

UNITED STATES
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, 2019
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
(State or other jurisdiction of
incorporation or organization)

46-5670947
(I.R.S. Employer
Identification No.)

27200 Tourney Road
Suite 200
Santa Clarita
California
(Address of principal executive offices)

91355
(Zip Code)

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

Securities registered pursuant to Section 12(b) of the Exchange Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock	CRC	New York Stock Exchange

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 (§232.405 of this chapter) 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, a smaller reporting company, or an emerging growth company. See the definitions 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, 2019

49,118,451

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, 2019 and December 31, 2018
(in millions, except share data)

	September 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash	\$ 22	\$ 17
Trade receivables	248	299
Inventories	66	69
Other current assets, net	174	255
Total current assets	510	640
PROPERTY, PLANT AND EQUIPMENT	22,828	22,523
Accumulated depreciation, depletion and amortization	(16,425)	(16,068)
Total property, plant and equipment, net	6,403	6,455
OTHER ASSETS	122	63
TOTAL ASSETS	<u>\$ 7,035</u>	<u>\$ 7,158</u>
CURRENT LIABILITIES		
Current maturities of long-term debt	100	—
Accounts payable	316	390
Accrued liabilities	305	217
Total current liabilities	721	607
LONG-TERM DEBT	4,896	5,251
DEFERRED GAIN AND ISSUANCE COSTS, NET	158	216
OTHER LONG-TERM LIABILITIES	679	575
MEZZANINE EQUITY		
Redeemable noncontrolling interests	789	756
EQUITY		
Preferred stock (20 million shares authorized at \$0.01 par value) no shares outstanding at September 30, 2019 and December 31, 2018	—	—
Common stock (200 million shares authorized at \$0.01 par value) outstanding shares (September 30, 2019 - 49,118,451 and December 31, 2018 - 48,650,420)	—	—
Additional paid-in capital	5,000	4,987
Accumulated deficit	(5,303)	(5,342)
Accumulated other comprehensive loss	(5)	(6)
Total equity attributable to common stock	(308)	(361)
Equity attributable to noncontrolling interests	100	114
Total equity	(208)	(247)
TOTAL LIABILITIES AND EQUITY	<u>\$ 7,035</u>	<u>\$ 7,158</u>

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, 2019 and 2018
(in millions, except share data)

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
REVENUES AND OTHER				
Oil and gas sales	\$ 541	\$ 700	\$ 1,720	\$ 1,932
Net derivative gain (loss) from commodity contracts	37	(54)	(31)	(259)
Other revenue	103	182	335	313
Total revenues and other	681	828	2,024	1,986
COSTS AND OTHER				
Production costs	221	236	684	679
General and administrative expenses	66	81	228	234
Depreciation, depletion and amortization	118	128	357	372
Taxes other than on income	42	45	119	120
Exploration expense	5	4	25	18
Other expenses, net	81	149	284	259
Total costs and other	533	643	1,697	1,682
OPERATING INCOME	148	185	327	304
NON-OPERATING (LOSS) INCOME				
Interest and debt expense, net	(95)	(95)	(293)	(281)
Net gain on early extinguishment of debt	82	2	108	26
Gain on asset divestitures	—	3	—	4
Other non-operating expenses	(8)	(4)	(18)	(16)
INCOME BEFORE INCOME TAXES	127	91	124	37
Income tax	—	—	—	—
NET INCOME	127	91	124	37
NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS				
Mezzanine equity	(30)	(28)	(87)	(71)
Equity	(3)	3	2	16
Net income attributable to noncontrolling interests	(33)	(25)	(85)	(55)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	\$ 94	\$ 66	\$ 39	\$ (18)
Net income (loss) attributable to common stock per share				
Basic	\$ 1.89	\$ 1.34	\$ 0.78	\$ (0.38)
Diluted	\$ 1.89	\$ 1.32	\$ 0.77	\$ (0.38)

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, 2019 and 2018
(in millions)

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Net income	\$ 127	\$ 91	\$ 124	\$ 37
Net income attributable to noncontrolling interests	(33)	(25)	(85)	(55)
Other comprehensive income:				
Reclassification of realized losses on pension and postretirement benefits to income ^(a)	—	—	1	3
Comprehensive income (loss) attributable to common stock	<u>\$ 94</u>	<u>\$ 66</u>	<u>\$ 40</u>	<u>\$ (15)</u>

(a) No associated tax for the three and nine months ended September 30, 2019 and 2018. See *Note 10 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, 2019 and 2018
(in millions)

	Nine months ended September 30,	
	2019	2018
CASH FLOW FROM OPERATING ACTIVITIES		
Net income	\$ 124	\$ 37
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	357	372
Net derivative loss from commodity contracts	31	259
Net proceeds (payments) on settled commodity derivatives	68	(178)
Net gain on early extinguishment of debt	(108)	(26)
Amortization of deferred gain	(54)	(58)
Gain on asset divestiture	—	(4)
Other non-cash charges to income, net	60	78
Dry hole expenses	7	4
Changes in operating assets and liabilities, net	55	(91)
Net cash provided by operating activities	540	393
CASH FLOW FROM INVESTING ACTIVITIES		
Capital investments	(393)	(504)
Changes in capital investment accruals	(49)	40
Asset divestitures	164	17
Acquisitions	(6)	(514)
Other	(7)	(4)
Net cash used in investing activities	(291)	(965)
CASH FLOW FROM FINANCING ACTIVITIES		
Proceeds from 2014 Revolving Credit Facility	1,749	1,822
Repayments of 2014 Revolving Credit Facility	(1,776)	(1,843)
Debt repurchases	(149)	(149)
Debt transaction costs	(2)	(4)
Contributions from noncontrolling interest holders, net	49	796
Distributions paid to noncontrolling interest holders	(115)	(80)
Issuance of common stock	3	52
Shares canceled for taxes	(3)	(11)
Net cash (used) provided by financing activities	(244)	583
Increase in cash	5	11
Cash—beginning of period	17	20
Cash—end of period	\$ 22	\$ 31

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 three and nine months ended September 30, 2019
(in millions)

	Three months ended September 30, 2019					
	Additional Paid-in Capital	Accumulated (Deficit) Earnings	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total Equity
Balance, June 30, 2019	\$ 4,994	\$ (5,397)	\$ (5)	\$ (408)	\$ 129	\$ (279)
Net income	—	94	—	94	3	97
Distributions to noncontrolling interest holders	—	—	—	—	(32)	(32)
Warrant	2	—	—	2	—	2
Share-based compensation, net	4	—	—	4	—	4
Balance, September 30, 2019	<u>\$ 5,000</u>	<u>\$ (5,303)</u>	<u>\$ (5)</u>	<u>\$ (308)</u>	<u>\$ 100</u>	<u>\$ (208)</u>
	Nine months ended September 30, 2019					
	Additional Paid-in Capital	Accumulated (Deficit) Earnings	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total Equity
Balance, December 31, 2018	\$ 4,987	\$ (5,342)	\$ (6)	\$ (361)	\$ 114	\$ (247)
Net income (loss)	—	39	—	39	(2)	37
Contribution from noncontrolling interest holders, net	—	—	—	—	49	49
Distributions to noncontrolling interest holders	—	—	—	—	(61)	(61)
Other comprehensive income	—	—	1	1	—	1
Warrant	2	—	—	2	—	2
Share-based compensation, net	11	—	—	11	—	11
Balance, September 30, 2019	<u>\$ 5,000</u>	<u>\$ (5,303)</u>	<u>\$ (5)</u>	<u>\$ (308)</u>	<u>\$ 100</u>	<u>\$ (208)</u>

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 three and nine months ended September 30, 2018
(in millions)

	Three months ended September 30, 2018					
	Additional Paid-in Capital	Accumulated (Deficit) Earnings	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total Equity
Balance, June 30, 2018	\$ 4,985	\$ (5,754)	\$ (20)	\$ (789)	\$ 144	\$ (645)
Net income (loss)	—	66	—	66	(3)	63
Distributions to noncontrolling interest holders	—	—	—	—	(21)	(21)
Share-based compensation, net	(2)	—	—	(2)	—	(2)
Balance, September 30, 2018	<u>\$ 4,983</u>	<u>\$ (5,688)</u>	<u>\$ (20)</u>	<u>\$ (725)</u>	<u>\$ 120</u>	<u>\$ (605)</u>

	Nine months ended September 30, 2018					
	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total Equity
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 to noncontrolling interest holders	—	—	—	—	(40)	(40)
Issuance of common stock	101	—	—	101	—	101
Other comprehensive income	—	—	3	3	—	3
Share-based compensation, net	3	—	—	3	—	3
Balance, September 30, 2018	<u>\$ 4,983</u>	<u>\$ (5,688)</u>	<u>\$ (20)</u>	<u>\$ (725)</u>	<u>\$ 120</u>	<u>\$ (605)</u>

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Notes to the Condensed Consolidated Financial Statements
September 30, 2019

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 exclusively within California. We were incorporated in Delaware as a wholly owned subsidiary of Occidental Petroleum Corporation (Occidental) on April 23, 2014, and we became an independent, 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.

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, 2019 and December 31, 2018 and the statements of operations, comprehensive income, cash flows and equity for the three and nine months ended September 30, 2019 and 2018, as applicable. We have eliminated all significant intercompany transactions and accounts. We account for our share of oil and gas exploration and development 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 condensed consolidated balance sheets, statements of operations, equity and cash flows.

We have prepared this report in accordance with generally accepted accounting principles in the United States (U.S.) and the rules and regulations of the U.S. Securities and Exchange Commission 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, 2018.

