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 June 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	**46-5670947**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

27200 Tourney Road	
Suite 315	
Santa Clarita	
California	**91355**
(Address of principal executive offices)	(Zip Code)

(888) 848-4754

(Registrant's telephone number, including area code)

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 June 30, 2019	49,004,413

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 June 30, 2019 and December 31, 2018
(in millions, except share data)

	June 30, 2019	December 31, 2018
CURRENT ASSETS		
Cash	$ 27	$ 17
Trade receivables	234	299
Inventories	70	69
Other current assets, net	191	255
Total current assets	522	640
PROPERTY, PLANT AND EQUIPMENT	22,717	22,523
Accumulated depreciation, depletion and amortization	(16,308)	(16,068)
Total property, plant and equipment, net	6,409	6,455
OTHER ASSETS	101	63
TOTAL ASSETS	$ 7,032	$ 7,158
CURRENT LIABILITIES		
Current maturities of long-term debt	100	—
Accounts payable	290	390
Accrued liabilities	220	217
Total current liabilities	610	607
LONG-TERM DEBT	5,060	5,251
DEFERRED GAIN AND ISSUANCE COSTS, NET	185	216
OTHER LONG-TERM LIABILITIES	679	575
MEZZANINE EQUITY		
Redeemable noncontrolling interests	777	756
EQUITY		
Preferred stock (20 million shares authorized at $0.01 par value) no shares outstanding at June 30, 2019 and December 31, 2018	—	—
Common stock (200 million shares authorized at $0.01 par value) outstanding shares (June 30, 2019 - 49,004,413 and December 31, 2018 - 48,650,420)	—	—
Additional paid-in capital	4,994	4,987
Accumulated deficit	(5,397)	(5,342)
Accumulated other comprehensive loss	(5)	(6)
Total equity attributable to common stock	(408)	(361)
Equity attributable to noncontrolling interests	129	114
Total equity	(279)	(247)
TOTAL LIABILITIES AND EQUITY	$ 7,032	$ 7,158

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 six months ended June 30, 2019 and 2018
(in millions, except share data)

	Three months ended June 30,		Six months ended June 30,	
	2019	**2018**	**2019**	**2018**
REVENUES AND OTHER				
Oil and gas sales	$ 578	$ 657	$ 1,179	$ 1,232
Net derivative gain (loss) from commodity contracts	21	(167)	(68)	(205)
Other revenue	54	59	232	131
Total revenues and other	653	549	1,343	1,158
COSTS AND OTHER				
Production costs	230	231	463	443
General and administrative expenses	79	90	162	153
Depreciation, depletion and amortization	121	125	239	244
Taxes other than on income	36	37	77	75
Exploration expense	10	6	20	14
Other expenses, net	55	49	203	110
Total costs and other	531	538	1,164	1,039
OPERATING INCOME	122	11	179	119
NON-OPERATING (LOSS) INCOME				
Interest and debt expense, net	(98)	(94)	(198)	(186)
Net gain on early extinguishment of debt	20	24	26	24
Gain on asset divestitures	—	1	—	1
Other non-operating expenses	(3)	(5)	(10)	(12)
INCOME (LOSS) BEFORE INCOME TAXES	41	(63)	(3)	(54)
Income tax	—	—	—	—
NET INCOME (LOSS)	41	(63)	(3)	(54)
NET (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS				
Mezzanine equity	(29)	(29)	(57)	(43)
Equity	—	10	5	13
Net income attributable to noncontrolling interests	(29)	(19)	(52)	(30)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 12	$ (82)	$ (55)	$ (84)
Net income (loss) attributable to common stock per share				
Basic	$ 0.25	$ (1.70)	$ (1.13)	$ (1.81)
Diluted	$ 0.24	$ (1.70)	$ (1.13)	$ (1.81)

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 six months ended June 30, 2019 and 2018
(in millions)

	Three months ended June 30,		Six months ended June 30,	
	2019	**2018**	**2019**	**2018**
Net income (loss)	$ 41	$ (63)	$ (3)	$ (54)
Net income attributable to noncontrolling interests	(29)	(19)	(52)	(30)
Other comprehensive income:				
Reclassification of realized losses on pension and postretirement benefits to income[(a)]	1	1	1	3
Comprehensive income (loss) attributable to common stock	$ 13	$ (81)	$ (54)	$ (81)

(a) No associated tax for the three and six months ended June 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 six months ended June 30, 2019 and 2018
(in millions)

	Six months ended June 30, 2019	Six months ended June 30, 2018
CASH FLOW FROM OPERATING ACTIVITIES		
Net loss	$ (3)	$ (54)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	239	244
Net derivative loss from commodity contracts	68	205
Net proceeds (payments) on settled commodity derivatives	28	(99)
Net gain on early extinguishment of debt	(26)	(24)
Amortization of deferred gain	(36)	(38)
Gain on asset divestiture	—	(1)
Dry hole expenses	7	4
Other non-cash charges to income, net	47	39
Changes in operating assets and liabilities, net	(52)	(42)
Net cash provided by operating activities	272	234
CASH FLOW FROM INVESTING ACTIVITIES		
Capital investments	(271)	(327)
Changes in capital investment accruals	(57)	22
Asset divestitures	165	13
Acquisitions	(2)	(512)
Other	(5)	(3)
Net cash used in investing activities	(170)	(807)
CASH FLOW FROM FINANCING ACTIVITIES		
Proceeds from 2014 Revolving Credit Facility	1,274	1,150
Repayments of 2014 Revolving Credit Facility	(1,289)	(1,236)
Debt repurchases	(59)	(119)
Contributions from noncontrolling interest holders, net	49	796
Distributions paid to noncontrolling interest holders	(65)	(41)
Issuance of common stock	1	50
Shares canceled for taxes	(3)	(5)
Net cash (used) provided by financing activities	(92)	595
Increase in cash	10	22
Cash—beginning of period	17	20
Cash—end of period	$ 27	$ 42

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 six months ended June 30, 2019
(in millions)

