CHEVRON CORP
Form 10-K
February 22, 2013

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012
OR

o 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 001-00368
Chevron Corporation
(Exact name of registrant as specified in its charter)

Delaware	94-0890210	6001 Bollinger Canyon Road, San Ramon, California 94583-2324
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)	(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code (925) 842-1000

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, par value $.75 per share	New York Stock Exchange, Inc.

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

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 o No þ

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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. o

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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter — $207,005,770,000 (As of June 29, 2012)

Number of Shares of Common Stock outstanding as of February 11, 2013 — 1,942,697,787

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2013 Annual Meeting and 2013 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company's 2013 Annual Meeting of Stockholders (in Part III)

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CAUTIONARY STATEMENT RELEVANT TO FORWARD-LOOKING INFORMATION
FOR THE PURPOSE OF “SAFE HARBOR” PROVISIONS OF THE
PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Annual Report on Form 10-K of Chevron Corporation contains forward-looking statements relating to Chevron’s operations that are based on management’s current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as “anticipates,” “expects,” “intends,” “plans,” “targets,” “forecasts,” “projects,” “believes,” “seeks,” “schedules,” “estimates,” “budgets,” “outlook” and similar expressions are intended to identify forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, many of which are beyond the company’s control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: changing crude oil and natural gas prices; changing refining, marketing and chemicals margins; actions of competitors or regulators; timing of exploration expenses; timing of crude oil liftings; the competitiveness of alternate-energy sources or product substitutes; technological developments; the results of operations and financial condition of equity affiliates; the inability or failure of the company’s joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company’s production or manufacturing facilities or delivery/transportation networks due to war, accidents, political events, civil unrest, severe weather or crude oil production quotas that might be imposed by the Organization of Petroleum Exporting Countries; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant investment or product changes required by existing or future environmental statutes, regulations and litigation; the potential liability resulting from other pending or future litigation; the company’s future acquisition or disposition of assets and gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; and the factors set forth under the heading “Risk Factors” on pages 28 through 30 in this report. In addition, such results could be affected by general domestic and international economic and political conditions. Other unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

PART I

Item 1. Business

General Development of Business

Summary Description of Chevron

Chevron Corporation,* a Delaware corporation, manages its investments in subsidiaries and affiliates and provides administrative, financial, management and technology support to U.S. and international subsidiaries that engage in fully integrated petroleum operations, chemicals operations, mining activities, power generation and energy services. Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; processing, liquefaction, transportation and regasification associated with liquefied natural gas; transporting crude oil by major international oil export pipelines; transporting, storage and marketing of natural gas; and a gas-to-liquids project. Downstream operations consist primarily of refining crude oil into petroleum products; marketing of crude oil and refined products; transporting crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses and fuel and lubricant additives.

A list of the company's major subsidiaries is presented on pages E-4 and E-5. As of December 31, 2012, Chevron had approximately 62,000 employees (including about 3,700 service station employees). Approximately 31,000 employees (including about 3,400 service station employees), or 50 percent, were employed in U.S. operations.

Overview of Petroleum Industry

Petroleum industry operations and profitability are influenced by many factors. Prices for crude oil, natural gas, petroleum products and petrochemicals are generally determined by supply and demand. The members of the Organization of Petroleum Exporting Countries (OPEC) are typically the world's swing producers of crude oil and their production levels are a major factor in determining worldwide supply. Demand for crude oil and its products and for natural gas is largely driven by the conditions of local, national and global economies, although weather patterns and taxation relative to

other energy sources also play a significant part. Laws and governmental policies, particularly in the areas of taxation, energy and the environment affect where and how companies conduct their operations and formulate their products and, in some cases, limit their profits directly.

Strong competition exists in all sectors of the petroleum and petrochemical industries in supplying the energy, fuel and chemical needs of industry and individual consumers. Chevron competes with fully integrated, major global petroleum companies, as well as independent and national petroleum companies, for the acquisition of crude oil and natural gas leases and other properties and for the equipment and labor required to develop and operate those properties. In its downstream business, Chevron competes with fully integrated, major petroleum companies and other independent refining, marketing, transportation and chemicals entities and national petroleum companies in the sale or acquisition of various goods or services in many national and international markets.

Operating Environment

Refer to pages FS-2 through FS-8 of this Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the company's current business environment and outlook.

Chevron's Strategic Direction

Chevron's primary objective is to create shareholder value and achieve sustained financial returns from its operations that will enable it to outperform its competitors. In the upstream, the company's strategies are to grow profitably in core areas, build new legacy positions and commercialize the company's equity natural gas resource base while growing a high-impact global natural gas business. In the downstream, the strategies are to improve returns and grow earnings across the value chain. The company also continues to utilize technology across all its businesses to differentiate performance, and to invest in profitable renewable energy and energy efficiency solutions.

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* Incorporated in Delaware in 1926 as Standard Oil Company of California, the company adopted the name Chevron Corporation in 1984 and ChevronTexaco Corporation in 2001. In 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. As used in this report, the term "Chevron" and such terms as "the company," "the corporation," "our," "we" and "us" may refer to Chevron Corporation, one or more of its consolidated subsidiaries, or all of them taken as a whole, but unless stated otherwise they do not include "affiliates" of Chevron — i.e., those companies accounted for by the equity method (generally owned 50 percent or less) or investments accounted for by the cost method. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

Description of Business and Properties

The upstream and downstream activities of the company and its equity affiliates are widely dispersed geographically, with operations and projects* in North America, South America, Europe, Africa, Asia and Australia. Tabulations of segment sales and other operating revenues, earnings and income taxes for the three years ending December 31, 2012, and assets as of the end of 2012 and 2011 — for the United States and the company's international geographic areas — are in Note 10 to the Consolidated Financial Statements beginning on page FS-36. Similar comparative data for the company's investments in and income from equity affiliates and property, plant and equipment are in Notes 11 and 12 on pages FS-38 through FS-40.

Capital and Exploratory Expenditures

Total expenditures for 2012 were $34.2 billion, including $2.1 billion for the company's share of equity-affiliate expenditures. In 2011 and 2010, expenditures were $29.1 billion and $21.8 billion, respectively, including the company's share of affiliates' expenditures of $1.7 billion in 2011 and $1.4 billion in 2010.

Of the $34.2 billion in expenditures for 2012, 89 percent, or $30.4 billion, was related to upstream activities. Approximately 89 and 87 percent was expended for upstream operations in 2011 and 2010, respectively. International upstream accounted for about 72 percent of the worldwide upstream investment in 2012, about 68 percent in 2011 and about 82 percent in 2010. These amounts exclude the acquisition of Atlas Energy, Inc., in 2011.

In 2013, the company estimates capital and exploratory expenditures will be $36.7 billion, including $3.3 billion of spending by affiliates. Approximately 90 percent of the total, or $33 billion, is budgeted for exploration and production activities, with $25.5 billion, or about 70 percent, of this amount for projects outside the United States.

Refer also to a discussion of the company's capital and exploratory expenditures on page FS-12.

Upstream

The table on the following page summarizes the net production of liquids and natural gas for 2012 and 2011 by the company and its affiliates. Worldwide oil-equivalent production was 2.610 million barrels per day, down about 2 percent from 2011. The decrease was mainly associated with normal field declines, the shut-in of the Frade Field in Brazil, and a major planned turnaround at the Tengizchevroil facilities in Kazakhstan. The start-up and ramp-up of several major capital projects — the Platong II natural gas project in Thailand, the Usan and Agbami 2 projects in Nigeria, and the Perdido, Tahiti 2 and Caesar/Tonga projects in the U.S. Gulf of Mexico — partially offset the decrease in net production from 2011. Refer to the "Results of Operations" section beginning on page FS-6 for a detailed discussion of the factors explaining the 2010 through 2012 changes in production for crude oil and natural gas liquids, and natural gas.

The company estimates its average worldwide oil-equivalent production in 2013 will be approximately 2.650 million barrels per day based on an average Brent price of $112 per barrel in 2012. This estimate is subject to many factors and uncertainties, including quotas that may be imposed by OPEC, price effects on entitlement volumes, changes in fiscal terms or restrictions on the scope of company operations, delays in project start-ups and ramp-ups, fluctuations in demand for natural gas in various markets, weather conditions that may shut in production, civil unrest, changing geopolitics, delays in completion of maintenance turnarounds, greater-than-expected declines in production from mature fields, or other disruptions to operations. The longer-term outlook for production levels is also affected by the size and number of economic investment opportunities and, for new, large-scale projects, the time lag between initial exploration and the beginning of production. Refer to the "Review of Ongoing Exploration and Production Activities in Key Areas," beginning on page 9, for a discussion of the company's major crude oil and natural gas development projects.

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* As used in this report, the term "project" may describe new upstream development activity, individual phases in a multiphase development, maintenance activities, certain existing assets, new investments in downstream and chemicals capacity, investments in emerging and sustainable energy activities, and certain other activities. All of these terms are used for convenience only and are not intended as a precise description of the term "project" as it relates to any specific governmental law or regulation.

Net Production of Crude Oil and Natural Gas Liquids and Natural Gas [1]

	Oil-Equivalent (Thousands of Barrels per Day)		Components of Oil-Equivalent Crude Oil & Natural Gas Liquids (Thousands of Barrels per Day)		Natural Gas (Millions of Cubic Feet per Day)	
	2012	2011	2012	2011	2012	2011
United States	655	678	455	465	1,203	1,279
Other Americas						
Argentina	22	27	21	26	4	4
Brazil	6	35	6	33	2	13
Canada	69	70	68	69	4	4
Colombia	36	39	—	—	216	234
Trinidad and Tobago	29	31	—	—	173	183
Total Other Americas	162	202	95	128	399	438
Africa						
Angola	137	147	128	139	53	50
Chad	23	26	22	25	6	6
Democratic Republic of the Congo	3	3	2	3	1	1
Nigeria	269	260	242	236	165	142
Republic of the Congo	19	23	17	21	13	10
Total Africa	451	459	411	424	238	209
Asia						
Azerbaijan	28	28	26	26	10	10
Bangladesh	94	74	2	2	550	434
China	21	22	20	20	9	10
Indonesia	198	208	158	166	236	253
Kazakhstan	61	62	37	38	139	144
Myanmar	16	14	—	—	94	86
Partitioned Zone[2]	90	91	86	88	21	20
Philippines	24	25	4	4	120	126
Thailand	243	209	67	65	1,060	867
Total Asia	775	733	400	409	2,239	1,950
Australia	99	101	28	26	428	448
Europe						
Denmark	36	44	24	29	74	91
Netherlands	9	7	2	2	42	31
Norway	3	3	3	3	1	1
United Kingdom	66	85	46	59	122	155
Total Europe	114	139	75	93	239	278
Total Consolidated Companies	2,256	2,312	1,464	1,545	4,746	4,602
Equity Affiliates[3]	354	361	300	304	328	339
Total Including Affiliates[4]	2,610	2,673	1,764	1,849	5,074	4,941

[1] Includes synthetic oil: Canada, net	43	40	43	40	—	—
Venezuelan affiliate, net	17	32	17	32	—	—

[2] Located between Saudi Arabia and Kuwait.

[3] Volumes represent Chevron's share of production by affiliates, including Tengizchevroil in Kazakhstan and Petroboscan, Petroindependiente and Petropiar in Venezuela.

[4] Volumes include natural gas consumed in operations of 586 million and 582 million cubic feet per day in 2012 and 2011, respectively. Total "as sold" natural gas volumes were 4,488 million and 4,359 million cubic feet per day for 2012 and 2011, respectively.

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Average Sales Prices and Production Costs per Unit of Production

Refer to Table IV on page FS-67 for the company's average sales price per barrel of crude oil, condensate and natural gas liquids and per thousand cubic feet of natural gas produced, and the average production cost per oil-equivalent barrel for 2012, 2011 and 2010.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2012 for the company and its affiliates:

Productive Oil and Gas Wells at December 31, 2012

	Productive Oil Wells		Productive Gas Wells	
	Gross	Net	Gross	Net
United States	50,180	32,758	14,248	7,737
Other Americas	736	548	48	28
Africa	2,579	861	17	7
Asia	13,127	11,335	3,148	1,924
Australia	815	458	65	11
Europe	330	97	227	48
Total Consolidated Companies	67,767	46,057	17,753	9,755
Equity Affiliates	1,300	456	7	2
Total Including Affiliates	69,067	46,513	17,760	9,757
Multiple completion wells included above	876	602	407	369

Reserves

Refer to Table V beginning on page FS-67 for a tabulation of the company's proved net crude oil and natural gas reserves by geographic area, at the beginning of 2010 and each year-end from 2010 through 2012. Reserves governance, technologies used in establishing proved reserves additions, and major changes to proved reserves by geographic area for the three-year period ended December 31, 2012, are summarized in the discussion for Table V. Discussion is also provided regarding the nature of, status of and planned future activities associated with the development of proved undeveloped reserves. The company recognizes reserves for projects with various development periods, sometimes exceeding five years. The external factors that impact the duration of a project include scope and complexity, remoteness or adverse operating conditions, infrastructure constraints, and contractual limitations.