NOTE 2 ACCOUNTING AND DISCLOSURE CHANGES

Recently Adopted Accounting and Disclosure Changes

We adopted the Financial Accounting Standards Board's new lease accounting rules (ASC 842), as of January 1, 2019, using the modified retrospective approach where the new lease standard is not applied to prior comparative periods, which continue to be presented under accounting standards in effect for those prior periods. Under the modified retrospective approach, we recognized right-of-use (ROU) assets and lease liabilities of \$66 million as of the adoption date. The adoption of the new lease accounting rules did not materially impact our consolidated results of operations and had no impact on cash flows or beginning retained earnings. The new lease standard does not affect our liquidity and has no impact on our debt-covenant calculations under our 2014 Revolving Credit Facility, 2016 Credit Agreement and 2017 Credit Agreement. See *Note 12 Leases* for more information.

NOTE 3 OTHER INFORMATION

Cash at September 30, 2019 and December 31, 2018 included \$2 million for each period which was restricted for capital investments and distributions to a joint venture (JV) partner.

Other current assets, net as of September 30, 2019 and December 31, 2018 consisted of the following:

	September 30, 2019	December 31, 2018
	(in millions)	
Derivative assets	\$ 97	\$ 168
Amounts due from joint interest partners	59	68
Prepaid expenses	18	16
Other	—	3
Other current assets, net	<u>\$ 174</u>	<u>\$ 255</u>

Accrued liabilities as of September 30, 2019 and December 31, 2018 consisted of the following:

	September 30, 2019	December 31, 2018
	(in millions)	
Accrued employee-related costs	\$ 93	\$ 109
Accrued taxes other than on income	57	38
Accrued interest	49	15
Lease liability	39	—
Asset retirement obligation	31	31
Other	36	24
Accrued liabilities	<u>\$ 305</u>	<u>\$ 217</u>

Other long-term liabilities included asset retirement obligations of \$480 million and \$402 million at September 30, 2019 and December 31, 2018, 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, 2019 and 2018. Interest paid, net of capitalized amounts, totaled \$290 million and \$278 million for the nine months ended September 30, 2019 and 2018, respectively.

Non-cash financing activities for the nine months ended September 30, 2019 included the first tranche of a warrant to purchase 0.2 million shares of our common stock (valued at \$2 million) issued in connection with a development joint venture. See *Note 14 Recent Transactions* and *Note 15 Equity* for more information. Non-cash financing activities for the nine months ended September 30, 2018 included 2.85 million shares of common stock (valued at \$51 million) issued in connection with an acquisition.

NOTE 4 INVENTORIES

Inventories as of September 30, 2019 and December 31, 2018 consisted of the following:

	September 30, 2019	December 31, 2018
	(in millions)	
Materials and supplies	\$ 64	\$ 65
Finished goods	2	4
Total	<u>\$ 66</u>	<u>\$ 69</u>

NOTE 5 DEBT

As of September 30, 2019 and December 31, 2018, our long-term debt consisted of the following credit agreements, Second Lien Notes and Senior Notes:

	Outstanding Principal		Interest Rate	Maturity	Security
	September 30, 2019	December 31, 2018			
Credit Agreements	(in millions)				
2014 Revolving Credit Facility	\$ 514	\$ 540	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	1,838	2,067	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	144	6%	November 15, 2024	Unsecured
Total Debt	4,996	5,251			
Less: Current Maturities	(100)	—			
Long-Term Debt	<u>\$ 4,896</u>	<u>\$ 5,251</u>			

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, 2018.

(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 \$290 million in June 2021, \$58 million in December 2021, \$61 million in June 2022 and \$1,429 million in December 2022.

Deferred Gain and Issuance Costs

As of September 30, 2019, net deferred gain and issuance costs were \$158 million, consisting of \$230 million of a deferred gain offset by \$72 million of deferred issuance costs and original issue discounts. The December 31, 2018 net deferred gain and issuance costs were \$216 million, consisting of \$313 million of a deferred gain offset by \$97 million of deferred issuance costs and original issue discounts.

2014 Revolving Credit Facility

As of September 30, 2019, we had \$320 million of available borrowing capacity under our \$1 billion revolving credit facility (2014 Revolving Credit Facility), before a \$150 million month-end minimum liquidity requirement. Effective November 1, 2019, the borrowing base under this facility was reaffirmed at \$2.3 billion. Our 2014 Revolving Credit Facility also includes a sub-limit of \$400 million for the issuance of letters of credit. As of September 30, 2019 and December 31, 2018, we had letters of credit outstanding of \$166 million and \$162 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

In August 2019, we entered into a ninth amendment to our 2014 Revolving Credit Facility to provide us with flexibility in connection with potential royalty transactions.

Note Repurchases

In the third quarter of 2019, we repurchased \$153 million in face value of our 8% senior secured second lien notes due December 15, 2022 (Second Lien Notes) for \$90 million in cash resulting in a pre-tax gain of \$82 million, including the effect of unamortized deferred gain and issuance costs. In the nine months ended September 30, 2019, we repurchased approximately \$229 million in face value of our Second Lien Notes for \$149 million in cash resulting in a pre-tax gain of \$108 million, including the effect of unamortized deferred gain and 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, 2019 and December 31, 2018, including the fair value of the variable-rate portion, was \$3.9 billion and \$4.5 billion, respectively, compared to a carrying value of \$5.0 billion and \$5.3 billion, respectively.

Other

At September 30, 2019, 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.

NOTE 6 NONCONTROLLING INTERESTS

The following table presents the changes in noncontrolling interests for our consolidated JVs, which is reported in equity and mezzanine equity on the condensed consolidated balance sheets for the nine months ended September 30, 2019 and 2018:

	Equity Attributable to Noncontrolling Interest			Mezzanine Equity - Redeemable Noncontrolling Interests
	Ares JV	BSP JV	Total	Ares JV
	(in millions)			
Balance, December 31, 2018	\$ 15	\$ 99	\$ 114	\$ 756
Net (loss) income attributable to noncontrolling interests	(9)	7	(2)	87
Contributions from noncontrolling interest holders, net	—	49	49	—
Distributions to noncontrolling interest holders	(6)	(55)	(61)	(54)
Balance, September 30, 2019	<u>\$ —</u>	<u>\$ 100</u>	<u>\$ 100</u>	<u>\$ 789</u>
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	<u>\$ 20</u>	<u>\$ 100</u>	<u>\$ 120</u>	<u>\$ 745</u>

Ares JV

Our condensed consolidated statements of operations reflect the operations of our midstream JV with ECR Corporate Holdings L.P. (ECR), a portfolio company of Ares, with ECR's share of net income (loss) reported in net income attributable to noncontrolling interests. ECR's redeemable noncontrolling interests are reported in mezzanine equity due to an embedded optional redemption feature.

BSP JV

Our condensed consolidated results reflect the operations of our development JV with BSP, with BSP's preferred interest reported in equity on our condensed consolidated balance sheets and BSP's share of net income (loss) being reported in net income attributable to noncontrolling interests in our condensed consolidated statements of operations.

NOTE 7 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

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

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at September 30, 2019 and December 31, 2018 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued would not be material to our consolidated financial position or results of operations.

NOTE 8 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 and interest-rate movements. 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 did not have any derivative instruments designated as accounting hedges as of and during the three and nine months ended September 30, 2019 and 2018. 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 accounting hedges.

Commodity Price Risk

We held the following Brent-based crude oil contracts as of September 30, 2019:

	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Purchased Puts:					
Barrels per day	35,000	30,000	15,000	10,000	5,000
Weighted-average price per barrel	\$ 75.71	\$ 70.83	\$ 68.33	\$ 65.00	\$ 65.00
Sold Puts:					
Barrels per day	35,000	30,000	15,000	10,000	5,000
Weighted-average price per barrel	\$ 60.00	\$ 56.67	\$ 55.00	\$ 55.00	\$ 55.00
Swaps:					
Barrels per day	—	—	5,000 ^(a)	—	—
Weighted-average price per barrel	\$ —	\$ —	\$ 70.05	\$ —	\$ —

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

The BSP JV entered into crude oil derivatives and natural gas swaps for insignificant volumes through 2021 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 BSP's noncontrolling interest.

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. 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 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 the relationship between our existing positions, 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, 2019 and December 31, 2018 (in millions):

September 30, 2019			
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, net	\$ 132	\$ (35)	\$ 97
Other assets	8	(3)	5
Liabilities:			
Accrued liabilities	(36)	35	(1)
Other long-term liabilities	(3)	3	—
Total derivatives	<u>\$ 101</u>	<u>\$ —</u>	<u>\$ 101</u>
December 31, 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, net	\$ 252	\$ (84)	\$ 168
Other assets	23	(9)	14
Liabilities:			
Accrued liabilities	(87)	84	(3)
Other long-term liabilities	(10)	9	(1)
Total derivatives	<u>\$ 178</u>	<u>\$ —</u>	<u>\$ 178</u>

Interest-Rate Contracts

The fair values of our interest-rate derivatives and the impact of the changes in those values on our condensed consolidated statements of operations were immaterial for all periods presented.

