ENERGY FOR CALIFORNIA BY CALIFORNIANS

CALIFORNIA
RESOURCES CORPORATION

California Resources Corporation 2014 Annual Report

FINANCIAL & OPERATING HIGHLIGHTS

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

Financial Highlights	2014	2013	2012
Revenues	$ 4,173	$ 4,284	$ 4,073
Income / (Loss) Before Income Taxes	$ (2,421)	$ 1,447	$ 1,181
Net Income / (Loss)	$ (1,434)	$ 869	$ 699
Core Income	$ 650	$ 869	$ 675
EPS – Basic and Diluted[a]	$ (3.75)	$ 2.24	$ 1.80
Core EPS – Basic and Diluted[a]	$ 1.67	$ 2.24	$ 1.74
Net Cash Provided by Operating Activities	$ 2,371	$ 2,476	$ 2,223
Capital Investments	$ (2,020)	$ (1,669)	$ (2,331)
Proceeds from Debt	$ 6,360	–	–
Cash Dividends to Occidental	$ (6,000)	–	–
Net Cash (Used) Provided by Other Financing Activities	$ (45)	$ (763)	$ 532
Total Assets	$ 12,497	$ 14,297	$ 13,764
Long-Term Debt	$ 6,360	–	–
Equity/Net Investment	$ 2,611	$ 9,989	$ 9,860
Weighted Average Shares Outstanding[a]	381.9	–	–
Year-End Shares	385.6	–	–
Operational Highlights			
Production:			
Crude Oil (MBbl/d)	99	90	88
NGLs (MBbl/d)	19	20	17
Natural Gas (MMcf/d)	246	260	256
Total (MBoe/d)	159	154	148
Average Realized Prices:			
Crude ($/Bbl)	$ 92.30	$ 104.16	$ 104.02
NGLs ($/Bbl)	$ 47.84	$ 50.43	$ 52.76
Natural Gas ($/Mcf)	$ 4.39	$ 3.73	$ 2.94
Reserves:			
Crude Oil (MMBbl)	551	532	497
NGLs (MMBbl)	85	71	61
Natural Gas (Bcf)	790	844	934
Total (MBoe/d)	768	744	714
Reserve Replacement from Capital Program	203%	159%	183%
PV-10	$16.1 billion	$14.0 billion	$13.8 billion
Acreage (in thousands):			
Net Developed	716	701	466
Net Undeveloped	1,691	1,604	1,646
Total	2,407	2,305	2,112
Closing Share Price	$ 5.51		

(a) On November 30, 2014, the spin-off date from Occidental Petroleum Corporation, 381.4 million shares of our common stock were distributed, of which approximately 18.5% was retained by Occidental. Additional shares were distributed in December to substitute for Occidental stock awards. For comparative purposes, and to provide a more meaningful calculation of weighted-average shares outstanding, we have assumed these amounts to be outstanding for each period prior to the spin-off.

All statements, other than statements of historical fact, included in this report that address activities, events or developments that California Resources Corporation (the "Company" or "CRC") believes will or may occur in the future are forward-looking statements. The words "believe," "expect," "may," "estimate," "will," "anticipate," "plan," "intend," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. Forward-looking statements specifically include the Company's expectations based on its plans, strategies, objectives and anticipated financial and operating results, including as to the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this report. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include, but are not limited to, commodity pricing; vulnerability to economic downturns and adverse developments due to our debt; insufficiency of our operating cash flow to fund planned capital investments; inability to implement our capital investment program profitably or at all; compliance with regulations or changes in regulations and the ability to obtain government permits and approvals; risks of drilling; tax law changes; competition for and costs of oilfield equipment, services, qualified personnel and acquisitions; the subjective nature of estimates of proved reserves and related future net cash flows; inability to drill identified locations when planned or at all; restrictions on our ability to obtain, use, manage or dispose of water; inability to operate in the United States outside of California; concerns about climate change and air quality issues; risks related to our acquisition activities; catastrophic events for which we may be uninsured or underinsured; cyber attacks; operational issues that restrict market access; and uncertainties related to the anticipated effects of restructuring or reorganizing our business. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, except as required by applicable law.

ENERGY FOR CALIFORNIA BY CALIFORNIANS

CRC's operations at THUMS in Long Beach, California

Engineer performing an inspection at CRC's power plant at Elk Hills Field near Bakersfield

Pumping units at CRC's operations in Ventura

63% CRUDE PRODUCTION
Our capital program is focused on high-margin crude oil production

2.4 MILLION NET ACRES
We believe we are the largest private mineral acreage holder in the State of California

Vision: To be the premier company providing Californians with long-term ample, affordable and reliable energy exclusively from California resources.

Mission: To maximize stockholder returns by safely and responsibly developing high-growth, high-return conventional and unconventional assets exclusively in California while benefiting our communities and the state.

California Resources Corporation (NYSE: CRC) is the largest independent oil and natural gas producer in the state. CRC operates its world-class resource base exclusively within the State of California. Using advanced technology, CRC's dedicated workforce focuses on safely and responsibly supplying affordable *energy for California by Californians.*

Plant operators at CRC's cryogenic gas processing plant at Elk Hills Field near Bakersfield, California

A MESSAGE TO OUR STOCKHOLDERS

Dear Stockholder,

I welcome you as an inaugural stockholder of California Resources Corporation (CRC), a company built on a solid foundation of high-quality assets, with an especially promising future as a newly independent oil and natural gas company.

We begin with a clear focus – to maximize stockholder returns by safely and responsibly developing conventional and unconventional assets exclusively in California while serving as responsible stewards and valued neighbors in the communities where we operate.

We bring three competitive strengths to our mission – world-class assets, operational and financial flexibility, and an experienced board of directors and management team committed to increasing your share value. To capitalize on these strengths, we are implementing a value-driven capital-investment strategy focused on sustaining economic production and enhancing our net asset value, with the objective of living within our annual cash flows and de-levering over time.

As you are likely aware, oil and natural gas markets have entered into a cyclical downturn, driven largely by global supply and demand fundamentals. These factors confront CRC with the challenges of a lower price environment, but also present us with the opportunity to demonstrate our competitive advantages through the lower end of the commodity price cycle.

We benefit from operational control of almost all of our fields and our diversified, flexible portfolio of assets. We have sufficient liquidity for our capital program and a strong asset base to operate within our cash flows, and we have a management team in place with deep experience in all phases of the energy industry cycle. We are closely monitoring market conditions and have already implemented decisive measures to adapt to this new price environment. As a result, we believe CRC is well positioned to emerge from the current commodity price downturn with a solid base.

Let me provide a more in-depth summary of our core strengths: a world-class asset base, operational and financial flexibility and our experienced board of directors and management team.

The California Opportunity

California Resources Corporation was launched as the largest independent oil and natural gas producer in the state. We are able to achieve that level of production partly because we enjoy the largest privately held mineral acreage position in the state with operations in all four of California's major oil and gas basins: the San Joaquin, Los Angeles, Ventura and Sacramento basins.

California is a tremendous oil province and has five fields that rank in the top 12 for production in the contiguous lower 48 states. We operate 137 oil and natural gas fields — nearly half the fields in the state — with an average recovery factor to date of 22 percent of an estimated 40 billion barrels of original oil in place.[1] Most of our production comes from Kern County, which is the largest oil-producing county in the continental United States. Overall, CRC has 2.4 million net mineral acres in California — larger than the combined areas of California's 80 biggest cities including Los Angeles, San Diego, San Jose and Bakersfield — with approximately 60 percent of that acreage held in fee.

We plan to drive long-term stockholder value by applying modern technology to develop this vast resource base and increase production. We have significant conventional opportunities to pursue, and we intend to develop our fields through their life cycles by increasing recovery factors as we transition from primary production to secondary recovery with waterfloods and in some cases steamfloods and other enhanced recovery methods. In addition to our wealth of conventional assets, we have significant unconventional assets and acreage that we can develop for future growth. Our diverse portfolio of long-lived assets also positions us to conserve natural resources, including water, habitat and energy, by maximizing the recovery from existing fields using existing infrastructure.

A Deep, Experienced Management Team

While CRC is a new company, we benefit from Occidental Petroleum Corporation's long and rich operating experience in California. We have formed strong leadership and technical teams with proven management and geologic and engineering expertise to develop our prolific fields. Many of CRC's key personnel, from the corporate office to our production facilities, helped build our current position in California and have extensive experience operating our assets. This team also has decades of experience working successfully with our regulators and our communities to develop these resources with exemplary safety and environmental performance. Our employees are energized about our new company and devoted to implementing our development projects to sustain production, drive overall efficiencies and uphold our company's core values. In particular, I commend our workforce for achieving record safety performance in 2014 and remaining focused on our mission during a year of organizational and market changes. We are proud of CRC's heritage and very excited about what we can accomplish together.

A Disciplined Strategy with Financial and Operational Flexibility

To grow our net asset value, our long-term strategic plan is to reinvest substantially all of our operating cash flows after debt service in our oil-focused, high-return assets including lower-risk conventional projects and select unconventional opportunities. CRC's strategy delivered crude oil production growth of 12 percent in 2014, and we replaced 203 percent[2] of our 2014 production through our capital program. Even while we focus on oil, we remain the state's leading producer of natural gas, and our Elk Hills power plant has the capacity to supply electricity to more than 500,000 homes.

California Resources Corporation began trading publicly under the NYSE ticker "CRC" on December 1, 2014, after we officially spun off from Occidental. As part of the recapitalization for our spin-off, CRC assumed certain debt obligations. These include $5 billion in

1. We use certain terms in this report, such as oil in place, that Securities and Exchange Commission (SEC) guidelines strictly prohibit us from using in our SEC filings. These terms represent our internal estimates of volumes of oil and gas that are potentially recoverable through exploratory drilling or additional drilling or recovery techniques and are not intended to correspond to probable or possible reserves as defined by SEC regulations. By their nature these estimates are more speculative than proved, probable or possible reserves and subject to greater risk they will not be realized.

2. The reserves replacement ratio is calculated for a specified period using the applicable proved oil-equivalent additions divided by oil-equivalent production. 76% of the additions are proved undeveloped. There is no guarantee that historical sources of reserves additions will continue as many factors fully or partially outside management's control, including the underlying geology, commodity prices and availability of capital, affect reserves additions. Management uses this measure to gauge results of its capital allocation. The measure is limited in that reserves may be added and produced based on costs incurred in separate periods and other oil and gas producers may use different replacement ratios affecting comparability.

notes, a $1 billion pre-payable term loan, with the first payment due in 2016, and a $2 billion bank line of credit, or revolver, which provides substantial available capacity for working capital needs.

We have already implemented significant measures to adapt to the recent drop in oil and gas prices and are evaluating different ways to de-lever our balance sheet, including using our cash flow for both debt reduction and capital investment in the near term.

CRC's rigorous capital allocation process applies our Value Creation Index (VCI) to prioritize development projects. Recognizing the long-lived nature of our fields, our VCI measures the net present value of the expected pre-tax cash flows of a project over the life of the project against the present value of the investment. To develop our investment plans for 2015, we applied our VCI and evaluated each project's ability to generate a VCI greater than 1.3, meaning that 30 cents of expected value is created above every dollar invested.

Contributing to California

Our board, management team and employees share three core values – Character, Responsibility and Commitment – that define how we conduct business and interact with our stockholders, creditors, workforce, partners, regulators and communities. As we work to create and deliver value to our stockholders, we are also committed to contributing to California – because we are the pure-play California energy company.

California has suffered from a chronic energy deficit. California imports approximately 90 percent of its natural gas supply, 60 percent of its crude oil needs and approximately 25 percent of its electricity. Nearly half of the oil used in the state is imported by supertankers from foreign countries like Saudi Arabia, Ecuador and Iraq. As a significant energy player and an economic engine in the state, we are doing our part to increase energy security, create well-paying jobs and provide royalties and tax revenues to the state. In 2014, we produced 118,000 barrels per day of crude oil and natural gas liquids (NGLs), 246 million cubic feet per day of natural gas and 462 gross megawatts of electricity per hour.

The drought is a critical issue in California. Through significant investments in water conservation and recycling, we recycled approximately 79 percent of our produced water to meet our operational needs in 2014. In addition, our steamflood operations supplied a record 2 billion gallons of water for agricultural use in 2014. As a result, our company is a net water supplier to agriculture in the state, providing a greater volume for irrigation than the amount of fresh water we purchase for our statewide operations.

In summary, we have an extraordinary and resilient resource base that can weather the volatility of the commodity cycle. As your management team, we will be good stewards of your CRC investment by utilizing our VCI metric to maximize the value of our resource base and reward stockholders over the long term. We are proud to be one of the top independent oil and gas companies in the United States, producing secure and affordable energy for California by Californians. We hope you are as excited about the future as we are.

Regards,

Todd A. Stevens, President & CEO

A MESSAGE FROM THE CHAIRMAN

Dear Stockholder,

California Resources Corporation's spin-off from Occidental Petroleum Corporation was structured to create an industry-leading, pure-play exploration and production company focused exclusively on California, one of the most prolific global hydrocarbon provinces. Cash flow generated from operations in California will be reinvested in California, where we have a world-class resource base with vast untapped potential.

Over the long-term, we believe this potential will drive the creation of substantial value for stockholders and contribute meaningfully to California's economy, environment and energy supply, and will reduce the state's chronic energy deficit.

As many of our investors know, prior to the spin-off, our California assets generated significant free cash flow that was returned to Occidental to fund its dividend and investment needs. As a stand-alone company, we can now fully deploy our cash flows, after debt service and reduction, into capital investment.

Your board believes you have an excellent management team with deep experience in place to develop these assets. And we have committed the company to core values that will help ensure we conduct business safely and responsibly.

We are constructive partners with our communities and our state. And we are firmly committed to solid corporate governance and take seriously our responsibilities as your board of directors.

I strongly believe that CRC has assembled a board that is not only committed to increasing stockholder value, but is comprised of individuals who have a track record of doing so. Each board member brings distinct expertise to furthering our objective of increasing stockholder value.

Our goal was to assemble an exemplary board for CRC that had deep knowledge and breadth of experience not only in the oil and gas industry, but also in the areas of finance, audit, governance and management of a large company in California. We have accomplished this, and you as the stockholder will be rewarded with their oversight, based on their talents and expertise.

CRC has a ten-member board with eight directors qualifying as independent directors. CRC also has the good fortune to have Harold Korell serve as our lead independent director. Harold brings over four decades of experience in the energy business to this important role. CRC also has the requisite three committees: nominating and corporate governance, audit and compensation, along with a health, safety and environmental committee.

I am honored and privileged to serve with a board of this caliber and am confident that CRC's strategy and opportunity set will provide a powerful combination to deliver superior performance to our investors.

Regards,

William E. "Bill" Albrecht, Executive Chairman

Field operator at CRC's operations at THUMS in Long Beach, California

2014
RESULTS SUMMARY

2014 was a year of significant accomplishment for California Resources Corporation, as we completed our spin-off from Occidental Petroleum Corporation and began executing our focused capital strategy. CRC is now the largest independent oil and natural gas producer in the state.

To prepare for the spin-off, CRC gathered information and built financial processes and other support systems in a very short period of time to operate successfully as a stand-alone independent company. CRC issued $5 billion of public debt in three tranches and negotiated an unsecured bank facility consisting of a pre-payable $1 billion term loan and a $2 billion revolver. This activity culminated in a $6 billion payment to Occidental structured as part of the spin-off. At year-end, CRC had a total of $6.4 billion of outstanding long-term debt.

Reflecting our seamless transition to independence, CRC generated core[3] income of $650 million ($1.67 per diluted share) for the 12 months of 2014, compared with $869 million ($2.24 per diluted share) for 2013. We had operational cash flow of $2.4 billion, allowing us to fund our capital investments from our cash flow.

Our 2014 daily oil and gas production volumes averaged a record 159,000 barrels of oil equivalent (BOE), compared with 154,000 BOE in 2013. This increase was largely driven by our focus on long-term value creation through investments in our conventional assets such as water and steamflood operations. Realized crude oil prices decreased 11 percent to $92.30 per barrel for the 12 months of 2014, compared with $104.16 per barrel for 2013. Natural gas liquid (NGL) prices decreased 5 percent to $47.84 per barrel for 2014, from $50.43 per barrel for 2013. Natural gas prices increased 18 percent in the 12 months of 2014 to $4.39 per thousand cubic feet (Mcf), compared with $3.73 per Mcf for 2013.

Across all of our California operations, we drilled 1,048 wells in 2014, of which 73 were focused on primary production, 259 were in waterflood fields, 532 were in our steamfloods and 184 wells were in unconventional reservoirs. We invested $1.3 billion in drilling and completion capital in 2014. Our 2014 total capital program of $2.1 billion also included investments in infrastructure upgrades, facilities, workovers and exploration. Our capital program added 118 million BOE of proved reserves in 2014, representing a 203 percent organic reserve replacement ratio. In addition, we invested $300 million in 2014 for the aquisition of properties with 6 million BOE of proved reserves, unproved properties and mineral interests.

San Joaquin Basin

We drilled 847 wells in the San Joaquin Basin in 2014; these consisted of 722 producers and 125 injector wells. We invested almost $900 million on

3. Core results reflect certain unusual and infrequent charges disclosed in the Form 10-K.

drilling and completions in our San Joaquin Basin operations, with an additional $100 million investment to acquire producing properties and mineral interests and $105 million for exploration. We produced 64,000 barrels per day (Bbl/d) of crude oil, 180 million cubic feet per day (MMcf/d) of natural gas and 18,000 Bbl/d of NGLs in this region. Reserves stood at 525 million BOE at year-end 2014 with 12,600 net drilling locations.

Los Angeles Basin

In our Los Angeles Basin operations, where we have mainly waterfloods, we drilled 177 wells including 123 producers and 54 injectors. The capital invested for this drilling activity was $340 million. We produced 29,000 Bbl/d of crude oil, and 1 MMcf/d of natural gas in this region. The year-end reserves were 166 million BOE in the Los Angeles Basin with 1,900 net drilling locations.

Ventura Basin

In the Ventura Basin, we invested $43 million to drill and complete 21 wells. We also acquired producing properties and mineral acreage in the West Montalvo Field in the fourth quarter for $200 million. We produced 6,000 Bbl/d of crude oil, 11 MMcf/d of natural gas and 1,000 Bbl/d of NGLs in this region. Our year-end reserves in the basin were 58 million BOE with 1,800 net drilling locations.

Sacramento Basin

We drilled three deep gas wells in the Sacramento Basin in 2014 representing $7 million of investment. We produced 54 MMcf/d in the basin. Our year-end reserves were 19 million BOE with 900 net drilling locations for this region.

Exploration Success

In our exploration program, we had notable successes in our conventional reservoir drilling from proven play trends offsetting the Pleito Ranch Field in the San Joaquin Basin and the Bardsdale Field in the Ventura Basin.

We continue to develop our understanding and knowledge of the significant prospective resources in the exploration of shale reservoirs. In 2014, we completed significant log, core and seismic data acquisition projects targeting the Kreyenhagen exploration shale reservoir around the Kettleman North Dome and Middle Dome fields.

Proactive Stewardship of Capital

We have successfully launched CRC as a strong independent company in 2014 with a world-class resource base and a capital allocation strategy focused on enhancing stockholder value.

We took immediate steps to address the steep decline in commodity prices. In December 2014, our first month as an independent company, we reduced our rig count from 27 rigs in late November to six rigs at year-end.

We could act quickly because of our nearly 100 percent operational control of our fields. Our rapid adjustment of our activity levels will enhance our economics as we move through this trough in the commodity cycle.

At the same time, we are optimizing our diverse portfolio to accelerate drilling and development projects as market conditions improve.

William E. Albrecht
Executive Chairman of the Board, California Resources Corporation

Justin A. Gannon[1, 3]
Former Regional Managing Partner, Grant Thornton LLP

Ronald L. Havner, Jr.[1, 4]
Chairman of the Board, President and Chief Executive Officer, Public Storage

Catherine A. Kehr[1, 3, *]
Former Senior Vice President and Director of Capital Research Company, The Capital Group Companies

Harold M. Korell[2, 3]
Lead Independent Director; Former Chairman of the Board, Southwestern Energy Company

Richard W. Moncrief[1, 4]
President and Chairman of the Board, Moncrief Oil International, Inc.

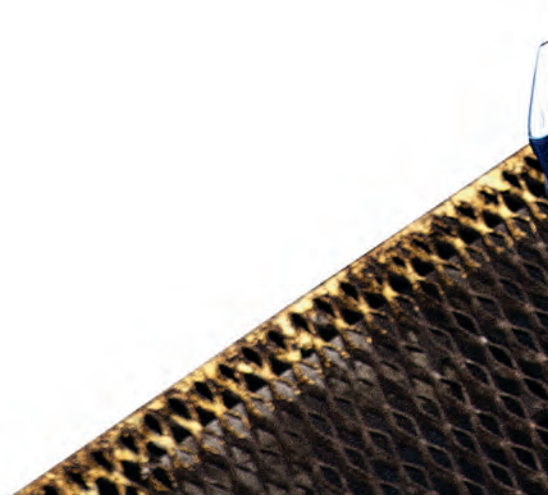
Avedick B. Poladian[2, 4]
Executive Vice President and Chief Operating Officer, Lowe Enterprises, Inc.

Robert V. Sinnott[2]
President, Chief Executive Officer and Chief Investment Officer, Kayne Anderson Capital Advisors, L.P.

Timothy J. Sloan[3, 4]
Senior Executive Vice President, Wholesale Banking, Wells Fargo & Company

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

1 Audit Committee
2 Nominating and Governance Committee
3 Compensation Committee
4 Health, Safety and Environmental Committee
* Member of the Board as of March 15, 2015



BOARD OF DIRECTORS

CALIFORNIA RESOURCES CORPORATION SNAPSHOT

NO.1

California Resources Corporation (CRC) is the largest independent oil and natural gas producer in the state.

CRC

CRC has operations at the Elk Hills Field in Kern County, the Wilmington Field in Long Beach and fields in the Los Angeles, San Joaquin, Ventura and Sacramento basins.

2BIL

In 2014, CRC supplied more than 2 billion gallons of water for agriculture through our steamflood operations. As a result, CRC provided more water for irrigation than the amount of fresh water we purchased for our statewide operations.

2.4MM

CRC is the largest private net mineral acreage holder in California with about 2.4 million net acres, larger than the combined areas of California's 80 biggest cities, including Los Angeles, San Diego, San Jose and Bakersfield.

203%

In 2014, CRC replaced 203 percent of its production from its capital program. At year-end, CRC's properties held an estimated 768 million barrels of oil equivalent in proved reserves.

540MM

At Elk Hills, CRC operates efficient gas processing facilities with a combined capacity of 540 million cubic feet of gas per day, including the largest cryogenic gas plant in California.

LEADER IN SAFETY

In 2014, CRC's dedicated California workforce achieved their best-ever combined safety performance. The 2014 Injury and Illness Incidence Rate (IIR) of 0.46 was 86 percent better than the 2013 average IIR of 3.3 for the private sector in the U.S.

159M

CRC's operations produced 159,000 barrels of oil equivalent per day in 2014.

NO.1

Kern County is the leading county in oil production in the lower 48 states.

IN 4 of 12

CRC operates in 4 of the 12 largest fields in the continental United States.

2014

CRC 2014

FORM 10-K

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, 2014

☐ **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.)
10889 Wilshire Blvd. **Los Angeles, California**	**90024**
(Address of principal executive offices)	(Zip Code)

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

Securities registered pursuant to Section 12(b) of the 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 and posted on its corporate Web site, if any, every Interactive Date File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or such shorter period as the registrant was required to submit and post 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☐	Accelerated Filer	☐
Non-Accelerated Filer	☑	Smaller Reporting Company	☐

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

As of June 30, 2014, there was no public market for the registrant's common stock.

At January 31, 2015, there were 385,639,582 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 2015 Annual Meeting of Stockholders, are incorporated by reference into Part III of this Form 10-K.

LIST OF OPERATING SUBSIDIARIES

The following is a list of our subsidiaries at December 31, 2014 other than certain subsidiaries that did not in the aggregate constitute a significant subsidiary.

Name	Jurisdiction of Formation
California Heavy Oil, Inc.	Delaware
California Resources Elk Hills, LLC	Delaware
California Resources Long Beach, Inc.	Delaware
California Resources Petroleum Corporation	Delaware
California Resources Production Corporation	Delaware
California Resources Tidelands, Inc.	Delaware
California Resources Wilmington, LLC	Delaware
CRC Marketing, Inc.	Delaware
CRC Services, LLC	Delaware
Elk Hills Power, LLC	Delaware
Socal Holding, LLC	Delaware
Southern San Joaquin Production, Inc.	Delaware
Tenby, Inc.	California
Thums Long Beach Company	Delaware
Tidelands Oil Production Company	Texas

TABLE OF CONTENTS

PART I

Item 1 BUSINESS

In this report, except when the context otherwise requires or where otherwise indicated, (1) all references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its subsidiaries or the California business, (2) all references to the ''California business'' refer to Occidental's California oil and gas exploration and production operations and related assets, liabilities and obligations, which we assumed in connection with the spin-off from Occidental on November 30, 2014 (the ''Spin-off''), and (3) all references to ''Occidental'' refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

General

We are an independent oil and natural gas exploration and production company operating properties exclusively within the State of California. We were incorporated in Delaware as a wholly-owned subsidiary of Occidental on April 23, 2014 and remained a wholly-owned subsidiary of Occidental until the Spin-off. On November 30, 2014, Occidental distributed shares of our common stock on a pro rata basis to Occidental stockholders and we became an independent, publicly traded company, referred to in this annual report as the Spin-off. Occidental retained approximately 18.5% of our outstanding shares of common stock which it has stated it intends to divest within 18 months of the Spin-off.

Business Operations

Our business is focused on conventional and unconventional assets, exclusively in California, which can generate positive cash flow throughout the oil and natural gas price cycle and have the capacity to provide significant production and cash flow growth in a higher price environment. We are the largest oil and gas producer in California on a gross operated basis and we believe we have established the largest privately-held mineral acreage position in the state, consisting of approximately 2.4 million net acres spanning the state's four major oil and gas basins. We produced on average approximately 159 MBoe/d net for the year ended December 31, 2014. As of December 31, 2014, we had net proved reserves of 768 MMBoe, with approximately 72% proved developed. Oil represented 72% of our proved reserves. Our aggregate PV-10 value was $16.1 billion. For an explanation of the non-GAAP financial measure PV-10 and a reconciliation of PV-10 to Standardized Measure, the most directly comparable GAAP financial measure, see ''Reserves and Production Information'' below. Our current drilling inventory comprises a diversified portfolio of oil and natural gas locations, which allows us to target drilling projects that are economically viable even in a low commodity price environment.

We develop our capital investment programs by prioritizing life of project returns to grow our net asset value over the long term, and balancing the short- and long-term growth potential of each of our assets. We use a Value Creation Index (''VCI'') for project selection and capital allocation in our portfolio. The VCI for each project is calculated by dividing the present value of the project's expected pre-tax cash flow before capital over its life by the present value of the investment, using a 10% discount rate. Projects are expected to meet a VCI of 1.3, meaning that 30% of expected value is created above every dollar invested. The diversity of our portfolio allows us to identify attractive investment opportunities in a variety of operating and commodity price environments. We regularly monitor internal performance and external factors and adjust our capital investment program with the objective of creating the most value from our portfolio of drilling opportunities. We intend to fund our capital investment program by reinvesting substantially all of our operating cash flow in our capital program, while considering any potential deleveraging opportunities.

Approximately 56% of our 2014 production was generated by our world-class Elk Hills and Wilmington fields. The remaining 44% was generated through a combination of conventional primary, steamflood and waterflood projects as well as unconventional projects. We grew our total production 5% on a compounded annual basis, from an average of 138 MBoe/d in 2011 to 159 MBoe/d for the year ended December 31, 2014, while the proportionate share of oil production for the same period grew from 58% to 63%. The growth of our oil production during this period was approximately 8% compounded annually. We expect the percentage of our oil production to continue to increase over time and favorably impact our overall margins as we anticipate directing virtually all of our capital investments toward oil-weighted opportunities in 2015 and beyond to the extent the oil-to-gas price relationship remains favorable. For example, our steamflood projects provide some of the highest returns in our portfolio when the oil-to-gas price ratio exceeds five to one. As of December 31, 2014, the ratio was approximately 23 to one.

The following table summarizes certain information concerning our acreage, wells and drilling activities (as of December 31, 2014, acres and dollars in millions, unless otherwise stated):

	Acreage		Gross Acreage Held in Fee (%)	Producing Wells, gross	Average Working Interest (%)	Identified Drilling Locations[1]		2015 Projected Gross Development Wells (2)	2015 Projected Development Drilling Capital (3)
	Gross	Net				Gross	Net		
San Joaquin Basin	1.9	1.6	58%	6,379	91%	14,450	12,600	265	96
Los Angeles Basin[4]	<0.1	<0.1	49%	1,476	93%	2,000	1,900	25	54
Ventura Basin	0.3	0.3	67%	757	89%	2,350	1,800	–	–
Sacramento Basin	0.7	0.5	34%	719	80%	1,000	900	–	–
Total	2.9	2.4	53%	9,331	89%	19,800	17,200	290	150

(1) Our total identified drilling locations include approximately 2,400 gross (2,300 net) locations associated with proved undeveloped reserves as of December 31, 2014 and 2,500 gross (2,400 net) injection well locations associated with our waterflood and steamflood projects. Our total identified drilling locations exclude 6,400 gross (5,300 net) prospective resource drilling locations. Please see ''—Our Reserves and Production Information'' for more information regarding the processes and criteria through which we identified our drilling locations. Of our total identified drilling locations, we believe approximately 75% are attributable to acreage owned or held by production.

(2) Includes 55 injection wells expected to be drilled in connection with our steamflood and waterflood projects.

(3) Includes drilling and completion expenditures of $16 million associated with injection wells. Our total 2015 capital budget of $440 million also includes investments in support equipment, seismic, workovers and exploration.

(4) We currently hold approximately 40,400 gross (34,400 net) acres in the Los Angeles basin. Our Los Angeles basin operations are concentrated with pad drilling.

During 2014, we operated an average of 26 drilling rigs across the state with the majority located in the San Joaquin and Los Angeles basins. We drilled 1,048 development wells with 847 wells in the San Joaquin basin, 177 in the Los Angeles basin, 21 in the Ventura basin and 3 in the Sacramento basin. We also drilled 9 exploration wells in the San Joaquin basin, 4 in the Ventura basin and 1 in the Sacramento basin.

As market conditions changed in the fourth quarter of 2014, we reduced our investment and drilling pace and exited the year with an active count of six drilling rigs. We currently have three active rigs with two drilling in the San Joaquin basin (targeting steamflood activities), one in the Los Angeles basin (targeting waterflood activities), and none in the Ventura and Sacramento basins. We have also reduced our workover rig count to focus on projects that meet our investment criteria in the current environment. With significant operating control of our properties, we have the ability to adjust our drilling and workover rig count in 2015 based on commodity prices and are monitoring market conditions to increase or decrease our program accordingly.

Our large acreage position contains numerous development and growth opportunities due to its varied geologic characteristics and multiple stacked pay reservoirs which, in many cases, are thousands of feet thick. We have a large portfolio of lower-risk, high-growth-potential conventional opportunities in each of our major oil and gas basins with approximately 72% of our proved reserves associated with conventional opportunities. Conventional reservoirs are capable of natural flow using primary, steamflood and waterflood recovery methods. In 2014, we targeted our capital investments primarily toward conventional development projects, including an increasing number of lower-risk steamflood recovery projects, that we expect will contribute significantly to near-term production and cash flow. We also have a significant portfolio of unconventional growth opportunities in lower permeability reservoirs which typically utilize established well stimulation techniques. We have approximately 4,800 identified drilling locations targeting unconventional reservoirs primarily in the San Joaquin basin. Over the last few years, we have continued to focus on higher-value unconventional production by exploiting seven discrete stacked pay horizons within the Monterey formation, primarily within the upper Monterey. We are seeking to duplicate our results there in the Kreyenhagen and Moreno formations which have similar geological attributes. Over the longer term, as project economics increase, we intend to pursue development opportunities in the lower Monterey shale, which contains a variety of reservoir lithologies, but has an extremely limited production history compared to the upper Monterey.

Over the past decade, we have also built a 3D seismic library that covers over 4,250 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. In recent years we have tested and successfully implemented various exploration, drilling, completion and enhanced recovery technologies to increase recoveries, growth and returns from our portfolio.

Our Business Strategy

We plan to drive long-term shareholder value by applying modern technology to develop our resource base and increase production. We have significant conventional opportunities to pursue, which we develop through their life-cycles to increase recovery factors by transitioning them from primary production to steamfloods, waterfloods and other enhanced recovery mechanisms. In the current price environment we are prioritizing oil projects that provide long-term stable cash flows with low production declines and high returns, such as steamfloods. The principal elements of our long-term business strategy include the following:

- ***Focus on high-margin crude oil projects to generate sufficient cash flows to internally fund our capital budget.*** We expect the percentage of our oil production to continue to increase over time and favorably impact our overall margins as we anticipate directing virtually all of our capital investments towards oil-weighted opportunities in 2015 and beyond to the extent the oil-to-gas price relationship remains favorable. Approximately 90% of our drilling inventory is associated with oil-rich projects. We intend to focus on increasing cost efficiencies and developing profitable opportunities in our portfolio in order to maintain self-funding throughout the commodity price cycle. We intend to reinvest substantially all of our operating cash flow in our capital investment program, while considering any potential deleveraging opportunities.
- ***Increase the share of conventional projects in our production mix to achieve lower declines and lower base maintenance capital requirements.*** Our portfolio of assets includes a large number of steamflood and waterflood projects that have much lower decline rates than many unconventional projects, while producing sufficient cash flow to self fund continued development. In the current commodity price environment, we intend to focus a greater portion of our capital investments in such projects, which we expect will result in lower decline rates in our production. Over time, we expect that this strategy will reduce the maintenance capital required to keep base production essentially flat. We have significant additional lower-risk conventional opportunities with over 15,000 identified drilling locations, 57% of which are associated with Improved Oil Recovery (''IOR'') and Enhanced Oil Recovery (''EOR'') projects. The remaining 43% are associated with primary recovery methods, many of which we expect will develop into IOR and EOR projects in the future.
- ***Continue to develop high-growth unconventional drilling opportunities.*** Over the longer term and in a higher oil-price environment, we expect significant production growth to come from unconventional reservoirs such as tight sandstones and shales. We would expect to generate sufficient cash flow from our conventional projects to fund numerous unconventional opportunities in our portfolio. We hold mineral interests in approximately 1.3 million net acres with unconventional potential and have identified 4,800 drilling locations on this acreage. As a result of our increased focus on these reservoirs over the past few years, a significant portion of our production now comes from unconventional assets. While we have not yet developed sufficient information to reliably predict success rates across our entire portfolio, our continued investment in unconventional projects is allowing us to better understand performance of these reservoirs in addition to improving our overall cycle time from project identification to development. As a result of our increased understanding of these reservoirs, we believe we will be able to direct our capital more precisely to higher value projects, allowing us to strategically increase our investment levels in unconventional drilling over time.
- ***Aggressively apply proven modern technologies to enhance production growth.*** Over the last several decades, the oil and gas industry has focused significantly less effort on utilizing modern development and exploration processes and technologies in California relative to other prolific U.S. basins. We believe this is largely due to other oil companies' limited capital investments in California, concentration on shallow zone thermal projects, or investments in other assets within their global portfolios. As an independent company focused exclusively on California, we intend to make significant use of proven modern technologies in drilling and completing wells, which we expect will substantially increase both our cost efficiency and production growth over time. We have developed an extensive 3D seismic library covering over 4,250 square miles in all four of our basins, representing approximately 90% of the 3D seismic data available for California, and have tested and successfully implemented various exploration, drilling, completion, IOR and EOR technologies in the state.

