VALUE DRIVEN GROWTH

CALIFORNIA RESOURCES CORPORATION
2018 ANNUAL REPORT

FINANCIAL AND OPERATIONAL HIGHLIGHTS

Amounts in millions, except per-share amounts as of and for the years ended December 31,

Financial Highlights	**2018**	**2017**	**2016**
Total Revenue	$ 3,064	$ 2,006	$ 1,547
Income (Loss) Before Income Taxes	$ 429	$ (262)	$ 201
Net Income Attributable to Noncontrolling Interests	$ 101	$ (4)	$ -
Net Income (Loss) Attributable to Common Stock	$ 328	$ (266)	$ 279
Adjusted Net Income (Loss)[a]	$ 61	$ (187)	$ (317)
Net Income (Loss) Attributable to Common Stock per Share – Basic and Diluted[b]	$ 6.77	$ (6.26)	$ 6.76
Adjusted Net Income (Loss) per Share – Basic and Diluted[b]	$ 1.27	$ (4.40)	$ (7.85)
Net Cash Provided by Operating Activities	$ 461	$ 248	$ 130
Capital Investments	$ 690	$ 371	$ 75
Net Payments on Debt	$ 26	$ 18	$ 73
Net Cash Provided (Used) by Financing Activities	$ 692	$ 73	$ (69)
Total Assets	$ 7,158	$ 6,207	$ 6,354
Long-Term Debt	$ 5,251	$ 5,306	$ 5,168
Deferred Gain and Issuance Costs, Net	$ 216	$ 287	$ 397
Equity	$ (247)	$ (720)	$ (557)
Weighted-Average Shares Outstanding[b]	47.4	42.5	40.4
Year-End Shares	48.7	42.9	42.5

Operational Highlights	**2018**	**2017**	**2016**
Production:			
Oil (MBbl/d)	82	83	91
NGLs (MBbl/d)	16	16	16
Natural Gas (MMcf/d)	202	182	197
Total (MBoe/d)[c]	132	129	140
Average Realized Prices:			
Oil with hedge ($/Bbl)	$ 62.60	$ 51.24	$ 42.01
Oil without hedge ($/Bbl)	$ 70.11	$ 51.47	$ 39.72
NGLs ($/Bbl)	$ 43.67	$ 35.76	$ 22.39
Natural Gas ($/Mcf)	$ 3.00	$ 2.67	$ 2.28
Reserves:			
Oil (MMBbl)	530	442	409
NGLs (MMBbl)	60	58	55
Natural Gas (Bcf)	734	706	626
Total (MMBoe)[c]	712	618	568
Organic Reserve Replacement Ratio[a]	127%	119%	71%
PV-10 of Proved Reserves[a] (in billions)	$ 9.4	$ 4.5	$ 2.8
Net Mineral Acreage (in thousands):			
Developed	701	703	717
Undeveloped	1,539	1,550	1,614
Total	2,240	2,253	2,331
Closing Share Price	$ 17.04	$ 19.44	$ 21.29

(a) See www.crc.com, Investor Relations for a discussion of these non-GAAP measures, including a reconciliation to the most closely related GAAP measure or information on the related calculations. (b) Share amounts presented on post-split basis.
(c) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

All statements, other than statements of historical fact, included in this report that address activities, events or developments that we believe will or may occur in the future are forward-looking statements. The words "anticipate," "believe," "continue," "could," "estimate," "expect," "goal," "intend," "likely," "may," "might," "plan," "potential," "project," "seek," "should," "target," "will" or "would" or other similar expressions identify forward-looking statements. Such statements specifically include our expectations as to our: future financial position • liquidity • cash flows • results of operations • business prospects • budgets • transactions • projects • operating costs • operations and operational results • maintenance capital requirements • reserves. Factors (but not necessarily all factors) that could cause our results to differ include: commodity price changes • debt limitations on our financial flexibility • insufficient cash flow to fund planned investment • inability to enter desirable transactions including asset sales and joint ventures • legislative or regulatory changes • insufficient capital • unexpected geologic conditions • changes in business strategy • inability to replace reserves • inability to enter efficient hedges • equipment, service or labor price inflation or unavailability • limitations on necessary permits and approvals • worse-than-expected results of development or acquisitions • disruptions from accidents, mechanical failures, transportation or storage constraints, natural disasters, labor difficulties, cyber-attacks, and other catastrophic events • other risk factors as discussed in our Annual Report on Form 10-K. Forward-looking statements speak only as of the date on which made and we undertake no obligation to correct or update such statements, except as required by applicable law.

A MESSAGE TO OUR SHAREHOLDERS

Dear Shareholder,

California continued its strong demand for energy and petroleum products in 2018. As the world's fifth largest economy, California consumes every drop of oil and natural gas produced in the state and imports approximately 90% of the natural gas, 74% of the oil and 30% of the electricity it consumes. California Resources Corporation (CRC) remains well-positioned to develop California's vast oil and natural gas resources in a safe and responsible manner to make our state's energy future more sustainable, self-sufficient and secure. Produced under the most stringent safety, labor, human rights and environmental standards, the native oil and natural gas production that CRC provides helps California reduce its reliance on imported petroleum from around the world. Native production also increases access to reliable and affordable energy and provides thousands of good local careers for a diverse workforce of Californians from all educational backgrounds.

CRC benefits from a world-class asset base and a team that has been pressure-tested. In 2018, we relied upon our flexible business model, the optionality of our portfolio and our differentiated integrated infrastructure to successfully respond to a variety of pricing conditions. Throughout the year, we remained dedicated to our value-driven strategy that centers on 1) capturing the full value of our portfolio; 2) driving operational excellence; 3) ensuring effective capital allocation; and 4) strengthening the balance sheet. As a result, CRC delivered a strong performance for 2018, which included profitable production growth supported by increased activity, managed operating costs, a strategic and accretive acquisition, as well as reserves growth over 2017 levels.

In 2018, CRC's dynamic capital program increased to our highest level as a public company to address production declines and deliver organic oil production growth in the second half of the year. Utilizing $641 million of internally funded capital, supplemented by $106 million of joint venture (JV) capital, CRC generated value-driven organic growth, which yielded higher average total production year-over-year and reflected a healthy Value Creation Index (VCI)[1] of 1.5 based on a $60 Brent price deck for 2018. Prioritizing capital investment toward oil-focused opportunities, we increased reserves to 712 million barrels of oil equivalent (BOE) and delivered a strong all-in reserve replacement ratio of 296%, reflecting 127% from the capital program alone, while adding to our inventory and actionable projects. We also reduced operating costs on a per barrel basis each quarter sequentially throughout the year and enhanced our overall margin performance for 2018. As a result, we ended 2018 in a strengthened position with production growth in the second half of the year and annual adjusted EBITDAX[1] of $1.1 billion, growing an impressive 43% compared to the prior year.

Complementing our operational focus on safety, quality, innovation and efficiency in 2018, CRC completed two major transactions early in the year that earned a S&P Global Platts Energy Award for "Corporate Deal of the Year" from among a global array of transactions across the energy sector. In February of 2018, we contributed our Elk Hills power and gas processing assets into a midstream JV with a portfolio company of Ares Management, L.P. in exchange for $750 million. This strategic move allowed CRC to monetize midstream assets that were not being fully valued by the market, deploy the proceeds toward debt reduction and acquire the remaining working, surface and mineral interests at our flagship Elk Hills field. Completed with $460 million in cash and the issuance of 2.85 million shares of CRC common stock, the Elk Hills acquisition immediately added value to CRC, improving both cash flow and credit metrics, in addition to delivering approximately $34 million of annualized synergies from consolidated operations by the end of 2018 — well ahead of initial expectations.

We also continued ongoing debt reduction efforts by opportunistically repurchasing $232 million of face value of our debt at a discount for $199 million in 2018. As we demonstrated in each of the past four years, CRC's balance sheet strengthening activities center on prioritizing the best value alternatives that further our goals to reduce overall levels of debt, simplify our capital structure and enhance our credit metrics. With many options available, we will continue to be thoughtful in our approach and disciplined in our execution for maximum benefit to our shareholders as we move toward our long-term leverage target.

At CRC, we pursue opportunities and investments that play to our strength as California's operator of choice and lead with our deep experience of operating successfully within California's prolific, stacked reservoirs, multiple drive mechanisms and comprehensive regulatory system. Our workforce comes from our state's diverse communities and their dedication and hard work provide energy that is essential to a beneficial, affordable quality of life for all Golden State residents. CRC's workforce prioritizes safeguarding people and the environment, and we achieved our annual safety, environmental stewardship and water conservation targets in 2018. Our workforce earned one of its highest safety ratings in the history of our operations and received 14 National Safety Council awards. We served as a net water supplier once again, delivering a record 5.3 billion gallons of treated, reclaimed water to agricultural water districts in 2018. In addition, our team continued to advance projects to attain our 2030 Sustainability Goals for water, renewables, methane and carbon. A key example is CRC's strategic project at Elk Hills to design carbon capture technologies to enhance oil production, while sequestering carbon dioxide in oil and gas formations, which would contribute meaningfully to meeting the state's long-term sustainability goals.

In 2019, CRC will continue to execute our value-driven strategy with dynamic operating and capital plans that can be quickly adjusted to match prevailing market conditions. We will utilize our technical knowledge and experience to target high-margin production and reserves that will enhance value and strengthen the balance sheet. With our disciplined capital allocation approach, diverse asset base and a workforce dedicated to sustained operational excellence in providing energy for California by Californians, CRC represents a compelling investment that is set to deliver long-term value creation for our shareholders for years to come.

Regards,

Todd A. Stevens
President and Chief Executive Officer
California Resources Corporation

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[1] See the Investor Relations page at www.crc.com for explanations of how CRC calculates and uses the non–GAAP measure of adjusted EBITDAX and a reconciliation to its nearest GAAP measure, and for other important information about possible and probable reserves and other hydrocarbon resource quantities and recycle ratio calculations. The Value Creation Index (VCI) metric is calculated by dividing the net present value of the project's expected pre-tax cash flow over its life by the net present value of the related investments, each using a 10% discount rate.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2018

☐ **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** (Address of principal executive offices)	**91355** (Zip Code)

(888) 848-4754
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act: Yes ☐ No ☑

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 Date File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or such shorter period as the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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 Act) Yes ☐ No ☑

The aggregate market value of the voting common stock held by nonaffiliates of the registrant was approximately $2.2 billion, computed by reference to the closing price on the New York Stock Exchange composite tape of $45.44 per share of Common Stock on June 30, 2018. Shares of Common Stock held by each executive officer and director have been excluded from this computation in that such persons may be deemed to be affiliates. This determination of potential affiliate status is not a conclusive determination for other purposes.

At January 31, 2019, there were 48,650,420 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission in connection with the registrant's 2019 Annual Meeting of Stockholders, are incorporated by reference into Part III of this Form 10-K.

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PART I

ITEMS 1 & 2 BUSINESS AND PROPERTIES

Business Operations and Environment

We are an independent oil and natural gas exploration and production company operating properties exclusively within the state of California. We are the largest oil and gas producer in California on a gross operated basis, with average net daily production of 132 thousand of barrels of oil equivalent per day (MBoe/d) in 2018. We have the largest privately held mineral acreage position in the state, consisting of approximately 2.2 million net mineral acres spanning four of California's major oil and gas basins. Our proved reserves totaled an estimated 712 million barrels of oil equivalent (MMBoe) at December 31, 2018.

We have a diversified portfolio of oil and natural gas locations and extensive drilling inventory that are economically viable in a variety of operating and commodity price conditions, including many that are high-value projects throughout the commodity price cycle. Our acreage position contains numerous development and growth opportunities due to its varied geologic characteristics and multiple stacked-pay reservoirs that are, in many cases, thousands of feet thick. Our returns are enhanced relative to our peers because we do not make royalty or other lease payments on over 60% of our acreage, which is held in fee.

Our large portfolio of low-risk and low-decline conventional opportunities spans each of our oil and gas basins and comprises approximately 72% of our proved reserves. We are in various phases of developing many of our conventional assets and will continue to develop them by using internally generated cash flow and, when appropriate, raising capital through joint ventures (JVs).

We also own or control a network of strategically placed infrastructure that is integrated with, and complementary to, our operations, including gas plants, oil and gas gathering systems, power plants and other related assets, which we use to maximize the value generated from our production.

Our 3D seismic library covers approximately 4,860 square miles, representing approximately 90% of the 3D seismic data available in California. We have developed unique, proprietary stratigraphic and structural models of the subsurface geology and hydrocarbon potential in each of the four basins in which we operate. We have successfully implemented various exploration, drilling, completion and enhanced recovery technologies to increase recoveries, growth and value from our portfolio.

We were formed in April 2014 and are currently listed on the New York Stock Exchange. All references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its subsidiaries.

Our Business Strategy

We provide ample, affordable and reliable energy, in a safe and responsible manner, to support and enhance the quality of life for Californians and the local communities where we operate. We do this through the development of our broad portfolio of assets while adhering to our commitment to providing value. Our long-term value-driven growth strategy is focused on five key priorities:

- Utilize our technical knowledge and experience to target production growth, delineate expansion areas and optimize hydrocarbon recovery;
- Use our Value Creation Index (VCI) metric to ensure consistent, disciplined and effective capital allocation;

- Optimize operational performance through streamlined processes, application of technology and entrepreneurial thinking to capture efficiencies, improve results and reduce costs;
- Strengthen our balance sheet by investing to grow cash flow, simplifying our capital structure, pursuing value-accretive acquisitions and reducing absolute levels of our debt and fixed charges; and
- Maintain a proactive and collaborative approach to safety, environmental protection and community outreach while helping California address its energy and water needs.

Our Strengths

The following characteristics position us to successfully execute our business strategy:

- ***Operational control and a diverse asset base provide us with flexibility.***

  We have ownership or operational control over substantially all of our assets. This allows us to adapt our investments by selecting drilling locations, timing the development and the drilling and completion techniques used and allocating capital in a manner designed to optimize cash flow over a wide range of commodity prices.

  We have a large and diverse mineral acreage position that permits a variety of recovery mechanisms and product types. The majority of our interests are in producing properties located in reservoirs that we believe have long-lived production profiles with repeatable development opportunities. The low base decline of our conventional assets allows us to limit production declines with minimal investment.

  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 uses. We are also exploring carbon dioxide capture and storage projects and reclaimed water opportunities.

- ***Largest acreage position in a world-class oil and natural gas province.***

  Our operations are located exclusively in California, which is one of the most prolific oil and natural gas producing regions in the world and is currently the sixth largest oil producing state in the nation. According to the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources' (DOGGR) information through 2017, cumulative California production from all four basins in which we operate is 36 billion barrels of oil equivalent (BBoe), including approximately 20 BBoe in the San Joaquin basin, 11 BBoe in the Los Angeles basin, 3 BBoe in the Ventura basin and 2 BBoe in the Sacramento basin. Additionally, Kern County, in the San Joaquin basin, is the second largest oil producing county in the lower 48 states. California is also the nation's largest state economy, and the world's fifth largest, with significant energy demands that exceed local supply. Our large acreage position and diverse development portfolio enable us to pursue the appropriate production strategy for the relevant commodity price environment without the need to acquire new acreage and allow us to quickly deploy the knowledge we gain in our existing operations, together with our seismic data, to other areas within our portfolio.

- ***Extensive drilling and workover portfolio.***

  Our drilling inventory at December 31, 2018 consisted of approximately 32,350 gross (25,090 net) identified well locations, of which approximately 95% are oil. In addition, we continue to maintain our available workover projects that can deliver high returns. Our inventory of largely lower-risk conventional development opportunities has increased more than our unconventional opportunities. In a sustained favorable oil and gas price environment, we believe we can achieve further long-term production growth through the development of unconventional reservoirs. In addition, our large conventional and unconventional portfolio can provide attractive JV opportunities.

- ***Proven operational management and technical teams with extensive experience operating in California.***

  The members of our operational management and technical teams have an average of over 25 years of experience in the oil and natural gas industry, with an average of over 15 years focused on our California oil and gas operations through different price cycles. Our teams have a proven track record of applying modern technologies and operating methods to develop our assets and improve their operating efficiencies.

Our Operations

The following table highlights key information about our operations as of and for the year ended December 31, 2018 in each of California's four major oil and gas basins:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Operations
Acreage:					
Net mineral acreage (thousands)	1,446	30	247	517	2,240
Average net mineral acreage held in fee (%)	66%	46%	74%	38%	60%
Number of fields	49	8	27	53	137
Average net revenue interest (%)[(a)]	90%	73%	83%	78%	86%
Average drilling rigs	7	3	—	—	10
Net wells drilled and completed	128.6	48.2	3.5	—	180.3
Proved reserves:					
Oil (MMBbl)	317	173	40	—	530
NGLs (MMBbl)	57	—	3	—	60
Natural Gas (Bcf)	621	13	32	68	734
Total (MMBoe)	478	175	48	11	712
Oil percentage of proved reserves	66%	99%	83%	—%	74%
Production:					
Total (MMBoe)	35	9	2	2	48
Average net daily production (MBoe/d)	96	25	6	5	132
Oil percentage of production	55%	100%	67%	—%	62%
Reserves to production ratio (years)[(b)]	13.7	19.4	24.0	5.5	14.8

Note: MMBbl refers to millions of barrels; Bcf refers to billions of cubic feet; MMBoe refers to millions of barrels of oil equivalent; and MBoe/d refers to thousands of barrels of oil equivalent 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.

(a) The average net revenue interest represents our interest in production after taking into account royalties and similar burdens and third- party working interests.

(b) Calculated as total proved reserves as of December 31, 2018 divided by total production for the year ended December 31, 2018.

San Joaquin Basin

According to the 2012 U.S. Geological Survey, the San Joaquin basin contained three of the 10 largest oil fields in the United States based on cumulative production and proved reserves. Commercial petroleum development in the basin began in the 1800s. The basin contains multiple stacked formations throughout its areal extent, and we believe that the San Joaquin basin provides appealing opportunities for field re-development of existing wells, as well as new discoveries and unconventional play potential. The complex geology in the San Joaquin basin has allowed continuing discoveries of stratigraphic and structural traps. Approximately 75% of California's total daily oil production for 2017 was produced in the San Joaquin basin, according to DOGGR.

The Elk Hills field is our largest producing asset and has been one of the largest fields in the continental U.S. based on proved reserves. Following the acquisition of Chevron's interest in April 2018, we now hold all of the working, surface and mineral interests in the former Elk Hills unit.

At Elk Hills we also operate efficient natural gas processing facilities, including a state-of-the-art cryogenic gas plant, with a combined gas processing capacity of over 520 MMcf/d. Additionally, the Elk Hills power plant generates sufficient electricity to operate the field, and sells excess power to the grid and to a utility. Our operations at Elk Hills also include an advanced central control facility and remote automation control on over 95% of our producing wells.

We believe our extensive 3D seismic library, which covers over 880,000 acres in the San Joaquin basin, or approximately 50% of our gross acreage in this basin, will give us a competitive advantage in further exploration. We have established a large ownership interest in several of the largest existing oil fields in the San Joaquin basin, including Elk Hills, Buena Vista and Kettleman North Dome. We have also been successfully developing steamfloods in our Kern Front operations and in the northwest portion of the Lost Hills field.

Los Angeles Basin

This basin is a northwest-trending plain about 50 miles long and 20 miles wide. Most of the significant discoveries in the Los Angeles basin date back to the 1920s. The Los Angeles basin has one of the highest concentrations per acre of crude oil in the world with 68 fields in an area of about 0.3 million acres. The basin contains multiple stacked formations throughout its depths, and we believe that the Los Angeles basin provides a considerable inventory of existing field re-development opportunities as well as new play discovery potential. Large active oil fields include the Wilmington and Huntington Beach fields, where we have significant operations.

The Wilmington field has been one of the largest fields in the continental U.S. based on proved reserves. Most of our Wilmington production is subject to a set of contracts similar to production-sharing contracts (PSCs) under which we recover the capital and operating costs we incur on behalf of the state and the city of Long Beach and receive our share of profits.

Ventura Basin

The Ventura Basin is the oldest operating petroleum basin in California extending from northern Los Angeles County to the coastal city of Ventura and continues offshore encompassing the Santa Barbara channel. The earliest discoveries were mines dug into hillsides to mine active oil seeps. The first commercial oil well started in 1866. All of the sedimentary section is productive at various locations, and most reservoirs are sandstones with favorable porosity and permeability. As of December 31, 2018, we operated more than 20 oilfields in this historic and prolific basin. The basin contains multiple stacked formations throughout its depths and provides an appealing inventory of existing field re-development opportunities, as well as new exploration potential. We continue to explore over 10,000 feet of proven stacked oil reservoirs throughout the basin.

Sacramento Basin

The Sacramento basin is a deep, thick sequence of sedimentary deposits within an elongated northwest-trending structural feature covering about 7.7 million acres. Exploration and development in the basin began in 1918. Our significant acreage position in the Sacramento basin gives us the option for future development and rapid production growth in an attractive natural gas price environment.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we held an interest as of December 31, 2018. Approximately 60% of our total net mineral interest position is held in fee, approximately 16% is held by production and the remainder is subject to term leases.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in thousands)		
Developed[a]					
Gross[b]	417	21	63	266	767
Net[c]	378	16	61	246	701
Undeveloped[d]					
Gross[b]	1,297	17	222	355	1,891
Net[c]	1,068	14	186	271	1,539
Total					
Gross[b]	1,714	38	285	621	2,658
Net[c]	1,446	30	247	517	2,240

(a) Acres spaced or assigned to productive wells.
(b) Total number of acres in which interests are owned.
(c) Sum of our fractional interests based on working interests or interests under PSC-type contracts.
(d) Acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether the acreage contains proved reserves.

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.

Work programs are designed to ensure that the exploration potential of any leased property is fully evaluated before expiration. In some instances, we may relinquish leased acreage in advance of the contractual expiration date if the evaluation process is complete and there is no longer a commercial reason for leasing that acreage. In cases where we determine we want to take the additional time required to fully evaluate undeveloped acreage, we have generally been successful in obtaining extensions. The combined net acreage covered by leases expiring in the next three years represented approximately 14% of our total net undeveloped acreage at December 31, 2018 and these expirations, should they occur, would not have a material adverse impact on us. Historically, we have not dedicated any significant portion of our capital program to prevent lease expirations and do not expect we will need to do so in the future.

Production, Price and Cost History

Oil, NGLs and natural gas are commodities, and the price we receive for our production is largely a function of market supply and demand. Product prices are affected by a variety of factors, including changes in domestic and global supply and demand; domestic and global inventory levels; political and economic conditions; the actions of OPEC and other significant producers and governments; changes or disruptions in actual or anticipated production, refining and processing; worldwide drilling and exploration activities; government energy policies and regulations, including with respect to climate change; the effects of conservation; weather conditions and other seasonal impacts; speculative trading in derivative contracts; currency exchange rates; technological advances; transportation and storage capacity, bottlenecks and costs in producing areas; the price, availability and acceptance of alternative energy sources; regional market conditions and other matters affecting the supply and demand dynamics for these products. Given the volatile oil price environment, as well as our leverage, we have a hedging program to help protect our cash flow and capital investment program.

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.

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to PSCs that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and production costs. We record a share of production and reserves to recover a portion of such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners' share of capital and production costs that we incur on their behalf, (ii) for our share of contractually defined base production, and (iii) for our share of remaining production thereafter. We recover our share of capital and production costs, and generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, assuming comparable capital investment and production costs. However, our net economic benefit is greater when product prices are higher. The contracts represented 15% of our production for the year ended December 31, 2018.

In addition, in line with industry practice for reporting PSC-type contracts, we report 100% of operating costs under such contracts in our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, 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 per barrel and has no effect on our net results.

The following table sets forth information regarding our production, realized and benchmark prices, and production costs per Boe for the years ended December 31, 2018, 2017 and 2016. For additional information on price calculations, see information set forth in *Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Production and Prices*.

	Year Ended December 31,		
	2018	2017	2016
Average net daily production:			
Oil (MBbl/d)[(a)]	82	83	91
NGLs (MBbl/d)	16	16	16
Natural gas (MMcf/d)	202	182	197
Total net production (MBoe/d)[(b)]	132	129	140
Total production (MMBoe)[(a)(b)]	48	47	51
Average realized prices:			
Oil prices with hedge ($/Bbl)	$ 62.60	$ 51.24	$ 42.01
Oil prices without hedge ($/Bbl)	$ 70.11	$ 51.47	$ 39.72
NGLs prices ($/Bbl)	$ 43.67	$ 35.76	$ 22.39
Natural gas prices ($/Mcf)	$ 3.00	$ 2.67	$ 2.28
Average benchmark prices:			
Brent oil ($/Bbl)	$ 71.53	$ 54.82	$ 45.04
WTI oil ($/Bbl)	$ 64.77	$ 50.95	$ 43.32
NYMEX gas ($/MMBtu)	$ 2.97	$ 3.09	$ 2.42
Average production costs per Boe[(b)]:			
Production costs	$ 18.88	$ 18.64	$ 15.61
Production costs, excluding effects of PSC-type contracts[(c)]	$ 17.47	$ 17.48	$ 14.69

Note: MBbl/d refers to thousands of barrels per day; MMcf/d refers to millions of cubic feet per day; MMBtu refers to Million British Thermal Units.

(a) Our PSC-type contracts negatively impacted our oil production in 2018 by over 1 MBoe/d compared to 2017. The impact on our oil production was immaterial in 2017 compared to 2016.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas (Mcf) to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(c) 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 production costs after adjusting for the excess costs attributable to PSC-type contracts.

The following table sets forth information regarding production, realized prices and production costs per Boe for our two largest fields, Elk Hills and Wilmington, for the years ended December 31, 2018, 2017 and 2016:

	Elk Hills			Wilmington		
	2018	2017	2016	2018	2017	2016
Average net production:						
Oil (MBbl/d)	22	19	21	21	23	25
NGLs (MBbl/d)	12	13	13	—	—	—
Natural gas (MMcf/d)	108	95	106	1	1	—
Total net production (MBoe/d)	52	48	52	21	23	25
Average realized prices[(a)]:						
Oil (MBbl/d)	$ 73.98	$ 55.58	$ 44.50	$ 67.81	$ 49.87	$ 37.98
NGLs (MBbl/d)	$ 43.58	$ 36.26	$ 23.03	$ —	$ —	$ —
Natural gas (MMcf/d)	$ 2.87	$ 2.52	$ 2.27	$ 1.71	$ 2.12	$ 1.83
Production costs per Boe[(b)]	$ 12.07	$ 11.76	$ 10.48	$ 29.81	$ 27.91	$ 22.27
Production costs per Boe, excluding effects of PSC-type contracts[(c)]	N/A	N/A	N/A	$ 21.02	$ 21.59	$ 17.21

(a) Excludes the effect of hedges.

(b) 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.

(c) 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 production costs after adjusting for the excess costs attributable to PSC-type contracts.

Reserves

The information with respect to our estimated reserves presented below has been prepared in accordance with the rules and regulations of the SEC.

Proved oil, NGLs and natural gas reserves were estimated using the unweighted arithmetic average of the first-day-of-the-month price for each month within the year (SEC Price), unless prices were defined by contractual arrangements. Oil, NGLs and natural gas prices used for this purpose were based on spot prices, adjusted for price differentials to account for gravity, quality and transportation costs. For our 2018 reserves estimates, the average benchmark Brent oil price was $71.75 per barrel and the average NYMEX gas price was $3.10 per MMBtu. The average realized prices used for our 2018 reserves were $70.92 per barrel for oil, $43.88 per barrel for NGLs and $2.95 per Mcf for natural gas.

The following table sets forth our net operating and non-operating interests in quantities of proved developed and undeveloped reserves of oil (including condensate), natural gas liquids (NGLs) and natural gas as of December 31, 2018. Estimated reserves include our economic interests under arrangements similar to PSCs at our Wilmington field in Long Beach.

	As of December 31, 2018				
	San Joaquin Basin	**Los Angeles Basin**	**Ventura Basin**	**Sacramento Basin**	**Total**
Proved developed reserves:					
Oil (MMBbl)	231	131	27	—	389
NGLs (MMBbl)	45	—	2	—	47
Natural Gas (Bcf)	473	9	23	60	565
Total (MMBoe)(a)(b)	355	132	33	10	530
Proved undeveloped reserves:					
Oil (MMBbl)	86	42	13	—	141
NGLs (MMBbl)	12	—	1	—	13
Natural Gas (Bcf)	148	4	9	8	169
Total (MMBoe)(b)	123	43	15	1	182
Total proved reserves:					
Oil (MMBbl)	317	173	40	—	530
NGLs (MMBbl)	57	—	3	—	60
Natural Gas (Bcf)	621	13	32	68	734
Total (MMBoe)(b)	478	175	48	11	712

(a) As of December 31, 2018, approximately 23% of proved developed oil reserves, 9% of proved developed NGLs reserves, 13% of proved developed natural gas reserves and, overall, 20% of total proved developed reserves are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full peak production response has not yet occurred due to the nature of such projects.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

Proved Reserves Additions

The components of the changes to our proved reserves during the year ended December 31, 2018 were as follows (in MMBoe):

	San Joaquin Basin	**Los Angeles Basin(a)**	**Ventura Basin**	**Sacramento Basin**	**Total**
Balance at December 31, 2017	419	145	40	14	618
Revisions related to price	16	23	1	(2)	38
Revisions related to performance	(8)	8	5	1	6
Improved recovery	4	—	—	—	4
Extensions and discoveries	18	8	4	—	30
Purchases	64	—	—	—	64
Sales	—	—	—	—	—
Production	(35)	(9)	(2)	(2)	(48)
Balance at December 31, 2018	478	175	48	11	712

Note: Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(a) Includes proved reserves related to PSC-type contracts of 131 MMBoe and 108 MMBoe at December 31, 2018 and 2017, respectively.

In 2018, total net additions to proved reserves from all sources were 142 MMBoe. Our 2018 realized prices for oil and natural gas increased over the prior year by 39% and 14%, respectively, which resulted in positive price-related revisions of 38 MMBoe.

We added 6 MMBoe from net positive performance-related revisions of which 27 MMBoe were from positive technical revisions due to better-than-expected performance and successful drilling efforts in the San Joaquin and Los Angeles basins. These additions were partially offset by 21 MMBoe of negative revisions due to management's discretion to downgrade proved undeveloped reserves (PUDs) that are not anticipated to be developed within their five-year window of initial booking. Approximately 11 MMBoe of these downgraded PUDs are expiring in 2019 and are not anticipated to be developed before then at current oil prices. The remaining 10 MMBoe of downgraded PUDs are projects that are no longer prioritized in our development plan based on current project economics.

We also added 4 MMBoe from improved recovery through proven IOR and EOR methods. The improved recovery additions were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin.

We added 30 MMBoe from extensions and discoveries, primarily resulting from new geologic interpretations and pressure data in the Ventura basin along with successful drilling in the San Joaquin and Los Angeles basins.

We also added 64 MMBoe in connection with acquisitions during the year, the majority of which resulted from the Elk Hills transaction.

Excluding PUD downgrades of 21 MMBoe that were made at management's discretion, we achieved an organic reserve replacement ratio of 127% from our capital program of $690 million. Additionally, our JV partner MIRA funded $57 million, which contributed to our reserve adds. Our total net reserve additions from all sources generated a reserve replacement ratio of 296%. For further information on our reserve replacement ratio, see the *PV-10, Standardized Measure and Reserve Replacement Ratio* section below.

See *Item 8 – Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited)* for further discussion of changes in our proved reserves.

Proved Undeveloped Reserves

The total changes to our PUDs during the year ended December 31, 2018 were as follows (in MMBoe):

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Balance at December 31, 2017	125	40	11	2	178
Revisions related to performance	(15)	1	4	—	(10)
Revisions related to price changes	2	2	(4)	(1)	(1)
Extensions and discoveries	12	5	4	—	21
Improved recovery	3	—	—	—	3
Purchases	17	—	—	—	17
Transfers to proved developed reserves	(21)	(5)	—	—	(26)
Balance at December 31, 2018	123	43	15	1	182

Note: Natural gas volumes have been converted to Boe based on the equivalence of energy content of six thousand cubic feet of natural gas and one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

In 2018, we had net negative performance-related revisions of 10 MMBoe, reflecting a 21 MMBoe downward adjustment based on management discretion as described above, which was partially offset by 11 MMBoe of positive revisions.

We added 21 MMBoe of PUDs through extensions and discoveries, primarily resulting from new geologic interpretations and pressure data in the Ventura basin along with successful drilling in the San Joaquin and Los Angeles basins.

We added proved reserves of 3 MMBoe from improved recovery through proven IOR and EOR methods. The improved recovery additions were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin. Approximately 79% of the PUD additions from extensions and discoveries and improved recovery were crude oil.

We transferred 26 MMBoe of PUDs to the proved developed category as a result of the 2018 capital program, all of which was in the San Joaquin and Los Angeles basins. As a result, we converted approximately 15% of our beginning-of-year PUDs to proved developed reserves during the year, investing approximately $235 million of development capital.

Our year-end development plans and associated PUDs are consistent with SEC guidelines for development within five years. We believe we will have sufficient capital to develop all year-end 2018 PUDs within five years of their original booking date. Management's capital commitment assumes an average $65 Brent price for 2019 and approximately $75 thereafter. Prices that are significantly below these levels for a prolonged period could require us to reduce expected capital investment over the next five years, potentially impacting either the quantity or the development timing of proved undeveloped reserves. For example, if the average future price remained at $65 Brent, our PUDs would be reduced by approximately 5 to 10% over the long term.

PV-10, Standardized Measure and Reserve Replacement Ratio

As of December 31, 2018, our standardized measure of discounted future net cash flows (Standardized Measure) was $7.3 billion and PV-10 was approximately $9.4 billion. In addition, we organically replaced 127% of our proved reserves in 2018, excluding the effect of PUDs downgraded at management's discretion.

PV-10 is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect the timing of future cash flows and using SEC-prescribed pricing assumptions for the period. PV-10 differs from Standardized Measure because Standardized Measure includes the effects of future income taxes on future net cash flows. Neither PV-10 nor Standardized Measure should be construed as the fair value of our oil and natural gas reserves. Standardized Measure is prescribed by the SEC as an industry standard asset value measure to compare reserves with consistent pricing, costs and discount assumptions. PV-10 facilitates the comparisons to other companies as it is not dependent on the tax-paying status of the entity.

		As of December 31, 2018
		(in millions)
Standardized measure of discounted future net cash flows	$	7,275
Present value of future income taxes discounted at 10%		2,136
PV-10 of proved reserves	$	9,411
Organic reserve replacement ratio[(a)]		127%
All-in reserve replacement ratio[(b)]		296%

(a) The organic reserve replacement ratio is calculated for a specified period using the proved oil-equivalent additions from extensions and discoveries, improved recovery and performance-related revisions (excluding 21 MMBoe of PUDs downgraded at management's discretion), divided by oil-equivalent production. There is no guarantee that historical sources of reserves additions will continue as many factors are fully or partially outside management's control, including commodity prices, availability of capital and the underlying geology, all of which affect reserves additions. Management uses this measure to gauge the results of its capital program. Other oil and gas producers may use different methods to calculate replacement ratios, which may affect comparability.

(b) The all-in reserve replacement ratio is calculated for a specified period using the proved oil-equivalent additions from extensions and discoveries, improved recovery, revisions and purchases, divided by oil-equivalent production. There is no guarantee that historical sources of reserves additions will continue as many factors are fully or partially outside management's control, including commodity prices, availability of capital and the underlying geology, all of which affect reserves additions. Management uses this measure to gauge the results of its capital program. Other oil and gas producers may use different methods to calculate replacement ratios, which may affect comparability.

