NEWS RELEASE

For immediate release

California Resources Corporation Announces Fourth Quarter 2015 Financial Results

LOS ANGELES, February 29, 2016 – California Resources Corporation ("CRC" or the "Company") (NYSE:CRC), an independent California-based oil and gas exploration and production company, today announced an adjusted net loss[1] of $77 million or ($0.20) per diluted share for the fourth quarter of 2015, compared with an adjusted net loss of $7 million or ($0.02) per diluted share for the fourth quarter of 2014. The adjusted net loss for the full year of 2015 was $311 million or ($0.81) per diluted share, compared with an adjusted net income of $650 million or $1.67 per diluted share for the same period in 2014. Adjusted EBITDAX[2] for the fourth quarter of 2015 was $226 million, compared with $454 million for the fourth quarter of 2014. Adjusted EBITDAX for the full year of 2015 was $906 million, compared with $2.5 billion for the full year of 2014.

Highlights Include:

- Annual crude oil production grew five percent to 104,000 barrels per day
- Annual total production increased one percent to 160,000 BOE per day
- Fourth quarter 2015 Adjusted EBITDAX was $226 million
- Proved reserves of 644MMBOE; replaced 140% of reserves, excluding price adjustments
- Organic F&D costs of $4.88 per BOE[3], excluding price adjustments
- $2.9 billion after-tax non-cash impairment charges
- Capital investment was $401 million in 2015
- 2016 capital investment plan of $50 million
- Approximately 30% of 2016 crude oil production hedged in excess of $50 per barrel

[1] See reconciliation on Attachment 3.
[2] For an explanation of how we calculate and use Adjusted EBITDAX (non-GAAP) and reconciliations of net income / (loss) (GAAP) to adjusted loss and net cash provided by operating activities (GAAP) to Adjusted EBITDAX (non-GAAP), please see Attachment 2.
[3] Excludes asset retirement obligation ("ARO") adjustment. Including ARO adjustment, organic F&D would be $4.11 per BOE. Also see calculation of F&D on Attachment 4.

Todd Stevens, President and Chief Executive Officer, said, "We recently executed an amendment to our credit facilities which we believe will provide sufficient liquidity and covenant relief at current price levels throughout 2016. As we work to live within our means again in 2016, the main focus of our teams will be to protect our base production and build inventory to take advantage of any sustained price increases."

"Today's results further highlight the resiliency of our asset base. Despite a severe downturn in commodity prices and an 81-percent capital reduction in 2015, we increased crude oil production five percent. Our focus on steamflood and waterflood opportunities and drilling efficiencies helped us add reserves at a cost lower than our historical average. We are proud of the progress our teams have made in reducing drilling costs and improving efficiencies, which allowed us to drill more wells than planned in 2015 with less capital. These results, our reserve replacement rate and F&D costs, which were achieved with meaningfully lower capital investment, demonstrate the favorable attributes of our assets in a stressed environment."

"As we entered 2016, crude oil prices deteriorated further. As a result, we took additional steps to align our capital program as well as overall activity and staffing levels with the commodity price environment and projected cash flows. Our reserves estimation process and production results at our flagship Elk Hills asset, where we had no drilling rig for all of 2015, supported our estimated corporate base decline range of 10-15 percent."

"Expect to see us demonstrate financial discipline to maintain sufficient liquidity through 2016. We plan to continue building economically viable drilling inventory, while managing our activity consistent with our principle of living within cash flow."

Fourth Quarter Results

The adjusted net loss was $77 million or ($0.20) per diluted share for the fourth quarter of 2015, compared with an adjusted net loss of $7 million or ($0.02) per diluted share for the same period of 2014. The 2015 quarter reflected lower production costs, depreciation, depletion and amortization expense (DD&A), adjusted general and administrative expense, exploration expense and ad valorem tax expense, offset by lower oil and gas volumes, significantly lower realized oil, NGL and gas prices and higher interest expense. The fourth quarter 2015 net loss was $3.3 billion or ($8.54) per diluted share, compared with a net loss of $2.1 billion or ($5.47) per diluted share for the same period of 2014. This loss was driven primarily by non-cash, after-tax impairment charges of $2.9 billion ($4.9 billion pre-tax) required under accounting rules to reflect the recent decline in commodity prices. The fourth quarter 2014 loss included non-cash, after-tax impairment charges of $2.0 billion ($3.4 billion pre-tax). The Company expects to develop these properties as energy prices recover sufficiently on a sustained basis.

