1,551	$ 10	$ (32)	$ 1,551
Total costs and other	165	1,298	9	(32)	1,440
Non-operating (loss) income	(256)	18	—	—	(238)
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)

Condensed Consolidating Statements of Cash Flows

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
For the nine months ended September 30, 2018			(in millions)		
Net cash (used) provided by operating activities	$ (433)	$ 645	$ 181	$ —	$ 393
Net cash used in investing activities	(3)	(921)	(41)	—	(965)
Net cash provided (used) by financing activities	429	278	(124)	—	583
Increase in cash	(7)	2	16	—	11
Cash—beginning of period	7	8	5	—	20
Cash—end of period	$ —	$ 10	$ 21	$ —	$ 31
For the nine months ended September 30, 2017					
Net cash (used) provided by operating activities	$ (403)	$ 621	$ 7	$ —	$ 225
Net cash used in investing activities	(2)	(90)	(82)	—	(174)
Net cash provided (used) by financing activities	409	(536)	92	—	(35)
Increase (decrease) in cash	4	(5)	17	—	16
Cash—beginning of period	—	12	—	—	12
Cash—end of period	$ 4	$ 7	$ 17	$ —	$ 28

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

General

We are an independent oil and natural gas exploration and production company operating properties within California. We are incorporated in Delaware and became a publicly traded company on December 1, 2014. 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.

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 as a result of numerous market-related variables. These and other factors make it impossible to predict realized prices reliably.

Global oil prices were higher in the third quarter and the first nine months of 2018 compared to the same periods of 2017. Further, the spread between Brent and WTI widened reflecting rising domestic shale production in the mid-continent and pipeline constraints in these areas. Prices for natural gas liquids (NGLs) have improved between comparative periods due to tighter local supplies and higher contract prices across the NGL spectrum. Natural gas prices in the U.S. were lower in the third quarter and the first nine months of 2018 than the comparable periods of 2017 due to higher natural gas production, which has outpaced demand.

The following table presents the average daily Brent, WTI and NYMEX prices for the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Brent oil ($/Bbl)	$ 75.97	$ 52.18	$ 72.68	$ 52.59
WTI oil ($/Bbl)	$ 69.50	$ 48.21	$ 66.75	$ 49.47
NYMEX gas ($/MMBtu)	$ 2.88	$ 2.95	$ 2.83	$ 3.12

We currently sell all of our crude oil into the California refining market, which offers relatively favorable pricing compared to other U.S. regions for similar grades. California is heavily reliant on imported sources of energy, with approximately 74% of the oil consumed in the first half of 2018 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 U.S. into California will continue to contribute to higher realizations than most other U.S. oil markets for comparable grades. Additionally, our differentials improved against Brent during 2017 and continuing into the third quarter of 2018 in response to strong demand for California crude oil to optimize local refinery yields as well as a decline in overall California crude oil production.

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 and seasonality can magnify pricing volatility.

Natural gas prices and differentials are strongly affected by local market fundamentals, such as storage capacity, as well as availability of transportation capacity from producing areas. Transportation capacity influences prices because California imports approximately 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 natural gas prices is partially offset by higher operating costs, but higher prices still 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 operating cost of our steamflood projects and power generation.

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 the Elk Hills power plant to reduce operating costs at our Elk Hills and nearby fields and increase reliability. The remaining electricity is sold to the wholesale power market and a utility under a power purchase and sales agreement that includes a capacity payment. The price obtained for excess power impacts our earnings but generally by an insignificant amount.

We procure tubular goods and equipment from multiple vendors. Tariffs of 25% for steel and 10% for aluminum on foreign imports were made effective in the first quarter of 2018. We do not expect these tariffs to have a material impact on our operating costs in the foreseeable future.

We opportunistically seek strategic hedging transactions to help protect our cash flow, operating margin and capital program from both the cyclical nature of commodity prices and interest rate movements while maintaining adequate liquidity and improving our ability to comply with our debt covenants in case of price deterioration. We are building our future commodity hedge positions to protect our downside risk without significantly limiting our upside potential. 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 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 identify efficiencies and cost savings. The reductions in our capital program in 2015 and 2016 negatively impacted our 2017 production levels. We exited 2017 with total daily production volumes in the fourth quarter averaging 126 MBoe per day and oil production averaging 80 MBoe per day. With our increased capital program in 2017, our oil production stabilized in the first half of 2018, excluding the impact of our PSC-type contracts and the additional Elk Hills interest acquired in the second quarter of 2018. We expect to exit 2018 with higher average daily production than the fourth quarter of 2017. Volatility in oil 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 has not been a material driver of changes in our quarterly results during the year.

Joint Ventures

Development and Exploration Joint Ventures

In line with our strategy, we have entered into a number of joint ventures (JVs) which allow us to accelerate the development of our assets while providing us with operational and financial flexibility as well as near term production benefits.

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 BSP joint venture (BSP 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 $150 million in three equal tranches, before transaction costs, in March 2017, July 2017 and June 2018. The funds contributed by BSP are used to develop certain of our oil and gas properties.

The BSP JV holds net profits interests (NPI) in existing and future cash flow from certain of our properties and the proceeds from the NPI are used by the BSP JV to (1) pay quarterly minimum distributions to BSP, (2) pay for development costs within the project area, upon mutual agreement between members, and (3) make distributions to BSP until the predetermined threshold is achieved. Our consolidated results reflect the full operations of our BSP JV, with BSP's share of net income being reported in net income attributable to noncontrolling interests on our condensed consolidated statements of operations.

In April 2017, we entered into a JV 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 increases to 75% if MIRA receives cash distributions equal to a predetermined threshold return. MIRA initially committed $160 million, which was intended to be invested over two years. In June 2018, the parties amended the joint development program to $140 million. The agreement provides for a commitment of up to 110% of the program amount. MIRA invested $58 million in 2017 and $46 million in the nine months ended September 30, 2018. MIRA expects to contribute $11 million for drilling projects in the fourth quarter of 2018 and the balance of the committed amount in 2019. Our consolidated results reflect only our working interest share in our MIRA JV.

In October 2018, we entered into three joint ventures where our partners carry a portion of our costs. The JV partners have committed capital of approximately $35 million and could provide additional capital if certain milestones are met. We have committed $13 million over a three-year period in connection with these joint ventures.

Midstream Joint Venture

In February 2018, we entered into a midstream JV with ECR Corporate Holdings L.P. (ECR), a portfolio company of Ares Management L.P. (Ares). This JV (Ares JV) holds the Elk Hills power plant (a 550-megawatt natural gas fired power plant) and a 200 million cubic foot per day cryogenic gas processing plant. We hold 50% of the Class A common interest and 95.25% of the Class C common interest in the Ares JV. ECR holds 50% of the Class A common interest, 100% of the Class B preferred interest and 4.75% of the Class C common interest. We received $750 million in proceeds upon entering into the Ares JV, before $3 million for transaction costs.