The net proved reserve balances at the end of each of the three years 2010 through 2012 are shown in the following table.

Net Proved Reserves at December 31

	2012	2011	2010
Liquids — Millions of barrels			

Consolidated Companies	4,353	4,295	4,270
Affiliated Companies	2,128	2,160	2,233
Total Liquids	6,481	6,455	6,503
Natural Gas — Billions of cubic feet			
Consolidated Companies	25,654	25,229	20,755
Affiliated Companies	3,541	3,454	3,496
Total Natural Gas	29,195	28,683	24,251
Oil-Equivalent — Millions of barrels			
Consolidated Companies	8,629	8,500	7,729
Affiliated Companies	2,718	2,736	2,816
Total Oil-Equivalent	11,347	11,236	10,545

Acreage

At December 31, 2012, the company owned or had under lease or similar agreements undeveloped and developed crude oil and natural gas properties throughout the world. The geographical distribution of the company's acreage is shown in the following table.

Acreage at December 31, 2012
(Thousands of Acres)

	Undeveloped*		Developed		Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
United States	6,399	5,161	7,788	5,008	14,187	10,169
Other Americas	26,913	15,898	1,348	365	28,261	16,263
Africa	8,848	3,840	3,328	1,373	12,176	5,213
Asia	30,795	14,189	1,487	857	32,282	15,046
Australia	11,427	5,728	918	239	12,345	5,967
Europe	5,481	4,153	648	126	6,129	4,279
Total Consolidated Companies	89,863	48,969	15,517	7,968	105,380	56,937
Equity Affiliates	938	430	259	102	1,197	532
Total Including Affiliates	90,801	49,399	15,776	8,070	106,577	57,469

* The gross undeveloped acres that will expire in 2013, 2014 and 2015 if production is not established by certain required dates are 1,254, 3,629 and 3,141, respectively.

Delivery Commitments

The company sells crude oil and natural gas from its producing operations under a variety of contractual obligations. Most contracts generally commit the company to sell quantities based on production from specified properties, but some natural gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the United States, the company is contractually committed to deliver to third parties 192 billion cubic feet of natural gas through 2015. The company believes it can satisfy these contracts through a combination of equity production from the company's proved developed U.S. reserves and third-party purchases. These commitments include a variety of pricing terms, including both indexed and fixed-price contracts.

Outside the United States, the company is contractually committed to deliver a total of 791 billion cubic feet of natural gas to third parties from 2013 through 2015 for operations in Australia, Colombia, Denmark and the Philippines. These sales contracts contain variable pricing formulas that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery. The company believes it can satisfy these contracts from quantities available from production of the company's proved developed reserves in these countries.

Development Activities

Refer to Table I on page FS-62 for details associated with the company's development expenditures and costs of proved property acquisitions for 2012, 2011 and 2010.

The following table summarizes the company's net interest in productive and dry development wells completed in each of the past three years, and the status of the company's development wells drilling at December 31, 2012. A "development well" is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Development Well Activity

	Wells Drilling at 12/31/12		Net Wells Completed 2012		2011		2010	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	78	45	941	6	909	9	634	7
Other Americas	13	6	50	—	37	—	32	—
Africa	10	4	23	—	29	—	33	—
Asia	75	35	566	15	549	15	445	15
Australia	8	4	—	—	—	—	—	—
Europe	5	—	9	—	6	—	4	—
Total Consolidated Companies	189	94	1,589	21	1,530	24	1,148	22
Equity Affiliates	6	3	26	—	25	—	8	—
Total Including Affiliates	195	97	1,615	21	1,555	24	1,156	22

Exploration Activities

Refer to Table I on page FS-62 for detail on the company's exploration expenditures and costs of unproved property acquisitions for 2012, 2011 and 2010.

The following table summarizes the company's net interests in productive and dry exploratory wells completed in each of the last three years, and the number of exploratory wells drilling at December 31, 2012. "Exploratory wells" are wells drilled to find and produce crude oil or natural gas in unproved areas and include delineation and appraisal wells, which are wells drilled to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir or to extend a known reservoir beyond the proved area.

Exploratory Well Activity

	Wells Drilling at 12/31/12		Net Wells Completed 2012		2011		2010	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry

United States	11	8	4	—	5	1	1	1
Other Americas	2	1	8	—	1	—	—	1
Africa	1	—	1	2	1	—	1	—
Asia	1	1	12	3	10	1	5	5
Australia	1	1	3	—	4	1	5	2
Europe	1	1	1	2	—	1	—	—
Total Consolidated Companies	17	12	29	7	21	4	12	9
Equity Affiliates	—	—	—	—	1	—	—	—
Total Including Affiliates	17	12	29	7	22	4	12	9

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron's 2012 key upstream activities, some of which are also discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations, beginning on page FS-2, are presented below. The comments include references to "total production" and "net production," which are defined under "Production" in Exhibit 99.1 on page E-11.

The discussion that follows references the status of proved reserves recognition for significant long-lead-time projects not on production and for projects recently placed on production. Reserves are not discussed for exploration activities or recent discoveries that have not advanced to a project stage, or for mature areas of production that do not have individual projects requiring significant levels of capital or exploratory investment. Amounts indicated for project costs represent total project costs, not the company's share of costs for projects that are less than wholly owned.

Chevron has exploration and production activities in most of the world's major hydrocarbon basins. The company's upstream strategy is to grow profitably in core areas, build new legacy positions and commercialize the company's equity natural gas resource base while growing a high-impact global natural gas business. The map above indicates Chevron's primary areas for exploration and production.

United States

Upstream activities in the United States are concentrated in California, the Gulf of Mexico, Colorado, Louisiana, Michigan, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia, and Wyoming. Average net oil-equivalent production in the United States during 2012 was 655,000 barrels per day.

In California, the company has significant production in the San Joaquin Valley. In 2012, net daily production averaged 163,000 barrels of crude oil, 70 million cubic feet of natural gas and 4,000 barrels of natural gas liquids (NGLs). Approximately

86 percent of the crude oil production is considered heavy oil (typically with API gravity lower than 22 degrees).

During 2012, net daily production for the company's combined interests in the Gulf of Mexico shelf and deepwater areas, and the onshore fields in the region, was 153,000 barrels of crude oil, 395 million cubic feet of natural gas and 16,000 barrels of NGLs.

Chevron was engaged in various exploration and development activities in the deepwater Gulf of Mexico during 2012. The Jack and St. Malo fields are located within 25 miles of each other and are being jointly developed. Chevron has a 50 percent interest in the Jack Field, a 51 percent interest in the St. Malo Field and a 50.7 percent interest in the production host facility. Both fields are company operated. Drilling operations progressed during 2012, with five of 10 planned wells drilled. At the end of 2012, project activities were more than 57 percent complete, with subsea and floating production unit installation activities expected in second-half 2013. The facility is planned to have a design capacity of 177,000 barrels of oil-equivalent per day to accommodate production from the Jack/St. Malo development, which is estimated to have maximum total daily production of 94,000 barrels of oil equivalent, plus production from a nearby third-party field. Total project costs for the initial phase of development are estimated at $7.5 billion and start-up is expected in 2014. The fields have an estimated production life of 30 years. Proved reserves have been recognized for this project.

In 2012, an evaluation of additional development opportunities was initiated for the Jack and St. Malo fields. Stage 2, the first phase of future development work, is expected to include four additional development wells, two each at the Jack and the St. Malo fields. Front-end engineering and design (FEED) activities are planned to begin in mid-2013. At the end of 2012, proved reserves had not been recognized for the Jack/St. Malo Stage 2 project.

Fabrication and development drilling continued in 2012 for the 60 percent-owned and operated Big Foot project. The development plan includes a 15-slot drilling and production platform with water injection facilities and a design capacity of 79,000 barrels of oil equivalent per day. At the end of 2012, project activities were 68 percent complete, and topside module installation is planned for mid-2013. First production is anticipated in 2014. The field has an estimated production life of 20 years. Proved reserves have been recognized for this project.

Tahiti 2 is the second development phase for the 58 percent-owned and operated Tahiti Field, and is designed to increase recovery and return production to more than 100,000 barrels of crude oil per day. The project includes two additional production wells, three water injection wells and water injection facilities. Drilling commenced on the first production well in early 2012, and water injection began in first quarter 2012. Start-up of the first production well is expected by third quarter 2013. Proved reserves have been recognized for the Tahiti 2 project, and the field has an estimated production life of 30 years.

The company has a 42.9 percent nonoperated working interest in the Tubular Bells Field. Development drilling began in second quarter 2012, and plans include three producing and two injection wells, with a subsea tieback to a third-party production facility. First oil is anticipated in 2014, and maximum total daily production is expected to reach 40,000 to 45,000 barrels of oil-equivalent. The field has an estimated production life of 25 years. The initial recognition of proved reserves for the project occurred in 2012.

Chevron has a 20.3 percent nonoperated working interest in the Caesar and Tonga area. First production occurred in first quarter 2012, and maximum total daily production reached about 62,000 barrels of oil-equivalent by year-end 2012. Drilling operations on the fourth development well concluded in early 2013, and the well is expected to commence production in second quarter 2013.

The company has a 15.6 percent nonoperated working interest in the Mad Dog II Project. FEED commenced in second quarter 2012 and a final investment decision is expected in 2014. The project includes the construction and installation of a new production and drilling spar facility and is expected to add incremental maximum total daily production of 120,000 to 140,000 barrels of oil equivalent. At the end of 2012, proved reserves had not been recognized for this project.

In 2012, Chevron signed commercial agreements for the Stampede project allowing for the joint development of the Knotty Head and Pony fields. Chevron holds a 20 percent nonoperated working interest in this joint development. The project is expected to enter FEED by mid-2013. At the end of 2012, proved reserves had not been recognized for this project.

Deepwater exploration activities in 2012 included participation in three exploratory wells — one appraisal and two wildcats. Drilling began on an appraisal well at the

43.8 percent-owned and operated Moccasin discovery in fourth quarter 2012. Drilling activities were placed on hold in early 2013 for equipment repair and are expected to resume later this year. Moccasin and the 55 percent-owned and operated Buckskin discovery, located 12 miles apart, could be jointly developed upon the successful completion of additional appraisal drilling planned for 2013. A second Coronado wildcat well began drilling in second quarter 2012, targeting the lower Tertiary Wilcox formation. Drilling was completed in February 2013, and the results are under evaluation. Chevron also had a 20 percent nonoperated working interest in the Hummer Shallow wildcat well.

Chevron added 15 leases to the deepwater portfolio as a result of awards from the central Gulf of Mexico lease sale in mid-2012. In addition, Chevron submitted the highest bids on 28 additional deepwater leases at the western Gulf of Mexico lease sale in late 2012.

Besides the activities connected with development and exploration projects in the Gulf of Mexico, the company also has contracted liquefied natural gas (LNG) offloading, storage and regasification capacity at the Sabine Pass LNG facility and natural gas transportation capacity in a third-party pipeline system connecting the terminal to the U.S. natural gas pipeline grid.

Company activities in the mid-continental United States include operated and nonoperated interests in properties primarily in Colorado, New Mexico, Oklahoma, Texas and Wyoming. During 2012, the company’s net daily production in these areas averaged 90,000 barrels of crude oil, 600 million cubic feet of natural gas and 29,000 barrels of NGL's.

In West Texas, the company continues to pursue development of tight oil and liquids-rich shale resources in the Midland Basin’s Wolfcamp play and several plays in the Delaware Basin through use of advanced drilling and completion technologies. Additional production growth is expected from interests in these formations in future years. In October 2012, an acquisition of more than 350,000 gross acres in New Mexico augmented the company's leasehold position in the Delaware Basin and surrounding areas.