The fourth quarter 2015 adjusted net loss excluded the impairment charge mentioned above and other after-tax adjustments of $36 million largely reflecting the impact of lower prices on other assets. The fourth quarter 2015 adjusted net loss also excluded a $294 million valuation allowance for deferred tax assets. The fourth quarter 2014 adjusted net loss excluded 2014 impairment charges as well as $64 million of other after-tax non-recurring adjustments. Adjusted EBITDAX for the fourth quarter of 2015 was $226 million compared to $454 million in the prior year period.

Average oil production decreased by three percent or, 3,000 barrels per day, to 102,000 barrels per day in the fourth quarter of 2015, compared to the same period of the prior year. NGL production decreased by five percent to 18,000 barrels per day and natural gas production decreased by 15 percent to 212 million cubic feet (MMcf) per day. Total daily production volumes averaged 155,000 barrels of oil equivalent (BOE) in the fourth quarter of 2015, compared with 165,000 BOE in the fourth quarter of 2014.

Realized crude oil prices decreased 33 percent to $45.88 per barrel, including the effect of realized hedges, in the fourth quarter of 2015 from $68.54 per barrel in the fourth quarter of 2014. Our fourth quarter hedges contributed $6.47 per barrel to our realized crude oil price. Realized NGL prices decreased 43 percent to $19.56 per barrel in the fourth quarter of 2015 from $34.41 per barrel in the fourth quarter of 2014. Realized natural gas prices decreased 39 percent to $2.44 per thousand cubic feet (Mcf), including the effect of realized hedges, in the fourth quarter of 2015, compared with $4.00 per Mcf in the same period of 2014. The realized natural gas price in the fourth quarter of 2015 before the effect of hedges was $2.28 per Mcf.

Production costs for the fourth quarter of 2015 were $221 million or $15.51 per BOE, compared with $252 million or $16.65 per BOE for the fourth quarter of 2014, a 7-percent reduction on a unit basis. The decrease was driven by cost reductions across the board, particularly in well servicing efficiency, surface operations, downhole maintenance and field personnel, and was aided by lower natural gas prices. Adjusted general and administrative expenses[4] were $69 million or $4.80 per BOE for the fourth quarter of 2015, compared with $84 million or $5.57 per BOE for the fourth quarter of 2014, reflecting our cost reduction initiatives. Exploration expenses for the fourth quarter of 2015 were significantly lower at $7 million, compared to $68 million for the same period of 2014, as a result of a decrease in activity. Ad valorem taxes were $26 million for the fourth quarter of 2015 and $42 million for the same period of 2014.

Fourth quarter 2015 operating cash flow, which included a semi-annual property tax payment, was ($9) million, compared to $504 million for the fourth quarter of 2014.

[4] See reconciliation on Attachment 5.

Full Year 2015 Results

The adjusted net loss for the full year of 2015 was $311 million or ($0.81) per diluted share, compared with an adjusted net income of $650 million or $1.67 per diluted share for the full year of 2014. The full year 2015 reflected higher oil production as well as total volumes, and lower production costs, DD&A, exploration expense and ad valorem tax expense, offset by significantly lower realized product prices in 2015 and higher interest expense. The net loss for 2015 was $3.6 billion or ($9.27) per diluted share, compared to a net loss of $1.4 billion or ($3.75) per diluted share for 2014. The 2015 adjusted net loss excluded the fourth quarter impairment charge and after-tax charges of $40 million for voluntary retirement and employee reductions and $54 million reflecting the effect of prices on other assets, as well as an after-tax gain of $31 million for unrealized hedges. The 2015 adjusted net loss also excluded a $294 million valuation allowance for deferred tax assets. Adjusted EBITDAX for 2015 was $906 million, compared with $2.5 billion for 2014.

Total daily production for the full year of 2015 averaged 160,000 BOE, compared with 159,000 BOE in 2014. Average oil production increased 5,000 barrels per day, or by five percent, to 104,000 barrels per day in 2015. NGL production decreased by five percent to 18,000 barrels per day and natural gas production decreased by seven percent to 229 MMcf per day.

Realized crude oil prices decreased 47 percent to $49.19 per barrel, including the effect of realized hedges, for the full year of 2015 from $92.30 per barrel for the full year of 2014.