NOTE 9 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, 2019 and 2018:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
(in millions, except per-share amounts)				
Net income	\$ 127	\$ 91	\$ 124	\$ 37
Net income attributable to noncontrolling interests	(33)	(25)	(85)	(55)
Net income (loss) attributable to common stock	94	66	39	(18)
Less: net income allocated to participating securities	(1)	(1)	(1)	—
Net income (loss) available to common stockholders	\$ 93	\$ 65	\$ 38	\$ (18)
Weighted-average common shares outstanding — basic	49.1	48.5	48.9	47
Basic EPS	\$ 1.89	\$ 1.34	\$ 0.78	\$ (0.38)
Net income	\$ 127	\$ 91	\$ 124	\$ 37
Net income attributable to noncontrolling interests	(33)	(25)	(85)	(55)
Net income (loss) attributable to common stock	94	66	39	(18)
Less: net income allocated to participating securities	(1)	(1)	(1)	—
Net income (loss) available to common stockholders	\$ 93	\$ 65	\$ 38	\$ (18)
Weighted-average common shares outstanding — basic	49.1	48.5	48.9	47
Dilutive effect of potentially dilutive securities	0.1	0.6	0.3	—
Weighted-average common shares outstanding — diluted	49.2	49.1	49.2	47
Diluted EPS	\$ 1.89	\$ 1.32	\$ 0.77	\$ (0.38)
Weighted-average anti-dilutive shares	3.2	1.1	2.3	2.8

NOTE 10 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 for the three and nine months ended September 30, 2019 and 2018:

	Three months ended September 30,			
	2019		2018	
	Pension Benefit	Postretirement Benefit	Pension Benefit	Postretirement Benefit
(in millions)				
Service cost	\$ —	\$ 1	\$ —	\$ 1
Interest cost	—	1	—	1
Expected return on plan assets	(1)	—	(1)	—
Recognized actuarial loss	1	—	1	—
Settlement loss	—	—	—	—
Total	\$ —	\$ 2	\$ —	\$ 2
	Nine months ended September 30,			
	2019		2018	
	Pension Benefit	Postretirement Benefit	Pension Benefit	Postretirement Benefit
(in millions)				
Service cost	\$ 1	\$ 3	\$ 1	\$ 3
Interest cost	2	3	1	3
Expected return on plan assets	(2)	—	(2)	—
Recognized actuarial loss	1	—	1	—
Settlement loss	1	—	4	—
Total	\$ 3	\$ 6	\$ 5	\$ 6

We contributed \$1 million and \$6 million to our defined benefit pension plans in each of the three months ended September 30, 2019 and 2018, respectively. We contributed \$2 million and \$8 million in the nine months ended September 30, 2019 and 2018, respectively. We do not expect to make any additional contributions to our defined benefit pension plans during the remainder of 2019. The 2019 and 2018 settlement losses, which were reclassified from accumulated other comprehensive income, were associated with early retirements.

NOTE 11 REVENUE RECOGNITION

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. Transportation and processing fees incurred by us prior to control being transferred to customers are recorded 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 delivery of the product.

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 (PPA) expiring in December 2023, which includes a fixed capacity payment and a variable monthly charge based on usage. Revenue is recognized when obligations under the terms of contracts with our customers 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. Payments under our PPA 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. In addition, we may from time-to-time enter into natural gas purchase and sale agreements with third parties to take advantage of market dislocations. We consider our performance obligations to be satisfied upon transfer of control of the commodity.

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, 2019 and 2018:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Oil and gas sales:				
Oil	\$ 457	\$ 568	\$ 1,433	\$ 1,587
NGLs	34	71	132	195
Natural gas	50	61	155	150
	541	700	1,720	1,932
Other revenue:				
Electricity	38	42	88	87
Marketing, trading and other	65	140	247	225
Interest income	—	—	—	1
	103	182	335	313
Net derivative gain (loss) from commodity contracts	37	(54)	(31)	(259)
Total revenues and other	\$ 681	\$ 828	\$ 2,024	\$ 1,986

NOTE 12 LEASES

On January 1, 2019, we adopted ASC 842 using the modified retrospective approach that requires us to determine our lease balances as of the date of adoption. Prior periods continue to be reported under accounting standards in effect for those periods. We also elected to carry forward our accounting treatment for land easements on existing agreements. Mineral leases, including oil and natural gas leases, are not included in the scope of ASC 842.

We have long-term operating leases for commercial office space, drilling rigs, fleet vehicles and certain facilities. In considering whether a contract contains a lease, we first considered whether there was an identifiable asset and then considered how and for what purpose the asset would be used over the contract term.

Our lease liability was determined by measuring the present value of the remaining fixed minimum lease payments as of the date of adoption discounted using our incremental borrowing rate (IBR). In determining our IBR, we considered the average cost of borrowing for publicly traded corporate bond yields, which were adjusted to reflect our credit rating, remaining lease term and frequency of payments.

We elected to combine lease and non-lease components in determining fixed minimum lease payments for our drilling rigs and commercial office space. If applicable, fixed minimum lease payments were reduced by lease incentives for our commercial buildings and increased by mobilization and demobilization fees related to our drilling rigs. Certain of our lease agreements include options to renew, which we exercise at our sole discretion, and we did not include these options in determining our fixed minimum lease payments over the lease term. Our lease liability does not include options to extend or terminate our leases. Our leases do not include options to purchase the leased property. Lease agreements for our fleet vehicles include residual value guarantees, none of which are recognized in our financial statements until the underlying contingency is resolved.

For all of our asset classes, we elected to keep leases with an initial term of 12 months or less off the balance sheet and have included costs related to these contracts in our short-term lease cost disclosure below. Contracts with terms of one month or less are excluded from our disclosure of short-term lease costs.

For our long-term contracts, variable lease costs were not included in the measurement of our lease balances. Variable lease costs for our drilling rigs included costs to operate, move and repair the rigs. Variable lease costs for certain of our commercial office buildings included utilities and common area maintenance charges. Variable lease costs for our fleet vehicles included other-than-routine maintenance and other various amounts in excess of our fixed minimum rental fee.

Our operating lease costs, including amounts capitalized to property, plant and equipment, for the three and nine months ended September 30, 2019 were as follows:

	Three months ended September 30, 2019	Nine months ended September 30, 2019
	(in millions)	
Operating lease cost	\$ 14	\$ 40
Short-term lease cost	18	56
Variable lease cost	6	15
Total operating lease costs	<u>\$ 38</u>	<u>\$ 111</u>

During the second quarter of 2019, we entered into contracts treated as finance leases, which were not material to our condensed consolidated results of operations.

We sublease certain commercial office space to third parties where we are the primary obligor under the head lease. The lease terms on those subleases never extend past the term of the head lease and the subleases contain no extension options or residual value guarantees. Sublease income is recognized based on the contract terms and included as a reduction of operating lease cost under our head lease. For the three and nine months ended September 30, 2019, sublease income was not material to our condensed consolidated financial statements.

Cash flow related to our operating leases for the three and nine months ended September 30, 2019 were as follows:

	Three months ended September 30, 2019	Nine months ended September 30, 2019
	(in millions)	
Operating cash flows	\$ 4	\$ 9
Investing cash flows	\$ 11	\$ 32

Our cash flows from finance leases were not significant for the three and nine months ended September 30, 2019.

Other information related to our operating and finance leases as of September 30, 2019 was as follows:

	September 30, 2019
Operating Leases	
ROU asset obtained in exchange for lease obligations (in millions)	\$ 81
Weighted-average remaining lease term (in years)	2.87
Weighted-average discount rate	11.4%
Finance Leases	
ROU asset obtained in exchange for lease obligations (in millions)	\$ 2
Weighted-average remaining lease term (in years)	2.58
Weighted-average discount rate	8.5%

Balance sheet information related to our operating and finance leases as of September 30, 2019 was as follows:

	Balance Sheet Location	September 30, 2019
		(in millions)
Assets		
Operating lease, net	Other assets	\$ 66
Finance lease, net	PP&E	1
Total lease assets		<u>\$ 67</u>
Liabilities		
Current		
Operating lease	Accrued liabilities	\$ 38
Finance lease	Accrued liabilities	1
Long-term		
Operating lease	Other long-term liabilities	30
Finance lease	Other long-term liabilities	1
Total lease liabilities		<u>\$ 70</u>

As part of our company-wide consolidation of office space, we are vacating certain office space in 2019, some of which we may sublease. If we enter into a sublease agreement, we will evaluate the carrying value of our ROU asset, along with the carrying value of related tenant improvements, for impairment based on future identifiable cash flows. For the three months ended September 30, 2019, we did not recognize material impairment charges. For the nine months ended September 30, 2019, we recognized impairment charges of \$3 million. We may terminate leases for vacated office space before the expiration of the lease term. Where we have decided to not sublease vacated commercial office space, we will shorten the useful life of the ROU assets and related tenant improvements to recover our remaining costs over our expected period of use. Once the leased office space is abandoned, lease costs will be classified as other non-operating expenses on our condensed consolidated statements of operations.

Maturities of our operating and finance lease liabilities at September 30, 2019 are as follows:

	Operating Leases	Finance Leases
	(in millions)	
2019	\$ 19	\$ —
2020	34	1
2021	10	1
2022	7	—
2023	6	—
Thereafter	9	—
Less: Interest	(17)	—
Present value of lease liabilities	<u>\$ 68</u>	<u>\$ 2</u>

We have entered into contracts for commercial office space and facilities that are under construction as of September 30, 2019. These leases are not included in our lease population at September 30, 2019 as the lease terms have not commenced because we do not control the assets during construction. We will apply the new lease standard when the asset is placed in service by us, which is expected to be in January and June 2020. Payments for these contracts were included in the table of our future minimum lease payments as of December 31, 2018, which is shown below.

At December 31, 2018, future minimum lease payments for noncancelable operating leases under ASC 840 (excluding oil and natural gas and other mineral leases, utilities, taxes, insurance and common area maintenance expenses) were:

	December 31, 2018
	(in millions)
2019	\$ 12
2020	8
2021	7
2022	7
2023	6
Thereafter	28
Total	\$ 68

Rent expense for operating leases under ASC 840 was \$3 million and \$9 million for the three and nine months ended September 30, 2018, respectively. Rental income from subleases for the three and nine months ended September 30, 2018 was not significant.

NOTE 13 INCOME TAXES

For the nine months ended September 30, 2019 and 2018, 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 can achieve.