The Class A common and Class B preferred interests held by ECR are reported as redeemable noncontrolling interest in mezzanine equity due to an embedded optional redemption feature. The Class C common interest held by ECR is reported in equity on our condensed consolidated balance sheets.

The Ares JV is required to make monthly distributions to the Class B holders. The Class B preferred interest has a deferred payment feature whereby a portion of the monthly distributions may be deferred for the first three years to the fourth and fifth year. The deferred amounts accrue an additional return. Distributions to the Class B preferred interest holders are reported as a reduction to mezzanine equity on our condensed consolidated balance sheets. Monthly, the Ares JV is also required to distribute its excess cash flow over its working capital requirements to the Class C common interests, on a pro-rata basis.

We can cause the Ares JV to redeem ECR's Class A and Class B interests, in whole, but not in part, at any time by paying $750 million for the Class B interest and $60 million for the Class A interest, plus any previously accrued but unpaid preferred distributions and a make-whole payment if the redemption happens prior to five years from inception. We have the option to extend the redemption period for up to an additional two and one-half years, in which case the interests can be redeemed for $750 million for the Class B interest and $80 million for the Class A interest, plus any previously accrued but unpaid preferred distributions and a make-whole payment if the redemption happens prior to seven and one-half years from inception. If we do not exercise a redemption at the end of the seven and one-half year period, ECR can either sell its Class A and Class B interests or cause the sale or lease of the Ares JV assets.

Our condensed consolidated statements of operations reflect the full operations of our Ares JV, with ECR's share of net income reported in net income attributable to noncontrolling interests.

Acquisitions and Divestitures

Acquisitions

On April 9, 2018, we acquired the remaining working, surface and mineral interests in the 47,000-acre Elk Hills unit from Chevron U.S.A., Inc. (Chevron) (the Elk Hills transaction) for approximately $518 million, including $7 million of liabilities assumed relating to asset retirement obligations and favorable customary purchase price adjustments. We accounted for the Elk Hills transaction as a business combination and allocated $435 million to proved properties, $77 million to other property, plant and equipment and $6 million to materials and supplies. The consideration paid consisted of $462 million in cash and 2.85 million shares of CRC common stock issued at the close of the transaction (valued at $51 million). After the transaction, we hold all of the working, surface and mineral interests in the Elk Hills unit. The effective date of the transaction was April 1, 2018. Since the acquisition, we estimate that we have recognized approximately $16 million in cost savings and revenue enhancements by streamlining operations and consolidating infrastructure. On an annualized basis, these synergies amount to approximately $34 million, exceeding the initial targeted $20 million over 24 months. Additionally, we realized approximately $15 million of nonrecurring capital savings through September 30, 2018 and we may have additional capital savings in the future. Chevron has sold all of the shares of CRC common stock it acquired in the Elk Hills transaction.

As part of the Elk Hills transaction, Chevron reduced its royalty interest in one of our oil and gas properties by half and extended the time frame to invest the remainder of our capital commitment on that property by two years, to the end of 2020. As of September 30, 2018, the remaining commitment was approximately $18 million. Any deficiency in meeting this capital investment obligation will be paid in cash to Chevron. We expect to fulfill the capital investment requirement within the extended period. In addition, the parties mutually agreed to release each other from pending claims with respect to the Elk Hills unit.

On April 2, 2018, we acquired an office building in Bakersfield, California for $48.4 million, which we believe is significantly less than the estimated replacement value of the property and the land. We currently have approximately 500 employees using eight different locations in Bakersfield across multiple leases. We expect that the new building will create significant value by bringing our Bakersfield employees together into a single location over the next 12 to 15 months, which will increase the efficiency, effectiveness and collaboration of these employees. This building was the only available office space in the Bakersfield area large enough to allow us to consolidate our workforce in a single location. For the initial eight months, a former owner of the building will occupy most of the space as a tenant, from which we expect to generate rental income of approximately $4 million in 2018. In December 2018, this tenant will downsize the space they are leasing, with a corresponding reduction in rent, until December 2022. The vacated space will be available to lease to other tenants to generate additional income. In addition, the unimproved land may be monetized in the future. Approximately $6 million of the purchase price was allocated to the in-place leases, which is included in other assets and is being amortized into other expenses, net.

Divestitures

During the nine months ended September 30, 2018, we divested non-core assets resulting in $17 million of proceeds and a $4 million gain. During the nine months ended September 30, 2017, we divested non-core assets resulting in $33 million of proceeds and a $21 million gain.

Operations

We conduct our operations on properties that we hold 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 mineral acres, approximately 60% of which we hold in fee and approximately 15% of which is held by production. Our oil and gas leases have primary terms ranging from one to ten years, which are extended through the end of production once commenced. We also own or control 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 approximately 15% of our production for the quarter ended September 30, 2018.

In addition, we report 100% of operating costs under the PSC-type contracts in our consolidated statements of operations as opposed to reporting only our share of those costs, which is in line with industry practice for reporting PSC-type contracts. 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, which is less than the total volumes produced under the PSC-type contracts. 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, and has no effect on our net results.

With our significant land holdings in California, we have undertaken new initiatives to unlock additional value from our real estate. Our real estate development initiatives include exploring renewable energy opportunities on our land such as solar energy projects, agricultural activities (such as the production of fruits and nuts) and other commercial real estate uses. We are also exploring carbon dioxide capture and storage projects and reclaimed water opportunities.

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, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Oil (MBbl/d)				
San Joaquin Basin	54	51	52	52
Los Angeles Basin	26	27	25	27
Ventura Basin	4	4	4	5
Sacramento Basin	—	—	—	—
Total	84	82	81	84
NGLs (MBbl/d)				
San Joaquin Basin	16	15	16	15
Los Angeles Basin	—	—	—	—
Ventura Basin	1	1	1	1
Sacramento Basin	—	—	—	—
Total	17	16	17	16
Natural gas (MMcf/d)				
San Joaquin Basin	172	139	162	140
Los Angeles Basin	1	2	1	1
Ventura Basin	6	8	7	8
Sacramento Basin	29	33	30	32
Total	208	182	200	181
Total Production (MBoe/d)[(a)]	136	128	131	130

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 following table sets forth the average realized prices for our products for the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Oil prices with hedge ($ per Bbl)	$ 63.63	$ 50.02	$ 63.53	$ 49.42
Oil prices without hedge ($ per Bbl)	$ 73.73	$ 48.90	$ 71.53	$ 48.76
NGLs prices ($ per Bbl)	$ 45.72	$ 34.63	$ 43.71	$ 33.00
Natural gas prices ($ per Mcf)[(a)]	$ 3.16	$ 2.56	$ 2.73	$ 2.64

(a) For the three and nine months ended September 30, 2018, the realized gas price was impacted by the adoption of new accounting rules on revenue recognition and would have been $2.98 and $2.52 per Mcf, respectively, under prior accounting standards.