Reserves Evaluation and Review Process

Our estimates of proved reserves and associated discounted future net cash flows as of December 31, 2018 were made by our technical personnel, such as reservoir engineers and geoscientists, with the assistance of operational and financial personnel and are the responsibility of management. The estimation of proved reserves is based on the requirement of reasonable certainty of economic producibility and management's funding commitments to develop the reserves. Reserves volumes are estimated by forecasts of production rates, operating costs and capital investments. Price differentials between specified benchmark prices and realized prices and specifics of each operating agreement are then applied against the SEC Price to estimate the net reserves. Production rate forecasts are derived using a number of methods, including estimates from decline-curve analysis, type-curve analysis, material balance calculations, which take into account the volumes of substances replacing the volumes produced and associated reservoir pressure changes, seismic analysis and computer simulations of reservoir performance. These field-tested technologies have demonstrated reasonably certain results with consistency and repeatability in the formations being evaluated or in analogous formations. Operating and capital costs are forecast using the current cost environment (without accounting for possible cost changes) applied to expectations of future operating and development activities related to the proved reserves.

Net proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods, for which the incremental cost of any additional required investment is relatively minor. Net proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.

Our Vice President, Reserves and Corporate Development has primary responsibility for overseeing the preparation of our reserves estimates. She has over 14 years of experience as an energy sector engineer including as a Senior Reservoir Engineer with Ryder Scott Company, L.P. (Ryder Scott). She is a member of the Society of Petroleum Engineers (SPE) for which she served as past chair of the U.S. Registration Committee. She holds a Master of Business Administration from the Massachusetts Institute of Technology, a Master of Engineering in Petroleum Engineering from the University of Houston and a Bachelor of Science from the University of Florida. She is also a registered Professional Engineer in the state of Texas.

We have an Oil and Gas Reserves Review Committee (Reserves Committee), consisting of senior corporate officers, which reviewed and approved our oil and natural gas reserves for 2018. The Reserves Committee reports its findings to the Audit Committee during the year.

Audits of Reserves Estimates

Ryder Scott was engaged to provide an independent audit of our reserves estimates for fields that comprised at least 80% of our total proved reserves. The primary technical engineer responsible for our audit has 39 years of petroleum engineering experience, the majority of which has been in the estimation and evaluation of reserves. He serves on the Ryder Scott Board of Directors and is a registered Professional Engineer in the state of Texas.

The 2018 reserves audit covered over 80% of our total proved reserves. Over 95% of our total 2018 proved reserves were audited by Ryder Scott at some time during 2015 through 2018. Ryder Scott examined the assumptions underlying our reserves estimates, adequacy and quality of our work product, and estimates of future production rates, net revenues, and the present value of such net revenues. Ryder Scott also examined the appropriateness of the methodologies employed to estimate our reserves as well as their categorization, using the definitions set forth by the SEC, and found them to be appropriate. As part of their process, Ryder Scott developed their own independent estimates of reserves for those fields that they audited. When compared on a field-by-field basis, some of our estimates were greater and some were less than the estimates of Ryder Scott. Given the inherent uncertainties and judgments in estimating proved reserves, differences between our and Ryder Scott's estimates are to be expected. The aggregate difference between our estimates and Ryder Scott's was less than 10%, which was within SPE's acceptable tolerance.

In the conduct of the reserves audit, Ryder Scott did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, crude oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if anything came to Ryder Scott's attention which brought into question the validity or sufficiency of any such information or data, Ryder Scott would not rely on such information or data until it had resolved its questions relating thereto or had independently verified such information or data.

Ryder Scott determined that our estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC as well as the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions. Ryder Scott issued an unqualified audit opinion on our proved reserves as of December 31, 2018. Ryder Scott's report is attached as an exhibit to this Form 10-K.

Recovery Mechanisms

The following table sets forth our reserves and production by basin and recovery mechanism:

	Total Proved Reserves	Average Net Daily Production (MBoe/d)
	% of Total Basin	Year ended December 31, 2018
San Joaquin Basin		
Primary	15%	15
Waterfloods	13%	9
Steamfloods	31%	24
Unconventional	41%	48
San Joaquin Basin subtotal(a)	478	96
Los Angeles Basin		
Waterfloods	100%	25
Los Angeles Basin subtotal(a)	175	25
Ventura Basin		
Primary	34%	3
Waterfloods	66%	3
Ventura Basin subtotal(a)	48	6
Sacramento Basin		
Primary	100%	5
Sacramento Basin subtotal(a)	11	5
Total	712	132

(a) Subtotal basin reserves in MMBoe. 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.

Conventional Reservoirs

Conventional reservoirs are capable of natural flow during primary recovery phase, often followed by waterflood and steamflood recovery methods to enhance ultimate recovery. We determine which development method to use based on reservoir characteristics, reserves potential and expected returns. We seek to optimize the potential of our conventional assets by using primary recovery methods, followed by secondary techniques such as Improved Oil Recovery (IOR) methods like waterflooding and Enhanced Oil Recovery (EOR) methods like steamflooding, both of which use vertical and horizontal drilling. All of these techniques are well understood technologies that we have used extensively in California.

Primary Recovery

Primary recovery is a reservoir drive mechanism that utilizes the natural energy of the reservoir and is the first technique we use to develop a conventional reservoir. Our successful exploration program continues to provide us with primary recovery opportunities in new reservoirs or through extensions of existing fields. Our primary recovery programs create future opportunities to convert these reservoirs to waterfloods or steamfloods after their primary production phase.

Waterfloods

Some of our fields have been partially produced and no longer have sufficient energy to drive oil to our producing wellbores. Waterflooding is a well understood process that has been used in California for over 50 years to re-introduce energy to the reservoir through water injection and to sweep oil to producing wellbores. This process has been known to increase recovery factors from approximately 10% under primary recovery methods to up to approximately 20%. Our waterflood operations have attractive margins and returns. These operations typically have low and predictable production declines and allow us to extend the productive life of a reservoir and significantly increase our incremental recovery after primary recovery. As a result, investments in waterfloods can yield attractive returns even in a low price environment.

Steamfloods

Some of our fields contain heavy, thick oil. Steamfloods work by injecting steam into the reservoir to heat the oil which allows it to flow more easily to the producing wellbores. Steamflooding is a well understood process that has been used in California since the early 1960s. This process has been known to increase recovery factors from approximately 10% under primary recovery methods to up to approximately 75%. Thermal operations are most effective in shallow reservoirs containing heavy, viscous oil. The steamflood process generally requires low capital investment with attractive margins and returns even in a low oil price environment as long as the oil-to-gas price ratio is in excess of five. The economics of steamflooding are largely a function of the ratio between oil and natural gas prices as gas is used to generate steam production. After drilling, these operations typically ramp up production over one to two years as the steam continues to influence the oil production, and then exhibit a plateau for several months, with a subsequent low, predictable production decline rate of 5 to 10% per year. This gradual decline allows us to extend the productive life of a reservoir and significantly increase our incremental recovery after primary production.

Unconventional Reservoirs

We have a significant portfolio of lower permeability unconventional reservoirs that typically utilize established well-stimulation techniques. We believe our undeveloped unconventional acreage has the potential to provide significant long-term production growth. In total, we hold mineral interests in approximately 1.3 million net acres with unconventional potential and have identified 4,620 (gross and net) unconventional drilling locations on this acreage, excluding unconventional exploration drilling locations. Approximately 36% of our 2018 production was from unconventional reservoirs, all in the San Joaquin basin. Our unconventional production from our largest field, the Elk Hills field in the San Joaquin basin, increased approximately 10% in 2018 from the prior year. As of December 31, 2018, we had proved reserves of approximately 196 MMBoe associated with our unconventional properties, approximately 25% of which were proved undeveloped reserves.

We hold significant interests in the Monterey formation, which is divided into upper and lower intervals. Prior to the severe price declines that began in late 2014, we were focused on developing higher-value unconventional production from seven discrete stacked pay horizons within the Monterey formation, primarily within the upper Monterey. In 2018, we continued our development activities in the upper Monterey formation and started to appraise and delineate the Kreyenhagen formation within our Kettleman North Dome field. During the year ended December 31, 2018, we had unconventional production of approximately 47 MBoe/d on average from the upper Monterey in the San Joaquin basin.

The lower Monterey is recognized as a world-class source rock but has an extremely limited production history compared to the upper Monterey, and therefore very limited knowledge exists regarding its potential. However, over the long term, we believe we will be able to apply knowledge we gain from the upper Monterey to the lower Monterey, Kreyenhagen and Moreno formations, which have similar geological attributes.

Drilling Locations

The table below sets forth our total gross identified drilling locations as of December 31, 2018, excluding our unconventional exploration drilling locations.

	Proven Drilling Locations		Total Identified Drilling Locations[(a)]	
	Oil and Natural Gas Wells	Injection Wells	Oil and Natural Gas Wells	Injection Wells
San Joaquin Basin				
Primary Conventional	140	—	8,080	—
Steamflood	570	150	8,350	450
Waterflood	90	40	1,970	980
Unconventional	220	—	4,520	—
San Joaquin Basin subtotal	1,020	190	22,920	1,430
Los Angeles Basin				
Waterflood	460	130	1,520	500
Los Angeles Basin subtotal	460	130	1,520	500
Ventura Basin				
Primary Conventional	30	—	1,400	—
Steamflood	—	—	120	—
Waterflood	80	60	1,560	520
Unconventional	—	—	100	—
Ventura Basin subtotal	110	60	3,180	520
Sacramento Basin				
Primary Conventional	10	—	2,280	—
Sacramento Basin subtotal	10	—	2,280	—
Total Drilling Locations	1,600	380	29,900	2,450

(a) Total gross identified drilling locations is comprised of gross proven drilling locations of 1,980 gross (1,970 net), gross unproven drilling locations of 17,030 gross (16,870 net) and gross conventional exploration drilling locations of 13,340 gross (6,250 net). Total gross identified drilling locations excludes gross unconventional exploration drilling locations of 6,400 gross (5,300 net).

Proven Drilling Locations

Based on our reserves report as of December 31, 2018, we have approximately 1,980 gross (1,970 net) drilling locations attributable to our proved undeveloped reserves. We use production data and experience gained from our development programs to identify and prioritize this proven drilling inventory. These drilling locations are included in our reserves only after we have adopted a development plan to drill them within a five-year time frame. As a result of rigorous technical evaluation of geologic and engineering data, we can estimate with reasonable certainty that reserves from these locations will be commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations and other factors it deems relevant in determining such locations.

Unproven Drilling Locations

We have also identified a multi-year inventory of 17,030 gross (16,870 net) drilling locations that are not associated with proved undeveloped reserves but are specifically identified on a field-by-field basis considering the applicable geologic, engineering and production data. We analyze past field development practices and identify analogous drilling opportunities taking into consideration historical production performance, estimated drilling and completion costs, spacing and other performance factors. These drilling locations primarily include (i) infill drilling locations, (ii) additional locations due to field extensions or (iii) potential IOR and EOR project expansions, some of which are currently in the pilot phase across our properties but have yet to be moved to the proven category. We believe the assumptions and data used to estimate these drilling locations are consistent with established industry practices with well spacing selected based on the type of recovery process we are using.

Exploration Drilling Locations

Conventional – Our exploration portfolio contains approximately 13,340 gross (6,250 net) unrisked prospective drilling locations in conventional reservoirs, the majority of which are located near existing producing fields. We use internally generated information and proprietary geologic models consisting of analog data, 3D seismic data, open hole and mud log data, cores and reservoir engineering data to help define the extent of the targeted intervals and the potential ability of such intervals to produce commercial quantities of hydrocarbons. Information used to identify exploration locations includes both our own proprietary data, as well as industry data available in the public domain. After defining the potential areal extent of an exploration prospect, we identify our exploration drilling locations within the prospect by applying the well spacing historically utilized for the applicable type of recovery process used in analogous fields.

Unconventional – We have approximately 6,400 gross (5,300 net) unrisked prospective resource drilling locations identified in the lower Monterey, Kreyenhagen and Moreno unconventional reservoirs based on screening criteria that include geologic and economic considerations and limited production information. Prospective areas are defined by geologic data consisting of well cuttings, hydrocarbon shows, open-hole well logs, geochemical data, available 3D or 2D seismic data and formation pressure data, where available. Information used to identify our prospective locations includes both our own proprietary data, as well as industry data available in the public domain. We identify our prospective resource drilling locations based on an assumption of 80-acre spacing per well throughout the prospective area.

Well Spacing Determination

Our well spacing determinations in the above categories of identified well locations are based on actual operational spacing within our existing producing fields, which we believe are reasonable for the particular recovery process employed (e.g., primary, waterflood or steamflood). Due to the significant vertical thickness and multiple stacked reservoirs, typical well spacing is generally less than 20 acres and often 10 acres or less in the majority of our fields unless specified differently above. These parameters also meet the general well spacing restrictions imposed on certain oil and gas fields in California.

Drilling Schedule

Our identified drilling locations are either included in our drilling schedule or are expected to be scheduled in the future. When we identify these locations, we make assumptions about the consistency and accuracy of data that may prove inaccurate. For a discussion of the risks associated with our drilling program, see *Item 1A – Risk Factors – Risks Related to Our Business and Industry*.

Drilling Statistics

The following table sets forth information on our net exploration and development oil wells completed during the periods indicated, regardless of when drilling was initiated. We did not drill any gas wells in 2018. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total Net Wells
2018					
Productive					
Exploratory	0.3	—	—	—	0.3
Development	127.0	48.2	3.2	—	178.4
Dry					
Exploratory	1.3	—	0.3	—	1.6
Development	—	—	—	—	—
2017					
Productive					
Exploratory	2.0	—	—	—	2.0
Development	91.8	14.5	1.6	—	107.9
Dry					
Exploratory	3.0	—	—	—	3.0
Development	—	—	—	—	—
2016					
Productive					
Exploratory	—	—	—	—	—
Development	37.0	5.4	—	—	42.4

The following table sets forth information on our exploration and development wells where drilling was either in progress or pending completion as of December 31, 2018, which is not included in the above table.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Exploratory and development wells					
Gross[(a)]	14.0	2.0	3.3	—	19.3
Net[(b)]	13.9	1.9	2.3	—	18.1

(a) The total number of wells in which interests are owned.
(b) Sum of our fractional interests.

On a gross basis, these projects included three primary, five steamflood, ten waterflood and one unconventional.

Productive Wells

Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Our average working interest in our producing wells is approximately 94%. Wells are categorized based on the primary product they produce.

The following table sets forth our productive oil and natural gas wells (both producing and capable of production) as of December 31, 2018, excluding wells that have been idle for more than five years:

	As of December 31, 2018			
	Productive Oil Wells		Productive Gas Wells	
	Gross(a)	Net(b)	Gross(a)	Net(b)
San Joaquin Basin	8,419	7,961	166	161
Los Angeles Basin	1,533	1,486	1	1
Ventura Basin	1,320	1,312	—	—
Sacramento Basin	—	—	1,012	930
Total	11,272	10,759	1,179	1,092
Multiple completion wells included in the total above	382	356	46	42

(a) The total number of wells in which interests are owned.
(b) Sum of our fractional interests.

Exploration Program

We have an active exploration program in both conventional and unconventional plays. We believe our experienced technical staff, proprietary geological models, acreage position and extensive 3D seismic library give us a strong competitive advantage. California basins have generated billions of barrels of oil and billions of cubic feet of natural gas and have established production from over 400 identified reservoir intervals in both structural and stratigraphic trap configurations. Historical industry activity has focused on the primary and secondary development of known hydrocarbon accumulations, many of which were discovered over a century ago. We have significant land positions in under-explored hydrocarbon reservoirs in each of California's four major oil and gas basins.

Our exploration program is designed to extend fields and add new trends and resource plays to our already broad portfolio, targeting new oil and gas accumulations and leveraging our existing infrastructure. We continue to focus on growing our exploration drilling locations and resource identification, in some cases working with JV partners, primarily in the San Joaquin, Sacramento and Ventura Basins. We have a ranked near-field portfolio of over 150 exploration prospects across the San Joaquin, Sacramento and Ventura basins.

We have executed a deliberate approach to fund a portion of our exploration program through farmouts and joint ventures allowing us to test multiple prospects for minimal net investment. Generally, our JV partners fund the drilling activity in an exploration area on a promoted basis with any future development wells funded in proportion to the respective working interest percentages.

Marketing Arrangements

We currently sell all of our crude oil into the California refining markets, which offer favorable pricing for comparable grades relative to other U.S. regions. Although California state policies actively promote and subsidize renewable energy, including solar, wind, biomass and geothermal resources, the demand for oil and natural gas in California remains strong. California is heavily reliant on imported sources of energy, with approximately 74% of oil and 90% of natural gas consumed in 2018 imported from outside the state. Nearly all 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 Brent prices. We believe that the limited crude transportation infrastructure from other parts of the U.S. into California will continue to contribute to higher realizations than most other U.S. oil markets for comparable grades. Additionally, our differentials improved against Brent during 2017 and 2018 in response to strong demand for California crude oil to optimize local refinery yields as well as a decline in overall California crude oil production.

Crude Oil – Substantially all of our crude oil production is connected to third-party pipelines and California markets via our gathering pipelines, which are used almost entirely for our production. We do not refine or process the crude oil we produce and do not have any significant long-term transportation arrangements. We sell all of our crude oil into the California refining markets, which we believe have offered relatively favorable pricing compared to other U.S. regions for similar grades. Currently, our index-based crude oil sales contracts have 30-day to nine-month terms with no such contracts extending past one year.

Natural Gas – We sell all of our natural gas to the California market. We have firm transportation capacity contracts to access markets and to facilitate deliveries. We sell virtually all of our natural gas production under individually negotiated contracts using market-based pricing on a monthly or shorter basis.

NGLs – We extract substantially all of our NGLs through our gas processing plants, which facilitate access to third-party delivery points near the Elk Hills field. We currently have pipeline capacity contracts to transport 20,000 barrels per day of NGLs to market. We sell virtually all of our NGLs using index-based pricing. Our NGLs are generally sold pursuant to one-year contracts that are renewed annually. Approximately 60% of our NGLs are sold to export markets.

Electricity – Part of the electrical output of the Elk Hills power plant operated by one of our subsidiaries is used by Elk Hills and other nearby fields, which reduces operating costs and increases reliability. We sell the excess electricity generated to the grid and a local utility. The power sold to the utility is subject to an agreement expiring at the end of 2020, which includes a minimum capacity payment.

Delivery Commitments

We have short-term commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2018, we had oil and NGL delivery commitments of 41 and 19 MBbl/d through March 2019, respectively, and natural gas commitments of 35 MMcf/d through the end of 2019. We have significantly more production capacity than the amounts committed for oil and natural gas. For NGL commitments, we have agreements to cash settle any shortfall between the committed quantities and our production. Further, we have the ability to secure additional volumes of all products if necessary. None of the commitments are expected to have a material impact on our financial statements. These are index-based contracts with prices set at the time of delivery.

Hedging

We maintain a commodity hedging program primarily focused on crude oil to help protect our cash flows, margins and capital program from the volatility of commodity prices and to improve our ability to comply with the covenants under our credit facilities. We will continue to be strategic and opportunistic in implementing our hedging program. 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. For more on our current derivative contracts, see *Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources*.

Our Principal Customers

We sell crude oil, natural gas and NGLs to marketers, California refineries and other purchasers that have access to transportation and storage facilities. Our ability to sell our products can be affected by factors that are beyond our control, and which cannot be accurately predicted.

For the year ended December 31, 2018, our principal customers, Phillips 66 Company and Valero Marketing & Supply Company, each accounted for at least 10%, and, collectively, 43% of our revenue. For the years ended December 31, 2017 and 2016, our principal customers, Phillips 66 Company, Andeavor (formerly Tesoro Refining & Marketing Company LLC), Valero Marketing & Supply Company and Shell Trading (US) Company, each accounted for at least 10%, and, collectively, 67% of our revenue.

Title to Properties

As is customary in the oil and natural gas industry for acquired properties, we initially conduct a high-level review of the title to our properties at the time of acquisition. Individual properties may be subject to ordinary course burdens that we believe do not materially interfere with the use or affect the value of such properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and tax obligations or duties under applicable laws, development obligations, or net profits interests, among other items. Prior to the commencement of drilling operations on those properties, we typically conduct a more thorough title examination and may perform curative work with respect to significant defects. We generally will not commence drilling operations on a property until we have cured known title defects that are material to the project. In addition, substantially all of our properties have been pledged as collateral for our secured debt.

Competition

We encounter strong competition from numerous parties in the oil and gas industry, ranging from small independent producers to major international oil companies. The oil market in California is a captive market with no interstate crude pipelines and only limited rail access and unloading capacity for refineries. As a result, 74% of the oil the state consumes is imported, virtually all from waterborne sources. Our proximity to the California refineries gives us a competitive advantage through lower transportation costs. Further, California refineries are generally designed to process crude with similar characteristics to the oil produced from our fields. The California natural gas market is serviced from a network of pipelines, including interstate and intrastate pipelines. We deliver our natural gas to customers using capacity on our firm transportation commitments.

We compete for third-party services to profitably develop our assets, to find or acquire additional reserves, to sell our production and to find and retain qualified personnel. Historically, higher commodity prices intensify competition for drilling and workover rigs, pipe, other oil field equipment and personnel. As oil prices and activity increased in 2017, the energy industry in certain parts of the country started experiencing increases in service costs. However, the California energy industry experienced only limited cost inflation in 2017 and 2018 due to excess capacity in the service and supply sectors. At current commodity price levels, we expect limited cost inflation to continue in 2019. Given our relative size compared to other in-state producers, our activity level influences the pricing of third-party services in the local market.

Infrastructure

We own a network of infrastructure that is integral to and complements our operations. Our significant footprint in California and wide network of infrastructure help us connect to third-party transportation pipelines, providing us with a competitive advantage by reducing our operating costs.

Our infrastructure includes the following:

Description	Quantity	Unit(a)	Capacity		
			San Joaquin Basin	Other Basins	Total
Gas Plants	9	MMcf/d	610	50	660
Power Plants	3	MW	600	50	650
Steam Generators/Plants	>50	MBbl/d	220	—	220
Compressors	400	MHp	300	20	320
Water Management Systems	22	MBw/d	2,400	2,100	4,500
Water Softeners	30	MBw/d	265	—	265
Oil and NGL Storage		MBbls	580	660	1,240
Gathering Systems		Miles			>20,000

(a) MW refers to megawatts of power; MBbl/d refers to thousand barrels of steam per day; MHp refers to thousand horsepower; MBw/d refers to thousand barrels of water per day; MBbl refers to thousands of barrels.

Gas Processing

We believe we own the largest gas processing system in California. In the San Joaquin basin, the Elk Hills cryogenic gas plant has a capacity of 200 MMcf/d of inlet gas, bringing our total processing capacity in the basin to over 610 MMcf/d. We also own and operate a system of natural gas processing facilities in the Ventura basin that are capable of processing our equity and third-party wellhead gas from the surrounding areas. Our natural gas processing facilities are interconnected via pipelines to nearby third-party rail and trucking facilities, with access to various North American NGL markets. In addition, we have truck rack facilities coupled with a battery of pressurized storage tanks at the Elk Hills natural gas processing facility for NGL sales to third parties.

Electricity

The 550-megawatt combined-cycle Elk Hills power plant, located adjacent to the Elk Hills gas processing facility, generates all the electricity needs for our Elk Hills and certain contiguous operations in the San Joaquin basin. We utilize approximately a third of its capacity for our operations and our subsidiary sells the excess to the grid and to a local utility. The Elk Hills power plant also provides primary steam supply to our cryogenic gas plant. We also operate, as needed, a 45-megawatt cogeneration facility at Elk Hills that provides additional flexibility and reliability to support field operations. Within our Long Beach operations in the Los Angeles basin, we operate a 48-megawatt power generating facility that provides over 40% of our Long Beach operation's electricity requirements. All of these facilities are integrated with our operations to improve their reliability and performance while reducing operating costs.

Steam Infrastructure

We own, control and operate all of our steam generation infrastructure in the San Joaquin basin, including steam generators, steam plants, steam distribution systems, steam injection lines and headers, water softeners and water disposal systems. We soften and self-supply water to generate steam, reducing our operating costs. This infrastructure is integral to our operations in the San Joaquin basin and supports our high margin and shallow- to medium-depth oil fields such as Kern Front and Lost Hills.

Gathering Systems

We own an extensive network of over 20,000 miles of oil and gas gathering lines. These gathering lines are dedicated almost entirely to collecting our oil and gas production and are in close proximity to field-specific facilities such as tank settings or central processing sites. These lines connect our producing wells and facilities to gathering networks, natural gas collection and compression systems, and water and steam processing, injection and distribution systems. Our oil gathering systems connect to multiple third-party transportation pipelines, which increases our flexibility to ship to various parties. In addition, virtually all of our natural gas facilities connect with major third-party natural gas pipeline systems. As a result of these connections, we typically have the ability to access multiple delivery points to improve the prices we obtain for our oil and natural gas production.

Oil and NGL Storage

Our tank storage capacity throughout California gives us flexibility for a period of time to store crude oil and NGLs, allowing us to continue production and avoid or delay any field shutdowns in the event of temporary power, pipeline or other shutdowns.

Employees

We had approximately 1,500 employees as of December 31, 2018 compared to approximately 1,450 as of December 31, 2017. The increase is primarily due to the conversion of certain long-term contractors to employees in 2018. Of the 1,500 employees, approximately 1,080 were employed in field operations and approximately 75 of those employees are represented by labor unions. We have not experienced any strikes or work stoppages by our employees since our formation in 2014. We also utilize the services of independent contractors to perform drilling, well work, operations, construction and other services, including construction contractors whose workforce is often represented by labor unions.

Regulation of the Oil and Natural Gas Industry

Our operations are subject to a wide range of federal, state and local laws and regulations. Those that specifically relate to oil and natural gas exploration and production are described in this section.

Regulation of Exploration and Production

Federal, state and local laws and regulations govern most aspects of exploration and production in California, including:

- oil and natural gas production, including siting and spacing of wells and facilities on federal, state and private lands with associated conditions or mitigation measures;
- methods of constructing, drilling, completing, stimulating, operating, maintaining and abandoning wells;
- the design, construction, operation, maintenance and decommissioning of facilities, such as natural gas processing plants, power plants, compressors and liquid and natural gas pipelines or gathering lines;
- improved or enhanced recovery techniques such as fluid injection for pressure management;
- sourcing and disposal of water used in the drilling, completion, stimulation, maintenance and improved or enhanced recovery processes;
- imposition of taxes and fees with respect to our properties and operations;
- the conservation of oil and natural gas, including provisions for the unitization or pooling of oil and natural gas properties;

- posting of bonds or other financial assurance to drill, operate and abandon or decommission wells and facilities; and
- occupational health, safety and environmental matters and the transportation, marketing and sale of our products as described below.

Collectively, the effect of these regulations is to potentially limit the number and location of our wells and the amount of oil and natural gas that we can produce from our wells compared to what we otherwise would be able to do.

DOGGR is California's primary regulator of the oil and natural gas industry on private and state lands, with additional oversight from the State Lands Commission's administration of state surface and mineral interests. The Bureau of Land Management (BLM) of the U.S. Department of the Interior exercises similar jurisdiction on federal lands in California, on which DOGGR also asserts jurisdiction over certain activities. Government actions, including the issuance of certain permits or approvals, by state and local agencies or by federal agencies may be subject to environmental reviews, respectively, under the California Environmental Quality Act or the National Environmental Policy Act (NEPA), which may result in delays, imposition of mitigation measures or litigation. For example, in September 2016, a federal judge issued an order finding that the BLM's NEPA review of the Resource Management Plan for portions of Ventura, Kern and other counties failed to sufficiently analyze the potential environmental impacts of hydraulic fracturing and directed the BLM to prepare a supplemental environmental impact statement (SEIS). In August 2018, BLM published a notice of intent to prepare an amendment to the Resource Management Plan and an associated SEIS regarding oil and gas exploration and production activities, including well stimulation, which process may impact future oil and gas leasing of federal lands in central California.

The jurisdiction and enforcement authority of DOGGR and other state agencies have significantly increased with respect to oil and gas activities in recent years, and these agencies have significantly revised their regulations, regulatory interpretations and data collection requirements. DOGGR has undertaken a comprehensive examination of existing regulations and began implementing an electronic permitting system in 2018. DOGGR issued additional regulations in 2018 that impose more stringent inspection and integrity management requirements with respect to certain gas pipelines located in sensitive areas, and the Office of the State Fire Marshal intends to issue regulations in 2019 that would require retrofitting certain oil pipelines in the coastal zone with best available control technology to mitigate oil spills. DOGGR is also finalizing updated regulations governing management of idle wells and underground fluid injection, which are expected to be adopted early in 2019 and to include specific implementation periods. Pursuant to Assembly Bill 2729, which the Legislature enacted in 2016, DOGGR requires operators to either submit annual idle well management plans describing how they will plug and abandon or reactivate a specified percentage of long-term idle wells or pay additional annual fees for each such well. The updated underground injection regulations are expected to address injection approvals, project data requirements, testing of injection wells, monitoring and reporting requirements with respect to injection parameters, containment and incident response, among other topics. Finally, DOGGR announced that it is reviewing and intends to update its well construction regulations in the next two years.

In 2013 California adopted Senate Bill 4 (SB 4), which increased regulation of certain well stimulation techniques, including acid matrix stimulation and hydraulic fracturing, which involves the injection of fluid under pressure into underground rock formations to create or enlarge fractures to allow oil and gas to flow more freely into producing wells. Among other things, SB 4 requires operators to obtain specific well stimulation permits, make detailed disclosures and implement groundwater monitoring and water management plans. The U.S. Environmental Protection Agency (EPA) and the BLM also regulate certain well stimulation activities. In 2017, the BLM rescinded its hydraulic fracturing regulations, which were being challenged in court, and is preparing a SEIS regarding well stimulation and other oil and gas activities on federal lands in central California. The implementation of federal and state well stimulation regulations has delayed, and increased the cost of, certain operations.

In addition, certain local governments have proposed or adopted ordinances that would restrict certain drilling activities in general and well stimulation, completion or injection activities in particular, impose setback distances from certain other land uses, or ban such activities outright. The most onerous of these local measures was adopted in 2016 by Monterey County, where we own mineral interests but do not have any production. As written, the measure sought to prohibit the drilling of new oil and gas wells, hydraulic fracturing and other well-stimulation techniques and to phase out the injection of produced water. This measure was challenged in state court, and the Monterey County Superior Court issued a decision in December 2017, finding that the bans on drilling new wells and water injection are preempted by and invalid under existing state and federal regulations and, if implemented, would constitute a taking of our property without compensation under the federal and state constitutions. The court did not rule on the ban on hydraulic fracturing because the court found that the issue was not ripe since hydraulic fracturing is not currently being conducted in Monterey County, noting that the ban could be challenged in the event a project involving hydraulic fracturing is proposed. Although the County is complying with and declined to appeal the Court's decision and settled the litigation, sponsors of the ballot measure have appealed.

Regulation of Health, Safety and Environmental Matters

Numerous federal, state, local, and other laws and regulations that govern health and safety, the release or discharge of materials, land use or environmental protection may restrict the use of our properties and operations, increase our costs or lower demand for or restrict the use of our products and services. Applicable federal health, safety and environmental laws include the Occupational Safety and Health Act, Clean Air Act, Clean Water Act, Safe Drinking Water Act, Oil Pollution Act, Natural Gas Pipeline Safety Act, Pipeline Safety Improvement Act, Pipeline Safety, Regulatory Certainty, and Job Creation Act, Endangered Species Act, Migratory Bird Treaty Act, Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act and National Environmental Policy Act, among others. California imposes additional laws that are analogous to, and often more stringent than, such federal laws. These laws and regulations:

- establish air, soil and water quality standards for a given region, such as the San Joaquin Valley, conduct regional, community or field monitoring of air, soil or water quality, and require attainment plans to meet those regional standards, which may include significant mitigation measures or restrictions on development, economic activity and transportation in such region;
- require various permits, approvals and mitigation measures before drilling, workover, production, underground fluid injection or waste disposal commences, or before facilities are constructed or put into operation;
- require the installation of sophisticated safety and pollution control equipment, such as leak detection, monitoring and shutdown systems, and implementation of inspection, monitoring and repair programs to prevent or reduce releases or discharges of regulated materials to air, land, surface water or ground water;
- restrict the use, types or sources of water, energy, land surface, habitat or other natural resources, require conservation and reclamation measures, impose energy efficiency or renewable energy standards on us or users of our products and services, and restrict the use of oil, natural gas or certain petroleum–based products such as fuels and plastics;
- restrict the types, quantities and concentrations of regulated materials, including oil, natural gas, produced water or wastes, that can be released or discharged into the environment, or any other uses of those materials resulting from drilling, production, processing, power generation, transportation or storage activities;

- limit or prohibit operations on lands lying within coastal, wilderness, wetlands, groundwater recharge, endangered species habitat and other protected areas, and require the dedication of surface acreage for habitat conservation;
- establish standards for the management of solid and hazardous wastes or the closure, abandonment, cleanup or restoration of former operations, such as plugging and abandonment of wells and decommissioning of facilities;
- impose substantial liabilities for unauthorized releases or discharges of regulated materials into the environment with respect to our current or former properties and operations and other locations where such materials generated by us or our predecessors were released or discharged;
- require comprehensive environmental analyses, recordkeeping and reports with respect to operations affecting federal, state and private lands or leases;
- impose taxes or fees with respect to the foregoing matters;
- may expose us to litigation with government authorities, counterparties, special interest groups or others; and
- may restrict our rate of oil, NGLs, natural gas and electricity production.

Due to the severe drought in California over the last several years, water districts and the state government have implemented regulations and policies that may restrict groundwater extraction and water usage and increase the cost of water. Water management is an essential component of our operations. We treat and reuse water that is co-produced with oil and natural gas for a substantial portion of our needs in activities such as pressure management, waterflooding, steamflooding and well drilling, completion and stimulation. We also provide reclaimed produced water to certain agricultural water districts. We also use supplied water from various local and regional sources, particularly for power plants and to support operations like steam injection in certain fields.

In 2014, at the request of the EPA, DOGGR commenced a detailed review of the multi-decade practice of permitting underground injection wells and associated aquifer exemptions under the Safe Drinking Water Act (SDWA). In 2015, the state set deadlines to obtain the EPA's confirmation of aquifer exemptions under the SDWA in certain formations in certain fields. Since the state and the EPA did not complete their review before the state's deadlines, the state announced that it will not rescind permits or enforce the deadlines with respect to many of the formations pending completion of the review, but has applied the deadlines to others. Several industry groups and operators challenged DOGGR's implementation of its aquifer exemption regulations. In March 2017, the Kern County Superior Court issued an injunction barring the blanket enforcement of DOGGR's aquifer exemption regulations. The court found that DOGGR must find actual harm results from an injection well's operations and go through a hearing process before the agency can issue fines or shut down operations. During the review, the state has restricted injection in certain formations or wells in several fields, including some operated by us, requested that we change injection zones in certain fields, and held certain pending injection permits in abeyance. We are coordinating with the state to change injection zones in certain fields to facilitate disposal of produced water in deeper formations where feasible or to increase recycling of produced water in pressure maintenance or waterfloods in lieu of disposal.

Separately, the state began a review in 2015 of permitted surface discharge of produced water and the use of reclaimed water for agricultural irrigation, which led to additional permitting and monitoring requirements in 2017 for surface discharge. To date, the foregoing regulatory actions have not affected our oil and natural gas operations in a material way. These reviews are ongoing, and government authorities may ultimately restrict injection of produced water or other fluids in additional formations or certain wells, restrict the surface discharge or use of produced water or take other administrative actions. The foregoing reviews could also give rise to litigation with government authorities and third parties.