The realized crude oil price for the year before the effect of hedges was $47.15 per barrel. Realized NGL prices decreased 59 percent to $19.62 per barrel in 2015 from $47.84 per barrel in 2014. Realized natural gas prices decreased 39 percent to $2.66 per Mcf compared with $4.39 per Mcf in 2014.

The 2015 production costs were $951 million or $16.30 per BOE, compared with $1.1 billion or $18.23 per BOE in 2014, resulting in an 11-percent reduction on a unit basis. The decrease was driven by the same factors discussed for the quarterly decline. Adjusted general and administrative expenses were $287 million or $4.92 per BOE for 2015, compared with $302 million or $5.21 per BOE for 2014. Exploration expenses were $36 million for 2015 and $139 million for 2014. Ad valorem taxes were $137 million for 2015 and $162 million for 2014.

Operating cash flow was $403 million for 2015, compared with $2.4 billion for 2014. In line with our key financial tenet of aligning our capital with our cash flow, our 2015 operating cash flow was sufficient to fund our capital program for the year.

Operational Update and 2016 Investment Plan

CRC entered the fourth quarter with three drilling rigs running, with two focused in the San Joaquin basin and one in the Los Angeles basin. In response to the continued decline in commodity prices in December, CRC further reduced activity and finished the quarter with no drilling rigs running. In the San Joaquin basin, CRC drilled 48 steamflood wells, including 11 in the Lost Hills field and 37 in the Kern Front field in the fourth quarter. In the Los Angeles basin, the Company drilled seven waterflood wells in the Wilmington field. In addition, CRC completed 90 capital workovers during the fourth quarter. As a result of capital efficiencies across its operations, CRC drilled more wells in 2015 than its plan with less capital than planned.

For 2016, CRC has developed a dynamic capital program to align our investments with projected cash flow. CRC currently has no drilling rigs running and expects to begin 2016 with a $50 million capital program focused on investments designed to ensure safe and reliable long-term operations. The Company will monitor cash flow throughout the year and retains flexibility to increase investments in drilling and capital workovers, to the extent crude oil prices show sustained improvement, while abiding by its financial covenants. CRC anticipates that this capital program, without any adjustments during the year, could result in average production declines closer to the higher end of the Company's historical base decline range.

2015 Proved Reserves

CRC's proved reserves estimates for the year-ended December 31, 2015, as audited by Ryder Scott, were 644 million BOE, consisting of 72 percent oil and 75 percent proved developed volumes. The Company achieved a total organic reserve replacement ratio (RRR) of 140 percent of 2015 production, excluding price adjustments. Price-related adjustments reduced overall reserves by 153 million BOE. These volumes are expected to return to CRC's proved base with the sustained recovery of crude oil prices. For example, at about a $65 Brent scenario, the Company's proved reserve base would increase by more than 10 percent.

Summary of Changes in 2015 Proved Reserves (Million BOE)

Balance at December 31, 2014	768
Revision of Previous Estimates (Performance-Related)	45
Extensions and Discoveries	33
Improved Recovery	3
Purchases of Proved Reserves	6
Revisions due to Price	(153)
Production	(58)
Balance at December 31, 2015	644*
2015 Organic F&D cost, excluding price adjustments	$4.88

*Calculated using the twelve-month average Brent oil price of $55.57 per barrel and Henry Hub price of $2.59 per million British Thermal units (BTU) for natural gas, before adjustments for quality, transportation fees and basis differentials, in accordance with Securities and Exchange Commission (SEC) guidelines.

The present value of the proved portion of CRC's reserves as of December 31, 2015 was approximately $5.1 billion, on a pre-tax basis, discounted at 10 percent (PV-10). The reduction from the prior year amount resulted from a 45-percent and 41-percent decrease in crude oil prices and natural gas prices, respectively. The effect of price decreases was partially offset by reserves additions, costs reductions and efficiencies identified in the Company's life-of-field plans.

Debt and Credit Agreement Update

The Company had total debt outstanding of $6.1 billion, including $0.7 billion drawn on its revolving credit facility, at December 31, 2015. The Company recently received 100% approval from its bank group to amend its credit facilities which set its borrowing base at $2.3 billion and suspended the first lien senior secured leverage ratio until the end of the first quarter of 2017. The amendment requires cash in excess of $150 million be applied to repay outstanding revolving loans, reduces the revolving commitments to $1.6 billion and imposes certain other restrictions. The amendment also introduced a cumulative minimum EBITDAX requirement and reset the interest coverage ratio, both designed to provide the Company with liquidity throughout 2016 based on a price outlook for the year that the parties deemed reasonable. At current prices, CRC expects that available liquidity plus expected operating cash flows will be sufficient to fund its capital program and 2016 commitments.