NOTE 14 RECENT EVENTS

Asset Divestiture

On May 1, 2019, we sold 50% of our working interest and transferred operatorship in certain zones within our Lost Hills field, located in the San Joaquin basin, for total consideration in excess of \$200 million, consisting of approximately \$168 million and a carried 200-well development program to be drilled through 2023 with an estimated value of \$35 million (Lost Hills divestiture). We received cash proceeds of \$165 million after transaction costs and purchase price adjustments, which were used to pay down our 2014 Revolving Credit Facility. The partial sale of proved property was accounted for as a normal retirement with no gain or loss recognized. The partial sale of unproved property was recorded as a recovery of cost.

Development Joint Venture

In July 2019, we entered into a development agreement with Alpine Energy Capital, LLC (Alpine) to develop portions of our Elk Hills field (Alpine JV). Alpine is a joint venture between subsidiaries of Colony Capital, Inc. (Colony) and Equity Group Investments. Alpine committed to invest \$320 million, which may be increased to a total investment of \$500 million, subject to the mutual agreement of the parties. The initial commitment will cover multiple development opportunities and is intended to be invested over approximately three years in accordance with a 275-well development plan. Alpine will fund 100% of the development wells and will earn a 90% working interest in those wells. If Alpine receives an agreed upon return, our working interest in those wells will increase from 10% to 82.5%. Our financial statements reflect only our working interest share in the developed wells.

See *Note 15 Equity* for information regarding a warrant issued to Colony in connection with this JV.

Organizational Changes

We have implemented organizational and operational efficiencies that resulted in a recent reduction in our headcount to approximately 1,250 employees. We expect to incur a charge in the range of \$35 million to \$40 million in the fourth quarter of 2019, which will be recorded in other non-operating expenses on the consolidated statement of operations.

NOTE 15 EQUITY

In connection with our Alpine JV, Colony received a warrant to purchase up to 1.25 million shares of our common stock at an exercise price of \$40 per share. Colony may exercise the warrant in tranches as funding milestones are met. Each tranche will have a five-year term commencing on the date on which such tranche becomes exercisable. Colony may elect, in its sole discretion, to pay cash or to exercise on a cashless basis, pursuant to which Colony will not be required to pay cash for shares of common stock upon exercise of the warrant but will instead receive fewer shares.

The fair value of the first tranche of 0.2 million shares was approximately \$2 million on the grant date using the Black-Scholes pricing model based on the assumptions below:

Volatility	85.00%
Risk-free interest rate	1.80%
Dividend yield	—%
Expected term (in years)	5.19
Fair value of underlying common stock	\$ 14.94

The first tranche was initially measured at fair value and will not be subsequently remeasured. The warrant was classified as additional paid-in-capital in equity on the condensed consolidated balance sheet as of September 30, 2019. The first tranche was not exercisable as of September 30, 2019.

NOTE 16 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, 2019 and December 31, 2018 and the condensed consolidating statements of operations and statements of cash flows for the three and nine months ended September 30, 2019 and 2018, 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 the Company 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
As of September 30, 2019 and December 31, 2018
(in millions)

As of September 30, 2019					
	Parent	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
Total current assets	\$ 6	\$ 453	\$ 62	\$ (11)	\$ 510
Total property, plant and equipment, net	26	5,889	488	—	6,403
Investments in consolidated subsidiaries	5,850	204	—	(6,054)	—
Other assets	2	90	30	—	122
TOTAL ASSETS	\$ 5,884	\$ 6,636	\$ 580	\$ (6,065)	\$ 7,035
Total current liabilities	259	464	9	(11)	721
Long-term debt	4,896	—	—	—	4,896
Deferred gain and issuance costs, net	158	—	—	—	158
Other long-term liabilities	137	538	4	—	679
Amounts due to (from) affiliates	742	(743)	1	—	—
Mezzanine equity	—	—	789	—	789
Total equity	(308)	6,377	(223)	(6,054)	(208)
TOTAL LIABILITIES AND EQUITY	\$ 5,884	\$ 6,636	\$ 580	\$ (6,065)	\$ 7,035
As of December 31, 2018					
	Parent	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
Total current assets	\$ 7	\$ 590	\$ 56	\$ (13)	\$ 640
Total property, plant and equipment, net	23	5,913	519	—	6,455
Investments in consolidated subsidiaries	5,440	96	—	(5,536)	—
Other assets	4	32	27	—	63
TOTAL ASSETS	\$ 5,474	\$ 6,631	\$ 602	\$ (5,549)	\$ 7,158
Total current liabilities	143	465	12	(13)	607
Long-term debt	5,251	—	—	—	5,251
Deferred gain and issuance costs, net	216	—	—	—	216
Other long-term liabilities	140	431	4	—	575
Amounts due to (from) affiliates	85	(86)	1	—	—
Mezzanine equity	—	—	756	—	756
Total equity	(361)	5,821	(171)	(5,536)	(247)
TOTAL LIABILITIES AND EQUITY	\$ 5,474	\$ 6,631	\$ 602	\$ (5,549)	\$ 7,158

Condensed Consolidating Statements of Operations
For the three and nine months ended September 30, 2019 and 2018

(in millions)

For the three months ended September 30, 2019					
	Parent	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues and other	\$ —	\$ 624	\$ 130	\$ (73)	\$ 681
Total costs and other	43	502	61	(73)	533
Non-operating (loss) income	(25)	4	—	—	(21)
NET (LOSS) INCOME	(68)	126	69	—	127
Net income attributable to noncontrolling interests	—	—	(33)	—	(33)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	<u>\$ (68)</u>	<u>\$ 126</u>	<u>\$ 36</u>	<u>\$ —</u>	<u>\$ 94</u>

For the three months ended September 30, 2018					
	Parent	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
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 (LOSS) INCOME	(161)	189	63	—	91
Net income attributable to noncontrolling interest	—	—	(25)	—	(25)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	<u>\$ (161)</u>	<u>\$ 189</u>	<u>\$ 38</u>	<u>\$ —</u>	<u>\$ 66</u>

For the nine months ended September 30, 2019					
	Parent	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues and other	\$ —	\$ 1,878	\$ 366	\$ (220)	\$ 2,024
Total costs and other	150	1,574	193	(220)	1,697
Non-operating (loss) income	(211)	8	—	—	(203)
NET INCOME (LOSS)	(361)	312	173	—	124
Net income attributable to noncontrolling interests	—	—	(85)	—	(85)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	<u>\$ (361)</u>	<u>\$ 312</u>	<u>\$ 88</u>	<u>\$ —</u>	<u>\$ 39</u>

For the nine months ended September 30, 2018					
	Parent	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
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 (LOSS) INCOME	(440)	341	136	—	37
Net income attributable to noncontrolling interest	—	—	(55)	—	(55)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	<u>\$ (440)</u>	<u>\$ 341</u>	<u>\$ 81</u>	<u>\$ —</u>	<u>\$ (18)</u>

Condensed Consolidating Statements of Cash Flows
For the nine months ended September 30, 2019 and 2018

(in millions)

For the nine months ended September 30, 2019					
	Parent	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
Net cash (used) provided by operating activities	\$ (470)	\$ 649	\$ 361	\$ —	\$ 540
Net cash used in investing activities	(9)	(271)	(11)	—	(291)
Net cash provided (used) by financing activities	479	(373)	(350)	—	(244)
Increase in cash	—	5	—	—	5
Cash—beginning of period	—	7	10	—	17
Cash—end of period	\$ —	\$ 12	\$ 10	\$ —	\$ 22

For the nine months ended September 30, 2018					
	Parent	Combined Guarantor Subsidiaries	Combined Non- Guarantor Subsidiaries	Eliminations	Consolidated
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
(Decrease) increase in cash	(7)	2	16	—	11
Cash—beginning of period	7	8	5	—	20
Cash—end of period	\$ —	\$ 10	\$ 21	\$ —	\$ 31

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 exclusively 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.

The following table presents the average daily Brent, WTI and NYMEX prices for the three and nine months ended September 30, 2019 and 2018:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Brent oil (\$/Bbl)	\$ 62.00	\$ 75.97	\$ 64.74	\$ 72.68
WTI oil (\$/Bbl)	\$ 56.45	\$ 69.50	\$ 57.06	\$ 66.75
NYMEX gas (\$/MMBtu)	\$ 2.27	\$ 2.88	\$ 2.72	\$ 2.83

Note: Bbl refers to a barrel; MMBtu refers to one million British Thermal Units.

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 73% of the oil consumed in 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.

Natural gas liquid (NGL) price realizations 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 and the availability of transportation capacity from producing areas. Transportation capacity influences prices because California imports more than 90% of its natural gas from other states and Canada. As a result, we typically enjoy favorable pricing relative to out-of-state producers due to lower transportation costs on the delivery of our gas. Changes in natural gas prices have a smaller impact on our operating results than changes in oil prices as only approximately 25% of our total equivalent production volume and even a smaller percentage of our revenue is from natural gas.

In addition to selling natural gas, we also use natural 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 of our steamflood projects and power generation, but higher prices still have a net positive effect on our operating results due to higher revenue. Conversely, lower natural gas prices lower the operating costs but have a net negative effect on our results.

Our earnings are also affected by the performance of our complementary 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 certain nearby fields and to increase reliability. The remaining electricity is sold to the wholesale power market and a utility under a power purchase and sales agreement expiring in December 2023, which includes a capacity payment. The prices obtained for excess power impact our earnings but generally by an insignificant amount.

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. We have built our commodity hedge positions to protect our downside risk without significantly limiting our upside potential, but 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 while continuing to identify efficiencies and cost savings. Volatility in oil prices may materially affect the quantities of oil and gas reserves we can economically produce over the longer term.

Operations

We conduct our operations on properties that we hold through fee interests, mineral leases and other contractual arrangements. We are the largest private oil and natural gas mineral acreage holder in California, with interests in 2.2 million net mineral acres, approximately 60% of which is held in fee and over 15% is held by production. Our oil and gas leases have primary terms ranging from one to ten years. Once production commences, the leases are extended through the end of their producing life. We also own or control a network of integrated infrastructure that complements our operations including gas plants, oil and gas gathering systems, power plants and other related assets. Our strategically located infrastructure helps us 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. These contracts represented approximately 15% of our net production for the quarter ended September 30, 2019.