Federal, state and local agencies may assert overlapping authority to regulate in these areas. In addition, certain of these laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Regulation of Climate Change and Greenhouse Gas (GHG) Emissions

A number of international, federal, state, regional and local efforts seek to prevent or mitigate the effects of climate change or to track, mitigate and reduce GHG emissions associated with energy use and industrial activity, including operations of the oil and natural gas production sector and those who use our products as a source of energy or feedstocks. The EPA has adopted federal regulations to:

- require reporting of annual GHG emissions from oil and gas exploration and production, power plants and gas processing plants; gathering and boosting compression and pipeline facilities; and certain completions and workovers;
- incorporate measures to reduce GHG emissions in permits for certain facilities; and
- restrict GHG emissions from certain mobile sources.

California has adopted the most stringent laws and regulations. These state laws and regulations:

- established a "cap-and-trade" program for GHG emissions that sets a statewide maximum limit on covered GHG emissions, and this cap declines annually to reach 40% below 1990 levels by 2030, the year that the cap-and-trade program currently expires;
- require allowances or qualifying offsets for GHGs emitted from California operations and for the volume of natural gas, propane and liquid transportation fuels sold for use in California;
- established a low carbon fuel standard and associated tradable credits that require a progressively lower carbon intensity of the state's fuel supply than baseline gasoline and diesel fuels;
- mandated that California derive 60% of its electricity for retail customers from renewable resources by 2030;
- established a policy to derive all of California's retail electricity from renewable or "zero-carbon" resources by 2045, subject to required evaluation of the feasibility by state agencies; and
- imposed state goals to double the energy efficiency of buildings by 2030 and to reduce emissions of methane and fluorocarbon gases by 40% and black carbon by 50% below 2013 levels by 2030.

The EPA and the California Air Resources Board (CARB) have also expanded direct regulation of methane as a contributor to GHG emissions. In 2016, the EPA adopted regulations to require additional emission controls for methane, volatile organic compounds and certain other substances for new or modified oil and natural gas facilities. Although the EPA proposed in 2018 to increase the flexibility of its 2016 methane requirements, CARB has adopted more stringent regulations to require monitoring, leak detection, repair and reporting of methane emissions from both existing and new oil and gas production, pipeline gathering and boosting facilities and natural gas processing plants beginning in 2018 and additional controls such as tank vapor recovery to capture methane emissions in subsequent years.

Legislation and regulation to address climate change could also increase the cost of consuming, and thereby reduce demand for, oil, natural gas and other products produced by us, and potentially lower the value of our reserves and other assets.

Regulation of Transportation, Marketing and Sale of Our Products

Our sales prices of oil, NGLs and natural gas in the U.S. are set by the market and are not presently regulated. In 2015, the U.S. federal government lifted restrictions on the export of domestically produced oil that allows for the sale of U.S. oil production, including ours, in additional markets, which may affect the prices we realize.

Federal and state laws regulate transportation rates for, and marketing and sale of, petroleum products and electricity with respect to certain of our operations and those of certain of our customers, suppliers and counterparties. Such regulations also govern:

- interstate and intrastate pipeline transportation rates for oil, natural gas and NGLs in regulated pipeline systems;
- prevention of market manipulation in the oil, natural gas, NGL and power markets;
- market transparency rules with respect to natural gas and power markets;
- the physical and futures energy commodities market, including financial derivative and hedging activity; and
- prevention of discrimination in natural gas gathering operations in favor of producers or sources of supply.

The federal and state agencies overseeing these regulations have substantial rate-setting and enforcement authority, and violation of the foregoing regulations could expose us to litigation with government authorities, counterparties, special interest groups and others.

Spin-Off and Reverse Stock Split

We were incorporated in Delaware as a wholly owned subsidiary of Occidental Petroleum Corporation (Occidental) on April 23, 2014, and remained a wholly owned subsidiary of Occidental until November 30, 2014 when Occidental distributed shares of our common stock on a pro-rata basis to Occidental stockholders (the Spin-off). On December 1, 2014, we became an independent, publicly traded company. Occidental initially retained approximately 18.5% of our outstanding shares of common stock, which were distributed to its stockholders on March 24, 2016. All references to ‘‘Occidental’’ refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

On May 31, 2016 we completed a reverse stock split using a ratio of one share of common stock for every ten shares then outstanding. Share and per share amounts included in this report have been restated to reflect this reverse stock split.

Available Information

We make available free of charge on our website, www.crc.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, our annual proxy statements and amendments to those reports, if any. Our website contains additional important information such as our Sustainability Report and descriptions of our health, safety, environmental and community outreach programs, as well as GAAP to non-GAAP reconciliations. Unless otherwise provided herein, information contained on our website is not part of this report.

ITEM 1A RISK FACTORS

Described below are certain risks and uncertainties that could adversely affect our business, financial condition, results of operations or cash flow. These risks are not the only risks we face. Our business could also be affected materially and adversely by other risks and uncertainties that are not currently known to us or that we currently deem to be immaterial.

Prices for our products can fluctuate widely and an extended period of low prices could adversely affect our financial condition, results of operations, cash flow and ability to invest in our assets.

Our financial condition, results of operations, cash flow and ability to invest in our assets are highly dependent on oil, natural gas and NGL prices. Historically, the markets for these commodities have been volatile and they are likely to continue to be so. We are particularly dependent on Brent crude prices that have been as low as $27.88 per barrel and as high as $115.19 per barrel during the period between 2014 and 2018. Factors affecting oil, natural gas and NGL prices include:

- changes in domestic and global supply and demand;
- domestic and global inventory levels;
- political and economic conditions;
- the actions of OPEC and other significant producers and governments;
- changes or disruptions in actual or anticipated production, refining and processing;
- worldwide drilling and exploration activities;
- government energy policies and regulation, including with respect to climate change;
- the effects of conservation;
- weather conditions and other seasonal impacts;
- speculative trading in derivative contracts;
- currency exchange rates;
- technological advances;
- transportation and storage capacity, bottlenecks and costs in producing areas;
- the price, availability and acceptance of alternative energy sources;
- regional market conditions; and
- other matters affecting the supply and demand dynamics for these products.

Lower prices could have adverse effects on our business, financial condition, results of operations and cash flow, including:

- reducing our proved oil and gas reserves over time, including as a result of impairments of existing reserves;
- limiting our ability to grow or maintain future production;
- causing a reduction in our borrowing base under our 2014 Revolving Credit Facility, which could affect our liquidity;
- reducing our ability to make interest payments or maintain compliance with financial covenants in the agreements governing our indebtedness, which could trigger mandatory loan repayments and default and foreclosure by our lenders and bondholders against our assets;
- forcing monetization events and potential issues under our JV arrangements;
- affecting our ability to attract counterparties and enter into commercial transactions, including hedging transactions; and
- limiting our access to funds through the capital markets and the price we could obtain for asset sales or other monetization transactions or our equity and debt securities.

A sustained period of low prices for oil, natural gas and NGLs would reduce our cash flows from operations and could reduce our borrowing capacity or cause a default under our financing agreements. Under these conditions, if we were unable to improve liquidity through additional financing, asset monetizations, restructuring of our debt obligations, equity issuances or otherwise, cash flow from operations and expected available credit capacity could be insufficient to meet our commitments. Successfully completing these actions could have significant adverse effects such as higher operating and financing costs, loss of certain tax benefits, dilution of equity and further covenant restrictions. Past refinancing activities have resulted in increases in our annual interest expense and future refinancing activities may have the same or greater effect.

Our hedging program does not provide downside protection for all of our production in 2019 and beyond. As a result, our hedges do not fully protect us from commodity price reductions and we may be unable to enter into acceptable additional hedges in the future.

Our lenders require us to comply with covenants that limit our borrowing capabilities and could restrict our ability to use or access capital.

Our 2014 Revolving Credit Facility is an important source of our liquidity and we may need to rely on this facility to fund a portion of our future capital and operating costs. Our ability to borrow under our 2014 Revolving Credit Facility is limited by our borrowing base, the size of our lenders' commitments and our ability to comply with covenants, including a minimum monthly liquidity requirement of $150 million. As of December 31, 2018, we had approximately $298 million of available borrowing capacity, before taking into account the minimum monthly liquidity requirement.

As of December 31, 2018, the lenders' aggregate commitment under our 2014 Revolving Credit Facility was $1 billion. The borrowing base under our 2014 Revolving Credit Facility is currently set at $2.3 billion and is redetermined each May 1 and November 1. The lenders take into account the $1.3 billion outstanding under our 2017 Credit Agreement in determining the total commitment that could be made available in the future under the 2014 Revolving Credit Facility. Our lenders determine our borrowing base by reference to the value of our reserves, which is influenced by commodity prices, expected future cash flows and other factors. If our lenders were to reduce our borrowing base significantly, the amount of availability under our 2014 Revolving Credit Facility could be reduced which could have an adverse effect on our liquidity and financial condition.

The financial covenants that we must satisfy under our 2014 Revolving Credit Facility include a monthly minimum liquidity test and certain financial ratios that measure our leverage and fixed interest charges on a quarterly basis and the present value of our reserves on a semi-annual basis. These covenants could limit our ability to borrow under our 2014 Revolving Credit Facility or obtain additional financing through the capital markets or otherwise. Certain other agreements governing our long-term indebtedness also include financial ratios that are generally less restrictive than our 2014 Revolving Credit Facility.

If we were to breach any of the covenants under our 2014 Revolving Credit Facility, the lenders would be permitted to cease lending under the facility, accelerate the repayment of the outstanding amounts due and foreclose against the assets securing them.

For a further description of our 2014 Revolving Credit Facility and our other credit agreements, see *Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Credit Agreements*.

We have significant indebtedness that could limit our financial and operating flexibility and make us more vulnerable in economic downturns.

As of December 31, 2018, the face value of our outstanding long-term consolidated indebtedness was $5.3 billion. Our financing agreements permit us to incur significant additional indebtedness as well as certain other obligations. In addition, we may seek amendments or waivers from our existing lenders and bondholders to the extent we need to incur indebtedness above amounts currently permitted by our financing agreements.

Our level of indebtedness may have adverse effects on our business, financial condition, cash flows or results of operations, including:

- jeopardizing our ability to execute our business plans;
- increasing our vulnerability to adverse changes in economic and industry conditions related to our business;
- putting us at a disadvantage against competitors that have lower fixed obligations and more cash flow to devote to their businesses;
- limiting our ability to obtain favorable financing for working capital, capital investments and general corporate and other purposes;
- limiting our ability to fund capital investments, react to competitive pressures and engage in certain transactions that might otherwise be beneficial to us;
- defaulting on commercial agreements with our JV partners; and
- failing to redeem the interests held by our JV partners.

Our financing agreements also include covenants that restrict management's discretion to operate our business in certain circumstances. These restrictions include limitations that could affect our ability to:

- incur additional indebtedness and granting additional liens;
- repay junior indebtedness, including our Second Lien Notes and Senior Notes;
- make investments;
- enter into JVs;
- pay dividends and making other restricted payments;
- selling assets;
- use the proceeds of asset sales for certain purposes;
- enter into mergers or acquisitions; and
- release collateral.

These limitations are further described in *Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Credit Agreements* and the documents governing our indebtedness that are filed with the SEC.

Our financing agreements, including the 2014 Revolving Credit Facility, contain customary cross-default mechanisms that provide that an event of default under any one of those agreements may trigger an event of default under all of those agreements. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us, which would negatively affect our ability to implement our business plan, make capital expenditures or finance our operations.

A significant portion of our outstanding indebtedness bears interest at variable rates. Although we have purchased derivative contracts that limit our interest rate exposure for a portion of this indebtedness, a rise in interest rates will increase our interest expense to the extent we do not have interest-rate hedges and could limit our liquidity and our ability to comply with our debt covenants.

Our ability to meet our debt obligations and other financial needs will depend on our future performance, which is influenced by market, financial, business, economic, regulatory and other factors. If our cash flow is not sufficient, we may be required to refinance debt, sell assets or issue additional equity on terms that may be unattractive, if it can be done at all. Failure to make a scheduled payment or to comply with covenants relating to our indebtedness could result in a default. Any of these factors could result in a material adverse effect on our business, financial condition, cash flows or results of operations and a default on our indebtedness could result in acceleration of all of our debt and foreclosure against assets constituting collateral for our indebtedness.

Our business requires substantial capital investments, which may include acquisitions. We may be unable to fund these investments which could lead to a decline in our oil and gas reserves or production. Our capital investment program is also susceptible to risks that could materially affect its implementation.

Our exploration, development and acquisition activities require substantial capital investments. Historically, we have funded our capital investments through a combination of cash flow from operations, borrowings under our 2014 Revolving Credit Facility and JV arrangements. We seek to manage our capital investments to closely align with projected cash flow from operations. Accordingly, a reduction in projected operating cash flow could cause us to reduce our future capital investments. In general, the ability to execute our capital plan depends on a number of variables, including:

- the amount of oil, gas and NGLs we are able to produce;
- commodity prices;
- regulatory and third-party approvals;
- our ability to timely drill, complete and stimulate wells;
- our ability to secure equipment, services and personnel; and
- the availability of external sources of financing.

Future capital availability may be reduced by (i) our lenders, (ii) our JV partners, (iii) capital markets constraints, (iv) activist funds or investors or (v) poor stock price performance. Because of these and other potential variables, we may be unable to deploy capital in the manner planned, which may negatively impact our production levels and development activities and limit our ability to make acquisitions.

Unless we make sufficient capital investments and conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our ability to make the necessary long-term capital investments or acquisitions needed to maintain or expand our reserves may be impaired to the extent we have insufficient cash flow from operations or liquidity to fund those activities. Over the long term, a continuing decline in our production and reserves would reduce our liquidity and ability to satisfy our debt obligations by reducing our cash flow from operations and the value of our assets.

Estimates of proved reserves and related future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.

Many uncertainties exist in estimating quantities of proved reserves and related future net cash flows. Our estimates are based on various assumptions that require significant judgment in the evaluation of available information. Our assumptions may ultimately prove to be inaccurate. Additionally, reservoir data may change over time as more information becomes available from development and appraisal activities.

Our ability to add reserves, other than through acquisitions, depends on the success of improved recovery, extension and discovery projects, each of which depends on reservoir characteristics, technology improvements and oil and natural gas prices, as well as capital and operating costs. Many of these factors are outside management's control and will affect whether the historical sources of proved reserves additions continue to provide reserves at similar levels.

Generally, lower prices adversely affect the quantity of our reserves as those reserves expected to be produced in later years, which tend to be costlier on a per unit basis, become uneconomic. In addition, a portion of our proved undeveloped reserves may no longer meet the economic producibility criteria under the applicable rules or may be removed due to a lower amount of capital available to develop these projects within the SEC-mandated five-year limit.

In addition, our reserves information represents estimates prepared by internal engineers. Although over 80% of our 2018 proved reserve estimates were audited by our independent petroleum engineers, Ryder Scott Company, L.P., we cannot guarantee that the estimates are accurate. Reserves estimation is a partially subjective process of estimating accumulations of oil and natural gas. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows from those reserves depend upon a number of variables and assumptions, including:

- historical production from the area compared with production from similar areas;
- the quality, quantity and interpretation of available relevant data;
- commodity prices;
- production and operating costs;
- ad valorem, excise and income taxes;
- development costs;
- the effects of government regulations; and
- future workover and facilities costs.

Changes in these variables and assumptions could require us to make significant negative reserves revisions, which could affect our liquidity by reducing the borrowing base under our 2014 Revolving Credit Facility. In addition, factors such as the availability of capital, geology, government regulations and permits, the effectiveness of development plans and other factors could affect the source or quantity of future reserves additions.

Acquisition and disposition activities and our JVs involve substantial risks.

Our acquisition activities carry risks that we may:

- not fully realize anticipated benefits due to less-than-expected reserves or production or changed circumstances;
- bear unexpected integration costs or experience other integration difficulties;
- experience share price declines based on the market's evaluation of the activity;
- assume liabilities that are greater than anticipated; and
- be exposed to currency, political, marketing, labor and other risks, particularly associated with investments in foreign assets.

In connection with our acquisitions, we are often only able to perform limited due diligence. Successful acquisitions of oil and gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing for recovering the reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact and incomplete, and we may be unable to make these assessments with a high degree of accuracy.

Part of our business strategy involves entering into JVs and divesting non-core assets. Our JVs and disposition activities carry risks that we may:

- not be able to realize reasonable prices or rates of return for assets;

- be required to retain liabilities that are greater than desired or anticipated;
- experience increased operating costs; and
- reduce our cash flows if we cannot replace associated revenue.

There can be no assurance that we will be able to successfully enter into new JVs or that JVs will occur in the time frames or with economic terms that we expect. We may also be unable to divest assets on financially attractive terms or at all. Our ability to enter into JVs and sell assets is also limited by the agreements governing our indebtedness.

If we are not able to make acquisitions, we may not be able to grow our reserves or develop our properties in a timely manner or at all. If we are not able to sell assets as needed or enter into JVs, we may not be able to generate proceeds to support our liquidity and capital investments. Any of the foregoing could adversely affect our business, financial condition, cash flows and results of operations.

Our business is highly regulated and government authorities can delay or deny permits and approvals or change requirements governing our operations, including hydraulic fracturing and other well stimulation methods, enhanced production techniques and fluid injection or disposal, that could increase costs, restrict operations and change or delay the implementation of our business plans.

Our operations are subject to complex and stringent federal, state, local and other laws and regulations relating to the exploration and development of our properties, as well as the production, transportation, marketing and sale of our products. Federal, state and local agencies may assert overlapping authority to regulate in these areas. For example, the jurisdiction and enforcement authority of various state agencies have significantly increased with respect to oil and gas activities in recent years, and these state agencies as well as certain cities and counties have significantly revised their regulations, regulatory interpretations and data collection requirements and plan to issue additional regulations of certain oil and gas activities in 2019. In addition, certain of these federal, state and local laws and regulations may apply retroactively and may impose strict or joint and several liability on us for events or conditions over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

See *Items 1 and 2 – Business and Properties – Regulation of the Oil and Natural Gas Industry* for a description of laws and regulations that affect our business. To operate in compliance with these laws and regulations, we must obtain and maintain permits, approvals and certificates from federal, state and local government authorities for a variety of activities including siting, drilling, completion, stimulation, operation, maintenance, transportation, storage, marketing, site remediation, decommissioning, abandonment, fluid injection and disposal and water recycling and reuse. Failure to comply may result in the assessment of administrative, civil and/or criminal fines and penalties and liability for noncompliance, costs of corrective action, cleanup or restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief restricting or prohibiting certain operations. Under certain environmental laws and regulations, we could be subject to strict or joint and several liability for the removal or remediation of contamination, including on properties over which we and our predecessors had no control, without regard to fault, legality of the original activities, or ownership or control by third parties.

Our customers, including refineries and utilities, and the businesses that transport our products to customers, are also highly regulated. For example, various government authorities have sought to restrict the use of oil, natural gas or certain petroleum–based products such as fuels and plastics. Federal and state pipeline safety agencies have adopted or proposed regulations to expand their jurisdiction to include more gas and liquid gathering lines and pipelines and to impose additional mechanical integrity requirements. The state has adopted additional regulations on the storage of natural gas that could affect the demand for or availability of such storage, increase seasonal volatility, or otherwise affect the prices we receive from customers.

Costs of compliance may increase and operational delays or restrictions may occur as existing laws and regulations are revised or reinterpreted, or as new laws and regulations become applicable to our operations, each of which has occurred in the past.

Government authorities and other organizations continue to study health, safety and environmental aspects of oil and gas operations, including those related to air, soil and water quality, ground movement or seismicity and natural resources. Government authorities have also adopted or proposed new or more stringent requirements for permitting, well construction and public disclosure or environmental review of, or restrictions on, oil and gas operations, including proposed setback distances from other land uses. Such requirements or associated litigation could result in potentially significant added costs to comply, delay or curtail our exploration, development, fluid injection and disposal or production activities, preclude us from drilling, completing or stimulating wells, or otherwise restrict our ability to access and develop mineral rights, any of which could have an adverse effect on our expected production, other operations and financial condition.

Changes in elected officials could result in different approaches to the regulation of the oil and gas industry. In 2018, California elected a new governor who took office in January 2019. Many representatives in the Legislature have also changed, with the commencement of a new two-year legislative session. We cannot predict the actions the Governor or Legislature may take with respect to the regulation of our business, the oil and gas industry or the state’s economic, fiscal or environmental policies.

Drilling for and producing oil and natural gas carry significant operational and financial risk and uncertainty. We may not drill wells at the times we scheduled, or at all. Wells we do drill may not yield production in economic quantities or generate our expected VCI.

The exploration and development of oil and gas properties depend in part on our analysis of geophysical, geologic, engineering, production and other technical data and processes, including the interpretation of 3D seismic data. This analysis is often inconclusive or subject to varying interpretations. We also bear the risks of equipment failures, accidents, environmental hazards, unusual geological formations or unexpected pressure or irregularities within formations, adverse weather conditions, permitting or construction delays, title disputes, surface access disputes, disappointing drilling results or reservoir performance (including lack of production response to workovers or improved and enhanced recovery efforts) and other associated risks.

We allocate capital by reference to a VCI metric. We calculate the VCI of a well or project at the time capital is allocated and frequently re-calculate the VCI after a well or project is completed. VCIs are calculated based on internal estimates of future cash flows and capital investment and are inherently uncertain. Our decisions and ultimate profitability are also affected by commodity prices, the availability of capital, regulatory approvals, available transportation and storage capacity, political resistance and other factors. Our cost of drilling, completing, stimulating, equipping, operating, maintaining and abandoning wells is also often uncertain.

Our production cost per barrel is higher than that of many of our peers due to the extraction methods we use, the large number of wells we operate and the effects of our PSC-type contracts. Overruns in budgeted investments is a common risk associated with oil and gas operations.

Any of the forgoing operational or financial risks could cause actual results to differ materially from the expected VCI or cause a well or project to become uneconomic or less profitable than forecast.

We have specifically identified locations for drilling over the next several years, which represent a significant part of our long-term growth strategy. Our actual drilling activities may materially differ from those presently identified. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. We make assumptions about the consistency and accuracy of data when we identify these locations that may prove inaccurate. We cannot guarantee that these exploration drilling locations or any other drilling locations we have identified will ever be drilled or if we will be able to produce crude oil or natural gas from these drilling locations. In addition, some of our leases could expire if we do not establish production in the leased acreage. The combined net acreage covered by leases expiring in the next three years represented approximately 14% of our total net undeveloped acreage at December 31, 2018.

Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. Our drilling results are uncertain, and the value of our undeveloped acreage may decline if drilling is unsuccessful.

The risk profile for our exploration drilling locations is higher than for other locations because we have less geologic and production data and drilling history, in particular those exploration drilling locations in unconventional reservoirs, which are in unproven geologic plays. Our ability to profitably drill and develop our identified drilling locations depends on a number of variables, including crude oil and natural gas prices, capital availability, costs, drilling results, regulatory approvals, available transportation capacity and other factors. We may not find commercial amounts of oil or natural gas or the costs of drilling completing and operating wells in these locations may be higher than initially expected. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling or development of these projects. In either case, the value of our undeveloped acreage may decline and could be impaired.

One of our important assets is our acreage in the Monterey shale play in the San Joaquin, Los Angeles and Ventura basins. The geology of the Monterey shale is highly complex and not uniform due to localized and varied faulting and changes in structure and rock characteristics. As a result, it differs from other shale plays that can be developed in part on the basis of their uniformity. Instead, individual Monterey shale drilling sites may need to be more fully understood and may require a more precise development approach, which could affect the timing, cost and our ability to develop this asset.

Our commodity-price risk-management activities may prevent us from fully benefiting from price increases and may expose us to other risks.

Our commodity-price risk-management activities may prevent us from realizing the full benefits of price increases above any levels set in certain derivative instruments we may use to manage price risk. For example, in 2018, we settled hedges that had the effect of reducing our realized oil price by $7.51 per barrel. In addition, our commodity-price risk-management activities may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), enacted in 2010, establishes federal oversight and regulation of the over-the-counter (OTC) derivatives market and entities, like us, that participate in that market. Among other things, the Dodd-Frank Act required the U.S. Commodity Futures Trading Commission to promulgate a range of rules and regulations applicable to OTC derivatives transactions, some of which are still ongoing. These regulations may affect both the size of positions that we may enter and the ability or willingness of counterparties to trade opposite us, potentially increasing costs for transactions. Moreover, the effects of these regulations could reduce our hedging opportunities which could adversely affect our revenues and cash flow during periods of low commodity prices. Recently, proposals have been made by U.S. regulators which would implement a new approach for calculating the exposure amount of derivative contracts under the applicable agencies' regulatory capital rules, referred to as the standardized approach for counterparty credit risk or SA-CCR. If adopted as proposed, certain financial institutions would be required to comply with the new SA-CCR rules beginning on July 1, 2020 and the rules could significantly increase the capital requirements for certain participants in the OTC derivatives market in which we participate. These increased capital requirements could result in significant additional costs being passed through to end-users like us or reduce the number of participants or products available to us in the OTC derivatives market. The effects of these regulations could reduce our hedging opportunities, or substantially increase the cost of hedging, which could adversely affect our revenues and cash flow.

The European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may become subject to or otherwise impacted by such regulations, which could also adversely affect our hedging opportunities.

Adverse tax law changes may affect our operations.

In California, there have been numerous proposals for additional income, sales, excise and property taxes, including taxes on oil and gas production. Although the proposals have not become law, campaigns by various interest groups could lead to additional future taxes. The imposition of increased taxes could significantly reduce our profit margins and cash flow and could ultimately reduce our capital investments and growth plans.

Our producing properties are located exclusively in California, making us vulnerable to risks associated with having operations concentrated in this geographic area.

Our operations are concentrated in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional conditions. These include local price fluctuations, changes in state or regional laws and regulations affecting our operations and other regional supply and demand factors, including gathering, pipeline, transportation and storage capacity constraints, limited potential customers, infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor. Our operations are also exposed to natural disasters and other nature-related events common to California, such as wildfires, mudslides, high winds and earthquakes. The concentration of our operations in California and limited local storage options also increase our exposure to mechanical failures, industrial accidents or labor difficulties, including those affecting our operations, our supply chain and those who purchase, transport or use our products. Any one of these events has the potential to cause producing wells to be shut in, delay operations and growth plans, decrease cash flows, increase operating and capital costs, prevent development of lease inventory before expiration and limit access to markets for our products.

Concerns about climate change and other air quality issues may affect our operations or results.

Concerns about climate change and regulation of GHGs and other air quality issues may materially affect our business in many ways, including increasing the costs to provide our products and services, and reducing demand for, and consumption of, our products and services, and we may be unable to recover or pass through a significant portion of our costs. In addition, legislative and regulatory responses to such issues may increase our operating costs and render certain wells or projects uneconomic, and potentially lower the value of our reserves and other assets. As these requirements become more stringent, we may be unable to implement them in a cost-effective manner. To the extent financial markets view climate change and GHG emissions as a financial risk, this could adversely impact our cost of, and access to, capital. Both the EPA and California have implemented laws, regulations and policies that seek to reduce GHG emissions as discussed in *Items 1 and 2 – Business and Properties – Regulation of the Oil and Natural Gas Industry*. California's cap-and-trade program operates under a market system and the costs of such allowances per metric ton of GHG emissions are expected to increase in the future as CARB tightens program requirements and annually increases the minimum state auction price of allowances and reduces the state's GHG emissions cap.

In addition, other current and proposed international agreements and federal and state laws, regulations and policies seek to restrict or reduce the use of petroleum products in transportation fuels, electricity generation and other applications, prohibit future use of certain vehicles and equipment that require petroleum fuels, impose additional taxes and costs on producers and consumers of petroleum products and require or subsidize the use of renewable energy. For example, former Governor Brown issued executive orders in 2018 setting a target of at least five million "zero-emission" vehicles in California by 2030 and a goal for the state to be "carbon-neutral" by 2045. A bill has been introduced in the California Legislature that seeks to prohibit the sale or registration of new automobiles in California with internal combustion engines by 2040. Various claimants, including certain municipalities, have also filed litigation alleging that energy producers are liable for conditions the claimants attribute to climate change.

Governmental authorities can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations, and various state and local agencies are conducting increased regional, community and field air monitoring specifically with respect to oil and natural gas operations. In addition, California air quality laws and regulations, particularly in southern and central California where most of our operations are located, are in most instances more stringent than analogous federal laws and regulations. For example, the San Joaquin Valley will be required to adopt more rigorous attainment plans under the Clean Air Act to comply with federal ozone and particulate matter standards, and these efforts could affect our activities in the region and our ability and cost to obtain permits for new or modified operations.

We may incur substantial losses and be subject to substantial liability claims as a result of catastrophic events. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not fully insured against all risks. Our oil and gas exploration and production activities and our assets are subject to risks such as fires, explosions, releases, discharges, equipment or information technology failures and industrial accidents, as are the assets and properties of third parties who supply us with energy, equipment and services or who purchase, transport or use our products. In addition, events such as earthquakes, floods, mudslides, wildfires, high winds, droughts, cyber-security or terrorist attacks and other events may cause operations to cease or be curtailed and could adversely affect our business, workforce and the communities in which we operate. We may be unable to obtain, or may elect not to obtain, insurance for certain risks if we believe that the cost of available insurance is excessive relative to the risks presented.

Information technology failures and cyber-security attacks could adversely affect us.

We rely on electronic systems and networks to communicate, control and manage our exploration, development and production activities. We also use these systems and networks to prepare our financial management and reporting information, to analyze and store data and to communicate internally and with third parties, including our service providers. If we record inaccurate data or experience infrastructure outages, our ability to communicate and control and manage our business could be adversely affected.

Cyber-security attacks on businesses have escalated and become more sophisticated in recent years and include attempts to gain unauthorized access to data, malicious software, ransomware and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential information or the corruption of data. In addition, our vendors, customers and other business partners may separately suffer disruptions or breaches from cyber-security attacks that, in turn, could adversely impact our operations and compromise our information. If we or the third parties with whom we interact were to experience a successful attack, the potential consequences to our business, workforce and the communities in which we operate could be significant including financial losses, loss of business, litigation risks and damage to reputation. As the sophistication of cyber-security attacks continues to evolve, we may be required to expend additional resources to further enhance our security.

We are exposed to certain risks related to our separation from Occidental in 2014.

In connection with our separation from Occidental, we entered into contracts that allocate risks and liabilities (including tax liabilities) between Occidental and ourselves. These contracts were not made on an arm's length basis and include mutual indemnity obligations. Indemnity payments that we may be required to provide Occidental may be significant and could adversely impact our business. Similarly, third parties could also seek to hold us responsible for liabilities that Occidental has agreed to retain and the indemnity from Occidental may not be sufficient or paid timely.

ITEM 1B UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 3 LEGAL PROCEEDINGS

For information regarding legal proceedings, see *Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Lawsuits, Claims, Commitments and Contingencies* and in *Item 8 – Financial Statements and Supplementary Data – Note 8 Lawsuits, Claims, Commitments and Contingencies*.

ITEM 4 MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS

Executive officers are appointed annually by the Board of Directors. The following table sets forth our current executive officers:

Name	Employment History	Age at February 27, 2019
Todd A. Stevens	President, Chief Executive Officer and Director since 2014; Occidental Petroleum Corporation Vice President - Corporate Development 2012 to 2014; Oxy Oil & Gas Vice President - California Operations 2008 to 2012; Occidental Petroleum Corporation Vice President - Acquisitions and Corporate Finance 2004 to 2012.	52
Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer since 2014; Ultra Petroleum Corporation Senior Vice President and Chief Financial Officer 2011 to 2014; Ultra Petroleum Corporation Chief Financial Officer 2005 to 2014.	59
Shawn M. Kerns	Executive Vice President - Operations and Engineering - 2018; Executive Vice President - Corporate Development 2014 to 2018; Vintage Production California President and General Manager 2012 to 2014; Occidental of Elk Hills General Manager 2010 to 2012; Occidental of Elk Hills Asset Development Manager 2008 to 2010.	48
Francisco J. Leon	Executive Vice President - Corporate Development and Strategic Planning - 2018; Vice President - Portfolio Management and Strategic Planning 2014 to 2018; Occidental Director - Portfolio Management 2012 to 2014; Occidental Director of Corporate Development and M&A 2010 to 2012; Occidental Manager of Business Development 2008 to 2010.	42
Roy M. Pineci	Executive Vice President - Finance since 2014; Occidental Vice President and Controller 2008 to 2014; Occidental Oil and Gas Senior Vice President 2007 to 2008.	56
Michael L. Preston	Executive Vice President, General Counsel and Corporate Secretary since 2014; Occidental Oil and Gas Vice President and General Counsel 2001 to 2014.	54
Charles F. Weiss	Executive Vice President - Public Affairs since 2014; Occidental Vice President, Health, Environment and Safety 2007 to 2014.	55
Darren Williams	Executive Vice President - Operations and Geoscience - 2018; Executive Vice President - Exploration 2014 to 2018; Marathon Upstream Gabon Limited President and Africa Exploration Manager 2013 to 2014; Marathon Oil Oklahoma Subsurface Manager 2010 to 2013; Marathon Oil Gulf of Mexico Exploration and Appraisal Manager 2008 to 2010.	47

PART II

ITEM 5 MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information for Common Stock

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol "CRC."

Holders of Record

Our common stock was held by approximately 20,700 stockholders of record at December 31, 2018.

Dividend Policy

No dividends were paid in 2018, 2017 and 2016, and we do not anticipate paying any dividends on our common stock in the foreseeable future. Covenants under our credit agreements generally restrict the payment of cash dividends on our stock, subject to certain exceptions. See *Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Credit Agreements* for a description of limitations on paying dividends under our credit facilities.

Securities Authorized for Issuance Under Equity Compensation Plans

A description of the stock-based compensation plans can be found in *Item 8 – Financial Statements and Supplementary Data – Note 11 Stock-Based Compensation*. The aggregate number of shares of our common stock authorized for issuance under our stock-based compensation plans for our executives, employees and non-employee directors is 6.2 million, of which approximately 4.9 million had been issued or reserved through December 31, 2018.

The following is a summary of the securities available for issuance under such plans as of December 31, 2018:

a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	b) Weighted-average exercise price of outstanding options, warrants and rights	c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities in column (a))
2,354,569	$62.82 [(a)]	1,253,892 [(b)]

(a) Exercise price applies only to approximately 1.3 million options included in column (a) and not to any other awards.
(b) Includes 656,929 shares available under our 2014 Employee Stock Purchase Plan (ESPP) for purchase at 85% of the lower of the market price at either (i) the beginning of a quarter or (ii) the end of a quarter.