The company holds leases in the Marcellus Shale and Utica Shale, primarily located in southwestern Pennsylvania, Ohio, and West Virginia, and in the Antrim Shale in Michigan. During 2012, the company's net daily production in these areas averaged approximately 138 million cubic feet of natural gas. In 2012, development of the Marcellus Shale proceeded at a measured pace, focused on improving execution capability and reservoir understanding. Activities in the Utica Shale during 2012 included acquisition of regional seismic data in eastern Ohio to identify core areas. The company commenced drilling on four exploratory wells during the year. This initial activity was focused on acquiring data necessary for potential future development. The company also holds a 49 percent interest in Laurel Mountain Midstream, LLC, an affiliate that owns more than 1,200 miles of natural gas gathering lines servicing the Marcellus.

Other Americas

“Other Americas” is composed of Argentina, Brazil, Canada, Colombia, Suriname, Trinidad and Tobago, and Venezuela. Net oil-equivalent production from these countries averaged 230,000 barrels per day during 2012, including the company’s share of synthetic oil production.

Canada: Chevron has interests in oil sands projects and shale acreage in Alberta, shale acreage and an LNG project in British Columbia, exploration, development and production projects offshore in the Atlantic region, and exploration and discovered resource interests in the Beaufort Sea region of the Northwest Territories. Average net oil-equivalent production during 2012 was 69,000 barrels per day, composed of 25,000 barrels of crude oil, 4 million cubic feet of natural gas and 43,000 barrels of synthetic oil from oil sands.

The company holds a 20 percent nonoperated working interest in the Athabasca Oil Sands Project (AOSP). Oil sands are mined from both the Muskeg River and the Jackpine mines and bitumen is extracted from the oil sands and upgraded into synthetic oil. During 2012, ramp-up from the AOSP Expansion 1 Project continued to boost production toward the total daily design capacity of approximately 255,000 barrels. Additionally, a final investment decision was reached in mid-2012 on the Quest Project, a carbon capture and sequestration project that is designed to capture and store more than one million tons annually of carbon dioxide produced by bitumen processing at the AOSP by 2015.

In February 2013, Chevron acquired a 50 percent-owned and operated interest in the Kitimat LNG project and proposed Pacific Trail Pipeline, and a 50 percent nonoperated working interest in 644,000 total acres in the Horn River and Liard shale gas basins in British Colombia. The Kitimat project is planned to include a two-train, 10.0 million-metric-ton-per-year LNG facility, and at the time of acquisition, FEED activities were in progress.

Chevron holds a 26.9 percent nonoperated working interest in the Hibernia Field and a 23.6 nonoperated working interest in the unitized Hibernia Southern Extension (HSE) offshore Atlantic Canada. The HSE development is expected to increase the economic life of the Hibernia Field. Fabrication of topside and subsea equipment progressed in 2012. Full production start-up is expected in 2014. Proved reserves have been recognized for the initial wells drilled.

The company holds a 26.6 percent nonoperated working interest in the heavy-oil Hebron Field, also offshore Atlantic Canada. The development plan includes a concrete, gravity-based platform with a capacity of 150,000 barrels of crude oil per day. The maximum total daily crude oil production is expected to be 134,000 barrels. FEED activities were completed in 2012, and a final investment decision was made in December 2012. Project costs are estimated at $14 billion. The project has an expected economic life of 30 years, and first oil is expected in 2017. The initial recognition of proved reserves for the project occurred in 2012.

During 2012, drilling continued on a multiwell program on the 100 percent-owned and operated leases in the Duvernay shale formation in Alberta. The company also holds exploration licenses and leases in the Flemish Pass and Orphan basins offshore Atlantic Canada and the Beaufort Sea region of the Northwest Territories, including a 35.4 percent nonoperated working interest in the offshore Amauligak discovery.

In addition, Chevron holds interests in the Aitken Creek and Alberta Hub natural gas storage facilities, which have aggregate total capacity of approximately 100 billion cubic feet. These facilities are located in western Canada near the Duvernay, Horn River, Liard and Montney shale gas plays.

Greenland: In December 2012, Chevron relinquished its 29.2 percent nonoperated working interest in Exploration License 2007/26, which includes Block 4 offshore West Greenland.

Argentina: Chevron holds operated interests in four concessions in the Neuquen Basin. Working interests range from 18.8 percent to 100 percent. Net oil-equivalent production in 2012 averaged 22,000 barrels per day, composed of 21,000 barrels of crude oil and 4 million cubic feet of natural gas. During 2012, two exploratory wells targeting shale gas and tight oil resources were drilled in the Vaca Muerta formation in the El Trapial concession. In early 2013, a third exploratory well commenced drilling and the results of the previous wells were under evaluation. Chevron plans to drill three additional appraisal wells in 2013. The El Trapial concession expires in 2032.

Brazil: Chevron holds working interests in three deepwater fields in the Campos Basin: Frade (51.7 percent-owned and operated), Papa-Terra and Maromba (37.5 percent and 30 percent nonoperated working interests, respectively). Net oil-equivalent production in 2012 averaged 6,000 barrels per day, composed of 6,000 barrels of crude oil and 2 million cubic feet of natural gas.

In March 2012, production was suspended as a precautionary measure at the Frade Field while studies were conducted to better understand the geology in the area. Production is expected to partially resume in 2013 subject to necessary regulatory approvals. The concession that includes the Frade Field expires in 2025.

During 2012, construction activities and development drilling continued for the Papa-Terra project. The project includes a floating production, storage and offloading vessel (FPSO) and a tension leg wellhead platform, with a design capacity of 140,000 barrels of crude oil per day. First production is expected in second-half 2013. Proved reserves have been recognized for this project. Evaluation of the field development concept for Maromba continued in 2012 with submission of an initial Plan of Development to the authorities in September. At the end of 2012, proved reserves had not been recognized for this project. These concessions expire in 2032.

Colombia: The company operates the offshore Chuchupa and the onshore Ballena and Riohacha natural gas fields as part of the Guajira Association contract. In exchange, Chevron receives 43 percent of the production for the remaining life of each field and a variable production volume based on prior Chuchupa capital contributions. Daily net production averaged 216 million cubic feet of natural gas in 2012.

Suriname: In November 2012, Chevron acquired a 50 percent nonoperated working interest in Blocks 42 and 45 offshore Suriname. Under the agreements, the company would assume the role of operator in the event of commercial discoveries. In 2013, planned exploration activities include seismic data acquisition and processing.

Trinidad and Tobago: The company has a 50 percent nonoperated working interest in three blocks in the East Coast Marine Area offshore Trinidad, which includes the Dolphin and Dolphin Deep producing natural gas fields and the Starfish development. Net production in 2012 averaged 173 million cubic feet of natural gas per day. Development of the Starfish Field commenced in third quarter 2012, and first gas is expected in 2014. Natural gas from the project will supply existing contractual commitments. Proved reserves have been recognized for this project. Chevron also holds a 50 percent-owned and operated interest in the Manatee Area of Block 6(d) where the Manatee discovery comprises a single cross-border field with Venezuela's Loran Field in Block 2. In 2012, work continued on maturing commercial development concepts.

Venezuela: Chevron holds interests in two producing affiliates located in western Venezuela and one producing affiliate in the Orinoco Belt. Chevron has a 30 percent interest in the Petropiar affiliate that operates the Hamaca heavy-oil production and upgrading project located in Venezuela’s Orinoco Belt, a 39.2 percent interest in the Petroboscan affiliate that operates the Boscan Field in the western part of the country, and a 25.2 percent interest in the Petroindependiente affiliate that operates the LL-652 Field in Lake Maracaibo. The company’s share of net oil-equivalent production during 2012 from these operations averaged 68,000 barrels per day, composed of 64,000 barrels of liquids and 27 million cubic feet of natural

gas.

Chevron holds a 34 percent interest in the Petroindependencia affiliate that is working toward commercialization of Carabobo 3, a heavy-oil project located within the Carabobo Area of the Orinoco Belt. During 2012, work continued on conceptual engineering for the potential development project.

The company operates and has a working interest of 60 percent in Block 2 in the Plataforma Deltana area offshore eastern Venezuela, which includes the Loran Field. During 2012, work continued on maturing commercial development concepts.

Africa

In Africa, the company is engaged in upstream activities in Angola, Chad, Democratic Republic of the Congo, Liberia, Morocco, Nigeria, Republic of the Congo, Sierra Leone and South Africa. Net oil-equivalent production in Africa averaged 451,000 barrels per day during 2012.

Angola: Chevron holds company-operated working interests in offshore Blocks 0 and 14 and nonoperated working interests in offshore Block 2 and the onshore Fina Sonangol Texaco (FST) area. Net production from these operations in 2012 averaged 137,000 barrels of oil-equivalent per day.

The company operates the 39.2 percent-owned Block 0, which averaged 98,000 barrels per day of net liquids production in 2012. The Block 0 concession extends through 2030.

Work on the second development stage of the Mafumeira Field in Block 0 continued in 2012. Mafumeira Sul, a project to develop the southern portion of the field, reached a final investment decision in 2012. Development plans include a central processing facility, two wellhead platforms, subsea pipelines, and 34 producing and 16 water injection wells. First production is planned for 2015, with maximum total production expected to reach 110,000 barrels of crude oil and 10,000 barrels of liquefied petroleum gas (LPG) per day. The project is estimated to cost $5.6 billion. The initial recognition of proved reserves for this project occurred in 2012.

A project to develop the Greater Vanza/Longui Area of Block 0 is scheduled to enter FEED in second-half 2013. FEED activities continued during 2012 on the south extension of the N'Dola Field development with a final investment decision expected in 2014. The facility is planned to have a design capacity of 28,000 barrels of crude oil per day. At the end of 2012, proved reserves had not been recognized for these projects.

Work continued in 2012 on the final stage of the Nemba Enhanced Secondary Recovery Stage 1 and 2 Project in Block 0. Installation activities are scheduled to begin in 2013, and project start-up is expected in early 2015. Maximum total production is expected to reach 13,000 barrels of oil-equivalent per day. Proved reserves have been recognized for this project.

Also in Block 0, drilling commenced on a post-salt/pre-salt dual objective exploration well in Area A in late 2012 and was completed in early 2013. The results are under evaluation. An additional pre-salt exploration well in Area A is planned for second-half 2013, along with one pre-salt and one post-salt appraisal well in Area B.

In the 31 percent-owned Block 14, net production in 2012 averaged 28,000 barrels of liquids per day. Development and production rights for the various producing fields in Block 14 expire between 2023 and 2028.

In June 2012, the project to develop the Lucapa Field in Block 14 entered FEED. Development plans include an FPSO and 17 subsea wells. The facility is planned to have a design capacity of 80,000 barrels of crude oil per day. A final investment decision is expected in 2014. During the year, development alternatives were evaluated for the Malange Field, and the project is expected to enter FEED in mid-2013. At the end of 2012, proved reserves had not been recognized for these projects.

In addition to the exploration and production activities in Angola, Chevron has a 36.4 percent interest in Angola LNG Limited, which will operate an onshore natural gas liquefaction plant in Soyo, Angola. The plant is designed to process 1.1 billion cubic feet of natural gas per day, with expected average total daily sales of 670 million cubic feet of natural gas and up to 63,000 barrels of NGLs. The plant reached mechanical completion, and commissioning activities continued through 2012. The first LNG shipment from the plant is expected to occur in second quarter 2013. The project is

estimated to cost $10 billion. The anticipated economic life of the project is in excess of 20 years. Proved reserves have been recognized for the producing operations associated with this project.

The company also holds a 38.1 percent interest in a pipeline project that is designed to transport up to 250 million cubic feet of natural gas per day from Block 0 and Block 14 to the Angola LNG plant. Construction on the project continued in 2012, and the project is expected to be completed in 2014.

Angola-Republic of the Congo Joint Development Area: Chevron operates and holds a 31.3 percent interest in the Lianzi development zone, located in an area shared equally by Angola and the Republic of the Congo. A final investment decision for the Lianzi development project was reached in July 2012. The project scope includes four producing wells and three water injection wells with a subsea tieback to an existing platform in Block 14. First production is anticipated in 2015, and maximum total daily production is expected to be 46,000 barrels of crude oil. The initial recognition of proved reserves for the project occurred in 2012.