	Three months ended June 30, 2019					
	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total Equity
Balance, March 31, 2019	$ 4,989	$ (5,409)	$ (6)	$ (426)	$ 137	$ (289)
Net loss	—	12	—	12	—	12
Contribution from noncontrolling interest holders, net	—	—	—	—	—	—
Distributions to noncontrolling interest holders	—	—	—	—	(8)	(8)
Issuance of common stock	—	—	—	—	—	—
Other comprehensive income	—	—	1	1	—	1
Share-based compensation, net	5	—	—	5	—	5
Balance, June 30, 2019	$ 4,994	$ (5,397)	$ (5)	$ (408)	$ 129	$ (279)

	Six months ended June 30, 2019					
	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, 2018	$ 4,987	$ (5,342)	$ (6)	$ (361)	$ 114	$ (247)
Net loss	—	(55)	—	(55)	(5)	(60)
Contribution from noncontrolling interest holders, net	—	—	—	—	49	49
Distributions to noncontrolling interest holders	—	—	—	—	(29)	(29)
Issuance of common stock	—	—	—	—	—	—
Other comprehensive income	—	—	1	1	—	1
Share-based compensation, net	7	—	—	7	—	7
Balance, June 30, 2019	$ 4,994	$ (5,397)	$ (5)	$ (408)	$ 129	$ (279)

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 six months ended June 30, 2018
(in millions)

	Three months ended June 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, March 31, 2018	$ 4,930	$ (5,672)	$ (21)	$ (763)	$ 109	$ (654)
Net loss	—	(82)	—	(82)	(10)	(92)
Contribution from noncontrolling interest holders, net	—	—	—	—	49	49
Distributions to noncontrolling interest holders	—	—	—	—	(4)	(4)
Issuance of common stock	51	—	—	51	—	51
Other comprehensive income	—	—	1	1	—	1
Share-based compensation, net	4	—	—	4	—	4
Balance, June 30, 2018	$ 4,985	$ (5,754)	$ (20)	$ (789)	$ 144	$ (645)

	Six months ended June 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	—	(84)	—	(84)	(13)	(97)
Contribution from noncontrolling interest holders, net	—	—	—	—	82	82
Distributions to noncontrolling interest holders	—	—	—	—	(19)	(19)
Issuance of common stock	101	—	—	101	—	101
Other comprehensive income	—	—	3	3	—	3
Share-based compensation, net	5	—	—	5	—	5
Balance, June 30, 2018	$ 4,985	$ (5,754)	$ (20)	$ (789)	$ 144	$ (645)

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

NOTE 1 THE SPIN-OFF AND BASIS OF PRESENTATION

The Separation and Spin-off

We are an independent oil and natural gas exploration and production company operating properties 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 June 30, 2019 and December 31, 2018 and the statements of operations, comprehensive income, cash flows and equity for the three and six months ended June 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 June 30, 2019 and December 31, 2018 included $12 million and $2 million, respectively, that was restricted for capital investments and distributions to a joint venture (JV) partner.

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

	June 30, 2019	December 31, 2018
	(in millions)	
Derivative assets	$ 92	$ 168
Amounts due from joint interest partners	66	68
Prepaid expenses	23	16
Other	10	3
Other current assets, net	$ 191	$ 255

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

	June 30, 2019	December 31, 2018
	(in millions)	
Accrued employee-related costs	$ 77	$ 109
Accrued taxes other than on income	33	38
Asset retirement obligation	31	31
Operating lease liability	29	—
Accrued interest	15	15
Other	35	24
Accrued liabilities	$ 220	$ 217

Other long-term liabilities included asset retirement obligations of $479 million and $402 million at June 30, 2019 and December 31, 2018, respectively.

Non-cash financing activities in 2018 included 2.85 million shares of common stock (valued at $51 million) issued in connection with an acquisition.

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 six months ended June 30, 2019 and 2018. Interest paid, net of capitalized amounts, totaled $219 million and $212 million for the six months ended June 30, 2019 and 2018, respectively.

NOTE 4 INVENTORIES

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

	June 30, 2019	December 31, 2018
	(in millions)	
Materials and supplies	$ 68	$ 65
Finished goods	2	4
Total	$ 70	$ 69

NOTE 5 DEBT

As of June 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
	June 30, 2019	December 31, 2018			
Credit Agreements	(in millions)				
2014 Revolving Credit Facility	$ 525	$ 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	1,991	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	5,160	5,251			
Less: Current Maturities	(100)	—			
Long-Term Debt	$ 5,060	$ 5,251			

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 $315 million in June 2021, $63 million in December 2021, $65 million in June 2022 and $1,548 million in December 2022.

Deferred Gain and Issuance Costs

As of June 30, 2019, net deferred gain and issuance costs were $185 million, consisting of $267 million of a deferred gain offset by $82 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 June 30, 2019, we had $309 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 May 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 June 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.

Note Repurchases

In the first quarter of 2019, we repurchased $18 million in face value of our 8% senior secured second lien notes due December 15, 2022 (Second Lien Notes) for $14 million in cash resulting in a pre-tax gain of $6 million, including the effect of unamortized deferred gain and issuance costs. In the second quarter of 2019, we repurchased $58 million in face value of our Second Lien Notes for $45 million in cash resulting in a pre-tax gain of $20 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 June 30, 2019 and December 31, 2018, including the fair value of the variable-rate portion, was $4.6 billion and $4.5 billion, respectively, compared to a carrying value of $5.2 billion and $5.3 billion, respectively.

Other

At June 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 JOINT VENTURES

We have two separate development JVs with Benefit Street Partners (BSP) and Macquarie Infrastructure and Real Assets Inc. (MIRA). In July 2019 we entered into a third development JV with subsidiaries of Colony Capital Inc. (Colony) as described in *Note 16 Subsequent Event*. In addition to these development JVs, we have a midstream JV with Ares Management L.P. (Ares) and several other smaller exploration JVs. The BSP and Ares JVs are consolidated, the details of which are described below. For all of our other JVs, we report our proportionate share of operations in our condensed consolidated financial statements.