Performance Graph

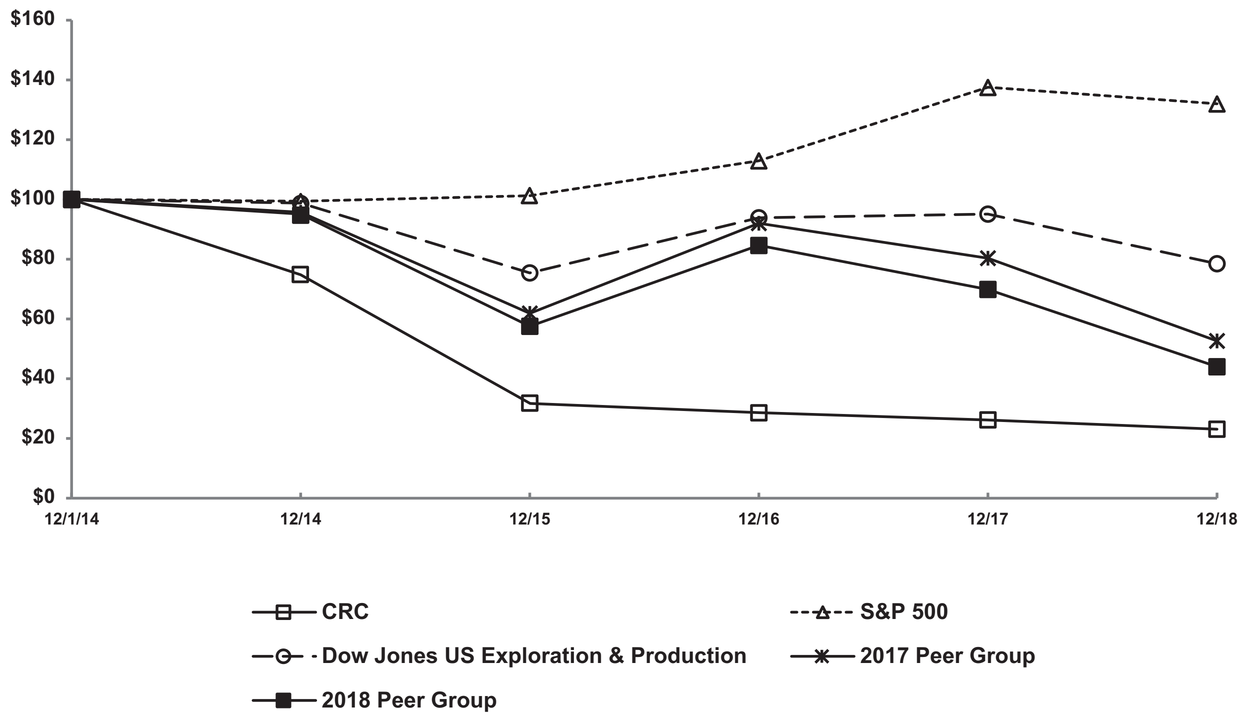
The following graph compares the cumulative total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 and Dow Jones U.S. Exploration and Production indexes and our peer groups (with reinvestment of all dividends). The graph assumes that on December 1, 2014, the date our common stock began trading on the NYSE, $100 was invested in our common stock, in each index and in each of the peer group companies' common stock weighted by their relative market values within the peer group, and that all dividends were reinvested. The results shown are based on historical results and are not intended to suggest future performance.

Our 2018 peer group consists of Cabot Oil & Gas Corporation; Callon Petroleum Company; Carrizo Oil & Gas, Inc.; Cimarex Energy Co.; Denbury Resources, Inc.; Diamondback Energy, Inc.; EP Energy Corporation; Gulfport Energy Corporation; Laredo Petroleum, Inc.; Matador Resources Company; Murphy Oil Corporation; Newfield Exploration Company; Oasis Petroleum Inc.; Parsley Energy, Inc.; PDC Energy, Inc.; QEP Resources, Inc.; Range Resources Corporation; SM Energy Company; Southwestern Energy Company; Whiting Petroleum Corporation and WPX Energy, Inc.

Our 2017 peer group included Cabot Oil and Gas Corporation; Cimarex Energy Co.; Concho Resources Inc.; Denbury Resources Inc.; Energen Corporation; EP Energy Corporation; Murphy Oil Corporation; Newfield Exploration Company; Oasis Petroleum Corporation; Parsley Energy, Inc.; QEP Resources, Inc.; Range Resources Corporation; SM Energy Company; Whiting Petroleum Corporation and WPX Energy, Inc. Energen Corporation is excluded from the graph below due to its acquisition by Diamondback Energy, Inc. in 2018.

PERFORMANCE GRAPH*

Among CRC, the S&P 500 Index,
the Dow Jones US Exploration & Production Index,
2017 Peer Group and 2018 Peer Group



	12/1/2014	December 31, 2014	2015	2016	2017	2018
CRC	$ 100	$ 75	$ 32	$ 29	$ 27	$ 23
S&P 500	$ 100	$ 100	$ 101	$ 113	$ 138	$ 132
Dow Jones US Exploration & Production	$ 100	$ 99	$ 76	$ 94	$ 95	$ 78
2018 Peer Group	$ 100	$ 95	$ 58	$ 85	$ 70	$ 53
2017 Peer Group	$ 100	$ 96	$ 62	$ 92	$ 81	$ 53

* This performance graph shall not be deemed “soliciting material” or to be “filed” with the SEC for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities under that Section, and shall not be deemed to be incorporated by reference into any filing of CRC under the Securities Act of 1933, as amended, or the Exchange Act except to the extent that we specifically request it be treated as soliciting material or specifically incorporate it by reference.

ITEM 6 SELECTED FINANCIAL DATA

Prior to the Spin-off on November 30, 2014, financial data was derived from Occidental's California oil and gas exploration and production operations and related assets, liabilities and obligations (California business), which we assumed with the Spin-off. All financial information presented after the Spin-off represents our stand-alone consolidated results of operations, financial position and cash flows. Accordingly, for the year ended December 31, 2014, the statement of operations and cash flows data includes the consolidated results for the month ended December 31, 2014 and the combined results of the California business prior to the Spin-off.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in millions, except for per share data)				
Statement of Operations Data					
Total revenues and other	$ 3,064	$ 2,006	$ 1,547	$ 2,403	$ 4,173
Income (loss) before income taxes	$ 429	$ (262)	$ 201	$ (5,476)	$ (2,421)
Net income (loss) attributable to common stock	$ 328	$ (266)	$ 279	$ (3,554)	$ (1,434)
Per common share					
Basic	$ 6.77	$ (6.26)	$ 6.76	$ (92.79)	$ (37.54)
Diluted	$ 6.77	$ (6.26)	$ 6.76	$ (92.79)	$ (37.54)
Statement of Cash Flows Data					
Net cash provided by operating activities	$ 461	$ 248	$ 130	$ 403	$ 2,371
Capital investments	$ (690)	$ (371)	$ (75)	$ (401)	$ (2,089)
Acquisitions and other	$ (553)	$ (2)	$ —	$ (151)	$ (292)
Net (repayments) borrowings and related costs	$ (26)	$ (18)	$ (73)	$ 356	$ 6,290
Contributions from noncontrolling interest holders, net	$ 796	$ 98	$ —	$ —	$ —
Distributions paid to noncontrolling interest holders	$ (121)	$ (8)	$ —	$ —	$ —
Spin-off related dividends to Occidental	$ —	$ —	$ —	$ —	$ (6,000)
Distributions to Occidental, net	$ —	$ —	$ —	$ —	$ (335)
Dividends per common share	$ —	$ —	$ —	$ 0.30	$ —

	As of December 31,				
	2018	2017	2016	2015	2014
	(in millions)				
Balance Sheet Data					
Total current assets	$ 640	$ 483	$ 425	$ 438	$ 701
Property, plant and equipment, net	$ 6,455	$ 5,696	$ 5,885	$ 6,312	$ 11,685
Total assets	$ 7,158	$ 6,207	$ 6,354	$ 7,053	$ 12,429
Current maturities of long-term debt	$ —	$ —	$ 100	$ 100	$ —
Total current liabilities	$ 607	$ 732	$ 726	$ 605	$ 922
Long-term debt	$ 5,251	$ 5,306	$ 5,168	$ 6,043	$ 6,360
Deferred gain and issuance costs, net	$ 216	$ 287	$ 397	$ 491	$ (68)
Other long-term liabilities	$ 575	$ 602	$ 620	$ 830	$ 549
Mezzanine equity	$ 756	$ —	$ —	$ —	$ —
Equity attributable to common stock	$ (361)	$ (814)	$ (557)	$ (916)	$ 2,611

The selected financial data presented above should be read in conjunction with *Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations* and the consolidated financial statements and accompanying notes included elsewhere in this Form 10-K.

ITEM 7 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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.

Basis of Presentation and Certain Factors Affecting Comparability

All financial information presented consists of our consolidated results of operations, financial position and cash flows. The assets and liabilities in the consolidated financial statements are presented on a historical cost basis. We have eliminated all significant intercompany transactions and accounts. We account for our share of oil and gas exploration and production ventures, in which we have a direct working interest, by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on the balance sheets and statements of operations and cash flows.

On May 31, 2016 we completed a reverse stock split using a ratio of one share of common stock for every ten shares then outstanding. Share and per share amounts included in this report reflect this stock split for all periods presented.

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.

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

The following table presents the average daily Brent, WTI and NYMEX prices for each of the years ended December 31, 2018, 2017 and 2016:

	2018	2017	2016
Brent oil ($/Bbl)	$ 71.53	$ 54.82	$ 45.04
WTI oil ($/Bbl)	$ 64.77	$ 50.95	$ 43.32
NYMEX gas ($/MMBtu)	$ 2.97	$ 3.09	$ 2.42

We currently sell all of our crude oil into the California refining market, which offers relatively favorable pricing compared to other U.S. regions for similar grades. California is heavily reliant on imported sources of energy, with approximately 74% of the oil consumed in 2018 imported from outside the state. A vast majority of the imported oil arrives via supertanker, mostly from foreign locations. As a result, California refiners have typically purchased crude oil at international waterborne-based prices. We believe that the limited crude transportation infrastructure from other parts of the U.S. into California will continue to contribute to higher realizations than most other U.S. oil markets for comparable grades. Additionally, our differentials improved against Brent during 2017 and 2018 in response to strong demand for California crude oil to optimize local refinery yields as well as a decline in overall California crude oil production.

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

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

In addition to selling natural gas, we also use gas for our steamfloods and power generation. As a result, the positive impact of higher natural gas prices is partially offset by higher operating costs, but higher prices still have a net positive effect on our operating results. Conversely, lower natural gas prices generally have a net negative effect on our results, but lower the operating costs of our steamflood projects and power generation.

Our earnings are also affected by the performance of our processing and power-generation assets. We process our wet gas to extract NGLs and other natural gas byproducts. We then deliver dry gas to pipelines and separately sell the NGLs. The efficiency with which we extract liquids from the wet gas stream affects our operating results. Additionally, we use part of the electricity from the Elk Hills power plant to reduce operating costs at our Elk Hills and 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 price obtained for excess power impacts our earnings but generally by an insignificant amount.

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

We opportunistically seek strategic hedging transactions to help protect our cash flow, operating margin and capital program from both the cyclical nature of commodity prices and interest rate movements while maintaining adequate liquidity and improving our ability to comply with our debt covenants in case of price deterioration. We built our 2019 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 and continuing to identify efficiencies and cost savings. The reductions in our capital program in 2015 and 2016 negatively impacted our 2017 production levels. Our oil production stabilized in the first half of 2018 with our increased 2017 capital program, even excluding the impact of the additional production from the Elk Hills transaction in the second quarter of 2018. Volatility in oil prices may materially affect the quantities of oil and gas reserves we can economically produce over the longer term.

Seasonality

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

Joint Ventures

Development Joint Ventures

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

In February 2017, we entered into a development JV with Benefit Street Partners (BSP) where BSP will contribute up to $250 million, subject to agreement of the parties, in exchange for a preferred interest in the BSP joint venture (BSP JV). BSP is entitled to preferential distributions and, if BSP receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. BSP funded a total of $150 million in three equal tranches, before transaction costs, in March 2017, July 2017 and June 2018. The funds contributed by BSP were used to develop certain of our oil and gas properties.

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

In April 2017, we entered into a development JV with Macquarie Infrastructure and Real Assets Inc. (MIRA) under which MIRA will invest up to $300 million, subject to agreement of the parties, to develop certain of our oil and gas properties in exchange for a 90% working interest in the related properties (MIRA JV). MIRA will fund 100% of the development cost of such properties. Our 10% working interest increases to 75% if MIRA receives cash distributions equal to a predetermined threshold return. MIRA initially committed $160 million, which was intended to be invested over two years. In June 2018, the parties amended the joint development program to $140 million. The agreement provides for a commitment of up to 110% of the program amount. MIRA invested $58 million in 2017 and $57 million in 2018. Our consolidated results reflect only our working interest share in our MIRA JV.

In October 2018, we entered into a development JV for a three-year program to drill 20 wells where our JV partner committed approximately $23 million and we are investing approximately $13 million. Our consolidated results reflect only our working interest share in this JV.

Exploration Joint Ventures

We entered into two exploration JVs where our JV partners have an initial total commitment of approximately $12 million. If certain milestones are met on the initial wells, the parties may move forward with a mutually agreed drilling program. Our consolidated results reflect only our working interest share in this JV.

Midstream Joint Venture

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

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

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

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

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

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

Acquisitions and Divestitures

Acquisitions

In April 2018, we acquired the remaining working, surface and mineral interests in the 47,000-acre Elk Hills unit from Chevron U.S.A., Inc. (Chevron) (the Elk Hills transaction) for approximately $518 million, including $7 million of liabilities assumed relating to asset retirement obligations. We accounted for the Elk Hills transaction as a business combination and allocated $435 million to proved properties, $77 million to other property, plant and equipment and $6 million to materials and supplies. The consideration paid consisted of $460 million in cash and 2.85 million shares of CRC common stock issued at the close of the transaction (valued at $51 million). After the transaction, we hold all of the working, surface and mineral interests in the Elk Hills unit. The effective date of the transaction was

April 1, 2018. Since the acquisition, we estimate that we have recognized approximately $25 million in cost savings and revenue enhancements by streamlining operations and consolidating infrastructure. On an annualized basis, these synergies total approximately $34 million, significantly exceeding our initial target and over a shorter time frame. Additionally, we realized approximately $20 million of nonrecurring capital savings through December 31, 2018, and we may have additional capital savings in the future. Chevron sold all of the shares of CRC common stock it acquired in the Elk Hills transaction in 2018.

As part of the Elk Hills transaction, Chevron reduced its royalty interest in one of our oil and gas properties by half and extended the time frame to invest the remainder of our capital commitment on that property by two years, to the end of 2020. As of December 31, 2018, the remaining commitment was approximately $17 million. In addition, the parties mutually agreed to release each other from pending claims with respect to the former Elk Hills unit.

In April 2018, we also acquired an office building and land in Bakersfield, California for $48.4 million, which we believe is significantly less than the estimated replacement value of the property and the land. At the time of acquisition, we had approximately 500 employees using eight different locations in Bakersfield across multiple leases. We expect that the new building will create significant value by bringing our Bakersfield employees together into a single location, which will increase the efficiency, effectiveness and collaboration of these employees. This building was the only available office space in the Bakersfield area large enough to allow us to consolidate our workforce in a single location. For the initial eight months in 2018, a former owner of the building occupied most of the space as a tenant, from which we generated approximately $4 million in rental income. In December 2018, this tenant downsized the space they are leasing through December 2022, with a corresponding reduction in rent. The vacated space not used by us will be available to lease to other tenants to generate additional income. In addition, the unimproved land may be monetized in the future. Approximately $6 million of the purchase price was allocated to the in-place leases, which is included in other assets and is being amortized into other expenses, net.

Additionally, we had several other upstream acquisitions totaling approximately $39 million in 2018.

Divestitures

In 2018, we divested non-core assets resulting in $18 million of proceeds and a $5 million gain. In 2017, we divested non-core assets resulting in $33 million of proceeds and a $21 million gain. In 2016, we divested non-core assets resulting in $20 million of proceeds and a $30 million gain.

Income Taxes

All of our income is earned from domestic operations and is subject to tax in the U.S. The following table sets forth our pre- and after-tax income (loss) and income tax amounts:

	For the years ended December 31,		
	2018	2017	2016
		(in millions)	
Pre-tax income (loss)	$ 429	$ (262)	$ 201
Income tax benefit	—	—	78
Net income (loss)	$ 429	$ (262)	$ 279

We did not make United States federal and state income tax payments in 2018, 2017 or 2016 due to the tax losses we incurred and do not expect to make any income tax payments in the foreseeable future, although this estimate could change.

Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of existing deferred tax assets. A significant piece of evidence evaluated is a history of operating losses. Such evidence limits our ability to consider other evidence such as projections for growth. As of December 31, 2018, we concluded that we could not realize, on a more-likely-than-not basis, any of our deferred tax assets and there is not sufficient evidence to support the reversal of all or any portion of this allowance. Given our recent and anticipated future earnings trends, we do not believe any of the valuation allowance as of December 31, 2018 will be released within the next 12 months. The amount of the deferred tax assets considered realizable could however be adjusted if estimates or amounts of deferred tax liabilities change.

Total income tax expense (benefit) differs from the amounts computed by applying the U.S. federal income tax rate to pre-tax income (loss) as follows:

	For the years ended December 31,		
	2018	**2017**	**2016**
U.S. federal statutory tax rate	21%	(35)%	35 %
State income taxes, net	6	(6)	6
Exclusion of tax attributable to noncontrolling interests	(5)	—	—
Decrease in U.S. federal corporate tax rate	—	91	—
Tax credits, net	(6)	(19)	—
Cancellation of debt income, net	—	—	(275)
Stock-based compensation, net	—	1	2
Change in valuation allowance, net	(17)	(33)	192
Other	1	1	1
Effective tax rate	—%	—%	(39)%

Our income tax provision for 2017 and 2016 was based on a U.S. federal statutory rate of 35% and a California statutory rate of 8.84%. Our effective rate was lower in each of these years primarily due to our debt reduction transactions in 2016 and the remeasurement of our net deferred tax assets in 2017 as a result of the reduction in the U.S. federal income tax rate from 35% to 21% as enacted by the Tax Cuts and Jobs Act signed by the President on December 22, 2017. Additionally, due to the low commodity price environment, the enhanced oil recovery credit was available in each of the years ended December 31, 2018 and 2017. These discrete items may not recur in subsequent years.

Our effective tax rate is affected by recurring items such as permanent differences, tax deductions related to equity compensation which is different from compensation expense recognized in the financial statements and income included in our consolidated results which is taxed to noncontrolling interests.

Given our tax status, any item affecting our effective tax rate described above is offset by an equal change in the valuation allowance. As of December 31, 2018, 2017 and 2016, we had valuation allowances of $625 million, $706 million and $780 million, respectively.

For additional information on items affecting our effective tax rate and the impact of 2017 tax reform, see information set forth in *Item 8 – Financial Statements and Supplementary Data – Note 10 Income Taxes*.

Production and Prices

The following table sets forth our average production volumes of oil, NGLs and natural gas per day for the years ended December 31, 2018, 2017 and 2016:

	2018	2017	2016
Oil (MBbl/d)[(a)]			
San Joaquin Basin	53	52	57
Los Angeles Basin	25	27	29
Ventura Basin	4	4	5
Total	82	83	91
NGLs (MBbl/d)			
San Joaquin Basin	15	15	15
Ventura Basin	1	1	1
Total	16	16	16
Natural gas (MMcf/d)			
San Joaquin Basin	165	140	150
Los Angeles Basin	1	1	3
Ventura Basin	7	8	8
Sacramento Basin	29	33	36
Total	202	182	197
Total Production (MBoe/d)[(a)(b)]	132	129	140

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

(a) Our PSC-type contracts negatively impacted our oil production in 2018 by over 1 MBoe/d compared to 2017. The impact on our oil production was immaterial in 2017 compared to 2016.

(b) 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.

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 years ended December 31, 2018, 2017 and 2016:

	2018		2017		2016	
	Price	Realization	Price	Realization	Price	Realization
Oil ($ per Bbl)						
Brent	$ 71.53		$ 54.82		$ 45.04	
Realized price, without hedge	$ 70.11	98%	$ 51.47	94%	$ 39.72	88%
Settled hedges	(7.51)		(0.23)		2.29	
Realized price, with hedge	$ 62.60	88%	$ 51.24	93%	$ 42.01	93%
WTI	$ 64.77		$ 50.95		$ 43.32	
Realized price, without hedge	$ 70.11	108%	$ 51.47	101%	$ 39.72	92%
Realized price, with hedge	$ 62.60	97%	$ 51.24	101%	$ 42.01	97%
NGLs ($ per Bbl)						
Realized price (% of Brent)	$ 43.67	61%	$ 35.76	65%	$ 22.39	50%
Realized price (% of WTI)	$ 43.67	67%	$ 35.76	70%	$ 22.39	52%
Natural gas						
NYMEX ($/MMBTU)	$ 2.97		$ 3.09		$ 2.42	
Realized price, w/out hedge ($/Mcf)	$ 3.00	101%	$ 2.67	86%	$ 2.28	94%
Settled hedges	(0.02)		—		—	
Realized price, with hedge ($/Mcf)	$ 2.98	100%	$ 2.67	86%	$ 2.28	94%

Note: We adopted a new revenue recognition standard on January 1, 2018 that required certain sales-related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard did not affect net income. Results for reporting periods beginning January 1, 2018 are presented under the new accounting standard while prior periods are not adjusted and continue to be reported under accounting standards in effect for the applicable period. Under prior accounting standards, the unhedged realized price and realization for natural gas would have been $2.79 per Mcf and 94%, respectively, and the hedged realized price and realization would have been $2.77 per Mcf and 93%, respectively. The new standard did not have a material impact to the realized price and realization for oil and NGLs.

Balance Sheet Analysis

The changes in our balance sheet as of December 31, 2018 and 2017, are discussed below:

	2018	2017
	(in millions)	
Cash	$ 17	$ 20
Trade receivables	$ 299	$ 277
Inventories	$ 69	$ 56
Other current assets, net	$ 255	$ 130
Property, plant and equipment, net	$ 6,455	$ 5,696
Other assets	$ 63	$ 28
Accounts payable	$ 390	$ 257
Accrued liabilities	$ 217	$ 475
Long-term debt	$ 5,251	$ 5,306
Deferred gain and issuance costs, net	$ 216	$ 287
Other long-term liabilities	$ 575	$ 602
Mezzanine equity	$ 756	$ —
Equity attributable to common stock	$ (361)	$ (814)
Equity attributable to noncontrolling interests	$ 114	$ 94

Cash at December 31, 2018 and 2017 included approximately $2 million and $5 million, respectively, that is restricted under one of our JV agreements. See *Liquidity and Capital Resources* for our cash flow analysis.

The increase in trade receivables was largely the result of higher total production volumes in December 2018 compared to December 2017. The increase in other current assets, net primarily reflected an increase in the fair value of the current portion of our derivative assets, partially offset by the sale of a non-core asset and decreases in amounts due from joint interest partners. The increase in property, plant and equipment, net primarily reflected capital investments and acquisitions for the period, partially offset by depreciation, depletion and amortization (DD&A). The increase in other assets was primarily due to changes in the fair value of our long-term derivative assets and prepaid power plant major maintenance expenses.

The increase in accounts payable at December 31, 2018 compared to December 31, 2017 reflected the increase in activity between periods. The decrease in accrued liabilities was primarily due to the change in value of our derivative positions held between the periods and payments made in 2018 for prior years' greenhouse gas obligations. These decreases were partially offset by higher accrued employee-related costs due to better performance against our bonus metrics, the timing of grants between years and executive awards granted in 2018 that have a partial cash payout feature. The decrease in deferred gain and issuance costs, net was largely the result of repurchases of our Second Lien Notes.

Mezzanine equity reflected the carrying amount of the Class A common and Class B preferred interests held by ECR in our Ares JV. The increase in equity attributable to common stock primarily reflected net income for the period and the issuance of common stock to an Ares-led investor group and to Chevron in connection with the Elk Hills transaction. Equity attributable to noncontrolling interests reflected contributions from and distributions to ECR's Class C common interest and BSP's preferred interest as well as their respective share of net income for the period. See *Item 8 – Financial Statements and Supplementary Data – Note 5 Joint Ventures* for more information.

Statement of Operations Analysis

Results of Oil and Gas Operations

The following represents key operating data for our oil and gas operations, excluding corporate items, on a per Boe basis for the years ended December 31, 2018, 2017 and 2016:

	2018	2017	2016
Production costs	$ 18.88	$ 18.64	$ 15.61
Production costs, excluding effects of PSC-type contracts[(a)]	$ 17.47	$ 17.48	$ 14.69
Field general and administrative expenses[(b)(c)(d)]	$ 1.01	$ 0.70	$ 0.68
Field depreciation, depletion and amortization[(b)]	$ 9.71	$ 10.85	$ 10.28
Field taxes other than on income[(b)]	$ 2.42	$ 2.34	$ 2.36

(a) As described in *Items 1 and 2 – Business and Properties – Our Operations – Production, Price and Cost History*, 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 amounts.

(c) Field general and administrative expenses increased in 2018, compared to 2017, following the Elk Hills transaction since certain costs are no longer collected from our former working interest partner through G&A expenses.

(d) For the years ended December 31, 2017 and 2016, certain pension benefit costs of $1 million and $2 million, respectively, have been reclassified to other non-operating expenses to conform to the current year presentation in accordance with new accounting rules adopted on January 1, 2018 related to the presentation of net periodic benefit costs for pension and postretirement benefits in the Consolidated Statements of Operations. See *Item 8 – Financial Statement and Supplementary Data – Note 2 Accounting and Disclosure Changes* for more information.

Consolidated Results of Operations

The following represents key operating data for consolidated operations for the years ended December 31, 2018, 2017 and 2016:

	2018	2017	2016
		(in millions)	
Oil and gas sales[(a)]	$ 2,590	$ 1,936	$ 1,621
Net derivative gain (loss) from commodity contracts	1	(90)	(206)
Other revenue[(a)]	473	160	132
Production costs	(912)	(876)	(800)
General and administrative expenses[(b)]	(299)	(249)	(235)
Depreciation, depletion and amortization	(502)	(544)	(559)
Taxes other than on income	(149)	(136)	(144)
Exploration expense	(34)	(22)	(23)
Other expenses, net[(a)]	(399)	(106)	(79)
Interest and debt expense, net	(379)	(343)	(328)
Net gain on early extinguishment of debt	57	4	805
Gain on asset divestitures	5	21	30
Other non-operating expenses[(b)]	(23)	(17)	(13)
Income (loss) before income taxes	429	(262)	201
Income tax	—	—	78
Net income (loss)	429	(262)	279
Net income attributable to noncontrolling interests	$ (101)	$ (4)	$ —
Net income (loss) attributable to common stock	$ 328	$ (266)	$ 279
Adjusted net income (loss)	$ 61	$ (187)	$ (317)
Adjusted EBITDAX	$ 1,117	$ 779	$ 616
Effective tax rate	—%	—%	(39)%

(a) We adopted a new revenue recognition standard on January 1, 2018 that required certain sales-related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard did not affect net income. Results for reporting periods beginning January 1, 2018 are presented under the new accounting standard while prior periods are not adjusted and continue to be reported under accounting standards in effect for the applicable period. Under prior accounting standards, the 2018 total oil and gas sales would have been $2,568 million, other revenue would have been $392 million and other expenses, net would have been $296 million. See *Item 8 – Financial Statement and Supplementary Data – Note 15 Revenue Recognition* for more information.

(b) For the years ended December 31, 2017 and 2016, certain pension benefit costs of $10 million and $13 million, respectively, have been reclassified from general and administrative expense to other non-operating expenses to conform to the current year presentation in accordance with new accounting rules adopted on January 1, 2018 related to the presentation of net periodic benefit costs for pension and postretirement benefits in the Consolidated Statements of Operations. See *Item 8 – Financial Statement and Supplementary Data – Note 2 Accounting and Disclosure Changes* for more information.

Year Ended December 31, 2018 vs. 2017

Oil and gas sales increased 34%, or $654 million, for 2018 compared to 2017 due to increases of approximately $561 million, $47 million and $21 million primarily from higher oil, NGL and natural gas realized prices, respectively, and an increase of $25 million primarily from higher natural gas production. The higher realized oil prices reflected the significant increase in average Brent prices between years and improved differentials.

Our total daily production volumes averaged 132 MBoe in 2018, compared with 129 MBoe in 2017, representing a year-over-year increase of 2%. Our total daily production volumes included 8 MBoe per day from the Elk Hills transaction, which closed in the second quarter of 2018. Our PSC-type contracts negatively impacted our 2018 production by approximately 1 MBoe per day compared with 2017, without which the year-over-year production increase would have been 3%.

Net derivative gain was $1 million in 2018, compared to a loss of $90 million in 2017, representing an overall change of $91 million. In 2018, we entered into derivative contracts to hedge our price risk for 2019 and the first quarter of 2020, which resulted in a non-cash derivative gain of $229 million. Offsetting this gain were settlement payments of $228 million. In 2017, we recognized a non-cash derivative loss of $83 million related to the fair value of our derivative contracts and settlement payments of $7 million.

The increase in other revenue of $313 million to $473 million in 2018, compared to $160 million in 2017, was largely the result of higher gas trading activity and the adoption of new accounting rules on revenue recognition that impact the current period but not prior periods. The increase in other revenue resulting from the accounting change was offset in its entirety by an increase in other expenses, net with no effect on net income. The prior comparative periods were not adjusted.

Production costs in 2018 increased $36 million to $912 million or $18.88 per Boe, compared to $876 million or $18.64 per Boe in 2017, resulting in a 1% increase on a per unit basis. The Elk Hills transaction and cash-settled stock-based compensation added $38 million and $4 million to our 2018 costs, respectively. Without these items, our production costs would have been approximately $870 million or $19.25 per Boe, which reflects cost savings of $17 million achieved following the Elk Hills transaction, partially offset by higher 2018 energy costs. Elk Hills production costs are lower than the average company-wide production costs per barrel. As a result, the Elk Hills transaction had a favorable effect on production costs per barrel.

Our G&A expenses increased $50 million to $299 million in 2018 compared to 2017. Our cash-settled stock-based compensation expense increased $14 million primarily due to the increase in our stock price during the year as noted in the stock-based compensation table below. Additionally, our G&A expenses increased following the Elk Hills transaction by approximately $8 million since certain costs are no longer collected from our former working interest partner. The remaining change in G&A expenses primarily related to an increase in compensation, training, community outreach and advocacy.

DD&A expense decreased by $42 million in 2018 compared to 2017, primarily resulting from lower DD&A rates, partially offset by higher production volumes in 2018. For example, our overall DD&A rate for our oil and gas operations in 2018 was $9.71 compared to $10.85 in 2017. The most significant financial statement effect from a change in our proved oil and gas reserves or impairment of the carrying value of our proved properties would be to our DD&A rate. For example, a 5% increase or decrease in the amount of oil and gas reserves would change our DD&A rate by approximately $0.60 per Boe, which would increase or decrease pre-tax income (loss) by $28 million annually based on our total production volume of 48 MMBoe for the year ended December 31, 2018.

Taxes other than on income increased 10% in 2018 compared to 2017, largely resulting from higher GHG allowance costs. The higher costs were related to annual price increases, as well as the state's reduction in the number of allowances granted to us between periods.

Exploration expense increased 55% in 2018 compared to 2017, due to higher exploration activity and dry hole costs in the fourth quarter of 2018.

The increase in other expenses of $293 million to $399 million in 2018, compared to $106 million in 2017, was largely the result of higher gas trading activity and reporting selling costs and unprocessed gas purchased as other expense in 2018 due to the adoption of new accounting rules on revenue recognition that impact the current period but not the prior period. The increase resulting from the accounting change was offset by an increase in oil and gas sales and other revenue with no effect on net income.

Interest and debt expense, net, increased to $379 million in 2018, compared to $343 million in 2017. The increase predominantly relates to higher interest on our variable-rate debt reflecting an overall increase in LIBOR during 2018.

In 2018 and 2017, the net gain on early extinguishment of debt consisted of the gain on open-market repurchases, including the effect of unamortized deferred gain and issuance costs.

Other non-operating expense increased by $6 million to $23 million in 2018, compared to 2017, primarily due to the derivative loss on our interest-rate contracts that were entered into in May 2018.

In 2018, we did not provide any current or deferred tax provision on pre-tax income of $429 million as a result of the partial release of our valuation allowance. In 2017, we did not provide any current or deferred tax benefit on pre-tax loss of $262 million as a result of our continued financial losses.

Net income attributable to noncontrolling interests increased by $97 million in 2018 compared to 2017, largely the result of the Ares JV entered into in February 2018.

Year Ended December 31, 2017 vs. 2016

Oil and gas net sales increased 19%, or $315 million, in 2017 compared to 2016, due to increases of approximately $392 million, $78 million and $29 million from higher oil, NGL and natural gas realized prices, respectively, partially offset by the effects of lower oil and natural gas production of $168 million and $16 million, respectively. The higher realized oil prices reflected the significant increase in global oil prices and improved differentials. Our total daily production volumes averaged 129 MBoe in 2017, compared with 140 MBoe in 2016, representing a year-over-year decline rate of 8%. Average oil production decreased by 9%, or 8 MBoe per day, from 91 MBoe per day in 2016 to 83 MBoe per day in 2017. NGL production was 16 MBoe per day in both 2017 and 2016. Natural gas production decreased by 8% to 182 MMcf per day.

Net derivative losses were $90 million in 2017, compared to $206 million in 2016, representing an overall change of $116 million. In 2017, we recorded $200 million less in non-cash derivative losses, partially offset by a cash payment of $7 million in 2017 compared with cash proceeds of $77 million in 2016. The non-cash change reflected changes in the commodity price curves based on our derivative positions at the end of each of the respective periods.

Other revenue increased 21%, or $28 million, in 2017 compared to 2016, due to increased natural gas trading activity and increased third-party power sales from the Elk Hills power plant, which was offline for about half of the first quarter of 2016 for a planned turnaround.

Production costs increased $76 million to $876 million or $18.64 per Boe in 2017, compared to $800 million or $15.61 per Boe in 2016, resulting in a 10% increase on an absolute dollar basis. The year-over-year increase was driven by increased activity in line with the stronger commodity prices and higher gas and electricity costs. Total production costs in 2016 reflected management's decision to selectively defer workovers and downhole maintenance activity in light of low commodity prices. The 2017 costs reflected higher downhole maintenance activity in line with the current price environment.

Our G&A expenses increased $14 million to $249 million in 2017 compared to 2016. The 2017 period primarily reflected higher compensation expense related to bonus and the timing of equity-based compensation grants between years. In 2017 and 2016, the non-cash portion of general and administrative expenses, which was primarily comprised of equity compensation, was approximately $16 million and $18 million, respectively.

DD&A expense decreased by $15 million in 2017 compared to 2016. Of this decrease, approximately $45 million was attributable to lower production volumes, partially offset by an increase in the DD&A rate of approximately $30 million.

Taxes other than on income decreased 6% in 2017 compared to 2016, largely due to lower property taxes and GHG allowance costs.

The increase in other expenses, net of $27 million to $106 million in 2017, compared to $79 million in 2016, was largely the result of the absence of energy and property tax refunds received in 2016 as well as charges related to fires in the Ventura basin, increased fuel gas costs at our Elk Hills power plant and higher accretion expense.

Interest and debt expense, net, increased to $343 million in 2017, compared to $328 million in 2016, primarily due to higher blended interest rates, increased average borrowings as a result of our debt transactions and increased amortization of our deferred financing costs.

Net gains on early extinguishment of debt consisted of the gains on open-market repurchases in 2017 of $12 million, partially offset by a write-off of deferred financing costs related to early repayment of our 2014 Term Loan of $8 million. Net gains on early extinguishment of debt in 2016 consisted of open-market purchases, a debt-for-equity exchange and a cash tender for our Senior Notes.

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

Other non-operating expense in 2017 primarily reflected certain net periodic benefit costs from our pension and postretirement benefit plans, which were reclassified from G&A expenses upon adoption of new accounting rules in 2018.

In 2017, we did not provide any current or deferred tax benefit on pre-tax loss of $262 million as a result of our continued financial losses. For the same period of 2016, we had a deferred tax benefit of $78 million resulting from an adjustment to our 2015 valuation allowance. For 2016, we did not provide a tax provision on our pre-tax income of $279 million because the exclusion of gains related to our debt-reduction actions resulted in a tax loss, which we determined was not more-likely-than-not to be realized in the future.