The following table presents our average price realizations as a percentage of Brent, WTI and NYMEX for the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Oil with hedge as a percentage of Brent	84%	96%	87%	94%
Oil with hedge as a percentage of WTI	92%	104%	95%	100%
Oil without hedge as a percentage of Brent	97%	94%	98%	93%
Oil without hedge as a percentage of WTI	106%	101%	107%	99%
NGLs as a percentage of Brent	60%	66%	60%	63%
NGLs as a percentage of WTI	66%	72%	65%	67%
Natural gas as a percentage of NYMEX[(a)]	110%	87%	96%	85%

(a) For the three and nine months ended September 30, 2018, the gas price realization as a percentage of NYMEX was impacted by the adoption of new accounting rules on revenue recognition and would have been 103% and 89%, respectively, under prior accounting standards.

Balance Sheet Analysis

The changes in our balance sheet from December 31, 2017 to September 30, 2018 are discussed below:

	September 30, 2018	December 31, 2017
	(in millions)	
Cash	$ 31	$ 20
Trade receivables	$ 293	$ 277
Inventories	$ 69	$ 56
Other current assets, net	$ 153	$ 130
Property, plant and equipment, net	$ 6,386	$ 5,696
Other assets	$ 52	$ 28
Accounts payable	$ 349	$ 257
Accrued liabilities	$ 522	$ 475
Long-term debt	$ 5,108	$ 5,306
Deferred gain and issuance costs, net	$ 253	$ 287
Other long-term liabilities	$ 612	$ 602
Mezzanine equity	$ 745	$ —
Equity attributable to common stock	$ (725)	$ (814)
Equity attributable to noncontrolling interests	$ 120	$ 94

Cash at September 30, 2018 and December 31, 2017 included approximately $13 million and $5 million, respectively, that is restricted under one of our joint venture agreements. See *Liquidity and Capital Resources* for our cash flow analysis.

The increase in other current assets, net primarily reflected increases in amounts due from joint interest partners, fair value changes in the current portion of our derivative assets and prepaid power plant major maintenance expenses, partially offset by the sale of a non-core asset. The increase in property, plant and equipment, net primarily reflected proved reserves acquired in connection with the Elk Hills transaction, the acquisition of our Bakersfield building and capital investments for the period, partially offset by depreciation, depletion and amortization (DD&A). The increase in other assets was primarily due to fair value changes in our long-term derivative assets.

The increase in accounts payable for the quarter ended September 30, 2018 reflected the increase in activity between periods. The increase in accrued liabilities was primarily due to higher accrued interest and property taxes due to the timing of payments, higher accrued employee-related costs due to increases in stock price between periods and the change in value of certain derivative positions due to higher Brent prices between periods. These increases were partially offset by payments made for greenhouse gas obligations. The decrease in long-term debt primarily reflected repurchases of our Second Lien Notes and 2024 Notes. The decrease in deferred gain and issuance costs, net, reflected the amortization of deferred gains, partially offset by the amortization of deferred issuance costs.

Mezzanine equity reflected the carrying amount of the Class A common and Class B preferred interests held by ECR in our Ares JV. The increase in equity attributable to common stock primarily reflected the issuance of common stock in connection with the Ares JV and the Elk Hills transaction. Equity attributable to noncontrolling interest reflected contributions from and distributions to ECR's Class C common interest and BSP's preferred interest as well as their respective share of net income or loss for the period. See *Note 6 Joint Ventures* in the Notes to the Condensed Consolidated Financial Statements included in Part I of this Form 10-Q for more information.

Statements of Operations Analysis

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,	
	2018	2017	2018	2017
Production costs	$ 18.92	$ 18.90	$ 18.98	$ 18.31
Production costs, excluding effects of PSC-type contracts[(a)]	$ 17.55	$ 17.81	$ 17.48	$ 17.21
Field general and administrative expenses[(b)]	$ 1.12	$ 0.77	$ 0.98	$ 0.76
Field depreciation, depletion and amortization[(b)]	$ 9.22	$ 10.73	$ 9.33	$ 10.92
Field taxes other than on income[(b)]	$ 2.97	$ 2.64	$ 2.68	$ 2.34

(a) As described in the *Operations* section, the reporting of our PSC-type contracts creates a difference between reported production costs, which are for the full field, and reported volumes, which are only our net share, inflating the per barrel production costs. These amounts represent the production costs for the company after adjusting for this difference.

(b) Excludes corporate amounts.

Consolidated Results of Operations

The following represents key operating data for consolidated operations for the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Oil and gas sales[(a)]	$ 700	$ 461	$ 1,932	$ 1,387
Net derivative (loss) gain	(54)	(65)	(259)	51
Other revenue[(a)]	182	49	313	113
Production costs	(236)	(222)	(679)	(649)
General and administrative expenses[(b)]	(81)	(61)	(234)	(183)
Depreciation, depletion and amortization	(128)	(134)	(372)	(412)
Taxes other than on income	(45)	(39)	(120)	(103)
Exploration expense	(4)	(5)	(18)	(17)
Other expenses, net[(a)]	(149)	(29)	(259)	(76)
Interest and debt expense, net	(95)	(85)	(281)	(252)
Net gain on early extinguishment of debt	2	—	26	4
Gain on asset divestitures	3	—	4	21
Other non-operating expenses[(b)]	(4)	(2)	(16)	(11)
Income (loss) before income taxes	91	(132)	37	(127)
Income tax	—	—	—	—
Net income (loss)	91	(132)	37	(127)
Net income attributable to noncontrolling interests	(25)	(1)	(55)	(1)
Net income (loss) attributable to common stock	$ 66	$ (133)	$ (18)	$ (128)
Adjusted net income (loss)	$ 41	$ (52)	$ 35	$ (173)
Adjusted EBITDAX	$ 308	$ 187	$ 803	$ 548
Effective tax rate	—%	—%	—%	—%

(a) We adopted the new revenue recognition standard on January 1, 2018 that required certain sales-related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard does not affect net income. Results for reporting periods beginning after January 1, 2018 are presented under the new accounting standard while prior periods are not adjusted and continue to be reported under accounting standards in effect during the prior periods. Under prior accounting standards, for the three and nine months ended September 30, 2018, oil and gas sales would have been $695 million and $1,915 million, respectively, other revenue would have been $177 million and $242 million, respectively, and other expenses, net would have been $139 million and $171 million, respectively. See *Note 12 Revenue Recognition* in the Notes to the Condensed Consolidated Financial Statements included in Part I of this Form 10-Q for more information.