In line with industry practice for reporting PSC-type contracts, we report 100% of operating costs under such contracts in our condensed consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, 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 equally inflates our revenue and operating costs 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 capture and storage projects, geothermal energy and reclaimed water opportunities.

Seasonality

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

Development Joint Ventures

We have a number of joint ventures (JVs) that 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 July 2019, we entered into a development agreement with Alpine Energy Capital, LLC (Alpine) to develop portions of our Elk Hills field (Alpine JV). Alpine is a joint venture between subsidiaries of Colony Capital, Inc. (Colony) and Equity Group Investments. Alpine committed to invest \$320 million, which may be increased to a total investment of \$500 million, subject to the mutual agreement of the parties. The initial commitment will cover multiple development opportunities and is intended to be invested over approximately three years in accordance with a 275-well development plan. Alpine will fund 100% of the development wells and will earn a 90% working interest in those wells. If Alpine receives an agreed upon return, our working interest in those wells will increase from 10% to 82.5%. Our financial statements reflect only our working interest share in the developed wells.

In connection with the Alpine JV, Colony received a warrant to purchase up to 1.25 million shares of our common stock at an exercise price of \$40 per share. Colony will be entitled to exercise the warrant in tranches as funding milestones are met. Each tranche will have a five-year term commencing on the date on which such tranche becomes exercisable. No tranches were exercisable as of September 30, 2019. Colony may elect, in its sole discretion, to pay cash or to exercise on a cashless basis, pursuant to which Colony will not be required to pay cash for shares of common stock upon exercise of the warrant but will instead receive fewer shares.

In our JV with Benefit Street Partners (BSP), BSP has funded an aggregate of \$200 million, of which \$49 million was funded in the nine months ended September 30, 2019.

In our JV with Macquarie Infrastructure and Real Assets Inc. (MIRA), MIRA has a total commitment of up to \$300 million in development capital. The initial agreed-upon capital program is \$140 million of which an aggregate of \$125 million has been funded to date. We expect the remaining balance of MIRA's initial commitment to be invested in the fourth quarter of 2019.

Asset Divestiture

On May 1, 2019, we sold 50% of our working interest and transferred operatorship in certain zones within our Lost Hills field, located in the San Joaquin basin, for total consideration in excess of \$200 million, consisting of \$168 million and a carried 200-well development program to be drilled through 2023 with an estimated value of \$35 million (Lost Hills divestiture). We received cash proceeds of \$165 million, after transaction costs and purchase price adjustments, which was used to pay down our 2014 Revolving Credit Facility.

Fixed and Variable Costs

Our production costs include variable costs that fluctuate with 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. 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. However, 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 minimize 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, 2019 and 2018:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Oil (MBbl/d)				
San Joaquin Basin	51	54	53	52
Los Angeles Basin	24	26	24	25
Ventura Basin	4	4	4	4
Total	79	84	81	81
NGLs (MBbl/d)				
San Joaquin Basin	16	16	15	16
Ventura Basin	—	1	1	1
Total	16	17	16	17
Natural gas (MMcf/d)				
San Joaquin Basin	162	172	163	162
Los Angeles Basin	2	1	2	1
Ventura Basin	4	6	6	7
Sacramento Basin	28	29	29	30
Total	196	208	200	200
Total Production (MBoe/d)				
	128	136	130	131

Note: MBbl/d refers to thousands of barrels per day; MMcf/d refers to millions of cubic feet per day; MBoe/d refers to thousands of barrels of oil equivalent (Boe) per day. Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

For the three months ended September 30, 2019 compared to the same period in 2018, total daily production decreased by approximately 8 MBoe/d or 6%. Over 2 MBoe/d of this decline resulted from the Lost Hills divestiture in May 2019. Without the effect of this transaction, the year-over-year decrease in total daily production would have been 4%.

For the nine months ended September 30, 2019 compared to the same period in 2018, total daily production volumes decreased by 1 MBoe/d or 1% which reflects an increase of 4 MBoe/d from the acquisition of the remaining working, surface and mineral interests in the Elk Hills unit from Chevron U.S.A., Inc. (the Elk Hills transaction), which closed in the second quarter of 2018, and a decrease of 1 MBoe/d of volumes sold in the Lost Hills divestiture in the second quarter of 2019. Without the effect of these transactions, our total daily production for the nine months ended September 30, 2019 would have been 127 MBoe/d, representing a 3% year-over-year decline.

The following tables set forth the average realized prices and price realizations as a percentage of average Brent, WTI and NYMEX for our products for the three and nine months ended September 30, 2019 and 2018:

	Three months ended September 30,			
	2019		2018	
	Price	Realization	Price	Realization
Oil (\$ per Bbl)				
Brent	\$ 62.00		\$ 75.97	
Realized price without hedge	\$ 62.85	101%	\$ 73.73	97%
Settled hedges	5.56		(10.10)	
Realized price with hedge	<u>\$ 68.41</u>	110%	<u>\$ 63.63</u>	84%
WTI	\$ 56.45		\$ 69.50	
Realized price without hedge	\$ 62.85	111%	\$ 73.73	106%
Realized price with hedge	\$ 68.41	121%	\$ 63.63	92%
NGLs (\$ per Bbl)				
Realized price (% of Brent)	\$ 23.55	38%	\$ 45.72	60%
Realized price (% of WTI)	\$ 23.55	42%	\$ 45.72	66%
Natural gas				
NYMEX (\$/MMBtu)	\$ 2.27		\$ 2.88	
Realized price without hedge (\$/Mcf)	\$ 2.73	120%	\$ 3.16	110%
Settled hedges	(0.01)		(0.04)	
Realized price with hedge (\$/Mcf)	<u>\$ 2.72</u>	120%	<u>\$ 3.12</u>	108%

	Nine months ended September 30,			
	2019		2018	
	Price	Realization	Price	Realization
Oil (\$ per Bbl)				
Brent	\$ 64.74		\$ 72.68	
Realized price without hedge	\$ 65.03	100%	\$ 71.53	98%
Settled hedges	3.13		(8.00)	
Realized price with hedge	<u>\$ 68.16</u>	105%	<u>\$ 63.53</u>	87%
WTI	\$ 57.06		\$ 66.75	
Realized price without hedge	\$ 65.03	114%	\$ 71.53	107%
Realized price with hedge	\$ 68.16	119%	\$ 63.53	95%
NGLs (\$ per Bbl)				
Realized price (% of Brent)	\$ 31.04	48%	\$ 43.71	60%
Realized price (% of WTI)	\$ 31.04	54%	\$ 43.71	65%
Natural gas				
NYMEX (\$/MMBtu)	\$ 2.72		\$ 2.83	
Realized price without hedge (\$/Mcf)	\$ 2.82	104%	\$ 2.73	96%
Settled hedges	(0.01)		(0.01)	
Realized price with hedge (\$/Mcf)	<u>\$ 2.81</u>	103%	<u>\$ 2.72</u>	96%

Brent prices were lower in both the three and nine months ended September 30, 2019 compared to the same prior-year periods. However, favorable hedge settlements in 2019 compared to hedge payments made in 2018, along with higher realizations, resulted in a higher 2019 Brent realized price with hedge settlements for both periods.

Prices for NGLs decreased significantly from the prior-year periods. In 2019, realized NGL prices declined as local and national markets experienced excess supply from Canadian imports coupled with weaker demand.

On average, our natural gas realized prices were lower in the three months ended September 30, 2019 than the comparable period of 2018. The decrease was due to milder temperatures and more pipeline availability within local California markets in 2019 as compared to 2018. Our natural gas realized prices were higher in the nine months ended September 30, 2019 than the comparable period of 2018 largely due to stronger California demand.

Balance Sheet Analysis

The changes in our balance sheet between September 30, 2019 and December 31, 2018 are discussed below:

	September 30, 2019	December 31, 2018
	(in millions)	
Cash	\$ 22	\$ 17
Trade receivables	\$ 248	\$ 299
Inventories	\$ 66	\$ 69
Other current assets, net	\$ 174	\$ 255
Property, plant and equipment, net	\$ 6,403	\$ 6,455
Other assets	\$ 122	\$ 63
Current maturities of long-term debt	\$ 100	\$ —
Accounts payable	\$ 316	\$ 390
Accrued liabilities	\$ 305	\$ 217
Long-term debt	\$ 4,896	\$ 5,251
Deferred gain and issuance costs, net	\$ 158	\$ 216
Other long-term liabilities	\$ 679	\$ 575
Mezzanine equity	\$ 789	\$ 756
Equity attributable to common stock	\$ (308)	\$ (361)
Equity attributable to noncontrolling interests	\$ 100	\$ 114

At both September 30, 2019 and December 31, 2018, cash included approximately \$2 million that was restricted for capital investments and distributions to a JV partner. See *Liquidity and Capital Resources* for our cash flow analysis.

The decrease in trade receivables was largely driven by lower natural gas prices and lower gas trading activities in the third quarter of 2019 compared to the fourth quarter of 2018.

The decrease in other current assets, net was primarily due to decreases in the fair value of the current portion of our derivative assets and the amounts due from our joint interest partners.

The decrease in property, plant and equipment, net primarily reflected our Lost Hills divestiture and depreciation, depletion and amortization, partially offset by capital investments and changes to our asset retirement obligations (ARO) resulting from idle well regulations enacted in the first quarter of 2019.

Other assets increased primarily due to recording an asset for operating leases as a result of adopting new accounting rules on January 1, 2019. This increase was partially offset by a decrease in the fair value of our long-term derivative assets.

Current maturities of long-term debt reflected \$100 million for our 5% senior notes due in January 2020.