Democratic Republic of the Congo: Chevron has a 17.7 percent nonoperated working interest in an offshore concession. Daily net production in 2012 averaged 3,000 barrels of oil-equivalent.

Republic of the Congo: Chevron has a 31.5 percent nonoperated working interest in the Haute Mer permit areas (Nkossa, Nsoko and Moho-Bilondo) and a 29.3 percent nonoperated working interest in the Kitina permit area, all of which are offshore. The licenses for Kitina, Nsoko, Nkossa and Moho-Bilondo expire in 2014, 2018, 2027 and 2030, respectively. Net production averaged 19,000 barrels of oil-equivalent per day in 2012.

FEED activities for the Moho Nord project, located in the Moho-Bilondo development area, continued in 2012. The project includes a new facilities hub and a subsea tieback to the existing Moho-Bilondo floating production unit. Maximum total daily production is expected to be 127,000 barrels of crude oil per day. A final investment decision is expected in first quarter 2013 and start-up is planned for 2015. At the end of 2012, proved reserves had not been recognized for this project.

Chad/Cameroon: Chevron has a 25 percent nonoperated working interest in crude oil producing operations in southern Chad, and an approximate 21 percent interest in two affiliates that own an export pipeline that transports crude oil to the coast of Cameroon. Average daily net production from the Chad fields in 2012 was 23,000 barrels of oil-equivalent. The Chad producing operations are conducted under a concession that expires in 2030.

Nigeria: Chevron holds a 40 percent interest in 13 concessions, predominantly in the onshore and near-offshore regions of the Niger Delta. The company operates under a joint-venture arrangement in this region with the Nigerian National Petroleum Corporation, which owns a 60 percent interest. The company also owns varying interests in four operated and six nonoperated deepwater blocks. In 2012, the company’s net oil-equivalent production in Nigeria averaged 269,000 barrels per day, composed of 238,000 barrels of crude oil, 165 million cubic feet of natural gas and 4,000 barrels of LPG.

Chevron operates and holds a 67.3 percent interest in the Agbami Field, located in deepwater Oil Mining Lease (OML) 127 and OML 128. During 2012, drilling continued on a 10-well, Phase 2 development program, Agbami 2, that is expected to offset field decline and maintain plateau production. The first well in this program commenced production in second quarter 2012. The leases that contain the Agbami Field expire in 2023 and 2024.

The company holds a 30 percent nonoperated working interest in the deepwater Usan project in OML 138. Production commenced in first quarter 2012, and total daily production at year-end 2012 was 81,000 barrels of crude oil and 3 million cubic feet of natural gas. The facilities have a maximum total production capacity of 180,000 barrels of crude oil per day. The production-sharing contract (PSC) expires in 2023.

Also in the deepwater area, the Aparo Field in OML 132 and OML 140 and the third-party-owned Bonga SW Field in OML 118 share a common geologic structure and are planned to be jointly developed. The project is expected to enter FEED in 2013. At the end of 2012, no proved reserves were recognized for this project.

In the Niger Delta, the company reached a final investment decision in early 2013 on the Dibi Long-Term Project that is designed to rebuild the Dibi facilities and replace the Early Production System facility. The facilities are planned to have a maximum production capacity of 70,000 barrels of crude oil per day, and start-up is expected in 2016.

Also in the Niger Delta, ramp-up activity continued at the Escravos Gas Plant (EGP). During 2012, construction continued on Phase 3B of the EGP project, which is designed to gather 120 million cubic feet of natural gas per day from eight offshore fields and to compress and transport the natural gas to onshore facilities. The Phase 3B project is expected to be completed in 2016. Proved reserves associated with this project have been recognized.

The 40 percent-owned and operated Sonam Field Development is designed to process natural gas through EGP, deliver 215 million cubic feet of natural gas per day to the domestic market and produce a total of 30,000 barrels of liquids per day. First production is expected in 2016. Proved reserves have been recognized for the project.

Chevron has a 75 percent-owned and operated interest in a gas-to-liquids facility at Escravos that is being developed with the Nigerian National Petroleum Corporation. The 33,000-barrel-per-day facility is designed to process 325 million cubic feet per day of natural gas supplied from the Phase 3A expansion of EGP. As of early 2013, overall work on the project was more than 89 percent complete and start-up is planned for late 2013. The estimated cost of the plant is $9.5 billion.

The company has a 40 percent-owned and operated interest in the Onshore Asset Gas Management project that is designed to restore approximately 125 million cubic feet per day of natural gas production from certain onshore fields that have been shut in since 2003 due to civil unrest. Construction was completed in third quarter 2012, and start-up commenced in late 2012.

In deepwater exploration, the company has a 27 percent nonoperated working interest in Oil Prospecting License (OPL) 223 where an exploration well was drilled in third quarter 2012. In addition, Chevron operates and holds a 95 percent interest in the deepwater Nsiko discovery in OML 140. Additional exploration activities are planned for 2013 and 2014.

Shallow-water exploration activities in 2012 included reprocessing 3-D seismic data from OML 86 and OML 88 and regional mapping activities.

With a 36.7 percent interest, Chevron is the largest shareholder in the West African Gas Pipeline Company Limited affiliate, which owns and operates the 421-mile West African Gas Pipeline. The pipeline supplies Nigerian natural gas to customers in Benin, Ghana and Togo for industrial applications and power generation and has the capacity to transport 170 million cubic feet per day.

Liberia: Chevron operates three deepwater blocks off the coast of Liberia. In July 2012, the company farmed down its interest from 70 percent to 45 percent in these blocks. Exploration wells were drilled in blocks LB-11 and LB-12 during 2012. In 2013, the company plans to mature drilling prospects based on the evaluation of 2012 drilling results and 3-D seismic data.

Morocco: In early 2013, the company entered into agreements to acquire a 75 percent operated interest in three deepwater areas offshore Morocco. The areas, Cap Rhir Deep, Cap Cantin Deep and Cap Walidia Deep, encompass approximately 7.2 million acres. Once the award is finalized, acquisition of seismic data is planned.

Sierra Leone: In September 2012, the company announced that it had been awarded operatorship and a 55 percent interest in a concession off the coast of Sierra Leone. The concession contains two deepwater blocks, with a combined area of approximately 1.4 million acres. Acquisition of 2-D seismic data is planned for 2013.

South Africa: In December 2012, the company entered into an agreement to seek shale gas exploration opportunities in the Karoo Basin in South Africa. This agreement allows Chevron and its partner to work together over a five-year period to obtain exploration permits in the 151 million-acre basin.

Asia

In Asia, the company is engaged in upstream activities in Azerbaijan, Bangladesh, Cambodia, China, Indonesia, Kazakhstan, the Kurdistan Region of Iraq, Myanmar, the Partitioned Zone located between Saudi Arabia and Kuwait, the Philippines, Russia, Thailand, and Vietnam. During 2012, net oil-equivalent production averaged 1,061,000 barrels per day.

Azerbaijan: Chevron holds an 11.3 percent nonoperated working interest in the Azerbaijan International Operating Company (AIOC), which produces crude oil from the Azeri-Chirag-Gunashli (ACG) project. The company's daily net production from AIOC averaged 28,000 barrels of oil-equivalent in 2012. AIOC operations are conducted under a PSC that expires in 2024.

During 2012, construction progressed on the next development phase of the ACG project, which will further develop the deepwater Gunashli Field. The total estimated cost of the project is $6 billion, with an incremental targeted maximum total daily production of 103,000 barrels of oil-equivalent. Production is expected to begin in late 2013. Proved reserves have been recognized for this project.

Chevron also has an 8.9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) affiliate, which owns and operates a crude oil export pipeline from Baku, Azerbaijan, through Georgia to Mediterranean deepwater port facilities at Ceyhan, Turkey. The BTC Pipeline has a capacity of 1.2 million barrels per day and transports the majority of ACG production. Another production export route for crude oil is the Western Route Export Pipeline, wholly owned and operated by AIOC, with capacity to transport 100,000 barrels per day from Baku, Azerbaijan, to a marine terminal at Supsa, Georgia.

Kazakhstan: Chevron participates in two major upstream developments in western Kazakhstan. The company holds a 50 percent interest in the Tengizchevroil (TCO) affiliate, which is operating and developing the Tengiz and Korolev crude oil fields under a concession that expires in 2033. Chevron's net oil-equivalent production in 2012 from these fields averaged 286,000 barrels per day, composed of 218,000 barrels of crude oil, 301 million cubic feet of natural gas and 18,000 barrels of NGLs. During 2012, the majority of TCO's crude oil production was exported through the Caspian Pipeline Consortium (CPC) pipeline that runs from Tengiz in Kazakhstan to tanker-loading facilities at Novorossiysk on the Russian coast of the Black Sea. The balance was exported via rail to Black Sea ports.

In 2012, FEED activities were initiated for three projects. The Wellhead Pressure Management Project is designed to maintain production capacity and extend the production plateau from existing assets. The Capacity and Reliability Project is designed to reduce facility bottlenecks and increase plant efficiency and reliability. The Future Growth Project is designed to increase total daily crude oil production by 250,000 to 300,000 barrels of oil-equivalent and to increase the ultimate recovery of the reservoir. The project will expand the utilization of sour gas injection technology proven in existing operations. The final investment decisions on these projects are planned for late 2013. At the end of

2012, proved reserves have only been recognized for the Wellhead Pressure Management Project.

Also at TCO, start-up commenced on the Sulfur Expansion Project in December 2012. This project is designed to eliminate routine additions to sulfur inventory.

In June 2012, the company's nonoperated working interest in the Karachaganak Field was reduced from 20 percent to 18 percent as a result of a 2011 agreement with the Republic of Kazakhstan government. Operations and development of the field are conducted under a PSC that expires in 2038. During 2012, Karachaganak net oil-equivalent production averaged 61,000 barrels per day, composed of 37,000 barrels of liquids and 139 million cubic feet of natural gas. Access to the CPC and Atyrau-Samara (Russia) pipelines enabled approximately 35,000 net barrels per day of Karachaganak liquids to be exported and sold at world-market prices during 2012. The remaining liquids were sold into local and Russian markets. During 2012, work continued on identifying the optimal scope for the future expansion of the field. At the end of 2012, proved reserves had not been recognized for any further expansion.

Kazakhstan/Russia: Chevron has a 15 percent interest in the CPC affiliate. During 2012, CPC transported an average of approximately 657,000 barrels of crude oil per day, including 590,000 barrels per day from Kazakhstan and 67,000 barrels per day from Russia. During 2012, work continued on the 670,000-barrel-per-day expansion of the pipeline capacity with the mechanical completion of the offshore loading system. The $5.4 billion project is expected to be implemented in three phases, with capacity increasing progressively until reaching maximum capacity of 1.4 million barrels per day in 2016. The first increase in capacity of 400,000 barrels per day is expected in 2014.

Turkey: In December 2012, Chevron relinquished its 50 percent interest in License 3921 in the Black Sea.

Bangladesh: Chevron holds a 98 percent interest in two operated PSCs covering Block 12 (Bibiyana) and Blocks 13 and 14 (Jalalabad and Moulavi Bazar fields). The rights to produce from Jalalabad expire in 2024, from Moulavi Bazar in 2028 and from Bibiyana in 2034. Net oil-equivalent production from these operations in 2012 averaged 94,000 barrels per day, composed of 550 million cubic feet of natural gas and 2,000 barrels of liquids.

In April 2012, start-up of the Muchai compression project was achieved. This project supports additional natural gas production capacity of 80 million cubic feet per day from the Bibiyana, Jalalabad and Moulavi Bazar fields. The Bibiyana Expansion project achieved a final investment decision in July 2012. The project scope includes a gas plant expansion, additional development drilling and an enhanced liquids recovery unit, and is expected to increase total maximum daily production by more than 300 million cubic feet of natural gas and 4,000 barrels of condensate. First production is expected in 2014. The initial recognition of proved reserves for this expansion project occurred in 2012.

Cambodia: Chevron owns a 30 percent interest and operates the 1.2 million-acre Block A, located in the Gulf of Thailand. In 2012, the company progressed discussions on the production permit for development of Block A. The planned development consists of a wellhead platform and a floating storage and offloading vessel (FSO). A final investment decision is pending resolution of commercial terms. At the end of 2012, proved reserves had not been recognized for the project.