- ***Proactive and collaborative approach to safety, environmental protection, and community relations.*** We are committed to developing our assets in a manner that safeguards people and protects the environment. For example, we seek to proactively engage with regulatory agencies, communities, other stakeholders and our workforce to pursue mutually beneficial outcomes. As a California company, helping our state meet its water needs during the drought is a key strategic focus. Through our investments in water conservation and in recycling of produced water from oil and gas reservoirs, we are a net water supplier to agriculture. In 2014, our steamflood operations supplied a record 2 billion gallons of water to California's agriculture industry, providing more water for irrigation than the fresh water we purchased for our operations statewide. We continue to implement measures to further decrease our purchased fresh water, and are designing projects to expand the beneficial use of our produced water over the next few years.
- ***Continued focus on our successful exploration program.*** As market conditions warrant, we intend to significantly increase our investment in exploration, focusing on both unconventional and conventional opportunities, primarily in areas that we believe can be quickly developed, such as those adjacent to our existing properties. In addition, we plan to explore and test new unconventional resource areas, which, if successful, could result in significant longer-term production growth.

Our Competitive Strengths

We believe we are well-positioned to successfully execute our business strategies because of the following competitive strengths:

- ***Flexible asset base that works in different commodity price environments and preserves future value and growth potential.*** Our near 100% operational control of 137 fields in California provides us flexibility to adapt our investments to various market environments through our ability to select drilling locations, the timing of our development and the drilling and completion techniques we use. Our large and diverse acreage position, approximately 60% of which we hold in fee, allows us to choose among multiple recovery mechanisms, including primary conventional, steamflood, waterflood and unconventional and to develop various products, including oil, natural gas and natural gas liquids (''NGLs''). Approximately 90% of our drilling inventory is associated with oil-rich projects, primarily located in the San Joaquin, Los Angeles and Ventura basins, and the remaining inventory is associated with natural gas properties in the Sacramento, San Joaquin and Ventura basins. The variety of recovery mechanisms and product types available to us, together with our operating control, allows us to allocate capital in a manner designed to optimize cash flow over a wide range of commodity price environments and target drilling projects that are economically viable through commodity price cycles. The low base decline of our conventional assets allows our future cash flows to build as commodity pricing permits capital investments to resume at higher levels to achieve significant production growth rates over the longer term.
- ***Favorable margins driven by California's deficit energy market.*** We sell all of our crude oil into the California refining markets at prices we believe are among the most favorable in the United States. California imports over 60% of its oil and approximately 90% of its natural gas. A vast majority of the oil is imported via supertanker, with a minor amount arriving by rail. As a result, California refiners have typically purchased crude oil at international waterborne-based prices that have exceeded West Texas Intermediate (''WTI'') based prices for comparable grades in recent years. We believe that the limited crude transportation infrastructure from other parts of the country to California will contribute to higher realizations. In addition, we own the fee minerals on approximately 60% of our net acreage position. The returns on developed mineral fee acreage are greatly enhanced because we do not pay royalties and other lease payments.
- ***Largest acreage position in a world-class oil and natural gas province.*** We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.4 million net acres. California is one of the most prolific oil and natural gas producing regions in the world and is the third largest oil producing state in the nation. It has five of the 12 largest fields in the lower 48 states based on proved reserves as of 2009, and our portfolio includes interests in four of these fields. California is also the nation's largest state economy, and the world's seventh largest, with significant energy demands that exceed local supply. Our large acreage position with a diverse development portfolio enables us to pursue the appropriate production strategy for the relevant commodity price environment without the need

to acquire new acreage. For example, in a high natural gas price environment we can rapidly increase our investments in the Sacramento basin to generate significant production growth. Our large acreage position also allows us to quickly deploy the knowledge we gain in our existing operations, together with our seismic data, in other areas within our portfolio.

- ***Significant growth potential from opportunity rich drilling portfolio.*** Our drilling inventory at December 31, 2014 consisted of approximately 19,800 identified well locations, including 15,000 gross (12,700 net) conventional drilling locations and approximately 4,800 gross (4,400 net) unconventional drilling locations. We have a large inventory of conventional development opportunities that we expect will provide stable lower-risk, near-term production with attractive returns. We believe we can also achieve significant long-term production growth through the development of unconventional reservoirs.
- ***Proven operational management and technical teams with extensive experience operating in California.*** Our experienced operational management team and technical staff have a proven track record of applying modern technologies and operating methods to develop our assets. The members of our operational management and technical teams have an average of over 26 years' experience in the oil and natural gas industry, with an average of 17 years focused on California oil and gas operations.

Portfolio Management and 2015 Capital Budget

We develop our capital investment programs 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 the VCI metric for project selection and capital allocation across our portfolio of opportunities. The VCI for each project is calculated by dividing the present value of the project's pre-tax cash flow before capital over its life by the present value of the investment, using a 10% discount rate. Projects are expected to meet a VCI of 1.3, meaning that 30% of expected value is created above every dollar invested.

In light of current commodity prices, our focus on creating value and our commitment to internally fund our capital budget with operating cash flows, we have significantly reduced our capital investment budget for 2015 to $440 million, as compared to $2.1 billion in 2014. We have focused a substantial majority of our 2015 budget on our mature steamfloods, waterfloods and capital workovers, which have much lower decline rates than many unconventional projects. We will also continue to pursue and fund our most attractive unconventional projects.

Our 2015 capital investment budget targets investments in the San Joaquin, Los Angeles and Ventura basins, and is expected to be directed almost entirely towards oil-weighted production consistent with 2014. Of the total 2015 capital budget, approximately $150 million is expected to be allocated to drilling wells, $50 million to workovers, $130 million to additional steam-generation capacity and compression expansion, $15 million to exploration and the rest to 3D seismic, maintenance capital, occupational health, safety and environmental projects and other items. The table below sets forth the expected allocation of our 2015 capital budget by recovery mechanism.

	Total 2015 Capital Investments Budget
	(in millions)
Conventional:	
Primary recovery	$ 40
Waterfloods	175
Steamfloods	155
Total conventional	370
Unconventional	35
Exploration	15
Corporate and other	20
Total	$ 440

In addition, during this period of lower activity levels, we will deploy our resources to refine modern techniques that will enhance the value and growth potential of other parts of our portfolio that will not be funded in 2015 and will continue to build our inventory of available projects. This will position us to rapidly take advantage of improved market conditions when prices reach more favorable levels.

Reserves and Production Information

The table below summarizes our proved reserves and average production as of and for the year ended December 31, 2014 in each of California's four major oil and gas basins:

	Proved Reserves as of December 31, 2014						Average Net Daily Production for the Year Ended December 31, 2014		
	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)	Oil (%)	Proved Developed (%)	(MBoe/d)	Oil (%)	R/P Ratio (Years)(1)
San Joaquin Basin	340	82	621	525	65%	70%	112	57%	12.8
Los Angeles Basin	163	–	16	166	99%	76%	29	100%	15.7
Ventura Basin	48	3	37	58	83%	72%	9	69%	17.7
Sacramento Basin	–	–	116	19	–	94%	9	–%	5.8
Total operations	551	85	790	768	72%	72%	159	63%	13.2

Note: MMBbl refers to millions of barrels; Bcf refers to billion cubic feet of natural gas; MMBoe refers to million barrels of oil equivalent; and MBoe/d refers to thousands of barrels of oil equivalent per day.

(1) Calculated as total proved reserves as of December 31, 2014 divided by annualized Average Net Daily Production for the year ended December 31, 2014.

Marketing Arrangements

We market our crude oil, natural gas, NGLs and electricity in accordance with standard energy industry practices.

Crude Oil. Substantially all of our crude oil production is connected to California markets via our crude oil gathering pipelines which are used almost entirely for our production. We generally do not transport, refine or process the crude oil we produce and do not have any long-term crude oil transportation arrangements in place. California is heavily reliant on imported sources of energy, with over 60% of oil consumed during 2014 imported from outside the state, mostly from foreign locations. We sell all of our crude oil into the California refining markets, which we believe are among the most favorable in the U.S. Since California imports a significant percentage of its crude oil requirements, California refiners typically purchase crude oil at international waterborne-based prices that have exceeded WTI-based prices for comparable grades in recent years. Currently, we do not have any crude oil sales contracts with a term extending past 2015.

Given the recent volatile and deteriorating oil price environment, as well as our leverage, we began a hedging program shortly after the Spin-off to protect our down-side price risk and preserve our ability to execute our capital program. In December 2014, we purchased put options with a $50 per barrel Brent strike price, measured monthly. This initial program covers almost all of our oil production for the first six months of 2015. More recently, we put into place additional hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between $55 and $72) for 30,000 barrels per day for July through September as well as put options at $50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a $75 per barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

Natural Gas. Because California imports approximately 90% of the natural gas consumed in the state, we do not have any significant interstate natural gas transportation commitments. We do have intrastate transportation capacity contracts where necessary to access markets. These contracts are required 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 process substantially all of our NGLs through our processing plants, which facilitates access to third party delivery points near the Elk Hills field. We currently have pipeline capacity contracts to transport 10,000 barrels per day of NGLs to market and will add another 10,000 barrels per day of capacity beginning in the second quarter of 2015. We sell virtually all of our NGLs to third parties using index-based pricing. Our NGLs are generally sold pursuant to one-year contracts that are renewed annually.

Electricity. While part of the electricity output of our generation facilities is provided to our Elk Hills production facilities to reduce field operating costs, and increase operational reliability, we sell a significant portion into the California market. We offer excess electricity daily into the California electricity market that is sold based on market pricing and other requirements.

Our Principal Customers

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

For the years ended December 31, 2014, 2013 and 2012, ConocoPhillips/Phillips 66 Company and Tesoro Refining & Marketing Company LLC each accounted for more than 10% of our revenue. Collectively, they accounted for 45%, 42% and 46% in each of those years, respectively.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct a high level review of the title to our properties at the time of acquisition. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and 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. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of our properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations, or net profits interests, among others.

Competition

We have many competitors, some of which are larger and better funded, may be willing to accept greater risks or have special competencies. See ''Risk Factors.''

Regulation of the Oil and Natural Gas Industry

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, the production, transportation, and sale of our products, and the services we provide.

Regulation of Exploration and Production

California has regulations governing:

- the conservation of oil and natural gas, including provisions for the unitization or pooling of oil and natural gas properties;
- oil and natural gas production, including well spacing or density, on private and state lands;
- methods of drilling, constructing and completing wells;
- well stimulation techniques such as hydraulic fracturing and acid matrix stimulation;
- design, construction, operation and maintenance of facilities, such as natural gas processing plants, power plants, compressors and pipelines;
- improved or enhanced recovery techniques such as fluid injection for waterflooding or steamflooding;
- sourcing and disposal of water used in the drilling, completion, stimulation and enhanced recovery processes;
- posting of bonds or other financial assurance to drill or operate wells and facilities;
- imposition of taxes and fees with respect to our properties and operations; and
- occupational health, safety and environmental matters and the transportation and sale of our products as described below.

The Division of Oil, Gas, and Geothermal Resources (''DOGGR'') of the Department of Conservation is the State'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 federal Bureau of Land Management of the U.S. Department of the Interior exercises similar jurisdiction on federal lands in California. In addition, specific aspects of our operations, such as occupational health, safety, air or water quality, labor, marketing and taxation, are regulated by other federal, state or local agencies. Collectively, the effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill to levels below those that would otherwise be possible.

For example, in 2013, California adopted Senate Bill 4 (''SB 4''), which mandated further regulation of certain well stimulation techniques, including hydraulic fracturing and acid matrix stimulation. Among other things, SB 4 requires:

- new permitting of defined well stimulation treatments;
- prior notification to proximate property owners or lessees of proposed stimulation treatments, and pre- and post-stimulation groundwater sampling as requested by the owner or lessee;
- monitoring of groundwater quality in areas where well stimulation treatments occur, or concurrence that monitoring is not warranted due to a lack of protected water as defined by SB 4;
- public disclosure of stimulation data, including data that may be considered proprietary or trade secret; and
- state agencies to prepare an environmental impact report and scientific studies regarding well stimulation.

The initial implementation of interim well stimulation regulations under SB 4 in 2014 delayed certain operations, and the State's implementation of final SB 4 regulations and associated studies and reports may increase costs and cause additional delays.

Finally, the Safe Drinking Water Act and comparable state laws regulate the injection of produced water, steam or carbon dioxide into underground reservoirs for enhanced oil recovery or disposal. If the existing underground injection program is changed then our ability to inject produced water may be curtailed and our development and production activities may be negatively affected.

In addition, certain local governments have proposed or adopted ordinances that purport within their jurisdictions to regulate drilling activities in general, or stimulation and completion activities in particular, or to ban such activities outright. None of the adopted local ordinances is expected to materially impact our current or expected future operations. If new or more stringent federal, state, or local restrictions are adopted in areas where we operate, we could incur potentially significant added costs, experience delays or curtailment of our exploration or production activities and potentially be precluded from drilling wells. Our competitors in the California oil and natural gas industry are generally subject to the same laws and regulations that affect our operations.

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 costs or lower demand for or restrict the use of our products and services. Applicable federal health, safety and environmental laws include, but are not limited to, 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, National Environmental Policy 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. California imposes additional laws that are analogous to, and often more stringent than, such federal laws. These laws and regulations:

- require various permits and approvals before drilling, workovers, production, underground fluid injection, or solid and hazardous waste disposal commences, or before facilities are constructed or put into operation;

- require the installation of sophisticated safety and pollution control equipment 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 measures, and impose energy efficiency or renewable energy standards;
- restrict the types, quantities, and concentrations of regulated materials, including, without limitation, oil, natural gas, produced water or wastes, that can be released or discharged into the environment in connection with drilling, production, processing, power generation or transportation activities;
- limit or prohibit operations on lands lying within coastal, wilderness, wetlands, groundwater recharge, endangered species habitat, and other protected areas;
- establish standards for the closure, abandonment, cleanup or restoration of former operations, such as plugging of abandoned 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 or wastes 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 by governmental authorities, special interest groups and other claimants; and
- may restrict the rate of oil, NGLs, natural gas and electricity production below the rate that would otherwise be possible.

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.

Federal, state and local governments frequently revise health, safety and environmental laws and regulations, and any changes that result in delays or more stringent permitting, materials handling, engineering, disposal, cleanup and restoration requirements for the oil and gas industry could have a significant impact on our capital investments and operating costs. Failure to comply with existing or new laws and regulations may result in the assessment of administrative, civil, and/or criminal fines and penalties and liability for non-compliance, costs of corrective action, installation of pollution control equipment, cleanup and restoration, compensation for personal injury, property damage or other losses, and the imposition of injunctive or declaratory relief that may delay, modify or prevent development, construction or operations. Releases or discharges may occur in the course of our operations and may result in significant costs and liabilities, including governmental or third-party claims for personal injury or damage to property or natural resources.

Regulation of Climate Change and Greenhouse Gas (''GHG'') Emissions

A number of international, federal, state, and regional efforts seek to prevent or mitigate the effects of climate change or to track or reduce GHG emissions associated with industrial activity, including operations of the oil and natural gas production sector and those who use our products as a source of energy. The U.S. Environmental Protection Agency has adopted regulations to restrict GHG emissions from certain mobile sources, require certain operations, including onshore and offshore oil and natural gas production facilities, to monitor and report GHG emissions on an annual basis, and incorporate measures to reduce GHG emissions in permits for certain facilities.

In 2006, California adopted Assembly Bill 32 (''AB 32''), which established a statewide ''cap-and-trade'' program for GHG emissions. Under the program, which commenced in 2012, the California Air Resources Board (''CARB'') set a statewide maximum limit on total GHG emissions, and this cap declines annually through 2020. CARB requires us, and other businesses in the oil and natural gas production sector, to report GHG emissions. We are required to obtain allowances or qualifying offset credits for each metric ton of GHGs emitted from our operations and from the sale of certain products to customers for use in California. The state grants a portion of the allowance, but we must make up any shortfall by purchasing additional allowances from either the state or a third party. The availability of allowances will decline over time, and the cost to acquire such allowances may increase. The cap-and-trade program currently expires in 2020. A California Senate bill in 2014 proposed to extend the program to 2050. Although that bill was not adopted, similar legislation may be proposed in the future.

In 2015, the California cap-and-trade program began to cover emissions from the sale of propane and liquid transportation fuels for use in the state. Producers or marketers of propane and refiners of liquid transportation fuels will be responsible for retiring allowances equivalent to the metric tons of carbon dioxide estimated to be produced from the combustion of the propane and transportation fuels they market for use in California. Under AB 32, CARB has also imposed a ''low carbon fuel'' standard, which requires refiners to reduce the carbon content of transportation fuels they market in California by 10% by 2020. In January 2015, California's Governor proposed goals for 2030 to derive 50% of California's electricity from renewable sources, to reduce petroleum use in cars and trucks by 50% from current levels, and to double the energy efficiency of buildings in the state, and legislation has been proposed to implement these goals. These programs and policies, as well as federal and California subsidies and tax incentives for the development and construction of alternative energy-fueled power generation and transportation, may reduce demand for our products and services or require further controls on, or modifications to, our operations.

If we are unable to recover or pass through a significant portion of our costs related to complying with climate change regulations, these regulations could materially affect our operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of, and access to, capital. Future legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy.

Regulation of Transportation and Sale of Our Products

Our sales prices of oil, NGLs and natural gas are set by the market and are not presently regulated. Interstate transportation rates for oil, NGLs and other products are regulated by the Federal Energy Regulatory Commission (''FERC''). Our sales price for these products is affected by transportation costs. The FERC has established an indexing system for such transportation, which allows pipelines to take an annual inflation-based rate increase. We are not able to predict what effect, if any, these regulations will have on us, but, other factors being equal, the regulations may, over time, tend to increase transportation costs, which may affect our margins for oil and NGLs. Federal law currently restricts the export of domestically produced oil, with certain exceptions, such as for a limited quantity of California heavy crude oil. If these restrictions were lifted, we may be able to sell our oil production in additional markets, which may increase prices we realize.

Market Manipulation and Market Transparency Regulations

Under the Energy Policy Act of 2005, the FERC possesses regulatory oversight over natural gas markets to prevent market manipulation. The Federal Trade Commission has similar regulatory oversight of oil markets to prevent market manipulation. The Commodity Futures Trading Commission (''CFTC'') also holds authority over the physical and futures energy commodities market pursuant to the Commodity Exchange Act. We are required to observe these laws and related regulations when we engage in physical purchases and sales of oil, NGLs and natural gas and when we engage in hedging activity. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. We could also be subject to related third-party damage claims for violation of these laws brought by, among others, sellers, royalty owners and taxing authorities. In addition, the FERC has issued market transparency rules for natural gas that affect some of our operations and impose reporting and other obligations on us.

Natural Gas Gathering Regulations

Section 1(b) of the federal Natural Gas Act exempts natural gas gathering facilities from the jurisdiction of the FERC. We own certain natural gas pipelines that we believe meet the traditional tests that FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. The distinction between FERC-regulated transmission facilities and federally unregulated gathering facilities is, however, the subject of ongoing litigation, and is otherwise subject to potential change.

In addition to the federal and state laws described above under the heading ''Business—Regulation of Health, Safety and Environmental Matters,'' our natural gas gathering operations are subject to state statutes designed to prohibit discrimination favoring producers or sources of supply. The regulations may restrict those with whom we contract to gather natural gas. In addition, our natural gas gathering operations could become subject to more stringent application of state or federal regulation of rates and services, though we do not believe any such action would affect us materially differently than our competitors.

Regulation of Power Sales and Transmission

The FERC regulates the sale of electricity at wholesale and the transmission of electricity under the Federal Power Act. The FERC's jurisdiction includes, among other things, authority over the rates, charges and other terms for the sale of electricity at wholesale by public utilities and for transmission services. In most cases, the FERC does not set rates for the sale of electricity at wholesale by generating companies (such as our subsidiary) that qualify for market-based rate authority, which allows companies to negotiate market rates. In order to be eligible for market-based rate authority, and to maintain exemptions from certain FERC regulations, our subsidiary has been granted market-based rate authorization from the FERC.

Employees

As of December 31, 2014, we had approximately 1,990 employees. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. Approximately 80 of our employees are represented by labor unions. We have not experienced any strikes or work stoppages by our employees in the past 35 years or longer. 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.

Effective January 1, 2015, we adopted the California Resources Corporation 2014 Employee Stock Purchase Plan (the "ESPP"). The ESPP will provide 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. As of January 1, 2015, about 45% of our employees have elected to participate in the plan.

Available Information

We make the following information available free of charge on our website at www.crc.com:

- Forms 10-K, 10-Q, 8-K and amendments to these forms as soon as reasonably practicable after they are electronically filed with, or furnished to, the Securities and Exchange Commission (SEC);
- Other SEC filings including Forms 3, 4, 5 and 10; and
- Corporate governance information, including our corporate governance guidelines, board-committee charters and code of business conduct (see Part III, Item 10, of this report for further information).

Information contained on our website is not part of this report.

ITEM 1A RISK FACTORS

RISK FACTORS

We are subject to certain risks and hazards due to the nature of the business activities we conduct. The risks discussed below, any of which could materially and adversely affect our business, financial condition, cash flows and results of operations, are not the only risks we face. We may experience additional risks and uncertainties not currently known to us or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may ultimately materially and adversely affect our business, financial condition, cash flows and results of operations.

Risks Related to Our Business

Commodity pricing can fluctuate widely and strongly affects our results of operations, financial condition, cash flow and ability to grow.

Our financial results, financial condition, cash flow and rate of growth correlate closely to the prices we obtain for our products. Recently, global energy commodity prices have declined significantly. For example, Brent crude prices have declined from over $115 per barrel in June 2014 to below $47 per barrel in January 2015. In a declining price environment we may incur costs to terminate drilling rig contracts, and may be required to write-down property values, such as we did in recent months. Product prices can fluctuate widely and are affected by a variety of factors, including changes in consumption patterns, global and local (particularly for natural gas) economic conditions, the actions of OPEC and other oil and natural gas producing countries, inventory levels, actual or threatened production disruptions, currency exchange rates, worldwide drilling and exploration activities, the effects of conservation, weather, geophysical and technical limitations, refining and processing disruptions, transportation bottlenecks and other matters affecting the supply and demand dynamics of oil, natural gas and NGLs, and the effect of changes in market perceptions. These and other factors make it impossible to predict realized prices reliably. In addition, any significant increase in transportation infrastructure that increases the importation of crude oil to California from other parts of the country could negatively impact the price we receive for our crude oil.

Any sustained periods of low prices for oil and natural gas may materially and adversely affect our financial position, the quantities of natural gas and oil reserves that we can economically produce, our cash flow available for capital investments and our ability to access funds under our revolving credit facility and through the capital markets.

We have significant indebtedness and may incur more debt. Higher levels of indebtedness could make us more vulnerable to economic downturns and adverse developments in our business.

As of December 31, 2014, we had $6.36 billion of consolidated indebtedness, comprising $5.0 billion of senior notes, $1.0 billion of borrowings outstanding under our term loan facility and $360 million of borrowings outstanding under our revolving credit facility, and we had the ability to incur $1.64 billion of additional borrowings under our revolving credit facility, which has effectively been reduced under the first amendment to our credit facilities discussed in ''Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources''. As of December 31, 2014, we had letters of credit in an aggregate amount of approximately $25 million that were issued to support ordinary course marketing, regulatory and other matters. In addition, the indenture relating to the notes and the credit facilities (as defined in ''Management's Discussion and Analysis of Financial Condition and Results of Operation-Liquidity and Capital Resources-Credit Facilities'') permits us to incur certain defined obligations, unrestricted by debt incurrence or lien covenants, or that do not constitute indebtedness (as defined in ''Management's Discussion and Analysis of Financial Condition and Results of Operation-Liquidity and Capital Resources-Credit Facilities'').

Indebtedness outstanding under our credit facilities bears interest at a variable rate, therefore a rise in interest rates will generate greater interest expense if and to the extent we do not purchase interest rate hedges.

Our level of indebtedness will have several important effects on our future operations, including, without limitation:

- increasing our vulnerability to adverse changes in our business and to general economic and industry conditions, and putting us at a disadvantage against other competitors that have lower fixed obligations and more cash flow to devote to their businesses;
- limiting our ability to obtain additional financing for working capital, capital investments, general corporate and other purposes; and
- limiting our flexibility in operating our business and preventing us from engaging in certain transactions that might otherwise be beneficial to us.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that may be unattractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness. Any of these factors could result in a material adverse effect on our business, financial condition, results of operations, cash flow and ability to satisfy our obligations under the notes.

Our business requires substantial capital investments. We may be unable to fund these investments through operating cash flow or obtain any needed additional capital on satisfactory terms or at all, 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.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital investments for the development and exploration of oil and gas reserves. We have developed a multi-year capital investment program to execute our strategy. We invested approximately $2.1 billion of capital on development and exploration activities during the year ended December 31, 2014, funded by our operating cash flow of $2.4 billion. Under our 2015 capital budget, we plan to invest approximately $420 million for development and exploration activities.

Our ability to deploy capital as planned depends on a number of variables, including: (i) commodity prices and sales point disruptions; (ii) regulatory and third-party approvals; (iii) our ability to timely drill wells due to technical factors and contract terms; (iv) the availability of capital, equipment, services and personnel; and (v) drilling and completion costs and results. Because of these and other potential variables, we may be unable to deploy capital in the manner planned and actual development activities may materially differ from those presently anticipated.

We intend to finance our future capital investments, other than any significant acquisitions, primarily through cash flow from operations and, if necessary, through borrowings under our Revolving Credit Facility or the issuance of debt or equity securities. We may not generate sufficient cash flow to fund our growth plans or to generate acceptable returns. Additional financing may not be available on acceptable terms or at all if there is not market demand or if our lenders refuse to exercise their discretion to expand our existing credit. In the event additional capital is needed and unavailable, we may curtail drilling, development and other activities or be forced to sell assets on an unfavorable basis.

Our business is highly regulated and governmental authorities can delay or deny permits and approvals or change legal requirements governing our operations, including hydraulic fracturing and other well stimulation, enhanced production techniques and fluid disposal, that could increase costs, restrict operations and delay our implementation of, or cause us to change, our business strategy.

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, the production, transportation and sale of our products, and the services we provide. See ''Business-Regulation of the Oil and Natural Gas Industry'' for a description of the 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 governmental authorities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal fines and penalties and liability for non-compliance, 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 limiting our 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.

Costs of compliance may increase or 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. Certain government agencies have adopted or proposed new or more stringent requirements for permitting, well construction, public disclosure or environmental review of, or restrictions on, certain oil and gas operations, including drilling, well stimulation, enhanced production techniques or fluid disposal. Such new requirements or restrictions or resulting litigation could result in potentially significant added costs to comply, delay or curtail our exploration, development, or production activities, and preclude us from drilling or stimulating wells, which could impair our expected production growth over the longer term. For example, in 2013, California adopted SB 4, which mandated further regulation of certain well stimulation techniques, including hydraulic fracturing.

The implementation of interim well stimulation regulations under SB 4 in 2014 delayed certain operations, and California's implementation of final SB 4 regulations and associated studies and reports may increase costs and cause additional delays. In addition, certain local governments have proposed or adopted ordinances that purport, within their jurisdictions, to regulate certain drilling activities in general, or well stimulation or completion activities in particular, including hydraulic fracturing, or to ban such activities outright.

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.

Exploration is inherently risky and its results are unpredictable. The results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production, and we may increase the proportion of our drilling in new or emerging plays over time. We may not find commercial amounts of oil or natural gas, in which 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 our ability, the timing or the cost to develop this asset.

Tax law changes may adversely affect our operations.

In California, there have been proposals for tax increases for the past several years including a severance tax as high as 12.5% on oil, natural gas and NGLs production in California. Although the proposals have not become law, well-funded campaigns by various interest groups could lead to future oil and gas severance taxes. The imposition of such a tax could severely reduce our profit margins and cash flow and could ultimately result in lower oil and natural gas production, which may reduce our capital investments and growth plans.

In addition, President Obama's budget proposal for fiscal year 2016 recommended the elimination of certain federal income tax preferences currently available to oil and gas exploration and production companies all of which could harm us. These changes include (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of expensing intangible drilling costs, (iii) an increase in the amortization period from two years to seven years for geophysical costs paid or incurred by independent producers in connection with the exploration for, or development of, oil or natural gas and (iv) repeal of the ability to claim the domestic manufacturing deduction against income derived from the sale or exchange of oil, natural gas or primary products produced in the United States.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our decisions to explore, develop, purchase or otherwise exploit prospects or properties will depend in part on the evaluation of geophysical, geologic, engineering, production and other technical data, the analysis of which is often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is also often uncertain. Overruns in budgeted investments are a common risk that can make a particular project uneconomical or less economical than forecast. We bear the risks of equipment failures, accidents, environmental hazards, adverse weather conditions, permitting or construction delays, title disputes, surface access disputes, disappointing drilling results or reservoir performance, including response to IOR or EOR efforts, and other associated risks.

We operate in a highly competitive environment for oilfield equipment, services, qualified personnel and acquisitions.

We compete for services to profitably develop our assets, to find or acquire additional reserves and to attract and retain qualified personnel. We have many competitors, some of which: (i) are larger and better funded; (ii) may be willing to accept greater risks or (iii) have special competencies. Historically, there have been periodic shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. The demand for qualified and experienced geologists, geophysicists and engineers, and for field and other personnel to drill wells, conduct field operations and construct and maintain facilities, can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages which may increase costs for such services. Finally, competition for reserves can make it more difficult to find attractive investment opportunities or require delay of reserve replacement efforts.

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, which may ultimately prove to be inaccurate.

The reserves information included in this report represents estimates prepared by internal engineers. The procedures and methods used to estimate our reserves by these internal engineers were reviewed by independent petroleum consultants; however, no audit of estimated reserve volumes was conducted by these consultants. Reserves estimation is a partially subjective process of estimating accumulations of oil and natural gas. Estimates of economically recoverable oil and gas reserves and of future net cash flows 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 remedial costs.

Misunderstanding of the variables, inaccurate assumptions, changed circumstances or new information could require us to make significant negative reserve revisions.

We currently expect improved recovery, extensions and discoveries to be our main sources for reserve additions, but factors such as geology, government regulations and permits and the effectiveness of development plans are partially or fully outside management's control and could cause unforeseen results.

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 geographically concentrated exclusively in California. Because of this geographic concentration, the success and profitability of our operations may be disproportionately exposed to the effect of regional events. These include, among others, fluctuations in the prices of crude oil and natural gas produced from wells in the region, changes in state or regional laws and regulations affecting our operations, and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints, available rigs, equipment, oil field services, supplies, labor and infrastructure capacity. The concentration of our operations in California also increases exposure to unexpected events that may occur in this region such as natural disasters, industrial accidents or labor difficulties. 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 and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our financial condition, results of operations and cash flows.

Restrictions on our ability to obtain, use, manage or dispose of water may have an adverse effect on our operations.

Water is an essential component of our operations. Approximately 90% of the fluids we produce are brackish waters, unsuitable for agricultural use, that need to be managed, recycled or disposed. We treat and re-use this water for a substantial portion of our needs related to activities such as steamflooding, waterflooding, pressure management, well completion and stimulation, including hydraulic fracturing, and we provide water for agricultural use in certain areas. We also use supplied water from various local and regional sources. Some of our fields are more dependent on supplied water to support operations like steam injection. Due to severe drought in California, some local and regional water districts and the state government are implementing policies or regulations that restrict water usage and increase the cost of water.

Existing regulations restrict our ability and increase our cost to manage and dispose of wastewater. The federal Clean Water Act and Safe Drinking Water Act and similar state laws impose restrictions and strict controls on the discharge of produced waters and waste and the subsurface injection of fluids. We must obtain permits or waivers for certain discharges and for construction activities that may affect regulated water resources. In addition, certain government agencies have investigated and continue to study whether fluid injection can induce ground movement or seismicity. Our enhanced production operations or fluid disposal could give rise to litigation over claims related to alleged damage to the environment or private or public property. The laws, regulations, policies and attendant liabilities relating to water use, wastewater disposal and fluid injection could increase our costs and negatively affect our development and production activities.

Our Area of Mutual Interest (''AMI'') Agreement may limit our ability to operate outside of California.

In connection with the Spin-off, we entered into an AMI Agreement, which provides Occidental with the right to acquire a 51% interest in, and rights with respect to, certain oil and gas properties we acquire in the United States, other than in the State of California, for five years following the completion of the Spin-off. If we were to change our current strategy of focusing exclusively on opportunities in California, the AMI Agreement could adversely affect our ability to pursue opportunities outside of California during the five years following the Spin-off.

We may not drill our identified sites at the times we scheduled or at all and sites we decide to drill may not yield crude oil or natural gas in economically producible quantities.