(b) For the three and nine months ended September 30, 2017, certain pension benefit costs of $2 million and $8 million, respectively, have been reclassified to other non-operating expenses to conform to the current year presentation in accordance with new accounting rules adopted on January 1, 2018 related to the presentation of net periodic benefit costs for pension and postretirement benefits in the Condensed Consolidated Statements of Operations. See *Note 2 Accounting and Disclosure Changes* in the Notes to the Condensed Consolidated Financial Statements included in Part I of this Form 10-Q for more information.

<u>*Stock-Based Compensation*</u>

Our consolidated results of operations for the three and nine months ended September 30, 2018 include the effects of our significantly higher stock price for certain stock-based long-term incentive plans payable in cash. We have stock-based compensation plans under which we annually grant stock-based awards to executives, non-executive employees and directors that are payable in shares of our common stock or phantom shares that are ultimately settled in cash and are generally paid out over a three-year time period. Our Board of Directors instituted these cash-settled long-term incentive awards for non-executives near the bottom of the price cycle to limit share dilution. Accounting rules require that we adjust our obligation for all vested but unpaid cash-settled awards under our long-term incentive program to the amount that would be paid using our stock price as of the end of each quarter. Conversely, stock-based compensation cost for our equity-settled awards are not similarly adjusted for changes in stock price.

Our stock price increased $38.07 or 364% from $10.46 as of September 30, 2017 to $48.53 as of September 30, 2018. Due to our stock price increase, we must accrue and mark-to-market the cash-settled long-term incentive awards based on the stock price each quarter, which has introduced volatility to our income statement. In the third quarter of 2018, we recognized a significant increase in stock-based compensation expense that is included in both general and administrative expenses and production costs as shown in the following table:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
	(in millions, except per Boe amounts)			
General and administrative expenses				
Cash-settled awards	$ 11	$ 2	$ 33	$ 3
Equity-settled awards	2	3	10	10
Total stock-based compensation in G&A	$ 13	$ 5	$ 43	$ 13
Total stock-based compensation in G&A per Boe	$ 1.04	$ 0.43	$ 1.20	$ 0.37
Production costs				
Cash-settled awards	$ 2	$ —	$ 8	$ —
Equity-settled awards	1	1	3	3
Total stock-based compensation in production costs	$ 3	$ 1	$ 11	$ 3
Total stock-based compensation in production costs per Boe	$ 0.24	$ 0.09	$ 0.31	$ 0.08
Total company stock-based compensation	$ 16	$ 6	$ 54	$ 16
Total company stock-based compensation per Boe	$ 1.28	$ 0.52	$ 1.51	$ 0.45

Three months ended September 30, 2018 vs. 2017

Oil and gas sales increased 52%, or $239 million, for the three months ended September 30, 2018 compared to the same period of 2017 due to increases of approximately $186 million, $15 million and $10 million from higher oil, NGL and natural gas realized prices, respectively, and $15 million, $5 million and $8 million from higher oil, NGL and natural gas production, respectively. The higher realized oil prices reflected the significant increase in global oil prices and improved differentials.

Our total daily production volumes averaged 136 MBoe per day in the three months ended September 30, 2018 compared with 128 MBoe per day in the comparable period of 2017, representing a year-over-year increase of 6%. Our total daily production volumes included the Elk Hills transaction effect of 12 MBoe per day. PSC-type contracts negatively impacted our third quarter 2018 production by 1 MBoe per day compared to the prior year quarter, without which the year-over-year production increase would have been 7%.

Net derivative loss was $54 million and $65 million for the three months ended September 30, 2018 and 2017, respectively, representing a decrease of $11 million. We made cash payments of $79 million in the three months ended September 30, 2018, compared to receiving $8 million in the prior year, primarily due to the upward movement of Brent prices relative to the strike price on our derivative contracts. The non-cash change of $98 million reflected changes in the commodity price curves based on our derivative positions at the end of each of the respective periods.

The increase in other revenue of $133 million for the three months ended September 30, 2018 compared to the same period of 2017 was the result of higher gas trading activity and the adoption of new accounting rules on the recognition of revenue on January 1, 2018 while the prior comparative period was not adjusted. The increase resulting from the accounting change was offset by an increase in other expenses, net with no effect on net income.

Production costs for the three months ended September 30, 2018 increased $14 million to $236 million or $18.92 per Boe, compared to $222 million or $18.90 per Boe for the same period of 2017, resulting in a 6% increase on an absolute dollar basis. Without the effect of the Elk Hills transaction and cash-settled stock-based compensation included in production costs, which added $12 million and $2 million to the 2018 costs, respectively, our production costs would have been $222 million or $19.46 per Boe. The Elk Hills unit production costs are lower than the average company-wide production costs per barrel. As a result, the Elk Hills transaction had a favorable effect on production costs per barrel. Third quarter 2018 production costs also reflect cost savings achieved following the Elk Hills transaction of $6 million.

Our general and administrative (G&A) expenses increased $20 million to $81 million for the three months ended September 30, 2018 compared to the same period of 2017. Our stock-based compensation expense for cash-settled awards increased $9 million due to the increase in our stock price. Additionally, our G&A expenses increased $3 million as these costs were no longer shared with our working interest partner following the Elk Hills transaction. The remaining increase in G&A expenses was the result of a number of smaller increases in various cost categories.

The increase in other expenses of $120 million to $149 million for the three months ended September 30, 2018, compared to $29 million in the same period of 2017, was largely the result of higher gas trading activity and the adoption of new accounting rules on revenue recognition that impact the current period but not the prior period. The increase resulting from the accounting change was offset by an increase in oil and gas sales and other revenue with no effect on net income.

Interest and debt expense, net, increased to $95 million for the three months ended September 30, 2018, compared to $85 million in the same period of 2017, primarily due to higher interest on our variable-rate debt, partially offset by lower interest due to paying off our 2014 Term Loan and repurchases of our Second Lien Notes and Senior Notes.

Nine months ended September 30, 2018 vs. 2017

Oil and gas sales increased 39%, or $545 million, for the nine months ended September 30, 2018 compared to the same period of 2017 due to increases of approximately $518 million, $46 million and $5 million from higher oil, NGL and natural gas realized prices, respectively, and an increase of $14 million and $3 million from higher natural gas and NGL production, respectively. These increases were partially offset by $41 million from lower oil production primarily from the first quarter of 2018. The higher realized oil prices reflected the significant increase in global oil prices and improved differentials.