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 six months ended June 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	(6)	1	(5)	57
Contributions from noncontrolling interest holders, net	—	49	49	—
Distributions to noncontrolling interest holders	(4)	(25)	(29)	(36)
Balance, June 30, 2019	$ 5	$ 124	$ 129	$ 777
Balance, December 31, 2017	$ —	$ 94	$ 94	$ —
Net (loss) income attributable to noncontrolling interests	(6)	(7)	(13)	43
Contributions from noncontrolling interest holders, net	33	49	82	714
Distributions to noncontrolling interest holders	(2)	(17)	(19)	(22)
Balance, June 30, 2018	$ 25	$ 119	$ 144	$ 735

<u>Ares JV</u>

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 consolidated results reflect the operations of our development JV with Benefit Street Partners (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 June 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 six months ended June 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 June 30, 2019:

	Q3 2019	Q4 2019	Q1 2020	Q2 2020
Purchased Puts:				
Barrels per day	40,000	35,000	25,000	10,000
Weighted-average price per barrel	$ 73.13	$ 75.71	$ 72.00	$ 70.00
Sold Puts:				
Barrels per day	40,000	35,000	25,000	10,000
Weighted-average price per barrel	$ 57.50	$ 60.00	$ 57.00	$ 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 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 June 30, 2019 and December 31, 2018 (in millions):

June 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	$ 117	$ (25)	$ 92
Other assets	2	—	2
Liabilities:			
Accrued liabilities	(28)	25	(3)
Other long-term liabilities	(1)	—	(1)
Total derivatives	$ 90	$ —	$ 90

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	$ 252	$ (84)	$ 168
Other assets	23	(9)	14
Liabilities:			
Accrued liabilities	(87)	84	(3)
Other long-term liabilities	(10)	9	(1)
Total derivatives	$ 178	$ —	$ 178

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 six months ended June 30, 2019 and 2018:

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
	(in millions, except per-share amounts)			
Net income (loss)	$ 41	$ (63)	$ (3)	$ (54)
Net income attributable to noncontrolling interests	(29)	(19)	(52)	(30)
Net income (loss) attributable to common stock	12	(82)	(55)	(84)
Less: net income allocated to participating securities	—	—	—	—
Net income (loss) available to common stockholders	$ 12	$ (82)	$ (55)	$ (84)
Weighted-average common shares outstanding - basic	48.9	48.2	48.8	46.3
Basic EPS	$ 0.25	$ (1.70)	$ (1.13)	$ (1.81)
Net income (loss)	$ 41	$ (63)	$ (3)	$ (54)
Net income attributable to noncontrolling interests	(29)	(19)	(52)	(30)
Net income (loss) attributable to common stock	12	(82)	(55)	(84)
Less: net income allocated to participating securities	—	—	—	—
Net income (loss) available to common stockholders	$ 12	$ (82)	$ (55)	$ (84)
Weighted-average common shares outstanding - basic	48.9	48.2	48.8	46.3
Dilutive effect of potentially dilutive securities	0.3	—	—	—
Weighted-average common shares outstanding - diluted	49.2	48.2	48.8	46.3
Diluted EPS	$ 0.24	$ (1.70)	$ (1.13)	$ (1.81)
Weighted-average anti-dilutive shares	1.9	3.0	2.6	2.9

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 six months ended June 30, 2019 and 2018:

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

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

We contributed $1 million to our defined benefit pension plans in each of the three months ended June 30, 2019 and 2018. We contributed $1 million and $2 million in the six months ended June 30, 2019 and 2018, respectively. We expect to satisfy minimum funding requirements with contributions of $2 million 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 2020, 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 six months ended June 30, 2019 and 2018:

	Three months ended June 30,		**Six months ended June 30,**	
	2019	**2018**	**2019**	**2018**
	(in millions)			
Oil and gas sales:				
Oil	$ 496	$ 553	$ 976	$ 1,019
NGLs	39	61	98	124
Natural gas	43	43	105	89
	578	657	1,179	1,232
Other revenue:				
Electricity	16	21	50	45
Marketing, trading and other	38	38	182	85
Interest income	—	—	—	1
	54	59	232	131
Net derivative gain (loss) from commodity contracts	21	(167)	(68)	(205)
Total revenues and other	$ 653	$ 549	$ 1,343	$ 1,158

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 six months ended June 30, 2019 were as follows:

	Three months ended June 30, 2019	Six months ended June 30, 2019
	(in millions)	
Operating lease cost	$ 14	$ 26
Short-term lease cost	18	38
Variable lease cost	3	8
Total operating lease costs	$ 35	$ 72

During the three months ended June 30, 2019, we entered into new contracts treated as finance leases, which are 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 six months ended June 30, 2019, sublease income was not material to our condensed consolidated financial statements.

Supplemental cash flow related to our operating leases for the three and six months ended June 30, 2019 were as follows:

	Three months ended June 30, 2019	Six months ended June 30, 2019
	(in millions)	
Operating cash flows	$ 2	$ 5
Investing cash flows	$ 12	$ 21

Our operating and financing cash flows from finance leases were not significant for the three months ended June 30, 2019.

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

	June 30, 2019
Operating Leases	
ROU asset obtained in exchange for lease obligations (in millions)	$ 52
Weighted-average remaining lease term (in years)	2.74
Weighted-average discount rate	11.5%
Finance Leases	
ROU asset obtained in exchange for lease obligations (in millions)	$ 2
Weighted-average remaining lease term (in years)	2.83
Weighted-average discount rate	8.5%

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

	Balance Sheet Location		June 30, 2019
			(in millions)
Assets			
Operating lease, net	*Other assets*	$	50
Finance lease, net	*PP&E*		2
Total lease assets		$	52
Liabilities			
Current			
Operating lease	*Accrued liabilities*	$	29
Finance lease	*Accrued liabilities*		1
Long term			
Operating lease	*Other long-term liabilities*		23
Finance lease	*Other long-term liabilities*		1
Total lease liabilities		$	54

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 June 30, 2019, we did not recognize any impairment charges. For the six months ended June 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 financing lease liabilities at June 30, 2019 are as follows:

		Operating Leases		Finance Leases
		(in millions)		
2019	$	19	$	—
2020		23		1
2021		7		1
2022		4		—
2023		2		—
Thereafter		6		—
Less: Interest		(9)		—
Present value of lease liabilities	$	52	$	2

We have entered into contracts for commercial office space and facilities that are under construction as of June 30, 2019. These leases are not included in our lease population at June 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

Rental expense for operating leases under ASC 840 was $2 million and $5 million for the three and six months ended June 30, 2018, respectively. Rental income from subleases for the three and six months ended June 30, 2018 was not significant.