We have specifically identified locations for scheduled drilling over the next several years. These drilling locations represent a significant part of our long-term growth strategy. Our ability to profitably drill and develop these locations depends on a number of variables, including crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals, available transportation capacity and other factors. 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 view the risk profile for our exploration drilling locations and our prospective resource drilling locations as being higher than for our other drilling locations due to relatively less available geologic and production data and drilling history, in particular with respect to our prospective resource locations, which are in unproven geologic plays. We make assumptions about the consistency and accuracy of data when we identify these locations that may prove inaccurate. We cannot guarantee that these prospective 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 represents 23% of our total net undeveloped acreage at December 31, 2014. Our actual drilling activities may materially differ from those presently identified.

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity-price, interest-rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (''Dodd-Frank Act''), enacted in 2010, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, like us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when this will be accomplished.

The CFTC is authorized to set position limits for certain futures contracts in designated physical commodities and for economically equivalent options and swaps. In November 2013, the CFTC proposed rules that would place limits on positions in certain futures and equivalent swap contracts for, or linked to, certain physical commodities; subject to exceptions for certain bona fide hedging transactions. We do not know when the CFTC will finalize these regulations; therefore, the impact of those provisions on us is currently uncertain.

The CFTC designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. In addition, the Dodd-Frank Act requires that regulators establish margin rules for uncleared swaps. The application of such requirements may indirectly change the cost and availability of the swaps that we may use for hedging.

The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter or reduce our ability to monetize or restructure derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

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

To the extent that we engage in commodity-price risk management activities to protect our cash flows from commodity-price declines, we may be prevented from realizing the full benefits of price increases above the levels stated in the derivative instruments used to manage price risk. In addition, our commodity-price risk-management and trading activities may expose us to the risk of financial loss in certain circumstances, including instances in which the following occur:

- our production is less than the notional volumes;
- a change in price basis differentials;
- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements; and
- an event materially impacts oil and natural-gas prices.

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

Climate change, the costs that may be associated with its effects and the regulation of GHGs may 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. In addition, legislative and regulatory responses to climate change may increase our operating costs. In 2006, California adopted AB 32, which established a statewide cap on GHG emissions, including on the oil and natural gas production industry, and a ''cap-and-trade'' program. Since 2012, CARB regulations have required us to obtain GHG emissions allowances corresponding to reported GHG emissions from operations and, starting in 2015, from the sale of certain products to customers for use in the State. In 2014, we incurred approximately $33 million to purchase mandatory GHG emissions allowances in California, and costs of such allowances are expected to increase in the future as CARB reduces the number of available allowances, increases their targeted price and covers more operations and products in the program. In addition, other CARB regulations, state policies and proposed legislation seek to restrict or reduce the use of petroleum products in transportation fuels and electricity generation in California and require the use of renewable energy, which could increase our costs and reduce the demand for our products and services.

Federal and state regulatory agencies 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. In addition, California air quality laws and regulations, particularly in Southern and Central California where most of our operations are located, are in many instances more stringent than comparable federal laws and regulations. As these requirements become more stringent, we may be unable to implement them in a cost-effective manner. As a result of existing and future air quality initiatives, we could face risks of increased costs and taxes, an inability to execute projects and reduced demand for our products and services.

Risks related to our acquisition activities could negatively impact our financial condition and results of operations.

Our acquisition activities carry risks that we may: (i) not fully realize anticipated benefits due to less-than-expected reserves or production or changed circumstances, such as the deterioration of natural gas prices in recent years and oil prices in recent months; (ii) bear unexpected integration costs or experience other integration difficulties; (iii) experience share price declines based on the market's evaluation of the activity or (iv) assume liabilities that are greater than anticipated.

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.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware or for which we are unable to obtain indemnity.

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, including well stimulation and completion activities, are subject to operating risks associated with drilling for and producing oil and natural gas, such as well blowouts, fires, explosions, releases or discharges of hazardous or toxic materials and industrial accidents. Other catastrophic events such as earthquakes, floods, mudslides, droughts, terrorist attacks and other events that cause operations to cease or be curtailed may negatively affect our business 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.

Cyber attacks could significantly affect us.

Cyber attacks on businesses have escalated in recent years. We rely on electronic systems and networks to communicate, control and manage our operations and prepare our financial management and reporting information. If we were to experience an attack and our security measures failed, the potential consequences to our business and the communities in which we operate could be significant.

Operational issues could restrict access to markets for the commodities we produce.

Our ability to market our production of oil, natural gas and NGLs depends on a number of factors, including the proximity of production fields to pipelines and terminal facilities, competition for capacity on such facilities, the ability of such facilities to gather, transport or process our products and regional disruptions, such as strikes and mechanical failures. If our access to markets for commodities we produce is restricted, our costs could increase and our expected production growth may be impaired.

Risks Related to the Spin-off

We may not realize the anticipated benefits from our separation from Occidental.

We may not realize the benefits that we anticipate from our separation from Occidental. These benefits include the following:

- enhancing our ability to grow by reinvesting substantially all of our cash flow in our business;
- enhancing growth and efficiency by enabling our management team to focus its attention on the development and execution of our business in a single state;
- enhancing our focus on, and accelerating our technical expertise in, specific reservoirs and fields in California; and
- enhancing our market recognition with investors because of our status as an industry leader in California.

We may not achieve the anticipated benefits from our separation for a variety of reasons. We may not generate sufficient cash flow to fund our long-term growth plans and to generate acceptable returns. We also may not fully realize the anticipated benefits from our separation if any of the other matters identified as risks in this ''Risk Factors'' section were to occur.

Our historical financial information may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.

The historical financial information included in this Form 10-K has been derived partly from Occidental's accounting records and may not reflect what our financial position, results of operations or cash flows would have been had we been an independent, stand-alone entity during the periods presented or those that we will achieve in the future. Occidental did not account for us, and we were not operated, as a separate, stand-alone company or as a separate segment for the historical periods presented. The costs and expenses reflected in our historical financial information include an allocation for certain corporate functions historically provided by Occidental, including expense allocations for: (i) executive oversight, accounting, procurement, engineering, drilling, exploration, finance, internal audit, legal, risk management, tax, treasury, information technology, government relations, investor relations, public relations, financial reporting, human resources, marketing, ethics and compliance, and certain other shared services; (ii) certain employee benefits and incentives and (iii) share-based compensation, that may be different from the comparable expenses that we would have incurred had we operated as a stand-alone company. We have allocated these expenses in our historical financial information on the basis of direct usage when identifiable, with the remainder allocated based on estimated time spent by Occidental personnel, headcount or our relative size compared to Occidental and its subsidiaries. The costs of operating as a stand-alone public company, other than the debt-related costs, may be slightly higher than the costs reported in the 2014 historical financial statements. These estimates may not prove to be accurate. Our capital investment requirements, including acquisitions, historically have been satisfied as part of the companywide cash management practices of Occidental. Following the Spin-off, we no longer have access to Occidental's working capital, and we may need to obtain additional financing from banks, through public offerings or private placements of debt or equity securities or other arrangements if our cash flow from operations and our existing credit facilities are not sufficient to fund our capital investment requirements.

In connection with our separation from Occidental, we agreed to indemnify Occidental for certain liabilities, including those related to the operation of our business while it was still owned by Occidental, and Occidental agreed to indemnify us for certain liabilities, which indemnities may not be adequate.

Pursuant to agreements with Occidental, Occidental has indemnified us for certain liabilities, and we agreed to indemnify Occidental for certain liabilities, in each case for uncapped amounts. Indemnity payments that we may be required to provide Occidental may be significant and could negatively impact our business, particularly indemnity payments relating to our actions that could impact the tax-free nature of the Spin-off. Third parties could also seek to hold us responsible for liabilities that Occidental has agreed to retain. Further, there can be no assurance that the indemnity from Occidental will be sufficient to protect us against the full amount of such liabilities, or that Occidental will be able to fully satisfy its indemnification obligations. Moreover, even if we ultimately succeed in recovering from Occidental any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves.

Our costs may increase as a result of operating as a stand-alone public company, and our management will be required to devote substantial time to complying with public company regulations.

Prior to the Spin-off, our operations were fully integrated within Occidental, and we relied on Occidental to provide certain corporate functions. As a stand-alone public company, we may incur additional expenses for executive oversight, accounting, finance, risk management, treasury, tax, financial reporting, internal audit, legal, information technology, governmental relations, public relations, investor relations, human resources, procurement, engineering, drilling, exploration, ethics and compliance, marketing and certain other services that we have not incurred historically. As part of Occidental, we were able to enjoy certain benefits from Occidental's scale and purchasing power. As an independent, publicly traded company, we do not have similar negotiating leverage.

In addition, we are now obligated to file with the SEC annual and quarterly information and other reports, and, as a result, must ensure that we have the ability to prepare financial statements that are fully compliant with all SEC reporting requirements on a timely basis. In addition, we are now subject to other reporting and corporate governance requirements, including certain requirements of the NYSE, and certain provisions of the Sarbanes-Oxley Act of 2002, and the regulations promulgated thereunder, which impose significant compliance obligations and costs upon us.

Our Tax Sharing Agreement with Occidental may limit our ability to take certain actions, including strategic transactions, and may require us to indemnify Occidental for significant tax liabilities.

Under the Tax Sharing Agreement, we have agreed to take certain actions or refrain from taking certain actions to ensure that the Spin-off and certain transactions taken in preparation for, or in connection with, the Spin-off, qualify for tax-free status under the relevant provisions of the Internal Revenue Code of 1986, as amended (the "Code"). We have also made various other covenants in the Tax Sharing Agreement intended to ensure the tax-free status of the Spin-off. These covenants restrict our ability to sell assets outside the ordinary course of business, to issue or sell additional common stock or other securities (including securities convertible into our common stock), or to enter into certain other corporate transactions. For example, for a period of two years after the final disposition of the securities retained by Occidental after the Spin-off, absent approval by Occidental, we may not enter into any transaction that would be reasonably likely to cause us to undergo either a 30% or greater change in the ownership of our voting stock or a 30% or greater change in the ownership (measured by value) of all classes of our stock.

We have agreed to indemnify Occidental for (a) taxes incurred as a result of the failure of the Spin-off or certain transactions undertaken in preparation for, or in connection with, the Spin-off, to qualify as tax-free transactions under the relevant provisions of the Internal Revenue Code of 1986, as amended, to the extent caused by (i) our breach of certain tax-related representations or covenants made in connection with the Spin-off, (ii) actions, failures to act and omissions inconsistent with such representations and covenants and (iii) certain permitted transactions, (b) our separate taxes due to capitalization of intangible drilling and development costs, (c) any finally determined increases of our liability for separate tax items included in combined or consolidated Occidental returns, and (d) 50% of certain sales, use, transfer, real property transfer, intangible, recordation, registration, documentary, stamp and similar taxes. We also have agreed to pay 50% of any taxes arising from the Spin-off or related transactions to the extent that the tax is not attributable to the fault of either party. However, if we receive an increase in the tax basis of our depletable, depreciable or amortizable assets as a result of any such tax begin imposed, we will pay to Occidental any amount equal to any reduction in our tax liability attributable to such basis increase at the time such reduction in tax liability arises. In addition, we have agreed to indemnify Occidental and its remaining subsidiaries against claims and liabilities relating to the past operation of our business.

We could have significant tax liabilities for periods during which Occidental operated our business.

For any tax periods (or portion thereof) in which Occidental owned at least 80% of the total voting power and value of our common stock, we and our subsidiaries will be included in Occidental's consolidated group for federal income tax purposes. In addition, we or one or more of our subsidiaries may be included in the combined, consolidated or unitary tax returns of Occidental or one or more of its subsidiaries for state or local income tax purposes. Under the Tax Sharing Agreement, for each period in which we or any of our subsidiaries are consolidated or combined with Occidental for purposes of any tax return, and with respect to which such tax return has not yet been filed, we will pay Occidental for any additional taxes payable by Occidental resulting from Occidental's election to capitalize some or all of certain CRC intangible drilling costs. We will also be responsible for any increase in Occidental's federal or state tax liability for any period in which we or any of our subsidiaries are combined or consolidated with Occidental if such increase results from audit adjustments attributable to our business. In addition, by virtue of Occidental's controlling ownership and the Tax Sharing Agreement, Occidental will effectively control all of our tax decisions in connection with any consolidated, combined or unitary income tax returns in which we (or any of our subsidiaries) are included. The Tax Sharing Agreement provides that Occidental will have sole authority to respond to and conduct all tax proceedings (including tax audits) relating to us, to prepare and file all consolidated, combined or unitary income tax returns in which we are included on our behalf (including the making of any tax elections). This arrangement may result in conflicts of interest between Occidental and us. For example, under the Tax Sharing Agreement, Occidental will be able to choose to contest, compromise or settle any adjustment or deficiency proposed by the relevant taxing authority in a manner that may be beneficial to Occidental and detrimental to us.

Moreover, notwithstanding the Tax Sharing Agreement, federal law provides that each member of a consolidated group is liable for the group's entire tax obligation. Thus, to the extent Occidental or other members of Occidental's consolidated group fail to make any federal income tax payments required by law, we could be liable for the shortfall with respect to periods in which we were a member of Occidental's consolidated group. Similar principles may apply for state or local income tax purposes where we file combined, consolidated or unitary returns with Occidental or its subsidiaries for federal, foreign, state or local income tax purposes.

The amount of tax for which we are liable for taxable periods preceding the Spin-off may be impacted by elections Occidental makes on our behalf.

Under the Tax Sharing Agreement, Occidental will have the right to make all elections, including elections to capitalize intangible drilling costs, relevant to the determination of our tax liability for periods while we, or any of our subsidiaries, are required to file tax returns with Occidental on a consolidated or combined basis or which include pre-Spin-off periods. As a result, the amount of tax for which we are liable for taxable periods preceding the Spin-off may be impacted by elections Occidental makes on our behalf.

We could have significant tax liabilities if the Spin-off, and certain transactions in preparation therefore, are not tax-free.

In certain circumstances, if the Spin-off is determined to be taxable for U.S. federal income tax purposes, we could incur significant liabilities under a tax-sharing agreement between us and Occidental. Occidental has received a private letter ruling from the IRS to the effect that certain aspects of the transactions that will be undertaken in preparation for, or in connection with, the Spin-off will not cause the distribution to be taxable to Occidental or its affiliates. Occidental also received opinions from tax counsel that (i) certain transactions that will be undertaken in preparation for, or in connection with, the Spin-off will not be taxable to Occidental or its affiliates for federal income tax purposes and (ii) the Spin-off generally qualifies as a tax-free transaction under Sections 355, 361 and/or 368(a)(1)(D) of the Code. The private letter ruling relies and the opinions rely on facts, assumptions, representations and undertakings from Occidental and us regarding the past and future conduct of the companies' respective businesses and other matters. If any of these facts, assumptions, representations, or undertakings are, or become, incorrect or not otherwise satisfied, Occidental may not be able to rely on the private letter ruling or the opinions of its tax advisor and could be subject to significant tax liabilities. In addition, an opinion of counsel is not binding upon the IRS, so, notwithstanding the opinions of Occidental's tax advisor, the IRS could conclude upon audit that the Spin-off is taxable in full or in part. The IRS may determine that the Spin-off is taxable for other reasons, including as a result of certain significant changes in the stock ownership of Occidental or us after the Spin-off.

Several members of our board of directors and management may have actual or potential conflicts of interest because of their ownership of shares of common stock of Occidental and the overlap of one member of our Board with the board of directors of Occidental.

Several members of our board of directors and management will initially own common stock of Occidental or options to purchase common stock of Occidental, because of their current or prior relationships with Occidental, which could create, or appear to create, potential conflicts of interest when our directors and executive officers are faced with decisions that could have different implications for Occidental and us. In addition, the board of directors of each of CRC and Occidental have one member in common, which could create actual or potential conflicts of interest.

The Spin-off may expose us to potential liabilities arising out of state and federal fraudulent conveyance laws and legal dividend requirements.

The Spin-off is subject to review under various state and federal fraudulent conveyance laws. Under these laws, if a court in a lawsuit by an unpaid creditor or an entity vested with the power of such creditor (including a trustee or debtor-in-possession in a bankruptcy by us or Occidental or any of our respective subsidiaries) were to determine that Occidental or any of its subsidiaries did not receive fair consideration or reasonably equivalent value for distributing our common stock or taking other action as part of the Spin-off, or that we or any of our subsidiaries did not receive fair consideration or reasonably equivalent value for incurring indebtedness, including the new debt incurred by us in connection with the Spin-off, transferring assets or taking other action as part of the Spin-off and, at the time of such action, we, Occidental or any of our respective subsidiaries (i) was insolvent or would be rendered insolvent, (ii) had unreasonably small capital with which to carry on its business and all business in which it intended to engage or (iii) intended to incur, or believed it would incur, debts beyond its ability to repay such debts as they would mature, then such court could void the Spin-off as a constructive fraudulent transfer. The court could impose a number of different remedies, including voiding our liens and claims against Occidental, or providing Occidental with a claim for money damages against us in an amount equal to the difference between the consideration received by Occidental and the fair market value of our company at the time of the Spin-off.

The measure of insolvency for purposes of the fraudulent conveyance laws will vary depending on which jurisdiction's law is applied. Generally, however, an entity would be considered insolvent if the present fair saleable value of its assets is less than (i) the amount of its liabilities (including contingent liabilities) or (ii) the amount that will be required to pay its probable liabilities on its existing debts as they become absolute and mature. No assurance can be given as to what standard a court would apply to determine insolvency or that a court would determine that we, Occidental or any of our respective subsidiaries were solvent at the time of or after giving effect to the Spin-off, including the distribution of our common stock.

Under the Separation and Distribution Agreement, from and after the Spin-off, each of Occidental and CRC will be responsible for the debts, liabilities and other obligations related to the business or businesses which it owns and operates following the consummation of the Spin-off, and each of Occidental and CRC will assume or retain certain liabilities for the operation of our respective businesses prior to the Spin-off and certain liabilities related to the Spin-off. Although we do not expect to be liable for any such obligations not expressly assumed by us pursuant to the Separation and Distribution Agreement, it is possible that a court would disregard the allocation agreed to between the parties, and require that we assume responsibility for obligations allocated to Occidental, particularly if Occidental were to refuse or were unable to pay or perform the subject allocated obligations.

The agreements between us and Occidental were not made on an arm's-length basis.

The agreements we entered into with Occidental in connection with the Spin-off, were negotiated in the context of the Spin-off while we were still a wholly-owned subsidiary of Occidental. Accordingly, during the period in which the terms of those agreements were negotiated, we did not have an independent board of directors or a management team independent of Occidental. As a result, the terms of those agreements, including those that are discussed elsewhere, may be unfavorable and may not reflect terms that would have resulted from arm's-length negotiations between unaffiliated third parties. The terms relate to, among other things, the allocation of assets, liabilities, rights and other obligations between Occidental and us.

ITEM 1B Unresolved Staff Comments

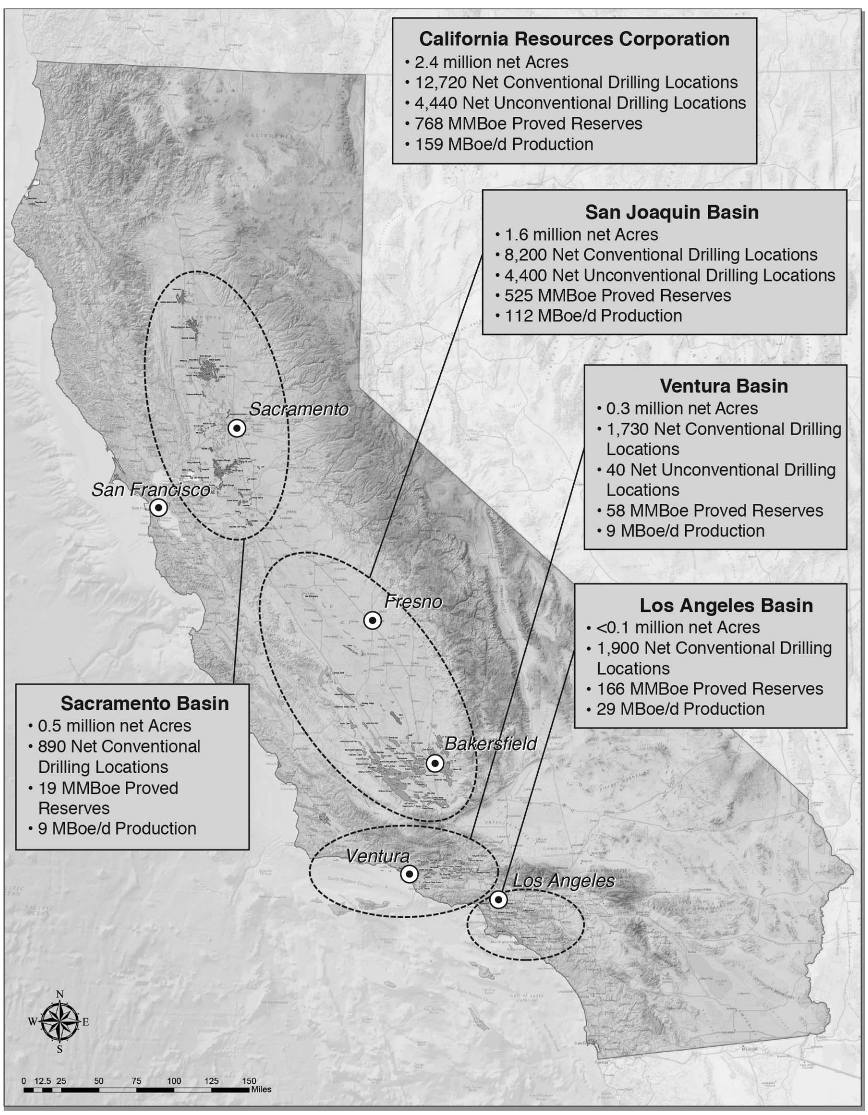
We have no unresolved SEC staff comments at December 31, 2014.

ITEM 2 PROPERTIES

Our Operations

Our Areas of Operation

California is one of the most prolific oil and natural gas producing regions in the world and is the third largest oil producing state in the nation. According to DOGGR, cumulative California production from all four basins in which we operate is 35 billion barrels of oil equivalent (''BBoe''), including approximately 19 BBoe in the San Joaquin basin, 10 BBoe in Los Angeles basin, 4 BBoe in Ventura basin and 10 trillion cubic feet (''Tcf'') of natural gas in Sacramento basin. Additionally, Kern County has been the largest oil producing county in the lower 48 states for a number of years. California imports more than 60% of its oil, mostly from foreign locations, and 90% of its natural gas. Because of limited crude transportation infrastructure from other parts of the country to California, the California market is generally isolated from the rest of the nation, which has typically allowed California producers to receive Brent-based prices, which are international waterborne prices. Brent prices were at a premium to WTI-based prices for comparable grades in recent years. Our operations include 137 fields with 9,331 gross active wellbores as of December 31, 2014. We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.4 million net acres. Approximately 60% of our total net mineral interest position is held in fee. A majority of our interests are in producing properties located in reservoirs characterized by what we believe to be long-lived production profiles with repeatable development opportunities.



Across all of our California operations, we drilled 1,048 development wells in 2014, of which 83% were producers and the rest were injectors. Our 2014 drilling capital was approximately $1.3 billion. Our 2014 total capital of $2.1 billion also included investments in support equipment, facilities, workovers and exploration. Our capital program added 118 MMBoe of proved reserves in 2014 representing a 203% reserve replacement ratio, calculated by using the proved reserves additions from our capital program for 2014 divided by our 2014 production of 58 MMBoe.

San Joaquin Basin

We actively operate and are developing 45 fields in this inland basin in the southern part of California's central valley which consists of conventional primary, IOR, EOR and unconventional project types with approximately 1.6 million net acres, approximately 62% of which we hold in fee. Approximately 68% of our estimated proved reserves as of December 31, 2014 and 70% of our average daily net production for the year ended December 31, 2014 were located in the San Joaquin basin.

According to DOGGR, approximately 74% of California's daily oil production for 2013 was produced in the San Joaquin basin. Commercial petroleum development began in the basin in the 1800s. Rapid discovery of many of the largest oil accumulations followed during the next several decades, including the Elk Hills field. We have been redeveloping this field and building our expertise to use in other fields across the state. According to the U.S. Geological Survey as of 2012, the San Joaquin basin contained three of the 10 largest oil fields in the United States based on cumulative production and proved reserves. Most discovered oil accumulations occur in Eocene-age through Pleistocene-age sedimentary sections. Source rocks are organic-rich shales from the Monterey, Kreyenhagen and Tumey formations. In the 1960s, introduction of thermal techniques resulted in substantial new additions to reserves in heavy oil fields. We have been successfully developing steamfloods in our Kern Front operations, which are located next to the giant Kern River field, and in the northwest portion of the Lost Hills field. Starting in the 1980s, reserves additions have continued in the Monterey formation on the west side of the basin and in our new conventional field discoveries. The basin contains multiple stacked formations throughout its areal extent, and we believe that the San Joaquin basin provides an appealing inventory of existing field re-development opportunities, as well as new play discovery and unconventional play potential. The complex stratigraphy and structure in the San Joaquin basin has allowed continuing discoveries of stratigraphic and structural traps. We believe our extensive 3D seismic library, which covers over 2,972 square miles in the San Joaquin basin, including approximately 50% of our San Joaquin acreage, will give us a competitive advantage in further exploring this basin.

We have established a large ownership interest in several of the largest existing oil fields in the San Joaquin basin, including Elk Hills, our largest producing field, as well as the Buena Vista and Kettleman North Dome fields.

Elk Hills

Elk Hills is one of the largest fields in the continental United States based on proved reserves and has produced over 1.6 BBoe. During the year ended December 31, 2014, we produced 64 MBoe/d on average from our Elk Hills properties, or approximately 40% of our total average daily production. Of our total Elk Hills production, more than 60% is liquids. At Elk Hills, we operate efficient natural gas processing facilities with a combined capacity of over 540 MMcf/d. Additionally, we generate sufficient electricity to operate the field and sell excess power to the grid. Our operations at Elk Hills possess a state-of-the-art central control facility and remote automation control on over 95% of our wells.

Los Angeles Basin

We actively operate and are developing 10 fields in this urban, coastal basin which consists of conventional primary, IOR, EOR and unconventional project types, approximately half of which we hold in fee. Approximately 22% of our estimated proved reserves as of December 31, 2014 and 18% of our average daily net production for the year ended December 31, 2014 were located in the Los Angeles basin.

The basin is a northwest-trending plain about 50 miles long and 20 miles wide containing prolific Miocene through Pleistocene sediments. 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 named in an area of about 450 square miles. 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 Huntington and the Wilmington fields, where we have significant operations as described further below.

Wilmington Oil Field

The Wilmington field located in Long Beach, is the third largest field in the United States and has produced over 2.9 BBoe. During the year ended December 31, 2014, we produced approximately 36,000 Boe/d gross on average, or 91% of the Wilmington field daily production from all producers for the year, where we operate on behalf of the State of California and the City of Long Beach. Our net production in this field equates to approximately 16% of our total average daily production. Most of our Wilmington production is covered under a set of contracts similar to production-sharing contracts under which we recover capital and operating costs and our share of profits from production. The field is developed by applying waterflood methods of oil recovery. Our waterflood operations have attractive margins and returns in the current price environment and extend the productive life of our reservoirs beyond the economic life expected for primary development.

Ventura Basin

We actively operate and are developing 29 fields in this central California coastal basin which consists of primary conventional, IOR, EOR and unconventional project types. We currently hold approximately 0.3 million net acres in the Ventura basin, approximately 72% of which we hold in fee. Approximately 8% of our estimated proved reserves as of December 31, 2014 and approximately 6% of our average daily net production for the year ended December 31, 2014 were located in the Ventura basin.

The Ventura basin contains a Cretaceous-age to Pleistocene-age, mostly marine, sedimentary section in a major fold and thrust belt that began developing during the late Pliocene. The Ventura basin is the onshore part of the main structural feature and its offshore extension is the modern Santa Barbara basin. All of the sedimentary section is productive at various locations, and most reservoirs are sandstones with favorable porosity and permeability. In general, most traps are anticlinal, modified to some degree by faults and with significant stratigraphic trapping. The basin contains multiple stacked formations throughout its depths, and we believe that the Ventura basin provides an appealing inventory of existing field re-development opportunities, as well as new play exploration potential.

In 2013, we completed the acquisition of, and are currently processing, the first ever 3D seismic survey in the Ventura basin. We believe this 3D seismic data gives us a competitive advantage in exploring this basin.

Sacramento Basin

We actively operate and are developing 53 fields in this inland basin in the northern part of California's central valley, primarily consisting of dry gas production. We currently hold approximately 0.5 million net acres in the Sacramento basin, approximately 35% of which we hold in fee. We believe 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. Approximately 2% of our estimated proved reserves as of December 31, 2014 and approximately 6% of our average daily net production for the year ended December 31, 2014 were located in the Sacramento basin.

The Sacramento basin is a deep, elongated northwest-trending basin covering about 12,000 square miles. It contains a thick sequence of sedimentary deposits that range in age from the lower Cretaceous to Neogene. Exploration in the basin started in 1918.

Conventional Reservoir Recovery Methods

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 progressively using primary recovery methods, which may include some well stimulation techniques, EOR methods like steamflooding and IOR methods such as waterflooding, using both vertical and horizontal drilling. All of these techniques are proven technologies we have used extensively in California.

Primary Recovery

Primary recovery methods are the first techniques we use to develop a reservoir. These methods consist of drilling and producing wells without supplementing the natural energy of the reservoir. Our successful exploration program continues to provide us with primary recovery opportunities in new reservoirs or through extensions of existing fields. Our conventional development programs create future opportunities to convert these reservoirs to steamfloods or waterfloods after their primary production phase.

Steamfloods

Some of our fields contain heavy, thick oil. Steamfloods work by injecting steam into the reservoir to heat the oil, decreasing its viscosity, or thinning the oil, allowing 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 is generally characterized by low capital investment with attractive margins and returns even in the current price environment. The economics of steamflooding are largely a function of the ratio between oil and natural gas prices. 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 oil 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 depletion. We use steamfloods extensively in the San Joaquin basin, where they have allowed us to grow our production from mature fields such as Kern Front and Lost Hills, among others.

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 by approximately double those experienced under primary recovery methods. Our waterflood operations have attractive margins and returns in the current price environment. 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 depletion. We use waterfloods extensively in the San Joaquin, Los Angeles and Ventura basins where they have allowed us to reduce production decline or modestly grow our production from mature fields such as Elk Hills and Wilmington.

Unconventional Reservoir Potential

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 over 4,900 gross (4,400 net) unconventional drilling locations on this acreage. As a result of focusing more on these reservoirs over the past few years, approximately 36% of our 2014 production was from unconventional reservoirs, an increase of approximately 150% since the acquisition of our Elk Hills field properties in 1998. As of December 31, 2014, we had proved reserves of 216 MMBoe associated with our unconventional properties, with approximately 24% proved undeveloped.

We hold significant interests in the Monterey formation, which is divided into upper and lower intervals. We have successfully produced from seven discrete stacked pay horizons within the Upper Monterey. The Lower Monterey is believed to be the principal source rock within the Monterey.

We plan to apply the knowledge acquired from our successes in the upper Monterey to other shales in the San Joaquin basin such as the Kreyenhagen and Moreno formations. The Kreyenhagen and Moreno formations are hydrocarbon source rocks that have generated oil and gas, and we believe they offer similar development opportunities to the upper Monterey due to their multiple stacked pay reservoirs and general reservoir characteristics. The lower Monterey has an extremely limited production history compared to the upper Monterey, and therefore very limited knowledge exists regarding its potential. For example, only about 25 wells have been drilled into the lower Monterey to date. However, we believe we will be able to apply knowledge we gain from the upper Monterey in the lower Monterey as well.

Exploration Program

We intend to continue our active exploration program in both conventional and unconventional plays where discoveries can quickly be developed into producing fields. We believe our experienced technical staff, leading acreage position and extensive 3D seismic library give us a strong competitive advantage. Our interpretation of this seismic data, covering a large portion of our prospective acreage, and our extensive knowledge of California geology and producing fields, has resulted in a large inventory of exploratory projects. As of December 31, 2014, our drilling inventory included 7,200 gross (5,100 net) exploration drilling locations in proven formations, the majority of which are located near existing producing fields. Additionally, we have identified 6,400 gross (5,300 net) prospective resource drilling locations in the lower Monterey, Kreyenhagen and Moreno resource plays.

In 2014, we continued our successful near-field and impact exploration programs in conventional and unconventional reservoirs. Our exploration program delivered a geologic success rate of approximately 80% with approximately half of those successful wells determined to be commercial in the current price environment. Notable successes include our conventional reservoir drilling results in proven play trends offsetting the Pleito Ranch field in the San Joaquin basin and the Bardsdale field in the Ventura basin.

In the San Emigdio trend, two exploration wells successfully extended the Pleito Ranch field. Both wells encountered the primary producing reservoir of the Pleito Ranch field at similar reservoir depths and pressures. Additional step-out exploration prospects have been identified that can further extend this trend.

In the Ventura basin, one exploration well encountered two hydrocarbon bearing reservoir intervals and successfully extended the depth of the known producing reservoirs. We have multiple, analogous prospects in this play trend that extends for approximately 30 miles onshore in the southern Ventura basin.

We continue to develop our understanding and knowledge of the significant prospective resources in the exploration shale reservoirs. In 2014, we completed significant log, core and seismic data acquisition projects targeting the Kreyenhagen exploration shale reservoir around the Kettleman North Dome and Middle Dome fields. We completed seven workovers in existing wellbores and drilled six new wells. In many cases, zonal completions were implemented to assess the expected performance of individual zones of interest and identify landing zones for future horizontal development.

In 2015, we expect to invest approximately three percent of our capital budget, or approximately $15 million, on exploration projects with a continued focus on prospects that can generate near-term returns. We expect exploration capital in the future to be focused in the San Joaquin, Ventura and Sacramento basins, and weighted toward projects where we have a proven track record of success.

Our Reserves and Production Information

Reserve Data

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

Reserves Presentation

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, unless prices were defined by contractual arrangements. Oil, NGLs and natural gas prices used for this purpose were based on posted benchmark prices and adjusted for price differentials including gravity, quality and transportation costs. For the 2014 disclosures, the calculated average Brent oil price was $101.30 per Bbl. The calculated average NYMEX gas price for 2014 disclosures was $4.42 per Mcf. The realized prices used for the 2014 disclosures were $95.20 per Bbl for oil, $49.94 per Bbl for NGLs and $4.73 per Mcf for natural gas.