Stock-Based Compensation

Our consolidated results of operations include the effects of long-term stock-based compensation plans under which we annually grant awards 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 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 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 income statement because we pay partially or fully cash-settled awards based on our stock price as of the vesting date and accounting rules require that we adjust our obligation for such awards to the amount that would be paid using our stock price as of the end of each reporting period. Cash-settled awards, including executive awards partially settled in cash, account for over 50% of our total outstanding awards. The increase in our stock price in 2018 resulted in higher cash-settled stock-based compensation expense in the second and third quarters of 2018 when a portion of these awards vested and our unvested awards were marked-to-market based on the period-end stock price. In the fourth quarter of 2018, our stock price declined and the year-end mark-to-market adjustments reduced our compensation expense. Equity-settled awards are not similarly adjusted for changes in our stock price. Our ending stock price for each of the quarters in 2018, 2017 and 2016 was as follows:

	2018	2017	2016
First quarter	$ 17.15	$ 15.04	$ 10.30
Second quarter	$ 45.44	$ 8.55	$ 12.20
Third quarter	$ 48.53	$ 10.46	$ 12.50
Fourth quarter	$ 17.04	$ 19.44	$ 21.29

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

	2018	2017	2016
	(in millions, except per Boe amounts)		
G&A expenses			
Cash-settled awards	$ 23	$ 9	$ 6
Equity-settled awards	13	14	17
Total stock-based compensation in G&A	$ 36	$ 23	$ 23
Total stock-based compensation in G&A per Boe	$ 0.75	$ 0.49	$ 0.45
Production costs			
Cash-settled awards	$ 6	$ 2	$ 2
Equity-settled awards	3	4	5
Total stock-based compensation in production costs	$ 9	$ 6	$ 7
Total stock-based compensation in production costs per Boe	$ 0.19	$ 0.13	$ 0.14
Total stock-based compensation	$ 45	$ 29	$ 30
Total stock-based compensation per Boe	$ 0.94	$ 0.62	$ 0.59

Non-GAAP Financial Measures

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

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

	2018	2017	2016
	(in millions, except share data)		
Net income (loss)	$ 429	$ (262)	$ 279
Net income attributable to noncontrolling interests	(101)	(4)	—
Net income (loss) attributable to common stock	328	(266)	279
Unusual, infrequent and other items:			
Non-cash derivative (gain) loss from commodities, excluding noncontrolling interest	(224)	78	283
Non-cash derivative loss from interest-rate contracts	6	—	—
Early retirement, severance and other costs	4	5	20
Net gain on early extinguishment of debt	(57)	(4)	(805)
Gain on asset divestitures	(5)	(21)	(30)
Other, net	9	21	(13)
Total unusual, infrequent and other items	(267)	79	(545)
Deferred debt issuance costs write-off	—	—	12
Reversal of valuation allowance for deferred tax assets[(a)]	—	—	(63)
Adjusted net income (loss)	$ 61	$ (187)	$ (317)
Net income (loss) attributable to common stock per diluted share	$ 6.77	$ (6.26)	$ 6.76
Adjusted net income (loss) per diluted share	$ 1.27	$ (4.40)	$ (7.85)

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

The following table presents the components of our net derivative gain (loss) from commodity contracts and our non-cash derivative loss from interest-rate contracts. Our non-cash derivative loss from interest-rate contracts is reported in other non-operating expenses.

	2018	2017	2016
		(in millions)	
Commodity Contracts:			
Non-cash derivative gain (loss), excluding noncontrolling interest	$ 224	$ (78)	$ (283)
Non-cash derivative gain (loss) included in noncontrolling interest	5	(5)	—
Net (payments) proceeds on settled commodity derivatives	(228)	(7)	77
Net derivative gain (loss) from commodity contracts	$ 1	$ (90)	$ (206)
Interest-Rate Contracts:			
Non-cash derivative loss	$ (6)	$ —	$ —

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:

	2018	2017	2016
		(in millions)	
Net income (loss)	$ 429	$ (262)	$ 279
Interest and debt expense, net	379	343	328
Income tax benefit	—	—	(78)
Depreciation, depletion and amortization	502	544	559
Exploration expense	34	22	23
Unusual, infrequent and other items	(267)	79	(545)
Other non-cash items	40	53	50
Adjusted EBITDAX	$ 1,117	$ 779	$ 616

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:

	2018	2017	2016
		(in millions)	
Net cash provided by operating activities	$ 461	$ 248	$ 130
Cash interest	441	396	384
Exploration expenditures	17	20	20
Working capital changes	199	94	95
Other, net	(1)	21	(13)
Adjusted EBITDAX	$ 1,117	$ 779	$ 616

Liquidity and Capital Resources

Cash Flow Analysis

	2018	2017	2016
		(in millions)	
Net cash provided by operating activities	$ 461	$ 248	$ 130
Net cash used in investing activities:			
Capital investments, net of accruals	$ (621)	$ (344)	$ (81)
Acquisitions, divestitures and other	$ (535)	$ 31	$ 20
Net cash provided (used) by financing activities	$ 692	$ 73	$ (69)

Year Ended December 31, 2018 vs. 2017

Our net cash provided by operating activities is sensitive to many variables, including changes in commodity prices. Commodity price sensitivity also leads to changes in other variables in our business including adjustments to our capital program. Our operating cash flow increased 86%, or $213 million, to $461 million in 2018 from $248 million in 2017 primarily due to higher realized prices, including the effect of hedges, and, to a lesser degree, the Elk Hills transaction. Our operating cash flow included payments of $124 million related to purchases of GHG allowances over the course of the year, of which $98 million related to allowances we sold in 2016 to enhance our liquidity at the lowest point of the commodity price cycle. The magnitude of these GHG payments are not expected in 2019. Operating cash flow was also affected by payments made to enter into our commodity derivative contracts as well as higher payments on our floating-interest rate debt.

Our net cash used in investing activities of $1,156 million in 2018 included $621 million of capital investments (net of $69 million in capital-related accruals), of which $49 million was funded by BSP. Cash used for acquisitions included $547 million primarily for the Elk Hills transaction and our new building in Bakersfield. These uses were partially offset by $18 million in proceeds from the sale of non-core assets. In 2017, our net cash used in investing activities of $313 million included approximately $344 million of capital investments (net of $27 million in capital-related accruals), of which $275 million was internally funded and reported as cash provided by financing activities. The capital investment was partially offset by proceeds from asset divestitures of $33 million.

Our net cash provided by financing activities of $692 million in 2018 primarily comprised $796 million in net contributions from the Ares JV and BSP JV, net proceeds from our 2014 Revolving Credit Facility of $177 million and the issuance of common stock of $54 million primarily to an Ares-led investor group in connection with the Ares JV, partially offset by $203 million of debt repurchases and transaction costs and $121 million of distributions to our Ares JV and BSP JV. In 2017, our net cash provided by financing activities of $73 million primarily comprised $1.3 billion of proceeds from our 2017 Credit Agreement and $98 million in net contributions from our BSP JV, partially offset by $650 million in repayments on our 2014 Term Loan, $484 million of net payments on our 2014 Revolving Credit Facility and $158 million of debt repurchases and transaction costs.

Year Ended December 31, 2017 vs. 2016

Our net cash provided by operating activities is sensitive to many variables including market changes in commodity prices. Commodity price sensitivity triggers changes in other variables in our business including our level of workover activity and adjustments to our capital program. Operating cash flow increased 91% or $118 million to $248 million in 2017 from $130 million in 2016 due to higher realized prices, after hedges, on lower volumes. Production costs increased in 2017 by $76 million as we ramped up activity primarily related to downhole maintenance and as fuel gas and electricity prices increased. Our hedging program reduced our sensitivity to price changes.

Cash interest increased $12 million in 2017 due to higher blended interest rates and increased borrowings on our overall debt. Taxes other than on income decreased $8 million from 2016 due to lower property taxes and GHG taxes, partially offset by an increase in the production tax rate. Other changes in operating cash flow related to higher general and administrative expenses and changes in working capital.

Our net cash used in investing activities of $313 million in 2017 included approximately $344 million of capital investments (net of $27 million in capital-related accruals), of which $275 million was internally funded. Our share of the total capital investment of $248 million was funded with cash from operations. The capital investment was partially offset by proceeds from asset divestitures of

$33 million. Our net cash used in investing activities of $61 million in 2016 primarily included $81 million of capital investments (net of changes in capital-related accruals), partially offset by $20 million from asset divestitures.

Our net cash provided by financing activities of $73 million in 2017 primarily comprised $1.3 billion of proceeds from our 2017 Credit Agreement and $98 million in net contributions from our BSP JV, partially offset by $650 million in repayments on our 2014 Term Loan, $484 million of net payments on our 2014 Revolving Credit Facility, $158 million of debt repurchases and transaction costs and $8 million of distributions paid to BSP. In 2016, our net cash used by financing activities of $69 million included approximately $821 million in debt repurchases and transaction costs and $350 million of payments on our 2014 Term Loan, partially offset by the $990 million in proceeds from the issuance of our 2016 Credit Agreement and $108 million of net proceeds from our 2014 Revolving Credit Facility.

Liquidity

Our primary sources of liquidity and capital resources are cash flow from operations and available borrowing capacity under our 2014 Revolving Credit Facility. We also rely on other sources such as JVs to supplement our capital program, fund acquisitions and for other corporate purposes. Our 2019 capital program will be dynamic and will be adjusted based on realized price trends during the year. We expect to fund our portion of the 2019 capital program with cash flow from operations.

In February 2018, we entered into the Ares JV where we received $747 million in net proceeds and raised $50 million in a private placement of our common stock with an Ares-led investor group. A portion of the net proceeds from the Ares JV were used to pay off the then outstanding balance on our 2014 Revolving Credit Facility and the remaining proceeds were used to fund a strategic acquisition in April 2018 when we acquired the remaining working, surface and mineral interests in the former Elk Hills unit for $460 million in cash and 2.85 million shares of our common stock. On an annualized basis, this transaction, including synergies, added over approximately $130 million to our operating cash flow, at about $65 Brent. During 2017, we closed two key JV transactions with BSP and MIRA. Under these arrangements, our JV partners have invested approximately $260 million in our drilling programs from inception through the end of 2018, some of which is not included in our consolidated results.

Significant changes in oil and natural gas prices 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 price risk.

Debt

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

	Outstanding Principal (in millions)	Interest Rate	Maturity	Security
Credit Agreements				
2014 Revolving Credit Facility	$ 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	LIBOR plus 4.75% ABR plus 3.75%	December 31, 2022[(a)]	Shared First-Priority Lien
2016 Credit Agreement	1,000	LIBOR plus 10.375% ABR plus 9.375%	December 31, 2021	First-Priority Lien
Second Lien Notes				
Second Lien Notes	2,067	8%	December 15, 2022[(b)]	Second-Priority Lien
Senior Notes				
5% Senior Notes due 2020	100	5%	January 15, 2020	Unsecured
5 ½% Senior Notes due 2021	100	5.5%	September 15, 2021	Unsecured
6% Senior Notes due 2024	144	6%	November 15, 2024	Unsecured
Total	$ 5,251			

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

(b) The Second Lien Notes require principal repayments of approximately $326 million in June 2021, $65 million in December 2021 and $68 million in June 2022.

As of December 31, 2018, we had approximately $298 million of available borrowing capacity, subject to a $150 million month-end minimum liquidity requirement. Our 2014 Revolving Credit Facility also includes a sub-limit of $400 million for the issuance of letters of credit. As of December 31, 2018 and 2017, we had letters of credit of approximately $162 million and $148 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

For additional information on long-term debt, see information set forth in *Item 8 – Financial Statements and Supplementary Data – Note 6 Debt*.

Derivatives

<u>*Commodity Contracts*</u>

Our strategy for protecting our cash flow, operating margin and capital program, while maintaining adequate liquidity, also includes our hedging program. We currently have the following Brent-based crude oil contracts, as of February 27, 2019:

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

The BSP JV entered into crude oil derivatives that are included in our consolidated results but not included above. The hedges entered into by the BSP JV could affect the timing of the redemption of the JV interest. The BSP JV sold calls for up to approximately 1,000 barrels per day at a weighted-average price per barrel of $60.00 per barrel for 2019 through 2020. The BSP JV purchased puts for up to approximately 2,000 barrels per day at a weighted-average price per barrel of approximately $50.00 for 2019 through 2021. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021.

<u>*Interest-Rate Contracts*</u>

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

2018 and 2019 Capital Program

We create value by investing our operating cash flow back into our business. In 2018, we focused our capital program on oil projects that provide high margins and low decline rates, which we believe will generate positive cash flow to fund capital program that will grow production. Our low decline rates compared to our industry peers together with our high level of operational control give us the flexibility to adjust the level of our capital investments as circumstances warrant.

We develop our capital program by prioritizing life-of-project returns to grow our net asset value over the long term, while balancing the short- and long-term growth potential of each of our assets. We use a Value Creation Index (VCI) metric for project selection and capital allocation across our asset portfolio. We calculate the VCI for each of our projects by dividing the net present value of the project's expected pre-tax cash flow over its life by the net present value of the investments, each using a 10% discount rate. Projects are expected to meet a VCI of 1.3, meaning that 30% of expected value is created above our cost of capital for every dollar invested. Our technical teams are consistently working to enhance value by improving the economics of our inventory through detailed geologic studies as well as application of more effective and efficient drilling and completion techniques. As a result, we expect many projects that do not currently meet our VCI threshold today will do so by the time of development. We regularly monitor internal performance and external factors and adjust our capital investment program with the objective of creating the most value from our asset portfolio.

2018 Capital Program

In 2018, we invested approximately $690 million of capital, including $49 million funded by BSP. Our JV partner MIRA funded an additional $57 million of investment, which is not included in our consolidated results, bringing our total capital deployed to $747 million as compared to $429 million in 2017. Our capital predominantly targeted projects in the San Joaquin and Los Angeles basins. Our 2018 capital was primarily directed towards oil-weighted production consistent with prior periods. Of the total 2018 capital program, approximately $396 million was allocated to drilling wells, $98 million to capital workovers, $129 million to facilities and compression expansion, $36 million to maintenance and occupational health, safety and environmental projects and $31 million to exploration and other items.

The table below sets forth our capital investments by basin and recovery mechanism for the year ended December 31, 2018 (in millions):

	Conventional				Unconventional		Total Capital Investments
	Primary	Waterflood	Steamflood	Total	Primary	Other	
Basin:							
San Joaquin	$ 93	$ 113	$ 59	$ 265	$ 199	$ —	$ 464
Los Angeles	—	155	—	155	—	—	155
Ventura	22	10	1	33	—	—	33
Sacramento	7	—	—	7	—	—	7
Basin Total	122	278	60	460	199	—	659
Exploration and other	—	—	—	—	—	31	31
Total	$ 122	$ 278	$ 60	$ 460	$ 199	$ 31	$ 690

2019 Capital Program

We entered 2019 with an internally funded capital program of $300 to $385 million, which may be adjusted during the course of the year depending on commodity prices. We are also in discussions to obtain additional investments from new and existing JV partners that could increase our capital program by $100 to $150 million to support a capital program of approximately $500 million.

We are focusing our 2019 capital on oil projects. Our approach to our 2019 drilling program is consistent with our stated strategy to remain financially disciplined and fund projects through either internally generated cash flow or JV capital. We will continue to deploy our partners' capital as part of our BSP and MIRA joint ventures and opportunistically pursue additional strategic relationships. We will deploy capital to projects that help continue to stabilize our production, develop our long-term resources and return our production to a growth profile. Our current drilling inventory comprises a diversified portfolio of oil and natural gas locations that are economically viable in a variety of operating and commodity price conditions.

We will continue to focus on our core fields: Elk Hills and surrounding areas, Wilmington, Kern Front and the delineation and appraisal of other long-term prospects.

We plan to use 60% 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 includes approximately 140 wells primarily in Wilmington, Huntington Beach, Kern Front and Mount Poso, which will largely consist of waterfloods and steamfloods along with some primary drilling. We also intend to drill approximately 10 unconventional wells mainly 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 15% of our 2019 capital program for capital workovers on existing well bores. Capital workovers are some of the highest VCI 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, over 15% 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 and safety. About 10% is intended to be used for exploration and other corporate uses.

As a result of higher activity levels, including the Elk Hills transaction, our production grew sequentially every quarter during 2018. The actions we have taken to streamline our business and reduce costs, together with higher realized prices, have enabled us to invest in our business and grow our production. In addition, we will continue to build our inventory of available projects, which we believe will position us to accelerate value by utilizing third-party capital and take advantage of potential future commodity price increases.

Off-Balance-Sheet Arrangements

As of December 31, 2018, we had letters of credit of $162 million under our 2014 Revolving Credit Facility and no other material off-balance-sheet arrangements other than operating leases and purchase obligations included in our *Contractual Obligations* table below.

Contractual Obligations

The table below summarizes and cross-references our contractual obligations as of December 31, 2018. This summary indicates on- and off-balance-sheet obligations as of December 31, 2018.

	Payments Due by Year				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
			(in millions)		
On-Balance Sheet					
Long-term debt[(a)]	$ 5,251	$ —	$ 5,107	$ 144	$ —
Interest on long-term debt[(b)]	1,535	444	1,075	16	—
Asset retirement obligations[(c)]	433	31	—	—	402
Pension and postretirement	147	6	25	26	90
Other long-term liabilities	6	—	6	—	—
Off-Balance Sheet					
Operating leases[(d)]	68	12	22	17	17
Purchase obligations[(e)]	172	65	73	16	18
Total[(f)]	$ 7,612	$ 558	$ 6,308	$ 219	$ 527

(a) In performing the calculation, the 2014 Revolving Credit Facility borrowings outstanding at December 31, 2018 of $540 million were assumed to be outstanding for the entire term of the agreement. See *Item 8 – Financial Statements and Supplementary Data – Note 6 Debt* for more information.

(b) The calculation of cash interest payments on our variable interest-rate debt assumes the interest rate at December 31, 2018 will continue for the entire term and no settlement payments will be received under our interest-rate cap agreements.

(c) Represents the estimated future asset retirement obligations on a discounted basis. We do not show the long-term asset retirement obligations by year as we are not able to precisely predict the timing of these amounts. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to revisions based on numerous factors, including the rate of inflation, changing technology, and changes to federal, state and local laws and regulations. See *Item 8 – Financial Statements and Supplementary Data – Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for more information.

(d) Amounts include obligations for office space and vehicles.

(e) Amounts include payments that will become due under long-term agreements to purchase goods and services used in the normal course of business primarily including pipeline capacity, land easements and field equipment. Obligations for field equipment include contractual agreements with third parties for drilling rigs and other related services. Purchase obligations for pipeline capacity are based on contractual volumes and our internal estimate of future prices during the contract period. Land easements include obligations for fixed payments under our term contracts, and those held by production cannot be reliably estimated.

(f) Amounts exclude unrecognized tax benefit of $25 million due to uncertainty with respect to the timing of future cash outflows.

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

See *Item 8 – Financial Statements and Supplementary Data – Note 8 Lawsuits, Claims, Commitments and Contingencies*.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates include property, plant and equipment, asset retirement obligations and fair value measurements. See *Item 8 – Financial Statements and Supplementary Data – Note 1 Nature of Business, Summary of Significant Accounting Policies and Other* for details on these critical accounting policies and estimates that involve management's judgment and that could result in a material impact to the financial statements due to the levels of subjectivity and judgment.

Significant Accounting and Disclosure Changes

See *Item 8 – Financial Statements and Supplementary Data – Note 2 Accounting and Disclosure Changes* for a discussion of new accounting standards.

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 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*.

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 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our financial results are sensitive to fluctuations in oil, NGL and gas prices. In 2019, we expect that price changes at current levels of production, excluding the impact of existing hedges discussed below, would affect our pre-tax annual income and cash flows as follows:

Pre-tax 2019 Price Sensitivities		(in millions)
$1 change in Brent index - Oil[(a)]	$	24.0
$1 change in Brent index - NGLs	$	3.5
$0.10 change in NYMEX - Gas[(b)]	$	3.8

(a) Amount reflects the upside sensitivity.
(b) Amount reflects the sensitivity with respect to unhedged volumes and includes the offsetting effect of internal gas use in the operations.

As a result of our 2019 hedge positions, we protected our downside price risk on approximately 45,000 and 40,000 barrels of oil per day at approximately $66 Brent and $70 Brent per barrel, respectively, for the first and second quarters of 2019. For the third and fourth quarters of 2019, we protected our downside price risk on approximately 40,000 and 35,000 barrels of oil per day at approximately $73 Brent and $76 Brent per barrel, respectively. The underlying instruments in our 2019 hedge program are puts and put spreads. For the full year 2019, we are protected at a weighted-average Brent price of approximately $71 per barrel, and Brent plus approximately $15 if Brent were to fall below a weighted-average of $56 per barrel. Except for a small portion primarily in the first quarter of 2019, the 2019 hedges do not contain caps, thereby providing upside to oil price movements.

Due to our tax position, there is no difference between the impact on our income and cash flows. These price-change sensitivities include the impact on income of volume changes under PSC-type contracts. If production and price levels change in the future, the sensitivity of our results to prices also will change.

As of December 31, 2018, we recognized a net asset of $178 million for our derivative commodity positions which are carried at fair value, using industry-standard models with various inputs, including the forward curve for the relevant price index. Based on the $178 million net derivative asset as of December 31, 2018, a 10% increase or decrease in their fair value would affect pre-tax earnings by approximately $18 million. See additional hedging information in *Item 7 – 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 continue to monitor their financial health. Concentration of credit risk is regularly reviewed to ensure that counterparty credit risk is adequately diversified.

As of December 31, 2018, the substantial majority of the credit exposure related to our derivative financial instruments was with investment grade counterparties. We believe exposure to credit-related losses at December 31, 2018 was not material and losses associated with credit risk have been insignificant for all years presented.

Interest-Rate Risk

As of December 31, 2018, we had borrowings of $1.3 billion outstanding under our 2017 Credit Agreement, $1 billion outstanding under our 2016 Credit Agreement and $540 million outstanding under our 2014 Revolving Credit Facility, all of which carry variable interest rates. A one-eighth percent change in the interest rates on these outstanding borrowings under these facilities would result in an approximately $4 million change in annual interest expense assuming no payments are received under our interest-rate cap agreements described below.

As of December 31, 2018, we had interest-rate caps that limit our interest rate exposure with respect to $1.3 billion of our variable-rate indebtedness. The interest rate contracts reset monthly and require the counterparties to pay any excess interest owed on such amount in the event the one-month LIBOR exceeds 2.75% for any monthly period prior to May 4, 2021. As of December 31, 2018, we recognized a net asset of $4 million for our interest-rate contracts which are carried at fair value, using industry-standard models with various inputs, including the LIBOR forward curve.

The following table shows our fixed- and variable-rate debt as of December 31, 2018 (in millions):

Year of Maturity	U.S. Dollar Fixed-Rate Debt	U.S. Dollar Variable-Rate Debt	Total
2019	$ —	$ —	$ —
2020	100	—	100
2021	491	1,540	2,031
2022[(a)]	1,676	1,300	2,976
2023	—	—	—
2024	144	—	144
Total	$ 2,411	$ 2,840	$ 5,251
Weighted-average interest rate	7.65%	9.13%	8.45%
Fair value	$ 1,652	$ 2,840	$ 4,492

(a) The $1.3 billion U.S. dollar variable-rate debt 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.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
California Resources Corporation:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of California Resources Corporation and subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles (GAAP). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Assessment of and Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

We have served as the Company's auditor since 2014.

Los Angeles, California
February 27, 2019

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
As of December 31, 2018 and 2017
(in millions, except share data)

	2018	2017
CURRENT ASSETS		
Cash	$ 17	$ 20
Trade receivables	299	277
Inventories	69	56
Other current assets, net	255	130
Total current assets	640	483
PROPERTY, PLANT AND EQUIPMENT	22,523	21,260
Accumulated depreciation, depletion and amortization	(16,068)	(15,564)
Total property, plant and equipment, net	6,455	5,696
OTHER ASSETS	63	28
TOTAL ASSETS	$ 7,158	$ 6,207
CURRENT LIABILITIES		
Accounts payable	390	257
Accrued liabilities	217	475
Total current liabilities	607	732
LONG-TERM DEBT	5,251	5,306
DEFERRED GAIN AND ISSUANCE COSTS, NET	216	287
OTHER LONG-TERM LIABILITIES	575	602
MEZZANINE EQUITY		
Redeemable noncontrolling interests	756	—
EQUITY		
Preferred stock (20 million shares authorized at $0.01 par value) no shares outstanding at December 31, 2018 or 2017	—	—
Common stock (200 million shares authorized at $0.01 par value) outstanding shares (2018 — 48,650,420 shares and 2017 — 42,901,946 shares)	—	—
Additional paid-in capital	4,987	4,879
Accumulated deficit	(5,342)	(5,670)
Accumulated other comprehensive loss	(6)	(23)
Total equity attributable to common stock	(361)	(814)
Noncontrolling interests	114	94
Total equity	(247)	(720)
TOTAL LIABILITIES AND EQUITY	$ 7,158	$ 6,207

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
For the years ended December 31, 2018, 2017 and 2016
(in millions, except per share data)

	2018	2017	2016
REVENUES AND OTHER			
Oil and gas sales	$ 2,590	$ 1,936	$ 1,621
Net derivative gain (loss) from commodity contracts	1	(90)	(206)
Other revenue	473	160	132
Total revenues and other	3,064	2,006	1,547
COSTS AND OTHER			
Production costs	912	876	800
General and administrative expenses	299	249	235
Depreciation, depletion and amortization	502	544	559
Taxes other than on income	149	136	144
Exploration expense	34	22	23
Other expenses, net	399	106	79
Total costs and other	2,295	1,933	1,840
OPERATING INCOME (LOSS)	769	73	(293)
NON-OPERATING (LOSS) INCOME			
Interest and debt expense, net	(379)	(343)	(328)
Net gain on early extinguishment of debt	57	4	805
Gain on asset divestitures	5	21	30
Other non-operating expenses	(23)	(17)	(13)
INCOME (LOSS) BEFORE INCOME TAXES	429	(262)	201
Income tax benefit	—	—	78
NET INCOME (LOSS)	429	(262)	279
Net income attributable to noncontrolling interests	(101)	(4)	—
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$ 328	$ (266)	$ 279
Net income (loss) attributable to common stock per share			
Basic	$ 6.77	$ (6.26)	$ 6.76
Diluted	$ 6.77	$ (6.26)	$ 6.76

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Comprehensive Income
For the years ended December 31, 2018, 2017 and 2016
(in millions)

	2018	2017	2016
Net income (loss)	$ 429	$ (262)	$ 279
Other comprehensive income (loss) items:			
Reclassification of unrealized gains (losses) on pension and postretirement losses[(a)]	13	(14)	(9)
Reclassification of realized losses on pension and postretirement to income[(a)]	4	5	10
Total other comprehensive income (loss)	17	(9)	1
Comprehensive income attributable to noncontrolling interests	(101)	(4)	—
Comprehensive income (loss) attributable to common stock	$ 345	$ (275)	$ 280

(a) No associated tax for 2018, 2017 and 2016. See *Note 14 Pension and Postretirement Benefit Plans* for additional information.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Equity
For the years ended December 31, 2018, 2017 and 2016
(in millions)

	Additional Paid-in Capital	Accumulated (Deficit) Earnings	Accumulated Other Comprehensive (Loss) Income	Equity Attributable to Common Stock	Equity Attributable to Noncontrolling Interests	Total Equity
Balance, December 31, 2015	$ 4,782	$ (5,683)	$ (15)	$ (916)	$ —	$ (916)
Net income	—	279	—	279	—	279
Other comprehensive income	—	—	1	1	—	1
Share-based compensation, net	79	—	—	79	—	79
Balance, December 31, 2016	$ 4,861	$ (5,404)	$ (14)	$ (557)	$ —	$ (557)
Net (loss) income	—	(266)	—	(266)	4	(262)
Contribution from noncontrolling interest holders, net	—	—	—	—	98	98
Distributions paid to noncontrolling interest holders	—	—	—	—	(8)	(8)
Other comprehensive loss	—	—	(9)	(9)	—	(9)
Share-based compensation, net	18	—	—	18	—	18
Balance, December 31, 2017	$ 4,879	$ (5,670)	$ (23)	$ (814)	$ 94	$ (720)
Net income	—	328	—	328	2	330
Contribution from noncontrolling interest holders, net	—	—	—	—	82	82
Distributions paid to noncontrolling interest holders	—	—	—	—	(64)	(64)
Issuance of common stock[(a)]	101	—	—	101	—	101
Other comprehensive income	—	—	17	17	—	17
Share-based compensation, net	7	—	—	7	—	7
Balance, December 31, 2018	$ 4,987	$ (5,342)	$ (6)	$ (361)	$ 114	$ (247)

Note: Excludes amounts related to redeemable noncontrolling interests recorded in mezzanine equity. See *Note 5 Joint Ventures* for more information.

(a) Includes 2.85 million shares of common stock (valued at $51 million at issuance) issued to Chevron in connection with our acquisition of Chevron's working interest in Elk Hills unit and 2.3 million shares of common stock (valued at $50 million at issuance) issued to an Ares-led investor group. See *Note 4 Acquisitions and Divestitures* and *Note 5 Joint Ventures* for more information.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
For the years ended December 31, 2018, 2017 and 2016
(in millions)

	2018	2017	2016
CASH FLOW FROM OPERATING ACTIVITIES			
Net income (loss)	$ 429	$ (262)	$ 279
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	502	544	559
Deferred income tax benefit	—	—	(78)
Net derivative (gain) loss from commodity contracts	(1)	90	206
Net (payments) proceeds on settled commodity derivatives	(228)	(7)	77
Net gain on early extinguishment of debt	(57)	(4)	(805)
Amortization of deferred gain	(76)	(74)	(71)
Gain on asset divestitures	(5)	(21)	(30)
Other non-cash charges to income, net	97	77	101
Dry hole expenses	16	2	3
Changes in operating assets and liabilities, net:			
Increase in trade receivables	(23)	(45)	(33)
(Increase) decrease in inventories	(6)	2	—
(Increase) decrease in other current assets	(9)	(2)	25
Decrease in accounts payable and accrued liabilities	(178)	(52)	(103)
Net cash provided by operating activities	461	248	130
CASH FLOW FROM INVESTING ACTIVITIES			
Capital investments	(690)	(371)	(75)
Changes in capital investment accruals	69	27	(6)
Asset divestitures	18	33	20
Acquisitions	(547)	—	—
Other	(6)	(2)	—
Net cash used in investing activities	(1,156)	(313)	(61)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from 2014 Revolving Credit Facility	2,823	1,696	2,218
Repayments of 2014 Revolving Credit Facility	(2,646)	(2,180)	(2,110)
Proceeds from 2016 Credit Agreement	—	—	990
Proceeds from 2017 Term Loan	—	1,274	—
Payments on 2014 Term Loan	—	(650)	(350)
Debt repurchases	(199)	(116)	(770)
Debt transaction costs	(4)	(42)	(51)
Contributions from noncontrolling interest holders, net	796	98	—
Distributions paid to noncontrolling interest holders	(121)	(8)	—
Issuance of common stock	54	3	4
Shares canceled for taxes	(11)	(2)	—
Net cash provided (used) by financing activities	692	73	(69)
(Decrease) increase in cash	(3)	8	—
Cash—beginning of year	20	12	12
Cash—end of year	$ 17	$ 20	$ 12

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

NOTE 1 NATURE OF BUSINESS, SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND OTHER

Nature of Business

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 remained a wholly owned subsidiary of Occidental until November 30, 2014. On November 30, 2014, Occidental distributed shares of our common stock on a pro-rata basis to Occidental stockholders (the Spin-off). We became an independent, publicly traded company on December 1, 2014. Occidental initially retained approximately 18.5% of our outstanding shares of common stock, which it distributed to Occidental stockholders on March 24, 2016.

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

Basis of Presentation

All financial information presented consists of our consolidated results of operations, financial position and cash flows. The assets and liabilities in the consolidated financial statements are presented on a historical cost basis. We have eliminated all of our significant intercompany transactions and accounts. We account for our share of oil and gas exploration and production ventures, in which we have a direct working interest, by reporting our proportionate share of assets, liabilities, revenues, costs and cash flows within the relevant lines on our consolidated balance sheets, statements of operations and cash flows.

Certain prior year amounts have been reclassified to conform to the 2018 presentation. On the statements of operations for 2017 and 2016, we reclassified interest cost, expected return on assets, amortization of prior service costs and settlements/curtailments, all associated with defined benefit pension plans, from general and administrative expenses to other non-operating expenses in accordance with new accounting rules. See *Note 2 Accounting and Disclosure Changes* for more information.

On May 31, 2016, we completed a reverse stock split using a ratio of one share of common stock for every ten shares then outstanding. Share and per share amounts included in this report have been restated to reflect this reverse stock split. The split proportionally decreased the number of authorized shares of common stock from 2.0 billion shares to 200 million shares and preferred stock from 200 million to 20 million shares.

Risks and Uncertainties

The process of preparing financial statements in conformity with United States (U.S.) generally accepted accounting principles (GAAP) requires management to select appropriate accounting policies and make informed estimates and judgments regarding certain types of financial statement balances and disclosures. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements and judgments on expected outcomes as well as the materiality of transactions and balances. Changes in facts and circumstances or discovery of new information relating to such transactions and events may result in revised estimates and judgments and actual results may differ from estimates upon settlement. Management believes that these estimates and judgments provide a reasonable basis for the fair presentation of our financial statements.

Concentration of Customers

For the year ended December 31, 2018, our principal customers, Phillips 66 Company and Valero Marketing & Supply Company, each accounted for at least 10%, and, collectively, 43% of our oil and gas sales and other revenue. For the years ended December 31, 2017 and 2016, our principal customers, Phillips 66 Company, Andeavor (formerly Tesoro Refining & Marketing Company LLC), Valero Marketing & Supply Company and Shell Trading (US) Company, each accounted for at least 10%, and, collectively, 67% of our oil and gas sales and other revenue.

Critical Accounting Policies

Property, Plant and Equipment

We use the successful efforts method to account for our oil and gas properties. Under this method, we capitalize costs of acquiring properties, costs of drilling successful exploration wells and development costs. The costs of exploratory wells, including permitting, land preparation and drilling costs, are initially capitalized pending a determination of whether we find proved reserves. If we find proved reserves, the costs of exploratory wells remain capitalized. Otherwise, we charge the costs of the related wells to expense. In some cases, we cannot determine whether we have found proved reserves at the completion of exploration drilling, and must conduct additional testing and evaluation of the wells. We generally expense the costs of such exploratory wells if we do not determine we have found proved reserves within a 12-month period after drilling is complete.

Proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. We have no proved oil and gas reserves for which the determination of economic producibility is subject to the completion of major additional capital investments.

Several factors could change our proved oil and gas reserves. For example, for long-lived properties, higher commodity prices typically result in additional reserves becoming economic and lower commodity prices may lead to existing reserves becoming uneconomic. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. These factors, in turn, could lead to changes in the quantity of proved reserves. Additional factors that could result in a change of proved reserves include production decline rates and operating performance differing from those estimated when the proved reserves were initially recorded as well as availability of capital to implement the development activities contemplated in the reserves estimates and changes in management's plans with respect to such development activities.

We perform impairment tests with respect to proved properties when product prices decline other than temporarily, reserves estimates change significantly, other significant events occur or management's plans change with respect to these properties in a manner that may impact our ability to realize the recorded asset amounts. Impairment tests incorporate a number of assumptions involving expectations of undiscounted future cash flows, which can change significantly over time. These assumptions include estimates of future product prices, which we base on forward price curves and, when applicable, contractual prices, estimates of oil and gas reserves and estimates of future expected operating and development costs. Any impairment loss would be calculated as the excess of the asset's net book value over its estimated fair value. We recognize any impairment loss on proved properties by adjusting the carrying amount of the asset.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2018, the net capitalized costs attributable to unproved properties were approximately $284 million. When we make acquisitions that include unproved properties, we assign values based on estimated reserves that we believe will ultimately be proved. As exploration and development work progresses and if reserves are proved, we transfer the book value from unproved based on the initially determined rate, not based on specific areas, leases or other units. If the exploration and development work were to be unsuccessful, or management decided not to pursue development of these properties as a result of lower commodity prices, higher development and operating costs, contractual conditions or other factors, the capitalized costs of the related properties would be expensed. The unproved amounts are not subject to depreciation, depletion and amortization (DD&A) until they are classified as proved properties.