NOTE 13 INCOME TAXES

For the six months ended June 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 are able to actually achieve.

NOTE 14 ASSET DIVESTITURE

On May 1, 2019, we sold 50% of our working interest and transferred operatorship in certain zones of 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 was 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.

NOTE 15 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 June 30, 2019 and December 31, 2018 and the condensed consolidating statements of operations and statements of cash flows for the three and six months ended June 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 June 30, 2019 and December 31, 2018
(in millions)

	As of June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total current assets	$ 10	$ 452	$ 73	$ (13)	$ 522
Total property, plant and equipment, net	23	5,874	512	—	6,409
Investments in consolidated subsidiaries	5,684	130	—	(5,814)	—
Other assets	2	71	28	—	101
TOTAL ASSETS	$ 5,719	$ 6,527	$ 613	$ (5,827)	$ 7,032
Total current liabilities	210	404	9	(13)	610
Long-term debt	5,060	—	—	—	5,060
Deferred gain and issuance costs, net	185	—	—	—	185
Other long-term liabilities	143	532	4	—	679
Amounts due to (from) affiliates	529	(529)	—	—	—
Mezzanine equity	—	—	777	—	777
Total equity	(408)	6,120	(177)	(5,814)	(279)
TOTAL LIABILITIES AND EQUITY	$ 5,719	$ 6,527	$ 613	$ (5,827)	$ 7,032

	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 six months ended June 30, 2019 and 2018
(in millions)

	For the three months ended June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues and other	$ —	$ 610	$ 113	$ (70)	$ 653
Total costs and other	52	490	59	(70)	531
Non-operating (loss) income	(83)	2	—	—	(81)
NET (LOSS) INCOME	(135)	122	54	—	41
Net income attributable to noncontrolling interests	—	—	(29)	—	(29)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (135)	$ 122	$ 25	$ —	$ 12

	For the three months ended June 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues and other	$ —	$ 526	$ 94	$ (71)	$ 549
Total costs and other	64	499	46	(71)	538
Non-operating (loss) income	(74)	—	—	—	(74)
NET (LOSS) INCOME	(138)	27	48	—	(63)
Net income attributable to noncontrolling interest	—	—	(19)	—	(19)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (138)	$ 27	$ 29	$ —	$ (82)

	For the six months ended June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues and other	$ —	$ 1,255	$ 235	$ (147)	$ 1,343
Total costs and other	106	1,074	131	(147)	1,164
Non-operating (loss) income	(187)	5	—	—	(182)
NET INCOME (LOSS)	(293)	186	104	—	(3)
Net income attributable to noncontrolling interests	—	—	(52)	—	(52)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (293)	$ 186	$ 52	$ —	$ (55)

	For the six months ended June 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues and other	$ 1	$ 1,111	$ 159	$ (113)	$ 1,158
Total costs and other	107	960	85	(113)	1,039
Non-operating (loss) income	(173)	—	—	—	(173)
NET (LOSS) INCOME	(279)	151	74	—	(54)
Net income attributable to noncontrolling interest	—	—	(30)	—	(30)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCK	$ (279)	$ 151	$ 44	$ —	$ (84)

Condensed Consolidating Statements of Cash Flows
For the six months ended June 30, 2019 and 2018

(in millions)

	For the six months ended June 30, 2019				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash (used) provided by operating activities	$ (348)	$ 303	$ 317	$ —	$ 272
Net cash used in investing activities	(5)	(154)	(11)	—	(170)
Net cash provided (used) by financing activities	353	(149)	(296)	—	(92)
Increase in cash	—	—	10	—	10
Cash—beginning of period	—	7	10	—	17
Cash—end of period	$ —	$ 7	$ 20	$ —	$ 27

	For the six months ended June 30, 2018				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash (used) provided by operating activities	$ (334)	$ 480	$ 88	$ —	$ 234
Net cash used in investing activities	(1)	(776)	(30)	—	(807)
Net cash provided (used) by financing activities	334	293	(32)	—	595
Decrease (increase) in cash	(1)	(3)	26	—	22
Cash—beginning of period	7	8	5	—	20
Cash—end of period	$ 6	$ 5	$ 31	$ —	$ 42

NOTE 16 SUBSEQUENT EVENT

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

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

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 six months ended June 30, 2019 and 2018:

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
Brent oil ($/Bbl)	$ 68.32	$ 74.90	$ 66.11	$ 71.04
WTI oil ($/Bbl)	$ 59.82	$ 67.88	$ 57.36	$ 65.37
NYMEX gas ($/MMBtu)	$ 2.66	$ 2.75	$ 2.95	$ 2.81

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 is made up of 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, generally, 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 2020, 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 built our 2019 and 2020 commodity hedge positions to protect our downside risk without significantly limiting our upside potential. We can give no assurances that our hedges will be adequate to accomplish our objectives. Unless otherwise indicated, we use the term "hedge" to describe derivative instruments that are designed to achieve our hedging program goals, even though they are not accounted for as cash-flow or fair-value hedges.

We respond to economic conditions by adjusting the amount and allocation of our capital program 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 June 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.

Recent Developments

New Joint Venture

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

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

Asset Divestiture

On May 1, 2019, we sold 50% of our working interest and transferred operatorship in certain zones of 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 selling costs and purchase price adjustments, which was used to pay down our 2014 Revolving Credit Facility.

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 our JV with Benefit Street Partners (BSP), BSP has funded an aggregate of $200 million, of which $50 million was funded in the first half of 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 $122 million has been funded to date, with $7 million funded in the first quarter of 2019. We expect the remaining balance of MIRA's initial commitment to be invested in the second half of 2019.