During the second half of 2014 oil prices experienced a steep decline, which has continued into 2015. If prices remain at or near current levels for the rest of 2015, or if they decline further, the prices used to determine our year-end 2015 reserves will be significantly lower than those used for year-end 2014, as mandated by SEC regulations. Under such circumstances, we may experience significant negative price-related revisions to our proved reserves at year-end 2015. For example, under a much lower price scenario used for reserves reporting purposes, a significant portion of our proved undeveloped reserves may no longer meet the economic producibility criteria under the rules. Similarly, while we have significant control over variable costs, certain costs in our long-lived fields, such as Elk Hills, are fixed, having the effect of increasing costs on a per barrel basis in later years as production declines, rendering them uneconomic in a lower price environment. We would expect that our production-sharing type contracts would partially offset these negative revisions. Further, we believe that a prolonged period of low oil prices would result in lower operating costs, which would tend to mitigate price related negative revisions to some extent by improving the economics of proved undeveloped reserves as well as extending the economic lives of long-lived fields.

The following tables summarize our estimated proved reserves and related PV-10 and Standardized Measure at December 31, 2014. Reserves are stated net of applicable royalties. Estimated reserves include our economic interests under arrangements similar to production-sharing contracts relating to the Wilmington field in Long Beach.

	As of December 31, 2014				
	San Joaquin Basin	**Los Angeles Basin**	**Ventura Basin**	**Sacramento Basin**	**Total**
Proved developed reserves:					
Oil (MMBbl)	229	124	34	–	387
NGLs (MMBbl)	62	–	2	–	64
Natural Gas (Bcf)	458	11	28	110	607
Total (MMBoe)(1)(2)	367	126	41	18	552
Proved undeveloped reserves:					
Oil (MMBbl)	111	39	14	–	164
NGLs (MMBbl)	20	–	1	–	21
Natural Gas (Bcf)	163	5	9	6	183
Total (MMBoe)(2)	158	40	17	1	216
Total proved reserves:					
Oil (MMBbl)	340	163	48	–	551
NGLs (MMBbl)	82	–	3	–	85
Natural Gas (Bcf)	621	16	37	116	790
Total (MMBoe)(2)	525	166	58	19	768

(1) Approximately 11% of proved developed oil reserves, 5% of proved developed NGLs reserves, 9% of proved developed natural gas reserves and 10% of total proved developed reserves are non-producing.

(2) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of gas and one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were $99.51 per Bbl and $4.34 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 23 to 1.

PV-10 and Standardized Measure

	At December 31, 2014
PV-10 of proved reserves (in millions)(1)	$ 16,091
Standardized measure (in millions)	$ 10,828

(1) 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. PV-10 and Standardized Measure are used by the industry and by our management as an asset value measure to compare against our past reserve bases and the reserve bases of other business entities because the pricing, cost environment and discount assumptions are prescribed by the SEC and are comparable. PV-10 further facilitates the comparisons to other companies as it is not dependent on the tax paying status of the entity.

The following table provides a reconciliation of our Standardized Measure to PV-10:

	At December 31, 2014
	(in millions)
PV-10	$ 16,091
Present value of future income taxes discounted at 10%	(5,263)
Standardized Measure of Discounted Future Net Cash Flows	$ 10,828

Proved Reserve Additions

Our total proved reserve additions from all sources were 82 MMBoe in 2014. Of these reserve additions, 118 MMboe were the result of our capital program and 6 MMBoe as a result of property acquisitions. These additions were partially offset by 42 MMBoe of negative revisions. The total additions to our proved reserves during the year ended December 31, 2014 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Improved recovery:					
Oil (MMBbl)	70	11	4	–	85
NGLs (MMBbl)	13	–	–	–	13
Natural Gas (Bcf)	107	–	2	5	114
Total (MMBoe)	101	11	4	1	117
Extensions and discoveries:					
Oil (MMBbl)	1	–	–	–	1
NGLs (MMBbl)	–	–	–	–	–
Natural Gas (Bcf)	–	–	–	–	–
Total (MMBoe)	1	–	–	–	1
Total reserve additions from capital program	102	11	4	1	118
Revisions of previous estimates[1]:					
Oil (MMBbl)	(41)	8	(4)	–	(37)
NGLs (MMBbl)	8	–	–	–	8
Natural Gas (Bcf)	(91)	–	4	7	(80)
Total (MMBoe)	(48)	8	(3)	1	(42)
Acquisitions:					
Oil (MMBbl)	1	–	5	–	6
NGLs (MMBbl)	–	–	–	–	–
Natural Gas (Bcf)	–	–	2	–	2
Total (MMBoe)	1	–	5	–	6
Total proved reserve additions					
Oil (MMBbl)	31	19	5	–	55
NGLs (MMBbl)	21	–	–	–	21
Natural Gas (Bcf)	16	–	8	12	36
Total (MMBoe)	55	19	6	2	82

(1) Of these, (1) MMBoe were price-related.

Our ability to add reserves, other than through purchases, 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 reserve additions continue to provide reserves at similar levels.

Improved Recovery

In 2014, we added proved reserves of 117 MMBoe from improved recovery through proven IOR and EOR methods, as well as unconventional primary mechanisms. The improved recovery additions in 2014 were mainly associated with the continued development of properties in the San Joaquin and Los Angeles basins. These properties comprise both conventional and unconventional projects. The types of conventional IOR and EOR development methods we use can be applied through existing wells, though additional drilling is frequently required to fully optimize the development configuration. Many of our projects, including unconventional projects, rely on improving permeability to increase flow in the wells. In addition, some improved recovery comes from drilling infill wells that allow recovery of reserves that would not be recoverable from existing wells.

Extensions and Discoveries

We also added 1 MMBoe of proved reserves from extensions and discoveries, which generally result from exploration and exploitation programs.

Revisions of Previous Estimates

Revisions can include upward or downward changes to previous proved reserve estimates due to the evaluation or interpretation of geologic, production decline or operating performance data. In addition, product price changes affect proved reserves we record. For example, higher prices may increase the economically recoverable reserves, because the extra margin extends the expected life of the operations. Offsetting this effect, higher prices slightly decrease our share of proved reserves under arrangements similar to production-sharing contracts at our Long Beach operations because less oil is required to recover costs. Conversely, when prices drop, our share of proved reserves slightly increases for such arrangements similar to production-sharing contracts and economically recoverable reserves may drop for other operations. The negative revisions of 42 million Boe were mainly the result of performance related adjustments to several legacy projects concentrated in the San Joaquin basin, primarily in Elk Hills.

Proved Undeveloped Reserves

In 2014, we had proved undeveloped reserve additions of 89 MMBoe from improved recovery, primarily in the San Joaquin and Los Angeles basins, partially offset by 24 MMBoe of negative revisions. We also transferred 81 MMBoe of proved undeveloped reserves to the proved developed category as a result of the 2014 development programs, of which 98% were in the San Joaquin and Los Angeles basins. We invested approximately $1.2 billion in 2014 to convert proved undeveloped reserves to proved developed reserves. The total changes to our proved undeveloped reserves during the year ended December 31, 2014 were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Improved recovery:					
Oil (MMBbl)	56	8	2	–	66
NGLs (MMBbl)	9	–	–	–	9
Natural Gas (Bcf)	80	–	1	–	81
Total (MMBoe)	79	8	2	–	89
Extensions and discoveries:					
Oil (MMBbl)	1	–	–	–	1
NGLs (MMBbl)	–	–	–	–	–
Natural Gas (Bcf)	–	–	–	–	–
Total (MMBoe)	1	–	–	–	1
Revisions of previous estimates:					
Oil (MMBbl)	(13)	(2)	(4)	–	(19)
NGLs (MMBbl)	2	–	–	–	2
Natural Gas (Bcf)	(40)	–	(2)	–	(42)
Total (MMBoe)	(18)	(2)	(4)	–	(24)
Acquisitions:					
Oil (MMBbl)	–	–	1	–	1
NGLs (MMBbl)	–	–	–	–	–
Natural Gas (Bcf)	–	–	–	–	–
Total (MMBoe)	–	–	1	–	1
Transfers to proved developed reserves:					
Oil (MMBbl)	(39)	(13)	(2)	–	(54)
NGLs (MMBbl)	(11)	–	–	–	(11)
Natural Gas (Bcf)	(93)	(2)	(1)	(1)	(97)
Total (MMBoe)	(66)	(13)	(2)	–	(81)
Proved undeveloped reserve changes, net of transfers:					
Oil (MMBbl)	5	(7)	(3)	–	(5)
NGLs (MMBbl)	–	–	–	–	–
Natural Gas (Bcf)	(53)	(2)	(2)	(1)	(58)
Total (MMBoe)	(4)	(7)	(3)	–	(14)

Reserves Evaluation and Review Process

Our estimates of proved reserves and associated future net cash flows as of December 31, 2014 were made by our technical personnel 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. This process involves reservoir engineers, geoscientists, planning engineers and financial analysts. As part of the proved reserves estimation process, all reserve volumes are estimated by a forecast 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 used to estimate the net reserves. Production rate forecasts are derived by a number of methods, including estimates from decline-curve analysis, type-curve analysis, material balance calculations that take into account the volumes of substances replacing the volumes produced and associated reservoir pressure changes, seismic analysis and computer simulation of the 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 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 for recompletion.

Our Vice President, Reserves and Corporate Development assumed primary responsibility for overseeing the preparation of our reserve estimates in connection with the Spin-off. She has over 14 years of experience as an energy sector engineer including as a Senior Reservoir Engineer with Ryder Scott. She is a member of the Society of Petroleum Engineers, for which she served as past chair of the U.S. Registration Committee. She holds a Master of Engineering in Petroleum Engineering from the University of Houston and a Bachelor of Science from the University of Florida and is a registered 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 2014. The Reserves Committee reports to the Audit Committee during the year. Ryder Scott was retained to separately review the oil and natural gas reserves estimation processes used in 2014 for our properties and to provide the opinion noted below.

Ryder Scott conducted a process review of the methods and analytical procedures used by our engineering and geological staff to estimate the proved reserves volumes, prepare the economic evaluations and determine reserves classifications as of December 31, 2014. Ryder Scott reviewed the specific application of such methods and procedures for selected oil and gas properties considered to be a valid representation of our 2014 year-end total proved reserves portfolio. In 2014, Ryder Scott reviewed approximately 32% of our proved oil and natural gas reserves. Since being engaged by our former parent in 2003, Ryder Scott has reviewed the specific application of reserve estimation methods and procedures for approximately 88% of our proved oil and natural gas reserves that existed at December 31, 2014. Ryder Scott was retained to provide objective third-party input on the methods and procedures used to estimate our oil and natural gas reserves for 2014 and to gather industry information applicable to the reserve estimation and reporting process for those reserves. Ryder Scott was not engaged to render an opinion as to the reasonableness of our reserves quantities. We filed Ryder Scott's independent report as an exhibit to this Form 10-K.

Based on its reviews, including the data, technical processes and interpretations presented with respect to our oil and natural gas reserves, Ryder Scott concluded that the overall procedures and methodologies utilized in estimating the proved reserves volumes, documenting the changes in reserves from prior estimates, preparing the economic evaluations and determining the reserves classifications for the reviewed properties are appropriate for the purpose thereof and comply with current SEC regulations.

Because the separation of CRC from Occidental occurred in late 2014, we used Occidental's established reserves review process described above to estimate our 2014 proved reserves. Following the 2014 reserve estimation, we intend to rely more heavily on independent reserves estimation companies, such as Ryder Scott, to estimate our proved reserves volumes.

Determination of Identified Drilling Locations

Proven Drilling Locations

Based on our reserves report as of December 31, 2014, we have approximately 2,400 gross (2,300 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 inventory only after they have been evaluated technically and are deemed to have a high likelihood of being drilled within a five-year time frame. As a result of rigorous technical evaluation of geologic and engineering data, it can be estimated 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 10,200 gross (9,800 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

Our portfolio of prospective drilling locations contains approximately 7,200 gross (5,100 net) unrisked exploration drilling locations in proven formations, the majority of which are located near existing producing fields. We use internally generated information and proprietary models consisting of data from analog plays, 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 reservoir target area, we identified our exploration drilling locations within the applicable intervals by applying the well spacing we have historically utilized for the applicable type of recovery process used.

Prospective Resource Drilling Locations

In addition, we have approximately 6,400 gross (5,300 net) unrisked prospective resource drilling locations identified in the lower Monterey, Kreyenhagen and Moreno resource plays based on screening criteria that contain geologic and economic considerations and very limited production information. Prospective play 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. Prospective resource drilling locations were based on an assumption of 80-acre spacing per well throughout the prospective area for each resource play.

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 (i.e., primary, waterflood or EOR). Due to the significant vertical thickness and multiple stacked reservoirs usually encountered by our drilling wells, 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 have been scheduled as part of our current multi-year drilling schedule or are expected to be scheduled in the future. However, we may not drill our identified sites at the times scheduled or at all. We view the risk profile for our exploration drilling locations and our prospective resource drilling locations as being higher than for our other drilling locations due to relatively less available geologic and production data and drilling history, in particular with respect to our prospective resource locations, which are in unproven geologic plays. We make assumptions about the consistency and accuracy of data when we identify these locations that may prove inaccurate.

Our ability to profitably drill and develop our identified drilling locations depends on a number of variables, including crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals, available transportation capacity and other factors. 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. For a discussion of the risks associated with our drilling program, see ''Risk Factors—Risks Related to Our Business.''

The table below sets forth our total gross identified drilling locations as of December 31, 2014, excluding our prospective drilling locations from new resource plays.

	Proven Drilling Locations		**Total Identified Drilling Locations**	
	Oil and Natural Gas Wells	**Injection Wells**	**Oil and Natural Gas Wells**	**Injection Wells**
San Joaquin Basin				
Primary Conventional	150	–	3,900	–
Steamflood	900	250	3,100	900
Waterflood	100	50	1,000	700
Unconventional	300	–	4,550	300
San Joaquin Basin subtotal	1,450	300	12,550	1,900
Los Angeles Basin				
Primary Conventional	–	–	50	–
Steamflood	–	–	–	–
Waterflood	300	150	1,300	650
Unconventional	–	–	–	–
Los Angeles Basin subtotal	300	150	1,350	650
Ventura Basin				
Primary Conventional	50	–	1,650	–
Steamflood	15	–	200	–
Waterflood	50	50	200	250
Unconventional	2	–	50	–
Ventura Basin subtotal	117	50	2,100	250
Sacramento Basin				
Primary Conventional	1	–	1,000	–
Sacramento Basin subtotal	1	–	1,000	–
Total Identified Drilling Locations	1,868	500	17,000	2,800

Production, Price and Cost History

Oil, NGLs and natural gas are commodities; therefore, the price that 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 consumption patterns, global and local (particularly for natural gas) economic conditions, the actions of OPEC and other oil and natural gas producing countries, inventory levels, actual or threatened production disruptions, currency exchange rates, worldwide drilling and exploration activities, the effects of conservation, weather, geophysical and technical limitations, refining and processing disruptions, transportation bottlenecks and other matters affecting the supply and demand dynamics of oil, natural gas and NGLs, and the effect of changes in market perceptions. We have only occasionally hedged commodity price risk. However, given the recent steep decline in oil prices, we recently started a hedging program to protect our down-side price risk and preserve our ability to execute our capital program in 2015.

The following table sets forth information regarding production, realized and benchmark prices, and production costs for oil and gas producing activities for the years ended December 31, 2014, 2013 and 2012. For additional information on price calculations, see information set forth in ''Management's Discussion and Analysis of Financial Condition and Results of Operations.''

	Year Ended December 31,		
	2014	**2013**	**2012**
Production Data:			
Oil (MBbl/d)	99	90	88
NGLs (MBbl/d)	19	20	17
Natural gas (MMcf/d)	246	260	256
Average daily combined production (MBoe/d)	159	154	148
Total combined production (MMBoe)	58	56	54
Average realized prices:			
Oil (per Bbl)	$ 92.30	$ 104.16	$ 104.02
NGLs (per Bbl)	$ 47.84	$ 50.43	$ 52.76
Natural gas (per Mcf)	$ 4.39	$ 3.73	$ 2.94
Average Benchmark prices:			
WTI oil ($/Bbl)	$ 93.00	$ 97.97	$ 94.21
Brent oil ($/Bbl)	$ 99.51	$ 108.76	$ 111.70
NYMEX gas ($/Mcf)	$ 4.34	$ 3.66	$ 2.81
Average costs per Boe:			
Production costs	$ 17.64	$ 17.10	$ 22.58
General and administrative expenses[a]	$ 2.31	$ 2.35	$ 2.48
Other operating expenses[b]	$ 0.55	$ 0.60	$ 0.33
Depreciation, depletion and amortization	$ 20.40	$ 20.11	$ 16.82
Taxes other than on income	$ 3.50	$ 3.05	$ 3.09

(a) For 2014, the amount excludes unusual and infrequent costs of $0.10 per Boe related to Spin-off and transition related costs.

(b) For 2014, the amount excludes unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs of $0.97 per Boe. For 2012, the amount excludes rig termination charges of $0.22 per Boe.

The following table sets forth information regarding production, realized prices and production costs for our largest two fields, Elk Hills and Wilmington, for the years ended December 31, 2014, 2013 and 2012.

	Elk Hills			Wilmington		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
Production data:						
Oil (MBbl/d)	25	26	29	25	22	21
NGLs (MBbl/d)	16	18	15	–	–	–
Natural gas (MMcf/d)	136	145	168	–	–	–
Average realized prices:						
Oil (MBbl/d)	$ 97.27	$ 106.32	$ 101.19	$ 90.37	$ 103.29	$ 102.15
NGLs (MBbl/d)	$ 48.68	$ 49.62	$ 53.19	$ –	$ –	$ –
Natural gas (MMcf/d)	$ 4.47	$ 3.67	$ 2.86	$ –	$ –	$ –
Production costs per Boe	$ 14.31	$ 12.34	$ 16.46	$ 28.98	$ 31.56	$ 35.13

Note: Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were $99.51 per Bbl and $4.34 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 23 to 1.

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

	Total Proved Reserves		Average Net Daily Production(MBoe/d)
	MMBoe	Oil (%)	Year Ended December 31, 2014
San Joaquin Basin			
Primary Conventional	70	72%	18
Waterfloods	60	76%	7
Steamfloods[(a)]	181	100%	30
Unconventional	214	33%	57
San Joaquin Basin subtotal	525	65%	112
Los Angeles Basin			
Primary Conventional	–	–%	–
Waterfloods	166	99%	29
Steamfloods	–	–%	–
Unconventional	–	–%	–
Los Angeles Basin subtotal	166	99%	29
Ventura Basin			
Primary Conventional	31	80%	6
Waterfloods	25	87%	2
Steamfloods	–	–%	–
Unconventional	2	61%	1
Ventura Basin subtotal	58	83%	9
Sacramento Basin			
Primary Conventional	19	–%	9
Sacramento Basin subtotal	19	–%	9
Total	768	72%	159

(a) Includes reserves and production from gas injection of 9% and 5%, respectively.

Productive Wells

As of December 31, 2014, we had a total of 9,331 gross (8,384 net) producing wells, approximately 90% of which were oil wells. Our average working interest in our producing wells is approximately 90%. Many of our oil wells produce associated natural gas and some of our natural gas wells also produce condensate and NGLs.

The following table sets forth our productive oil and natural gas wells (both producing and capable of production) as of December 31, 2014.

	San Joaquin Basin		Los Angeles Basin		Ventura Basin		Sacramento Basin		Total	
Oil										
Gross[(a)(b)]	10,106	(1,057)	1,943	(56)	1,602	(61)	–	–	13,651	(1,174)
Net[(a)(c)]	8,994	(817)	1,835	(51)	1,590	(59)	–	–	12,419	(927)
Natural Gas										
Gross[(a)(b)]	293	(110)	8	–	–	–	1,345	(52)	1,646	(162)
Net[(a)(c)]	248	(84)	8	–	–	–	1,260	(50)	1,516	(134)

(a) Numbers in parentheses indicate the number of wells with multiple completions.
(b) The total number of wells in which interests are owned.
(c) The sum of fractional interests.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2014, of which approximately 60% is held in fee. Of the 40% which is leased, approximately 35% was held by production at December 31, 2014.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in thousands)		
Developed[1]					
Gross[2]	416	24	70	271	781
Net[3]	379	20	69	248	716
Undeveloped[4]					
Gross[2]	1,460	16	232	386	2,094
Net[3]	1,187	14	191	299	1,691

(1) Acres spaced or assigned to productive wells.
(2) Total acres in which we hold an interest.
(3) Sum of fractional interests owned based on working interests or interests under arrangements similar to production-sharing contracts.
(4) 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.

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 not a business basis for extension. In cases where additional time may be required to fully evaluate acreage, we have generally been successful in obtaining extensions. The combined net acreage covered by leases expiring in the next three years represents 23% of our total net undeveloped acreage at December 31, 2014 and these expirations would not have a material adverse impact on us. Historically, we have not dedicated any significant portion of our capital to prevent lease expirations and do not expect we will need to do so in the future.

Participation in Exploratory and Development Wells Being Drilled

The following table sets forth our participation in exploratory and development wells being drilled as of December 31, 2014.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Exploratory and development wells					
Gross	3	8	–	1	12
Net	3	8	–	1	12

At December 31, 2014, we were participating in eight steamflood and 40 waterflood projects. All of the significant steamflood projects were located in the San Joaquin basin. Twenty-five waterflood projects were located in the Los Angeles basin and 15 in the San Joaquin basin.

Drilling Activity

The following table describes our drilling activity for the periods indicated. 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. 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. Net wells represent the sum of fractional interests in wells in which we own an interest.

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
2014					
Oil					
Exploratory	2.0	–	1.7	–	3.7
Development	775.2	170.2	20.3	–	965.7
Natural Gas					
Exploratory	–	–	–	–	–
Development	–	–	–	3.0	3.0
Dry					
Exploratory	8.0	–	2.0	1.0	11.0
Development	2.3	0.9	–	–	3.2
2013					
Oil					
Exploratory	2.0	–	–	–	2.0
Development	543.1	125.7	18.8	–	687.6
Natural Gas					
Exploratory	–	–	–	–	–
Development	–	–	–	7.7	7.7
Dry					
Exploratory	5.0	–	1.0	1.0	7.0
Development	2.5	0.9	–	–	3.4
2012					
Oil					
Exploratory	8.0	–	2.0	–	10.0
Development	485.7	121.4	63.9	–	671.0
Natural Gas					
Exploratory	1.0	–	–	–	1.0
Development	2.5	–	–	3.0	5.5
Dry					
Exploratory	11.0	–	–	–	11.0
Development	4.0	–	–	–	4.0

Delivery Commitments

We have made commitments to certain refineries and other buyers to deliver oil, natural gas and NGLs. As of December 31, 2014, the total amount contracted to be delivered is approximately 34 MBbls/d of oil under 60-day contracts, 2 Bcf of natural gas under 90-day contracts, and 1 MMBbls of NGLs through March 2015. These are index-based contracts with prices set at the time of delivery at benchmark prices. We have significantly more production capacity than the amounts committed and have the ability to secure additional volumes in case of a shortfall. None of the commitments in any given year is expected to have a material impact on our financial statements.

Our Infrastructure

We own infrastructure that is integral to and significantly complements our operations. Our Elk Hills cryogenic gas plant has a capacity of 200 MMcf/d of wellhead gas bringing our total Elk Hills processing capacity to over 540 MMcf/d. We also own and operate a system of natural gas processing facilities in the Ventura basin that are capable of processing equity 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 certain North American NGLs markets. In addition, we have truck rack facilities coupled with a battery of pressurized storage tanks at our Elk Hills natural gas processing facility for NGL sales to third parties.

We generate all of our electricity needs at our Elk Hills operations, which run at about 130 megawatts, through our wholly-owned 550 megawatt combined-cycle power plant located adjacent to our Elk Hills processing facilities, and sell the excess. We also operate a 46 megawatt cogeneration facility at Elk Hills that provides resource diversity and additional reliability to support field operations. Within our

Long Beach operations, we operate a 45 megawatt power generating facility that provides over 40% of the Long Beach operation's electricity requirements, reducing operating costs. These power facilities are integrated with our operations to improve their reliability and performance.

We own an extensive network of over 20,000 miles of oil and gas gathering lines. These gathering lines are dedicated almost entirely to collect our oil and gas production and are in close proximity to field specific facilities such as tank settings or central processing sites. These lines provide a variety of services, including connecting our producing wells to gathering networks, natural gas collection and compression systems, lines for water treating and injection services, steam supply for our thermal properties, and water lines that deliver treated water for agriculture. Nearly all of our oil is then transported through third party pipelines with flexibility to ship to various parties. In addition, virtually all of our natural gas production interconnects 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.

ITEM 3 Legal Proceedings

The following is a description of a reportable legal proceeding for this reporting period. It describes significant developments in this matter previously reported in our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014. No new reportable matters arose during the fourth quarter of 2014.

One of our subsidiaries settled a previously disclosed civil claim by the District Attorney for Ventura County, California for seven releases of oil or produced water between 2011 and 2014 by paying a $200,000 penalty in January 2015.

ITEM 4 Mine Safety Disclosures

Not applicable.

EXECUTIVE OFFICERS

The current term of employment of each of our executive officers will expire at the May 7, 2015 organizational meeting of the Board of Directors or when a successor is selected. The following table sets forth our executive officers:

Name	Positions Held with CRC and Predecessor and Employment History	Age at February 26, 2015
William E. Albrecht	Executive Chairman since 2014; Occidental Vice President 2008 to 2014; Oxy Oil & Gas, Americas President 2012 to 2014; Oxy Oil & Gas, USA President 2008 to 2012.	63
Todd A. Stevens	President, Chief Executive Officer and Director since 2014; Occidental Vice President—Corporate Development 2012 to 2014; Oxy Oil & Gas Vice President—California Operations 2008 to 2012; Occidental Vice President—Acquisitions and Corporate Finance 2004 to 2012.	48
Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer since 2014; Ultra Petroleum Corp. Chief Financial Officer 2005 to 2014; Ultra Petroleum Corp. Senior Vice President 2011 to 2014.	55
Robert A. Barnes	Executive Vice President—Northern Operations since 2014; Occidental of Elk Hills President and General Manager 2012 to 2014; Oxy Permian CO_2 Operations Manager 2011 to 2012, Occidental Argentina Deputy General Manager and Senior Vice President, Operations 2010 to 2011; Occidental Argentina Vice President, Operations 2007 to 2010.	58
Frank E. Komin	Executive Vice President—Southern Operations since 2014; OXY Long Beach President and General Manager 2001 to 2014; Oxy THUMS President and General Manager 2001 to 2009.	60
Shawn M. Kerns	Executive Vice President—Corporate Development since 2014; 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.	44
Roy Pineci	Executive Vice President—Finance since 2014; Occidental Vice President and Controller 2008 to 2014.	52
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.	50
Charles F. Weiss	Executive Vice President—Public Affairs since 2014; Occidental Vice President, Health, Environment and Safety 2007 to 2014.	51
Darren Williams	Executive Vice President—Exploration since 2014; 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.	43

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 began trading "regular way" on the New York Stock Exchange (NYSE) under the symbol "CRC" on December 1, 2014. Prior to that date there was no public trading market for our common stock. The following schedule sets forth the high and low sales price per share of our common stock as reported on the NYSE for the period indicated:

	Stock Price	
	High	**Low**
Fourth Quarter 2014 (starting December 1, 2014)	$ 7.37	$ 5.29

Holders of Record

CRC common stock was held by approximately 27,000 stockholders of record at December 31, 2014, and by approximately 400,000 additional stockholders whose shares were held for them in street name or nominee accounts.

Dividend Policy

Our Board of Directors declared a cash dividend of $0.01 per share on February 26, 2015, payable on April 15, 2015 to stockholders of record on March 10, 2015. The payment of future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our financial condition, results of operations, capital requirements and development expenditures, future business prospects and any restrictions imposed by future debt instruments.

Securities Authorized for Issuance Under Equity Compensation Plans

Our stock-based compensation plans were approved by our sole stockholder prior to the Spin-off. A description of the plans can be found in Note 11 of our Financial Statements and Supplementary Data. The aggregate number of shares of our common stock authorized for issuance under stock-based compensation plans for our employees and non-employee directors is 30 million, of which approximately 4.3 million had been issued through December 31, 2014.

The following is a summary of the securities available for issuance under such plans:

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))
8,481,337 (1)	$8.11 (2)	17,115,099 (3)

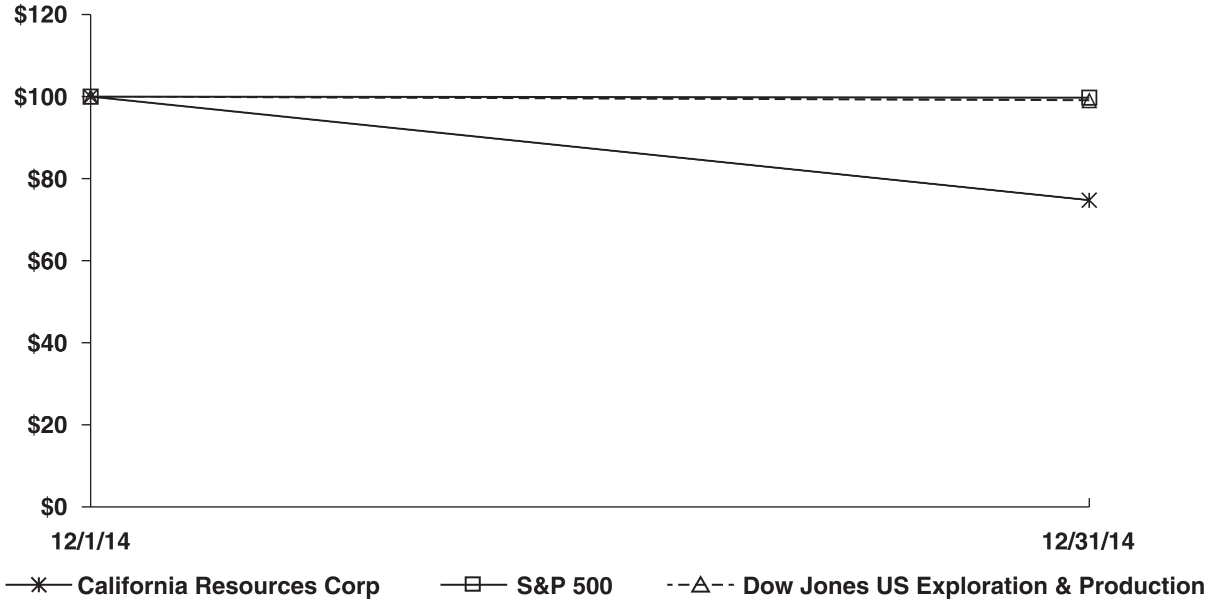
(1) Includes shares reserved to be issued pursuant to stock options and performance-based awards. Shares for performance-based awards are included assuming maximum payout, based on the certification of such awards on February 26, 2015.

(2) Price applies only to the Options included in column (a). Exercise price is not applicable to the other awards included in column (a).

(3) Includes 5 million shares subject to rights to purchase common stock at 85% of the lower of the market price at (i) the start of a quarter and (ii) the end of a quarter. Shares will first become subject to purchase at the end of the first quarter of 2015.

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 (with reinvestment of all dividends). The graph assumes $100 was invested in our common stock and in each index on December 1, 2014, the date our common stock began trading on the NYSE, and its relative performance is tracked through December 31, 2014. The returns shown are based on historical results and are not intended to suggest future performance.



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, the following selected financial data was derived from the California business of Occidental. All financial information presented after the Spin-off represents CRC's consolidated results of operations, financial position and cash flows. Accordingly:

- The selected statement of operations and cash flows data for the year ended December 31, 2014 consists of the stand-alone consolidated results of California Resources Corporation post Spin-off and the consolidated and combined results of the California business prior to the Spin-off. The selected statement of operations data for the years ended December 31, 2013, 2012, 2011, and 2010 consist entirely of the combined results of the California business.
- The selected balance sheet data at December 31, 2014 consists of the consolidated balances of California Resources Corporation, while the selected balance sheet data at December 31, 2013, 2012, 2011 and 2010 consists of the combined balances of the California business.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in millions)				
Statement of Operations Data					
Revenues	$ 4,173	$ 4,284	$ 4,073	$ 3,934	$ 2,912
Income / (loss) before income taxes	$ (2,421)	$ 1,447	$ 1,181	$ 1,641	$ 1,129
Net income / (loss)	$ (1,434)	$ 869	$ 699	$ 971	$ 719
Per common share[(a)]					
Basic	$ (3.75)	$ 2.24	$ 1.80	$ 2.50	$ 1.85
Diluted	$ (3.75)	$ 2.24	$ 1.80	$ 2.50	$ 1.85
Statement of Cash Flows Data					
Net cash provided by operating activities	$ 2,371	$ 2,476	$ 2,223	$ 2,456	$ 1,751
Capital investments	$ (2,020)	$ (1,669)	$ (2,331)	$ (2,164)	$ (1,056)
Acquisitions	$ (288)	$ (48)	$ (427)	$ (1,405)	$ (448)
Borrowings, net of costs	$ 6,290	$ –	$ –	$ –	$ –
Spin-off related dividends to Occidental	$ (6,000)	$ –	$ –	$ –	$ –
(Distributions to) contributions from Occidental, net	$ (335)	$ (763)	$ 532	$ 1,106	$ (248)

(a) See Note 13—Earnings Per Share, in the Notes to the Financial Statements.

	As of December 31,				
	2014	2013	2012	2011	2010
	(in millions)				
Balance Sheet Data					
Total current assets	$ 701	$ 254	$ 245	$ 195	$ 148
Property, plant and equipment, net	$ 11,685	$ 14,008	$ 13,499	$ 11,778	$ 8,823
Total assets	$ 12,497	$ 14,297	$ 13,764	$ 11,989	$ 8,987
Total current liabilities	$ 906	$ 689	$ 551	$ 664	$ 471
Long-term debt	$ 6,360	$ –	$ –	$ –	$ –
Equity / Net Investment	$ 2,611	$ 9,989	$ 9,860	$ 8,624	$ 6,557

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

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

Except when the context otherwise requires or where otherwise indicated, (1) all references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its subsidiaries or the California business, (2) all references to the ''California business'' refer to Occidental's California oil and gas exploration and production operations and related assets, liabilities and obligations, which we have assumed in connection with the spin-off from Occidental on November 30, 2014 (the ''Spin-off''), and (3) all references to ''Occidental'' refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

The Separation and Spin-off

We are an independent oil and natural gas exploration and production company operating properties exclusively within the State of California. We were incorporated in Delaware as a wholly-owned subsidiary of Occidental on April 23, 2014 and remained a wholly-owned subsidiary of Occidental until the Spin-off. On November 30, 2014, Occidental distributed shares of our common stock on a pro rata basis to Occidental stockholders and we became an independent, publicly traded company. Occidental retained approximately 18.5% of our outstanding shares of common stock which it has stated it intends to divest within 18 months of the Spin-off.