Our total daily production volumes averaged 131 MBoe in the nine months ended September 30, 2018 compared with 130 MBoe in the comparable period of 2017, representing a year-over-year increase of 1%. Our total daily production volumes included the Elk Hills transaction effect of 8 MBoe per day in the nine months ended September 30, 2018. Our PSC-type contracts negatively impacted our 2018 production by 2 MBoe per day compared with the prior year period, without which the year-over-year production increase would have been 2%.

Net derivative loss was $259 million for the nine months ended September 30, 2018 compared to a gain of $51 million in the comparable period of 2017, representing an overall change of $310 million. We made cash payments of $178 million in the nine months ended September 30, 2018, compared to receiving $15 million in the prior year, primarily due to the upward movement of Brent prices relative to the strike price on our derivative contracts. The non-cash change of $117 million reflected changes in the commodity price curves based on our derivative positions at the end of each of the respective periods.

The increase in other revenue of $200 million for the nine months ended September 30, 2018 compared to the same period of 2017 was largely the result of higher gas trading activity and the adoption of new accounting rules on the recognition of revenue in the nine months ended September 30, 2018 while the prior comparative period was not adjusted. The increase resulting from the accounting change was offset in its entirety by an increase in other expenses, net with no effect on net income.

Production costs for the nine months ended September 30, 2018 increased $30 million to $679 million or $18.98 per Boe, compared to $649 million or $18.31 per Boe for the same period of 2017, resulting in a 5% increase on an absolute dollar basis. Without the Elk Hills transaction and cash-settled stock-based compensation included in production costs, which added $24 million and $8 million to the 2018 costs, respectively, our production costs would have been $647 million or $19.18 per Boe. The Elk Hills unit production costs are lower than the average company-wide production costs per barrel. As a result, the Elk Hills transaction had a favorable effect on production costs per barrel. For the nine months ended September 30, 2018, production costs also reflect cost savings achieved following the Elk Hills transaction of $11 million.

Our G&A expenses increased $51 million to $234 million for the nine months ended September 30, 2018 compared to the same period of 2017. Our stock-based compensation increased $30 million due to the increase in our stock price as noted in the stock-based compensation table above. Additionally, our G&A expenses increased approximately $6 million as these costs were no longer shared with our working interest partner following the Elk Hills transaction.

DD&A expense decreased by $40 million for the nine months ended September 30, 2018 compared to the same period of 2017, primarily resulting from lower DD&A rates due to increased reserves at year-end 2017.

Taxes other than on income increased 17% for the nine months ended September 30, 2018 compared to the same period of 2017, largely resulting from higher property taxes due to the increase in commodity prices and greenhouse gas allowance costs due to higher prices.

The increase in other expenses of $183 million to $259 million for the nine months ended September 30, 2018 compared to $76 million in the same period of 2017 was largely the result of higher gas trading activity and the adoption of new accounting rules on revenue recognition that impact the current period but not the prior period. The increase resulting from the accounting change was offset by an increase in oil and gas sales and other revenue with no effect on net income.

Interest and debt expense, net, increased to $281 million for the nine months ended September 30, 2018 compared to $252 million in the same period of 2017, primarily due to higher interest on our variable-rate debt, partially offset by lower interest due to paying off our 2014 Term Loan and repurchases of our Second Lien Notes and Senior Notes.

Net gain on early extinguishment of debt consisted of the gain on open-market repurchases for the nine months ended September 30, 2018 and 2017.

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 particular certain non-cash items such as derivative gains and losses) in nature, timing, amount and frequency. Therefore, management uses a measure called adjusted net income (loss) which excludes those items. This measure is not meant to disassociate items from management's performance, but rather is meant to provide useful information to investors interested in comparing our performance between periods. Reported earnings are considered representative of management's performance over the long term. Adjusted net income (loss) is not considered to be an alternative to net income (loss) reported in accordance with U.S. generally accepted accounting principles (GAAP).

The following table presents a reconciliation of the GAAP financial measure of net income (loss) attributable to common stock to the non-GAAP financial measure of adjusted net income (loss) and presents the GAAP financial measure of net income (loss) attributable to common stock per diluted share and the non-GAAP financial measure of adjusted net income (loss) per diluted share:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
	(in millions, except share data)			
Net income (loss)	$ 91	$ (132)	$ 37	$ (127)
Net income attributable to noncontrolling interests	(25)	(1)	(55)	(1)
Net income (loss) attributable to common stock	66	(133)	(18)	(128)
Unusual, infrequent and other items:				
Non-cash derivative (gain) loss, excluding noncontrolling interest	(28)	72	71	(38)
Early retirement and severance costs	—	1	4	4
Net gain on early extinguishment of debt	(2)	—	(26)	(4)
Gain on asset divestitures	(3)	—	(4)	(21)
Other, net	8	8	8	14
Total unusual, infrequent and other items	(25)	81	53	(45)
Adjusted net income (loss)	$ 41	$ (52)	$ 35	$ (173)
Net income (loss) attributable to common stock per diluted share	$ 1.32	$ (3.11)	$ (0.38)	$ (3.01)
Adjusted net income (loss) per diluted share	$ 0.81	$ (1.22)	$ 0.71	$ (4.07)

We define Adjusted EBITDAX as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; other unusual, out-of-period and infrequent items; and other non-cash items. We believe this measure 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. Although this is a non-GAAP measure, the amounts included in the calculation were computed in accordance with GAAP. Certain items excluded from this non-GAAP measure 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. This measure should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP. A version of Adjusted EBITDAX is a material component of certain of our financial covenants under our 2014 Revolving Credit Facility and is provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP.