Hedging Update

Since the last earnings release, CRC has continued to opportunistically add hedges to protect its cash flow, margins and capital program and to maintain liquidity. Currently, the Company has the following Brent crude oil hedges in place:

	1Q2016*		2Q2016		3Q2016		4Q2016	
	Production	Strike	Production	Strike	Production	Strike	Production	Strike
Calls	35,500	$66.15	35,500	$66.15	3,000	$74.42	3,000	$74.42
Puts	33,800	$51.75	55,500	$50.14	28,000	$50.65	3,000	$50.00
Swap					1,000	$61.25	1,000	$61.25

* Q1 2016 averages include puts for 10,000 barrels of oil per day of our March 2016 production at $46 per barrel.

As an offset to certain of these hedges, the Company also sold 30,000 b/d of Brent calls in 2017 at an average strike price of $55.68 and 23,300 barrels per day in 2018 at an average strike price of $57.99.

NYSE Continued Listing Standard Letter

The Company was notified on February 26, 2016 by the New York Stock Exchange ("NYSE") that it does not presently satisfy the NYSE's continued listing standard requiring the average closing price of its common stock to be at least $1.00 per share over any period of 30 consecutive trading days. As of February 24, 2016, the average closing price of CRC's common stock over the preceding 30 trading-day period was $ 0.97 per share. Under NYSE rules, CRC will notify the NYSE within 10 business days of receipt of the notification that it intends to cure the deficiency and to seek stockholder approval for a reverse stock split at its May 2016 annual meeting. CRC has a period of six months from the date of the notification to regain compliance with the minimum share price criteria. CRC's common stock will continue to be listed and traded on the NYSE during this period, subject to compliance with all other NYSE continued listing requirements.

The current noncompliance with the NYSE listing standard does not affect CRC's ongoing business operations or its Securities and Exchange Commission reporting requirements, and does not cause an event of default under CRC's debt instruments.

Conference Call Details

To participate in today's conference call, either dial (877) 328-5505 (International calls please dial +1 (412) 317-5421) or access via webcast at www.crc.com, fifteen minutes prior to the scheduled start time to register. Participants may also pre-register for the conference call at http://dpregister.com/10076862. A digital replay of the conference call will be archived for approximately 30 days and supplemental slides for the conference call will be available online in Investor Relations at www.crc.com.

About California Resources Corporation

California Resources Corporation is the largest oil and natural gas exploration and production company in California on a gross-operated basis. The Company operates its world class resource base exclusively within the State of California, applying integrated infrastructure to gather, process and market its production. Using advanced technology, California Resources Corporation focuses on safely and responsibly supplying affordable energy for California by Californians.

Forward-Looking Statements

This press release contains forward-looking statements that involve risks and uncertainties that could materially affect our expected results of operations, liquidity, cash flows and business prospects. Such statements specifically include our expectations as to our future financial position, drilling program, production, projected costs, future operations, hedging activities, future transactions, planned capital investments and other guidance. Actual results may differ from anticipated results, sometimes materially, and reported results should not be considered an indication of future performance. 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, sometimes materially. Factors (but not necessarily all the factors) that could cause results to differ include: commodity price fluctuations; the effect of our debt on our financial flexibility; sufficiency of our operating cash flow to fund planned capital expenditures; the ability to obtain government permits and approvals; effectiveness our capital investments; our ability to monetize selected assets; restrictions and changes in restrictions imposed by regulations, including those related to our ability to obtain, use, manage or dispose of water or use advanced well stimulation techniques like hydraulic fracturing; risks of drilling; tax law changes; competition with larger, better funded competitors 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; restriction of operations to, and concentration of exposure to events such as industrial accidents, natural disasters and labor difficulties in, California; limitations on our ability to enter efficient hedging transactions; the recoverability of resources; concerns about climate change and air quality issues; lower-than-expected production from development projects or acquisitions; catastrophic events for which we may be uninsured or underinsured; the effects of litigation; cyber attacks; operational issues that restrict market access; and uncertainties related to the spin-off and the agreements related thereto. Material risks are further discussed in "Risk Factors" in our Annual Report on Form 10-K and subsequent 10Qs available on our website at crc.com. 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" or similar expressions that convey the prospective nature of events or outcomes generally indicate forward-looking statements. Any forward-looking statement speaks only as of the date on which such statement is made and CRC undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.*