Basis of Presentation and Certain Factors Affecting Comparability

Up until the Spin-off, the accompanying consolidated and combined financial statements were derived from the consolidated financial statements and accounting records of Occidental. These consolidated and combined financial statements reflect the historical results of operations, financial position and cash flows of the California business. All financial information presented after the Spin-off consists of the stand-alone consolidated results of operations, financial position and cash flows of CRC. 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 income and cash flows.

The consolidated and combined statements of income for periods prior to the Spin-off include expense allocations for certain corporate functions and centrally-located activities historically performed by Occidental. These functions include executive oversight, accounting, treasury, tax, financial reporting, finance, internal audit, legal, risk management, information technology, government relations, public relations, investor relations, human resources, procurement, engineering, drilling, exploration, marketing, ethics and compliance, and certain other shared services. These allocations are based primarily on specific identification of time or activities associated with us, employee headcount or our relative size compared to Occidental. Our management believes the assumptions underlying the consolidated and combined financial statements, including the assumptions regarding allocating expenses from Occidental, are reasonable. However, the financial statements may not include all of the actual expenses that would have been incurred, or may include duplicative costs and may not reflect our results of operations, financial position and cash flows had we operated as a stand-alone public company during the periods presented. Actual costs that would have been incurred if we had been a stand-alone company prior to the Spin-off would depend on multiple factors, including organizational structure and strategic and operating decisions. There may be some additional non-recurring costs of operating as a stand-alone company, which are not expected to be material.

Prior to the Spin-off, we participated in Occidental's centralized treasury management program and did not incur any debt. Additionally, excess cash generated by our business was distributed to Occidental, and likewise our cash needs were provided by Occidental, in the form of contributions.

Had we been a stand-alone company for the full year 2014, and had the same level of debt throughout the year as we did on December 31, 2014, of approximately $6.4 billion, we would have incurred $314 million, $186 million after-tax, of interest expense, on a pro-forma basis, for the year ended December 31, 2014, compared to the $72 million pre-tax interest expense reported in our statement of operations for the year then ended.

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 index prices and differentials may fluctuate significantly, generally as a result of changes in supply and demand and other market-related uncertainties. These and other factors make it impossible to predict realized prices reliably. We respond to economic conditions primarily by adjusting our capital investments to be in line with current economic conditions, including adjusting the size and allocation of our capital program. The changes in the capital program have an impact on our production levels and cash flows.

Given the recent volatile and deteriorating oil price environment, as well as our leverage, we began a hedging program shortly after the Spin-off to protect our down-side price risk and preserve our ability to execute our capital program. In December 2014, we purchased put options with a $50 per barrel Brent strike price, measured monthly. This initial program covers almost all of our oil production for the first six months of 2015. More recently, we put into place additional hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between $55 and $72) for 30,000 barrels per day for July through September as well as put options at $50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a $75 per barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

We sell all of our crude oil into California markets, which typically reflect international waterborne-based prices because the structural energy deficit in the State results in most of its oil being imported. Over the last several years, these prices have exceeded and continue to exceed West Texas Intermediate (''WTI'') based prices for comparable grades. Due to much lower levels of natural gas production compared to our oil production, the changes in natural gas prices have a significantly lower impact on our operating results. Lower natural gas prices generally have a positive effect on our steamflood projects that use natural gas to generate the steam being injected. Average oil prices were lower in 2014 than 2013, caused by a steep decline in prices in the last half of 2014. Average Brent prices were $108.76 per barrel in 2013 and $99.51 per barrel in 2014 ending 2014 at $57.33. Our realized price for crude oil as a percentage of Brent prices was approximately 93% and 96% for 2014 and 2013, respectively. Oil prices continued to decline in the early part of 2015.

The following table presents the average daily WTI oil, Brent oil and NYMEX gas prices for each of the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
WTI oil ($/Bbl)	$ 93.00	$ 97.97	$ 94.21
Brent oil ($/Bbl)	$ 99.51	$ 108.76	$ 111.70
NYMEX gas ($/Mcf)	$ 4.34	$ 3.66	$ 2.81

Oil prices and differentials will continue to be affected by (i) global supply and demand, which are generally a function of global economic conditions, the actions of OPEC, other significant producers and governments, inventory levels, threatened or actual production or refining disruptions, the effects of conservation, technological advances and regional market conditions; (ii) transportation capacity and cost in producing areas; (iii) currency exchange rates; and (iv) the effect of changes in these variables on market perceptions.

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

Natural gas prices and differentials are strongly affected by local supply and demand fundamentals, as well as availability of transportation capacity from producing areas.

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, and 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. In addition, a portion of the power produced by our Elk Hills power plant is used for certain of our operations while a majority of the output is sold to third parties.

Seasonality

Seasonality is not a primary driver of changes in our quarterly earnings during the year.

Taxes

Deferred tax liabilities, net of deferred tax assets of $444 million, were approximately $2.0 billion at December 31, 2014. The current portion of total deferred tax assets was $61 million as of December 31, 2014, which was reported in other current assets. The realization of deferred tax assets is assessed periodically based on several factors, including our expectation to generate sufficient future taxable income and reversal of taxable temporary differences.

The following table sets forth the calculation of our effective income tax rate for each of the years ended December 31 (in millions):

	2014	2013	2012
Pre-tax income/(loss)	$ (2,421)	$ 1,447	$ 1,181
Income tax (expense)/benefit	987	(578)	(482)
Net income/(loss)	$ (1,434)	$ 869	$ 699
Effective tax rate	41%	40%	41%

Operations

We conduct our operations through fee interests, land leases and other contractual arrangements. We believe we are the largest private oil and natural gas mineral acreage holder in California, with interests in approximately 2.4 million net acres, approximately 60% of which we hold in fee. Our oil and gas leases have a primary term ranging from one to ten years, which is extended through the end of production once it commences. We also own a network of strategically placed and integral infrastructure assets, including gas plants, oil and gas gathering systems, a power plant and other related assets to maximize the value generated from our production.

Our share of production and reserves from operations in Long Beach, California are subject to contractual arrangements similar to production-sharing contracts and 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 such capital and production costs and an additional share for profit. Our portion of the production represents volumes: (1) to recover our partners' share of capital and production costs that we incur on their behalf and costs associated with contractually defined base production, (2) for our defined share of base production and (3) for our defined share of production in excess of base production for each period. We recover our share of capital and production costs, and generate returns, through our defined share of production from base and incremental production in (2) and (3) 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, however, our net economic benefit is greater when product prices are higher. These contracts represented approximately 16% of our production for the year ended December 31, 2014.

Results

Results for the year ended December 31, 2014 were a net loss of $1,434 million, compared with net income of $869 million for the year ended December 31, 2013. The net loss in 2014 largely reflected a $2.0 billion non-cash after-tax impairment charge for proved and unproved properties in the fourth quarter of 2014 and approximately $64 million in after-tax charges for rig terminations, other price-related charges and Spin-off and transition related costs. There were no similar charges or costs in 2013. Net income for 2014, excluding these charges, was $650 million as reflected in the table below.

The table below reconciles net income / (loss) to core income and lists unusual and infrequent items affecting earnings for each year (in millions):

	2014	2013	2012
Net income / (loss)	$ (1,434)	$ 869	$ 699
Unusual and infrequent items:			
Asset impairments	3,402	–	29
Rig terminations and other price-related costs	52	–	12
Spin-off and transition related costs	55	–	–
	3,509	–	41
Tax effect of pre-tax adjustments	(1,425)	–	17
Core income	$ 650	$ 869	$ 675

Our results of operations can include the effects of significant unusual and infrequent transactions and events affecting earnings that vary widely and unpredictably in nature, timing and amount. Therefore, management uses a measure called ''core income,'' which excludes those items. This non-GAAP measure is not meant to disassociate those items from management's performance, but rather is meant to provide useful information to investors interested in comparing our earnings performance between periods. Reported earnings are considered representative of management's performance over the long term. Core income is not considered to be an alternative to income reported in accordance with generally accepted accounting principles.

Core income for 2014, compared to 2013, benefited from higher oil production and higher realized natural gas prices, which were more than offset by lower realized oil prices and lower realized NGL prices and volumes, and higher production costs, depreciation rates, property taxes, selling, general and administrative costs and interest expenses. In addition, unit production costs increased mainly due to higher natural gas and other energy costs, and expenses for surface operations and maintenance.

Core income for the year ended December 31, 2013 was $869 million, compared to $675 million for the year ended December 31, 2012. The higher income in 2013 reflected higher oil and gas prices and volumes and higher NGL volumes, partially offset by higher depreciation rates, taxes other than on income and other expenses. Production costs decreased in 2013, compared to 2012, due to a wide range of operational efficiency initiatives implemented in 2012.

The following table sets forth our average production volumes of oil, NGLs and natural gas per day for each of the three years in the period ended December 31, 2014:

	2014	2013	2012
Oil (MBbl/d)			
San Joaquin Basin	64	58	58
Los Angeles Basin	29	26	24
Ventura Basin	6	6	6
Sacramento Basin	–	–	–
Total	99	90	88
NGLs (MBbl/d)			
San Joaquin Basin	18	19	16
Los Angeles Basin	–	–	–
Ventura Basin	1	1	1
Sacramento Basin	–	–	–
Total	19	20	17
Natural gas (MMcf/d)			
San Joaquin Basin	180	182	204
Los Angeles Basin	1	2	3
Ventura Basin	11	11	12
Sacramento Basin	54	65	37
Total	246	260	256
Total Production (MBoe/d) (a)	159	154	148

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

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, for the year ended December 31, 2014, the average prices of Brent oil and NYMEX natural gas were $99.51 per barrel and $4.34 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 23 to 1.

Daily oil and gas production volumes averaged 159,000 Boe for the year ended December 31, 2014, compared with 154,000 Boe for the year ended December 31, 2013. Average daily oil production increased by 9,000 Boe, or by ten percent, while daily NGLs production decreased by 1,000 Boe and natural gas decreased by 14 MMcf. The increase in oil production and decline in NGL and natural gas production reflected our emphasis on high margin oil drilling and reduction of drilling capital for natural gas. Our oil production, as well as total production, increased sequentially each quarter during 2014, reaching 105,000 barrels per day and 165,000 Boe/d, respectively, in the fourth quarter, both of which were record levels for us.

For the year ended December 31, 2013, daily oil and gas production volumes averaged 154,000 Boe, compared with 148,000 Boe for the year ended December 31, 2012. Our daily liquids production increased by 5,000 Boe while our daily natural gas production increased by 4 MMcf, or less than 700 Boe. The slight increase in our natural gas production reflected increased production from acquisitions made in 2012 and associated natural gas produced from oil drilling, partially offset by lower gas production due to reduced investment in natural gas drilling in 2013.

The following table sets forth the average realized prices for our products:

	2014	2013	2012
Oil Prices ($ per Bbl)	$ 92.30	$ 104.16	$ 104.02
NGLs Prices ($ per Bbl)	$ 47.84	$ 50.43	$ 52.76
Gas Prices ($ per Mcf)	$ 4.39	$ 3.73	$ 2.94

The following table presents our average realized prices as a percentage of WTI, Brent and NYMEX for each of the three years in the period ended December 31, 2014:

	2014	2013	2012
WTI oil	99%	106%	110%
Brent oil	93%	96%	93%
NYMEX gas	101%	102%	105%

Balance Sheet Analysis

The changes in our balance sheet as of December 31, 2014 and 2013, are discussed below:

	2014	2013
	(in millions)	
Cash and cash equivalents	$ 14	$ –
Trade receivables, net	$ 308	$ 30
Inventories	$ 71	$ 75
Other current assets	$ 308	$ 149
Property, plant and equipment, net	$ 11,685	$ 14,008
Other assets	$ 111	$ 35
Accounts payable	$ 588	$ 448
Accrued liabilities	$ 318	$ 241
Long-term debt	$ 6,360	$ –
Deferred income taxes	$ 2,055	$ 3,122
Other long-term liabilities	$ 565	$ 497
Equity / Net investment	$ 2,611	$ 9,989

See ''Liquidity and Capital Resources'' for discussion of changes in our cash and cash equivalents and long-term debt.

The increase in trade receivables was largely the result of marketing our own products directly to third parties, rather than through Occidental, beginning in mid-2014. The increase in other current assets included additional California greenhouse gas emissions allowances, an increase in the current portion of our deferred tax assets, increases in joint interest receivables and the fair value of the put option purchased in December 2014. The decrease in property, plant and equipment, net, reflected the $3.4 billion pre-tax impairment charge for proved and unproved properties and additional depreciation, depletion and amortization (''DD&A'') in 2014, partially offset by capital investments of approximately $2.1 billion. The increase in other assets reflected deferred debt costs incurred in 2014.

The increase in accounts payable reflected higher capital levels in the last quarter of 2014, compared to 2013. The increase in accrued liabilities included unpaid interest attributable to our 2014 borrowings. The decrease in deferred income taxes reflected the impact of the impairment charges, partially offset by accelerated tax depreciation of the capital investments in 2014. The increase in other long-term liabilities was mostly due to employee related liabilities. The decrease in equity / net investment reflected dividends and distributions to Occidental prior to the Spin-off and our net loss for the year.

Statement of Operations Analysis

The following table presents the results of our operations, including the unusual and infrequent items discussed in the ''Results'' section above:

	2014	2013	2012
		(in millions)	
Oil and natural gas sales (including related parties)	$ 4,023	$ 4,139	$ 3,967
Other revenue	150	145	106
Production costs	(1,023)	(960)	(1,219)
Selling, general and administrative expenses	(336)	(292)	(273)
Depreciation, depletion and amortization	(1,198)	(1,144)	(926)
Asset impairments	(3,402)	–	(29)
Taxes other than on income	(217)	(185)	(167)
Exploration expense	(139)	(116)	(148)
Interest and debt expense, net	(72)	–	–
Other expenses	(207)	(140)	(130)
Income tax (expense) / benefit	987	(578)	(482)
Net income / (loss)	$ (1,434)	$ 869	$ 699
EBITDAX[(1)]	$ 2,548	$ 2,733	$ 2,296
Effective tax rate	41%	40%	41%

(1) We define EBITDAX consistent with our Credit Facilities as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; and certain other non-cash items and unusual, infrequent charges. Our management believes EBITDAX provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry and investment community. The amounts included in the calculation of EBITDAX were computed in accordance with GAAP. This measure is a material component of one of our financial covenants under our Credit Facilities and is provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. EBITDAX should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

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

	2014	2013	2012
Net income / (loss)	$ (1,434)	$ 869	$ 699
Interest expense	72	–	–
Income tax expense / (benefit)	(987)	578	482
Asset impairments	3,402	–	29
Depreciation, depletion and amortization	1,198	1,144	926
Exploration expense	139	116	148
Other non-cash items	51	26	–
Unusual and infrequent charges[(a)]	107	–	12
EBITDAX	$ 2,548	$ 2,733	$ 2,296

(a) Includes rig terminations and other price-related costs, and Spin-off and transition related costs.

The following represents key metrics of our oil and gas operations, excluding certain corporate items, on a per BOE basis for the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
Production costs	$ 17.64	$ 17.10	$ 22.58
General and administrative expenses[(a)]	$ 2.31	$ 2.35	$ 2.48
Other operating expenses[(b)]	$ 0.55	$ 0.60	$ 0.33
Depreciation, depletion and amortization	$ 20.40	$ 20.11	$ 16.82
Taxes other than on income	$ 3.50	$ 3.05	$ 3.09

(a) For 2014, the amount excludes unusual and infrequent costs of $0.10 per Boe related to Spin-off and transition related costs.

(b) For 2014, the amount excludes unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs of $0.97 per Boe. For 2012, the amount excludes rig termination charges of $0.22 per Boe.

Year Ended December 31, 2014 vs. 2013

Oil and natural gas sales decreased 3%, or $116 million, in 2014, compared to 2013. Lower oil prices, which declined significantly in the second half of 2014, contributed $377 million to this decrease, lower natural gas volumes contributed $71 million and lower NGL prices and volumes contributed $54 million. Partially offsetting these decreases were $318 million related to higher oil volumes and $61 million related to higher natural gas prices. Crude oil production increased by 9,000 Boe/d while our NGL and natural gas production decreased by 1,000 Boe/d and 14 MMcf/d, or approximately 2,000 Boe/d, respectively. The lower NGL and natural gas production reflects our planned shift in our capital toward higher margin oil projects.

Other revenue in 2014, attributable to sales from our Elk Hills power plant, was consistent with 2013.

Production costs increased by 6%, or $63 million to $17.64 per Boe in 2014, compared to $17.10 per Boe in 2013. Of this increase, $32 million was due to higher volumes and $31 million due to higher costs for natural gas used in our steamflood operations and higher energy costs and expenses for surface operations and maintenance. In the fourth quarter we started an aggressive cost containment program and have seen costs start to decline in December.

Selling, general and administrative expenses increased 15%, or $44 million, in 2014 compared to 2013, mostly due to higher employee related costs and costs related to the Spin-off. They were, however, consistent with 2013 on a per barrel basis.

DD&A expense increased 5%, or $54 million, in 2014, compared to 2013. Of this increase, $22 million was attributable to higher volumes and $32 million resulted from a higher DD&A rate, due to additional capital investments.

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of $3.4 billion on proved and unproved properties throughout our asset base. The impairment charge was related to certain properties in the San Joaquin and Los Angeles basins and a portion of our assets in the Ventura basin, as well as our gas properties in the Sacramento basin. Approximately $650 million of the charge was related to unproved acreage. The properties were impaired as a result of accounting rules that require us to evaluate our properties based on the year-end forward price curve, as well as projects we determined we would not pursue in the foreseeable future given the current environment. We expect a substantial portion of these assets would ultimately become economical as prices recover to higher levels we view as more sustainable.

Taxes other than on income increased 17%, or $32 million, in 2014 compared to 2013 reflecting higher property taxes largely due to a refund received in 2013, which reduced that year's property taxes.

Exploration expense increased 20%, or $23 million, in 2014 compared to 2013 mostly due to higher dry hole expenses in the San Joaquin basin, including $12 million of non-core charges.

Interest expense in 2014 was $72 million, due to our debt incurred in connection with the Spin-off of approximately $6.4 billion in the fourth quarter of 2014.

Other expenses increased 48%, or $67 million in 2014, compared to 2013, and included non-core rig termination costs of $33 million and $35 million for Spin-off, transition and other related items.

Provision for income taxes showed a benefit of $987 million in 2014, reflecting the pre-tax loss of approximately $2.4 billion and a slight increase in the effective tax rate compared to 2013.

Year Ended December 31, 2013 vs. 2012

Oil and natural gas sales increased 4%, or $172 million, in 2013, compared to 2012. Of this increase, $47 million was attributable to higher oil and natural gas volumes, $77 million was attributable to higher oil and gas prices and $63 million was attributable to higher volumes for NGLs. The increase was partially offset by $15 million attributable to lower prices for NGLs. Our daily liquids production increased by 5,000 Boe while our daily natural gas production increased by 4 MMcf, or less than 700 Boe. The increase in liquids production primarily reflected our strategy to increase our overall capital investment program with a focus on oil drilling while reducing drilling capital for natural gas in light of higher oil prices and lower gas prices in recent years. The slight increase in our natural gas production reflected increased production from acquisitions made in 2012 and associated natural gas produced from oil drilling, partially offset by lower natural gas production due to reduced investment in natural gas drilling in 2013.

Other revenue increased 37%, or $39 million in 2013, compared to 2012, due to higher realized prices on third party power sales from our Elk Hills power plant.

Production costs decreased by $259 million to $17.10 per Boe in 2013, compared to $22.58 per Boe for 2012, almost entirely due to a wide range of operational efficiency initiatives implemented in late 2012, including activities such as high-grading and more efficient utilization of service rigs, improved job scheduling, more efficient liquids usage and handling, optimization of field supervision and contractor usage, and reduced consumption of purchased fuel, power and field rental equipment.

Selling, general and administrative and other operating expenses increased 7%, or $19 million, in 2013, compared to 2012, mostly due to higher compensation and employee related costs, in particular higher headcount and equity compensation in part due to the higher price of Occidental's stock.

DD&A expense increased by $218 million. Of this increase, $44 million was attributable to higher volumes and $174 million was attributable to a $3.29 per Boe increase in the DD&A rate, which was a result of additional capital investments throughout our asset base. In recent years, we have been systematically increasing our investments in IOR and EOR recovery assets and facilities. Significant investment on the front end of these projects is necessary, which has caused an increase in our DD&A rate.

Asset impairments of $29 million in 2012 reflected the write-down of uneconomic properties in various areas, in particular natural gas properties.

Taxes other than on income increased 11%, or $18 million, in 2013, compared to 2012, primarily due to a $32 million increase in California greenhouse gas costs, which we began incurring at the beginning of 2013, partially offset by lower property taxes of $14 million.

Exploration expense decreased 22%, or $32 million, in 2013, compared to 2012, due to higher success rates resulting in lower dry hole expense of $78 million in the San Joaquin and Los Angeles basins, partially offset by higher dry hole expense of $14 million in the Ventura basin and higher expense of $30 million for seismic, geological and geophysical and lease rentals.

Other expenses increased 8%, or $10 million in 2013, compared to 2012, primarily due to higher natural gas prices for purchased natural gas used at our Elk Hills power plant and higher rig idling costs.

Provision for income taxes increased by $96 million due to the effect of higher pre-tax income of $266 million, partially offset by a 1% lower effective tax rate.

Liquidity and Capital Resources

The primary source of liquidity and capital resources to fund our capital programs is cash flow from operations. Through November 2014, any excess cash generated by our business was distributed to Occidental, and our cash needs were provided by Occidental, in the form of a contribution. We expect our needs for capital investments and any potential acquisitions for at least the next twelve months will be met by cash generated from operations, and borrowings when necessary. We may, however, consider other options, such as joint ventures and similar arrangements as we work to deleverage. At December 31, 2014, we had more than $1.6 billion available on our revolving credit facilities, which has effectively been reduced by $750 million under the first amendment to our credit facilities. Operating cash flows are largely dependent on oil and gas prices and differentials, sales volumes and costs. If the current conditions persist we expect our production levels will be affected as we will not look to accelerate production in this price environment.

Given the recent volatile and deteriorating oil price environment, as well as our leverage, we began a hedging program shortly after the Spin-off to protect our down-side price risk and preserve our ability to execute our capital program. In December 2014, we purchased put options with a $50 per barrel Brent strike price, measured as a monthly average. This initial program covers almost all of our oil production for the first six months of 2015. More recently, we put into place additional hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between $55 and $72) for 30,000 barrels per day for July through September as well as put options at $50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a $75 per barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

Credit Facilities

On September 24, 2014, we entered into a credit agreement with a syndicate of lenders, providing for (i) a five-year senior term loan facility (the ''Term Loan Facility'') and (ii) a five-year senior revolving loan facility (the ''Revolving Credit Facility'' and, together with the Term Loan Facility, the ''Credit Facilities''). All borrowings under these facilities are subject to certain customary conditions. We amended the Credit Facilities effective as of February 25, 2015, and changed certain of our covenants through December 31, 2016 or such earlier time as we elect and demonstrate compliance with our original covenants for two successive quarters (the ''Interim Covenant Period'').

The aggregate initial commitments of the lenders under the Revolving Credit Facility are $2.0 billion and under the Term Loan Facility are $1.0 billion. The Revolving Credit Facility includes a sub-limit of $400 million for the issuance of letters of credit. We will be required to repay the Term Loan Facility in equal quarterly installments equal to 2.5% (10.00% per annum) of the principal amount of the Term Loan Facility beginning on March 31, 2016. As of December 31, 2014, we had $360 million outstanding under our Revolving Credit Facility with the ability to incur total net borrowings of up to $1.25 billion during the Interim Covenant Period under this facility.

Borrowings under the Credit Facilities bear interest, at our election, at either a LIBOR rate or an alternate base rate (''ABR'') (equal to the greatest of (i) the administrative agent's prime rate, (ii) the one-month LIBOR rate plus 1.00% and (iii) the federal funds effective rate plus 0.50%), in each case plus an applicable margin. This applicable margin is based on our most recent leverage ratio and will vary from (a) in the case of LIBOR loans, 1.50% to 2.25% and (b) in the case of ABR loans, from 0.50% to 1.25%. The unused portion of the Revolving Credit Facility is subject to commitment fees ranging from 0.30% to 0.50% per annum, based on our most recent leverage ratio. We also pay customary fees and expenses under the Revolving Credit Facility.

Interest payments under the Credit Facilities vary based on the borrowing options chosen. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period.

All obligations under the Credit Facilities are guaranteed jointly and severally by all of our wholly-owned material subsidiaries, and will be unsecured while we maintain our credit ratings at the minimum levels defined in the Credit Facilities. During the Interim Covenant Period, we would be required to grant security to our lenders if our corporate family ratings experienced a two-notch decline from either of our rating agencies. Outside the Interim Covenant Period we would be required to grant security in the event of a three-notch decline subject to certain exceptions described in our Credit Facilities. The assets and liabilities of subsidiaries not guaranteeing the debt are de minimis.

The Credit Facilities also require us to maintain the following financial covenants for the trailing twelve months ended as of the last day of each fiscal quarter: (a) a leverage ratio of no more than 4.50 to 1.00 except during the Interim Covenant Period when the ratio increases by varying amounts to a maximum of 8.25 to 1.00 by December 31, 2015 and (b) an interest expense ratio of no less than 2.50 to 1.00 except as of December 31, 2015 when the ratio must be no less than 2.25 to 1.00. In addition, during the Interim Covenant Period, we must maintain an asset coverage ratio of no less than 1.05 to 1.00 measured as of the last day of each fiscal quarter. Finally, during the Interim Covenant Period, we must apply cash on hand in excess of $250 million to repay certain amounts outstanding under the Revolving Credit Facility. If we were to breach either of these covenants the banks would be permitted to accelerate the principal amount due under the facilities. If payment were accelerated it would result in a default under the notes.

Senior Notes

On October 1, 2014, we issued $5.00 billion in aggregate principal amount of our senior notes, including $1.00 billion of 5% senior notes due January 15, 2020 (the 2020 notes), $1.75 billion of 5½% senior notes due September 15, 2021 (the 2021 notes) and $2.25 billion of 6% senior notes due November 15, 2024 (the ''2024 notes'' and together with the 2020 notes and the 2021 notes, the ''notes''), in a private placement.

We will pay interest on the 2020 notes semi-annually in cash in arrears on January 15 and July 15 of each year, beginning on July 15, 2015. We will pay interest on the 2021 notes semi-annually in cash in arrears on March 15 and September 15 of each year, beginning on March 15, 2015. We will pay interest on the 2024 notes semi-annually in cash in arrears on May 15 and November 15 of each year, beginning on May 15, 2015.

In connection with the private placement of the notes, we granted the initial purchasers certain registration rights under a registration rights agreement. We expect to file a registration statement to register the exchange of the notes in the near future.

The indenture governing the notes includes covenants that, among other things, limit our and our restricted subsidiaries' ability to incur debt secured by liens. These covenants also restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. These covenants are subject to a number of important qualifications and limitations that are set forth in the indenture. 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) with respect to a series of notes, we will be required, unless we have exercised our right to redeem the notes of such series, to offer to purchase the notes of such series at a purchase price equal to 101 percent of their principal amount, plus accrued and unpaid interest.

Spin-off Related Distributions to Occidental

We used the net proceeds from the private placement of our notes to make a $4.95 billion cash distribution to Occidental in October 2014. See ''—Senior Notes'' for more details regarding the terms of our senior notes. On November 25, 2014, we borrowed $1.0 billion under our Term Loan Facility and $50 million under a Revolving Credit Facility to make a $1.05 billion cash distribution to Occidental on November 26, 2014.

Cash Flow Analysis

	2014	2013	2012
		(in millions)	
Net cash flows provided by operating activities	$ 2,371	$ 2,476	$ 2,223
Net cash flows used in investing activities	$ (2,312)	$ (1,713)	$ (2,755)
Net cash flows (used in) provided by financing activities	$ (45)	$ (763)	$ 532
EBITDAX(1)	$ 2,548	$ 2,733	$ 2,296

(1) We define EBITDAX consistent with our Credit Facilities as earnings before interest expense; income taxes; depreciation, depletion and amortization; exploration expense; and certain other non-cash items and unusual, infrequent charges. Our management believes EBITDAX provides useful information in assessing our financial condition, results of operations and cash flows and is widely used by the industry and investment community. The amounts included in the calculation of EBITDAX were computed in accordance with GAAP. This measure is a material component of one of our financial covenants under our Credit Facilities and is provided in addition to, and not as an alternative for, income and liquidity measures calculated in accordance with GAAP. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. EBITDAX should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

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

	2014	2013	2012
		(in millions)	
Net cash provided by operating activities	$ 2,371	$ 2,476	$ 2,223
Interest expense	72	–	–
Current income taxes	165	318	(121)
Cash exploration expenses	38	44	20
Changes in operating assets and liabilities	(143)	(103)	202
Other, net	45	(2)	(28)
EBITDAX	$ 2,548	$ 2,733	$ 2,296

Year Ended December 31, 2014 vs. 2013

Our operating cash flows in 2014 decreased by $105 million from $2.476 billion in 2013 to $2.371 billion in 2014. The decrease reflected approximately $110 million in lower sales due to lower oil and NGL prices partially offset by higher oil volumes and gas prices, higher interest expense of $70 million, higher production costs of approximately $65 million, higher taxes other than on income of $30 million, higher selling, general and administrative costs of $20 million, partially offset by lower income taxes of $150 million and working capital changes of $40 million in 2014 compared to 2013.

Our cash flows used in investing activities increased by approximately $600 million in 2014, to $2.3 billion in 2014, compared to $1.7 billion in 2013. The increase mainly consisted of approximately $350 million of higher capital investments and higher acquisition costs of $240 million. The 2014 capital investments reported in the statement of cash flows exclude the effect of accruals. Total capital investments in 2014 were $2.089 billion, of which $2.020 billion was paid in cash during the year as reported in the statement of cash flows and $69 million reflected an increase in capital accruals. For the years 2013 and 2012, the capital accrual amount was not material.

Our net cash flows used in financing activities decreased by approximately $720 million in 2014, compared to 2013, and reflected the dividend distribution of $6.0 billion to Occidental prior to the Spin-off, proceeds of approximately $6.3 billion of debt, net of $70 million of debt issuance costs, and lower excess cash distributions to Occidental prior to the Spin-off.

Year Ended December 31, 2013 vs. 2012

Our operating cash flows in 2013 increased by approximately $250 million compared to 2012. The increase reflected lower operating expenses of $250 million resulting from cost efficiencies and $210 million in higher revenues due to higher oil and gas prices and volumes. Other significant items affecting operating cash flows consisted of higher tax payments of $440 million and other costs of $70 million in 2013, as well as $300 million in positive working capital changes.

Our cash flow used in investing activities decreased by approximately $1.0 billion in 2013 to $1.7 billion, compared to 2012. We reduced our capital investments in 2013 by approximately $660 million primarily due to approximately 20% lower drilling costs and lower capital needs for the Elk Hills cryogenic gas plant, which was completed during 2012. Further, our 2013 acquisitions of $50 million were approximately $380 million lower than the 2012 acquisition amount.

Cash used for financing activities in 2013 reflected excess cash flow distributed to Occidental. Cash provided by financing activities in 2012 reflected contributions from Occidental primarily to fund our acquisitions.

Acquisitions

During the year ended December 31, 2014, we paid approximately $290 million to acquire certain producing and nonproducing oil and gas properties, including oil and gas properties in the Ventura Basin purchased for approximately $200 million in the fourth quarter of 2014.

During the year ended December 31, 2013, we paid approximately $50 million to acquire certain oil and gas properties. An acquisition in the San Joaquin basin also included an obligation to invest at least $250 million on exploration and development activities over a period of five years from the date of acquisition. We currently plan to invest significantly more than this amount in capital during that period. Any deficiency in meeting this capital investment obligation would need to be paid in cash at the end of the five-year period. Through December 31, 2014, we have already fulfilled about 20% of this obligation.

During the year ended December 31, 2012, we paid approximately $380 million for oil and gas properties including $275 million for certain producing and non-producing assets in the Sacramento basin and undeveloped acreage in the San Joaquin basin.

2014 Capital Program and 2015 Capital Budget

In 2014 we invested $2.1 billion for projects targeting investments in the San Joaquin, Los Angeles and Ventura basins, as compared to $1.7 billion in 2013. Virtually all of our 2014 capital investments were directed towards oil-weighted production consistent with 2013. Of the total 2014 capital program, approximately $1.3 billion was allocated to well drilling and completions, $181 million to workovers, $346 million to surface support equipment to handle higher production, $36 million to additional steam generation capacity expansion, $100 million to exploration and the rest to maintenance capital, health, safety and environmental projects and other items.

The table below sets forth our 2014 capital investments for the year ended December 31, 2014 (in millions):

	Conventional				Unconventional		Total
	Primary	Waterflood	Steamflood	Total	Primary	Other	Capital Investments
Basin:							
San Joaquin	$ 280	$ 129	$ 381	$ 790	$ 604	$ –	$ 1,394
Los Angeles	3	466	–	469	–	–	469
Ventura	82	13	8	103	1	–	104
Sacramento	14	–	–	14	1	–	15
Basin Total	379	608	389	1,376	606	–	1,982
Exploration and Other	–	–	–	–	–	107	107
Total	$ 379	$ 608	$ 389	$ 1,376	$ 606	$ 107	$ 2,089

We have a 2015 capital investment budget of $440 million for projects targeting investments in the San Joaquin, Los Angeles and Ventura basins, as compared to $2.1 billion invested in 2014. We expect virtually all of our 2015 capital budget to be directed towards oil-weighted production consistent with 2014. Of the total 2015 capital budget, approximately $150 million is allocated to drilling wells, $50 million to workovers, $130 million to additional steam-generation capacity and compression expansion, $15 million to exploration and the rest to 3D seismic, maintenance capital, health, safety and environmental projects and other items.

Off-Balance-Sheet Arrangements

We have no material off-balance-sheet arrangements other than those noted below.