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

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Net income (loss)	$ 91	$ (132)	$ 37	$ (127)
Interest and debt expense, net	95	85	281	252
Interest income	—	—	(1)	—
Depreciation, depletion and amortization	128	134	372	412
Exploration expense	4	5	18	17
Unusual, infrequent and other items	(25)	81	53	(45)
Other non-cash items	15	14	43	39
Adjusted EBITDAX	$ 308	$ 187	$ 803	$ 548

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,	
	2018	2017
	(in millions)	
Net cash provided by operating activities	$ 393	$ 225
Cash interest	284	251
Exploration expenditures	14	16
Changes in operating assets and liabilities	113	42
Other, net	(1)	14
Adjusted EBITDAX	$ 803	$ 548

The following table presents the components of our net derivative gain (loss) from commodity contracts:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
	(in millions)			
Non-cash derivative gain (loss), excluding noncontrolling interest	$ 28	$ (72)	$ (71)	$ 38
Non-cash derivative loss included in noncontrolling interest	(3)	(1)	(10)	(2)
Net (payments) proceeds on settled commodity derivatives	(79)	8	(178)	15
Net derivative (loss) gain from commodity contracts	$ (54)	$ (65)	$ (259)	$ 51

Liquidity and Capital Resources

Cash Flow Analysis

	Nine months ended September 30,	
	2018	2017
	(in millions)	
Net cash provided by operating activities	$ 393	$ 225
Net cash used in investing activities:		
Capital investments, net of accruals	$ (464)	$ (206)
Acquisitions, divestitures and other	$ (501)	$ 32
Net cash provided (used) by financing activities	$ 583	$ (35)
Adjusted EBITDAX	$ 803	$ 548

Our net cash provided by operating activities is sensitive to many variables, including changes in commodity prices. Commodity price sensitivity also leads to changes in other variables in our business including adjustments to our capital program. Our operating cash flow increased 75%, or $168 million, to $393 million for the nine months ended September 30, 2018 from $225 million in the same period of 2017 primarily due to higher realized prices, including the effect of hedges, and, to a lesser degree, the Elk Hills transaction.

Cash interest increased by $33 million for the nine months ended September 30, 2018 due to higher interest rates on our variable-rate debt. Payments related to taxes other than on income increased $120 million for the nine months ended September 30, 2018 predominantly due to greenhouse gas payments related to prior years' activities. In 2018, changes in working capital, primarily related to these greenhouse gas payments, reduced our operating cash flow by $91 million compared to an increase of $9 million in 2017.

Our net cash used in investing activities of $965 million for the nine months ended September 30, 2018 included approximately $514 million of acquisition costs primarily related to the Elk Hills transaction and our new building in Bakersfield. Cash used in investing activities also included $464 million of capital investments (net of $40 million in capital-related accruals), of which $37 million was funded by BSP. These uses were partially offset by $17 million in proceeds from the sale of non-core assets. Our net cash used in investing activities of $174 million for the nine months ended September 30, 2017 primarily included $206 million of capital investments (net of $26 million in capital-related accruals), of which $82 million was funded by BSP. These uses were partially offset by $33 million in proceeds from asset divestitures.

Our net cash provided by financing activities of $583 million for the nine months ended September 30, 2018 primarily comprised of $796 million in net contributions related to our Ares JV and BSP JV and $52 million primarily from the issuance of common stock to an Ares-led investor group in connection with the Ares JV, partially offset by $153 million of debt repurchases and transaction costs. For the nine months ended September 30, 2017, our net cash used in financing activities of $35 million primarily included approximately $91 million of payments on the 2014 Term Loan and $26 million of debt repurchases and transaction costs, partially offset by $98 million in net contributions related to our BSP JV.

Our primary sources of liquidity and capital resources are cash flow from operations and available borrowing capacity under our 2014 Revolving Credit Facility. We also rely on other sources such as JV funding to supplement our capital program, fund acquisitions and for other corporate purposes. In February 2018, we entered into the Ares JV where we received $747 million in net proceeds and raised $50 million in a private placement of our common stock with an Ares-led investor group. The net proceeds from the Ares JV were used to pay off the then outstanding balance on our 2014 Revolving Credit Facility. During 2017, we closed two key JV transactions with BSP and MIRA. Under these arrangements, our JV partners have invested approximately $238 million in our drilling programs from inception through September 30, 2018, some of which is not included in our consolidated results. In April 2018, we acquired the remaining working, surface and mineral interests in the Elk Hills unit for $462 million in cash and 2.85 million shares of CRC common stock. As a result of the transaction, we expect to add operating cash flow in excess of $100 million per year, at about current prices.

Significant changes in oil and natural gas prices have a material impact on our liquidity. Declining commodity prices negatively affect our operating cash flow but lower natural gas prices have a positive effect on operating expenses. The inverse applies during periods of rising commodity prices. To mitigate some of the risk inherent in oil prices, we have utilized various derivative instruments to hedge price risk. We have historically aligned our capital program with our cash flow from operations, and we currently expect to fund our remaining portion of the planned 2018 capital program with cash flow from operations and funds available under our revolving credit facility as needed.

The Tax Cuts and Jobs Act enacted in December 2017 provides for 100% bonus depreciation on tangible personal property acquired and placed in service after September 27, 2017 and before December 31, 2022. It also provides for a phase down of bonus depreciation for the years 2023 through 2026. Given our net operating loss and tax credit carryforwards from prior periods coupled with future capital spending eligible for bonus depreciation, we do not expect to pay cash taxes in the foreseeable future.

As of September 30, 2018, our long-term debt consisted of the following credit agreements, second lien notes and senior notes:

	Outstanding Principal (in millions)	Interest Rate	Maturity	Security
Credit Agreements				
2014 Revolving Credit Facility	$ 342	LIBOR plus 3.25%-4.00% ABR plus 2.25%-3.00%	June 30, 2021	Shared First-Priority Lien
2017 Credit Agreement	1,300	LIBOR plus 4.75% ABR plus 3.75%	December 31, 2022[(a)]	Shared First-Priority Lien
2016 Credit Agreement	1,000	LIBOR plus 10.375% ABR plus 9.375%	December 31, 2021	First-Priority Lien
Second Lien Notes				
Second Lien Notes	2,122	8%	December 15, 2022[(b)]	Second-Priority Lien
Senior Notes				
5% Senior Notes due 2020	100	5%	January 15, 2020	Unsecured
5½% Senior Notes due 2021	100	5.5%	September 15, 2021	Unsecured
6% Senior Notes due 2024	144	6%	November 15, 2024	Unsecured
Total	$ 5,108			

Note: For a detailed description of our credit agreements, second lien notes and senior notes, please see our most recent Form 10-K for the year ended December 31, 2017.

(a) The 2017 Credit Agreement is subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million in principal of the 2016 Credit Agreement is outstanding at that time.

(b) The Second Lien Notes require principal repayments of approximately $335 million in June 2021, $67 million in December 2021 and $70 million in June 2022.

2014 Revolving Credit Facility

As of September 30, 2018, we had approximately $490 million of available borrowing capacity, subject to a $150 million month-end minimum liquidity requirement. The borrowing base under this facility was reaffirmed at $2.3 billion in October 2018. Our $1 billion senior revolving loan facility (2014 Revolving Credit Facility) also includes a sub-limit of $400 million for the issuance of letters of credit. As of September 30, 2018 and December 31, 2017, we had letters of credit outstanding of approximately $167 million and $148 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

Note Repurchases

In the third quarter of 2018, we repurchased $31 million in aggregate principal amount of our 8% senior secured second lien notes due December 15, 2022 (Second Lien Notes) and $1 million of our 6% senior notes due November 15, 2024 (2024 Notes) for $30 million, resulting in a $2 million pre-tax gain, net of a reduction in deferred issuance costs. In the nine months ended September 30, 2018, we repurchased $128 million and $49 million in aggregate principal amount of our Second Lien Notes and our 2024 Notes, respectively, for $149 million in cash resulting in a pre-tax gain of $26 million, net of a reduction in deferred issuance costs.