Myanmar: Chevron has a 28.3 percent nonoperated working interest in a PSC for the production of natural gas from the Yadana and Sein fields, within Blocks M5 and M6, in the Andaman Sea. The PSC expires in 2028. The company also has a 28.3 percent nonoperated interest in a pipeline company that transports the natural gas to the Myanmar-Thailand border for delivery to power plants in Thailand. The company’s average net natural gas production in 2012 was 94 million cubic feet per day.

Thailand: Chevron has operated and nonoperated working interests in multiple offshore blocks in the Gulf of Thailand. The company’s net oil-equivalent production in 2012 averaged 243,000 barrels per day, composed of 67,000 barrels of crude oil and condensate and 1.1 billion cubic feet of natural gas. The company’s natural gas production is sold to the domestic market under long-term sales contracts.

The company holds operated interests in the Pattani Basin with ownership interests ranging from 35 percent to 80 percent. Concessions for producing areas within this basin expire between 2020 and 2035. Chevron has a 16 percent nonoperated working interest in the Arthit Field located in the Malay Basin. Concessions for the producing areas within this basin expire between 2036 and 2040.

During 2012, the company drilled six exploration wells in the Pattani Basin, and four were successful. The company also holds exploration interests in the Thailand-Cambodia overlapping claim area that are inactive, pending resolution of border issues between Thailand and Cambodia.

Vietnam: Chevron is the operator of two PSCs in the Malay Basin off the southwest coast of Vietnam. The company has a 42.4 percent interest in a PSC that includes Blocks B and 48/95, and a 43.4 percent interest in a PSC for Block 52/97.

The Block B Gas Development Project is designed to produce natural gas from the Malay Basin for delivery to state-owned Petrovietnam. The project includes installation of wellhead and hub platforms, an FSO, a central processing platform and a pipeline to shore. FEED continued during 2012. Maximum total daily production is expected to be 490 million cubic feet of natural gas and 4,000 barrels of condensate. A final investment decision for the development is pending resolution of commercial terms. At the end of 2012, proved reserves had not been recognized for the development project.

During 2012, the company drilled two exploratory wells in Block 52/97, and both were successful.

China: Chevron has operated and nonoperated working interests in several areas in China. The company's net oil-equivalent production in 2012 averaged 21,000 barrels per day, composed of 20,000 barrels of crude oil and condensate and 9 million cubic feet of natural gas.

The company operates and holds a 49 percent interest in the

Chuandongbei PSC, located in the onshore Sichuan Basin. The full development includes two new sour-gas processing plants with an aggregate inlet design capacity of 740 million cubic feet per day, connected by a natural gas gathering system to five fields. During 2012, the company continued construction of the first natural gas processing plant, and site preparation commenced for the second natural gas processing plant. The initial plant, with an expected maximum total production of 258 million cubic feet per day, is targeted for mechanical completion at the end of 2013. Planned maximum total natural gas production is 558 million cubic feet per day, and the total project cost is estimated to be $6.4 billion. Proved reserves have been recognized for this project. The PSC for Chuandongbei expires in 2037.

The company holds a 59.2 percent-owned and operated interest in deepwater Block 42/05 in the South China Sea, which covers exploratory acreage of approximately 1.3 million acres. During 2012, the company drilled two exploration wells in South China Sea deepwater Blocks 53/30 and 64/18, and both were unsuccessful. In November 2012, the company relinquished its interest in deepwater Blocks 53/30 and 64/18.
Additional 3-D seismic data was acquired over Block 42/05, and further exploration drilling is under evaluation. In 2012, Chevron entered into an agreement to acquire a 100 percent-owned and operated interest in shallow-water Blocks 15/10 and 15/28, which cover approximately 1.4 million exploratory acres. Government approval is expected in first-half 2013, and a 3-D seismic survey is expected to commence in mid-2013.

During 2012, the company drilled an initial exploratory well for shale gas in the Qiannan Basin. Evaluation of the well continues in early 2013. Additional drilling is planned for 2013.

The company also has nonoperated working interests of 32.7 percent in Blocks 16/08 and 16/19 in the Pearl River Mouth Basin and nonoperated working interests of 24.5 percent in the QHD 32-6 Field and 16.2 percent in Block 11/19 in the Bohai Bay.

Philippines: The company holds a 45 percent nonoperated working interest in the Malampaya natural gas field located 50 miles offshore Palawan Island. Net oil-equivalent production in 2012 averaged 24,000 barrels per day, composed of 120 million cubic feet of natural gas and 4,000 barrels of condensate. During 2012, plans progressed on Malampaya Phase 2 to drill two additional infill wells and to add depletion compression facilities. Start-up is planned for 2014. Proved reserves have been recognized for this project.

Chevron also develops and produces geothermal resources in southern Luzon, which supply steam to third-party, 637-megawatt power generation facilities. During fourth quarter 2012, Chevron sold 60 percent of its interest in these geothermal operations in order to secure a 25-year geothermal operating contract with the Philippine government for the continued development and operation of the steam fields. Chevron also has a 90 percent-owned and operated interest in the Kalinga geothermal prospect area in northern Luzon and is in the early phase of geological and geophysical assessments.

Indonesia: Chevron holds operated and nonoperated working interests in Indonesia. The company has 100 percent-owned and operated interests in the Rokan and Siak PSCs onshore Sumatra. Chevron also operates four PSCs in the Kutei Basin, located offshore East Kalimantan. These interests range from 62 percent to 92.5 percent. Chevron also has 51 percent operated working interests in two exploration blocks in western Papua, West Papua I and West Papua III, and a 25 percent nonoperated working interest in a joint venture in Block B in the South Natuna Sea.

The company's net oil-equivalent production in 2012 from its interests in Indonesia averaged 198,000 barrels per day, composed of 158,000 barrels of liquids and 236 million cubic feet of natural gas. The largest producing field is Duri, located in the Rokan PSC. Duri has been under steamflood since 1985 and is one of the world's largest steamflood developments. The North Duri Development is divided into multiple expansion areas. Construction began on the Duri Area 13 expansion project in fourth quarter 2012. First production is scheduled for late 2013, and maximum total daily production of 17,000 barrels of crude oil is expected to be reached in 2016. The Rokan PSC expires in 2021.

During 2012, two deepwater development projects in the Kutei Basin progressed under a single plan of development. In the first of these projects, Chevron completed FEED for the Gendalo-Gehem deepwater natural gas project, and a final investment decision is expected during 2014. The project includes two separate hub developments, natural gas and condensate pipelines, and an onshore receiving facility. Maximum total daily production from the project is expected to be about 1.1 billion cubic feet of natural gas and 31,000 barrels of condensate. Gas from the project is expected to be used

domestically and for LNG export. The company's working interest is approximately 63 percent. At the end of 2012, proved reserves had not been recognized for this project.

In the second of these projects, the company requested bids for all major contracts for the Bangka deepwater natural gas project. A final investment decision is expected in 2013. The project scope includes a subsea tieback to a floating production unit, and maximum total daily production is expected to be about 114 million cubic feet of natural gas and 4,000 barrels of condensate. The company's working interest is 62 percent. At year-end 2012, proved reserves had not been recognized for this project.

In Sumatra, four exploration wells were drilled. Two wells were successful and the results for two wells are under evaluation in early 2013. Appraisal and exploration drilling is planned for 2013. In the West Papua exploration blocks, which are in close proximity to a third-party LNG facility, seismic data acquisition and processing was completed for West Papua I in 2012 and is planned for completion for West Papua III in 2013.

In West Java, the company operates and holds a 95 percent interest in the Darajat geothermal field, which supplies steam to a power plant with a total operating capacity of 259 megawatts. Chevron also operates and holds a 100 percent interest in the Salak geothermal field in West Java, which supplies steam to a power plant with a total operating capacity of 377 megawatts. In Sumatra, Chevron operates and holds a 95 percent interest in the North Duri Cogeneration Plant, supplying up to 300 megawatts of power to the company's Sumatra operations and steam in support of the Duri steamflood project. In the Suoh-Sekincau prospect area of Sumatra, the company holds a 95 percent-owned and operated interest in a license to explore and develop a geothermal prospect.

Kurdistan Region of Iraq: In July 2012, the company announced the acquisition of an 80 percent-owned and operated interest in two PSCs covering the Rovi and Sarta blocks in the Kurdistan Region of Iraq. The blocks cover a combined area of approximately 232,000 acres.

Partitioned Zone (PZ): Chevron holds a concession to operate the Kingdom of Saudi Arabia's 50 percent interest in the petroleum resources in the onshore area of the PZ between Saudi Arabia and Kuwait. The concession expires in 2039.

During 2012, the company's average net oil-equivalent production was 90,000 barrels per day, composed of 86,000 barrels of crude oil and 21 million cubic feet of natural gas. During 2012, the company continued a steam injection pilot project in the First Eocene carbonate reservoir that was initiated in 2009. A project to expand the steam injection pilot to the Second Eocene reservoir is expected to enter FEED by late 2013. Development planning also continued during 2012 on a full-field steamflood application in the Wafra Field. The Wafra Steamflood Stage 1 Project is expected to enter FEED in 2014. At the end of 2012, proved reserves had not been recognized for any of these steamflood developments.

Also in 2012, FEED activities continued on the Central Gas Utilization Project. The project is intended to increase natural gas utilization and eliminate routine flaring. A final investment decision is expected in 2014. At year-end 2012, proved reserves had not been recognized for this project.

Australia

In Australia, the company’s upstream efforts are concentrated off the northwest coast. During 2012, the average net oil-equivalent production from Australia was 99,000 barrels per day.

Chevron holds a 47.3 percent ownership interest across most of the Greater Gorgon Area and is the operator of the Gorgon Project, which combines the development of the Gorgon and nearby Io/Jansz natural gas fields. The development includes a three-train, 15.6 million-metric-ton-per-year LNG facility, a carbon sequestration project and a domestic natural gas plant. Maximum total daily production from the project is expected to reach approximately 2.6 billion cubic feet of natural gas and 20,000 barrels of condensate. Start-up of the first train is expected in late 2014, leading to the first LNG cargo in first quarter 2015. Total estimated project costs for the first phase of development are $52 billion. Proved reserves have been recognized for this project. The project's estimated economic life exceeds 40 years from the time of start-up.

Work on the Gorgon project continued during 2012. As of year-end 2012, more than 55 percent of the project activities had been completed. Key milestones achieved in 2012 were the arrival and installation of the first LNG plant modules, subsea wellhead trees and subsea pipelines. The development drilling program also progressed during 2012.

Chevron has signed binding, long-term LNG Sales and Purchase Agreements with six Asian customers for delivery of about 4.8 million metric tons of LNG per year, which brings delivery commitments to about 65 percent of Chevron's share of LNG from this project. Discussions continue with potential customers to increase long-term sales to 85 percent of Chevron's net LNG offtake. Chevron also has binding long-term agreements for delivery of about 65 million cubic feet per day of natural gas to Western Australian natural gas consumers starting in 2015, and the company continues to market additional natural gas quantities from the Gorgon Project.

An expansion project to develop a fourth train at the Gorgon LNG facility is expected to enter FEED in late 2013. At the end of 2012, proved reserves had not been recognized for the fields associated with this project.

Chevron is the operator of the Wheatstone Project, which includes a two-train, 8.9 million-metric-ton-per-year LNG facility and a domestic gas plant located at Ashburton North, along the northwest coast of Australia. The company plans to supply natural gas to the facilities from three company-operated licenses, containing the Wheatstone Field and nearby Iago Field. Maximum total daily production from these and third-party fields is expected to be about 1.6 billion cubic feet of natural gas and 30,000 barrels of condensate. Start-up of the first train is expected in 2016. Total estimated project costs for the first phase of development are $29 billion. Proved reserves have been recognized for this project. The project's estimated economic life exceeds 30 years from the time of start-up.

In 2012, construction and fabrication activities progressed, with a focus on delivering site infrastructure and key components of the platform and subsea equipment. Chevron signed additional commercial agreements that decreased Chevron's interest in the offshore licenses to 80.2 percent and in the LNG facilities to 64.1 percent. The company also executed agreements with Asian customers for the delivery of additional volumes of LNG. As of year-end 2012, more than 80 percent of Chevron's equity LNG offtake was covered under long-term agreements with customers in Asia. In addition, the company has begun marketing its equity share of natural gas of approximately 120 million cubic feet per day to Western Australia natural gas consumers.