Leases

We, or certain of our subsidiaries, have entered into various operating lease agreements, mainly for field equipment, office space and office equipment. We lease assets when leasing offers greater operating flexibility. Lease payments are generally expensed as part of production costs or selling, general and administrative expenses. For more information, see ''Contractual Obligations.''

Contractual Obligations

The table below summarizes and cross-references our contractual obligations as of December 31, 2014. This summary indicates on- and off-balance-sheet obligations as of December 31, 2014.

	Payments Due by Year				
	Total	2015	2016 and 2017	2018 and 2019	2020 and thereafter
			(in millions)		
On-Balance Sheet					
Long-term debt (Note 5)[(a)]	$ 6,360	$ –	$ 200	$ 1,160	$ 5,000
Other long-term liabilities[(b)]	147	6	19	16	106
Off-Balance Sheet					
Operating leases	125	13	28	26	58
Purchase obligations[(c)]	364	70	79	204	11
Total	$ 6,996	$ 89	$ 326	$ 1,406	$ 5,175

(a) Excludes interest on the debt. As of December 31, 2014, interest on long-term debt totaling $2.4 billion is payable in the following years (in millions): 2015–$312, 2016 and 2017–$620, 2018 and 2019–$608, 2020 and thereafter–$825. The calculation of interest payable on the variable interest debt assumes the interest rate at December 31, 2014 to be the applicable interest rate for the entire term. In performing the calculation, the Revolving Credit Facility borrowings outstanding at December 31, 2014 of $360 million were assumed to be outstanding for the entire term of the agreement.

(b) Includes obligations under postretirement benefit and deferred compensation plans, as well as certain accrued liabilities.

(c) Amounts include payments, which will become due under long-term agreements to purchase goods and services used in the normal course of business to secure pipeline capacity, drilling rigs and services. These amounts were significantly reduced as a result of rig contract terminations in 2014. Long-term purchase contracts are discounted using a discount rate of approximately 5%.

Lawsuits, Claims, Contingencies and Commitments

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, 2014 and 2013 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We, our subsidiaries, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with the Spin-off, purchases and other transactions that they have entered into with us. These indemnities include indemnities made to Occidental against certain tax-related liabilities that may be incurred by Occidental relating to the Spin-off and liabilities related to operation of our business while it was still owned by Occidental. As of December 31, 2014, we are not aware of circumstances that we believe would reasonably be expected to lead to indemnity claims that would result in payments materially in excess of reserves.

Critical Accounting Policies and Estimates

The process of preparing financial statements in accordance with generally accepted accounting principles requires management to select appropriate accounting policies and to make informed estimates and judgments regarding certain items and transactions. Changes in facts and circumstances or discovery of new information may result in revised estimates and judgments, and actual results may differ from these estimates upon settlement. We consider the following to be our most critical accounting policies and estimates that involve management's judgment and that could result in a material impact on the financial statements due to the levels of subjectivity and judgment.

Oil and Gas Properties

The carrying value of our property, plant and equipment (''PP&E'') represents the cost incurred to acquire or develop the asset, including any asset retirement obligations, 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.

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 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.

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.

Proved oil and gas reserves and production volumes are used as the basis for recording depreciation and depletion of oil and gas producing properties. Proved reserves are those quantities of oil and gas which, 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—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, we receive a share of production from arrangements similar to production-sharing contracts to recover costs and generally an additional share for profit. Our share of production and reserves from these contracts decreases when product prices rise and increases when prices decline. Overall, our net economic benefit from these contracts is greater at higher product prices. In other cases, particularly with long-lived properties, lower product prices may lead to a situation where production of a portion of proved reserves becomes uneconomical. For such properties, higher product prices typically result in additional reserves becoming economical. 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.

Additionally, we perform impairment tests with respect to our proved properties when product prices decline other than temporarily, reserve 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.

The most significant ongoing financial statement effect from a change in our oil and gas reserves or impairment of the carrying value of our proved properties would be to the DD&A rate. For example, a 5% increase or decrease in the amount of oil and gas reserves would change the DD&A rate by approximately $1.00 per Bbl, which would increase or decrease pre-tax income by approximately $60 million annually based on production rates for the year ended December 31, 2014.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2014, the net capitalized costs attributable to unproved properties were approximately $300 million. While exploration and development work progresses, the unproved amounts are not subject to DD&A until they are classified as proved properties. However, 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 timing of any write-downs of these unproved properties, if warranted, depends upon management's plans, the nature, timing and extent of future exploration and development activities and their results. We believe our current plans and exploration and development efforts will allow us to realize the unproved property balance.

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of $3.4 billion on proved and unproved properties throughout our asset base. The impairment charge was related to certain properties in the San Joaquin and Los Angeles basins and a portion of our assets in the Ventura basin, as well as our natural gas properties in the Sacramento basin. Approximately $650 million of the charge was related to unproved acreage. The properties were impaired as a result of accounting rules that require us to evaluate our properties based on the year-end forward price curve, as well as projects we determined we would not pursue in the foreseeable future given the current environment. We expect a substantial portion of these assets would ultimately become economical as prices recover to higher levels we view as more sustainable.

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 primarily apply the market approach for recurring fair value measurement, 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 and discounts those cash flows using a risk-adjusted discount rate.

The most significant items on our balance sheet that would be affected by recurring fair value measurements are derivatives. Based on year end 2014 amounts on the balance sheet for derivatives, a 10% increase or decrease in their fair value would affect income by $2.4 million.

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. See ''—Lawsuits, Claims, Contingencies and Commitments'' for additional information.

Significant Accounting and Disclosure Changes

In August 2014, the Financial Accounting Standards Board (''FASB'') issued rules relating to management's responsibility to evaluate and make disclosures, if applicable, regarding the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. These rules are effective for annual periods ending after December 15, 2016. They are not expected to have a material impact on our financial statements upon adoption and will require assessment on an ongoing basis.

In June 2014, the FASB issued rules for employee share-based payment awards in which the terms of the awards provide that a performance target can be achieved after the requisite service period. A performance target that affects vesting and that could be achieved after the requisite service period will be treated as a performance condition. These rules are effective for annual periods beginning on or after December 15, 2015 and are not expected to have a material impact on our financial statements upon adoption but will require assessment on an ongoing basis.

In May 2014, the FASB issued rules related to revenue recognition. Under the new rules, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects to receive in exchange for the goods or services. The rules will also require more detailed disclosures of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The rules are effective for interim and annual periods beginning after December 15, 2016 and early application is not permitted. While we are evaluating any potential impact of these new rules, we currently believe the effect of the new rules will not have a material impact on our financial statements.

In April 2014, the FASB issued rules changing the requirements for reporting discontinued operations such that only the disposals of components of an entity that represent a strategic shift that has (or will have) a major effect on an entity's operations and financial results will be reported as discontinued operations in the financial statements. These rules are effective for the annual periods beginning on or after December 15, 2014. They are not expected to have a material impact on our financial statements upon adoption and will require assessment on an ongoing basis.

ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

General

Our results are sensitive to fluctuations in oil, NGL and gas prices. Price changes at current levels of production affect our pre-tax annual income by approximately $32 million for a $1 per Bbl change in Brent oil prices and $4 million for a $1 per Bbl change in NGL prices. If natural gas prices varied by $0.50 per Mcf, it would have an estimated annual effect on our pre-tax income of approximately $20 million. These price-change sensitivities include the impact on income of volume changes under arrangements similar to production-sharing contracts. If production levels change in the future, the sensitivity of our results to prices also will change.

Derivatives

In February 2015, we put into place hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between $55 and $72) for 30,000 barrels per day for July through September as well as put options at $50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a $75 per barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

In December 2014, we purchased put options to hedge the risk associated with declining oil prices for 100,000 barrels of crude oil production per day, effective on a monthly basis from January 1, 2015 through June 30, 2015. The strike price of the put option is $50 per barrel and is tied to the Brent oil index. Changes in the intrinsic value of the put option are deferred in other comprehensive income/(loss) as a cash flow hedge until the hedged transactions are recognized in the statement of operations. Changes in the time value of the put option are marked to market through the statement of operations. The time value of the put option was valued using Level 2 inputs in the fair value hierarchy and was valued at approximately $24 million in other current assets, as of December 31, 2014, which approximated the value of the instrument and the amount we paid the counterparty at the time the option was acquired.

In November 2012, we entered into financial swap agreements for the sale of 50 MMcf/d of our natural gas production beginning in January 2013 through March 2014. These agreements qualified as cash-flow hedges and represented approximately 5% of our 2013 total production on a Boe basis. The weighted-average strike price of these swaps was $4.30.

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 the derivative options entered into December 2014, we are subject to counterparty credit risk to the extent the counterparty to this derivative is unable to meet its settlement commitments. We actively manage this credit risk by selecting counterparties that we believe to be financially strong and continuing to monitor their financial health.

As of December 31, 2014, the substantial majority of the credit exposures related to our business was with investment grade counterparties. We believe exposure to credit-related losses related to our business at December 31, 2014 was not material and losses associated with credit risk have been insignificant for all years presented.

Concentration of Credit Risk

Through July 2014, substantially all of our products were sold through Occidental's marketing subsidiaries at market prices and were settled at the time of sale to those entities. Beginning August 2014, we began marketing our own products directly to third parties. For the years ended December 31, 2014, 2013 and 2012, sales through Occidental subsidiaries accounted for approximately 65%, 97% and 97% of our net sales, respectively. For the years ended December 31, 2014, 2013 and 2012, ConocoPhillips/Phillips 66 Company and Tesoro Refining & Marketing Company LLC each accounted for more than 10% of our net sales. Collectively, they accounted for 45%, 42% and 46% in each of those years, respectively. No other customer accounted for more than 10% of our net sales during these periods.

Interest Rate Risk

Historically, we had no interest rate risk exposure as we did not have debt balances. In November 2014, we made initial borrowings on our variable-rate Credit Facilities. As of December 31, 2014, we had borrowings of $1.0 billion outstanding under our Term Loan Facility and approximately $360 million outstanding under our Revolving Credit Facility. A one-eighth percent change in the variable interest rates on these outstanding borrowings under our Term Loan Facility and Revolving Credit Facility would result in an approximately $1.7 million change in annual interest expense.

The following table shows our fixed- and variable-rate debt as of December 31, 2014:

Year of Maturity	U.S. Dollar Fixed-Rate Debt	U.S. Dollar Variable-Rate Debt	Total
	(amounts in millions)		
2015	$ –	$ –	$ –
2016	–	100	100
2017	–	100	100
2018	–	100	100
2019	–	1,060	1,060
Thereafter	5,000	–	5,000
Total	$ 5,000	$ 1,360	$ 6,360
Weighted-average interest rate	5.63%	2.24%	4.9%
Fair Value	$ 4,285	$ 1,360	$ 5,645

FORWARD-LOOKING STATEMENTS

The information in this document includes ''forward-looking statements.'' The factors identified in this cautionary statement are important factors (but not necessarily all of the important factors) that could cause actual results to differ materially from those expressed in any forward-looking statement made by us, or on our behalf. You can typically identify ''forward-looking statements'' by the use of forward-looking words such as ''aim,'' ''anticipate,'' ''believe,'' ''budget,'' ''continue,'' ''could,'' ''effort,'' ''estimate,'' ''expect,'' ''forecast,'' ''goal,'' ''guidance,'' ''intend,'' ''likely,'' ''may,'' ''might,'' ''objective,'' ''outlook,'' ''plan,'' ''potential,'' ''predict,'' ''project,'' ''seek,'' ''should,'' ''target, ''will'' or ''would'' and other similar words. Such statements may include statements regarding our future financial position, budgets, capital investments, projected production growth, projected costs, plans and objectives of management for future operations and possible future strategic transactions. For any such forward-looking statement that includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results. The differences between assumed facts or bases and actual results can be material, depending upon the circumstances. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading ''Risk Factors'' included in this report.

Any forward-looking statement in which we, or our management, express an expectation or belief as to future results, is made in good faith and believed to have a reasonable basis. However, there can be no assurance that the statement of expectation or belief will result or be achieved or accomplished. Taking this into account, the following are identified as important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by, or on behalf of, our company:

- commodity pricing;
- vulnerability to economic downturns and adverse developments in our business due to our debt;
- insufficiency of our operating cash flow to fund planned capital investments;
- inability to implement our capital investment program profitably or at all;
- compliance with regulations or changes in regulations and the ability to obtain government permits and approvals;
- uncertainties associated with drilling for and producing oil and natural gas;
- tax law changes;
- competition for oilfield equipment, services, qualified personnel and acquisitions;
- the subjective nature of estimates of proved reserves and related future net cash flows;
- concentration of operations in a single geographic area;
- restrictions on our ability to obtain, use, manage or dispose of water;
- inability to drill identified locations when planned or at all;
- concerns about climate change and other air quality issues;
- risks related to our acquisition activities;
- catastrophic events for which we may be uninsured or underinsured;
- cyber attacks;
- operational issues that restrict market access; and
- uncertainties related to the Spin-off, the agreements related thereto and the anticipated effects of restructuring or reorganizing our business.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. Unless legally required, we undertake no responsibility to publicly release the result of any revision of our forward-looking statements after the date they are made.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

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

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm on Consolidated and Combined Financial Statements

To the Board of Directors and Stockholders
California Resources Corporation:

We have audited the accompanying consolidated and combined balance sheets of California Resources Corporation and subsidiaries (the ''Company'') as of December 31, 2014 and 2013, and the related consolidated and combined statements of operations, comprehensive income, equity and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated and combined financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated and combined financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of California Resources Corporation and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Los Angeles, California
February 26, 2015

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Balance Sheets
As of December 31, 2014 and 2013
(in millions)

	2014	2013
CURRENT ASSETS		
Cash and cash equivalents	$ 14	$ –
Trade receivables, net	308	30
Inventories	71	75
Other current assets	308	149
Total current assets	701	254
PROPERTY, PLANT AND EQUIPMENT	20,536	20,972
Accumulated depreciation, depletion and amortization	(8,851)	(6,964)
	11,685	14,008
OTHER ASSETS	111	35
TOTAL ASSETS	$ 12,497	$ 14,297
CURRENT LIABILITIES		
Accounts payable	$ 588	$ 448
Accrued liabilities	318	241
Total current liabilities	906	689
LONG-TERM DEBT	6,360	–
DEFERRED INCOME TAXES	2,055	3,122
OTHER LONG-TERM LIABILITIES	565	497
COMMITMENTS AND CONTINGENCIES		
EQUITY		
Preferred stock—no shares outstanding at December 31, 2014 or 2013 (200 million shares authorized at $0.01 par value)		
Common stock (2.0 billion shares authorized at $0.01 par value) Outstanding shares (2014—385,639,582 shares and 2013—0 shares)	4	–
Additional paid-in capital	4,748	–
Accumulated deficit	(2,117)	–
Net parent company investment	–	10,013
Accumulated other comprehensive income (loss)	(24)	(24)
Total Equity / Net Investment	2,611	9,989
TOTAL LIABILITIES AND EQUITY	$ 12,497	$ 14,297

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Operations
For the years ended December 31, 2014, 2013 and 2012
(in millions)

	2014	2013	2012
REVENUES			
Oil and natural gas sales to related parties	$ 2,617	$ 4,054	$ 3,878
Oil and natural gas sales to third parties	1,406	85	89
Other revenue	150	145	106
	4,173	4,284	4,073
COSTS AND OTHER DEDUCTIONS			
Production costs	1,023	960	1,219
Selling, general and administrative expenses	336	292	273
Depreciation, depletion and amortization	1,198	1,144	926
Asset impairments	3,402	–	29
Taxes other than on income	217	185	167
Exploration expense	139	116	148
Interest and debt expense, net	72	–	–
Other expenses	207	140	130
	6,594	2,837	2,892
INCOME / (LOSS) BEFORE INCOME TAXES	(2,421)	1,447	1,181
Income tax (expense) / benefit	987	(578)	(482)
NET INCOME / (LOSS)	$ (1,434)	$ 869	$ 699
Net income / (loss) per share of common stock			
Basic	$ (3.75)	$ 2.24	$ 1.80
Diluted	$ (3.75)	$ 2.24	$ 1.80

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Comprehensive Income
For the years ended December 31, 2014, 2013 and 2012
(in millions)

	2014	2013	2012
Net income / (loss)	$ (1,434)	$ 869	$ 699
Other comprehensive income (loss) items:			
Unrealized (losses) gains on derivatives[(a)]	(2)	(2)	3
Pension and postretirement (losses) gains[(b)]	(1)	27	2
Reclassification to income of realized losses (gains) on derivatives[(c)]	3	(2)	–
Other comprehensive income, net of tax	–	23	5
Comprehensive income / (loss)	$ (1,434)	$ 892	$ 704

(a) Net of tax of $1, $1 and $(1) in 2014, 2013, and 2012, respectively.
(b) Net of tax of $(1), $(16) and $(1) in 2014, 2013 and 2012, respectively. See Note 14, Retirement and Postretirement Benefit Plans, for additional information.
(c) Net of tax of $(2), $1 and zero in 2014, 2013 and 2012, respectively.

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Equity
For the years ended December 31, 2014, 2013 and 2012
(in millions)

	Common Stock	Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Net Parent Company Investment	Total Equity/Net Investment
			(in millions)			
Balance, December 31, 2011	$ –	$ –	$ –	$ (52)	$ 8,676	$ 8,624
Net income / (loss)	–	–	–	–	699	699
Other comprehensive loss, net of tax	–	–	–	5	–	5
Net contributions from Occidental	–	–	–	–	532	532
Balance, December 31, 2012	$ –	$ –	$ –	$ (47)	$ 9,907	$ 9,860
Net income / (loss)	–	–	–	–	869	869
Other comprehensive income, net of tax	–	–	–	23	–	23
Net distributions to Occidental	–	–	–	–	(763)	(763)
Balance, December 31, 2013	$ –	$ –	$ –	$ (24)	$ 10,013	$ 9,989
Net income / (loss)[(a)]	–	–	(2,117)	–	683	(1,434)
Other comprehensive income, net of tax	–	–	–	–	–	–
Net contributions from Occidental[(b)]	–	–			56	56
Dividend to Occidental	–	–	–	–	(6,000)	(6,000)
Issuance of common stock at Spin-off	4	–	–	–	(4)	–
Reclassification of net parent company investment to additional paid-in capital	–	4,748	–	–	(4,748)	–
Balance, December 31, 2014	$ 4	$ 4,748	$ (2,117)	$ (24)	$ –	$ 2,611

(a) Net income of $683 million related to operations from January 1, 2014 through the spin-off date of November 30, 2014 and was included in Net Parent Company Investment. The net loss of $2,117 million for the month ended December 31, 2014 reflected our accumulated deficit as of that date as a stand-alone company.
(b) Net contributions from Occidental include non-cash contributions of approximately $400 million, predominantly trade receivables, partially offset by $335 million in cash distributions to Occidental.

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

CALIFORNIA RESOURCES CORPORATION AND SUBSIDIARIES
Consolidated and Combined Statements of Cash Flows
For the years ended December 31, 2014, 2013 and 2012
(in millions)

	2014	2013	2012
CASH FLOW FROM OPERATING ACTIVITIES			
Net income / (loss)	$ (1,434)	$ 869	$ 699
Adjustments to reconcile net income / (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,198	1,144	926
Asset impairments	3,402	–	29
Deferred income tax expense / (benefit)	(1,152)	260	603
Other noncash charges to income	113	29	40
Dry hole expenses	101	72	128
Changes in operating assets and liabilities, net			
(Increase) decrease in trade receivables, net	146	(8)	20
(Increase) decrease in inventories	2	8	(23)
(Increase) decrease in other current assets	(133)	2	(49)
Increase (decrease) in accounts payable and other current liabilities	128	100	(150)
Net cash provided by operating activities	2,371	2,476	2,223
CASH FLOW FROM INVESTING ACTIVITIES			
Capital investments	(2,020)	(1,669)	(2,331)
Acquisitions and other	(292)	(44)	(424)
Net cash used by investing activities	(2,312)	(1,713)	(2,755)
CASH FLOW FROM FINANCING ACTIVITIES			
(Distributions to) contributions from Occidental, net	(335)	(763)	532
Dividends to Occidental	(6,000)	–	–
Issuance of senior notes	5,000	–	–
Issuance of term loan	1,000	–	–
Proceeds from revolving credit facility	515	–	–
Repayments of revolving credit facility	(155)	–	–
Debt issuance costs	(70)	–	–
Net cash (used) provided by financing activities	(45)	(763)	532
Increase in cash and cash equivalents	14	–	–
Cash and cash equivalents—beginning of year	–	–	–
Cash and cash equivalents—end of year	$ 14	$ –	$ –

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

NOTE 1 THE SPIN-OFF AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Separation and Spin-off

We are an independent oil and natural gas exploration and production company operating properties exclusively within the State of 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 the spin-off on November 30, 2014 (the ''Spin-off''). Prior to the Spin-off, all material existing assets, operations and liabilities of the California business were consolidated under us. On November 30, 2014, Occidental distributed shares of our common stock on a pro rata basis to Occidental stockholders and we became an independent, publicly traded company. Occidental retained approximately 18.5% of our outstanding shares of common stock which it has stated it intends to divest within 18 months of the Spin-off.

Except when the context otherwise requires or where otherwise indicated, (1) all references to ''CRC,'' the ''Company,'' ''we,'' ''us'' and ''our'' refer to California Resources Corporation and its subsidiaries or the California business, (2) all references to the ''California business'' refer to Occidental's California oil and gas exploration and production operations and related assets, liabilities and obligations, which we have assumed in connection with the Spin-off, and (3) all references to ''Occidental'' refer to Occidental Petroleum Corporation, our former parent, and its subsidiaries.

Basis of Presentation

Up until the Spin-off, the accompanying consolidated and combined financial statements were derived from the consolidated financial statements and accounting records of Occidental. These consolidated and combined financial statements reflect the historical results of operations, financial position and cash flows of the California business. 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 income and cash flows.

The consolidated and combined statements of income for periods prior to the Spin-off include expense allocations for certain corporate functions and centrally-located activities historically performed by Occidental. These functions include executive oversight, accounting, treasury, tax, financial reporting, finance, internal audit, legal, risk management, information technology, government relations, public relations, investor relations, human resources, procurement, engineering, drilling, exploration, marketing, ethics and compliance, and certain other shared services. These allocations are based primarily on specific identification of time or activities associated with us, employee headcount or our relative size compared to Occidental. Our management believes the assumptions underlying the consolidated and combined financial statements, including the assumptions regarding allocating expenses from Occidental, are reasonable. However, the financial statements may not include all of the actual expenses that would have been incurred, may include duplicative costs and may not reflect our consolidated and combined results of operations, financial position and cash flows had we operated as a stand-alone public company during the periods presented. Actual costs that would have been incurred if we had been a stand-alone company prior to the Spin-off would depend on multiple factors, including organizational structure and strategic and operating decisions. There may be some additional non-recurring costs of operating as a stand-alone company, which are not expected to be material.

The assets and liabilities in the consolidated and combined financial statements are presented on a historical cost basis. We have eliminated all of our significant intercompany transactions and accounts. Prior to the Spin-off, we participated in Occidental's centralized treasury management program and had not incurred any debt. Additionally, excess cash generated by our business was distributed to Occidental, and likewise our cash needs were provided by Occidental, in the form of contributions.

All financial information presented after the Spin-off represents the financial position, results of operations and cash flows of CRC, as follows:

- Our consolidated and combined statements of operations, comprehensive income and cash flows for the year ended December 31, 2014 consist of the stand-alone consolidated results of CRC following the Spin-off, and the consolidated and combined results of the California business from

January 1, 2014, through the Spin-off. Our statements of income, comprehensive income and cash flows for the years ended December 31, 2013 and 2012 consist entirely of the combined results of the California business.

- Our consolidated and combined balance sheet at December 31, 2014 consists of the consolidated balances of CRC, while at December 31, 2013, it consists of the combined balances of the California business.
- Our consolidated and combined statement of changes in equity for the year ended December 31, 2014 consists of both the California business prior to the Spin-off and the consolidated activity for CRC subsequent to the Spin-off. Our consolidated statement of changes in equity for the years ended December 31, 2013 and 2012 consist entirely of the combined activity of the California business.

Had we been a stand-alone company for the full year 2014, and had the same level of debt throughout the year as we did on December 31, 2014, of approximately $6.4 billion, we would have incurred $314 million pre-tax, or $186 million after-tax, of interest expense, on a pro-forma basis, for the year ended December 31, 2014, compared to the $72 million pre-tax interest expense reported in our statement of operations for the year then ended.

Certain prior year amounts have been reclassified to conform to the 2014 presentation.

Risks and Uncertainties

The process of preparing financial statements in conformity with United States generally accepted accounting principles requires management to 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.

Revenue Recognition

We recognize revenue from oil and natural gas production when title has passed from us to the transportation company or the customer, as applicable. We recognize our share of revenues net of any royalties and other third-party share.

Net Parent Company Investment

Prior to the Spin-off, our balance sheets included net parent company investment, which represented Occidental's historical investment in us, our accumulated net income and the net effect of transactions with, and allocations from, Occidental.

Inventories

Materials and supplies are valued at weighted-average cost and are reviewed periodically for obsolescence. Finished goods include oil and natural gas products, which are valued at the lower of cost or market.

Property, Plant and Equipment

The carrying value of our property, plant and equipment (PP&E) represents the cost incurred to acquire or develop the asset, including any asset retirement obligations and capitalized interest, net of accumulated depreciation, depletion and amortization (DD&A) and any impairment charges. For assets acquired, PP&E cost is based on fair values at the acquisition date. Asset retirement obligations are capitalized and amortized over the lives of the related assets.

We use the successful efforts method to account for 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 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 the 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.

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

	2014	2013	2012
		(in millions)	
Balance—Beginning of Year	$ 18	$ 18	$ 63
Additions to capitalized exploratory well costs pending the determination of proved reserves	3	46	62
Reclassification to property, plant and equipment based on the determination of proved reserves	(8)	(31)	(61)
Capitalized exploratory well costs charged to expense	(9)	(15)	(46)
Balance—End of Year	$ 4	$ 18	$ 18

We expense annual lease rentals, the costs of injection used in production and exploration geological, geophysical and seismic costs as incurred. Cost 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.

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. Substantially all of our total depreciation, depletion and amortization expense relates to production costs.

Proved oil and gas reserves and production volumes are used as the basis for recording depreciation and depletion of oil and gas properties. Proved reserves are those quantities of oil and natural gas which, 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.

Our gas plant 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 ranging from two to 30 years. Other property and equipment is depreciated using the straight-line method based on expected initial lives of the individual assets or group of assets ranging from two to 20 years.

We perform impairment tests with respect to proved properties when product prices decline other than temporarily, reserve 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, 2014, the net capitalized costs attributable to unproved properties were approximately $300 million. The unproved amounts are not subject to DD&A until they are classified as proved properties. As exploration and development work progresses, if reserves on these properties are proved, capitalized costs attributable to the properties become subject to DD&A. 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 timing of any write-downs of these 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.

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of $3.4 billion on proved and unproved properties throughout our asset base. The impairment charge was related to certain properties in the San Joaquin and Los Angeles basins and a portion of our assets in the Ventura basin, as well as our natural gas properties in the Sacramento basin. Approximately $650 million of the charge was related to unproved properties. The properties were impaired as a result of accounting rules that require us to evaluate our properties based on the year-end forward price curve, as well as projects we determined we would not pursue in the foreseeable future given the current environment.

In 2012, management decided not to pursue development of certain of our natural gas properties which were impacted by persistently low natural gas prices. As a result, we recorded an impairment charge in 2012 of $29 million.

Asset Retirement Obligations

We recognize the fair value of asset retirement obligations 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 liability amounts are based on future retirement cost estimates and incorporate many assumptions such as time to abandonment, 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 PP&E balances. If the estimated future cost of the asset retirement obligation changes, we record an adjustment to both the asset retirement obligation and PP&E. Over time, the liability is increased and expense is recognized for accretion, and the capitalized cost is depreciated over the useful life of the asset.

At certain of our facilities, we have identified asset retirement obligations 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 may settle these obligations and, therefore, we cannot reasonably estimate the fair value of these liabilities. We will recognize these asset retirement obligations 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 the asset retirement obligation, of which $397 million and $388 million is included in other long-term liabilities, with the remaining current portion in accrued liabilities at December 31, 2014 and 2013, respectively.

	For the years ended December 31,	
	2014	**2013**
	(in millions)	
Beginning balance	$ 415	$ 387
Liabilities incurred—capitalized to PP&E	19	25
Liabilities settled and paid	(29)	(9)
Accretion expense	22	21
Acquisitions, disposition and other—changes in PP&E	26	(2)
Revisions to estimated cash flows—changes in PP&E	(34)	(7)
Ending balance	$ 419	$ 415

Derivative Instruments

Derivatives are carried at fair value and on a net basis when a legal right of offset exists with the same counterparty. Fair value gains and losses from derivative instruments are recognized in earnings in the current period and are reported on a net basis in the statements of operations. We apply hedge accounting when transactions meet specified criteria for hedge treatment and management elects and documents such treatment. For hedges, the gain or loss on the effective portion of the derivative is reported as a component of other comprehensive income (OCI) with an offsetting adjustment to the basis of the item being hedged. Realized gains or losses from hedges, and any ineffective portion, are recorded as a component of net sales in the statements of operations. Ineffectiveness is primarily created by a lack of correlation between the hedged item and the hedging instrument due to location, quality, grade or changes in the expected quantity of the hedged item.

A hedge is regarded as highly effective such that it qualifies for hedge accounting if, at inception and throughout its life, we expect that changes in the fair value or cash flows of the hedged item will be offset by 80 to 125 percent of the changes in the fair value or cash flows, respectively, of the hedging instrument. In the case of hedging a forecast transaction, the transaction must be probable and must present an exposure to variations in cash flows that could ultimately affect reported net income or loss. We discontinue hedge accounting when we determine that a derivative has ceased to be highly effective as a hedge; when the hedged item matures or is sold or repaid; or when a forecast transaction is no longer deemed probable.

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. A summary of our accounting policy for awards issued under our plans is as follows.

The fair value of stock options granted to our employees is estimated on the date of grant using the Black-Scholes option pricing model. 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 stock option award. Of the required assumptions, the expected life of the stock option award and the expected volatility of our stock price have the most significant impact on the fair value calculation. In the absence of adequate stock price history of CRC common stock, the volatility factor is based on the average volatilities of the stocks of a select group of peer companies, which are similar in nature to us. The average expected life is calculated based on the simplified method.

For cash- and stock-settled restricted stock units, compensation value is initially measured on the grant date using the quoted market price of CRC common stock. Compensation expense for restricted stock units is recognized on a straight-line basis over the requisite service periods. Compensation expense for the cash-settled portion of the awards is adjusted cumulatively for changes in the value of the underlying stock on a quarterly basis. All stock-price-related changes are recognized in periodic compensation expense. The stock-settled portion of these awards is expensed using the initially measured compensation value.

Earnings Per Share

Our instruments containing rights to nonforfeitable dividends granted in stock-based awards are considered participating securities prior to vesting and, therefore, have been deducted from earnings in computing basic and diluted earnings per share under the two-class method.

Basic earnings per share was computed by dividing net income attributable to common stock, net of income allocated to participating securities, by the weighted-average number of common shares outstanding during each period, net of treasury shares, if any, and including vested but unissued shares and share units. The computation of diluted earnings per share reflects the additional dilutive effect of stock options and unvested stock awards.

Retirement and Postretirement Benefit Plans

Prior to the Spin-off, a majority of our employees participated in postretirement benefit plans sponsored by Occidental, which included participants from other Occidental subsidiaries. These plans had an insignificant amount of assets and were substantially funded as benefits were paid. We recognized a liability in the accompanying balance sheets for the employees of the California operations. The related postretirement expenses were allocated to us from Occidental based on the employees of the California business. Following the Spin-off, all of our employees participate in postretirement benefit plans sponsored by us. These plans are substantially funded as benefits are paid.

For defined benefit pension and postretirement plans that are sponsored by us, we recognize the net overfunded or underfunded amounts in the 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. Common stock, preferred stock, publicly registered mutual funds, U.S. government securities and corporate bonds are valued using quoted market prices in active markets when available. When quoted market prices are not available, these investments are valued using pricing models with observable inputs from both active and non-active markets. Common and collective trusts are valued at the fund units' net asset value (NAV) provided by the issuer, which represents the quoted price in a non-active market. Short-term investment funds are valued at the fund units' NAV provided by the issuer.

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

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 and discounts those cash flows using a risk-adjusted discount rate.

Commodity derivatives are carried at fair value. We utilize the mid-point between bid and ask prices for valuing these instruments. 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 (OTC) 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 carrying amounts of on-balance-sheet financial instruments approximate fair value.

Other Current Assets

Other current assets at December 31, 2014 include amounts due from joint interest partners of approximately $120 million, greenhouse gas emission credits of $65 million and deferred tax assets of $61 million. At December 31, 2013 other current assets included $97 million due from joint interest partners.

Accrued Liabilities

Accrued liabilities at December 31, 2014 include accrued compensation-related costs of approximately $80 million, interest payable of approximately $70 million, and greenhouse gas liabilities of approximately $65 million. At December 31, 2013 accrued liabilities included $70 million of accrued compensation-related costs.

Supplemental Cash Flow Information

We have not made United States federal and state income tax payments directly to taxing jurisdictions. Up until the Spin-off, our share of Occidental's tax payments or refunds were paid or received, as applicable, by our parent and are reflected as part of the net parent company investment. Such amounts paid during the year ended December 31, 2014 and 2013 were approximately $165 million and $318 million, respectively, while the year ended December 31, 2012 resulted in a net refund of approximately $121 million. We also paid taxes other than on income, consisting mostly of property taxes, of approximately $183 million, $185 million and $171 million during the years ended December 31, 2014, 2013 and 2012, respectively. Interest paid totaled approximately $3 million for the year ended December 31, 2014, and zero for each of the two years ended December 31, 2013 and 2012.

The 2014 capital investments reported on the statement of cash flows exclude changes to the consolidated balance sheets that did not affect cash primarily consisting of the increase in capital accruals during the year. Total capital investments in 2014 were $2.089 billion, which included $2.020 billion of cash paid for capital investments as reported in the statement of cash flows and $69 million in increase in capital accruals. For the years 2013 and 2012, the changes in the capital accrual amounts were not material.

In 2014, Occidental transferred to us certain assets, liabilities and accruals, of which the most significant consisted of outstanding trade receivables of approximately $400 million.

These non-cash transfers and the corresponding net contribution to us from Occidental were excluded from net cash provided by operating activities and cash flow from financing activities.