Impairments of unproved properties are primarily based on qualitative factors including intent of property development, lease term and recent development activity. The timing of impairments on unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We recognize any impairment loss on unproved properties by providing a valuation allowance.

We determine depreciation and depletion of oil and gas producing properties by the unit-of-production method. We amortize acquisition costs over total proved reserves, and capitalized development and successful exploration costs over proved developed reserves. Our gas and power plant assets are depreciated over the estimated useful lives of the assets, using the straight-line method, with expected initial useful lives of the assets of up to 30 years. Other non-producing property and equipment is depreciated using the straight-line method based on expected initial lives of the individual assets or group of assets of up to 20 years.

We expense annual lease rentals, the costs of injection used in production and exploration, and geological, geophysical and seismic costs as incurred. Costs of maintenance and repairs are expensed as incurred, except that the costs of replacements that expand capacity or add proven oil and gas reserves are capitalized.

Asset Retirement Obligations

We recognize the fair value of asset retirement obligations (ARO) in the period in which a determination is made that a legal obligation exists to dismantle an asset and reclaim or remediate the property at the end of its useful life and the cost of the obligation can be reasonably estimated. The fair value of the retirement obligation is estimated based on future retirement cost estimates and incorporates many assumptions such as time of abandonment, current regulatory requirements, technological changes, future inflation rates and the risk-adjusted discount rate. When the liability is initially recorded, we capitalize the cost by increasing the related property, plant and equipment (PP&E) balances. If the estimated future cost or timing of cash flow changes, we record an adjustment to both the ARO and PP&E. Over time, the liability is increased and expense is recognized for accretion, and the capitalized cost is recovered over either the useful life of our facilities or the unit-of-production method for our minerals.

At certain of our facilities, we have identified ARO that are related mainly to plant and field decommissioning, including plugging and abandonment of wells. In certain cases, we do not know or cannot estimate when we would perform the ARO work and, therefore, we cannot reasonably estimate the fair value of these liabilities. We will recognize ARO in the periods in which sufficient information becomes available to reasonably estimate their fair values. Additionally, for certain plants, we do not have a legal obligation to decommission them and, accordingly, we have not recorded a liability.

The following table summarizes the activity of our ARO, of which $402 million and $403 million is included in other long-term liabilities, with the remaining current portion in accrued liabilities at December 31, 2018 and 2017, respectively.

	For the years ended December 31,	
	2018	2017
	(in millions)	
Beginning balance	$ 422	$ 411
Liabilities incurred, capitalized to PP&E	4	2
Liabilities settled and paid	(15)	(9)
Accretion expense	27	25
Acquisitions, capitalized to PP&E[(a)]	8	—
Dispositions and other, reduction to PP&E	(2)	—
Revisions in estimated cash flows, changes in PP&E	(11)	(7)
Ending balance	$ 433	$ 422

(a) Includes $7 million related to the Elk Hills transaction and $1 million related to other acquisitions in 2018.

Fair Value Measurements

We have categorized our assets and liabilities that are measured at fair value in a three-level fair value hierarchy, based on the inputs to the valuation techniques:

Level 1—using quoted prices in active markets for the assets or liabilities;
Level 2—using observable inputs other than quoted prices for the assets or liabilities; and
Level 3—using unobservable inputs.

Transfers between levels, if any, are recognized at the end of each reporting period. We apply the market approach for certain recurring fair value measurements, maximize our use of observable inputs and minimize use of unobservable inputs. We generally use an income approach to measure fair value when observable inputs are unavailable. This approach utilizes management's judgments regarding expectations of projected cash flows using a risk-adjusted discount rate.

Commodity and interest-rate derivatives are carried at fair value. For commodity derivatives, we utilize the mid-point between bid and ask prices for valuing these instruments. For interest-rate derivatives, we utilize the LIBOR forward curve. In addition to using market data in determining these fair values, we make assumptions about the risks inherent in the inputs to the valuation technique. Our commodity derivatives comprise over-the-counter bilateral financial commodity contracts, which are generally valued using industry-standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility factors, credit risk and current market and contracted prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable data or are supported by observable prices at which transactions are executed in the marketplace. We classify these measurements as Level 2. The most significant items on our balance sheet that would be affected by recurring fair value measurements are derivatives.

Our PP&E is written down to fair value if we determine that there has been an impairment in its value. The fair value is determined as of the date of the assessment using discounted cash flow models based on management's expectations for the future. Inputs include estimates of future production, prices based on commodity forward price curves as of the date of the estimate, estimated future operating and development costs and a risk-adjusted discount rate.

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

Other Accounting Policies

Revenue Recognition

We recognize revenue in accordance with ASC 606, *Revenue from Contracts with Customers*, which is more fully described in *Note 15 Revenue Recognition*.

Inventories

Materials and supplies are valued at weighted-average cost and are reviewed periodically for obsolescence. Finished goods predominantly comprise oil and natural gas liquids (NGLs), which are valued at the lower of cost or market. Inventories as of December 31, 2018 and 2017 consisted of the following:

	2018	2017
	(in millions)	
Materials and supplies	$ 65	$ 53
Finished goods	4	3
Total	$ 69	$ 56

Derivative Instruments

We apply hedge accounting when transactions meet specified criteria for cash-flow hedge treatment and management elects and documents such treatment. 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.

Our derivative contracts are carried at fair value and on a net basis when a legal right of offset exists with the same counterparty. Since we did not apply hedge accounting for any of the periods presented, we recognize any fair value gains or losses on a net basis, over the remaining term of the instrument, in our consolidated statement of operations.

Stock-Based Incentive Plans

We have stockholder-approved stock-based incentive plans for certain employees and directors that are more fully described in *Note 11 Stock Compensation*.

Earnings Per Share

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

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

Other Loss Contingencies

In the normal course of business, we are involved in lawsuits, claims and other environmental and legal proceedings and audits. We accrue reserves for these matters when it is probable that a liability has been incurred and the liability can be reasonably estimated. In addition, we disclose, if material, in aggregate, our exposure to loss in excess of the amount recorded on the balance sheet for these matters if it is reasonably possible that an additional material loss may be incurred. We review our loss contingencies on an ongoing basis.

Loss contingencies are based on judgments made by management with respect to the likely outcome of these matters and are adjusted as appropriate. Management’s judgments could change based on new information, changes in, or interpretations of, laws or regulations, changes in management’s plans or intentions, opinions regarding the outcome of legal proceedings, or other factors.

Income Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. Deferred tax assets are recognized when it is more-likely-than-not that they will be realized. We periodically assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We recognize the financial statement effects of tax positions when it is more-likely-than-not, based on the technical merits, that the position will be sustained upon examination by a tax authority. We recognize interest and penalties, if any, related to uncertain tax positions as a component of the income tax provision. No interest or penalties related to uncertain tax positions were recognized in the financial statements for the periods presented.

Production-Sharing Type Contracts

Our share of production and reserves from operations in the Wilmington field is subject to contractual arrangements similar to production-sharing contracts (PSCs) that are in effect through the economic life of the assets. Under such contracts we are obligated to fund all capital and production costs. We record a share of production and reserves to recover a portion of such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (i) to recover our partners’ share of capital and production costs that we incur on their behalf, (ii) for our share of contractually defined base production and (iii) for our share of remaining production thereafter. We recover our share of capital and production costs, and generate returns through our defined share of production from (ii) and (iii) above. These contracts do not transfer any right of ownership to us and reserves reported from these arrangements are based on our economic interest as defined in the contracts. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline, assuming comparable capital investment and production costs. However, our net economic benefit is greater when product prices are higher. The contracts represented approximately 15% of our production for the year ended December 31, 2018.

In line with industry practice for reporting PSC-type contracts, we report 100% of operating costs under such contracts in our consolidated statements of operations as opposed to reporting only our share of those costs. We report the proceeds from production designed to recover our partners' share of such costs (cost recovery) in our revenues. Our reported production volumes reflect only our share of the total volumes produced, including cost recovery, 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 per barrel and has no effect on our net results.

Pension and Postretirement Benefit Plans

All of our employees participate in postretirement benefit plans sponsored by us. These plans are funded as benefits are paid. In addition, a small number of our employees also participate in defined benefit pension plans sponsored by us. We recognize the net overfunded or underfunded amounts in the consolidated financial statements using a December 31 measurement date.

We determine our defined benefit pension and postretirement benefit plan obligations based on various assumptions and discount rates. The discount rate assumptions used are meant to reflect the interest rate at which the obligations could effectively be settled on the measurement date. We estimate the rate of return on assets with regard to current market factors but within the context of historical returns.

Pension plan assets are measured at fair value. Publicly registered mutual funds are valued using quoted market prices in active markets. Commingled funds are valued at the fund units' net asset value (NAV) provided by the issuer, which represents the quoted price in a non-active market. Guaranteed deposit accounts are valued at the book value provided by the issuer.

Actuarial gains and losses that have not yet been recognized through income are recorded in accumulated other comprehensive income within equity, net of taxes, until they are amortized as a component of net periodic benefit cost.

Cash

Cash at December 31, 2018 and 2017 included approximately $2 million and $5 million, respectively, that is restricted under one of our joint venture (JV) agreements.

Other Current Assets

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

	2018	2017
	(in millions)	
Derivative assets	$ 168	$ 23
Amounts due from joint interest partners	68	76
Prepaid expenses	16	19
Assets held for sale	—	12
Other	3	—
Other current assets, net	$ 255	$ 130

Accrued Liabilities

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

	2018	2017
	(in millions)	
Accrued employee-related costs	$ 109	$ 86
Accrued taxes other than on income	38	130
Current portion of asset retirement obligation	31	19
Accrued interest	15	23
Derivative liabilities	3	154
Other	21	63
Accrued liabilities	$ 217	$ 475

Supplemental Cash Flow Information

We did not make any U.S. federal and state income tax payments in 2018, 2017 or 2016. Interest paid, net of capitalized amounts, totaled approximately $433 million, $393 million and $382 million for the years ended December 31, 2018, 2017 and 2016, respectively. Non-cash financing activities in 2018 included 2.85 million shares of common stock (valued at $51 million) issued in connection with the Elk Hills transaction. See *Note 4 Acquisitions and Divestitures* for more on the Elk Hills transaction.

NOTE 2 ACCOUNTING AND DISCLOSURE CHANGES

Recently Issued Accounting and Disclosure Changes

In February 2016, the Financial Accounting Standards Board (FASB) issued rules requiring lessees to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months and to include qualitative and quantitative disclosures with respect to the amount, timing, and uncertainty of cash flows arising from leases. In January 2018, the FASB issued an update to the lease standard providing an optional transition approach for land easements allowing entities to evaluate only new or modified land easements. In July 2018, the FASB provided optional transition relief allowing a prospective approach in applying the new rules by not adjusting comparative period financial information for the effects of the new rules and not requiring disclosures for periods before the effective date. In December 2018, the FASB issued an update to the lease standard for lessors regarding certain tax and other costs and the reporting of these costs against rental income. These rules will be effective for us on January 1, 2019, which we expect to apply prospectively. We are currently evaluating the impact of this accounting standard on our financial statements. We expect the adoption of these rules to increase both our assets and liabilities by an equal amount, which we do not expect to be material to our consolidated balance sheets.

Recently Adopted Accounting and Disclosure Changes

In May 2014, the FASB issued rules on the recognition of revenue that created Topic 606 (ASC 606), which superseded existing revenue recognition requirements reported in accordance with GAAP, and required an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The new rules required certain sales-related costs to be reported as other expense as opposed to being netted against oil and gas sales or other revenue. We adopted ASC 606 on January 1, 2018 using the modified retrospective method with no adjustment to opening retained earnings. Results for reporting periods beginning after January 1, 2018 are presented under ASC 606, while prior period amounts are not adjusted and continue to be reported under the accounting standards in effect prior to adoption. See *Note 15 Revenue Recognition* for more information.

In March 2017, the FASB issued rules requiring employers that sponsor defined benefit plans for pensions and postretirement benefits to present the service cost component of net periodic benefit cost in the same income statement line item as other employee compensation costs arising from services rendered during the period. Only the service cost component will be eligible for capitalization to assets. Under the new rules, employers are required to present the other components of the net periodic benefit cost separately from the line item that includes the service cost and outside of any subtotal of operating income. We adopted these rules in the first quarter of 2018 with no significant impact on our financial statements. The interest cost, expected return on assets, amortization of prior service costs and settlements/curtailments have been reclassified from general and administrative expense to other non-operating expenses. We elected to use the amounts disclosed for the various components of net periodic benefit cost in the pension and postretirement benefit plans footnote as the basis of the retrospective application.

In August 2018, the FASB issued rules to amend the guidance on defined benefit pension and postretirement plans. The rules add, remove and clarify specific requirements of disclosures in the notes to financial statements. We early adopted these rules retrospectively in 2018 with changes reflected in *Note 14 Pension and Postretirement Benefit Plans*.

In May 2017, the FASB issued rules to simplify the guidance on the modification of share-based payment awards. The amendments provide clarity on which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting prospectively. We adopted these rules in the first quarter of 2018 with no impact on our financial statements.

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

NOTE 3 PROPERTY, PLANT AND EQUIPMENT

The carrying value of our PP&E represents the cost incurred to acquire or develop the asset, including any ARO and capitalized interest, net of accumulated DD&A and any impairment charges. For assets acquired, initial PP&E cost is based on fair values at the acquisition date. ARO are capitalized and recovered over the lives of the related assets. No impairment charges were recorded in 2018, 2017 or 2016.

Property, plant and equipment, net as of December 31, 2018 and 2017 consisted of the following:

	2018	2017
	(in millions)	
Proved oil and gas properties	$ 20,882	$ 19,664
Unproved oil and gas properties	1,103	1,111
Facilities and other	538	485
Total property, plant and equipment	22,523	21,260
Accumulated depreciation, depletion and amortization	(16,068)	(15,564)
Total property, plant and equipment, net	$ 6,455	$ 5,696

The following table summarizes the activity of capitalized exploratory well costs for the years ended December 31:

	2018	2017	2016
		(in millions)	
Balance, beginning of year	$ 4	$ 4	$ 6
Additions to capitalized exploratory well costs	19	4	1
Reclassification to property, plant and equipment	(2)	(2)	—
Charged to expense	(16)	(2)	(3)
Balance, end of year	$ 5	$ 4	$ 4

NOTE 4 ACQUISITIONS AND DIVESTITURES

Acquisitions

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

As part of the Elk Hills transaction, Chevron reduced its royalty interest in one of our oil and gas properties by half and extended the time frame to invest the remainder of our capital commitment on that property by two years, to the end of 2020. As of December 31, 2018, the remaining commitment was approximately $17 million. In addition, the parties mutually agreed to release each other from pending claims with respect to the former Elk Hills unit.

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

Consideration:	
Cash	$ 460
Common stock issued (2.85 million shares)	51
Liabilities assumed	7
	$ 518
Identifiable assets acquired:	
Proved properties	$ 435
Other property and equipment	77
Materials and supplies	6
	$ 518

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

Also in April 2018, we acquired an office building and land in Bakersfield, California for $48.4 million, which we believe is significantly less than the estimated replacement value of the property and the land. We have approximately 500 employees who have been using eight different locations in Bakersfield across multiple leases. We expect that the new building will create significant value by bringing our Bakersfield employees together into a single location, which will increase the efficiency, effectiveness and collaboration of these employees. This building was the only available office space in the Bakersfield area large enough to allow us to consolidate our workforce in a single location. For the initial eight months in 2018, a former owner of the building occupied most of the space as a tenant, from which we generated approximately $4 million in rental income. In December 2018, this tenant downsized the space they are leasing through December 2022, with a corresponding reduction in rent. The vacated space not used by us will be available to lease to other tenants to generate additional income. In addition, the unimproved land may be monetized in the future. Approximately $6 million of the purchase price was allocated to the in-place leases, which is included in other assets and is being amortized into other expenses, net.

Additionally, we had several other upstream acquisitions totaling approximately $39 million in 2018, excluding assumed ARO liabilities of $1 million.

Divestitures

In 2018, we divested non-core assets resulting in $18 million of proceeds and a $5 million gain. In 2017, we divested non-core assets resulting in $33 million of proceeds and a $21 million gain. In 2016, we divested non-core assets resulting in $20 million of proceeds and a $30 million gain.

NOTE 5 JOINT VENTURES

Noncontrolling Interests

The following table presents the changes in noncontrolling interests by JV partners (described in greater detail below), reported in equity and mezzanine equity on the consolidated balance sheets, for the years ended December 31, 2018 and 2017:

	Equity Attributable to Noncontrolling Interest			Mezzanine Equity - Redeemable Noncontrolling Interest
	Ares JV	BSP JV	Total	Ares JV
		(in millions)		
Balance, December 31, 2017	$ —	$ 94	$ 94	$ —
Net (loss) income attributable to noncontrolling interests	(11)	13	2	99
Contributions from noncontrolling interest holders, net	33	49	82	714
Distributions to noncontrolling interest holders	(7)	(57)	(64)	(57)
Balance, December 31, 2018	$ 15	$ 99	$ 114	$ 756

<u>*Ares Management L.P. (Ares)*</u>

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

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

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

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

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

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

Benefit Street Partners (BSP)

In February 2017, we entered into a development joint venture with BSP (BSP JV) where BSP will contribute up to $250 million, subject to agreement of the parties, in exchange for a preferred interest in the BSP JV. BSP is entitled to preferential distributions and, if it receives cash distributions equal to a predetermined threshold, the preferred interest is automatically redeemed in full with no additional payment. BSP funded a total of $150 million in three equal tranches, before transaction costs, in March 2017, July 2017 and June 2018. The funds contributed by BSP were used to develop certain of our oil and gas properties.

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

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

Other

In October 2018, we entered into a development JV for a three-year program to drill 20 wells where our JV partner committed approximately $23 million and we are investing approximately $13 million. We also entered into two exploration JVs where our JV partners have an initial total commitment of approximately $12 million. If certain milestones are met on the initial wells, the parties may move forward with a mutually agreed drilling program. Our consolidated results reflect only our working interest share in these JVs.

In April 2017, we entered into a development JV with Macquarie Infrastructure and Real Assets Inc. (MIRA) under which MIRA will invest up to $300 million, subject to agreement of the parties to develop certain of our oil and gas properties in exchange for a 90% working interest in the related properties. MIRA will fund 100% of the development cost of such properties. Our 10% working interest increases to 75% if MIRA receives cash distributions equal to a predetermined threshold return. MIRA initially committed $160 million, which was intended to be invested over two years. In June 2018, the parties amended the joint development program to $140 million. The agreement provides for a commitment of up to 110% of the program amount. MIRA invested $58 million in 2017 and $57 million in 2018. Our consolidated results reflect only our working interest share in this JV.

NOTE 6 DEBT

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

	Outstanding Principal (in millions) 2018	2017	Interest Rate	Maturity	Security
Credit Agreements					
2014 Revolving Credit Facility	$ 540	$ 363	LIBOR plus 3.25%-4.00% ABR plus 2.25%-3.00%	June 30, 2021	Shared First-Priority Lien
2017 Credit Agreement	1,300	1,300	LIBOR plus 4.75% ABR plus 3.75%	December 31, 2022[(a)]	Shared First-Priority Lien
2016 Credit Agreement	1,000	1,000	LIBOR plus 10.375% ABR plus 9.375%	December 31, 2021	First-Priority Lien
Second Lien Notes					
Second Lien Notes	2,067	2,250	8%	December 15, 2022[(b)]	Second-Priority Lien
Senior Notes					
5% Senior Notes due 2020	100	100	5%	January 15, 2020	Unsecured
5 1/2% Senior Notes due 2021	100	100	5.5%	September 15, 2021	Unsecured
6% Senior Notes due 2024	144	193	6%	November 15, 2024	Unsecured
Total	$ 5,251	$ 5,306			

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

(b) The Second Lien Notes require principal repayments of approximately $326 million in June 2021, $65 million in December 2021 and $68 million in June 2022.

Credit Agreements

2014 Revolving Credit Facility

In September 2014, we entered into a Credit Agreement with JPMorgan Chase Bank, N.A, as administrative agent, and certain other lenders. This credit agreement currently consists of a $1 billion senior revolving loan facility (2014 Revolving Credit Facility), which we are permitted to increase by up to $50 million if we obtain additional commitments from new or existing lenders.

As of December 31, 2018, we had approximately $298 million of available borrowing capacity, before a $150 million month-end minimum liquidity requirement. Our 2014 Revolving Credit Facility also includes a sub-limit of $400 million for the issuance of letters of credit. As of December 31, 2018 and 2017, we had letters of credit of approximately $162 million and $148 million, respectively. These letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

Security – The lenders share a first-priority lien on a substantial majority of our assets with the lenders under of 2017 Credit Agreement, excluding the Elk Hills power plant and midstream assets that are part of the Ares JV.

Interest Rate – We can elect to borrow at either a London Interbank Offered Rate (LIBOR) rate or an alternate base rate (ABR), in each case plus an applicable margin. The ABR is equal to the highest of (i) the federal funds effective rate plus 0.50%, (ii) the administrative agent's prime rate and (iii) the one-month LIBOR rate plus 1.00%. The applicable margin is adjusted based on the borrowing base utilization percentage under the 2014 Revolving Credit Facility and will vary from (i) in the case of LIBOR loans, 3.25% to 4.00% and (ii) in the case of ABR loans, 2.25% to 3.00%. The unused portion of the facility is subject to a commitment fee of 0.50% per annum. We also pay customary fees and expenses. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period, but not less than quarterly.

Maturity Date – Our 2014 Revolving Credit Facility matures on June 30, 2021.

Amortization Payments – The 2014 Revolving Credit Facility does not include any obligation to make amortization payments.

Borrowing Base – The borrowing base is redetermined each May 1 and November 1, and was most recently reaffirmed at $2.3 billion in October 2018. The borrowing base is based upon a number of factors, including commodity prices and reserves, declines in which could cause our borrowing base to be reduced. Increases in our borrowing base require approval of at least 80% of our lenders while decreases or affirmations require a two-thirds approval, in each case as measured by relative commitment amount. We and the lenders (requiring a request from the lenders holding two-thirds of the commitments) each may request a special redetermination once in any period between three consecutive scheduled redeterminations. We will be permitted to have collateral released when both (i) our credit ratings are at least Baa3 from Moody's and BBB- from S&P, in each case with a stable or better outlook, and (ii) certain permitted liens securing other debt are released.

Financial Covenants – As of December 31, 2018, our financial performance covenants included a monthly minimum liquidity requirement of not less than $150 million and the following:

Ratio	**Components**(a)	**Required Levels**	**Tested**
Maximum leverage ratio	Ratio of indebtedness under our 2014 Revolving Credit Facility to trailing four-quarter Adjusted EBITDAX	Not greater than 1.90 to 1.00 through 2019 Not greater than 1.50 to 1.00 after 2019	Quarterly
Minimum interest coverage ratio	Ratio of Adjusted EBITDAX to consolidated cash interest charges	Not less than 1.20 to 1.00	Quarterly
Minimum asset coverage ratio	Ratio of PV-10 to first lien indebtedness	Not less than 1.20 to 1.00	Quarterly

(a) Refer to the terms of our credit agreements for more detailed descriptions of the components of our financial covenants.

Other Covenants – Our 2014 Revolving Credit Facility includes covenants that, among other things, restrict our ability to incur additional indebtedness, grant liens, make asset sales and investments, repay existing indebtedness, make subsidiary distributions and enter into transactions that would result in fundamental changes. We are also restricted from paying cash dividends on our stock. Generally, these covenants include exceptions that allow us to pursue some of these activities in certain circumstances. In addition to these covenants, we must also apply cash on hand in excess of $150 million daily to repay amounts outstanding. Finally, we are also subject to a cross-default provision that causes a default under this facility if certain defaults occur under any of our other credit agreements or bond indentures.

Except for dispositions to development JVs, we must generally apply all of the proceeds from the sale of assets included in our borrowing base to repay loans outstanding under our 2014 Revolving Credit Facility. With respect to the sale of non-borrowing base assets (other than the Elk Hills power plant), we must apply the net cash proceeds to repay outstanding loans as follows:

- 25% of such proceeds for all net cash proceeds received up to $500 million
- 50% of such proceeds for all net cash proceeds received between $500 million and $1 billion
- 75% of such proceeds for all net cash proceeds received in excess of $1 billion.

We are permitted to use the balance of proceeds from non-borrowing base asset sales for general corporate purposes including acquisitions and to repurchase our Second Lien Notes and Senior Notes subject to certain conditions, including pro-forma compliance with our financial performance covenants and that we have minimum liquidity of $300 million following such repurchase.

Events of Default and Change of Control – Our 2014 Revolving Credit Facility provides for certain events of default, including upon a change of control, that entitle our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions.

Recent Amendments – Our 2014 Revolving Credit Facility was most recently amended in August 2018 and became effective in September 2018. The 2014 Credit Agreement was amended to, among other things:

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

2017 Credit Agreement

In November 2017, we entered into a $1.3 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2017 Credit Agreement). The net proceeds were used to pay the $559 million remaining balance of our 2014 Term Loan, resulting in a loss on the early extinguishment of debt of $8 million, reduce the balance of our 2014 Revolving Credit Facility and pay accrued interest. The proceeds received were net of a

$26 million original issue discount and $38 million in transaction costs. As of December 31, 2018, we had a $1.3 billion term loan outstanding under our 2017 Credit Agreement.

Security – Our 2017 Credit Agreement is secured by the same shared first-priority lien used to secure our 2014 Revolving Credit Facility.

Maturity Date – The loans mature on December 31, 2022, subject to a springing maturity of 91 days prior to the maturity of our 2016 Credit Agreement if more than $100 million is outstanding at that time. Prepayment more than 90 days prior to maturity is subject to a 2% premium.

Financial and Other Covenants – We are required to maintain a first-lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31. In addition, our 2017 Credit Agreement provides for customary covenants and events of default consistent with, or generally less restrictive than, the covenants in our 2014 Revolving Credit Facility. The covenants include limitations on additional indebtedness, liens, asset dispositions and investments among others, and are in each case subject to certain limitations and exceptions. We are also restricted from paying cash dividends on our stock.

Events of Default and Change of Control – Our 2017 Credit Agreement provides for certain events of default, including upon a change of control, that entitle our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions. We are also subject to a cross-default provision that causes a default under this credit agreement if certain defaults occur under any of our other credit agreements or indentures.

Recent Amendments – In September 2018, our 2017 Credit Agreement was most recently amended to, among other things:

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

2016 Credit Agreement

In August 2016, we entered into a $1 billion credit agreement with The Bank of New York Mellon Trust Company, N.A., as administrative agent, and certain other lenders (2016 Credit Agreement). The net proceeds from the 2016 Credit Agreement were used to (i) prepay $250 million of our 2014 Term Loan and (ii) reduce our 2014 Revolving Credit Facility by $740 million. The proceeds received were net of a $10 million original issue discount. As of December 31, 2018, we had a $1 billion term loan outstanding under our 2016 Credit Agreement.

Security – Our 2016 Credit Agreement is secured by a first-priority lien on a substantial majority of our assets (excluding the Elk Hills power plant and midstream assets that are part of the Ares JV) but is second in collateral recovery to our 2014 Revolving Credit Facility and 2017 Credit Agreement.

Maturity Date – The loans mature on December 31, 2021. Prepayment is subject to a variable make-whole amount prior to the fourth anniversary. Following the fourth anniversary, we may redeem at par.

Financial and Other Covenants – We are required to maintain a first–lien asset coverage ratio of not less than 1.20 to 1.00 as of any June 30 and December 31. Our 2016 Credit Agreement also includes other covenants that are substantially similar to our 2017 Credit Agreement. We are also restricted from paying cash dividends on our stock.

Events of Default and Change of Control – Our 2016 Credit Agreement provides for certain events of default, including upon a change of control, that entitle our lenders to declare the outstanding loans immediately due and payable, subject to certain limitations and conditions. We are also subject to a cross-default provision that causes a default under this credit agreement if certain defaults occur under any of our other credit agreements or indentures.

Second Lien Notes

In December 2015, we issued $2.25 billion in aggregate principal amount of 8% senior secured second-lien notes due December 15, 2022 (Second Lien Notes). The Second Lien Notes were issued in exchange for $2.8 billion of our then outstanding Senior Notes. We recorded a deferred gain of approximately $560 million on the debt exchange, which is being amortized using the effective interest rate method over the term of our Second Lien Notes. We pay cash interest semiannually in arrears on June 15 and December 15.

Security – Our Second Lien Notes are secured on a junior-priority basis to the first-priority liens that secure the loans under our 2014 Revolving Credit Facility, 2017 Credit Agreement and 2016 Credit Agreement.

Repurchases – In 2018, we repurchased $183 million in face value of our Second Lien Notes, for $159 million in cash resulting in a pre-tax gain of $48 million, including the effect of unamortized deferred gain and issuance costs.

Financial and Other Covenants – The indenture includes covenants that, among other things, limit our ability to grant liens securing borrowed money (subject to certain exceptions) and restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a “change of control triggering event” (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Second Lien Notes, to offer to purchase our Second Lien Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest. The indenture also restricts our ability to sell certain assets and to release collateral from liens securing our Second Lien Notes, unless the collateral is also released in compliance with our senior credit facilities. We are also subject to a cross-default provision that causes a default under this indenture if certain defaults occur under any of our other credit agreements or indentures.

Redemption – We may redeem our Second Lien Notes (i) prior to December 15, 2018, in whole or in part at a redemption price equal to 100% of the principal amount redeemed plus a make-whole amount and accrued and unpaid interest, (ii) between December 15, 2018 and 2020, in whole or in part at a fixed redemption price ranging from 104% to 102% of the principal amount redeemed plus accrued and unpaid interest and (iii) thereafter in whole or in part at a redemption price equal to 100% of the principal amount redeemed plus accrued and unpaid interest.

Senior Notes

In October 2014, we issued $5 billion in aggregate principal amount of our senior unsecured notes, including $1 billion of 5% notes due January 15, 2020 (2020 Notes), $1.75 billion of 5½% notes due September 15, 2021 (2021 Notes) and $2.25 billion of 6% notes due November 15, 2024 (2024 Notes and, collectively, Senior Notes). We used the net proceeds from the issuance of our Senior Notes to make a $4.95 billion cash distribution to Occidental in October 2014.

Repurchases – In 2018, we repurchased $49 million in face value of our 2024 Notes for $40 million in cash resulting in a pre-tax gain of $9 million, including the effect of unamortized deferred issuance costs. In 2017, we repurchased $128 million in face value of our 2020 Notes and 2021 Notes for $116 million in cash, resulting in a $12 million pre-tax gain.

Financial and Other Covenants – The indenture includes covenants that, among other things, limit our ability to grant liens securing borrowed money subject to certain exceptions and restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. The covenants are not, however, directly linked to measures of our financial performance. In addition, if we experience a "change of control triggering event" (as defined in the indenture), we will be required, unless we have exercised our right to redeem our Senior Notes, to offer to purchase our Senior Notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest. We are also subject to a cross-default provision that causes a default under this indenture if certain defaults occur under any of our other credit agreements or indentures.

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

Deferred Gain and Issuance Costs

At December 31, 2018, net deferred gain and issuance costs were $216 million, consisting of $313 million of deferred gains offset by $97 million of deferred issuance costs and original issue discounts. The December 31, 2017 net deferred gain and issuance costs were $287 million, consisting of $415 million of deferred gains offset by $128 million of deferred issuance costs and original issue discounts.

Other

At December 31, 2018, we were in compliance with all financial and other debt covenants.

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

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

Principal maturities of long-term debt outstanding at December 31, 2018 are as follows (in millions):

2019	$ —
2020	100
2021	2,031
2022	2,976
2023	—
Thereafter	144
Total	$ 5,251

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 December 31, 2018 and 2017, including the fair value of the variable-rate portion, was approximately $4.5 billion and $4.8 billion, respectively, compared to a carrying value of approximately $5.3 billion in both periods.

NOTE 7 LEASE COMMITMENTS

We have entered into various operating lease agreements, mainly for office space and vehicles. We lease assets when leasing offers greater operating flexibility. Lease payments are expensed as part of production costs or general and administrative expenses. At December 31, 2018, future minimum lease payments for noncancelable operating leases (excluding oil and natural gas and other mineral leases, utilities, taxes, insurance and common area maintenance expenses) totaled (in millions):

2019	$ 12
2020	8
2021	7
2022	7
2023	6
Thereafter	28
Total	$ 68

Rental expense for operating leases was $11 million in 2018 and $13 million in both 2017 and 2016. Rental income from subleases was approximately $4 million in 2018 and was de minimis in 2017 and 2016.

NOTE 8 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

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

We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2018 and 2017 were not material to our consolidated balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued would not be material to our consolidated financial position or results of operations.

We have certain commitments under contracts, including purchase commitments for goods and services used in the normal course of business such as pipeline capacity, land easements and field equipment. At December 31, 2018, total purchase obligations on a discounted basis were as follows (in millions):

2019	$ 65
2020	63
2021	6
2022	4
2023	10
Thereafter	24
Total	$ 172

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

NOTE 9 DERIVATIVES

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 commodity price deterioration.

Commodity Price Risk

We did not have any commodity derivatives designated as accounting hedges as of and during the years ended December 31, 2018, 2017 and 2016. As part of our hedging program, we held the following Brent-based crude oil contracts as of December 31, 2018:

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

The BSP JV entered into crude oil derivatives that are included in our consolidated results but not in the above table. The hedges entered into by the BSP JV could affect the timing of the redemption of the JV interest. The BSP JV sold calls for up to approximately 1,000 barrels per day at a weighted-average price per barrel of $60.00 per barrel for 2019 through 2020. The BSP JV purchased puts for up to approximately 2,000 barrels per day at a weighted-average price per barrel of approximately $50.00 for 2019 through 2021. The BSP JV also entered into natural gas swaps for insignificant volumes for periods through May 2021.

The outcomes of the derivative positions are as follows:

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

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

From time to time, we may use combinations of these positions to increase the efficacy of our hedging program.

For the years ended December 31, 2018, 2017 and 2016, we recognized a non-cash derivative gain (loss) of approximately $229 million, $(83) million and $(283) million, respectively, from marking these contracts to market, which were included in net derivative gain (loss) from commodity contracts on our consolidated statements of operations. For the years ended December 31, 2018 and 2017, we made settlement payments of $228 million and $7 million, respectively. For the year ended December 31, 2016, we received settlement payments of $77 million.

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 4, 2021.

For the year ended December 31, 2018, we reported a $6 million loss on these contracts in other non-operating expense on our consolidated statements of operations. No payments were received in 2018.

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.

Commodity Contracts

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

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)
	$ 178	$ —	$ 178

December 31, 2017			
Balance Sheet Classification	**Gross Amounts Recognized at Fair Value**	**Gross Amounts Offset in the Balance Sheet**	**Net Fair Value Presented in the Balance Sheet**
Assets:			
Other current assets	$ 39	$ (16)	$ 23
Other assets	1	—	1
Liabilities:			
Accrued liabilities	(170)	16	(154)
Other long-term liabilities	(3)	—	(3)
	$ (133)	$ —	$ (133)

Interest-Rate Contracts

As of December 31, 2018, we reported the fair value of our interest-rate derivatives of $4 million in other assets on our consolidated balance sheets.