Amendments

On August 20, 2018, we entered into an amendment to the 2014 Credit Agreement. The 2014 Credit Agreement was amended to, among other things:

- permit us to draw on our revolver to repurchase our Second Lien Notes and Senior Notes at a discount to par in an amount up to $300 million;
- permit us to draw on our revolver to repurchase our Second Lien Notes and Senior Notes at a discount to par, without regard to time limit, in an amount not to exceed a specified portion of proceeds from future dispositions of certain assets;
- in connection with any repurchase of certain of our indebtedness, increase the minimum liquidity required to make such repurchase (calculated on a pro forma basis after giving effect to the repurchase) from $250 million to $300 million; and
- enhance our ability to refinance our outstanding term loans under our 2017 Credit Agreement and 2016 Credit Agreement, Second Lien Notes and Senior Notes, in each case by allowing the use of permitted refinancing indebtedness for such refinancing so long as certain conditions are met.

On September 18, 2018, we entered into an amendment to the 2017 Credit Agreement. The 2017 Credit Agreement was amended to, among other things:

- permit us to repurchase our Second Lien Notes and Senior Notes at a discount to par, without regard to time limit, in an amount not to exceed a specified portion of proceeds from dispositions of certain assets; and
- enhance our ability to refinance our outstanding Second Lien Notes, Senior Notes and 2016 Credit Agreement, in each case by allowing the use of permitted refinancing indebtedness for such refinancing so long as certain conditions are met.

Other

At September 30, 2018, we were in compliance with all financial and other debt covenants.

All obligations under our 2014 Revolving Credit Facility, 2017 Credit Agreement and 2016 Credit Agreement (collectively, Credit Facilities) as well as our Second Lien Notes and Senior Notes are guaranteed both fully and unconditionally and jointly and severally by all of our material wholly owned subsidiaries.

A one-eighth percent change in the variable interest rates on the borrowings under our Credit Facilities on September 30, 2018 would result in a $3 million change in annual interest expense.

Derivatives

Commodity Contracts

Our strategy for protecting our cash flow, operating margin and capital program, while maintaining adequate liquidity, also includes our hedging program. We currently have the following Brent-based crude oil contracts, including contracts entered into subsequent to September 30, 2018:

	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Q1 2020
Sold Calls:						
Barrels per day	15,000	15,000	5,000	—	—	—
Weighted-average price per barrel	$ 58.83	$ 66.15	$ 68.45	$ —	$ —	$ —
Purchased Calls:						
Barrels per day	—	2,000	—	—	—	—
Weighted-average price per barrel	$ —	$ 71.00	$ —	$ —	$ —	$ —
Purchased Puts:						
Barrels per day	—	38,000	40,000	40,000	35,000	10,000
Weighted-average price per barrel	$ —	$ 65.66	$ 69.75	$ 73.13	$ 75.71	$ 75.00
Sold Puts:						
Barrels per day	19,000	40,000	35,000	40,000	35,000	10,000
Weighted-average price per barrel	$ 45.00	$ 51.88	$ 55.71	$ 57.50	$ 60.00	$ 60.00
Swaps:						
Barrels per day	48,000	7,000(1)	—	—	—	—
Weighted-average price per barrel	$ 60.35	$ 67.71	$ —	$ —	$ —	$ —

(1) 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 $70.00 for the first quarter of 2019.

The BSP JV entered into crude oil derivatives that are included in our consolidated results but not in the above table. The hedges entered into by the BSP JV could affect the timing of the redemption of the JV interest. The BSP JV sold calls for up to approximately 1,000 barrels per day at a weighted-average price per barrel of $60.00 per barrel for 2018 through 2020. The BSP JV purchased puts for up to approximately 2,000 barrels per day at a weighted-average price per barrel of approximately $50.00 for 2018 through 2021. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021.

Refer to *Note 9 Derivatives* in the Notes to the Condensed Consolidated Financial Statements included in Part I of this Form 10-Q for more information on the outcomes of our derivative instruments.

Interest-Rate Contracts

In May 2018, we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. The interest rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021.

2018 Capital Program

Our 2018 capital program ranges from $720 million to $750 million (including approximately $100 million of JV capital). This program reflects management's strategy to align the capital program with stronger-than-expected cash flows from commodity price improvements and increased production and synergies from the Elk Hills transaction. The additional capital will allow us to sustain current workover and facility activity through the end of the year. The 2018 capital is being deployed primarily to drilling, workovers and facilities projects in the San Joaquin, Los Angeles and Ventura basins. Total capital (including JV capital) was $550 million for the nine months ended September 30, 2018, of which $467 million was internally funded.

We are focusing our 2018 capital on oil projects, which provide high margins and low decline rates that we believe will generate cash flow to fund increasing capital budgets that will grow production. Our approach to our 2018 drilling program is consistent with our stated strategy to remain financially disciplined. We continue to deploy our partners' capital as part of our BSP and MIRA joint ventures and opportunistically pursue additional strategic relationships. We will deploy capital to projects that help continue to stabilize our production, develop our long-term resources and enhance our production growth profile. Our current drilling inventory comprises a diversified portfolio of oil and natural gas locations that are economically viable in a variety of operating and commodity price conditions. This includes our core fields of Elk Hills, Buena Vista, Wilmington, Huntington Beach and Kern Front, and the continued delineation and appraisal of our assets that offer future value-driven growth such as the fields in the Ventura and southern San Joaquin areas.

Our 2018 drilling program includes development of conventional and unconventional resources. The depth of our primary conventional wells is expected to range from 2,000 to 15,000 feet. With a significant reduction in our drilling costs since 2014, many of our deep conventional and unconventional wells have become more competitive. We expect to use approximately 60% of our total capital (including JV capital) on drilling projects. Our program continues to focus on conventional drilling across our primary assets, including Wilmington, Huntington Beach, Kern Front, Buena Vista, Mount Poso and fields in the southern San Joaquin areas.

We also plan to use 14% of our 2018 capital program for capital workovers on existing well bores. Capital workovers are some of the highest value projects in our portfolio and generally include well deepenings, recompletions, changes of lift methods and other activities designed to add incremental productive intervals and reserves.