We calculate organic finding and development costs by dividing the costs incurred for the year from the capital program (including development and exploration costs, but excluding acquisitions) by the amount of proved reserves added in the same year from improved recovery, extensions and discoveries and performance-related revisions (excluding acquisitions and price-related revisions). We believe that reporting our finding and development costs can aid investors in their evaluation of our ability to add proved reserves at a reasonable cost but is not a substitute for GAAP disclosures. Various factors, including timing differences and effects of commodity price changes, can cause finding and development costs to reflect costs associated with particular reserves imprecisely. For example, we will need to make more investments in order to develop the proved undeveloped reserves added during the year and any future revisions may change the actual measure from that presented above. In addition, part of last year's costs were incurred to convert proved undeveloped reserves from prior years to proved developed reserves. Our calculations of finding and development costs may not be comparable to similar measures provided by other companies.

Attachment 4 includes calculations and GAAP reconciliations for each of the above measures.

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SUMMARY OF RESULTS

($ and shares in millions, except per share amounts)	Fourth Quarter 2015	Fourth Quarter 2014	Twelve Months 2015	Twelve Months 2014
Statement of Operations Data:				
Revenues				
Oil and gas sales	**$ 540**	$ 785	**$ 2,294**	$ 4,023
Other revenue	**26**	35	**109**	150
	566	820	**2,403**	4,173
Costs and other deductions				
Production costs	**221**	252	**951**	1,057
General and administrative expenses	**64**	84	**354**	302
Depreciation, depletion and amortization	**247**	312	**1,004**	1,198
Asset impairments	**4,852**	3,402	**4,852**	3,402
Taxes other than on income	**30**	54	**180**	217
Exploration expense	**7**	68	**36**	139
Interest and debt expense, net	**82**	72	**326**	72
Other expenses	**102**	98	**176**	207
	5,605	4,342	**7,879**	6,594
Income / (loss) before income taxes	**(5,039)**	(3,522)	**(5,476)**	(2,421)
Income tax (expense) / benefit	**1,757**	1,431	**1,922**	987
Net income / (loss)	**$ (3,282)**	$ (2,091)	**$ (3,554)**	$ (1,434)
EPS - diluted	**$ (8.54)**	$ (5.47)	**$ (9.27)**	$ (3.75)
Adjusted net income / (loss)	**$ (77)**	$ (7)	**$ (311)**	$ 650
Adjusted EPS - diluted	**$ (0.20)**	$ (0.02)	**$ (0.81)**	$ 1.67
Weighted average diluted shares outstanding [(a)]	**384.2**	381.9	**383.2**	381.9

(a) On December 1, 2014, the Spin-off date from Occidental Petroleum Corporation, we issued 381.4 million shares of our common stock. Additional shares were distributed to our employees and vested in December. 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.

	Fourth Quarter 2015	Fourth Quarter 2014	Twelve Months 2015	Twelve Months 2014
Adjusted EBITDAX	**$ 226**	$ 454	**$ 906**	$ 2,548
Effective tax rate	**35%**	41%	**35%**	41%
Cash Flow Data:				
Net cash provided by operating activities	**$ (9)**	$ 504	**$ 403**	$ 2,371
Net cash used by investing activities	**$ (215)**	$ (698)	**$ (757)**	$ (2,312)
Net cash provided (used) by financing activities	**$ 232**	$ 103	**$ 352**	$ (45)

Balance Sheet Data:	**December 31, 2015**	December 31, 2014
Total current assets	**$ 497**	$ 701
Property, plant and equipment, net	**$ 6,312**	$ 11,685
Total current liabilities	**$ 605**	$ 922
Long-term debt, principal amount	**$ 6,043**	$ 6,360
Total equity	**$ (916)**	$ 2,611
Outstanding shares	**388.2**	385.6

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

We define adjusted 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 as well as unusual or infrequent items. Our management believes adjusted 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 adjusted EBITDAX were computed in accordance with U.S. generally accepted accounting principles (GAAP). This measure is a material component of certain 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 adjusted 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. Adjusted EBITDAX should be read in conjunction with the information contained in our financial statements prepared in accordance with GAAP.