The reduction in accounts payable for the quarter ended September 30, 2019 reflected lower capital investments and gas trading activities, which were higher in the fourth quarter of 2018 compared to the third quarter of 2019.

The increase in accrued liabilities reflected the current portion of our operating lease liability resulting from the adoption of new lease accounting rules, higher accrued interest and property taxes due to the timing of payments. These increases were partially offset by lower accrued employee-related costs, which primarily reflected employee bonus payments in the first quarter of 2019.

The decrease in long-term debt reflected the reclassification of \$100 million of our Senior Notes to current maturities of long-term debt, repurchases of our Second Lien Notes and pay down of the 2014 Revolving Credit Facility from the proceeds of the Lost Hills divestiture in May 2019 and positive cash flow.

Other long-term liabilities reflected the increases in ARO primarily due to the new idle well regulations and long-term operating lease liabilities due to the adoption of new lease accounting rules. The annual incremental cash expenditures for ARO resulting from the new idle well regulations are not expected to be material in the foreseeable future.

Mezzanine equity reflected the carrying amount of the Class A common and Class B preferred interests held by the noncontrolling interest partner in our midstream JV.

Equity attributable to common stock increased primarily as a result of the net income for the nine months ended September 30, 2019.

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,	
	2019	2018	2019	2018
Production costs	\$ 18.82	\$ 18.92	\$ 19.32	\$ 18.98
Production costs, excluding effects of PSC-type contracts ^(a)	\$ 17.44	\$ 17.55	\$ 17.82	\$ 17.48
Field general and administrative expenses ^(b)	\$ 1.19	\$ 1.12	\$ 1.24	\$ 0.98
Field depreciation, depletion and amortization ^(b)	\$ 9.28	\$ 9.62	\$ 9.38	\$ 9.73
Field taxes other than on income ^(b)	\$ 2.73	\$ 2.97	\$ 2.60	\$ 2.68

(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 our production costs after adjusting for this difference.

(b) Excludes corporate expenses.

Consolidated Results of Operations

The following represents key operating data for our consolidated operations for the three and nine months ended September 30, 2019 and 2018:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
	(in millions)			
Oil and gas sales	\$ 541	\$ 700	\$ 1,720	\$ 1,932
Net derivative gain (loss) from commodity contracts	37	(54)	(31)	(259)
Other revenue	103	182	335	313
Production costs	(221)	(236)	(684)	(679)
General and administrative expenses	(66)	(81)	(228)	(234)
Depreciation, depletion and amortization	(118)	(128)	(357)	(372)
Taxes other than on income	(42)	(45)	(119)	(120)
Exploration expense	(5)	(4)	(25)	(18)
Other expenses, net	(81)	(149)	(284)	(259)
Interest and debt expense, net	(95)	(95)	(293)	(281)
Net gain on early extinguishment of debt	82	2	108	26
Gain on asset divestitures	—	3	—	4
Other non-operating expenses	(8)	(4)	(18)	(16)
Income before income taxes	127	91	124	37
Income tax	—	—	—	—
Net income	127	91	124	37
Net income attributable to noncontrolling interests	(33)	(25)	(85)	(55)
Net income (loss) attributable to common stock	\$ 94	\$ 66	\$ 39	\$ (18)
Adjusted net income	\$ 17	\$ 41	\$ 34	\$ 35
Adjusted EBITDAX	\$ 278	\$ 308	\$ 834	\$ 803
Effective tax rate	—%	—%	—%	—%

Three months ended September 30, 2019 vs. 2018

Oil and gas sales - Oil and gas sales, excluding the impact of settled hedges, decreased 23%, or \$159 million, for the three months ended September 30, 2019 compared to the same period of 2018 due to changes in realized prices and production as reflected in the following table:

	Oil	NGLs	Natural Gas	Total
	(in millions)			
Three months ended September 30, 2018	\$ 568	\$ 71	\$ 61	\$ 700
Changes in realized prices	(84)	(35)	(8)	(127)
Changes in production	(27)	(2)	(3)	(32)
Three months ended September 30, 2019	\$ 457	\$ 34	\$ 50	\$ 541

Note: See Production and Prices for index prices, realizations and production.

The effect of settled hedges are not included in the table above. Proceeds from settled hedges were \$40 million for the three months ended September 30, 2019 compared to payments of \$79 million for the same period of 2018, which had a positive impact of \$119 million on our realized prices. Including the effect of settled hedges, our oil and gas revenue decreased by \$40 million or 6% compared to the same prior-year period.

Net derivative gain (loss) from commodity contracts - Net derivative gain from commodity contracts was \$37 million for the three months ended September 30, 2019 compared to a loss of \$54 million in the same period of 2018, representing an overall change of \$91 million as reflected in the following table. Non-cash changes in the fair value of our outstanding derivatives resulted from the positions held each period as well as the relationship between contract prices and the associated forward curves.

	Three months ended September 30,	
	2019	2018
	(in millions)	
Non-cash derivative (loss) gain, excluding noncontrolling interest	\$ (6)	\$ 28
Non-cash derivative gain (loss), noncontrolling interest	3	(3)
Total non-cash changes	(3)	25
Net proceeds (payments) on settled commodity derivatives	40	(79)
Net derivative gain (loss)	\$ 37	\$ (54)

Other revenue - The decrease in other revenue of \$79 million to \$103 million for the three months ended September 30, 2019 compared to \$182 million in the same period of 2018 was largely the result of lower gas trading activity in 2019.

Production costs - Production costs for the three months ended September 30, 2019 decreased \$15 million to \$221 million compared to \$236 million for the same period of 2018, resulting in a 6% decrease. The decrease was primarily attributable to lower surface operations costs, lower downhole maintenance activities, lower field employee-related costs and lower costs resulting from the Lost Hills divestiture in May 2019. These decreases were partially offset by higher energy costs in the third quarter of 2019 than in the comparable period in 2018.

General and administrative expenses - Our general and administrative (G&A) expenses decreased \$15 million to \$66 million for the three months ended September 30, 2019 compared to the same period of 2018, predominantly due to \$13 million of lower cash-settled stock-based compensation expense resulting from the approximately \$38.00 decline in our stock price from September 30, 2018 to September 30, 2019. See the *Stock-Based Compensation* section below.

Other expenses, net - The decrease in other expenses of \$68 million to \$81 million for the three months ended September 30, 2019 compared to \$149 million for the same period of 2018 was largely the result of lower gas trading activity in the third quarter of 2019.

Net gain on early extinguishment of debt - The increase in net gain on early extinguishment of debt of \$80 million for the three months ended September 30, 2019 compared to the same period of 2018 was the result of the gain on open-market repurchases of our Second Lien Notes.

Nine months ended September 30, 2019 vs. 2018

Oil and gas sales - Oil and gas sales, excluding the impact of settled hedges, decreased 11%, or \$212 million, for the nine months ended September 30, 2019, compared to the same period of 2018, due to changes in realized prices and production as reflected in the following table:

	Oil	NGLs	Natural Gas	Total
	(in millions)			
Nine months ended September 30, 2018	\$ 1,587	\$ 195	\$ 150	\$ 1,932
Changes in realized prices	(148)	(58)	5	(201)
Changes in production	(6)	(5)	—	(11)
Nine months ended September 30, 2019	\$ 1,433	\$ 132	\$ 155	\$ 1,720

Note: See Production and Prices for index prices, realizations and production.

The effect of settled hedges are not included in the table above. Proceeds from settled hedges were \$68 million for the nine months ended September 30, 2019 compared to payments of \$178 million in the same period of 2018, which had a positive impact of \$246 million on our realized prices. Including the effect of settled hedges, our oil and gas revenue increased by \$34 million or 2% compared to the same prior-year period.

Net derivative loss from commodity contracts - Net derivative loss from commodity contracts was \$31 million for the nine months ended September 30, 2019 compared to \$259 million in the same period of 2018, representing an overall change of \$228 million as reflected in the following table. Non-cash changes in the fair value of our outstanding derivatives resulted from the positions held each period as well as the relationship between contract prices and the associated forward curves.

	Nine months ended September 30,	
	2019	2018
	(in millions)	
Non-cash derivative loss, excluding noncontrolling interest	\$ (99)	\$ (71)
Non-cash derivative loss, noncontrolling interest	—	(10)
Total non-cash changes	(99)	(81)
Net proceeds (payments) on settled commodity derivatives	68	(178)
Net derivative loss from commodity contracts	\$ (31)	\$ (259)

Other revenue - The increase in other revenue of \$22 million to \$335 million for the nine months ended September 30, 2019 compared to \$313 million in the same period of 2018 was largely the result of higher gas trading activity in the first quarter of 2019.

Production costs - Production costs for the nine months ended September 30, 2019 increased \$5 million to \$684 million, compared to \$679 million for the same period of 2018, resulting in a 1% increase. The increase was primarily attributable to the Elk Hills transaction that closed at the beginning of April 2018, higher surface operations and maintenance costs and other items, partially offset by lower downhole maintenance activity and lower costs resulting from the Lost Hills divestiture.

General and administrative expenses - Our G&A expenses decreased \$6 million to \$228 million for the nine months ended September 30, 2019 compared to the same period of 2018, predominantly due to \$22 million of lower cash-settled stock-based compensation expense resulting from the approximately \$38.00 decline in our stock price from September 30, 2018 to September 30, 2019. See the *Stock-Based Compensation* section below. This decrease was partially offset by higher expenses across a number of functions.

Other expenses, net - The increase in other expenses of \$25 million to \$284 million for the nine months ended September 30, 2019 compared to \$259 million for the same period of 2018 was largely the result of higher gas trading activity in the first quarter of 2019, higher accretion expenses and expenses related to our gas and power plants, partially offset by property tax refunds.