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 six months ended June 30, 2019 and 2018:

	Three months ended June 30,		Six months ended June 30,	
	2019	**2018**	**2019**	**2018**
Oil (MBbl/d)				
San Joaquin Basin	52	54	54	52
Los Angeles Basin	23	25	24	24
Ventura Basin	4	4	4	4
Total	79	83	82	80
NGLs (MBbl/d)				
San Joaquin Basin	15	15	14	15
Ventura Basin	1	1	1	1
Total	16	16	15	16
Natural gas (MMcf/d)				
San Joaquin Basin	164	172	164	157
Los Angeles Basin	3	1	3	1
Ventura Basin	6	8	6	7
Sacramento Basin	30	29	29	31
Total	203	210	202	196
Total Production (MBoe/d)	129	134	131	129

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

For the three months ended June 30, 2019 compared to the same period in 2018, total daily production decreased by approximately 5 MBoe/d or 4%. Over 2 MBoe/d of this decline resulted from the Lost Hills divestiture in May 2019 and PSC effects. Non-recurring events including power and plant outages lowered quarterly production by 1 MBoe/d.

For the six months ended June 30, 2019 compared to the same period in 2018, total daily production volumes increased by 2 MBoe/d or 2% as a result of 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. This increase was partially offset by the non-recurring events described above and production sold in the Lost Hills divestiture in the second quarter of 2019.

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 six months ended June 30, 2019 and 2018:

	Three months ended June 30,			
	2019		2018	
	Price	Realization	Price	Realization
Oil ($ per Bbl)				
Brent	$ 68.32		$ 74.90	
Realized price, without hedge	$ 68.77	101%	$ 73.19	98%
Settled hedges	1.89		(9.08)	
Realized price, with hedge	$ 70.66	103%	$ 64.11	86%
WTI	$ 59.82		$ 67.88	
Realized price, without hedge	$ 68.77	115%	$ 73.19	108%
Realized price, with hedge	$ 70.66	118%	$ 64.11	94%
NGLs ($ per Bbl)				
Realized price (% of Brent)	$ 27.82	41%	$ 42.13	56%
Realized price (% of WTI)	$ 27.82	47%	$ 42.13	62%
Natural gas				
NYMEX ($/MMBTU)	$ 2.66		$ 2.75	
Realized price, w/out hedge ($/Mcf)	$ 2.33	88%	$ 2.25	82%
Settled hedges	0.03		0.01	
Realized price, with hedge ($/Mcf)	$ 2.36	89%	$ 2.26	82%

	Six months ended June 30,			
	2019		2018	
	Price	Realization	Price	Realization
Oil ($ per Bbl)				
Brent	$ 66.11		$ 71.04	
Realized price, without hedge	$ 65.97	100%	$ 70.35	99%
Settled hedges	1.93		(6.88)	
Realized price, with hedge	$ 67.90	103%	$ 63.47	89%
WTI	$ 57.36		$ 65.37	
Realized price, without hedge	$ 65.97	115%	$ 70.35	108%
Realized price, with hedge	$ 67.90	118%	$ 63.47	97%
NGLs ($ per Bbl)				
Realized price (% of Brent)	$ 34.97	53%	$ 42.63	60%
Realized price (% of WTI)	$ 34.97	61%	$ 42.63	65%
Natural gas				
NYMEX ($/MMBTU)	$ 2.95		$ 2.81	
Realized price, w/out hedge ($/Mcf)	$ 2.87	97%	$ 2.51	90%
Settled hedges	(0.01)		0.01	
Realized price, with hedge ($/Mcf)	$ 2.86	97%	$ 2.52	89%

Brent prices were lower in both the three and six months ended June 30, 2019 compared to the same prior-year periods. 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.

Prices for NGLs decreased significantly from the prior-year periods. In the second quarter of 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 higher in the second quarter and in the six months ended June 30, 2019 than the comparable periods of 2018 largely due to stronger California demand.

Balance Sheet Analysis

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

	June 30, 2019	December 31, 2018
	(in millions)	
Cash	$ 27	$ 17
Trade receivables	$ 234	$ 299
Inventories	$ 70	$ 69
Other current assets, net	$ 191	$ 255
Property, plant and equipment, net	$ 6,409	$ 6,455
Other assets	$ 101	$ 63
Current maturities of long-term debt	$ 100	$ —
Accounts payable	$ 290	$ 390
Accrued liabilities	$ 220	$ 217
Long-term debt	$ 5,060	$ 5,251
Deferred gain and issuance costs, net	$ 185	$ 216
Other long-term liabilities	$ 679	$ 575
Mezzanine equity	$ 777	$ 756
Equity attributable to common stock	$ (408)	$ (361)
Equity attributable to noncontrolling interests	$ 129	$ 114

Cash at June 30, 2019 and December 31, 2018 included approximately $12 million and $2 million, respectively, which is 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 due to our gas trading activities that were higher in the fourth quarter of 2018 compared to the second quarter of 2019.

The decrease in other current assets, net was primarily due to a decrease in the fair value of the current portion of our derivative assets.

The decrease in property, plant and equipment, net primarily reflected our Lost Hills divestiture and depreciation, depletion and amortization, partially offset by capital investments in the first half of 2019 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 a right-of-use asset for operating leases as a result of adopting new accounting rules on January 1, 2019 that impact the current period but not the prior period. 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 June 30, 2019 reflected lower capital investments and gas trading activities, which were higher in the fourth quarter of 2018 compared to the second quarter of 2019.

The decrease in long-term debt reflected a reclassification of $100 million of our senior notes to current maturities of long-term debt and the proceeds from the Lost Hills divestiture that were used to pay down debt.

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.

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 decreased primarily as a result of the net loss for the period.