The following tables present a reconciliation of the GAAP financial measure of net income / (loss) to the non-GAAP financial measure of adjusted EBITDAX:

	Fourth Quarter		Twelve Months	
($ millions)	**2015**	2014	**2015**	2014
Net income / (loss)	**$ (3,282)**	$ (2,091)	**$ (3,554)**	$ (1,434)
Interest expense	**82**	72	**326**	72
Income tax expense / (benefit)	**(1,757)**	(1,431)	**(1,922)**	(987)
Depreciation, depletion and amortization	**247**	312	**1,004**	1,198
Exploration expense	**7**	68	**36**	139
Asset impairment and related items	**4,852**	3,402	**4,852**	3,402
Adjusted income items	**60**	107	**105**	107
Other non-cash expenses	**17**	15	**59**	51
Adjusted EBITDAX	**$ 226**	$ 454	**$ 906**	$ 2,548
Net cash provided by operating activities	**$ (9)**	$ 504	**$ 403**	$ 2,371
Interest expense	**82**	72	**326**	72
Cash income taxes	**—**	(17)	**—**	165
Cash exploration expense	**7**	19	**27**	38
Changes in operating assets and liabilities	**104**	(155)	**147**	(143)
Other, net	**42**	31	**3**	45
Adjusted EBITDAX	**$ 226**	$ 454	**$ 906**	$ 2,548

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

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

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

	Fourth Quarter		Twelve Months	
($ millions, except per share amounts)	**2015**	2014	**2015**	2014
Adjusted net income / (loss)	**$ (77)**	$ (7)	**$ (311)**	$ 650
Unusual and infrequent items:				
Asset impairments	**(4,852)**	(3,402)	**(4,852)**	(3,402)
Write-down of certain other assets	**(71)**	—	**(71)**	—
Early retirement and severance costs	**5**	—	**(67)**	—
Rig terminations and other costs	**(5)**	(52)	**(11)**	(52)
Debt transactions	**(8)**	—	**(8)**	—
Non-cash hedge-related gains	**19**	—	**52**	—
Spin-off and transition related costs	**—**	(55)	**—**	(55)
Valuation allowance for deferred tax assets	**(294)**	—	**(294)**	—
Tax effects of these items and related adjustments	**2,001**	1,425	**2,008**	1,425
Net income / (loss)	**$ (3,282)**	$ (2,091)	**$ (3,554)**	$ (1,434)
Adjusted EPS - diluted	**$ (0.20)**	$ (0.02)	**$ (0.81)**	$ 1.67

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

The following table presents a reconciliation of the non-GAAP financial measure of PV-10 to the GAAP financial measure of standardized measure of discounted future net cash flows:

PV-10 and Standardized Measure		2015
PV-10 of proved reserves (1)	$	5,059
Present value of future income taxes discounted at 10%		(1,035)
Standardized measure of discounted future net cash flows	$	4,024

(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 reserves bases and the reserves 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.

Organic Reserve Replacement Ratio (2)	2015
Proved reserves added in 2015 - MMBOE	
Extensions and Discovery	33
Improved Recovery	3
Revisions related to performance	45
Total (A)	81
Production in 2015 - MMBOE (B)	58
Organic Reserves Replacement Ratio (A)/(B)	140%

(2) The organic reserves replacement ratio is calculated for a specified period using the proved oil-equivalent additions from extensions and discoveries, improved recovery, and performance-related provisions, divided by oil-equivalent production. Approximately 48% of the additions for 2015 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 commodity prices, availability of capital and the underlying geology, 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.

Finding and Development Costs		2015
Organic costs incurred - in millions (A)	$	333 (3)
Organic costs incurred (excluding ARO adjustments) - in millions (B)	$	395 (4)
Proved Reserves Added - MMBOE (C)		81
Organic Finding and Development Costs - $/BOE (A)/(C)	$	4.11
Organic Finding and Development Costs (excluding ARO adjustments) - $/BOE (B)/(C)	$	4.88

(3) Includes development and exploration costs, as well as ARO; excludes acquisitions.

(4) Reflects the items in (3) above, except that it excludes the ARO adjustment, which reduced costs incurred in 2015.