Interest and debt expense, net - Interest and debt expense, net increased \$12 million to \$293 million for the nine months ended September 30, 2019 compared to \$281 million for the same period of 2018, primarily due to higher balances and interest rates on our variable-rate debt, partially offset by a lower outstanding balance on our Second Lien Notes as a result of repurchases.

Net income attributable to noncontrolling interests - The increase in net income attributable to noncontrolling interests of \$30 million reflected both changes in the fair value of derivative instruments held by the BSP JV and additional income allocated to our noncontrolling interest holders in 2019 since the Ares JV was entered into during the first quarter of 2018.

Stock-Based Compensation

Our consolidated results of operations for the three and nine months ended September 30, 2019 and 2018 include the effects of long-term stock-based compensation plans under which awards are granted annually to executives, non-executive employees and non-employee directors that are either settled with shares of our common stock or cash. Our equity-settled awards granted to executives include stock options, restricted stock units and performance stock units that either cliff vest at the end of a three-year period or vest ratably over a three-year period, some of which are partially settled in cash. Our equity-settled awards granted to non-employee directors are stock grants that vest immediately or restricted stock units that cliff vest after one year. Our cash-settled awards granted to non-executive employees vest ratably over a three-year period.

Changes in our stock price introduce volatility in our results of operations because we pay cash-settled awards based on our stock price on the vesting date and accounting rules require that we adjust our obligation for unvested awards to the amount that would be paid using our stock price at the end of each reporting period. Cash-settled awards, including executive awards partially settled in cash, account for over 50% of our total outstanding awards. Equity-settled awards are not similarly adjusted for changes in our stock price.

Stock-based compensation is included in both G&A expenses and production costs as shown in the table below:

	Three months ended September 30,			Nine months ended September 30,		
	2019	2018	Variance	2019	2018	Variance
(in millions, except per Boe amounts)						
G&A expenses						
Cash-settled awards	\$ (2)	\$ 11	\$ (13)	\$ 11	\$ 33	\$ (22)
Equity-settled awards	3	2	1	10	10	—
Total in G&A	\$ 1	\$ 13	\$ (12)	\$ 21	\$ 43	\$ (22)
Total in G&A per Boe	\$ 0.09	\$ 1.04	\$ (0.95)	\$ 0.59	\$ 1.20	\$ (0.61)
Production costs						
Cash-settled awards	\$ —	\$ 2	\$ (2)	\$ 4	\$ 8	\$ (4)
Equity-settled awards	1	1	—	3	3	—
Total in production costs	\$ 1	\$ 3	\$ (2)	\$ 7	\$ 11	\$ (4)
Total in production costs per Boe	\$ 0.09	\$ 0.24	\$ (0.15)	\$ 0.20	\$ 0.31	\$ (0.11)
Total company	\$ 2	\$ 16	\$ (14)	\$ 28	\$ 54	\$ (26)
Total company per Boe	\$ 0.18	\$ 1.28	\$ (1.10)	\$ 0.79	\$ 1.51	\$ (0.72)

Non-GAAP Financial Measures

Our results of operations, which are presented in accordance with U.S. generally accepted accounting principles (GAAP), can include the effects of unusual, out-of-period and infrequent transactions and events affecting earnings that vary widely and unpredictably (in particular certain non-cash items such as derivative gains and losses) in nature, timing, amount and frequency. Therefore, management uses a measure called adjusted net income (loss) that excludes those items. This measure is not meant to disassociate these 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 GAAP.

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

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
(in millions, except share data)				
Net income	\$ 127	\$ 91	\$ 124	\$ 37
Net income attributable to noncontrolling interests	(33)	(25)	(85)	(55)
Net income (loss) attributable to common stock	94	66	39	(18)
Unusual, infrequent and other items:				
Non-cash derivative loss (gain) from commodities, excluding noncontrolling interest	6	(28)	99	71
Severance costs	—	—	2	4
Net gain on early extinguishment of debt	(82)	(2)	(108)	(26)
Gain on asset divestitures	—	(3)	—	(4)
Other, net	(1)	8	2	8
Total unusual, infrequent and other items	(77)	(25)	(5)	53
Adjusted net income	\$ 17	\$ 41	\$ 34	\$ 35
Net income (loss) attributable to common stock per diluted share	\$ 1.89	\$ 1.32	\$ 0.77	\$ (0.38)
Adjusted net income per diluted share	\$ 0.35	\$ 0.81	\$ 0.69	\$ 0.71

Adjusted EBITDAX - We define adjusted EBITDAX as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; other unusual, out-of-period and infrequent items; and other non-cash items. 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,	
	2019	2018	2019	2018
(in millions)				
Net income	\$ 127	\$ 91	\$ 124	\$ 37
Interest and debt expense, net	95	95	293	281
Depreciation, depletion and amortization	118	128	357	372
Exploration expense	5	4	25	18
Unusual, infrequent and other items	(77)	(25)	(5)	53
Other non-cash items	10	15	40	42
Adjusted EBITDAX	\$ 278	\$ 308	\$ 834	\$ 803

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,	
	2019	2018
	(in millions)	
Net cash provided by operating activities	\$ 540	\$ 393
Cash interest	300	284
Exploration expenditures	15	14
Working capital changes	(21)	113
Other, net	—	(1)
Adjusted EBITDAX	\$ 834	\$ 803

Adjusted EBITDAX increased by \$31 million primarily due to higher realized oil prices with hedges.

Liquidity and Capital Resources

Cash Flow Analysis

	Nine months ended September 30,	
	2019	2018
	(in millions)	
Net cash provided by operating activities	\$ 540	\$ 393
Net cash used in investing activities:		
Capital investments	\$ (393)	\$ (504)
Changes in capital investment accruals	\$ (49)	\$ 40
Acquisitions, divestitures and other	\$ 151	\$ (501)
Net cash (used) provided by financing activities:		
Debt transactions	\$ (178)	\$ (174)
Contributions (distributions) with noncontrolling interest holders	\$ (66)	\$ 716
Issuance of common stock and other	\$ —	\$ 41

Our net cash provided by operating activities is sensitive to many variables, including changes in commodity prices. Commodity price movements may also lead to changes in other variables in our business, including adjustments to our capital program. Our operating cash flow increased 37%, or \$147 million, to \$540 million for the nine months ended September 30, 2019 from \$393 million in the same period of 2018. Changes in operating assets and liabilities increased our operating cash flow by \$55 million in 2019 compared to a reduction of \$91 million in 2018, which was largely the result of repurchases of greenhouse gas allowances in 2018 that were previously monetized in 2016. The increase was also attributable to higher realized oil prices, including hedge settlements, in the nine months ended September 30, 2019. We expect our cash provided by operating activities to fully fund our internally funded capital program in 2019.

Our net cash used in investing activities of \$291 million for the nine months ended September 30, 2019 primarily reflected \$393 million of capital investments (excluding \$49 million in negative capital-related accrual changes), of which \$48 million was funded by BSP. Cash used in investing activities also included proceeds of \$164 million related to the Lost Hills divestiture. For the nine months ended September 30, 2018, our net cash used in investing activities of \$965 million primarily included approximately \$514 million of acquisition costs primarily related to the Elk Hills transaction and a building in Bakersfield and \$504 million of capital investments (excluding \$40 million in positive capital-related accrual changes), 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.

The amounts in the table below reflect our capital investment, excluding changes in capital investment accruals, for the nine months ended September 30, 2019 and 2018:

	Nine months ended September 30,	
	2019	2018
	(in millions)	
Oil and gas	\$ 325	\$ 446
Exploration	9	16
Corporate and other	11	5
Total internally funded capital	345	467
BSP funded capital	48	37
Total capital	\$ 393	\$ 504

Our net cash used in financing activities of \$244 million for the nine months ended September 30, 2019 primarily comprised \$149 million of debt repurchases on our Second Lien Notes, \$115 million of distributions to our noncontrolling interest holders and net payments on our 2014 Revolving Credit Facility of \$27 million, partially offset by a contribution from BSP of \$49 million. For the nine months ended September 30, 2018, our net cash provided by financing activities of \$583 million primarily comprised \$796 million in net contributions from our noncontrolling interest holders and \$52 million from the issuance of common stock to an Ares-led investor group in connection with the Ares JV, partially offset by \$149 million used for debt repurchases on our Senior Notes, \$80 million of distributions paid to our noncontrolling interest holders and \$21 million of net payments on our 2014 Revolving Credit Facility.

Liquidity

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 JVs to supplement our capital program and for other corporate purposes.

We have implemented organizational and operational efficiencies that resulted in a recent reduction of our headcount to approximately 1,250 employees, which is slightly more than half the employees we had at the time of our spin off from our former parent company, Occidental Petroleum Corporation, in 2014. We expect to incur a charge in the range of \$35 million to \$40 million in the fourth quarter of 2019, which will be recorded in other non-operating expenses on the consolidated statement of operations. As a result, we anticipate ongoing cost savings of approximately \$50 million annually, with slightly more than 50% of the reduction in G&A expense with the remainder in production cost, starting in the fourth quarter of 2019.

As of September 30, 2019, our long-term debt consisted of the following credit agreements, Second Lien Notes and Senior Notes:

	Outstanding Principal	Interest Rate	Maturity	Security
Credit Agreements	(in millions)			
2014 Revolving Credit Facility	\$ 514	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	1,838	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	4,996			
Less: Current Maturities	(100)			
Long-Term Debt	\$ 4,896			

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, 2018.

(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 \$290 million in June 2021, \$58 million in December 2021, \$61 million in June 2022 and \$1,429 million in December 2022.