Further, approximately 22% of our 2018 capital program is intended for facilities for our newer projects, including pipeline and gathering line interconnections, gas compression, water management systems, associated safety and environmental controls, and also for maintaining the mechanical integrity, safety and environmental performance of existing systems. About 3% is proposed for exploration activities.

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, 2018 and December 31, 2017 were not material to our condensed consolidated 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 would not be material to our consolidated financial position or results of operations.

We 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, 2018, we are not aware of material indemnity claims pending or threatened against us.

In October 2018, we settled the examination by the Internal Revenue Service (IRS) of our U.S. federal income tax returns for the post-Spin-off period in 2014 and calendar year 2015. There were no changes to our tax filings as a result of the examination. We remain subject to examination by the IRS for calendar years 2016 and 2017 as well as for all periods subsequent to the Spin-off by the state of California.

Significant Accounting and Disclosure Changes

See *Note 2 Accounting and Disclosure Changes* in the Notes to the Condensed Consolidated Financial Statements included in Part I of this Form 10-Q 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 and results of operations; business prospects; transactions and projects; operating costs; Value Creation Index metrics, which are based on certain estimates including future production rates, costs and commodity prices; operations and operational results, including production, hedging and capital investment; budgets and maintenance capital requirements; reserves; type curves; and expected synergies from acquisitions and joint ventures. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While we believe such assumptions or bases to be reasonable and make them in good faith, they almost always vary from actual results, sometimes materially. We also believe third-party statements we cite are accurate, but we have not independently verified such statements. 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. Material risks that may affect our results of operations and financial position appear in Part I, Item 1A, Risk Factors of the 2017 Form 10-K.

Factors (but not necessarily all the factors) that could cause results to differ include: commodity price changes; debt limitations on our financial flexibility; insufficient cash flow to fund planned investments, debt repurchases or changes to our capital plan; inability to enter desirable transactions, including acquisitions, asset sales and joint ventures; legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products; joint ventures and acquisitions and our ability to achieve expected synergies; the recoverability of resources and unexpected geologic conditions; incorrect estimates of reserves and related future cash flows and the inability to replace reserves; changes in business strategy; PSC effects on production and unit production costs; effect of stock price on costs associated with incentive compensation; insufficient capital, including as a result of lender restrictions, unavailability of capital markets or inability to attract potential investors; effects of hedging transactions; equipment, service or labor price inflation or unavailability availability or timing of, or conditions imposed on, permits and approvals; lower-than-expected production, reserves or resources from development projects, joint ventures or acquisitions, or higher-than-expected decline rates; disruptions due to accidents, mechanical failures, transportation or storage constraints, natural disasters, labor difficulties, cyber attacks or other catastrophic events. 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, 2018, 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 2017 Form 10-K, except as discussed below.

Commodity Price Risk

As of September 30, 2018, we had a net derivative liability of $153 million carried at fair value, as determined from prices provided by external sources that are not actively quoted, which expire through 2021. See additional hedging information in *Item 2 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources.*

Interest Rate Risk

In May 2018, we entered into derivative contracts that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. The interest rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021.

Counterparty 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, 2018, 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, 2018 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, 2018.

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) 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 8 Lawsuits, Claims and Contingencies* in the Notes to the Condensed Consolidated Financial Statements included in Part I of this Form 10-Q; Part II, Item 1, *Legal Proceedings* in the Form 10-Q for the quarter ended March 31, 2018 and Part I, Item 3, *Legal Proceedings* in the Form 10-K for the year ended December 31, 2017.

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 under the heading *Risk Factors* in our Form 10-K for the year ended December 31, 2017.

Item 5. Other Disclosures

None.

Item 6. Exhibits

10.1	Eighth Amendment to 2014 Credit Agreement, dated August 20, 2018 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on August 24, 2018, and incorporated herein by reference).
10.2	First Amendment to 2017 Credit Agreement, dated September 18, 2018 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 18, 2018, and incorporated herein by reference).
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.

* - Filed herewith

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 1, 2018	/s/ Roy Pineci
	Roy Pineci
	Executive Vice President - Finance
	(Principal Accounting Officer)

EXHIBIT 12

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

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,				
(in millions, except ratios)	2018	2017	2016	2015	2014[(a)]	2013
EARNINGS:						
Income (loss) before income taxes[(b)(c)]	$ 37	$ (262)	$ 201	$ (5,476)	$ (2,421)	$ 1,447
Net income attributable to noncontrolling interests	(55)	(4)	—	—	—	—
Fixed charges	348	350	334	339	79	4
Capitalized interest	(6)	(3)	(2)	(9)	(4)	—
Earnings (loss) before fixed charges	$ 324	$ 81	$ 533	$ (5,146)	$ (2,346)	$ 1,451
FIXED CHARGES						
Interest and debt expense, net[(d)]	$ 339	$ 343	$ 328	$ 326	$ 72	$ —
Capitalized interest	6	3	2	9	4	—
Rental expense representative of interest factor	3	4	4	4	3	4
Total fixed charges	$ 348	$ 350	$ 334	$ 339	$ 79	$ 4
RATIO OF EARNINGS TO FIXED CHARGES	n/a	n/a	1.6	n/a	n/a	363
INSUFFICIENT COVERAGE	$ 24	$ 269	$ —	$ 5,485	$ 2,425	$ —

(a) Note: If we had 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, 2018 amount includes unusual, infrequent and other items consisting of $71 million of non-cash derivative losses on outstanding hedges, $26 million of net gains on the early extinguishment of debt, $4 million of gains from asset divestitures and $12 million of other unusual and infrequent charges. Excluding these items, our earnings before fixed charges for the nine months ended September 30, 2018 would have been approximately $377 million. Therefore, our ratio of earnings to fixed charges would have been 1.1.

(c) The year ended December 31, 2017 amount includes unusual and infrequent items consisting of $78 million of non-cash derivative losses on outstanding hedges, $21 million of gains from asset divestitures, $4 million of net gains on the early extinguishment of debt and $26 million of other unusual, out-of-period and infrequent charges. Excluding these items, our earnings before fixed charges for the year ended December 31, 2017 would have been approximately $160 million. Therefore, the insufficient coverage would have been approximately $190 million.

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, $28 million of debt issuance costs and $11 million of rig termination and other costs, partially offset by $52 million of non-cash derivative gains and $20 million of net gains on the early extinguishment of debt. 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 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.

(d) Excludes $58 million of amortization of deferred gains for the nine months ended September 30, 2018.

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 1, 2018

/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 1, 2018

/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, 2018, as filed with the Securities and Exchange Commission on November 1, 2018 (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 1, 2018

/s/ Marshall D. Smith

Name:	Marshall D. Smith
Title:	Senior Executive Vice President and Chief Financial Officer
Date:	November 1, 2018

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.