ADJUSTED GENERAL AND ADMINISTRATIVE EXPENSES

($ millions)	Fourth Quarter 2015	Fourth Quarter 2014	Twelve Months 2015	Twelve Months 2014
General and administrative expenses per statements of operations	**$ 64**	$ 84	**$ 354**	$ 302
Early retirement and severance costs	**5**	—	**(67)**	—
Adjusted general and administrative expenses	**$ 69**	$ 84	**$ 287**	$ 302

ADJUSTED NET INCOME / (LOSS) VARIANCE ANALYSIS

($ millions)

2014 4th Quarter Adjusted Net Loss	**$ (7)**
Price - Oil and NGLs	(243)
Price - Natural Gas	(36)
Volume	(3)
Production cost rate	27
DD&A rate	47
Exploration expense	40
Interest expense	(10)
Income tax	44
All Others	64
2015 4th Quarter Adjusted Net Loss	**$ (77)**

2014 Twelve Month Adjusted Net Income	**$ 650**
Price - Oil and NGLs	(1,739)
Price - Natural Gas	(157)
Volume	52
Production cost rate	107
DD&A rate	198
Exploration expense	82
Interest expense	(254)
Income tax	646
All Others	104
2015 Twelve Month Adjusted Net Loss	**$ (311)**

CAPITAL INVESTMENTS

($ millions)	Fourth Quarter 2015	Fourth Quarter 2014	Twelve Months 2015	Twelve Months 2014
Capital Investments:				
Conventional	**$ 62**	$ 335	**$ 328**	$ 1,376
Unconventional	**8**	163	**25**	606
Exploration	**—**	21	**17**	100
Corporate and Other	**8**	1	**31**	7
	$ 78	$ 520	**$ 401**	$ 2,089

PRODUCTION STATISTICS

	Fourth Quarter		Twelve Months	
Net Oil, NGLs and Natural Gas Production Per Day	**2015**	2014	**2015**	2014
Oil (MBbl/d)				
San Joaquin Basin	**61**	66	**64**	64
Los Angeles Basin	**35**	32	**34**	29
Ventura Basin	**6**	7	**6**	6
Sacramento Basin	**—**	—	**—**	—
Total	**102**	105	**104**	99
NGLs (MBbl/d)				
San Joaquin Basin	**17**	18	**17**	18
Los Angeles Basin	**—**	—	**—**	—
Ventura Basin	**1**	1	**1**	1
Sacramento Basin	**—**	—	**—**	—
Total	**18**	19	**18**	19
Natural Gas (MMcf/d)				
San Joaquin Basin	**161**	184	**172**	180
Los Angeles Basin	**2**	2	**2**	1
Ventura Basin	**9**	10	**11**	11
Sacramento Basin	**40**	52	**44**	54
Total	**212**	248	**229**	246
Total Barrels of Oil Equivalent (MBoe/d)*	**155**	165	**160**	159

*Natural gas volumes have been converted to BOE based on the equivalence of energy content between six Mcf of natural 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 2015, the average prices of Brent oil and NYMEX natural gas were $53.64 per Bbl and $2.75 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 20 to 1.

PRICE STATISTICS

	Fourth Quarter		Twelve Months	
	2015	2014	**2015**	2014
Realized Prices				
Oil with hedge ($/Bbl)	**$ 45.88**	$ 68.54	**$ 49.19**	$ 92.30
Oil without hedge ($/Bbl)	**$ 39.41**	$ 68.54	**$ 47.15**	$ 92.30
NGLs ($/Bbl)	**$ 19.56**	$ 34.41	**$ 19.62**	$ 47.84
Natural gas with hedge ($/Mcf)	**$ 2.44**	$ 4.00	**$ 2.66**	$ 4.39
Natural gas without hedge ($/Mcf)	**$ 2.28**	$ 4.00	**$ 2.61**	$ 4.42
Index Prices				
Brent oil ($/Bbl)	**$ 44.71**	$ 76.98	**$ 53.64**	$ 99.51
WTI oil ($/Bbl)	**$ 42.18**	$ 73.15	**$ 48.80**	$ 93.00
NYMEX gas ($/MMBtu)	**$ 2.44**	$ 3.99	**$ 2.75**	$ 4.34
Realized Prices as Percentage of Index Prices				
Oil with hedge as a percentage of Brent	**103%**	89%	**92%**	93%
Oil without hedge as a percentage of Brent	**88%**	89%	**88%**	93%
Oil with hedge as a percentage of WTI	**109%**	94%	**101%**	99%
Oil without hedge as a percentage of WTI	**93%**	94%	**97%**	99%
NGLs as a percentage of Brent	**44%**	45%	**37%**	48%
NGLs as a percentage of WTI	**46%**	47%	**40%**	51%
Natural gas with hedge as a percentage of NYMEX	**100%**	100%	**97%**	101%
Natural gas without hedge as a percentage of NYMEX	**93%**	100%	**95%**	102%