During 2012 and early 2013, the company announced seven natural gas discoveries in the Carnarvon Basin. These include natural gas discoveries at the 47.3 percent-owned and operated Pontus prospect in Block WA-37-L, the 50 percent-owned and operated Satyr prospect in Block WA-374-P, the 50 percent-owned and operated Pinhoe prospect in Block WA-383-P, the 50 percent-owned and operated Arnhem prospect in Block WA-364-P, and the 50 percent-owned and operated Kentish Knock South prospect in Block WA-365-P. These discoveries are expected to contribute to potential expansion opportunities at company-operated LNG facilities.

Chevron has a 16.7 percent nonoperated working interest in the North West Shelf (NWS) Venture in Western Australia. Daily net production from the project during 2012 averaged 20,000 barrels of crude oil and condensate, 428 million cubic feet of natural gas, and 4,000 barrels of LPG. Approximately 70 percent of the natural gas was sold in the form of LNG to major utilities in Asia, primarily under long-term contracts. The remaining natural gas was sold to the Western Australia domestic market. The concession for the NWS Venture expires in 2034.

The North Rankin 2 project continued to advance during 2012, with start-up expected in mid-2013. The project is designed to recover remaining low-pressure natural gas from the North Rankin and Perseus fields to meet gas supply needs and maintain NWS production capacity of about 2 billion cubic feet of natural gas and 39,000 barrels of condensate. Total estimated projects costs are $5.4 billion. Proved reserves have been recognized for the project. The project's estimated economic life exceeds 20 years from the time of start-up.

In October 2012, the company exchanged its 16.7 percent interest in the East Browse leases and its 20 percent interest in the West Browse leases for financial consideration and a 33.3 percent interest in the WA-205-P and WA-42-R blocks in the Carnarvon Basin and now holds a 100 percent interest in these blocks, which contain the Clio and Acme fields. The company retains other nonoperated working interests ranging from 24.8 percent to 50 percent in three other blocks in the Browse Basin. In Block WA-274-P, drilling in the fourth quarter 2012 resulted in a natural gas discovery at the Crown prospect.

Europe

In Europe, the company is engaged in upstream activities in Bulgaria, Denmark, Lithuania, the Netherlands, Norway, Poland, Romania, Ukraine and the United Kingdom. Net oil-equivalent production in Europe averaged 114,000 barrels per day during 2012.

Denmark: Chevron has a 12 percent working interest in the partner-operated Danish Underground Consortium (DUC), which produces crude oil and natural gas from 13 fields in the Danish North Sea. Net oil-equivalent production in 2012 from DUC averaged 36,000 barrels per day, composed of 24,000 barrels of crude oil and 74 million cubic feet of natural gas. In July 2012, as part of a 30-year concession extension, the state-owned Danish North Sea Fund received a 20 percent ownership of the DUC in exchange for the previous 20 percent government profit-take arrangements and the company's interest was reduced from 15 percent to 12 percent. The concession expires in 2042.

Netherlands: Chevron operates and holds interests ranging from 34.1 percent to 80 percent in 10 blocks in the Dutch sector of the North Sea. In 2012, the company’s net oil-equivalent production was 9,000 barrels per day, composed of 2,000 barrels of crude oil and 42 million cubic feet of natural gas.

Norway: The company holds a 7.6 percent nonoperated working interest in the Draugen Field. The company’s net production averaged 3,000 barrels of oil-equivalent per day during 2012. Chevron is the operator and has a 40 percent working interest in exploration licenses PL 527 and PL 598. Both licenses are in the deepwater portion of the Norwegian Sea.

United Kingdom: The company’s average net oil-equivalent production in 2012 from 10 offshore fields was 66,000 barrels per day, composed of 46,000 barrels of liquids and 122 million cubic feet of natural gas. Most of the production was from three fields: the 85 percent-owned and operated Captain Field, the 23.4 percent-owned and operated Alba Field, and the 32.4 percent-owned and jointly operated Britannia Field.

Procurement and fabrication activities began in 2012 for the Clair Ridge project, located west of the Shetland Islands, in which the company has a 19.4 percent nonoperated working interest. The project is the second development phase of the Clair Field. Total planned design capacity is 120,000 barrels of crude oil per day, and the total estimated cost of the project is $7 billion. Production is scheduled to begin in 2016 and the project's estimated economic life exceeds 40 years from the time of start-up. Proved reserves have been recognized for the Clair Ridge project.

At the 70 percent-owned and operated Alder discovery, FEED activities progressed during 2012, and a final investment decision is planned for late 2013. The 40 percent-owned and operated Rosebank Project northwest of the Shetland Islands entered FEED in July 2012. A final investment decision is planned for 2014. Maximum total daily production is expected to reach 64,000 barrels of liquids and 42 million cubic feet of natural gas. At the end of 2012, proved reserves had not been recognized for these projects.

An unsuccessful exploration well was drilled at the Aberlour prospect west of the Shetland Islands. Full and partial block relinquishments were made during 2012 under Licenses P119 (Strathspey area), P1026, P1191 and P1194 (Aberlour).

Bulgaria: In June 2011, the Bulgarian government advised that Chevron had submitted a winning tender for a permit for exploration in a 1.1 million-acre area in northeast Bulgaria. In January 2012, prior to execution of the license agreement, the Bulgarian government announced the withdrawal of the decision awarding the permit and the Bulgarian parliament imposed a ban on hydraulic fracturing, a technology commonly used for shale development and production. Chevron continues to work with the government of Bulgaria to provide the necessary assurances to both the government and the public that hydrocarbons from shale can be developed safely and responsibly.

Lithuania: In October 2012, Chevron acquired a 50 percent interest in a Lithuanian exploration and production company. In 2013, the affiliate plans to commence shale exploration activities in the 394,000-acre Rietavas block.

Poland: Chevron holds four shale concessions in southeast Poland (Frampol, Grabowiec, Krasnik and Zwierzyniec). All four exploration licenses are 100 percent-owned and operated and comprise a total of 1.1 million acres. During 2012, drilling was completed on the first well in the Grabowiec concession and evaluation of this well continued into early 2013. An initial well was also drilled in the Frampol concession in 2012. Drilling of a well in the Zwierzyniec concession commenced in

December 2012, and continued exploratory drilling of the concessions is planned for 2013.

Romania: The company holds a 100 percent interest and operates the Barlad shale concession. This license is located in northeast Romania and covers 1.6 million acres. Drilling of an exploration well is planned for second-half 2013. In March 2012, three additional petroleum concession agreements, covering approximately 670,000 acres in southeast Romania, were approved by the government of Romania. Chevron holds a 100 percent interest and operates the concessions. Acquisition of 2-D seismic data across these concessions is expected to commence in second-half 2013.

Ukraine: In 2012, Chevron was the successful bidder for the right to exclusively negotiate a 50-year PSC with the government of Ukraine for the Oleska block in western Ukraine. Chevron is expected to operate and hold a 50 percent interest in the 1.6 million-acre concession. As of early 2013, the PSC and Joint Operating Agreement terms were being negotiated.

Sales of Natural Gas and Natural Gas Liquids

The company sells natural gas and natural gas liquids from its producing operations under a variety of contractual arrangements. In addition, the company also makes third-party purchases and sales of natural gas and natural gas liquids in connection with its trading activities.

During 2012, U.S. and international sales of natural gas were 5.5 billion and 4.3 billion cubic feet per day, respectively, which includes the company’s share of equity affiliates’ sales. Outside the United States, substantially all of the natural gas sales from the company’s producing interests are from operations in Australia, Bangladesh, Europe, Kazakhstan, Indonesia, Latin America, Myanmar, Nigeria, the Philippines and Thailand.

U.S. and international sales of natural gas liquids were 157 thousand and 88 thousand barrels per day, respectively, in 2012. Substantially all of the international sales of natural gas liquids from the company's producing interests are from operations in Africa, Kazakhstan, Indonesia and the United Kingdom.

Refer to “Selected Operating Data,” on page FS-10 in Management’s Discussion and Analysis of Financial Condition and Results of Operations, for further information on the company’s sales volumes of natural gas and natural gas liquids. Refer also to “Delivery Commitments” on page 7 for information related to the company’s delivery commitments for the sale of crude oil and natural gas.

Downstream

Refining Operations

At the end of 2012, the company had a refining network capable of processing about 2.0 million barrels of crude oil per day. Operable capacity at December 31, 2012, and daily refinery inputs for 2010 through 2012 for the company and affiliate refineries are summarized in the table below.

Average crude oil distillation capacity utilization during 2012 was 88 percent, compared with 89 percent in 2011. At the U.S. refineries, crude oil distillation capacity utilization averaged 87 percent in 2012, compared with 89 percent in 2011. Chevron processes both imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 77 percent and 85 percent of Chevron's U.S. refinery inputs in 2012 and 2011, respectively.

At the Pascagoula Refinery, construction progressed on a facility to produce approximately 25,000 barrels per day of premium base oil for use in manufacturing high-performance finished lubricants, such as motor oils for consumer and commercial applications. Mechanical completion is expected by year-end 2013. In July 2012, the company completed the sale of its idled 80,000-barrel-per-day Perth Amboy, New Jersey, refinery, which was operating as a terminal.

At the refinery in El Segundo, a new processing unit designed to further improve the facility's overall reliability, enhance high-value product yield and provide additional flexibility to process a broad range of crude slates came online in July 2012. Similar projects were progressed in 2012 at the Salt Lake City and Pascagoula refineries and are scheduled to be completed in late 2013.

Outside the United States, GS Caltex, a 50 percent-owned equity affiliate, reached mechanical completion of a 53,000-barrel-per-day gas oil fluid catalytic cracking unit at the Yeosu Refinery in South Korea in early 2013. The unit is designed to increase high-value product yield and lower feedstock costs. In 2012, construction was completed on modifications to the 64 percent-owned Star Petroleum Refinery in Thailand to meet regional specifications for cleaner fuels. Also in 2012, Caltex Australia Ltd., a 50 percent-owned equity affiliate, announced plans to convert the Kurnell, Australia, refinery to an import terminal in 2014.

Petroleum Refineries: Locations, Capacities and Inputs
(Crude-unit capacities and crude oil inputs in thousands of barrels per day; includes equity share in affiliates)

		December 31, 2012		Refinery Inputs		
Locations		Number	Operable Capacity	2012	2011	2010
Pascagoula	Mississippi	1	330	335	327	325
El Segundo	California	1	269	265	244	250
Richmond	California	1	257	142	192	228
Kapolei	Hawaii	1	54	46	47	46
Salt Lake City	Utah	1	45	45	44	41
Total Consolidated Companies — United States		5	955	833	854	890
Pembroke[1]	United Kingdom	—	—	—	122	211
Map Ta Phut[2]	Thailand	1	158	95	—	—
Cape Town[3]	South Africa	1	110	79	77	70
Burnaby, B.C.	Canada	1	55	49	43	40
Total Consolidated Companies — International		3	323	223	242	321

Affiliates[2,4]	Various Locations	6	675	646	691	683
Total Including Affiliates — International		9				

Zip Code **Zip Code**

Taxpayer Identification or Social Security Number **Taxpayer Identification or Social Security Number**

o Credit unexchanged Old Notes delivered by book-entry transfer to the Book-Entry Transfer Facility account set forth below.

Book-Entry Facility Account Number, if applicable

A-7

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INSTRUCTIONS
Forming Part of the Terms and Conditions
of the Exchange Offer

1. **Guarantee of Signatures.**

No signature guarantee on this Letter of Transmittal is required if:

(i) this Letter of Transmittal is signed by the registered Holder of Old Notes tendered herewith, or

(ii) such Old Notes are tendered for the account of a firm that is an "eligible guarantor institution" within the meaning of Rule 17Ad-15 under the Securities Exchange Act of 1934, as amended (an "Eligible Institution").

In all other cases, an Eligible Institution must guarantee the signature(s) on this Letter of Transmittal.

2. **Delivery of this Letter of Transmittal and Old Notes.**

The certificates for the tendered Old Notes (or a confirmation of a book-entry into the Exchange Agent's account at DTC of all Old Notes delivered electronically), as well as a properly completed and duly executed copy of this Letter of Transmittal or facsimile hereof and any other documents required by this Letter of Transmittal must be received by the Exchange Agent at its address set forth herein prior to 11:59 p.m., Eastern Time, on the Expiration Date. The method of delivery of the tendered Old Notes, this Letter of Transmittal and all other required documents to the Exchange Agent are at the election and risk of the Holder and, except as otherwise provided below, the delivery will be deemed made only when actually received by the Exchange Agent. Instead of delivery by mail, it is recommended that the Holder use an overnight or hand delivery service. In all cases, sufficient time should be allowed to assure timely delivery. No Letter of Transmittal or Old Notes should be sent to the Company.