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 June 30,		Six months ended June 30,	
	2019	**2018**	**2019**	**2018**
Production costs	$ 19.62	$ 18.93	$ 19.54	$ 19.01
Production costs, excluding effects of PSC-type contracts[(a)]	$ 17.98	$ 17.41	$ 17.99	$ 17.44
Field general and administrative expenses[(b)]	$ 1.28	$ 1.07	$ 1.27	$ 0.90
Field depreciation, depletion and amortization[(b)]	$ 9.55	$ 9.67	$ 9.41	$ 9.78
Field taxes other than on income[(b)]	$ 2.39	$ 2.38	$ 2.53	$ 2.53

(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 consolidated operations for the three and six months ended June 30, 2019 and 2018:

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
	(in millions)			
Oil and gas sales	$ 578	$ 657	$ 1,179	$ 1,232
Net derivative gain (loss) from commodity contracts	21	(167)	(68)	(205)
Other revenue	54	59	232	131
Production costs	(230)	(231)	(463)	(443)
General and administrative expenses	(79)	(90)	(162)	(153)
Depreciation, depletion and amortization	(121)	(125)	(239)	(244)
Taxes other than on income	(36)	(37)	(77)	(75)
Exploration expense	(10)	(6)	(20)	(14)
Other expenses, net	(55)	(49)	(203)	(110)
Interest and debt expense, net	(98)	(94)	(198)	(186)
Net gain on early extinguishment of debt	20	24	26	24
Gain on asset divestitures	—	1	—	1
Other non-operating expenses	(3)	(5)	(10)	(12)
Income (loss) before income taxes	41	(63)	(3)	(54)
Income tax	—	—	—	—
Net income (loss)	41	(63)	(3)	(54)
Net income attributable to noncontrolling interests	(29)	(19)	(52)	(30)
Net Income (loss) attributable to common stock	$ 12	$ (82)	$ (55)	$ (84)
Adjusted net (loss) income	$ (14)	$ (14)	$ 17	$ (6)
Adjusted EBITDAX	$ 255	$ 245	$ 556	$ 495
Effective tax rate	—%	—%	—%	—%

Three months ended June 30, 2019 vs. 2018

Oil and gas sales - Oil and gas sales, excluding the impact of settled hedges, decreased 12%, or $79 million, for the three months ended June 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 June 30, 2018	$ 553	$ 61	$ 43	$ 657
Changes in realized prices	(33)	(22)	2	(53)
Changes in production	(24)	—	(2)	(26)
Three months ended June 30, 2019	$ 496	$ 39	$ 43	$ 578

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 on oil were $14 million for the three months ended June 30, 2019 compared to payments of $68 million for the three months ended June 30, 2018, which had a positive impact of $82 million on our realized price for oil. Including the effect of settled hedges, our oil and gas revenue was slightly higher compared to the same prior-year period.

Net derivative gain (loss) from commodity contracts - Net derivative gain from commodity contracts was $21 million for the three months ended June 30, 2019 compared to a loss of $167 million in the same period of 2018, representing an overall change of $188 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 June 30, 2019	Three months ended June 30, 2018
	(in millions)	
Non-cash derivative gain (loss), excluding noncontrolling interest	$ 4	$ (92)
Non-cash derivative gain (loss), noncontrolling interest	3	(7)
Total non-cash changes	7	(99)
Net proceeds (payments) on settled commodity derivatives	14	(68)
Net derivative gain (loss)	$ 21	$ (167)

General and administrative expenses - Our general and administrative (G&A) expenses decreased $11 million to $79 million for the three months ended June 30, 2019 compared to the same period of 2018 predominantly due to expenses related to our cash-settled equity awards, resulting from the adjustment of the obligation to our stock price at the end of each quarter. Our stock price decreased by approximately $10.00 from the beginning to the end of the second quarter of 2019 compared to an increase of approximately $30.00 in our stock price from the beginning to the end of the second quarter of 2018. This had the effect of lower non-cash stock-based compensation expense for cash-settled equity awards in the second quarter of 2019 compared to the same prior-year period. Additionally, the stock price for the cash-settled equity awards that vested during the three months ended June 30, 2019 were paid at a lower stock price compared to the cash-settled equity awards that vested in the same prior-year period. The decrease in stock-based compensation expense was partially offset by higher overhead in 2019.

Six months ended June 30, 2019 vs. 2018

Oil and gas sales - Oil and gas sales, excluding the impact of settled hedges, decreased 4%, or $53 million, for the six months ended June 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)		
Six months ended June 30, 2018	$ 1,019	$ 124	$ 89	$ 1,232
Changes in realized prices	(64)	(23)	13	(74)
Changes in production	21	(3)	3	21
Six months ended June 30, 2019	$ 976	$ 98	$ 105	$ 1,179

See *Production and Prices* for index prices, realizations and production.

The effect of settled hedges are not included in the table above. Proceeds from settlements on our oil contracts were $28 million for the six months ended June 30, 2019 compared to payments of $99 million for the six months ended June 30, 2018, which had a positive impact of $127 million on our realized price for oil. Including the effect of settled hedges, our oil and gas revenue was higher compared to the same prior-year period.

Net derivative gain (loss) from commodity contracts - Net derivative loss from commodity contracts was $68 million for the six months ended June 30, 2019 compared to $205 million in the same period of 2018, representing an overall change of $137 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.

	Six months ended June 30,	
	2019	2018
	(in millions)	
Non-cash derivative gain (loss), excluding noncontrolling interest	$ (93)	$ (99)
Non-cash derivative gain (loss), noncontrolling interest	(3)	(7)
Total non-cash changes	(96)	(106)
Net proceeds (payments) on settled commodity derivatives	28	(99)
Net derivative gain (loss) from commodity contracts	$ (68)	$ (205)

Other revenue - The increase in other revenue of $101 million to $232 million for the six months ended June 30, 2019 compared to $131 million in the same period of 2018, was largely the result of higher trading activity in 2019.

Production costs - Production costs for the six months ended June 30, 2019 increased $20 million to $463 million, compared to $443 million for the same period of 2018, resulting in a 5% increase. The increase is 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 increased $9 million to $162 million for the six months ended June 30, 2019 compared to the same period of 2018 predominantly due to higher expenses across a number of functions, partially offset by lower cash-settled stock-based compensation expense. Our stock price was relatively flat from the beginning to the end of the six months ended June 30, 2019 compared to an increase of approximately $25.00 in our stock price from the beginning to the end of the six months ended June 30, 2018. This had the effect of lower non-cash stock-based compensation expense for cash-settled awards in the first half of 2019 compared to the same prior-year period.