Major Customers

For the years ended December 31, 2014, 2013 and 2012, ConocoPhillips/Phillips 66 Company and Tesoro Refining & Marketing Company LLC each accounted for more than 10% of our net sales. Collectively, they accounted for 45%, 42% and 46% in each of those years, respectively.

Income Taxes

Our taxable income was historically included in the consolidated U.S. federal income tax returns of Occidental and in a number of their consolidated state income tax returns. In the accompanying financial statements, our provision for income taxes is computed as if we were a stand-alone tax-paying entity.

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 recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several factors, including our expectation that we will generate sufficient future taxable income and reversals of taxable temporary differences.

NOTE 2 ACCOUNTING AND DISCLOSURE CHANGES

Recently Adopted Accounting and Disclosure Changes

In August 2014, the Financial Accounting Standards Board (FASB) issued rules relating to management's responsibility to evaluate and make disclosures, if applicable, regarding the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. These rules are effective for annual periods ending after December 15, 2016. They are not expected to have a material impact on our financial statements upon adoption and will require assessment on an ongoing basis.

In June 2014, the FASB issued rules for employee share-based payment awards in which the terms of the awards provide that a performance target can be achieved after the requisite service period. A performance target that affects vesting and that could be achieved after the requisite service period will be treated as a performance condition. These rules are effective for annual periods beginning on or after December 15, 2015 and are not expected to have a material impact on our financial statements upon adoption but will require assessment on an ongoing basis.

In May 2014, the FASB issued rules related to revenue recognition. Under the new rules, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects to receive in exchange for the goods or services. The rules will also require more detailed disclosures of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The rules are effective for interim and annual periods beginning after December 15, 2016 and early application is not permitted. While we are evaluating any potential impact of these new rules, we currently believe the effect of the new rules will not have a material impact on our financial statements.

In April 2014, the FASB issued rules changing the requirements for reporting discontinued operations such that only the disposals of components of an entity that represent a strategic shift that has (or will have) a major effect on an entity's operations and financial results will be reported as discontinued operations in the financial statements. These rules are effective for the annual periods beginning on or after December 15, 2014. They are not expected to have a material impact on our financial statements upon adoption and will require assessment on an ongoing basis.

NOTE 3 ACQUISITIONS

2014

During the year ended December 31, 2014, we paid approximately $290 million to acquire certain producing and non-producing oil and gas properties, including oil and gas properties in the Ventura basin purchased for approximately $200 million in the fourth quarter of 2014.

2013

During the year ended December 31, 2013, we paid approximately $50 million to acquire certain oil and gas properties, including an acquisition in the San Joaquin basin, which obligates us to invest at least $250 million on exploration and development activities over a period of five years from the date of acquisition. We currently plan to invest more than this amount during that period. Any deficiency in meeting this capital investment obligation would need to be paid in cash at the end of the five-year period. Through December 31, 2014, we have already fulfilled about 20% of this obligation.

2012

During the year ended December 31, 2012, we paid approximately $380 million for oil and gas properties, including an acquisition for $275 million for certain producing and non-producing assets in the Sacramento basin and undeveloped acreage in the San Joaquin basin.

NOTE 4 INVENTORIES

Inventories consisted of the following:

	Balance at December 31,	
	2014	**2013**
	(in millions)	
Materials and supplies	$ 66	$ 73
Finished goods	5	2
Total	$ 71	$ 75

NOTE 5 DEBT

Debt consisted of the following:

	December 31,	
	2014	**2013**
	(in millions)	
Revolving Credit Facility	$ 360	$ –
Term Loan Facility	1,000	–
5% notes due 2020	1,000	–
5½% notes due 2021	1,750	–
6% notes due 2024	2,250	–
Total	$ 6,360	$ –

Credit Facilities

On September 24, 2014, we entered into a credit agreement with a syndicate of lenders, providing for (i) a five-year senior term loan facility (the "Term Loan Facility") and (ii) a five-year senior revolving loan facility (the "Revolving Credit Facility" and, together with the Term Loan Facility, the "Credit Facilities"). All borrowings under these facilities are subject to certain customary conditions. We amended the Credit Facilities effective as of February 25, 2015, and changed certain of our covenants through December 31, 2016 or such earlier time as we elect and demonstrate compliance with our original covenants for two successive quarters (the "Interim Covenant Period").

The aggregate initial commitments of the lenders under the Revolving Credit Facility are $2.0 billion and under the Term Loan Facility are $1.0 billion. The Revolving Credit Facility includes a sub-limit of $400 million for the issuance of letters of credit. We will be required to repay the Term Loan Facility in equal quarterly installments equal to 2.5% (10.00% per annum) of the principal amount of the Term Loan Facility beginning on March 31, 2016. As of December 31, 2014, we had $360 million outstanding under our Revolving Credit Facility with the ability to incur total net borrowings of up to $1.25 billion during the Interim Covenant Period under this facility.

Borrowings under the Credit Facilities bear interest, at our election, at either a LIBOR rate or an alternate base rate ("ABR") (equal to the greatest of (i) the administrative agent's prime rate, (ii) the one-month LIBOR rate plus 1.00% and (iii) the federal funds effective rate plus 0.50%), in each case plus an applicable margin. This applicable margin is based on our most recent leverage ratio and will vary from (a) in the case of LIBOR loans, 1.50% to 2.25% and (b) in the case of ABR loans, from 0.50% to 1.25%. The unused portion of the Revolving Credit Facility is subject to commitment fees ranging from 0.30% to 0.50% per annum, based on our most recent leverage ratio. We also pay customary fees and expenses under the Revolving Credit Facility.

Interest payments under the Credit Facilities vary based on the borrowing options chosen. Interest on ABR loans is payable quarterly in arrears. Interest on LIBOR loans is payable at the end of each LIBOR period.

All obligations under the Credit Facilities are guaranteed jointly and severally by all of our wholly-owned material subsidiaries, and will be unsecured while we maintain our credit ratings at the minimum levels defined in the Credit Facilities. During the Interim Covenant Period, we would be required to grant security to our lenders if our corporate family ratings experienced a two-notch decline from either of our rating agencies. Outside the Interim Covenant Period we would be required to grant security in the event of a three-notch decline subject to certain exceptions described in our Credit Facilities. The assets and liabilities of subsidiaries not guaranteeing the debt are de minimis.

The Credit Facilities also require us to maintain the following financial covenants for the trailing twelve months ended as of the last day of each fiscal quarter: (a) a leverage ratio of no more than 4.50 to 1.00 except during the Interim Covenant Period when the ratio increases by varying amounts to a maximum of 8.25 to 1.00 by December 31, 2015 and (b) an interest expense ratio of no less than 2.50 to 1.00 except as of December 31, 2015 when the ratio must be no less than 2.25 to 1.00. In addition, during the Interim Covenant Period, we must maintain an asset coverage ratio of no less than 1.05 to 1.00 measured as of the last day of each fiscal quarter. Finally, during the Interim Covenant Period, we must apply cash on hand in excess of $250 million to repay certain amounts outstanding under the Revolving Credit Facility. If we were to breach either of these covenants the banks would be permitted to accelerate the principal amount due under the facilities. If payment were accelerated it would result in a default under the notes.

Senior Notes

On October 1, 2014, we issued $5.00 billion in aggregate principal amount of our senior notes, including $1.00 billion of 5% senior notes due January 15, 2020 (the 2020 notes), $1.75 billion of 5½% senior notes due September 15, 2021 (the 2021 notes) and $2.25 billion of 6% senior notes due November 15, 2024 (the "2024 notes" and together with the 2020 notes and the 2021 notes, the "notes"), in a private placement. The notes were issued at par and initially are fully and unconditionally guaranteed on a senior unsecured basis by all of our material subsidiaries. We used the net proceeds from the notes to make a $4.95 billion cash distribution to Occidental in October 2014.

We will pay interest on the 2020 notes semi-annually in cash in arrears on January 15 and July 15 of each year, beginning on July 15, 2015. We will pay interest on the 2021 notes semi-annually in cash in arrears on March 15 and September 15 of each year, beginning on March 15, 2015. We will pay interest on the 2024 notes semi-annually in cash in arrears on May 15 and November 15 of each year, beginning on May 15, 2015.

In connection with the private placement of the notes, we granted the initial purchasers certain registration rights under a registration rights agreement.

The indenture governing the notes includes covenants that, among other things, limit our and our restricted subsidiaries' ability to incur debt secured by liens. These covenants also restrict our ability to merge or consolidate with, or transfer all or substantially all of our assets to, another entity. These covenants are subject to a number of important qualifications and limitations that are set forth in the indenture. 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) with respect to a series of notes, we will be required, unless we have exercised our right to redeem the notes of such series, to offer to purchase the notes of such series at a purchase price equal to 101 percent of their principal amount, plus accrued and unpaid interest.

Principal maturities of long-term debt outstanding at December 31, 2014 are as follows:

(in millions)	
2015	$ –
2016	100
2017	100
2018	100
2019	1,060
Thereafter	5,000
Total	$ 6,360

We estimate the fair value of fixed-rate debt based on prices from known market transactions for our instruments. The estimated fair value of our debt at December 31, 2014, the fixed rate portion of which was classified as Level 1, and the variable rate portion approximated fair value, was approximately $5.6 billion, compared to a carrying value of approximately $6.4 billion. A one-eighth percent change in the variable interest rates on the borrowings under our Term Loan Facility and Revolving Credit Facility on December 31, 2014, would result in an approximately $1.7 million change in annual interest expense. In 2014, we incurred $70 million in debt issuance costs related to the notes and the Credit Facility which we amortize using the effective interest rate method over the respective term of each instrument.

As of December 31, 2014, we had letters of credit in the aggregate amount of approximately $25 million that were issued to support ordinary course marketing, regulatory and other matters.

NOTE 6 LEASE COMMITMENTS

We have entered into various operating lease agreements, mainly for office space, office equipment, and field equipment. We lease assets when leasing offers greater operating flexibility. Lease payments are generally expensed as part of production costs or selling, general and administrative expenses. At December 31, 2014, future net minimum lease payments for noncancelable operating leases (excluding oil and natural gas and other mineral leases, utilities, taxes, insurance and maintenance expense) totaled:

	Amount (in millions)
2015	$ 13
2016	14
2017	14
2018	14
2019	12
Thereafter	58
Total minimum lease payments	$ 125

Rental expense for operating leases was $10 million in 2014, $11 million in 2013 and $12 million in 2012.

NOTE 7 LAWSUITS, CLAIMS, COMMITMENTS AND CONTINGENCIES

We, or certain of our subsidiaries, are involved, in the normal course of business, in lawsuits, environmental and other claims and other contingencies that seek, among other things, compensation for alleged personal injury, breach of contract, property damage or other losses, punitive damages, civil penalties, or injunctive or declaratory relief. We accrue reserves for currently outstanding lawsuits, claims and proceedings when it is probable that a liability has been incurred and the liability can be reasonably estimated. Reserve balances at December 31, 2014 and 2013 were not material to our balance sheets as of such dates. We also evaluate the amount of reasonably possible losses that we could incur as a result of these matters. We believe that reasonably possible losses that we could incur in excess of reserves accrued on our balance sheet would not be material to our consolidated financial position or results of operations.

We have certain commitments under contracts, including purchase commitments for goods and services. At December 31, 2014, total purchase obligations were approximately $364 million, which included approximately $70 million, $47 million, $32 million, $186 million and $18 million that will be paid in 2015, 2016, 2017, 2018 and 2019, respectively. Included in the purchase obligations are commitments for major fixed and determinable capital investments during 2015 and thereafter, which were approximately $264 million.

We, our subsidiaries, or both, have indemnified various parties against specific liabilities those parties might incur in the future in connection with the Spin-off, purchases and other transactions that they have entered into with us. These indemnities include indemnities made to Occidental against certain tax-related liabilities that may be incurred by Occidental relating to the Spin-off and liabilities related to operation of our business while it was still owned by Occidental. As of December 31, 2014, we are not aware of circumstances that we believe would reasonably be expected to lead to indemnity claims that would result in payments materially in excess of reserves.

NOTE 8 DERIVATIVES

In February 2015, we put into place additional hedging instruments to protect the pricing for almost two-thirds of our expected third quarter 2015 oil production. For this program we chose a combination of Brent-based collars (between $55 and $72) for 30,000 barrels per day for July through September as well as put options at $50 per barrel Brent for 40,000 barrels per day in the same period. In addition, we sold a $75 per barrel call for 30,000 barrels per day of oil production in March through June of 2015. Going forward as an independent company, we will continue to be strategic and opportunistic in implementing any hedging program. Our objective is to protect against the cyclical nature of commodity prices to provide a level of certainty around our margins and cash flows necessary to implement our investment program.

In December 2014, we purchased put options, to hedge the risk associated with declining oil prices, for 100,000 barrels of crude oil production per day, effective on a monthly basis from January 1, 2015 through June 30, 2015. The strike price of the put option is $50 tied to the Brent oil index. Changes in the intrinsic value of the put option are deferred in other comprehensive income/(loss) as a cash flow hedge until the hedged transactions are recognized in the statement of operations. Changes in the time value of the put option are marked to market through the statement of operations. The put option was valued using Level 2 inputs in the fair value hierarchy and was valued at approximately $24 million in other current assets, as of December 31, 2014, which approximated the value of the instrument and the amount we paid the counterparty at the time the option was acquired.

We entered into financial swap agreements in November 2012 for the sale of a portion of our natural gas production. These swap agreements hedged 50 MMcf of natural gas per day beginning in January 2013 through March 2014 and qualified as cash-flow hedges. The weighted-average strike price of these swaps was $4.30. The gross and net fair values of these derivatives as of December 31, 2013 were not material and were considered Level 2.

The after-tax gains and losses recognized in, and reclassified to income from, Accumulated Other Comprehensive Income (AOCI), for derivative instruments classified as cash-flow hedges for the years ended December 31, 2014, 2013 and 2012, and the ending AOCI balances for each period were not material. We recognized gains and losses reclassified to income in net sales. The amount of the ineffective portion of cash-flow hedges was immaterial for the years ended December 31, 2014, 2013 and 2012. Refer to Note 1 for our accounting policy on derivatives.

There were no fair value hedges as of and during the years ended December 31, 2014, 2013 and 2012.

NOTE 9 FAIR VALUE MEASUREMENTS

Fair Values—Recurring

The following table presents assets accounted for at fair value on a recurring basis as of December 31, 2014:

	December 31, 2014				
(in millions)	**Level**	**Level 2**	**Level 3**	**Collateral**	**Total**
Commodity derivative instruments, other current assets	–	24	–	–	
Total	–	24	–	–	24

Commodity derivative instruments in Level 2 are over-the-counter put options for the first 100,000 barrels of crude oil production per day, effective on a monthly basis from January 1, 2015 through June 30, 2015, and are measured at fair value by using industry-standard models using various inputs, including quoted forward prices. We had no material assets or liabilities accounted for at fair value as of December 31, 2013.

Fair Values—Nonrecurring

At year end 2014, we performed impairment tests with respect to our proved and unproved properties as a result of significant declines in oil prices largely during the last half of 2014. We determined the carrying amounts of certain assets were not recoverable from future cash flows and, therefore, were impaired. As a result, in the fourth quarter of 2014, we recorded pre-tax asset impairment charges of $3.4 billion, of which $2.7 billion was for proved properties throughout our asset base to reduce these assets to their estimated fair values. The impairment charge was related to certain properties in the San Joaquin and Los Angeles basins and a portion of our assets in the Ventura basin, as well as our natural gas properties in the Sacramento basin.

The fair values of the proved properties held and used were determined as of the date of the assessment using discounted cash flow models based on management's expectations for the future. Inputs included estimates of future oil and natural gas production, prices based on recent commodity forward price curves as of the date of the estimate, estimated operating and development costs, and a risk-adjusted discount rate of 10%.

Financial Instruments Fair Value

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

NOTE 10 INCOME TAXES

Income / (loss) before income taxes was ($2,421) million, $1,447 million and $1,181 million for the years ended December 31, 2014, 2013 and 2012, respectively. The provision (benefit) for federal, state and local income taxes consists of the following:

For the years ended December 31,	United States Federal	State and Local	Total
		(in millions)	
2014			
Current	$ 66	$ 99	$ 165
Deferred	(840)	(312)	(1,152)
	$ (774)	$ (213)	$ (987)
2013			
Current	$ 227	$ 91	$ 318
Deferred	222	38	260
	$ 449	$ 129	$ 578
2012			
Current	$ (140)	$ 19	$ (121)
Deferred	518	85	603
	$ 378	$ 104	$ 482

The following reconciliation of the United States federal statutory income tax rate to our effective tax rate is stated as a percentage of pre-tax income or loss:

	For the years ended December 31,		
	2014	2013	2012
United States federal statutory tax rate	35%	35%	35%
State income taxes, net of federal benefit	6	6	6
Other	–	(1)	–
Effective tax rate	41%	40%	41%

The tax effects of temporary differences resulting in deferred income taxes at December 31, 2014 and 2013 were as follows:

	2014		2013	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
		(in millions)		
Property, plant and equipment differences	$ –	$ (2,437)	$ –	$ (3,583)
Postretirement benefit accruals	39	–	14	–
Deferred compensation and benefits	62	–	60	–
Asset retirement obligations	184	–	182	–
Federal benefit of state income taxes	68	–	208	–
Net operating loss carryforwards	64	–	8	–
All other	27	(1)	14	(2)
Total deferred taxes	$ 444	$ (2,438)	$ 486	$ (3,585)

The current portion of deferred tax assets was $61 million and $23 million as of December 31, 2014 and 2013, respectively, which was reported in other current assets. The noncurrent portion of total deferred tax assets was reported net against deferred tax liabilities.

We evaluate our deferred tax assets to determine if a valuation allowance is required to reduce our deferred tax assets to an amount expected to be realized. We expect to realize our deferred tax assets through future taxable income and reversals of taxable temporary differences.

Due to the Spin-off on November 30, 2014, we will file short year U.S. federal and California income tax returns for the one month ended December 31, 2014. Prior to the Spin-off date, we were included in the Occidental income tax returns for all applicable years. There could be a settlement between us and Occidental under the tax sharing agreement related to income taxes for the periods prior to the Spin-off. The income tax provision was calculated as if we filed separate tax returns for all periods presented prior to the Spin-off. For the one-month period ended December 31, 2014, there is no current income tax provision and a $1.5 billion deferred income tax benefit for U.S. federal and California taxes. As of December 31, 2014, an insignificant amount is due to Occidental under the tax sharing agreement. There were no amounts due to Occidental as of December 31, 2013.

We have no liabilities for unrecognized tax benefits as of December 31, 2014 and 2013. We believe there will not be material changes to our unrecognized tax benefits within the next 12 months. We recognize interest and penalties, if any, related to uncertain tax positions in the income tax provision. There were no amounts of interest and penalties related to uncertain tax positions during the years ended December 31, 2014, 2013 and 2012.

As of December 31, 2014, we had $182 million of U.S. federal net operating losses and $207 million of California net operating losses. The net operating loss carryforwards resulted from operations during the one-month ended December 31, 2014 and from the acquisition of a subsidiary in a prior year. The U.S. federal net operating losses begin expiring in 2017 and the California net operating losses begin expiring in 2015. Utilization of $22 million of the U.S. federal and $112 million of the California net operating loss carryforward is subject to an annual limitation as a result of these acquisitions and no financial statement benefit has been recognized for this portion of the net operating loss carryforward.

Our tax returns for the one-month period December 2014 will be subject to examination by U.S. federal and California tax authorities when filed. 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.

NOTE 11 STOCK COMPENSATION

General

Prior to the Spin-off, our employees participated in Occidental's stock-based incentive plans under which, if they were eligible, they received Occidental stock awards. Effective on the Spin-off date of November 30, 2014, our employees and non-employee directors began participating in our long-term incentive plan.

Our incentive plan authorizes the Compensation Committee of our Board of Directors to grant up to a total of 25 million shares in the form of stock options, stock appreciation rights, stock awards, performance awards and cash awards, among others, to our employees, non-employee directors and other plan participants.

In connection with the Spin-off, unvested share-based compensation awards granted to our employees under Occidental's stock-based incentive plans and held by grantees as of November 30, 2014 were replaced with substitute awards based on CRC common shares. These substitute awards were intended to generally preserve the value of the original Occidental award determined as of November 30, 2014. Original and remaining vesting periods of Occidental awards were unaffected by the substitution. There were approximately 650 employees affected by the substitution of awards. The substitution of awards did not cause us to recognize incremental compensation expense. These substitute awards reduced the maximum number of shares of our common stock available for delivery under our incentive plan.

We expense all share-based payments to employees and non-employee directors based on the grant date fair value of the awards over the requisite service period, adjusted for estimated forfeitures.

During 2014, non-employee directors were granted awards for approximately 74,600 shares of restricted stock, which fully vest one year from the date of grant. Compensation expense for these awards that will be recognized during the vesting period was measured using the quoted market price of our common stock on the grant date.

Compensation expense for stock-based awards for the month ended December 31, 2014 was approximately $1 million. Prior to the Spin-off, Occidental allocated certain costs to us which included compensation costs for stock-based awards of Occidental stock. If we were to estimate the equity compensation component of all costs allocated to us by Occidental using the same allocation method used by Occidental, stock compensation expense allocated to us was approximately $26 million, $33 million and $20 million for January 1, 2014 through November 30, 2014, total year 2013, and total year 2012, respectively. Since these costs were allocated to us, it is not practical to calculate the tax benefit for those years.

As of December 31, 2014, unrecognized compensation expense for all our unvested stock-based incentive awards, based on the year end value of our common stock, was $74 million. This expense is expected to be recognized over a weighted-average period of 2.3 years.

Restricted Stock Units

Certain employees are awarded restricted stock units (RSUs), some of which have performance criteria, and are in the form of, or equivalent in value to, actual shares of CRC common stock. Depending on their terms, restricted stock units are settled in cash or stock at the time of vesting. These awards vest ratably over three years, or at the end of two or three years, following the date of grant, or upon satisfaction of any performance criteria, if later. For a substantial majority of the restricted stock units, dividend equivalents are paid during the vesting period.

There were no CRC restricted stock units granted for the years ended December 31, 2013 or 2012. The following summarizes our restricted stock unit activity for the year ended December 31, 2014:

	Cash-Settled		Stock-Settled	
	RSUs (000's)	Weighted-Average Grant-Date Fair Value	RSUs (000's)	Weighted-Average Grant-Date Fair Value
Unvested at December 31, 2013	–	$ –	–	$ –
Granted	4,562	$ 7.37	6,663	$ 7.84
Vested	–	$ –	–	$ –
Forfeited	(14)	$ 7.37	–	$ –
Unvested at December 31, 2014	4,548	$ 7.37	6,663	$ 7.84

Of the total awards granted, approximately 4,562,000 cash-settled units and 5,950,000 stock-settled units were substitute awards. The remainder were new awards granted following the Spin-off.

Stock Options

Following the Spin-off, we granted stock options to certain employees under our long-term incentive plan. The options permit 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, with one-third vesting and becoming exercisable on each anniversary date following the date of grant.

The fair value of each option 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 expected life of stock options is calculated based on the simplified method and represents the period of time that options granted are expected to be held prior to exercise. In the absence of adequate stock price history of CRC common stock, the volatility factor is based on the average volatilities of the stocks of a select group of peer companies, which are similar in nature to us. The risk-free interest rate is the implied yield available on zero coupon (US Treasury Strip) T-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. Estimates of fair value are not intended to predict actual future events or the value ultimately realized by employees who receive stock-based incentive awards, and subsequent events may not be indicative of the reasonableness of the original estimates of fair value made by us.

The following table summarizes our option activity during the year ended December 31, 2014:

	Options (000's)	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Aggregate Intrinsic Value
Beginning balance, December 31, 2013	–	$ –	$ –	$ –
Granted	8,481	8.11	1.98	–
Exercised	–	–	–	–
Forfeited	–	–	–	–
Expired or Canceled	–	–	–	–
Ending balance, December 31, 2014	8,481	$ 8.11	$ 1.98	$ –

There were no CRC options granted for the years ended December 31, 2013 and 2012. There were no vested or exercisable options at December 31, 2014.

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

	2014
Exercise price per share	$ 8.11
Expected life (in years)	4.5
Expected volatility	35.4%
Risk-free interest rate	1.4%
Dividend yield	0.5%
Grant date fair value of stock option awards granted	$ 1.98

Employee Stock Purchase Plan

Effective January 1, 2015, we have adopted the California Resources Corporation 2014 Employee Stock Purchase Plan (the ''ESPP''). The ESPP will provide 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 shares of our common stock which may be issued pursuant to the ESPP is subject to certain annual limits and has a cumulative limit of 5 million shares, subject to adjustment pursuant to the terms of the ESPP. As of January 1, 2015, about 45% of our employees have elected to participate in the plan.

NOTE 12 EQUITY

The following is a summary of common stock issuances:

	Common Stock
	(in 000's)
Balance, December 31, 2013	–
Issued	385,640
Balance, December 31, 2014	385,640

All stock issuances occurred in conjunction with the Spin-off. Approximately 3,537,000 shares consisted of CRC employee stock-based incentive awards converted from Occidental awards and approximately 713,000 shares were for new CRC employee awards, all of which were unvested as of the Spin-off date.

Preferred Stock

In November 2014, our board of directors authorized 200 million shares of preferred stock with a par value of $0.01 per share. At December 31, 2014, we had no outstanding shares of preferred stock.

ACCUMULATED OTHER COMPREHENSIVE INCOME / (LOSS)

Accumulated other comprehensive loss consisted of the following after-tax amounts:

	Balance at December 31, 2014	Balance at December 31, 2013
	(in millions)	
Unrealized losses (gains) on derivatives	$ –	$ (1)
Pension and post-retirement adjustments[(a)]	(24)	(23)
Total	$ (24)	$ (24)

(a) See Note 14 for further information.

NOTE 13 EARNINGS PER SHARE

We compute earnings per share (EPS) using the two-class method required for participating securities. Undistributed earnings allocated to participating securities are subtracted from net income in determining net income attributable to common stockholders. Restricted stock awards are considered participating securities because holders of such shares have non-forfeitable dividend rights in the event of our declaration of a dividend for common shares.

The denominator of basic EPS is the sum of the daily weighted-average number of common shares outstanding during the periods presented and vested stock awards that have not yet been issued as common stock. The denominator of diluted EPS is based on the basic shares outstanding, adjusted for the effect of outstanding option awards, to the extent they are dilutive.

On December 1, 2014, the Spin-off date, 381.4 million shares of our common stock were distributed, of which approximately 18.5% was retained by Occidental. For comparative purposes, and to provide a more meaningful calculation of weighted-average shares outstanding, we have assumed this amount to be outstanding as of the beginning of each period prior to the Spin-off presented in the calculation of weighted-average shares. In addition, we have assumed the vested stock awards granted in December 2014 were also outstanding for each of the periods presented prior to the Spin-off, resulting in a weighted-average basic share count of 381.8 million shares. The effect of stock options granted in December 2014 was anti-dilutive.

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

	2014	2013	2012
	(in millions, except per-share amounts)		
Basic EPS calculation			
Net income / (loss)	$ (1,434)	$ 869	$ 699
Net income / (loss) allocated to participating securities	–	(14)	(11)
Net income / (loss) available to common stockholders	$ (1,434)	$ 855	$ 688
Weighted-average common shares outstanding—basic	381.9	381.8	381.8
Basic EPS	$ (3.75)	$ 2.24	$ 1.80
Diluted EPS calculation			
Net income / (loss)	$ (1,434)	$ 869	$ 699
Net income / (loss) allocated to participating securities	–	(14)	(11)
Net income / (loss) available to common stockholders	$ (1,434)	$ 855	$ 688
Weighted average common shares outstanding—basic	381.9	381.8	381.8
Dilutive effect of potentially dilutive securities	–	–	–
Weighted-average common shares outstanding—diluted	381.9	381.8	381.8
Diluted EPS	$ (3.75)	$ 2.24	$ 1.80

NOTE 14 RETIREMENT AND POSTRETIREMENT BENEFIT PLANS

We have various benefit plans for our salaried, union and nonunion hourly employees.

Defined Contribution Plans

All of our employees were eligible to participate in one or more of the defined contribution retirement or savings plans that provide for periodic contributions by us, our subsidiaries or, prior to the Spin-off, by Occidental, based on plan-specific criteria, such as base pay, age, level and employee contributions. Certain salaried employees participated in a supplemental retirement plan that restored benefits lost due to governmental limitations on qualified retirement benefits. The accrued liabilities for the supplemental retirement plan were $27 million and $17 million as of December 31, 2014 and 2013, respectively, and we expensed $29 million in 2014, $34 million in 2013 and $35 million in 2012 under the provisions of these defined contribution and supplemental retirement plans.

Defined Benefit Plans

Participation in defined benefit pension plans sponsored by us is limited. Approximately 260 employees, including union and certain nonunion employees who joined us from acquired operations with grandfathered benefits, are currently accruing benefits under these plans.

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

Postretirement and Other Benefit Plans

We provided postretirement medical and dental benefits and life insurance coverage for our employees and their eligible dependents through Occidental-sponsored plans prior to the Spin-off, and provide them through CRC-sponsored plans following the Spin-off. The benefits were generally funded as they were paid during the year. These benefit costs were approximately $22 million in 2014, $18 million in 2013 and $17 million in 2012.

Obligations and Funded Status

The following tables show the amounts recognized in our balance sheets related to pension and postretirement benefit plans, including our share of obligations for Occidental-sponsored plans as well as plans that we or our subsidiaries sponsor, and their funding status, obligations and plan asset fair values (in millions):

	Pension Benefits		Postretirement Benefits	
	As of December 31,			
	2014	2013	2014	2013
Amounts recognized in the balance sheet:				
Accrued liabilities	$ –	$ –	$ –	$ (1)
Other long-term liabilities	(21)	(12)	(68)	(62)
	$ (21)	$ (12)	$ (68)	$ (63)
AOCI included the following after-tax balances:				
Net loss	$ 22	$ 19	$ 2	$ 4

	Pension Benefits		Postretirement Benefits	
	2014	2013	2014	2013
Changes in the benefit obligation:				
Benefit obligation—beginning of year	$ 103	$ 108	$ 63	$ 74
Service cost—benefits earned during the period	4	5	4	4
Interest cost on projected benefit obligation	4	3	2	3
Actuarial (gain) loss	6	(2)	(1)	(18)
Benefits paid	(9)	(11)	–	–
Benefit obligation—end of year	$ 108	$ 103	$ 68	$ 63
Changes in plan assets:				
Fair value of plan assets—beginning of year	$ 91	$ 74	$ –	$ –
Actual return on plan assets	5	13	–	–
Employer contributions	–	15	–	–
Benefits paid	(9)	(11)	–	–
Fair value of plan assets—end of year	$ 87	$ 91	$ –	$ –
(Unfunded) status:	$ (21)	$ (12)	$ (68)	$ (63)

The following table sets forth the accumulated and projected benefit obligations and fair values of assets of the defined benefit pension plans:

	Accumulated Benefit Obligation in Excess of Plan Assets		Plan Assets in Excess of Accumulated Benefit Obligation	
	As of December 31,			
	2014	2013	2014	2013
	(in millions)			
Projected Benefit Obligation	$ 31	$ 30	$ 77	$ 73
Accumulated Benefit Obligation	$ 26	$ 25	$ 62	$ 58
Fair Value of Plan Assets	$ 19	$ 23	$ 68	$ 68

We do not expect any plan assets to be returned during 2014.

COMPONENTS OF NET PERIODIC BENEFIT COST

The following table sets forth the components of net periodic benefit costs:

	Pension Benefits			Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
	(in millions)					
Net periodic benefit costs:						
Service cost—benefits earned during the period	$ 4	$ 5	$ 4	$ 4	$ 5	$ 4
Interest cost on projected benefit obligation	4	3	4	2	3	3
Expected return on plan assets	(6)	(4)	(4)	–	–	–
Recognized actuarial loss	2	4	4	1	2	2
Settlement cost	2	2	6	–	–	–
Net periodic benefit cost	$ 6	$ 10	$ 14	$ 7	$ 10	$ 9

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $2 million and zero, respectively. We do not expect to have any estimated net loss or prior service cost for the defined benefit postretirement plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year.

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

	Pension Benefits		Postretirement Benefits	
	For the years ended December 31,			
	2014	2013	2014	2013
Benefit Obligation Assumptions:				
Discount rate	3.82%	4.45%	4.44%	4.75%
Rate of compensation increase	4.00%	4.00%	–	–
Net Periodic Benefit Cost Assumptions:				
Discount rate	4.45%	3.59%	4.75%	3.89%
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 2014 and the Aon/Hewitt AA-AAA Universe yield curve in 2013. 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 2014, we adopted the Society of Actuaries 20014 Mortality Tables Report and Mortality Improvement Scale, which updated the mortality assumptions that private defined benefit pension plans in the United States use in the actuarial valuations that determine a plan sponsor's pension and postretirement obligations. The updated mortality data reflects increasing life expectancies in the United States, and affected plans generally expect the value of the actuarial obligations to increase, depending on the specific demographic characteristics of the plan participants and the types of benefits. The changes in the mortality assumptions resulted in an increase of $2 million and $7 million in the pension and postretirement benefit obligation, respectively, at December 31, 2014.

The postretirement benefit obligation was determined by application of the terms of medical and dental benefits and life insurance coverage, 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 1.79% and 2.36% as of December 31, 2014 and 2013, 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 healthcare cost trend rates would decrease 0.25 percent per year from 7.75 percent in 2014 until they reach 5.0% in 2025, and remain at 5.0% thereafter. A 1-percent increase or a 1-percent decrease in these assumed healthcare cost trend rates would result in an increase of $6 million or a reduction of $5 million, respectively, in the postretirement benefit obligation as of December 31, 2014. The annual service and interest costs would not be materially affected by these changes.