Counterparty Credit Risk

Our credit risk relates primarily to trade receivables, joint interest receivables and derivative financial instruments. Credit exposure for each customer is monitored for outstanding balances and current activity. 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 December 31, 2018, the substantial majority of the credit exposures related to our derivative financial instruments was with investment-grade counterparties. We believe exposure to credit-related losses at December 31, 2018 was not material and losses associated with credit risk have been insignificant for all years presented.

All of our derivative instruments are covered by International Swap Dealers Association Master Agreements with counterparties. We had no collateral posted, and held no collateral, at December 31, 2018 and 2017.

NOTE 10 INCOME TAXES

Prior to the Spin-off date, we were included in the Occidental income tax returns for all applicable years. Under the tax sharing agreement, Occidental controls tax examinations for the periods in which we were included in a consolidated or combined income tax return filed by Occidental. There were no amounts due to Occidental as of December 31, 2018 and 2017 under the tax sharing agreement.

The Tax Cuts and Jobs Act (the Tax Act) was enacted on December 22, 2017. The Tax Act includes significant changes to U.S. income tax and related laws. In addition to the reduction in the top corporate tax rate, other provisions of the Tax Act include, but are not limited to, fully expensing the cost of acquired qualified property, subject to certain phase-out provisions, and limiting the deduction for interest expense. We evaluated the provisions of the Tax Act, most of which are effective January 1, 2018, and determined that because of our current tax position and resulting valuation allowance, there was no net impact on our financial statements.

Income Tax Expense (Benefit)

Income (loss) before income taxes, which is all domestic, was $429 million, $(262) million and $201 million for the years ended December 31, 2018, 2017 and 2016, respectively. We had no provision (benefit) for federal, state and local income taxes in each of the years ended December 31, 2018 and 2017. For the year ended December 31, 2016, we recognized a $78 million deferred tax benefit, which consisted of $66 million in the U.S. federal jurisdiction and $12 million deferred tax benefit for state and local taxes.

Total income tax expense (benefit) differs from the amounts computed by applying the U.S. federal income tax rate to pre-tax income (loss) as follows:

	For the years ended December 31,		
	2018	**2017**	**2016**
U.S. federal statutory tax rate	21%	(35)%	35 %
State income taxes, net	6	(6)	6
Exclusion of tax attributable to noncontrolling interests	(5)	—	—
Decrease in U.S. federal corporate tax rate	—	91	—
Tax credits, net	(6)	(19)	—
Cancellation of debt income, net	—	—	(275)
Stock-based compensation, net	—	1	2
Change in valuation allowance, net	(17)	(33)	192
Other	1	1	1
Effective tax rate	—%	—%	(39)%

Our effective tax rate is affected by recurring items such as permanent differences, tax deductions related to equity compensation which is different from compensation expense recognized in the financial statements and income included in our consolidated results which is taxed to noncontrolling interests. Additionally, due to the low commodity price environment, the enhanced oil recovery credit was available in each of the years ended December 31, 2018 and 2017. During 2017, U.S. federal deferred tax assets and liabilities were remeasured due to the reduction of the top corporate tax rate from 35% to 21% under the Tax Act. During 2016, our effective tax rate differed from the U.S. federal statutory rate primarily due to excluding cancellation of debt income which is described further below.

Given our tax status, any item affecting our effective tax rate described above is offset by an equal change in the valuation allowance. As of December 31, 2018, 2017 and 2016, we had valuation allowances of $625 million, $706 million and $780 million, respectively.

In the first quarter of 2016, we reduced our valuation allowance due to our evaluation of our assets and liabilities at the time of our 2015 debt exchange, which generated $1.4 billion of cancellation of debt income (CODI) for tax purposes. Our evaluation indicated that our liabilities exceeded the value of our assets, both calculated in accordance with tax rules, enabling us to move the liability related to CODI to deferred tax liabilities. The resulting increase of our deferred tax liabilities that could be offset against deferred tax assets caused an $82 million reduction in the valuation allowance and resulted in an income tax benefit of $78 million, net of $4 million in state tax. During the rest of 2016, we increased the valuation allowance by $480 million, which resulted in a net increase of the allowance by $398 million for the year. The net change in the valuation allowance had the effect of increasing our provision by $384 million, after $14 million in state taxes, which increased our effective tax rate by 192%. We concluded, on a more-likely-than-not basis, that we could not realize any of the deferred tax assets generated during 2016.

As a result of our 2015 and 2016 debt transactions, we generated CODI of $1.4 billion and $1.3 billion, respectively ($2.7 billion in the aggregate), for both U.S. federal and California state tax purposes. These respective amounts were excluded from taxable income because we determined that our liabilities exceeded the value of our assets for tax purposes immediately prior to each of the deleveraging transactions. In exchange for this exclusion, tax rules require us to reduce the tax basis of our assets. Accordingly, we have reduced our net operating losses and the basis of property, plant and equipment by $1.2 billion for U.S. federal tax purposes and $1.9 billion for California tax purposes. We were not required to make any further reductions in those assets because, beyond this point, our liabilities would have exceeded the tax basis of our assets. Accordingly, any tax liability attributable to the remaining approximately $1.5 billion of U.S. federal and $800 million of California CODI was relieved without any future tax liability, which reduced our effective rate by 275%.

Deferred Tax Assets and Liabilities

The tax effects of temporary differences resulting in deferred income taxes at December 31, 2018 and 2017 were as follows:

	2018		2017	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
	(in millions)			
Debt	$ 253	$ —	$ 324	$ —
Property, plant and equipment differences	11	(316)	33	(261)
Postretirement benefit accruals	27	—	33	—
Deferred compensation and benefits	56	—	53	—
Asset retirement obligations	129	—	126	—
Net operating loss carryforwards and credits	396	—	417	—
Investment in partnerships	93	—	—	—
All other	17	(41)	22	(41)
Subtotal	982	(357)	1,008	(302)
Valuation allowance	(625)	—	(706)	—
Total net deferred taxes	$ 357	$ (357)	$ 302	$ (302)

Components of accumulated other comprehensive income (loss) (AOCI) are presented net of tax. We use the “with-and-without” intraperiod allocation approach to allocate taxes and the portfolio approach to clear remaining taxes recorded to AOCI when our pension plans are terminated.

Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit use of existing deferred tax assets. A significant piece of evidence evaluated is a history of operating losses. Such evidence limits our ability to consider other evidence such as projections for growth. As of December 31, 2018, we concluded that we could not realize, on a more-likely-than-not basis, any of our deferred tax assets and there is not sufficient evidence to support the reversal of all or any portion of this allowance. Given our recent and anticipated future earnings trends, we do not believe any of the valuation allowance as of December 31, 2018 will be released within the next 12 months. The amount of the deferred tax assets considered realizable could however be adjusted if estimates or amounts of deferred tax liabilities change.

As of December 31, 2018, we had U.S. federal net operating loss carryforwards of $555 million, generated in 2017, which expire in 2037 and are available to offset up to 100% of taxable income in the year utilized. As of December 31, 2018, we had a carryforward for disallowed interest expense of $393 million for U.S. federal purposes, which does not expire.

In California, we had $1.6 billion of net operating loss carryforwards which begin to expire in 2026.

As of December 31, 2018, we had U.S. federal tax credit carryforwards of $49 million, which begin to expire in 2037, and we have $16 million of California tax credit carryforwards which begin to expire in 2037.

Unrecognized Tax Benefits

Tax benefits are recognized only for tax positions that are more-likely-than-not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50 percent likely to be realized upon settlement. A liability for unrecognized tax benefits is recorded for any tax benefits claimed in the Company's tax returns that do not meet these recognition and measurement standards. As of December 31, 2018 and 2017, we recorded a $25 million liability for tax positions taken in prior periods that was classified as a deferred tax liability. This amount of unrecognized tax benefit, if recognized, would affect the effective tax rate positively. We believe there will not be significant increases or decreases to our unrecognized tax benefits within the next 12 months.

NOTE 11 STOCK-BASED COMPENSATION

General

In 2016, our stockholders approved the California Resources Corporation Long-Term Incentive Plan (the Plan), which provides for the issuance of incentive and non-qualified stock options, restricted stock awards, restricted stock units, stock appreciation rights, stock bonuses, performance-based awards and other awards to executives, employees and non-employee directors. The maximum number of authorized shares of our common stock that may be issued pursuant to our long-term incentive plan is 4.7 million shares. As of December 31, 2018, 4.1 million shares were issued or reserved under the Plan and 0.6 million shares were available for future issuance of awards under the Plan. Our incentive compensation program is administered by the Compensation Committee of our Board of Directors.

Shares of our common stock may be withheld by us in satisfaction of tax withholding obligations arising upon the exercise of stock options or the vesting of restricted stock units. Further, shares of our common stock may be withheld by us in payment of the exercise price of employee stock options, which also count against the authorized shares specified above.

Compensation expense for stock-based awards for the year ended December 31, 2018 was $45 million, of which $36 million was included in general and administrative expenses and $9 million was included in production costs in our consolidated statement of operations. Compensation expense for stock-based awards for the year ended December 31, 2017 was $29 million, of which $23 million was included in general and administrative expenses and $6 million was included in production costs in our consolidated statement of operations. Compensation expense for stock-based awards for the year ended December 31, 2016 was $30 million, of which $23 million was included in general and administrative expenses and $7 million was included in production costs in our consolidated statement of operations. For the years ended December 31, 2018, 2017 and 2016, we did not recognize any income tax benefit related to our stock-based compensation. For the years ended December 31, 2018, 2017 and 2016, we made cash payments of $24 million, $6 million and $5 million for the cash-settled portion of our awards, respectively. Cash payments on our stock-based compensation were higher in 2018 compared to prior years due to the significant increase in our stock price during the second quarter of 2018.

As of December 31, 2018, the unrecognized compensation expense for all our unvested stock-based incentive awards was $44 million, based on the year-end value of our common stock. This expense is expected to be recognized over a weighted-average period of two years.

Restricted Stock

Certain executives and non-employee directors are granted restricted stock units (RSUs), which are in the form of, or equivalent in value to, actual shares of our common stock. RSUs are service based and, depending on the terms of the awards, are settled in cash or stock at the time of vesting. The awards vest ratably over three years or at the end of three years for employees and at the end of one year for non-employee directors. Our RSUs have nonforfeitable dividend rights, and any dividends or dividend equivalents declared during the vesting period are paid as declared.

For cash- and stock-settled RSUs, compensation value is initially measured on the grant date using the quoted market price of our common stock. Compensation expense for cash-settled RSUs is adjusted on a monthly basis for the cumulative change in the value of the underlying stock. Compensation expense for the stock-settled RSUs is recognized on a straight-line basis over the requisite service periods, adjusted for actual forfeitures.

The following summarizes our restricted stock activity for the year ended December 31, 2018:

	Stock-Settled		Cash-Settled
	Number of Units (in thousands)	**Weighted-Average Grant-Date Fair Value**	**Number of Units** (in thousands)
Unvested at January 1	1,035	$ 16.04	2,066
Granted[(a)]	291	$ 20.62	1,656
Vested	(466)	$ 16.57	(903)
Forfeited	(41)	$ 16.33	(183)
Unvested at December 31	**819**	**$ 17.36**	**2,636**

(a) During 2018 and 2017, our non-employee directors were granted stock-settled RSUs representing approximately 46,000 and 98,000 shares, respectively.

Performance Stock

Our performance stock units (PSUs) granted prior to 2015 were restricted stock awards with a performance target based on cumulative earnings before interest, taxes and depreciation. The units vested at the later of the three years following the grant date or when the performance target is met, if prior to seven years following the grant date. The performance target was met in 2018. Fair value was based on Occidental's stock price on the grant date divided by a conversion factor used at the time of the Spin-off. The resulting fair value was recognized as compensation expense on a straight-line basis over the three-year service period, adjusted for actual forfeitures. These awards accrue dividend equivalents as dividends are declared during the vesting period, which are paid upon certification for the number of vested units.

The PSUs granted in 2015 are RSUs based 50% on achievement of specified Value Creation Index (VCI) results and 50% on total stockholder return (TSR) relative to a selected peer group of companies over specified multi-year performance periods, with payouts ranging from 0% to 200% of the target award. The awards were originally granted as cash-settled awards accounted for as liability awards until they were modified in May 2016 and became stock-settled awards accounted for as equity awards from that point forward. Fewer than 50 people were impacted by this modification, which resulted in no incremental compensation cost.

Prior to the modification, the fair value of the VCI-based portions of the PSUs was determined on the grant date based on an estimated performance achievement at the target level. Additionally, the fair value of the TSR-based portions of the PSUs was determined on the grant date using a Monte Carlo simulation model based on applicable assumptions. The volatility was derived from corresponding peer group companies, which we used in the absence of adequate stock price history for our common stock at the date of grant. The expected life was based on the vesting period of the award. The risk-free rate was the implied yield available on zero-coupon U.S. Treasury notes at the time of grant and subsequent measurement periods with a remaining term equal to the remaining term of the awards. The dividend yield was the expected annual dividend yield over the term, expressed as a percentage of the stock price on the valuation date. The fair values were then recognized on a straight-line basis over the requisite service period, adjusted for actual forfeitures. Compensation expense was adjusted quarterly, on a cumulative basis, for any changes in the number of share equivalents expected to be paid based on the relevant performance criteria.

On the modification date, the fair value of the PSUs was redetermined based on target-level VCI and TSR Monte Carlo results as of that date. The resulting fair value was being recognized as compensation expense on a straight-line basis over the remaining requisite service period, adjusted for actual forfeitures. Dividend equivalents, if any, declared during the vesting period were accumulated and paid upon certification for the number of vested shares.

The modification and grant date assumptions used in the Monte Carlo valuation for the TSR-based portion of the outstanding PSU awards are as follows:

	Modification Date	Grant Date
Risk-free interest rate	0.77%	1.06%
Dividend yield	—%	0.95%
Volatility factor	69.69%	43.63%
Expected life (years)	2.16	2.9
Fair value of underlying common stock	$ 18.50	$ 42.00

The PSUs granted in 2018 are based 50% on achievement of specified cumulative VCI results and 50% on the change in CRC combined production costs compared to the change in production costs of a selected peer group of companies over a three-year period, with payouts ranging from 0% to 200% of the target award. The awards are paid out 60% in stock and 40% cash up to target. Amounts over target are paid out in cash. These awards accrue dividend equivalents as dividends are declared during the vesting period, which are paid upon certification for the number of vested units.

The following summarizes our PSU activity for the year ended December 31, 2018:

	Stock-Settled		Cash-Settled
	Number of Awards (in thousands)	Weighted-Average Grant-Date Fair Value	Number of Units (in thousands)
Unvested at January 1	384	$ 39.05	—
Granted	306	$ 18.34	204
Vested	(384)	$ 39.05	—
Forfeited	(12)	$ 18.34	(8)
Unvested at December 31	**294**	**$ 18.34**	**196**

Stock Options

In 2018, 2015 and 2014, we granted stock options to certain executives under our long-term incentive plan. The options permit the purchase of our common stock at exercise prices no less than the fair market value of the stock on the date the options were granted. The options have terms of seven years and vest ratably over three years, with one third of the granted options becoming exercisable on the day before each anniversary date following the date of grant, subject to certain restrictions including continued employment. No stock options were issued during 2017 and 2016.

Fair value is measured on the grant date using the Black-Scholes option valuation model and expensed on a straight-line basis over the vesting period. The model uses various assumptions, based on management's estimates at the time of grant, which impact the calculation of fair value and ultimately the amount of expense recognized over the vesting period of the award. Expected life is calculated based on the simplified method and represents the period of time that options granted are expected to be held prior to exercise. For options granted in 2018, volatility was based on the average historical volatility of our stock. For options granted in 2015 and 2014, in the absence of adequate stock price history of our common stock at the time of grant, volatility was based on the average volatility of the stocks of a select group of peer companies. The risk-free interest rate is the implied yield available on zero-coupon U.S. Treasury notes at the grant date with a remaining term approximating the expected life. The dividend yield is the expected annual dividend yield over the expected life, expressed as a percentage of the stock price on the grant date. Of the required assumptions, the expected life of the stock option award and the expected volatility have the most significant impact on the fair value calculation.

The grant date assumptions used in the Black-Scholes valuation for options granted during 2018, 2015 and 2014 were as follows:

	2018	2015	2014
Exercise price per share	$ 20.17	$ 42.00	$ 81.10
Expected life (in years)	4.5	4.5	4.5
Expected volatility	69.85%	44.7%	35.4%
Risk-free interest rate	2.63%	1.56%	1.40%
Dividend yield	—%	0.95%	0.50%
Grant-date fair value of stock option awards	$ 10.02	$ 15.00	$ 19.80

The following table summarizes our option activity during the year ended December 31, 2018:

	Options (000's)	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Aggregate Intrinsic Value
Beginning balance, January 1	1,105	$ 69.95	$ 18.43	$ —
Granted	187	$ 20.17	$ 10.02	$ —
Exercised	—	$ —	$ —	$ —
Forfeited	—	$ —	$ —	$ —
Expired or Canceled	(5)	$ 42.00	$ 15.00	$ —
Ending balance, December 31	**1,287**	**$ 62.82**	**$ 17.22**	**$ —**
Exercisable at December 31	**1,109**	**$ 69.66**	**$ 18.38**	**$ —**

Employee Stock Purchase Plan

Effective January 1, 2015, we adopted the California Resources Corporation 2014 Employee Stock Purchase Plan (ESPP), which was subsequently amended in May 2016 and May 2018. The ESPP provides our employees the ability to purchase shares of our common stock at a price equal to 85% of the closing price of a share of our common stock as of the first or last day of each offering period (a fiscal quarter), whichever amount is less.

The maximum number of authorized shares of our common stock that may be issued pursuant to the ESPP is 1.5 million shares, subject to adjustment pursuant to the terms of the ESPP. In addition, participants in the ESPP are subject to certain limits on the number of shares that can be purchased in any given year and during any given offering period. As of December 31, 2018, 0.8 million shares were issued under our ESPP and 0.7 million shares were available for future issuance. For the year ended December 31, 2018, we issued approximately 0.1 million shares of common stock in connection with our ESPP.

NOTE 12 EQUITY

The following is a summary of common stock issuances:

	Common Stock
	(in thousands)
Balance, December 31, 2016	42,543
Issued	359
Balance, December 31, 2017	42,902
Issued	6,110
Canceled	(362)
Balance, December 31, 2018	48,650

At December 31, 2018 and 2017, we had 200 million authorized shares of common stock and 20 million authorized shares of preferred stock, both with a $0.01 par value per share, and no outstanding shares of preferred stock on either date.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of pension and post-retirement losses of $6 million and $23 million, at December 31, 2018 and 2017, respectively.

NOTE 13 EARNINGS PER SHARE

The following table presents the calculation of basic and diluted EPS for the years ended December 31:

	2018	2017	2016
	(in millions, except per share amounts)		
Basic EPS calculation			
Net income (loss)	$ 429	$ (262)	$ 279
Less: Net income attributable to noncontrolling interests	(101)	(4)	—
Net income (loss) attributable to common stock	328	(266)	279
Less: Net income allocated to participating securities	(7)	—	(6)
Net income (loss) available to common stockholders	$ 321	$ (266)	$ 273
Weighted-average common shares outstanding	47.4	42.5	40.4
Basic EPS	$ 6.77	$ (6.26)	$ 6.76
Diluted EPS calculation			
Net income (loss)	$ 429	$ (262)	$ 279
Less: Net income attributable to noncontrolling interests	(101)	(4)	—
Net income (loss) attributable to common stock	328	(266)	279
Less: Net income allocated to participating securities	(7)	—	(6)
Net income (loss) available to common stockholders	$ 321	$ (266)	$ 273
Weighted-average common shares outstanding	47.4	42.5	40.4
Dilutive effect of potentially dilutive securities	$ —	$ —	$ —
Diluted EPS	$ 6.77	$ (6.26)	$ 6.76
Weighted-average anti-dilutive shares[a]	1.6	2.3	1.1

(a) Anti-dilutive shares represent potential common shares that are excluded from the computation of diluted EPS.

NOTE 14 PENSION AND POSTRETIREMENT BENEFIT PLANS

We have various qualified and non-qualified benefit plans for our salaried and union and nonunion hourly employees.

Defined Contribution Plans

All of our employees are eligible to participate in our tax-qualified, defined contribution retirement plan that provides for periodic cash contributions by us based on annual cash compensation and employee deferrals.

Certain salaried employees participate in supplemental plans that restore benefits lost due to government limitations on qualified plans. As of December 31, 2018 and 2017, we recognized $36 million and $32 million in other long-term liabilities for these supplemental plans, respectively.

We expensed $35 million in 2018, $33 million in 2017 and $32 million in 2016 under the provisions of these defined contribution and supplemental plans.

Defined Benefit Plans

Participation in defined benefit pension plans sponsored by us is limited. During 2018, approximately 70 employees accrued benefits under these plans, all of whom were union employees. Effective December 31, 2015, the plans were amended such that participants other than union employees no longer earn benefits for service after December 31, 2015.

Pension costs for the defined benefit pension plans, determined by independent actuarial valuations, are funded by us through payments to trust funds, which are administered by independent trustees.

Postretirement Benefit Plans

We provide postretirement medical and dental benefits for our eligible former employees and their dependents. Our former employees are required to make monthly contributions to the plan, but the benefits are primarily funded by us as claims are paid during the year.

Obligations and Funded Status of our Defined Benefit Plans

The following tables show the amounts recognized in our balance sheets related to pension and postretirement benefit plans, as well as plans that we or our subsidiaries sponsor, and their funding status, obligations and plan asset fair values:

	As of December 31,			
	2018	**2017**	**2018**	**2017**
	Pension Benefits		Postretirement Benefits	
	(in millions)			
Amounts recognized in the balance sheet:				
Accrued liabilities	$ —	$ —	$ (2)	$ (3)
Other long-term liabilities	(14)	(19)	(82)	(90)
	$ (14)	$ (19)	$ (84)	$ (93)
Amounts recognized in accumulated other comprehensive (loss) income:	$ (10)	$ (13)	$ 4	$ (10)

	As of December 31,			
	2018	**2017**	**2018**	**2017**
	Pension Benefits		Postretirement Benefits	
	(in millions)			
Changes in the benefit obligation:				
Benefit obligation—beginning of year	$ 65	$ 70	$ 93	$ 77
Service cost—benefits earned during the period	1	1	4	3
Interest cost on projected benefit obligation	2	2	4	4
Actuarial (gain) loss	(2)	7	(14)	11
Benefits paid	(10)	(15)	(3)	(2)
Benefit obligation—end of year	$ 56	$ 65	$ 84	$ 93
Changes in plan assets:				
Fair value of plan assets—beginning of year	$ 46	$ 44	$ —	$ —
Actual return on plan assets	(2)	5	—	—
Employer contributions	8	12	3	2
Benefits paid	(10)	(15)	(3)	(2)
Fair value of plan assets—end of year	$ 42	$ 46	$ —	$ —
Unfunded status	$ (14)	$ (19)	$ (84)	$ (93)

The following table sets forth our defined benefit pension plans with accumulated benefit obligations in excess of plan assets for the years ended December 31:

	2018	2017
	(in millions)	
Projected Benefit Obligation	$ 56	$ 65
Accumulated Benefit Obligation	$ 53	$ 62
Fair Value of Plan Assets	$ 42	$ 46

None of our defined benefit pension plans had plan assets in excess of accumulated benefit obligations.

Components of Net Periodic Benefit Cost

The following tables set forth our pension and postretirement benefit costs and amounts recognized in other comprehensive income (loss) (before tax):

	For the years ended December 31,					
	2018	2017	2016	2018	2017	2016
	Pension Benefits			Postretirement Benefits		
	(in millions)					
Net periodic benefit costs:						
Service cost—benefits earned during the period	$ 1	$ 1	$ 1	$ 4	$ 3	$ 3
Interest cost on projected benefit obligation	2	2	3	4	4	3
Expected return on plan assets	(3)	(3)	(3)	—	—	—
Amortization of net actuarial loss	2	2	2	—	—	—
Settlement costs	4	5	8	—	—	—
Net periodic benefit cost	$ 6	$ 7	$ 11	$ 8	$ 7	$ 6

	For the years ended December 31,					
	2018	2017	2016	2018	2017	2016
	Pension Benefits			Postretirement Benefits		
	(in millions)					
Amounts recognized in other comprehensive income (loss):						
Net actuarial (loss) gain	$ (3)	$ (4)	$ (9)	$ 14	$ (12)	$ —
Settlement costs	4	5	8	—	—	—
Amortization of net actuarial gain/loss	2	2	2	—	—	—
Total recognized in other comprehensive income (loss)	$ 3	$ 3	$ 1	$ 14	$ (12)	$ —

Settlement costs related to our pension plans were associated with early retirements.

The following table sets forth the weighted-average assumptions used to determine our benefit obligations and net periodic benefit cost:

	For the years ended December 31,			
	2018	2017	2018	2017
	Pension Benefits		Postretirement Benefits	
Benefit Obligation Assumptions:				
Discount rate	4.22%	3.53%	4.57%	3.87%
Rate of compensation increase	4.00%	4.00%	—	—
Net Periodic Benefit Cost Assumptions:				
Discount rate	3.53%	3.88%	3.87%	4.58%
Assumed long-term rate of return on assets	6.50%	6.50%	—	—
Rate of compensation increase	4.00%	4.00%	—	—

For pension plans and postretirement benefit plans that we or our subsidiaries sponsor, we based the discount rate on the Aon/Hewitt AA Above Median yield curve in both 2018 and 2017. The weighted-average rate of increase in future compensation levels is consistent with our past and anticipated future compensation increases for employees participating in retirement plans that determine benefits using compensation. The assumed long-term rate of return on assets is estimated with regard to current market factors but within the context of historical returns for the asset mix that exists at year end.

Effective in 2018, we adopted the Society of Actuaries MP-2018 Mortality Improvement Scale, which updated the Society of Actuaries Adjusted RP-2014 mortality assumptions that private defined benefit pension plans in the U.S. use in the actuarial valuations that determine a plan sponsor's pension and postretirement obligations. In 2017, we utilized the Society of Actuaries Adjusted RP-2014 Mortality Table reflecting the MP-2017 Mortality Improvement Scale. At December 31, 2018, the changes in the mortality assumptions did not significantly change the pension benefit obligations or the postretirement benefit obligations.

The postretirement benefit obligation was determined by application of the terms of medical and dental benefits, including the effect of established maximums on covered costs, together with relevant actuarial assumptions and healthcare cost trend rates projected at an assumed U.S. Consumer Price Index (CPI) increase of 1.78% and 1.97% as of December 31, 2018 and 2017, respectively. Under the terms of our postretirement plans, participants other than certain union employees pay for all medical cost increases in excess of increases in the CPI. For those union employees, we projected that, as of December 31, 2018, healthcare cost trend rates would decrease 0.25% per year from 7.00% in 2018 until they reach 6.00% in 2022, then decrease 0.50% per year until they reach 4.50% in 2025 and remain at 4.50% thereafter.

The actuarial assumptions used could change in the near term as a result of changes in expected future trends and other factors that, depending on the nature of the changes, could cause increases or decreases in the plan assets and liabilities.

Fair Value of Pension Plan Assets

We employ a total return investment approach that uses a diversified blend of equity and fixed-income investments to optimize the long-term return of plan assets at a prudent level of risk. Equity investments were diversified across U.S. and non-U.S. stocks, as well as differing styles and market capitalizations. Other asset classes, such as private equity and real estate, may have been used with the goals of enhancing long-term returns and improving portfolio diversification. In 2018 and 2017, the target allocation of plan assets was 65% equity securities and 35% debt securities. Investment performance was measured and monitored on an ongoing basis through quarterly investment portfolio and manager guideline compliance reviews, annual liability measurements and periodic studies.

The fair values of our pension plan assets by asset category are as follows:

	Fair Value Measurements at December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Asset Class:				
Cash equivalents	$ 1	$ —	$ —	$ 1
Commingled funds:				
Fixed income	—	9	—	9
U.S. equity	—	9	—	9
International equity	—	5	—	5
Mutual funds:				
Bond funds	5	—	—	5
Blend funds	2	—	—	2
Value funds	2	—	—	2
Growth funds	2	—	—	2
Guaranteed deposit account	—	—	7	7
Total pension plan assets	$ 12	$ 23	$ 7	$ 42

	Fair Value Measurements at December 31, 2017			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Asset Class:				
Cash equivalents	$ 3	$ —	$ —	$ 3
Commingled funds:				
Fixed income	—	7	—	7
U.S. equity	—	9	—	9
International equity	—	5	—	5
Mutual funds:				
Bond funds	6	—	—	6
Blend funds	3	—	—	3
Value funds	3	—	—	3
Growth funds	3	—	—	3
Guaranteed deposit account	—	—	7	7
Total pension plan assets	$ 18	$ 21	$ 7	$ 46

The activity during the years ended December 31, 2018 and 2017, for the assets using Level 3 fair value measurements was insignificant.

Expected Cash Flows

In 2019, we expect to contribute $3 million to our postretirement benefit plans and at least our minimum funding requirement of $3 million to our defined benefit pension plans. Estimated future undiscounted benefit payments, which reflect expected future service, as appropriate, are as follows:

For the years ended December 31,	Pension Benefits	Postretirement Benefits
	(in millions)	
2019	$ 17	$ 3
2020	$ 5	$ 4
2021	$ 4	$ 4
2022	$ 4	$ 4
2023	$ 4	$ 4
2024 - 2028	$ 14	$ 23

NOTE 15 REVENUE RECOGNITION

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

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

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

Commodity Sales Contracts

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

Our commodity sales contracts are based on index prices. We recognize revenue in the amount that we expect to receive once we are able to adequately estimate the consideration (i.e., when market prices are known). Our contracts with customers typically require payment within 30 days following invoicing.

Electricity

The electrical output of the Elk Hills power plant that is not used in our operations is sold to the wholesale power market and to a utility under a power purchase and sales agreement expiring in

December 2020, which includes a capacity payment. Revenue is recognized when obligations under the terms of a contract with our customer are satisfied; generally, this occurs upon delivery of the electricity. We report electricity sales as other revenue on our consolidated statements of operations. Revenue is measured as the amount of consideration we expect to receive based on average index or California Independent System Operator market pricing with payment due the month following delivery. Capacity payments are based on a fixed annual amount per kilowatt hour and monthly rates vary based on seasonality, which is consistent with how we earn the capacity payment. Capacity payments are settled monthly. We consider our performance obligations to be satisfied as delivery occurs and in the amount we have a right to invoice 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 marketing, storing and transporting third-party volumes.

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

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

Disaggregation of Revenue

The following table provides disaggregated revenue for the years ended December 31, 2018, 2017 and 2016:

	2018	2017	2016
		(in millions)	
Oil and gas sales:			
Oil	$ 2,110	$ 1,549	$ 1,325
NGLs	260	210	132
Natural gas	220	177	164
	2,590	1,936	1,621
Other revenue:			
Electricity	111	125	107
Marketing, trading and other	361	35	25
Interest income	1	—	—
	473	160	132
Net derivative gain from commodity contracts	1	(90)	(206)
Total revenues and other	$ 3,064	$ 2,006	$ 1,547

The impact of the adoption of ASC 606 on our consolidated statements of operations for the year ended December 31, 2018 was as follows:

	2018		
	As Reported ASC 606	Previous GAAP	Change
		(in millions)	
Oil and gas sales	$ 2,590	$ 2,568	$ 22
Other revenue	$ 473	$ 392	$ 81
Other expenses, net	$ 399	$ 296	$ 103

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

Quarterly Financial Data (Unaudited)

	2018				2017			
	First	Second	Third	Fourth	First	Second	Third	Fourth
	(in millions, except per share amounts)							
Revenues and other[a]	$ 609	$ 549	$ 828	$ 1,078	$ 590	$ 516	$ 445	$ 455
Operating income (loss)[b]	$ 108	$ 11	$ 185	$ 465	$ 115	$ 41	$ (45)	$ (38)
Net (loss) income attributable to common stock[c]	$ (2)	$ (82)	$ 66	$ 346	$ 53	$ (48)	$ (133)	$ (138)
Net (loss) income attributable to common stock per share:								
Basic	$ (0.05)	$ (1.70)	$ 1.34	$ 7.00	$ 1.23	$ (1.13)	$ (3.11)	$ (3.23)
Diluted	$ (0.05)	$ (1.70)	$ 1.32	$ 7.00	$ 1.22	$ (1.13)	$ (3.11)	$ (3.23)

(a) We adopted the new revenue recognition standard on January 1, 2018 which required certain sales-related costs to be reported as expense as opposed to being netted against revenue. The adoption of this standard did not affect net income. Results for reporting periods beginning January 1, 2018 are presented under the new accounting standard while prior periods were not adjusted and continue to be reported under accounting standards in effect for the applicable period.

(b) For 2017, certain pension benefit costs of have been reclassified to other non-operating expenses to conform to the current year presentation in accordance with new accounting rules adopted on January 1, 2018 related to the presentation of net periodic benefit costs for pension and postretirement benefits in the Consolidated Statements of Operations. See *Item 8 – Financial Statement and Supplementary Data – Note 2 Accounting and Disclosure Changes* for more information.

(c) Net (loss) income attributable to common stock included the following unusual, infrequent and other items:

	2018				2017			
	First	Second	Third	Fourth	First	Second	Third	Fourth
	(in millions)							
Non-cash derivative loss (gain) from commodities, excluding noncontrolling interest	$ 7	$ 92	$ (28)	$ (295)	$ (75)	$ (35)	$ 72	$ 116
Non-cash derivative loss from interest-rate contracts	$ —	$ 1	$ (1)	$ 6	$ —	$ —	$ —	$ —
Early retirement, severance and other costs	$ 2	$ 2	$ —	$ —	$ 3	$ —	$ 1	$ 1
Net gain on early extinguishment of debt	$ —	$ (24)	$ (2)	$ (31)	$ (4)	$ —	$ —	$ —
Gain on asset divestitures	$ —	$ (1)	$ (3)	$ (1)	$ (21)	$ —	$ —	$ —
Other, net	$ 1	$ (2)	$ 9	$ 1	$ 1	$ 5	$ 8	$ 7

Supplemental Oil and Gas Information (Unaudited)

The following table sets forth our net operating and non-operating interests in quantities of proved developed and undeveloped reserves of oil (including condensate), NGLs and natural gas and changes in such quantities. Estimated reserves include our economic interests under PSC-type contracts relating to our Wilmington field in Long Beach. All of our proved reserves are located within the state of California.

PROVED DEVELOPED AND UNDEVELOPED RESERVES

	Oil (MMBbl)[(a)]	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)[(b)]
Balance at December 31, 2015	466	59	715	644
Revisions of previous estimates[(c)]	(40)	—	(42)	(47)
Improved recovery	3	—	—	3
Extensions and discoveries	14	2	25	20
Purchases	—	—	—	—
Sales	(1)	—	—	(1)
Production	(33)	(6)	(72)	(51)
Balance at December 31, 2016	409	55	626	568
Revisions of previous estimates[(c)]	47	7	104	71
Improved recovery	—	—	—	—
Extensions and discoveries	24	2	45	34
Purchases	—	—	—	—
Sales	(8)	—	(3)	(8)
Production	(30)	(6)	(66)	(47)
Balance at December 31, 2017	442	58	706	618
Revisions of previous estimates[(c)]	51	(4)	(15)	44
Improved recovery	4	—	—	4
Extensions and discoveries	25	1	27	30
Purchases	38	11	89	64
Sales	—	—	—	—
Production	(30)	(6)	(73)	(48)
Balance at December 31, 2018	530	60	734	712
PROVED DEVELOPED RESERVES				
December 31, 2015	338	47	575	481
December 31, 2016	279	44	500	406
December 31, 2017	304	45	543	440
December 31, 2018[(d)]	389	47	565	530
PROVED UNDEVELOPED RESERVES				
December 31, 2015	128	12	140	163
December 31, 2016	130	11	126	162
December 31, 2017	138	13	163	178
December 31, 2018	141	13	169	182

(a) Includes proved reserves related to economic arrangements similar to PSCs of 131 MMBbl, 108 MMBbl, 85 MMBbl and 103 MMBbl at December 31, 2018, 2017, 2016 and 2015, respectively.