3. **Partial Tenders.**

Holders may tender some or all of their Old Notes pursuant to the Exchange Offer in denominations of $2,000 and $1,000 integral multiples in excess of $2,000 thereof. If a tender for exchange is to be made with respect to less than the entire principal amount of any Old Notes, fill in the principal amount of Old Notes which are tendered for exchange in column (3) of the box entitled "Description of Old Notes." In case of a partial tender for exchange, the untendered principal amount of the Old Notes will be credited to the DTC account of the tendering Holder, unless otherwise indicated in the appropriate box on this Letter of Transmittal, promptly after the expiration or termination of the Exchange Offer.

4. **Signatures on the Letter of Transmittal; Bond Powers and Endorsements.**

If this Letter of Transmittal is signed by the registered holder of the Old Notes tendered hereby, the signature must correspond exactly with the name as written on the face of the certificates without any change whatsoever.

If any tendered Old Notes are owned of record by two or more joint owners, all such owners must sign this Letter of Transmittal.

If any tendered Old Notes are registered in different names on several certificates, it will be necessary to complete, sign and submit as many separate copies of this Letter of Transmittal as there are different registrations of certificates.

When this Letter of Transmittal is signed by the registered holder or holders of the Old Notes specified herein and tendered hereby, no endorsements of certificates or separate bond powers are required. If, however, the New Notes are to be issued, or any nontendered Old Notes are to be reissued, to a person other than the registered holder, then endorsements of any certificates transmitted hereby or separate bond powers are required. Signatures on such certificate(s) or bond powers must be guaranteed by an Eligible Institution.

If this Letter of Transmittal is signed by a person other than the registered holder or holders of any certificate(s) specified herein, such certificates must be endorsed or accompanied by appropriate bond powers, in either case signed exactly as the name or names of the registered holder or holders appear(s) on the certificate(s) and signatures on such certificates(s) or bond powers must be guaranteed by an Eligible Institution.

If this Letter of Transmittal (or facsimile hereof) or any Old Notes or bond powers are signed by trustees, executors, administrators, guardians, attorneys-in-fact, or officers of corporations or others acting in a fiduciary or representative capacity, such persons should so indicate when signing, and unless waived by the Company, evidence satisfactory to the Company of their authority so to act must be submitted with this Letter of Transmittal.

Endorsements on Old Notes or signatures on bond powers required by this Instruction 4 must be guaranteed by an Eligible Institution.

5.

Transfer Taxes.

The Company will pay all transfer taxes, if any, applicable to the exchange of Old Notes pursuant to the Exchange Offer. If, however, certificates representing New Notes or Old Notes for principal amounts not tendered or accepted for exchange are to be delivered to, or are to be registered or issued in the name of, any person other than the registered Holder of the Old Notes tendered hereby, or if tendered Old Notes are registered in the name of any person other than the person signing this Letter of Transmittal, or if a transfer tax is imposed for any reason other than the exchange of Old Notes pursuant to the Exchange Offer, then the amount of any such transfer taxes (whether imposed on the registered Holder or any other person) will be payable by the tendering Holder. If satisfactory evidence of payment of such taxes or exemption therefrom is not submitted with this Letter of Transmittal, the amount of such transfer taxes will be billed directly to such tendering Holder.

Except as provided in this Instruction 5, it will not be necessary for transfer tax stamps to be affixed to the Old Notes listed in this Letter of Transmittal.

6.

Irregularities.

All questions as to the form of documents and the validity, eligibility (including time of receipt), acceptance and withdrawal of Old Notes will be determined by the Company, in its sole discretion, whose determination shall be final and binding. The Company reserves the absolute right to reject any or all tenders for exchange of any particular Old Notes that are not in proper form, or the acceptance of which would, in the opinion of the Company (or its counsel), be unlawful. The Company reserves the absolute right to waive any defect, irregularity or condition of tender for exchange with regard to any particular Old Notes. The Company's interpretation of the terms of, and conditions to, the Exchange Offer (including the instructions herein) will be final and binding. Unless waived, any defects or irregularities in connection with the Exchange Offer must be cured within such time as the Company shall determine. Neither the Company, the Exchange Agent nor any other person shall be under any duty to give notice of any defects or irregularities in Old Notes tendered for exchange, nor shall any of them incur any liability for failure to give such notice. A tender of Old Notes will not be deemed to have been made until all defects and irregularities with respect to such tender have been cured or waived. Any Old Notes received by the Exchange Agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned by the Exchange Agent to the tendering Holders, unless otherwise provided in this Letter of Transmittal, promptly following the Expiration Date.

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7. Waiver of Conditions.

The Company reserves the absolute right to amend, waive or modify specified conditions in the Exchange Offer in the case of any Old Notes tendered.

8. Requests for Information or Additional Copies.

Questions and requests for assistance and requests for the Prospectus, Letter of Transmittal and the related documents may be directed to the Exchange Agent at the address set forth on the cover page of this Letter of Transmittal. Holders may also contact their broker, dealer, commercial bank, trust company or other nominee for assistance concerning the Exchange Offer.

IMPORTANT: THIS LETTER OF TRANSMITTAL (OR A FACSIMILE THEREOF), OR AN AGENT'S MESSAGE IN LIEU THEREOF, AND ALL OTHER REQUIRED DOCUMENTS MUST BE RECEIVED BY THE EXCHANGE AGENT ON OR PRIOR TO THE EXPIRATION DATE.

(DO NOT WRITE IN SPACE BELOW)

Certificate Surrendered	Old Notes Tendered	Old Notes Accepted

Delivery Prepared by ________ Checked by ________________ Date ______________________

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PROSPECTUS

PDC Energy, Inc.

Offer to Exchange up to

$600,000,000

5.750% Senior Notes due 2026
That Have Been Registered Under the Securities Act of 1933

For Any and All Outstanding Unregistered
5.750% Senior Notes due 2026

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 20. ***Indemnification of Officers and Directors***

Section 102 of the DGCL, which is applicable to us, permits a corporation to eliminate or limit the personal liability of directors of a corporation to the corporation or its stockholders for monetary damages for a breach of fiduciary duty as a director, except where the director breached his or her duty of loyalty to the corporation or its stockholders, failed to act in good faith, engaged in intentional misconduct, knowingly violated a law, authorized the payment of an unlawful dividend, approved an unlawful stock purchase or redemption or derived an improper personal benefit. Our certificate of incorporation eliminates the personal liability of our directors to the maximum extent permitted by Section 102 of the DGCL.

Section 145 of the DGCL authorizes a corporation to indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative (other than an action by or in the right of the corporation), because such person is or was a director, officer, employee or agent of the corporation or is or was serving at the request of the corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise, against expenses (including attorneys' fees), judgments, fines and amounts paid in settlement actually and reasonably incurred by such person in connection with such suit or proceeding if such person acted in good faith and in a manner such person reasonably believed to be in or not opposed to the best interests of the corporation, and, with respect to any criminal action or proceeding, had no reason to believe such person's conduct was unlawful. Similar indemnity is authorized for such persons against expenses (including attorneys' fees) actually and reasonably incurred in defense or settlement of any such pending, completed or threatened action or suit by or in the right of the corporation if such person acted in good faith and in a manner such person reasonably believed to be in or not opposed to the best interests of the corporation, and provided further that, unless a court of competent jurisdiction otherwise provides, such person shall not have been adjudged liable to the corporation. Any such indemnification may be made only as authorized in each specific case upon a determination that indemnification is proper because the indemnitee has met the applicable standard of conduct. Our bylaws generally provide we will indemnify our directors and officers to the extent permitted by the DGCL.

We have entered into indemnification agreements with all of our directors. Under the indemnification agreements, we are generally required to indemnify the directors to the full extent authorized or permitted by applicable law.

Item 21. ***Exhibits and Financial Statement Schedules.***

2.1 Plan of Conversion, dated June 5, 2015, by PDC Energy, Inc. (Incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K12B filed on June 8, 2015).

2.2 Stock Purchase and Sale Agreement, dated August 23, 2016, by and among the seller parties thereto, Kimmeridge Energy Management Company GP, LLC, Arris Petroleum Corporation, and PDC Energy, Inc. (Incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed on August 24, 2016).

2.3 Asset Purchase and Sale Agreement, dated August 23, 2016, by and among 299 Resources, LLC, 299 Production, LLC, 299 Pipeline, LLC, Kimmeridge Energy Management Company GP, LLC and PDC Energy, Inc. (Incorporated by reference to Exhibit 2.2 to our Current Report on Form 8-K filed on August 24, 2016).

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3.1	Certificate of Incorporation of PDC Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K12B filed on June 8, 2015).
3.2	Bylaws of PDC Energy, Inc. (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K12B of PDC Energy, Inc. filed on June 8, 2015).
4.1	Form of Common Stock Certificate of the Company (Incorporated by reference to Exhibit 4.1 to our Annual Report on Form 10-K filed on February 28, 2017).
4.2	Indenture, dated as of November 29, 2017, by and between PDC Energy, Inc., PDC Permian, Inc., a subsidiary guarantor of the Company, and U.S. Bank Trust National Association, as Trustee, relating to the 5.750% Senior Notes due 2026 (Incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed on November 29, 2017).
4.3	Base Indenture, dated as of September 14, 2016, by and between the Company and U.S. Bank Trust National Association, as Trustee (Incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed on September 14, 2016).
4.4	First Supplemental Indenture, dated as of September 14, 2016, by and between the Company and U.S. Bank Trust National Association, as Trustee, relating to the 1.125% Convertible Senior Notes due 2021 (Incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed on September 14, 2016).
4.5	Indenture, dated as of September 15, 2016, by and between PDC Energy, Inc. and U.S. Bank Trust National Association, as Trustee, relating to the 6.125% Senior Notes due 2024 (Incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed on September 15, 2016).
5.1	Opinion of Davis Graham & Stubbs LLP.
10.1	Form of Indemnification Agreement (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on June 8, 2015).
10.2	401(k) and Profit Sharing Plan, as amended on January 4, 2016 (Incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K filed on February 28, 2017).
10.3	Amended and Restated Non-Employee Director Deferred Compensation Plan (Incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K filed on February 27, 2018).
10.4	2004 Long-Term Equity Compensation Plan amended and restated as of March 8, 2008 ("2004 Plan") (Incorporated by reference to Exhibit 10.26 to our Annual Report on Form 10-K filed on February 27, 2009).
10.4.1	Summary of 2010 Stock Appreciation Rights and Restricted Stock Awards under the 2004 Plan (Incorporated by reference to our Current Report on Form 8-K filed on April 23, 2010).
10.5	Amended and Restated 2010 Long-Term Equity Compensation Plan, as amended (Incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K filed on February 22, 2016).
10.6	Executive Severance Compensation Plan, as amended (Incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K filed on February 22, 2016).
10.7	Form of 2011 Restricted Stock/Stock Appreciation Rights Agreement (Incorporated by reference to Exhibit 10.5.2 to our Annual Report on Form 10-K filed on February 21, 2014).
10.7.1	Form of 2013 Performance Share Agreement (Incorporated by reference to Exhibit 10.9 to our Annual Report on Form 10-K filed on February 27, 2013).