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. The investments were monitored by Occidental's Investment Committee in its role as fiduciary through November 30, 2014, and by our Investment Committee thereafter. Equity investments were diversified across United States and non-United States 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. 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 (in millions):

	Fair Value Measurements at December 31, 2014 Using			
	Level 1	Level 2	Level 3	Total
Asset Class:				
Commingled funds:				
Fixed income	$ –	$ 20	$ –	$ 20
U.S. equity	–	31	–	31
International equity	–	17	–	17
Mutual funds:				
Bond funds	5	–	–	5
Blend funds	2	–	–	2
Value funds	2	–	–	2
Growth funds	3	–	–	3
Guaranteed deposit account	–	–	7	7
Total pension plan assets	$ 12	$ 68	$ 7	$ 87

	Fair Value Measurements at December 31, 2013 Using			
	Level 1	Level 2	Level 3	Total
Asset Class:				
Master trust investment account[(a)]	$ –	$ 69	$ –	$ 69
Mutual funds:				
Bond funds	5	–	–	5
Blend funds	3	–	–	3
Value funds	3	–	–	3
Growth funds	3	–	–	3
Guaranteed deposit account	–	–	9	9
Total pension plan assets[(b)]	$ 14	$ 69	$ 9	$ 92

(a) Represents our investment in a master trust investment account established by Occidental. The trust investments include common stock, preferred stock, publicly registered mutual funds, U.S. government securities and corporate bonds.
(b) Amounts exclude net payables of approximately $1 million.

The activity during the years ended December 31, 2014 and 2013, for the assets using Level 3 fair value measurements was insignificant. We expect to contribute $3 million to our defined benefit pension plans during 2015.

Estimated future benefit payments, which reflect expected future service, as appropriate, are as follows:

For the years ended December 31,	Pension Benefits	Postretirement Benefits
	(in millions)	
2015	$ 15	$ –
2016	$ 9	$ 1
2017	$ 8	$ 1
2018	$ 10	$ 2
2019	$ 9	$ 2
2020 - 2024	$ 44	$ 17

NOTE 15 RELATED-PARTY TRANSACTIONS

During 2014, 2013 and 2012, we entered into the following related-party transactions:

	2014	2013	2012
		(in millions)	
Sales[(a)]	$ 2,706	$ 4,174	$ 3,970
Allocated costs for services provided by affiliates	$ 126	$ 146	$ 129
Purchases	$ 175	$ 164	$ 119

(a) Amounts include related-party sales from our Elk Hills power plant of $89 million, $120 million and $92 million during 2014, 2013 and 2012, respectively. These sales are included in other revenue in the statements of operations.

Through July 2014, substantially all of our products were sold through Occidental's marketing subsidiaries at market prices and were settled at the time of sale to those entities. Beginning August 2014, we started marketing our own products directly to third parties. For the years ended December 31, 2014, 2013 and 2012, sales to Occidental subsidiaries accounted for approximately 65%, 97% and 97% of our net sales, respectively.

The statements of operations include expense allocations for certain corporate functions and centrally-located activities performed by Occidental prior to the Spin-off. These functions include executive oversight, accounting, treasury, tax, financial reporting, internal audit, legal, risk management, information technology, government relations, public relations, investor relations, human resources, procurement, engineering, drilling, exploration, finance, marketing, ethics and compliance, and certain other shared services. Charges from Occidental for these services are generally reflected in selling, general and administrative expenses and also include employee-related costs such as salaries, bonuses and stock compensation costs.

Purchases from related parties reflect products purchased at market prices from Occidental's subsidiaries and used in our operations. These purchases are included in production costs. There were no significant related-party receivable or payable balances at December 31, 2014, 2013 and 2012.

Quarterly Financial Data (Unaudited)

Quarter	2014 First	2014 Second	2014 Third	2014 Fourth	2013 First	2013 Second	2013 Third	2013 Fourth
	(in millions, except per share amounts)							
Revenues	$ 1,121	$ 1,140	$ 1,092	$ 820	$ 1,047	$ 1,051	$ 1,107	$ 1,079
Gross profit	865	878	830	577	812	813	863	836
Net income / (loss)[a]	$ 223	$ 246	$ 188	$ (2,091)	$ 217	$ 205	$ 235	$ 212
Net income / (loss) per share[b]:								
Basic	$ 0.57	$ 0.63	$ 0.48	$ (5.47)	$ 0.56	$ 0.53	$ 0.61	$ 0.55
Diluted	$ 0.57	$ 0.63	$ 0.48	$ (5.47)	$ 0.56	$ 0.53	$ 0.61	$ 0.55

(a) For the quarter ended December 31, 2014, amount includes after-tax non-cash charges consisting of $2.0 billion of asset impairments, $31 million of rig termination and other price-related costs, and $33 million of Spin-off and transition related costs.

(b) For comparative purposes, and to provide a more meaningful calculation for weighted-average shares, we assumed the shares distributed to Occidental stockholders in conjunction with the Spin-off were outstanding at the beginning of each period prior to the Spin-off.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

The following tables set forth our net interests in quantities of proved developed and undeveloped reserves of oil (including condensate), natural gas liquids (NGLs) and natural gas and changes in such quantities. Reserves are stated net of applicable royalties. Estimated reserves include our economic interests under arrangements similar to production-sharing contracts (PSCs) relating to the Wilmington field in Long Beach. All of our proved reserves are located within the State of California.

Oil Reserves

	San Joaquin Basin	Los Angeles Basin[(a)]	Ventura Basin	Sacramento Basin	Total
	(in millions of barrels (MMBbl))				
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2011	337	130	41	–	508
Revisions of previous estimates	(44)	1	(3)	–	(46)
Improved recovery	36	16	11	–	63
Extensions and discoveries	3	–	–	–	3
Purchases of proved reserves	1	–	–	–	1
Sales of proved reserves	–	–	–	–	–
Production	(21)	(9)	(2)	–	(32)
Balance at December 31, 2012	312	138	47	–	497
Revisions of previous estimates	(8)	3	(3)	–	(8)
Improved recovery	49	24	3	–	76
Extensions and discoveries	–	–	–	–	–
Purchases of proved reserves	–	–	–	–	–
Sales of proved reserves	–	–	–	–	–
Production	(21)	(10)	(2)	–	(33)
Balance at December 31, 2013	332	155	45	–	532
Revisions of previous estimates	(41)	8	(4)	–	(37)
Improved recovery	70	11	4	–	85
Extensions and discoveries	1	–	–	–	1
Purchases of proved reserves	1	–	5	–	6
Sales of proved reserves	–	–	–	–	–
Production	(23)	(11)	(2)	–	(36)
Balance at December 31, 2014	340	163	48	–	551
PROVED DEVELOPED RESERVES					
December 31, 2011	240	97	30	–	367
December 31, 2012	221	104	30	–	355
December 31, 2013	226	109	28	–	363
December 31, 2014[(b)]	229	124	34	–	387
PROVED UNDEVELOPED RESERVES					
December 31, 2011	97	33	11	–	141
December 31, 2012	91	34	17	–	142
December 31, 2013	106	46	17	–	169
December 31, 2014	111	39	14	–	164

(a) Includes proved reserves related to economic arrangements similar to PSCs of 116 MMBbl, 102 MMBbl, 98 MMBbl and 92 MMBbl at December 31, 2014, 2013, 2012 and 2011, respectively.

(b) Approximately 11 percent of the proved developed reserves at December 31, 2014 are nonproducing.

NGLs Reserves

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in MMBbl)		
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2011	66	–	2	–	68
Revisions of previous estimates	(14)	–	–	–	(14)
Improved recovery	12	–	1	–	13
Extensions and discoveries	–	–	–	–	–
Purchases of proved reserves	–	–	–	–	–
Sales of proved reserves	–	–	–	–	–
Production	(6)	–	–	–	(6)
Balance at December 31, 2012	58	–	3	–	61
Revisions of previous estimates	13	–	–	–	13
Improved recovery	4	–	–	–	4
Extensions and discoveries	–	–	–	–	–
Purchases of proved reserves	–	–	–	–	–
Sales of proved reserves	–	–	–	–	–
Production	(7)	–	–	–	(7)
Balance at December 31, 2013	68	–	3	–	71
Revisions of previous estimates	8	–	–	–	8
Improved recovery	13	–	–	–	13
Extensions and discoveries	–	–	–	–	–
Purchases of proved reserves	–	–	–	–	–
Sales of proved reserves	–	–	–	–	–
Production	(7)	–	–	–	(7)
Balance at December 31, 2014	82	–	3	–	85
PROVED DEVELOPED RESERVES					
December 31, 2011	42	–	2	–	44
December 31, 2012	42	–	1	–	43
December 31, 2013	47	–	1	–	48
December 31, 2014[(a)]	62	–	2	–	64
PROVED UNDEVELOPED RESERVES					
December 31, 2011	24	–	–	–	24
December 31, 2012	16	–	2	–	18
December 31, 2013	21	–	2	–	23
December 31, 2014	20	–	1	–	21

(a) Approximately 5 percent of the proved developed reserves at December 31, 2014 are nonproducing.

Natural Gas Reserves

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
		(in billions of cubic feet (Bcf))			
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2011	810	24	34	48	916
Revisions of previous estimates	(150)	(6)	(3)	(9)	(168)
Improved recovery	100	1	9	1	111
Extensions and discoveries	6	–	–	6	12
Purchases of proved reserves	2	–	–	154	156
Sales of proved reserves	–	–	–		–
Production	(74)	(1)	(4)	(14)	(93)
Balance at December 31, 2012	694	18	36	186	934
Revisions of previous estimates	(4)	(4)	(1)	(38)	(47)
Improved recovery	47	3	2	–	52
Extensions and discoveries	–	–	–	–	–
Purchases of proved reserves	–	–	–	–	–
Sales of proved reserves	–	–	–	–	–
Production	(66)	(1)	(4)	(24)	(95)
Balance at December 31, 2013	671	16	33	124	844
Revisions of previous estimates	(91)	–	4	7	(80)
Improved recovery	107	–	2	5	114
Extensions and discoveries	–	–	–	–	–
Purchases of proved reserves	–	–	2	–	2
Sales of proved reserves	–	–	–	–	–
Production	(66)	–	(4)	(20)	(90)
Balance at December 31, 2014	621	16	37	116	790
PROVED DEVELOPED RESERVES					
December 31, 2011	550	18	29	48	645
December 31, 2012	475	13	26	154	668
December 31, 2013	455	9	22	117	603
December 31, 2014[(a)]	458	11	28	110	607
PROVED UNDEVELOPED RESERVES					
December 31, 2011	260	6	5	–	271
December 31, 2012	219	5	10	32	266
December 31, 2013	216	7	11	7	241
December 31, 2014	163	5	9	6	183

(a) Approximately 9 percent of the proved developed reserves at December 31, 2014 are nonproducing.

Total Reserves

	San Joaquin Basin	Los Angeles Basin[b]	Ventura Basin	Sacramento Basin	Total
			(in MMBoe[a])		
PROVED DEVELOPED AND UNDEVELOPED RESERVES					
Balance at December 31, 2011	537	134	52	6	729
Revisions of previous estimates	(83)	–	(4)	(1)	(88)
Improved recovery	65	16	13	–	94
Extensions and discoveries	5	–	1	1	7
Purchases of proved reserves	1	–	–	25	26
Sales of proved reserves	–	–	–	–	–
Production	(39)	(9)	(4)	(2)	(54)
Balance at December 31, 2012	486	141	58	29	714
Revisions of previous estimates	4	2	(3)	(6)	(3)
Improved recovery	61	25	3	–	89
Extensions and discoveries	–	–	–	–	–
Purchases of proved reserves	–	–	–	–	–
Sales of proved reserves	–	–	–	–	–
Production	(40)	(10)	(3)	(3)	(56)
Balance at December 31, 2013	511	158	55	20	744
Revisions of previous estimates	(48)	8	(3)	1	(42)
Improved recovery	101	11	4	1	117
Extensions and discoveries	1	–	–	–	1
Purchases of proved reserves	1	–	5	–	6
Sales of proved reserves	–	–	–	–	–
Production	(41)	(11)	(3)	(3)	(58)
Balance at December 31, 2014	525	166	58	19	768
PROVED DEVELOPED RESERVES					
December 31, 2011	372	99	40	6	517
December 31, 2012	341	105	38	24	508
December 31, 2013	349	110	35	20	514
December 31, 2014[c]	367	126	41	18	552
PROVED UNDEVELOPED RESERVES					
December 31, 2011	165	35	12	–	212
December 31, 2012	145	36	20	5	206
December 31, 2013	162	48	20	–	230
December 31, 2014	158	40	17	1	216

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one Bbl of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were $99.51 per Bbl and $4.34 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 23 to 1.

(b) Includes proved reserves related to economic arrangements similar to PSCs of 116 MMBbl, 102 MMBbl, 98 MMBbl and 92 MMBbl at December 31, 2014, 2013, 2012 and 2011, respectively.

(c) Approximately 10 percent of the proved developed reserves at December 31, 2014 are nonproducing.

Capitalized Costs

Capitalized costs relating to oil and gas producing activities and related accumulated DD&A were as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in millions)		
December 31, 2014					
Proved properties	$ 15,362	$ 1,982	$ 1,353	$ 326	$ 19,023
Unproved properties	469	106	113	323	1,011
Total capitalized costs[(a)]	15,831	2,088	1,466	649	20,034
Accumulated depreciation, depletion and amortization[(b)]	(6,846)	(826)	(495)	(497)	(8,664)
Net capitalized costs	$ 8,985	$ 1,262	$ 971	$ 152	$ 11,370
December 31, 2013					
Proved properties	$ 15,120	$ 2,487	$ 1,479	$ 542	$ 19,628
Unproved properties	589	105	95	110	899
Total capitalized costs[(a)]	15,709	2,592	1,574	652	20,527
Accumulated depreciation, depletion and amortization[(b)]	(5,764)	(571)	(346)	(146)	(6,827)
Net capitalized costs	$ 9,945	$ 2,021	$ 1,228	$ 506	$ 13,700
December 31, 2012					
Proved properties	$ 14,359	$ 1,974	$ 1,327	$ 286	$ 17,946
Unproved properties	650	97	96	97	940
Total capitalized costs[(a)]	15,009	2,071	1,423	383	18,886
Accumulated depreciation, depletion and amortization[(b)]	(4,905)	(424)	(276)	(95)	(5,700)
Net capitalized costs	$ 10,104	$ 1,647	$ 1,147	$ 288	$ 13,186

(a) Includes acquisition costs, development costs and asset retirement obligations.
(b) Includes accumulated valuation allowance for total unproved properties of $715 million, $27 million and $20 million at December 31, 2014, 2013 and 2012, respectively.

Costs Incurred

Costs incurred includes capital investments, exploration (whether expensed or capitalized), acquisitions, and asset retirement obligations, as follows:

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in millions)		
FOR THE YEAR ENDED DECEMBER 31, 2014					
Property acquisition costs					
Proved properties	$ 79	$ 3	$ 128	$ –	$ 210
Unproved properties	21	–	81	–	102
Exploration costs	105	–	14	5	124
Development costs	1,356	495	99	12	1,962
Costs incurred	$ 1,561	$ 498	$ 322	$ 17	$ 2,398
FOR THE YEAR ENDED DECEMBER 31, 2013					
Property acquisition costs					
Proved properties	$ 14	$ 1	$ –	$ 5	$ 20
Unproved properties	23	9	1	–	33
Exploration costs	127	–	1	3	131
Development costs	1,078	371	110	15	1,574
Costs incurred	$ 1,242	$ 381	$ 112	$ 23	$ 1,758
FOR THE YEAR ENDED DECEMBER 31, 2012					
Property acquisition costs					
Proved properties	$ 83	$ 8	$ –	$ 274	$ 365
Unproved properties	30	1	–	10	41
Exploration costs	153	4	1	1	159
Development costs	1,721	348	124	26	2,219
Costs incurred	$ 1,987	$ 361	$ 125	$ 311	$ 2,784

Results of Operations

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

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in millions)		
FOR THE YEAR ENDED DECEMBER 31, 2014					
Revenues[(a)]	$ 2,735	$ 956	$ 244	$ 88	$ 4,023
Production costs[(b)]	579	330	89	25	1,023
General and administrative expenses[(c)]	76	42	11	11	140
Other operating expenses[(d)]	44	21	16	5	86
Depreciation, depletion and amortization	875	148	79	81	1,183
Taxes other than on income	140	49	8	6	203
Asset impairments[(e)]	1,266	1,110	437	589	3,402
Exploration expenses[(f)]	125	–	9	5	139
Pretax income	(370)	(744)	(405)	(634)	(2,153)
Income tax benefit	(151)	(304)	(165)	(259)	(879)
Results of operations	$ (219)	$ (440)	$ (240)	$ (375)	$ (1,274)
FOR THE YEAR ENDED DECEMBER 31, 2013					
Revenues[(a)]	$ 2,823	$ 968	$ 259	$ 89	$ 4,139
Production costs[(b)]	552	306	75	27	960
General and administrative expenses	74	36	9	13	132
Other operating expenses	21	8	3	2	34
Depreciation, depletion and amortization	851	108	73	97	1,129
Taxes other than on income	109	43	9	10	171
Exploration expenses	94	1	13	8	116
Pretax income	1,122	466	77	(68)	1,597
Income tax expense / (benefit)	447	185	31	(27)	636
Results of operations	$ 675	$ 281	$ 46	$ (41)	$ 961
FOR THE YEAR ENDED DECEMBER 31, 2012					
Revenues[(a)]	$ 2,738	$ 921	$ 262	$ 46	$ 3,967
Production costs[(b)]	790	331	81	17	1,219
General and administrative expenses	73	44	10	7	134
Other operating expenses[(d)]	26	–	2	2	30
Depreciation, depletion and amortization	724	79	61	44	908
Taxes other than on income	114	37	9	7	167
Asset impairments	19	10	–	–	29
Exploration expenses	112	29	1	6	148
Pretax income	880	391	98	(37)	1,332
Income tax expense / (benefit)	359	160	40	(15)	544
Results of operations	$ 521	$ 231	$ 58	$ (22)	$ 788

(a) Revenues are net of royalty payments.
(b) 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, but do not include DD&A, royalties, income taxes and general and administrative expenses.
(c) Includes unusual and infrequent costs related to Spin-off and transition related costs of $6 million in total.
(d) For 2014, the total amounts include unusual and infrequent costs related to rig termination charges and Spin-off and transition related costs totaling $55 million. For 2012, the total amounts include rig termination charges of $12 million.
(e) At year end 2014, we recorded pre-tax asset impairment charges of $3.4 billion on certain proved and unproved properties in the San Joaquin, Los Angeles, Ventura and Sacramento basins.
(f) Includes $21 million of unusual and infrequent costs related to dry holes and seismic charges.

Results per Unit of Production

	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
			(in millions)		
FOR THE YEAR ENDED DECEMBER 31, 2014					
Revenue from each barrel of oil equivalent ($/Boe)[(a)(b)]	$ 67.32	$ 88.96	$ 75.73	$ 26.11	$ 69.40
Production costs	14.24	30.71	27.62	7.42	17.64
General and administrative expenses	1.87	3.91	3.41	3.26	2.41
Other operating expenses	1.13	1.95	4.97	1.48	1.52
Depreciation, depletion and amortization	21.52	13.77	24.52	24.04	20.40
Taxes other than on income	3.44	4.56	2.48	1.78	3.50
Asset impairments[(c)]	31.14	103.29	135.63	174.78	58.66
Exploration expenses	3.07	–	2.79	1.48	2.40
Pretax income	(9.09)	(69.23)	(125.69)	(188.13)	(37.13)
Income tax benefit	(3.71)	(28.29)	(51.21)	(76.85)	(15.16)
Results of operations	$ (5.38)	$ (40.94)	$ (74.48)	$ (111.28)	$ (21.97)
FOR THE YEAR ENDED DECEMBER 31, 2013					
Revenue from each barrel of oil equivalent ($/Boe)[(a)(b)]	$ 71.86	$ 101.17	$ 79.28	$ 22.09	$ 73.72
Production costs	14.05	31.98	22.96	6.70	17.10
General and administrative expenses	1.88	3.76	2.75	3.23	2.35
Other operating expenses	0.53	0.83	0.92	0.50	0.60
Depreciation, depletion and amortization	21.66	11.29	22.34	24.08	20.11
Taxes other than on income	2.77	4.49	2.75	2.48	3.05
Exploration expenses	2.39	0.10	3.98	1.99	2.07
Pretax income	28.58	48.72	23.58	(16.89)	28.44
Income tax expense / (benefit)	11.38	19.34	9.49	(6.70)	11.33
Results of operations	$ 17.20	$ 29.38	$ 14.09	$ (10.19)	$ 17.11
FOR THE YEAR ENDED DECEMBER 31, 2012					
Revenue from each barrel of oil equivalent ($/Boe)[(a)(b)]	$ 69.30	$ 102.45	$ 81.85	$ 20.09	$ 73.48
Production costs	20.00	36.82	25.30	7.42	22.58
General and administrative expenses	1.85	4.89	3.12	3.06	2.48
Other operating expenses	0.66	–	0.62	0.88	0.56
Depreciation, depletion and amortization	18.33	8.79	19.06	19.21	16.82
Taxes other than on income	2.89	4.12	2.81	3.06	3.09
Asset impairments	0.48	1.11	–	–	0.54
Exploration expenses	2.83	3.23	0.31	2.62	2.74
Pretax income	22.26	43.49	30.63	(16.16)	24.67
Income tax expense / (benefit)	9.09	17.80	12.50	(6.55)	10.08
Results of operations	$ 13.17	$ 25.69	$ 18.13	$ (9.61)	$ 14.59

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were $99.51 per Bbl and $4.34 per Mcf, respectively, resulting in an oil to gas price ratio of approximately 23 to 1.

(b) Revenues are net of royalty payments.

(c) At year end 2014, we recorded pre-tax asset impairment charges of $3.4 billion on certain proved and unproved properties in the San Joaquin, Los Angeles, Ventura and Sacramento basins.

Standardized Measure, Including Year-to-Year Changes Therein, of Discounted Future Net Cash Flows

For purposes of the following disclosures, future 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, 2014, 2013 and 2012, respectively. The realized prices used to calculate future cash flows vary by producing area and market conditions. Future operating and capital costs were forecast using the current cost environment applied to expectations of future operating and development activities. Future income tax expenses were computed by applying, generally, year-end statutory tax rates (adjusted for permanent differences, tax credits and allowances) to the estimated net future pre-tax cash flows, after allowing for the tax basis of the assets as of December 31, 2014. The discount was computed by application of a 10-percent discount factor. The calculations assumed the continuation of existing economic, operating and contractual conditions at December 31, 2014, 2013 and 2012. 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

	Total (in millions)
AT DECEMBER 31, 2014	
Future cash inflows	$ 59,709
Future costs	
Production costs[a]	(22,906)
Development costs[b]	(4,858)
Future income tax expense	(10,322)
Future net cash flows	21,623
Ten percent discount factor	(10,795)
Standardized measure of discounted future net cash flows	$ 10,828
AT DECEMBER 31, 2013	
Future cash inflows	$ 60,884
Future costs	
Production costs[a]	(29,523)
Development costs[b]	(6,327)
Future income tax expense	(8,213)
Future net cash flows	16,821
Ten percent discount factor	(7,598)
Standardized measure of discounted future net cash flows	$ 9,223
AT DECEMBER 31, 2012	
Future cash inflows	$ 57,468
Future costs	
Production costs[a]	(26,968)
Development costs[b]	(5,961)
Future income tax expense	(8,059)
Future net cash flows	16,480
Ten percent discount factor	(7,407)
Standardized measure of discounted future net cash flows	$ 9,073

(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,		
	2014	2013	2012
		(in millions)	
Beginning of year	$ 9,223	$ 9,073	$ 10,347
Sales and transfers of oil and natural gas produced, net of production costs and other operating expenses	(2,658)	(3,082)	(2,695)
Net change in prices received per Bbl, net of production costs and other operating expenses	567	575	(1,431)
Extensions, discoveries and improved recovery, net of future production and development costs	2,593	1,914	1,897
Change in estimated future development costs	75	(688)	(1,526)
Revisions of quantity estimates	(925)	(62)	(1,405)
Previously estimated development costs incurred during the period	1,440	1,185	1,039
Accretion of discount	1,324	1,292	1,512
Net change in income taxes	(468)	(95)	984
Purchases and sales of reserves in place, net	125	4	221
Changes in production rates and other	(468)	(893)	130
Net change	1,605	150	(1,274)
End of year	$ 10,828	$ 9,223	$ 9,073

Oil, NGLs and Natural Gas Production Per Day

The following table set forth the production volumes of oil, NGLs and natural gas per day for each of the three years in the period ended December 31, 2014.

	2014	2013	2012
Oil (MBbl/d)			
San Joaquin Basin[b]	64	58	58
Los Angeles Basin[c]	29	26	24
Ventura Basin	6	6	6
Sacramento Basin	–	–	–
Total	99	90	88
NGLs (MBbl/d)			
San Joaquin Basin[b]	18	19	16
Los Angeles Basin	–	–	–
Ventura Basin	1	1	1
Sacramento Basin	–	–	–
Total	19	20	17
Natural gas (MMcf/d)			
San Joaquin Basin[b]	180	182	204
Los Angeles Basin[c]	1	2	3
Ventura Basin	11	11	12
Sacramento Basin	54	65	37
Total	246	260	256
Total Production (MBoe/d)[a]	159	154	148

(a) Natural gas volumes have been converted to Boe based on the equivalence of energy content between six Mcf of natural gas to one barrel of oil. Barrels of oil equivalence does not necessarily result in price equivalence. The price of natural gas on a barrel of oil equivalent basis is currently substantially lower than the corresponding price for oil and has been similarly lower for a number of years. For example, in 2014, the average prices of Brent oil and NYMEX natural gas were $99.51 per Bbl and $4.34 per Mcf, respectively, resulting in an oil to gas price ratio of approximately 23 to 1.

(b) Includes daily production from Elk Hills field of 25 MBbl oil, 16 MBbl NGLs and 136 MMcf natural gas in 2014; 26 MBbl oil, 18 MBbl NGLs and 145 MMcf natural gas in 2013; and 29 MBbl oil, 15 MBbl NGLs and 168 MMcf natural gas in 2012.

(c) Includes daily production from Wilmington field of 25 MBbl Oil in 2014; 22 MBbl Oil in 2013; and 21 MBbl Oil in 2012.

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

None.

ITEM 9A CONTROLS AND PROCEDURES

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, 2014, 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

Until November 30, 2014 our internal control environment was administered by Occidental. As part of the Spin-off we assumed administration of our internal controls. Our environment as a stand-alone company including key personnel responsible for our key internal controls is substantially similar to that administered by Occidental.

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) identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during our fourth fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

The Annual Report on Form 10-K does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by the rules of the SEC for newly public companies.

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 to our Proxy Statement for the 2015 Annual Meeting of Stockholders to be filed with the Securities and Exchange Commission (SEC) within 120 days of the fiscal year ended December 31, 2014 where it appears under the caption ''Corporate Governance—General Overview,'' ''—Our Board of Directors,'' ''—Committees of the Board—Audit Committee,'' ''Stock Ownership Information—Section 16(a) Beneficial Ownership Reporting Compliance'' and ''Stockholder Proposals and Other Company Information—Stockholder Proposals and Director Nominations.'' The list of our executive officers and related information under ''Executive Officers'' set forth in Part I of this Annual Report on Form 10-K is incorporated by reference herein.

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 to our Proxy Statement for the 2015 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2014 where it appears under the caption ''Compensation Discussion and Analysis'' and ''Compensation Committee Interlocks and Insider Participation.'' Pursuant to the rules and regulations under the Exchange Act, the information under the caption ''Compensation Discussion and Analysis—Compensation Committee Report'' 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 to our Proxy Statement for the 2015 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2014 where it appears under the caption ''Stock Ownership Information—Security Ownership of Directors, Management and Certain Beneficial Holders. See also the information under ''Securities Authorized for Issuance Under Equity Compensation Plans'' in Part II, Item 5 of this report.

ITEM 13 CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated by reference to our Proxy Statement for the 2015 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2014 where it appears under the caption ''Certain Relationships and Related Transactions'' (except under the subheading ''—Policies and Procedures'') and ''Corporate Governance—Director Independence Determinations.''

ITEM 14 PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated by reference to our Proxy Statement for the 2015 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2014 where it appears under the caption ''Proposal 2: Ratification of the Appointment of the Independent Registered Public Accounting Firm.''

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 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 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 4.1 to the Registrant's Registration Statement on Form S-8 filed November 26, 2014 and incorporated herein by reference).
3.2	Amended and Restated Bylaws of California Resources Corporation (filed as Exhibit 4.2 to the Registrant's Registration Statement on Form S-8 filed November 26, 2014 and incorporated herein by reference).
4.1	Stockholder's and Registration Rights Agreement (filed as Exhibit 10.1 to Registrant's Current Report on Form 8-K filed December 1, 2014 and incorporated herein by reference).
4.2	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).
4.3	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).
4.4	Form of 5% Senior Note due 2020 (included in Exhibit 4.2)
4.5	Form of 5½% Senior Note due 2021 (included in Exhibit 4.2)
4.6	Form of 6% Senior Note due 2024 (included in Exhibit 4.2)
10.1	Transition Services Agreement 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).

Exhibit Number	Exhibit Description
10.2	Tax Sharing Agreement 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).
10.3	Employee Matters Agreement 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).
10.4	Intellectual Property License Agreement 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).

The Exhibits numbered 10.5 to 10.18; 10.23 to 10.27 and 10.31 to 10.33 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.

Exhibit Number	Exhibit Description
10.5	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).
10.6	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).
10.7	Form of Restricted Stock Incentive Award Terms and Conditions (Performance-Based) (filed as Exhibit 10.7 to Amendment No. 3 to the Registrant's Information Statement on Form 10 filed September 22, 2014 and incorporated herein by reference).
10.8	Form of Restricted Stock Incentive Award Terms and Conditions (Not 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 and incorporated herein by reference).
10.9	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).
10.10	Form of Long-Term Incentive Award Terms and Conditions (Replacement 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).
10.11	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).
10.12	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).
10.13	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).
10.14	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).
10.15	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).

Exhibit Number	Exhibit Description
10.16	California Resources Corporation Supplemental Savings Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 2, 2014, and incorporated herein by reference and incorporated herein by reference).
10.17	California Resources Corporation Deferred Compensation Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed December 2, 2014, and incorporated herein by reference and incorporated herein by reference).
10.18	California Resources Corporation Supplemental Retirement Plan II (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed December 2, 2014, and incorporated herein by reference).
10.19	Area of Mutual Interest Agreement 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).
10.20	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).
10.21	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).
10.22	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).
10.23	Form of Retention Letter Assignment and Assumption Agreement (filed as Exhibit 10.20 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, and incorporated herein by reference).
10.24	Bonus Acknowledgement Agreement between Occidental Petroleum Corporation and William E. Albrecht (filed as Exhibit 10.21 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, and incorporated herein by reference).
10.25	Retention and Separation Arrangement with Todd A. Stevens (filed as Exhibit 10.22 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, and incorporated herein by reference).
10.26	Retention and Separation Arrangement with William E. Albrecht (filed as Exhibit 10.23 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, and incorporated herein by reference).
10.27	Retention and Separation Arrangement with Robert A. Barnes (filed as Exhibit 10.24 to Amendment No. 3 to the Company's Registration Statement on Form 10 filed September 22, 2014, and incorporated herein by reference).
10.30	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).

Exhibit Number	Exhibit Description
10.31	Form of 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).
10.32	Form of California Resources Corporation Supplemental Retirement Plan II (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).
10.33	Form of California Resources Corporation Deferred Compensation Plan (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).
10.34	Confidentiality and Trade Secret Protection Agreement 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).
10.35*	First Amendment to 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.
12*	Computation of Ratio of Earnings to Fixed Charges.
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.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	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 Process Review of the Estimated Future Proved Reserves and Income Attributable to Certain Fee, Leasehold and Royalty Interests and Certain Economic Interests Derived Through Certain Production Sharing Type Contracts as of December 31, 2014.
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 26, 2015

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 26, 2015
/s/ MARSHALL D. SMITH Marshall D. Smith	Senior Executive Vice President and Chief Financial Officer	February 26, 2015
/s/ ROY PINECI Roy Pineci	Executive Vice President—Finance and Principal Accounting Officer	February 26, 2015
/s/ WILLIAM E. ALBRECHT William E. Albrecht	Executive Chairman of the Board	February 26, 2015
/s/ JUSTIN A. GANNON Justin A. Gannon	Director	February 26, 2015
/s/ RONALD L. HAVNER Ronald L. Havner	Director	February 26, 2015
/s/ HAROLD M. KORELL Harold M. Korell	Director	February 26, 2015
/s/ RICHARD W. MONCRIEF Richard W. Moncrief	Director	February 26, 2015
/s/ AVEDICK B. POLADIAN Avedick B. Poladian	Director	February 26, 2015
/s/ ROBERT V. SINNOTT Robert V. Sinnott	Director	February 26, 2015
/s/ TIMOTHY J. SLOAN Timothy J. Sloan	Director	February 26, 2015

NOTES

NOTES

Annual Meeting

California Resources Corporation's annual meeting of stockholders will be held at 11:00 a.m. on May 7, 2015, at the Bakersfield Marriott at the Convention Center, 801 Truxtun Avenue, Bakersfield, CA 93301.

Investor Relations Contact

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.

Dividend Information

CRC's first dividend record date is March 10, 2015, and stockholders of record will be paid on April 15. We currently intend to pay a quarterly cash dividend of $0.01 per share. Payment of future dividends, if any, will be at the discretion of our board of directors.

Auditors

KPMG LLP, Los Angeles, California

Transfer Agent & Registrar

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Shareholder Services
6201 15th Avenue, Brooklyn, NY 11219
(866) 659-2647
crc@amstock.com
www.amstock.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

William E. Albrecht
Executive Chairman

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

EXECUTIVE VICE PRESIDENTS

Robert A. Barnes
Northern Operations

Shawn M. Kerns
Corporate Development

Frank E. Komin
Southern Operations

Roy Pineci
Finance

Michael L. Preston
General Counsel and
Corporate Secretary

Charles F. Weiss
Public Affairs

Darren Williams
Exploration

VICE PRESIDENTS

Carlos A. Contreras
Commercial

Elizabeth A. DeStephens
Reserves and Corporate
Development

Duane D. Dudics
Health, Safety and Environment

Scott A. Espenshade
Investor Relations

Michael S. Helm
Controller

Chia-Fu Hsu
Resource Optimization and
Production Technology

Cynthia J. Johnson
Chief Information Officer

Francisco J. Leon
Portfolio Management and
Strategic Planning

Darren K. Mallick
Operations Finance

Mike McGraw
Government Affairs

Noelle M. Repetti
Tax

Alana A. Sotiri
Human Resources

Margita N. Thompson
Communications

Daniel S. Watts
Compensation and Benefits

OTHER EXECUTIVES

Ivan I. Gaydarov
Treasurer

UFCW 888

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