(b) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six Mcf of natural gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(c) Commodity price changes affect the proved reserves we record. For example, higher prices generally increase the economically recoverable reserves in all of our operations, because the extra margin extends their expected lives and renders more projects economic. Partially offsetting this effect, higher prices decrease our share of proved cost recovery reserves under arrangements similar to production-sharing contracts at our Wilmington field in Long Beach because fewer reserves are required to recover costs. Conversely, when prices drop, we experience the opposite effects. Performance-related revisions can include upward or downward changes to previous proved reserves estimates due to the evaluation or interpretation of recent geologic, production decline or operating performance data.

(d) Approximately 23% of proved developed oil reserves, 9% of proved developed NGLs reserves, 13% of proved developed natural gas reserves and, overall, 20% of total proved developed reserves are non-producing. A majority of our non-producing reserves relate to steamfloods and waterfloods where full peak production response has not yet occurred due to the nature of such projects.

2018

In 2018, total net additions to proved reserves from all sources were 142 MMBoe. Our 2018 realized prices for oil and natural gas increased over the prior year by 39% and 14%, respectively, which resulted in positive price-related revisions of 38 MMBoe.

We added 6 MMBoe from net positive performance-related revisions of which 27 MMBoe were from positive technical revisions primarily due to better-than-expected performance and successful drilling efforts in the San Joaquin and Los Angeles basins. These additions were partially offset by 21 MMBoe of negative revisions due to management's discretion to downgrade proved undeveloped reserves (PUDs) that are not anticipated to be developed within their five-year window of initial booking. Approximately 11 MMBoe of these downgraded PUDs are expiring in 2019 and are not anticipated to be developed before then at current oil prices. The remaining 10 MMBoe of downgraded PUDs are projects that are no longer prioritized in our development plan based on current project economics.

We also added 4 MMBoe from improved recovery through proven IOR and EOR methods. The improved recovery additions were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin.

We added 30 MMBoe from extensions and discoveries, primarily resulting from new geologic interpretations and pressure data in the Ventura basin along with successful drilling in San Joaquin and Los Angeles basins.

We also added 64 MMBoe in connection with the acquisitions during the year, the majority of which resulted from the Elk Hills transaction.

Excluding these downgrades of 21 MMBoe that were made at management's discretion, our organic reserve replacement ratio would have been 127% from our capital program of $690 million. Our total net reserves additions from all sources generated an organic reserve replacement ratio of 296%. For further information on our reserve replacement ratio, see *Items 1 and 2 – Business and Properties – Our Operations – Reserves*.

2017

Our total net positive price revision was 49 MMBoe, which was primarily the result of higher prices net of modestly higher operating costs due to the current commodity price environment, partially reinstating reserves that were removed in prior years due to lower prices. Our net positive performance-related revision of 22 MMBoe resulted primarily from the successful renegotiation of our Huntington Beach royalty agreement and improved performance in the San Joaquin basin, partially offset by negative revisions to remove proved undeveloped reserves due to a downward adjustment of our committed capital in a project area and technical revisions due to updated testing results in one of our project areas.

We added 34 MMBoe of proved reserves primarily from extensions, which were associated with the continued successful drilling program mostly in the San Joaquin and Los Angeles basins. Our drilling program in the San Joaquin basin benefited from the deployment of JV capital at Elk Hills and at waterflood projects in Buena Vista. Our drilling program in the Los Angeles basin resulted in expanded economic inventory due to improvements in performance compared to 2016. We also added new projects in the Sacramento basin as a result of analyzing new data from capital workover projects.

We sold 8 MMBoe of proved reserves based on beginning-of-year reserves balances. Included in this amount was 7 MMBoe of proved undeveloped reserves in the San Joaquin basin conveyed to MIRA as part of our JV with MIRA. There were no material reserves added from improved recovery.

2016

Total net negative price revisions of 60 MMBoe incorporated the negative effect of lower prices, partially offset by the positive effect of lower operating costs also caused by the lower commodity price environment. Our positive performance related revisions of 13 MMBoe resulted primarily from better-than-expected reservoir performance and comprehensive field development planning. These positive revisions primarily came from the San Joaquin and Ventura basins.

We added proved reserves of 3 MMBoe from improved recovery through proven IOR and EOR methods in 2016 which were associated with the continued development of steamflood and waterflood properties in the San Joaquin basin. We added 20 MMBoe of proved reserves from extensions and discoveries, which generally resulted from exploration and development programs primarily in the San Joaquin, Los Angeles and Ventura basins.

CAPITALIZED COSTS

Capitalized costs relating to oil and gas producing activities and related accumulated depreciation, depletion and amortization (DD&A) were as follows:

	As of December 31,	
	2018	2017
	(in millions)	
Proved properties	$ 20,883	$ 19,664
Unproved properties	1,103	1,111
Total capitalized costs[(a)]	21,986	20,775
Accumulated depreciation, depletion and amortization[(b)]	(15,839)	(15,391)
Net capitalized costs	$ 6,147	$ 5,384

(a) Includes acquisition and development costs.
(b) Includes accumulated valuation allowance for total unproved properties of $819 million at December 31, 2018, 2017 and 2016.

COSTS INCURRED

Costs incurred relating to oil and gas activities include capital investments, exploration (whether expensed or capitalized), acquisitions and asset retirement obligations but exclude corporate items. The following table summarizes our costs incurred:

	For the years ended December 31,		
	2018	2017	2016
		(in millions)	
Property acquisition costs			
Proved properties[(a)]	$ 553	$ —	$ —
Unproved properties	1	—	—
Exploration costs	38	25	21
Development costs[(b)]	652	357	102
Costs incurred	$ 1,244	$ 382	$ 123

(a) Acquisition costs capitalized to proved properties include $8 million of liabilities assumed related to ARO in 2018.
(b) Development costs include a $7 million decrease, a $5 million decrease and a $49 million increase in ARO in 2018, 2017 and 2016, respectively.

RESULTS OF OPERATIONS

Our oil and gas producing activities, which exclude items such as asset dispositions, corporate overhead and interest, were as follows:

	For the years ended December 31,					
	2018		2017		2016	
	(millions)	($/Boe)[a]	(millions)	($/Boe)[a]	(millions)	($/Boe)[a]
Revenues[b]	$ 2,378	$ 49.23	$ 1,931	$ 41.09	$ 1,700	$ 33.17
Production costs[c]	912	18.88	876	18.64	800	15.61
General and administrative expenses[d]	49	1.01	33	0.70	35	0.68
Adjusted other operating expenses[e]	66	1.38	26	0.56	34	0.67
Depreciation, depletion and amortization	469	9.71	510	10.85	527	10.28
Taxes other than on income	117	2.42	110	2.34	121	2.36
Exploration expenses	34	0.70	22	0.47	23	0.45
Pretax income	731	15.13	354	7.53	160	3.12
Income tax expense[f]	(181)	(3.75)	(116)	(2.47)	(65)	(1.27)
Results of operations	$ 550	$ 11.38	$ 238	$ 5.06	$ 95	$ 1.85

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content of six Mcf of natural gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence.

(b) Revenues include cash settlements on our commodity derivatives which are reported in net derivative (gain) loss from commodity contracts on our consolidated statements of operations. Revenues also include sales related to processing third-party gas which are reported in other revenue on the consolidated statements of operations.

(c) Production costs are the costs incurred in lifting the oil and natural gas to the surface and include gathering, processing, field storage and insurance on proved properties. Production costs on a per Boe basis, excluding the effects of PSC contracts, were $17.47, $17.48 and $14.69 for 2018, 2017 and 2016, respectively.

(d) For the years ended December 31, 2017 and 2016, certain pension benefit costs of $1 million and $2 million, respectively, have been reclassified to other non-operating expenses to conform to the current year presentation in accordance with new accounting rules adopted on January 1, 2018 related to the presentation of net periodic benefit costs for pension and postretirement benefits in the Consolidated Statements of Operations. See *Item 8 – Financial Statement and Supplementary Data – Note 2 Accounting and Disclosure Changes* for more information.

(e) Other operating expenses include accretion expense in 2018, 2017 and 2016. Other operating expenses in 2018 also include wet gas purchases from third parties, transportation and other expenses due to the adoption of a new accounting standard related to revenue recognition on January 1, 2018. Adjusted other operating expenses for 2018 exclude net unusual and infrequent gains of $10 million ($0.21 per Boe) that include receivables and refunds partially offset by rig termination expenses. For 2017, the amounts exclude net unusual and infrequent charges of $5 million ($0.10 per Boe) primarily related to rig termination expenses partially offset by property tax refunds, recovery of amounts due from joint interest partners and other items. For 2016, the amounts exclude net unusual and infrequent gains of $18 million ($0.35 per Boe) that include refunds partially offset by plant turnaround charges and other items.

(f) Income taxes are calculated on the basis of a stand-alone tax filing entity. The combined U.S. federal and California statutory tax rate for 2018 was 28% as compared to 41% in both 2017 and 2016. The top corporate tax rate was reduced beginning January 1, 2018 as a result of tax reform legislation enacted on December 22, 2017. The effective tax rate for 2018 and 2017 reflects the benefit of enhanced oil recovery tax credits.

STANDARDIZED MEASURE, INCLUDING YEAR-TO-YEAR CHANGES THEREIN, OF DISCOUNTED FUTURE NET CASH FLOWS

For purposes of the following disclosures, discounted future net cash flows were computed by applying to our proved oil and gas reserves the unweighted arithmetic average of the first-day-of-the-month price for each month within the years ended December 31, 2018, 2017 and 2016, respectively. The realized prices used to calculate future cash flows vary by producing area and market conditions. Future operating and capital costs were determined using the current cost environment applied to expectations of future operating and development activities. Future income tax expense was computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences and tax credits) to the estimated net future pre-tax cash flows, after allowing for the deductions for intangible drilling costs and tax DD&A. The cash flows were discounted using a 10% discount factor. The calculations assumed the continuation of existing economic, operating and contractual conditions at December 31, 2018, 2017 and 2016. Such assumptions, which are prescribed by regulation, have not always proven accurate in the past. Other valid assumptions would give rise to substantially different results.

Standardized Measure of Discounted Future Net Cash Flows

	At December 31, 2018	2017	2016
		(in millions)	
Future cash inflows	$ 42,325	$ 26,685	$ 18,831
Future costs			
Production costs[a]	(19,452)	(13,988)	(10,092)
Development costs[b]	(4,432)	(3,848)	(3,376)
Future income tax expense	(4,231)	(1,585)	(340)
Future net cash flows	14,210	7,264	5,023
Ten percent discount factor	(6,935)	(3,499)	(2,356)
Standardized measure of discounted future net cash flows	$ 7,275	$ 3,765	$ 2,667

(a) Includes general and administrative expenses and taxes other than on income.
(b) Includes asset retirement costs.

Changes in the Standardized Measure of Discounted Future Net Cash Flows from Proved Reserve Quantities

	For the years ended December 31, 2018	2017	2016
		(in millions)	
Beginning of year	$ 3,765	$ 2,667	$ 4,024
Sales of oil and natural gas, net of production and other operating costs	(1,511)	(918)	(742)
Changes in price, net of production and other operating costs	3,648	1,405	(2,297)
Previously estimated development costs incurred	351	159	62
Change in estimated future development costs	(38)	(98)	89
Extensions, discoveries and improved recovery, net of costs	443	177	117
Revisions of previous quantity estimates[a]	738	737	(247)
Accretion of discount	427	260	458
Net change in income taxes	(1,356)	(599)	854
Purchases and sales of reserves in place	766	(43)	(4)
Changes in production rates and other	42	18	353
Net change	3,510	1,098	(1,357)
End of year	$ 7,275	$ 3,765	$ 2,667

(a) Includes revisions related to performance and price changes.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

(in millions)	Balance at Beginning of Period	Charged (Credited) to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2018					
Deferred tax valuation allowance	$ 706	$ (76)	$ (5)	$ —	$ 625
Other asset valuation allowance	$ 44	$ (13)	$ —	$ —	$ 31
2017					
Deferred tax valuation allowance	$ 780	$ (78)	$ 4	$ —	$ 706
Other asset valuation allowance	$ 56	$ (12)	$ —	$ —	$ 44
2016					
Deferred tax valuation allowance	$ 382	$ 398	$ —	$ —	$ 780
Other asset valuation allowance	$ 68	$ (12)	$ —	$ —	$ 56

ITEM 9 CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A CONTROLS AND PROCEDURES

Management's Annual Assessment of and Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

We have assessed the effectiveness of our internal control system as of December 31, 2018 based on the criteria for effective internal control over financial reporting described in Internal Control—Integrated Framework issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, we believe that, as of December 31, 2018, our system of internal control over financial reporting is effective.

Our independent auditors, KPMG LLP, have issued a report on our internal control over financial reporting, which is set forth in *Item 8 – Financial Statements and Supplementary Data*.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer (CEO) and chief financial officer (CFO), has evaluated the effectiveness 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 amended (Exchange Act)), as of the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation, our CEO and CFO have concluded that, as of December 31, 2018, our disclosure controls and procedures are effective and are designed to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission (SEC), and that such information is accumulated and communicated to our management, including our CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act of 1934) identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations on Effectiveness of Controls and Procedures

In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

ITEM 9B OTHER INFORMATION

None.

PART III

ITEM 10 DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference from our Proxy Statement for the 2019 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission (SEC) within 120 days of the fiscal year ended December 31, 2018 (2019 Proxy Statement). See *Part I – Executive Officers* of this report for the list of our executive officers and related information.

Our board of directors has adopted a code of business conduct applicable to all officers, directors and employees, which is available on our website (www.crc.com). We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our code of business conduct by posting such information on our website at the address specified above.

ITEM 11 EXECUTIVE COMPENSATION

The information required by this item is incorporated by reference from our 2019 Proxy Statement. Pursuant to the rules and regulations under the Exchange Act, the information in the *Compensation Discussion and Analysis – Compensation Committee Report* section shall not be deemed to be “soliciting material,” or to be “filed” with the SEC, or subject to Regulation 14A or 14C under the Exchange Act or to the liabilities under Section 18 of the Exchange Act, nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

ITEM 12 SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated by reference from our 2019 Proxy Statement. See also *Item 5 – Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities – Securities Authorized for Issuance Under Equity Compensation Plans*.

ITEM 13 CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference from our 2019 Proxy Statement.

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated by reference from our 2019 Proxy Statement.

PART IV

ITEM 15 EXHIBITS

The agreements included as exhibits to this report are included to provide information about their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement that were made solely for the benefit of the other agreement parties and:

- should not be treated as categorical statements of fact, but rather as a way of allocating the risk among the parties if those statements prove to be inaccurate;
- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from the way the Company and investors may view materiality; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

(a) (1) and (2). Financial Statements

Reference is made to Item 8 of the Table of Contents of this report where these documents are listed.

(a) (3). Exhibits

Exhibit Number	Exhibit Description
2.1	Separation and Distribution Agreement, dated as of November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 2.1 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
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).
4.1	Indenture, dated October 1, 2014, by and among California Resources Corporation, the Guarantors and Wells Fargo Bank, National Association (filed as Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.2	Indenture, dated December 15, 2015, by and among California Resources Corporation, the Guarantors and the Bank of New York Mellon Trust Company, N.A. (filed as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed December 18, 2015 and incorporated herein by reference).
4.3	Guarantor Supplemental Indenture dated as of March 5, 2015, among California Resources Corporation, certain guarantors named therein and Wells Fargo Bank, National Association (filed as Exhibit 4.2 to Registrant's Registration Statement on Form S-4 filed March 12, 2015 and incorporated herein by reference).

Exhibit Number	Exhibit Description
4.4	Guarantor Supplemental Indenture dated as of March 4, 2016, among California Resources Corporation, certain guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
4.5	Guarantor Supplement Indenture dated as of March 4, 2016, among California Resources Corporation, certain guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.2 to Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
4.6	Guarantor Supplemental Indenture No. 2, dated as of April 29, 2016, among California Resources Corporation, certain guarantors named therein and Wilmington Trust, National Association, as trustee (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
4.7	Assumption Agreement dated as of March 6, 2015, among CRC Construction Services, LLC and JP Morgan Chase Bank, N.A., as Administrative Agent for lenders (filed as Exhibit 10.31 to Registrant's Registration Statement on Form S-4 filed March 12, 2015 and incorporated herein by reference).
4.8	Registration Rights Agreement, dated October 1, 2014, by and among California Resources Corporation, the Guarantors and the Initial Purchasers (filed as Exhibit 4.3 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.9	Form of 5% Senior Note due 2020 (included in Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.10	Form of 5½% Senior Note due 2021 (included in Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.11	Form of 6% Senior Note due 2024 (included in Exhibit 4.2 to Amendment No. 4 to the Registrant's Information Statement on Form 10 filed October 8, 2014 and incorporated herein by reference).
4.12	Form of 8% Senior Secured Second Lien Note due 2022 (included in Exhibit 4.1 to Registrant's Current Report on Form 8-K filed December 18, 2015 and incorporated herein by reference).
4.13	Registration Rights Agreement, dated as of April 9, 2018, by and between California Resources Corporation and Chevron U.S.A. Inc. (filed as Exhibit 4.01 to the Registrant's Current Report on Form 8-K filed April 9, 2018, and incorporated herein by reference).
4.14	Guarantor Supplemental Indenture, dated as of April 16, 2018, among California Resources Corporation, certain guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q filed August 2, 2018, and incorporated herein by reference).
4.15	Third Guarantor Supplemental Indenture, dated as of June 29, 2018, among California Resources Corporation, certain guarantors named therein and Wilmington Trust, National Association, as trustee (filed as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q filed August 2, 2018, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.1	Credit Agreement, dated as of September 24, 2014, among California Resources Corporation, the Lenders and JPMorgan Chase Bank, N.A. as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A. as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.25 to Amendment No. 5 to the Company's Registration Statement on Form 10 filed October 14, 2014, and incorporated herein by reference).
10.2	First Amendment to Credit Agreement, dated as of February 25, 2015, among California Resources Corporation, the Lenders and JPMorgan Chase Bank, N.A. as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A. as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.35 to the Registrant's Annual Report on Form 10-K filed February 27, 2015, and incorporated herein by reference).
10.3	Second Amendment to Credit Agreement, dated November 2, 2015, among California Resources Corporation, the Lenders and JPMorgan Chase Bank, N.A. as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A. as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.4	Third Amendment to Credit Agreement, dated February 23, 2016, among California Resources Corporation and JP Morgan Chase Bank, N.A., as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A. as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed February 23, 2016, and incorporated herein by reference).
10.5	Fourth Amendment to Credit Agreement dated as of April 22, 2016, among California Resources Corporation, as the Borrower and JP Morgan Chase Bank, N.A., as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A., as Syndication Agent, Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed April 22, 2016, and incorporated herein by reference).
10.6	Fifth Amendment and Waiver to Credit Agreement, dated August 12, 2016, among California Resources Corporation, as the Borrower and JP Morgan Chase Bank, N.A., as Administrative Agent, a Swingline Lender and a Letter of Credit Issuer and Bank of America, N.A., as Syndication Agent, a Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.2 to the Registration's Current Report on Form 8-K filed August 17, 2016 and incorporated herein by reference).
10.7	Sixth Amendment to Credit Agreement, dated as of February 14, 2017, among California Resources Corporation, as the Borrower, JP Morgan Chase Bank, N.A., as Administrative Agent, Swingline Lender and a Letter of Credit Issuer, Bank of America, N.A., as Syndication Agent, Swingline Lender and a letter of Credit Issuer, and the Lenders (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 16, 2017, and incorporated herein by reference).
10.8	Seventh Amendment to Credit Agreement, dated as of November 9, 2017, among California Resources Corporation, as the Borrower, JP Morgan Chase Bank, N.A., as Administrative Agent, Swingline Lender and a Letter of Credit Issuer, Bank of America, N.A., as Syndication Agent, Swingline Lender and a Letter of Credit Issuer (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed November 13, 2017, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.9	Eighth Amendment to 2014 Credit Agreement, dated August 20, 2018 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed August 24, 2018 and incorporated herein by reference).
10.10	Credit Agreement, dated August 12, 2016, among California Resources Corporation, as the Borrower, the several Lenders from time to time parties thereto, Goldman Sachs Bank USA, as Lead Arranger and Bookrunner, and The Bank of New York Mellon Trust Company, N.A., as Administrative Agent and Collateral Agent (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed August 17, 2016 and incorporated herein by reference).
10.11	Credit Agreement, dated as of November 17, 2017, by and among the Company, as the Borrower, Bank of New York Mellon Trust, N.A., as Administrative Agent, and the various Lenders identified therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed November 17, 2017, and incorporated herein by reference).
10.12	First Amendment to 2017 Credit Agreement, dated September 18, 2018 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed September 18, 2018, and incorporated herein by reference).
10.13	Omnibus Amendment, dated September 12 2016, among California Resources Corporation, the Guarantors party thereto, the Collateral Trustee and the other party lien representatives party thereto (filed as Exhibit 10.3 to the Registration's Quarterly Report on Form 10-Q filed November 3, 2016 and incorporated herein by reference).
10.14	Transition Services Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.4 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.15	Tax Sharing Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.2 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.16	Employee Matters Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.3 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.17	Intellectual Property License Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.7 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.18	Area of Mutual Interest Agreement, dated November 25, 2014, between Occidental Petroleum Corporation and California Resources Corporation (filed as Exhibit 10.5 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
10.19	Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated November 5, 1991, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, Atlantic Richfield Company and ARCO Long Beach, Inc. (filed as Exhibit 10.10 to Amendment No. 2 to the Company's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.20	Amendment to the Agreement for Implementation of an Optimized Waterflood Program for the Long Beach Unit, dated January 16, 2009, by and among the State of California, by and through the State Lands Commission, the City of Long Beach, and Oxy Long Beach, Inc. (filed as Exhibit 10.11 to Amendment No. 2 to the Company's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).
10.21	Contractors' Agreement, by and between the City of Long Beach, Humble Oil & Refining Company, Shell Oil Company, Socony Mobil Oil Company, Inc., Texaco, Inc., Union Oil Company of California, Pauley Petroleum, Inc., Allied Chemical Corporation, Richfield Oil Corporation and Standard Oil Company of California (filed as Exhibit 10.12 to Amendment No. 2 to the Company's Registration Statement on Form 10 filed August 20, 2014, and incorporated herein by reference).
10.22	Confidentiality and Trade Secret Protection Agreement, dated November 25, 2014, by and between Occidental Petroleum Corporation and California Resources Corporation, dated November 24, 2014 (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K filed on December 1, 2014, and incorporated herein by reference).
10.23	Second Amended and Restated Limited Liability Company Agreement of Elk Hills Power, LLC, dated as of February 7, 2018, by and among Elk Hills Power, LLC, California Resources Elk Hills, LLC and ECR Corporate Holdings L.P. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.24	Commercial Agreement, dated as of February 7, 2018, by and between Elk Hills Power, LLC and California Resources Elk Hills, LLC (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.25	Master Services Agreement, dated as of February 7, 2018, by and between Elk Hills Power, LLC and California Resources Elk Hills, LLC (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.26	Form of Stock Purchase Agreement, dated as of February 7, 2018 (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
10.27	Registration Rights Agreement, dated as of February 7, 2018, by and between California Resources Corporation and the purchasers named therein (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K filed on February 7, 2018, and incorporated herein by reference).
	The following are management contracts and compensatory plans required to be identified specifically as responsive to Item 601(b)(10)(iii)(A) of Regulation S-K pursuant to Item 15(b) of Form 10-K.
10.28	California Resources Corporation Long-Term Incentive Plan Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.3 to the Registrant's Quarterly Report Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.29	California Resources Corporation Long-Term Incentive Plan, 2016 Annual Incentive Award Summary (filed as Exhibit 10.5 on Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.30	California Resources Corporation Long-Term Incentive Plan Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.31	California Resources Corporation Long-Term Incentive Plan Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.4 to the Registrant's Quarterly Report Form 10-Q filed November 6, 2015, and incorporated herein by reference).
10.32	California Resources Corporation Supplemental Savings Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 2, 2014, and incorporated herein by reference).
10.33	First Amendment to California Resources Corporation Supplemental Savings Plan (filed as Exhibit 10.18 to the Registrant's Annual Report on Form 10-K filed February 29, 2016, and incorporated herein by reference).
10.34	California Resources Corporation Supplemental Retirement Plan II (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on December 2, 2014, and incorporated herein by reference).
10.35	California Resources Corporation Deferred Compensation Plan (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on December 2, 2014, and incorporated herein by reference).
10.36	California Resources Corporation Long-Term Incentive Plan (filed as Exhibit 4.3 to the Registrant's related Registration Statement on Form S-8 filed November 26, 2014 and incorporated herein by reference).
10.37*	First Amendment to California Resources Corporation Long-Term Incentive Plan (As Amended and Restated Effective as of May 4, 2016).
10.38	Acknowledgment of Amendment to Long-Term Incentive Award Terms with William E. Albrecht (filed as Exhibit 10.22 to the Registrant's Annual Report on Form 10-K filed February 29, 2016, and incorporated herein by reference).
10.39	Form of Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.6 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.40	Form of Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q filed August 4, 2016 and incorporated herein by reference).
10.41	Form of Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q filed November 3, 2016, and incorporated herein by reference).
10.42	Form of Performance Incentive Award Terms and Conditions (filed as Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q filed November 3, 2016, and incorporated herein by reference).
10.43	Form of Restricted Stock Incentive Award Terms and Conditions (Not Performance-Based) (filed as Exhibit 10.8 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.44	Form of Restricted Stock Incentive Award Terms and Conditions (Performance-Based) (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 10, 2015, and incorporated herein by reference).

Exhibit Number	Exhibit Description
10.45	Form of Restricted Stock Unit Award for Non-Employee Directors Grant Agreement (filed as Exhibit 10.9 to Amendment No. 3 to the Registrant’s Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.46	Form of Long-Term Incentive Award Terms and Conditions (Cash-based, Equity, and Cash-settled Award) (filed as Exhibit 10.10 to Amendment No. 3 to the Registrant’s Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.47	Form of Restricted Stock Incentive Award Terms and Conditions (Replacement Award-Performance-Based) (filed as Exhibit 10.11 to Amendment No. 3 to the Registrant’s Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.48	Form of Restricted Stock Incentive Award Terms and Conditions (Replacement Award-Not Performance-Based) (filed as Exhibit 10.12 to Amendment No. 3 to the Registrant’s Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.49	Form of Phantom Share Unit Award Terms and Conditions (Replacement Award) (filed as Exhibit 10.13 to Amendment No. 3 to the Registrant’s Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.50	Form of 2018 Nonstatutory Stock Option Award Terms and Conditions (filed as Exhibit 10.1 to the Registrant’s Quarterly Report on Form 10-Q filed May 9, 2018, and incorporated herein by reference).
10.51	Form of 2018 Restricted Stock Unit Award Terms and Conditions (filed as Exhibit 10.2 to the Registrant’s Quarterly Report on Form 10-Q filed May 9, 2018, and incorporated herein by reference).
10.52	Form of 2018 Performance Stock Unit Award Terms and Conditions (filed as Exhibit 10.3 to the Registrant’s Quarterly Report on Form 10-Q filed May 9, 2018, and incorporated herein by reference).
10.53	California Resources Corporation 2014 Employee Stock Purchase Plan (filed as Exhibit 4.3 to the Registrant’s related Registration Statement on Form S-8 filed November 26, 2014 and incorporated herein by reference).
10.54	Form of Indemnification Agreements (filed as Exhibit 10.14 to Amendment No. 3 Registrant’s Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.55	First Amendment to the California Resources Corporation 2014 Employee Stock Purchase Plan effective May 4, 2016 (filed as Annex C-1 to the Registrant’s Definitive Proxy Statement on Schedule 14A filed March 23, 2016 and incorporated herein by reference).
21*	List of Subsidiaries of California Resources Corporation.
23.1*	Consent of Independent Registered Public Accounting Firm.
23.2*	Consent of Independent Petroleum Engineers.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit Number	Exhibit Description
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Ryder Scott Company Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2018.
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 Labels 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 Section 13 or 15(d) 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

February 27, 2019

By: /s/ Todd A. Stevens

Todd A. Stevens
President
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

	Title	Date
/s/ Todd A. Stevens Todd A. Stevens	President, Chief Executive Officer and Director	February 27, 2019
/s/ Marshall D. Smith Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer	February 27, 2019
/s/ Roy Pineci Roy Pineci	Executive Vice President - Finance and Principal Accounting Officer	February 27, 2019
/s/ William E. Albrecht William E. Albrecht	Chairman of the Board	February 27, 2019
/s/ Justin A. Gannon Justin A. Gannon	Director	February 27, 2019
/s/ Harold M. Korell Harold M. Korell	Director	February 27, 2019
/s/ Harry T. McMahon Harry T. McMahon	Director	February 27, 2019
/s/ Richard W. Moncrief Richard W. Moncrief	Director	February 27, 2019
/s/ Avedick B. Poladian Avedick B. Poladian	Director	February 27, 2019
/s/ Anita M. Powers Anita M. Powers	Director	February 27, 2019
/s/ Laurie A. Siegel Laurie A. Siegel	Director	February 27, 2019
/s/ Robert V. Sinnott Robert V. Sinnott	Director	February 27, 2019

EXHIBIT INDEX

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99.1	Ryder Scott Company Estimated Future Reserves Attributable to Certain Leasehold and Royalty Interests as of December 31, 2018.
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 Labels Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

Annual Meeting

California Resources Corporation's annual meeting of stockholders will be held at 11:00 a.m. on May 8, 2019 at the Bakersfield Marriott at the Convention Center located at 801 Truxtun Avenue, Bakersfield, California 93301.

Investor Relations

Company financial information, public disclosures and other information are available through our website at www.crc.com. We will promptly deliver free of charge, upon request, an annual report on Form 10-K to any stockholder requesting a copy. Requests should be directed to our Investor Relations team at our corporate headquarters address or sent to ir@crc.com.

Auditors

KPMG LLP, Los Angeles, California

Transfer Agent & Registrar

American Stock Transfer and Trust Company, LLC
Shareholder Services
6201 15th Avenue, Brooklyn, New York 11219
(866) 659-2647
crc@astfinancial.com
www.astfinancial.com

Stock Exchange Listing

California Resources Corporation's common stock is listed on the New York Stock Exchange (NYSE). The symbol is CRC.

CRC LISTED NYSE

Officers

Todd A. Stevens
President,
Chief Executive Officer
and Director

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

Shawn M. Kerns
Executive Vice President,
Operations and Engineering

Francisco J. Leon
Executive Vice President,
Corporate Development and
Strategic Planning

Roy M. Pineci
Executive Vice President,
Finance

Michael L. Preston
Executive Vice President,
General Counsel and
Corporate Secretary

Charles F. Weiss
Executive Vice President,
Public Affairs

Darren Williams
Executive Vice President,
Operations and Geoscience

Board Of Directors

William E. Albrecht
Chairman of the Board, Former
Vice President, Occidental
Petroleum Corporation

Justin A. Gannon
Former Regional Managing
Partner, Grant Thornton LLP

Harold M. Korell
Lead Independent Director,
Former Chairman of the Board
and Chief Executive Officer,
Southwestern Energy Company

Harry T. McMahon
Former Executive Vice
Chairman, Bank of America
Merrill Lynch

Richard W. Moncrief
Chairman of the Board and
Chief Executive Officer,
Moncrief Oil International

Avedick B. Poladian
Former Executive Vice
President and Chief Operating
Officer, Lowe Enterprises

Anita M. Powers
Former Executive Vice
President of Worldwide
Exploration, Occidental Oil
and Gas Corporation and
Vice President, Occidental
Petroleum Corporation

Laurie A. Siegel
President,
LAS Advisory Services

Robert V. Sinnott
Co-Chairman,
Kayne Anderson Capital

Todd A. Stevens
President, Chief Executive
Officer and Director, California
Resources Corporation

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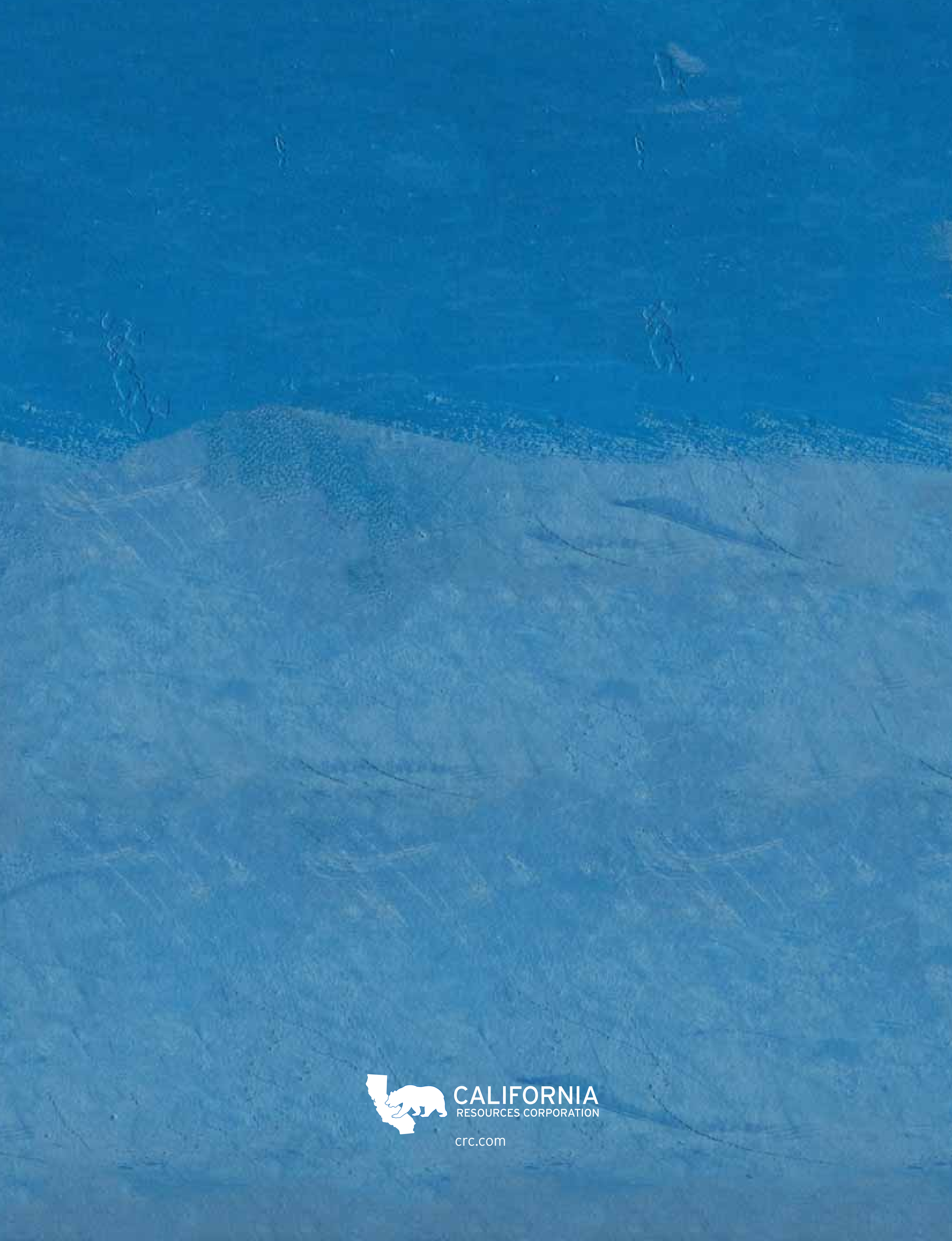
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