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10.7.2	Form of 2013 Restricted Stock/Stock Appreciation Rights Agreement (Incorporated by reference to Exhibit 10.10 to our Annual Report on Form 10-K filed on February 27, 2013).
10.7.3	Form of 2014 Performance Share Agreement (Incorporated by reference to Exhibit 10.5.4 to our Annual Report on Form 10-K filed on February 19, 2015).
10.7.4	Form of 2014 Restricted Stock/Stock Appreciation Rights Agreement (Incorporated by reference to Exhibit 10.5.5 to our Annual Report on Form 10-K filed on February 19, 2015).
10.7.5	Form of 2015 Performance Share Agreement (Incorporated by reference to Exhibit 10.5.6 to our Annual Report on Form 10-K filed on February 19, 2015).
10.7.6	Form of 2015 Restricted Stock Unit Agreement (Incorporated by reference to Exhibit 10.5.7 to our Annual Report on Form 10-K filed on February 19, 2015).
10.7.7	Form of 2015 Stock Appreciation Rights Agreement (Incorporated by reference to Exhibit 10.5.8 to our Annual Report on Form 10-K filed on February 19, 2015).
10.7.8	Form of 2016 Performance Share Agreement (Incorporated by reference to Exhibit 10.7.8 to our Annual Report on Form 10-K filed on February 22, 2016).
10.7.9	Form of 2018 Performance Share Agreement (Incorporated by reference to Exhibit 99.1 to our Quarterly Report on Form 10-Q filed on May 3, 2018).
10.7.10	Form of 2018 Restricted Stock Unit Agreement (Executives) (Incorporated by reference to Exhibit 99.2 to our Quarterly Report on Form 10-Q filed on May 3, 2018).
10.7.11	Form of 2018 Restricted Stock Unit Agreement (Directors) (Incorporated by reference to Exhibit 99.3 to our Quarterly Report on Form 10-Q filed on May 3, 2018).
10.8	Employment Agreement with Daniel W. Amidon, General Counsel and Corporate Secretary, dated as of April 19, 2010 (Incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed on April 23, 2010).
10.9	Employment Agreement with Lance A. Lauck, Senior Vice President of Business Development, dated as of April 19, 2010 (Incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed on April 23, 2010).
10.10	Third Amended and Restated Credit Agreement dated as of May 21, 2013, among PDC Energy, Inc. as Borrower, Riley Natural Gas Company, a Subsidiary of PDC Energy, Inc., as Guarantor, JP Morgan Chase Bank, N.A. as Administrative Agent, J.P. Morgan Securities LLC as Sole Bookrunner and Co-Lead Arranger, Wells Fargo Bank, N.A. as Syndication Agent, and Wells Fargo Securities, LLC as Co-Lead Arranger, and Certain Lenders (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on May 28, 2013).
10.10.1	First and Second Amendments to Third Amended and Restated Credit Agreement dated as of May 14, 2014 and September 30, 2015, respectively, among PDC Energy, Inc. as the Borrower, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent for the Lenders (Incorporated by reference to Exhibit 10.11.1 to our Annual Report on Form 10-K filed on February 22, 2016).
10.10.2	Third Amendment to the Third Amended and Restated Credit Agreement, dated as of September 6, 2016, among the Company, as Borrower, certain Subsidiaries of the Company, as Guarantors, the lenders from time to time party thereto (the "Lenders") and JPMorgan Chase Bank, N.A., as Administrative Agent for the Lenders (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on September 8, 2016).

10.10.3	Fourth Amendment to the Third Amended and Restated Credit Agreement, dated as of October 14, 2016, among the Company, as Borrower, certain Subsidiaries of the Company, as Guarantors, the lenders from time to time party thereto (the "Lenders") and JPMorgan Chase Bank, N.A., as Administrative Agent for the Lenders (Incorporated by reference to Exhibit 99.1 to our Quarterly Report on Form 10-Q filed on November 3, 2016).
10.10.4	Fifth Amendment to Third Amended and Restated Credit Agreement, dated as of May 10, 2017, among the Company, as Borrower, certain Subsidiaries of the Company, as Guarantors, JPMorgan Chase Bank, N.A., as administrative agent, and the other lenders party thereto (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on May 16, 2017).
10.10.5	Sixth Amendment to the Third Amended and Restated Credit Agreement, dated as of October 6, 2017, among the Company, as Borrower, certain Subsidiaries of the Company, as Guarantors, the lenders from time to time party thereto (the "Lenders") and JPMorgan Chase Bank, N.A., as Administrative Agent for the Lenders (Incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q filed on November 7, 2017).
10.10.6	Fourth Amended and Restated Credit Agreement, dated as of May 23, 2018, among PDC Energy, Inc. as Borrower, each of the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent for the Lenders (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on May 25, 2018).
10.11	Change of Control and Severance Plan (Incorporated by reference to Exhibit 10.14 to our Annual Report on Form 10-K filed on February 28, 2017).
10.11.1	Amendment to the PDC Energy Change of Control and Severance Plan (Incorporated by reference to Exhibit 10.14.1 to our Annual Report on Form 10-K filed on February 28, 2017).
10.12	Registration Rights Agreement, dated as of September 15, 2016, by and between PDC Energy, Inc. and J.P. Morgan Securities LLC, as representative of the initial purchasers, relating to the 6.125% Senior Notes due 2024 (Incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on September 15, 2016).
10.13	Investment Agreement, dated December 6, 2016, by and among the Investor parties identified therein and PDC Energy, Inc. (relating to the Stock Purchase and Sale Agreement) (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on December 7, 2016).
10.14	Investment Agreement, dated December 6, 2016, by and among the Investor parties identified therein and PDC Energy, Inc. (relating to the Asset Purchase and Sale Agreement) (Incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on December 7, 2016).
10.15	Purchase Agreement, dated as of November 14, 2017, by and between 10.PDC Energy, Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the initial purchasers named therein, and PDC Permian, Inc., a subsidiary guarantor of the Company, relating to the 5.750% Senior Notes due 2026 (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on November 17, 2017).
10.16	Registration Rights Agreement, dated as of November 29, 2017, by and between PDC Energy, Inc., PDC Permian, Inc., a subsidiary guarantor of the Company, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the initial purchasers, relating to the 5.750% Senior Notes due 2026 (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on November 29, 2017).

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10.17 2018 Equity Incentive Plan (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on May 31, 2018).

12.1 Statement regarding computation of ratio of earnings to fixed charges (Incorporated by reference to Exhibit 12.1 to our Registration Statement on Form S-3 filed on May 31, 2018).

21.1 Subsidiaries (Incorporated by reference to Exhibit 21.1 to our Annual Report on Form 10-K filed on February 27, 2018).

23.1 Consent of PricewaterhouseCoopers LLP.

23.2 Consent of Ryder Scott Company, LP.

23.3 Consent of Netherland, Sewell & Associates, Inc.

23.4 Consent of Davis Graham & Stubbs (included in exhibit 5.1).

24.1 Power of Attorney (included on the signature page hereto for PDC Energy, Inc.).

25.1 Form T-1 Statement of Eligibility and Qualification under the Trust Indenture Act of 1939 of the trustee under the Indenture with respect to the 5.750% Senior Notes due 2026.

Item 22. ***Undertakings***

The undersigned Registrants hereby undertake:

(a) (1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(i) To include any prospectus required by section 10(a)(3) of the Securities Act of 1933;

(ii) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement; and

(iii) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement.

(2) That, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial *bona fide* offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unexchanged at the termination of the offering.

(4) That, for the purpose of determining liability under the Securities Act of 1933 to any purchaser, if the registrant is subject to Rule 430C, each prospectus filed pursuant to Rule 424(b) as part of a registration statement relating to an offering, other than registration statements relying on Rule 430B or other than prospectuses filed in reliance on Rule 430A, shall be deemed to be part of and included in the registration statement as of the date it is first used after effectiveness; *provided*, *however*, that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such first use, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such date of first use.

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(5) That, for the purpose of determining liability of the registrants under the Securities Act of 1933 to any purchaser in the initial distribution of the securities, in a primary offering of securities of the undersigned registrants pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, the undersigned registrants will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser.

(i) any preliminary prospectus or prospectus of the undersigned registrants relating to the offering required to be filed pursuant to Rule 424;

(ii) any free writing prospectus relating to the offering prepared by or on behalf of the undersigned registrants or used or referred to by the undersigned registrants;

(iii) the portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrants or their securities provided by or on behalf of the undersigned registrants; and

(iv) any other communication that is an offer in the offering made by the undersigned registrants to the purchaser.

(b) That, for purposes of determining any liability under the Securities Act of 1933, each filing of a Registrant's annual report pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 that is incorporated by reference in the registration statement shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial *bona fide* offering thereof.

(c) To deliver or cause to be delivered with the prospectus, to each person to whom the prospectus is sent or given, the latest annual report to security holders that is incorporated by reference in the prospectus and furnished pursuant to and meeting the requirements of Rule 14a3 or Rule 14c3 under the Securities Exchange Act of 1934; and, where interim financial information required to be presented by Article 3 of Regulation S-X are not set forth in the prospectus, to deliver, or cause to be delivered to each person to whom the prospectus is sent or given, the latest quarterly report that is specifically incorporated by reference in the prospectus to provide such interim financial information.

(d) Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the Registrants pursuant to the foregoing provisions, or otherwise, the Registrants have been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act of 1933 and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the Registrants will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act of 1933 and will be governed by the final adjudication of such issue.

(d) To respond to requests for information that is incorporated by reference into the prospectus pursuant to Items 4, 10(b), 11, or 13 of this Form, within one business day of receipt of such request, and to send the incorporated documents by first class mail or other equally prompt means. This includes information contained in documents filed subsequent to the effective date of the registration statement through the date of responding to the request.

(e) To supply by means of a post-effective amendment all information concerning a transaction, and the company being acquired involved therein, that was not the subject of and included in the registration statement when it became effective.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the Registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado on June 13, 2018.

PDC ENERGY, INC.

By: /s/ BARTON R. BROOKMAN

Name: Barton R. Brookman
Title: *President and Chief Executive Officer*

POWER OF ATTORNEY

The undersigned directors and officers of PDC Energy, Inc. hereby constitute and appoint Barton R. Brookman, R. Scott Meyers, and Daniel W. Amidon, and each of them, each with full power to act and with full power of substitution and resubstitution, our true and lawful attorneys-in-fact and agents with full power to execute in our name and behalf in the capacities indicated below any and all amendments (including post-effective amendments) to this registration statement and to file the same, with all exhibits and other documents relating thereto with the United States Securities and Exchange Commission and hereby ratify and confirm all that such attorney-in-fact or his or her substitute shall lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ BARTON R. BROOKMAN Barton R. Brookman	President and Chief Executive Officer and Director (principal executive officer)	June 13, 2018
/s/ R. SCOTT MEYERS R. Scott Meyers	Chief Financial Officer (principal financial officer and principal accounting officer)	June 13, 2018
/s/ JEFFREY C. SWOVELAND Jeffrey C. Swoveland	Chairman of the Board of Directors	June 13, 2018
/s/ ANTHONY J. CRISAFIO Anthony J. Crisafio	Director	June 13, 2018
/s/ MARK E. ELLIS Mark E. Ellis	Director	June 13, 2018

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Signature	Title	Date
/s/ CHRISTINA M. IBRAHIM Christina M. Ibrahim	Director	June 13, 2018
/s/ LARRY F. MAZZA Larry F. Mazza	Director	June 13, 2018
/s/ RANDY S. NICKERSON Randy S. Nickerson	Director	June 13, 2018
/s/ DAVID C. PARKE David C. Parke	Director	June 13, 2018

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Pursuant to the requirements of the Securities Act of 1933, the co-registrant certifies that it has reasonable grounds to believe that it meets all of the requirements for filing on Form S-4 and has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on June 13, 2018.

PDC PERMIAN, INC.
By: /s/ SCOTT J. REASONER

Name: Scott J. Reasoner
Title: *President and Chief Operating Officer*

POWER OF ATTORNEY

The undersigned directors and officers of PDC Permian, Inc. hereby constitute and appoint Barton R. Brookman, R. Scott Meyers, and Daniel W. Amidon, and each of them, each with full power to act and with full power of substitution and resubstitution, our true and lawful attorneys-in-fact and agents with full power to execute in our name and behalf in the capacities indicated below any and all amendments (including post-effective amendments) to this registration statement and to file the same, with all exhibits and other documents relating thereto with the United States Securities and Exchange Commission and hereby ratify and confirm all that such attorney-in-fact or his or her substitute shall lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ SCOTT J. REASONER Scott J. Reasoner	President, Chief Operating Officer and Director (principal executive officer)	June 13, 2018
/s/ R. SCOTT MEYERS R. Scott Meyers	Chief Financial Officer (principal financial officer and principal accounting officer)	June 13, 2018
/s/ BARTON R. BROOKMAN Barton R. Brookman	Director	June 13, 2018
/s/ LANCE A. LAUCK Lance A. Lauck	Director	June 13, 2018
/s/ DANIEL W. AMIDON Daniel W. Amidon	Director	June 13, 2018