Other expenses, net - The increase in other expenses of $93 million to $203 million for the six months ended June 30, 2019 compared to $110 million for the same period of 2018, was largely the result of higher trading activity in 2019.

Interest and debt expense, net - Interest and debt expense, net increased $12 million to $198 million for the six months ended June 30, 2019 compared to $186 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 $22 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.

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

Our consolidated results of operations for the three and six months ended June 30, 2019 and 2018 include the effects of long-term stock-based compensation plans under which awards are granted annually to executives, non-executive employees and non-employee directors that are either settled with shares of our common stock or cash. Our equity-settled awards granted to executives include stock options, restricted stock units and performance stock units that either cliff vest at the end of a three-year period or vest ratably over a three-year period, some of which are partially settled in cash. Our equity-settled awards granted to non-employee directors are 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 approximately 50% of our total outstanding awards. Equity-settled awards are not similarly adjusted for changes in our stock price.

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

	Three months ended June 30,			Six months ended June 30,		
	2019	2018	Variance	2019	2018	Variance
	(in millions, except per Boe amounts)					
G&A expenses						
Cash-settled awards	$ 3	$ 19	$ (16)	$ 13	$ 22	$ (9)
Equity-settled awards	4	4	—	7	7	—
Total in G&A	$ 7	$ 23	$ (16)	$ 20	$ 29	$ (9)
Total in G&A per Boe	$ 0.60	$ 1.89	$ (1.29)	$ 0.84	$ 1.24	$ (0.40)
Production costs						
Cash-settled awards	$ 1	$ 5	$ (4)	$ 4	$ 6	$ (2)
Equity-settled awards	1	1	—	2	2	—
Total in production costs	$ 2	$ 6	$ (4)	$ 6	$ 8	$ (2)
Total in production costs per Boe	$ 0.17	$ 0.49	$ (0.32)	$ 0.25	$ 0.34	$ (0.09)
Total company	$ 9	$ 29	$ (20)	$ 26	$ 37	$ (11)
Total company per Boe	$ 0.77	$ 2.38	$ (1.61)	$ 1.09	$ 1.58	$ (0.49)

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 (loss) to the non-GAAP financial measure of adjusted net (loss) 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 (loss) income per diluted share:

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

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 June 30,		Six months ended June 30,	
	2019	**2018**	**2019**	**2018**
	(in millions)			
Net income (loss)	$ 41	$ (63)	$ (3)	$ (54)
Interest and debt expense, net	98	94	198	186
Depreciation, depletion and amortization	121	125	239	244
Exploration expense	10	6	20	14
Unusual, infrequent and other items	(26)	68	72	78
Other non-cash items	11	15	30	27
Adjusted EBITDAX	$ 255	$ 245	$ 556	$ 495

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:

	Six months ended June 30,	
	2019	**2018**
	(in millions)	
Net cash provided by operating activities	$ 272	$ 234
Cash interest	225	215
Exploration expenditures	10	10
Working capital changes	49	37
Other, net	—	(1)
Adjusted EBITDAX	$ 556	$ 495

Adjusted EBITDAX increased by $61 million primarily due to higher oil and natural gas production, higher realized oil prices with hedges and higher trading income, partially offset by higher production costs.

Liquidity and Capital Resources

Cash Flow Analysis

	Six months ended June 30,	
	2019	2018
	(in millions)	
Net cash provided by operating activities	$ 272	$ 234
Net cash used in investing activities:		
Capital investments	$ (271)	$ (327)
Changes in capital investment accruals	$ (57)	$ 22
Acquisitions, divestitures and other	$ 158	$ (502)
Net cash (used) provided by financing activities:		
Debt transactions	$ (74)	$ (205)
Contributions (distributions) with noncontrolling interest holders	$ (16)	$ 755
Issuance of common stock and other	$ (2)	$ 45

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 16%, or $38 million, to $272 million for the six months ended June 30, 2019 from $234 million in the same period of 2018. The increase was primarily due to higher realized prices, including hedge settlements, and higher volumes in the first half of 2019. These increases were partially offset by changes in operating assets and liabilities related to higher interest payments on variable-rate debt that reduced our operating cash flow by $52 million in 2019 compared to $42 million in 2018. 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 $170 million for the six months ended June 30, 2019 primarily reflected $271 million of capital investments (excluding $57 million in capital-related accrual changes), of which $43 million was funded by BSP. Cash used in investing activities also included proceeds of $165 million related to the Lost Hills divestiture. For the six months ended June 30, 2018, our net cash used in investing activities of $807 million primarily included approximately $512 million of acquisition costs related to the Elk Hills transaction and a building in Bakersfield and $327 million of capital investments (excluding $22 million in capital-related accrual changes), of which $18 million was funded by BSP.

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

	Six months ended June 30,	
	2019	2018
	(in millions)	
Oil and gas	$ 212	$ 296
Exploration	9	10
Corporate and other	7	3
Total internally funded capital	228	309
BSP funded capital	43	18
Total capital	$ 271	$ 327

Our net cash used in financing activities of $92 million for the six months ended June 30, 2019 primarily comprised $65 million of distributions to our noncontrolling interest holders, $59 million of debt repurchases on our Second Lien Notes and net payments on our 2014 Revolving Credit Facility of $15 million, partially offset by contributions from BSP of $49 million. For the six months ended June 30, 2018, our net cash provided by financing activities of $595 million primarily comprised $796 million in net contributions from our noncontrolling interest holders and $50 million from the issuance of common stock to an Ares-led investor group in connection with the Ares JV, partially offset by $119 million used for debt repurchases on our senior notes, $86 million of net payments on our 2014 Revolving Credit Facility and $41 million of distributions paid to our noncontrolling interest holders.

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, fund acquisitions and for other corporate purposes. We expect that the combination of these sources of funds will be adequate for our 2019 capital program, debt service and operating needs.