2016 FIRST QUARTER GUIDANCE

Anticipated Realizations Against the Prevailing Index Prices for Q1 2016 [a]

Oil	83% to 87% of Brent
NGLs	45% to 49% of Brent
Natural Gas	96% to 100% of NYMEX

2016 First Quarter Production, Capital and Income Statement Guidance

Production [b]	145 to 150 Mboe per day
Capital [c]	$18 million to $28 million
Production costs	$14.50 to $15.00 per BOE
General and administrative expenses	$3.95 to $4.15 per BOE
Depreciation, depletion and amortization	$10.30 to $10.50 per BOE
Taxes other than on income	$36 million to $40 million
Exploration expense	$7 million to $11 million
Interest expense [d]	$74 million to $78 million
Cash Interest [d]	$47 million to $51 million
Income tax expense rate [e]	10%
Cash tax rate	0%

Pre-tax Quarterly Price Sensitivities	On Income [f]	On Cash [f]
$1 change in Brent index - Oil	$7.0 million	$7.0 million
$1 change in Brent index - NGLs	$0.5 million	$0.5 million
$0.50 change in NYMEX - Gas	$3.0 million	$3.0 million
Pre-tax Quarterly Hedge Price Sensitivities		
$1 change in Brent index at below $45.00 - Oil	$2.5 million	$2.5 million
Quarterly Volumes Sensitivities		
$1 change in the Brent index [g]	700 BOE/d	

(a) Realizations exclude hedge effects. California price postings are currently lagging the widening WTI to Brent spreads; putting pressure on first quarter realizations.

(b) The Elk Hills Power Plant has a major turnaround scheduled in the first quarter of 2016. The production guidance incorporates the anticipated negative effect on production of approximately 2 Mboe per day.

(c) The first quarter capital guidance includes the cost of the Elk Hills Power Plant turnaround of approximately $17 million, which is expected to be completed by the end of the quarter.

(d) Interest expense includes the amortization of the deferred gain that resulted from the December 2015 debt exchange. Cash interest for the quarter is lower than interest expense due to the timing of interest payments and the prepayment of interest on the notes that were exchanged in the 2015 debt exchange.

(e) The 2016 tax benefit will be limited to amounts that can be recognized as deferred tax assets.

(f) All amounts exclude hedge effects and reflect the effect of production sharing type contracts in our Wilmington field operations.

(g) Reflects the effect of production sharing type contracts in our Wilmington field operations.

FULL YEAR DRILLING ACTIVITY

Wells Drilled (Net)	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Development Wells					
Primary	6	—	—	—	6
Waterflood [a]	8	29	—	—	37
Steamflood [b]	240	—	—	—	240
Unconventional	—	—	—	—	—
Total	254	29	—	—	283
Exploration Wells					
Primary	1	—	—	—	1
Waterflood	—	—	—	—	—
Steamflood	2	—	—	—	2
Unconventional	—	—	—	—	—
Total	3	—	—	—	3
Total Wells	257	29	—	—	286
Development Drilling Capital ($ millions)	$85	$45	—	—	$130

(a) Waterflood wells include 4 injector wells.

(b) Steamflood wells include 40 injector wells.

RESERVES

<u>As of December 31, 2015</u>	San Joaquin Basin	Los Angeles Basin	Ventura Basin	Sacramento Basin	Total
Oil Reserves (in millions of barrels)					
Proved Developed Reserves	205	103	30	—	338
Proved Undeveloped Reserves	92	27	9	—	128
Total	297	130	39	—	466
NGLs Reserves (in millions of barrels)					
Proved Developed Reserves	45	—	2	—	47
Proved Undeveloped Reserves	11	—	1	—	12
Total	56	—	3	—	59
Natural Gas Reserves (in billions of cubic feet)					
Proved Developed Reserves	456	9	24	86	575
Proved Undeveloped Reserves	135	2	3	—	140
Total	591	11	27	86	715
Total Reserves (in millions of barrels of oil equivalent)*					
Proved Developed Reserves	326	105	36	14	481
Proved Undeveloped Reserves	125	27	11	—	163
Total	451	132	47	14	644

*Natural gas volumes have been converted to BOE based on the equivalence of energy content between six Mcf of natural 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 2015, the average prices of Brent oil and NYMEX natural gas were $53.64 per Bbl and $2.75 per Mcf, respectively, resulting in an oil-to-gas price ratio of approximately 20 to 1.