2014 Revolving Credit Facility

As of September 30, 2019, we had \$320 million of available borrowing capacity under our \$1 billion revolving credit facility (2014 Revolving Credit Facility), before a \$150 million month-end minimum liquidity requirement. Effective November 1, 2019, the borrowing base under this facility was reaffirmed at \$2.3 billion. Our 2014 Revolving Credit Facility also includes a sub-limit of \$400 million for the issuance of letters of credit. As of September 30, 2019 and December 31, 2018, we had letters of credit outstanding of \$166 million and \$162 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

In August 2019, we entered into a ninth amendment to our 2014 Revolving Credit Facility to provide us with flexibility in connection with potential royalty transactions.

Note Repurchases

In the third quarter of 2019, we repurchased \$153 million in face value of our 8% senior secured second lien notes due December 15, 2022 (Second Lien Notes) for \$90 million in cash resulting in a pre-tax gain of \$82 million, including the effect of unamortized deferred gain and issuance costs. In the nine months ended September 30, 2019, we repurchased approximately \$229 million in face value of our Second Lien Notes for \$149 million in cash resulting in a pre-tax gain of \$108 million, including the effect of unamortized deferred gain and issuance costs.

Other

At September 30, 2019, 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, 2019 would result in a \$4 million change in annual interest expense before the impact of interest-rate contracts.

Derivatives

Significant changes in oil and natural gas prices may have a material impact on our liquidity. Declining commodity prices negatively affect our operating cash flow, and the inverse applies during periods of rising commodity prices. To mitigate some of the risk inherent in the downward movement in oil prices, we have utilized various derivative instruments to hedge commodity price risk.

Commodity Contracts

Our strategy for protecting our cash flow, operating margin and capital program, while maintaining adequate liquidity, includes our hedging program. We currently have the following Brent-based crude oil contracts, as of November 4, 2019:

	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Purchased Puts:					
Barrels per day	35,000	30,000	15,000	10,000	5,000
Weighted-average price per barrel	\$ 75.71	\$ 70.83	\$ 68.33	\$ 65.00	\$ 65.00
Sold Puts:					
Barrels per day	35,000	30,000	15,000	10,000	5,000
Weighted-average price per barrel	\$ 60.00	\$ 56.67	\$ 55.00	\$ 55.00	\$ 55.00
Swaps:					
Barrels per day	—	—	5,000 ^(a)	—	—
Weighted-average price per barrel	\$ —	\$ —	\$ 70.05	\$ —	\$ —

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

The BSP JV entered into crude oil derivatives for insignificant volumes through 2021 that are included in our consolidated results but not in the above table. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021. The hedges entered into by the BSP JV could affect the timing of the redemption of the JV interest.

2019 Capital Program

We expect our 2019 internally funded capital program to be in the range of \$385 million to \$400 million, of which \$345 million has been invested through the third quarter of 2019. We also anticipate JV investment of \$200 million to \$225 million, of which \$121 million has been invested through the third quarter of 2019, for a total 2019 capital program of \$585 million to \$625 million.

Our 2019 capital is focused on oil and will be largely directed to short payout projects, such as primary drilling of both vertical and lateral wells and capital workovers, and low-risk projects including waterflood and steamflood investments that maintain base production. We will continue to focus on our core fields: Elk Hills, Buena Vista, Wilmington, Kern Front and Mt. Poso.

We plan to use approximately 74% of our capital program on drilling and development of conventional and unconventional resources. The depth of our conventional wells is expected to range from 2,000 to 15,000 feet. Our conventional program largely consists of waterfloods and steamfloods along with some primary drilling. We also intend to drill unconventional wells in the Buena Vista area. With continued focus on cost savings and efficiencies, many of our deep conventional and unconventional wells have become more competitive.

We also plan to use approximately 8% of our 2019 capital program for capital workovers on existing well bores. Capital workovers are some of the highest Value Creation Index projects in our portfolio and generally include well deepening, recompletions, changes of lift methods and other activities designed to add incremental productive intervals and reserves.

Further, approximately 13% of our 2019 capital program is intended for facilities development for our newer projects, including pipeline and gathering line interconnections, gas compression and water management systems, and for mechanical integrity, safety and environmental projects. About 5% is intended to be used for exploration and other corporate uses.

Efficiency gains in our capital costs have enabled us to maintain a meaningful capital program in the lower commodity prices in 2019. We will continue to build our inventory of available projects, which will position us to accelerate value by utilizing third-party capital and taking advantage of potential future commodity price increases.

Lawsuits, Claims, Commitments and Contingencies

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, 2019 and December 31, 2018 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.

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.

Forward-Looking Statements

The information included herein contains forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements include those regarding our expectations as to our future:

- financial position, liquidity, cash flows and results of operations
- business prospects
- transactions and projects
- operating costs
- Value Creation Index (VCI) metrics, which are based on certain estimates including future production rates, costs and commodity prices
- operations and operational results including production, hedging and capital investment
- budgets and maintenance capital requirements
- reserves
- type curves
- expected synergies from acquisitions and joint ventures

Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. While we believe assumptions or bases underlying our expectations are 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 have not independently verified them and do not warrant their accuracy or completeness. Factors (but not necessarily all the factors) that could cause results to differ include:

- commodity price changes
- debt limitations on our financial flexibility
- insufficient cash flow to fund our capital plan, planned investments, debt repurchases and distributions to JV partners
- inability to enter into desirable transactions including acquisitions, asset sales and joint ventures
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of 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
- factors discussed in *Item 1A – Risk Factors* of our Form 10-K for the year ended December 31, 2018.

Words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "goal," "intend," "likely," "may," "might," "plan," "potential," "project," "seek," "should," "target," "will" or "would" and similar words that reflect the prospective nature of events or outcomes typically identify forward-looking statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For the three and nine months ended September 30, 2019, there were no material changes to commodity price risk, interest rate risk or counterparty credit risk from the information 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 2018 Form 10-K, except as discussed below.

Commodity Price Risk

Our current oil hedge positions provide the following:

	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Barrels per day	35,000	30,000	15,000	10,000	5,000
	Receive Brent if Brent > \$76	Receive Brent if Brent > \$71	Receive Brent if Brent > \$68	Receive Brent if Brent > \$65	Receive Brent if Brent > \$65
	Receive \$76 if Brent between \$60 and \$76	Receive \$71 if Brent between \$57 and \$71	Receive \$68 if Brent between \$55 and \$68	Receive \$65 if Brent between \$55 and \$65	Receive \$65 if Brent between \$55 and \$65
	Receive Brent + \$16 if Brent < \$60	Receive Brent + \$14 if Brent < \$57	Receive Brent + \$13 if Brent < \$55	Receive Brent + \$10 if Brent < \$55	Receive Brent + \$10 if Brent < \$55
Barrels per day	5,000 ^(a)				
	Receive \$70 Brent at all prices				

(a) Subject to an additional 5,000 barrels per day at the same price at the option of the counterparties.

See additional hedging information in *Item 2 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources*.

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, 2019, 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, 2019 was not material and losses associated with credit risk have been insignificant for all periods 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, 2019.

There were no changes in our internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the three months ended September 30, 2019 that materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

In the third quarter of 2019, we settled a previously disclosed investigation of characterization of waste sent to a licensed third-party facility prior to the time of our spin off from our former parent company, Occidental Petroleum Corporation, in 2014. In October 2019, we paid civil penalties of \$250,000 to Ventura County and \$50,000 each to three other agencies as part of the settlement.

For information regarding legal proceedings, see *Note 7 Lawsuits, Claims, Commitments and Contingencies* in the Notes to the Condensed Consolidated Financial Statements included in Part I of this Form 10-Q and Part I, Item 3, Legal Proceedings in the Form 10-K for the year ended December 31, 2018.

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, 2018.

Item 5. Other Disclosures

None.

Item 6. Exhibits

- 3.1 [Amended and Restated Certificate of Incorporation of California Resources Corporation \(filed as Exhibit 3.1 to Registrant's Current Report on Form 8-K filed June 3, 2016 and incorporated herein by reference\).](#)
- 3.2 [Amended and Restated Bylaws of California Resources Corporation \(filed as Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed November 10, 2015 and incorporated herein by reference\).](#)
- 10.1 [Purchase Warrant for Common Stock, dated July 22, 2019 \(filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed July 23, 2019 and incorporated herein by reference\).](#)
- 10.2 [Ninth Amendment to Credit Agreement, dated as of August 28, 2019, among California Resources Corporation, as the Borrower, JP Morgan Chase Bank, N.A., as Administrative Agent, Swingline Lender and a Letter of Credit Issuer, Bank of America, N.A., as Syndication Agent, Swingline Lender and a Letter of Credit Issuer \(filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed September 3, 2019, and incorporated herein by reference\).](#)
- 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* Inline XBRL Instance Document.
- 101.SCH* Inline XBRL Taxonomy Extension Schema Document.
- 101.CAL* Inline XBRL Taxonomy Extension Calculation Linkbase Document.
- 101.LAB* Inline XBRL Taxonomy Extension Label Linkbase Document.
- 101.PRE* Inline XBRL Taxonomy Extension Presentation Linkbase Document.
- 101.DEF* Inline XBRL Taxonomy Extension Definition Linkbase Document.
- 104 Cover Page Interactive Data File (formatted in inline XBRL and contained in Exhibits 101).

* - 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 4, 2019

/s/ Roy M. Pineci

Roy M. Pineci

Executive Vice President - Finance

(Principal Accounting Officer)

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 4, 2019

/s/ Todd A. Stevens

Todd A. Stevens

President and Chief Executive Officer
(Principal Executive Officer)

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 4, 2019

/s/ Marshall D. Smith

Marshall D. Smith

Senior Executive Vice President and

Chief Financial Officer

(Principal Financial Officer)

**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, 2019, as filed with the Securities and Exchange Commission on November 4, 2019 (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 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 4, 2019

/s/ Marshall D. Smith

Name: Marshall D. Smith
Title: Senior Executive Vice President and Chief Financial Officer
Date: November 4, 2019

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.