As of June 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	$	525	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		1,991	8%	December 15, 2022[(b)]	Second-Priority Lien
Senior Notes					
5% Senior Notes due 2020		100	5%	January 15, 2020	Unsecured
5½% Senior Notes due 2021		100	5.5%	September 15, 2021	Unsecured
6% Senior Notes due 2024		144	6%	November 15, 2024	Unsecured
Total		5,160			
Less: Current Maturities		(100)			
Long-Term Debt	$	5,060			

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 $315 million in June 2021, $63 million in December 2021, $65 million in June 2022 and $1,548 million in December 2022.

2014 Revolving Credit Facility

As of June 30, 2019, we had $309 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 May 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 June 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.

Note Repurchases

In the first quarter of 2019, we repurchased $18 million in face value of our 8% senior secured second lien notes due December 15, 2022 (Second Lien Notes) for $14 million in cash resulting in a pre-tax gain of $6 million, including the effect of unamortized deferred gain and issuance costs. In the second quarter of 2019, we repurchased $58 million in face value of our Second Lien Notes for $45 million in cash resulting in a pre-tax gain of $20 million, including the effect of unamortized deferred gain and issuance costs.

Other

At June 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 June 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 August 1, 2019:

	Q3 2019	Q4 2019	Q1 2020	Q2 2020
Purchased Puts:				
Barrels per day	40,000	35,000	25,000	10,000
Weighted-average price per barrel	$ 73.13	$ 75.71	$ 72.00	$ 70.00
Sold Puts:				
Barrels per day	40,000	35,000	25,000	10,000
Weighted-average price per barrel	$ 57.50	$ 60.00	$ 57.00	$ 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.

Interest-Rate Contracts

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

2019 Capital Program

We expect our 2019 internally funded capital program to be in the range of $350 million to $385 million, of which $228 million has been invested in the first half of 2019. We have front-loaded our internally funded capital investments for 2019. With additional investment from new and existing JV partners, we anticipate JV investment of $175 million to $225 million, of which $50 million has been invested in the first half of 2019, for a total 2019 capital program of $525 million to $610 million.

We are focusing our 2019 capital on oil projects. Our capital program 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 70% 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 12% 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 deepenings, recompletions, changes of lift methods and other activities designed to add incremental productive intervals and reserves.

Further, approximately 12% 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 6% is intended to be used for exploration and other corporate uses.

Efficiency gains in our capital costs have enabled us to maintain a robust capital program even in light of 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 June 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 planned investments, debt repurchases, distributions to JV partners or changes to our capital plan
- inability to enter desirable transactions including acquisitions, asset sales and joint ventures
- legislative or regulatory changes, including those related to drilling, completion, well stimulation, operation, maintenance or abandonment of wells or facilities, managing energy, water, land, greenhouse gases or other emissions, protection of health, safety and the environment, or transportation, marketing and sale of our products
- joint ventures and acquisitions and our ability to achieve expected synergies
- the recoverability of resources and
  unexpected geologic conditions
- incorrect estimates of reserves and related future cash flows and the inability to replace reserves
- changes in business strategy
- PSC effects on production and unit production costs
- effect of stock price on costs associated with incentive compensation
- insufficient capital, including as a result of lender restrictions, unavailability of capital markets or inability to attract potential investors
- effects of hedging transactions
- equipment, service or labor price inflation or unavailability
- availability or timing of, or conditions imposed on, permits and approvals
- lower-than-expected production, reserves or resources from development projects, joint ventures or acquisitions, or higher-than-expected decline rates
- disruptions due to accidents, mechanical failures, transportation or storage constraints, natural disasters, labor difficulties, cyber attacks or other catastrophic events
- 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 six months ended June 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

For the third and fourth quarters of 2019, we protected our downside risk on 40,000 and 35,000 barrels per day at approximately $73 Brent and $76 Brent, respectively. These put spreads provide full upside to oil price movements and downside price protection until Brent prices drop below approximately $58 and $60 per barrel in the third and fourth quarters, respectively, at which point we receive Brent plus $15 per barrel.

For the first and second quarters of 2020, we protected our downside risk on 25,000 and 10,000 barrels per day at $72 Brent and $70 Brent, respectively. These put spreads provide downside price protection until Brent prices drop below $57 and $55 per barrel in the first and second quarters, respectively, at which point we receive Brent plus $15 per barrel. We also entered into a swap for 5,000 barrels per day in the second quarter of 2020 at approximately $70 Brent, which is subject to another 5,000 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 June 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 June 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 June 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 June 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

Ventura County and other local authorities are conducting a civil investigation of the characterization of certain waste sent off-site for treatment or disposal at a licensed third-party facility. We do not expect the result of this investigation to have a material adverse effect on our condensed consolidated financial statements.

For information regarding legal proceedings, see *Note 8 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 (filed as Exhibit 4.1 to Registrant's Current Report on Form 8-K Filed July 22, 2019 and incorporated herein by reference).
10.2	California Resources Corporation Long-Term Incentive Plan, as amended and restated, effective May 8, 2019 (filed as Exhibit 4.3 to Registrant's Registration Statement on Form S-8 filed May 9, 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*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.

* - Filed herewith

SIGNATURES

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

CALIFORNIA RESOURCES CORPORATION

DATE: August 1, 2019

/s/ Roy M. Pineci

Roy M. Pineci
Executive Vice President - Finance
(Principal Accounting Officer)

EXHIBIT 31.1

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

I, Todd A. Stevens, certify that:

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

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

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

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

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

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

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

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

Date: August 1, 2019

/s/ Todd A. Stevens

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

EXHIBIT 31.2

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

I, Marshall D. Smith, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 1, 2019

/s/ Marshall D. Smith

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

EXHIBIT 32.1

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

In connection with the Quarterly Report on Form 10-Q of California Resources Corporation (the “Company”) for the fiscal period ended June 30, 2019, as filed with the Securities and Exchange Commission on August 1, 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 the best of his or her knowledge, respectively:

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

/s/ Todd A. Stevens

Name:	Todd A. Stevens
Title:	President and Chief Executive Officer
Date:	August 1, 2019

/s/ Marshall D. Smith

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