SUNCOR ENERGY INC
Form 40-F
February 28, 2014

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

o	Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934
	or
ý	Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For fiscal year ended:	December 31, 2013
Commission File Number:	No. 1-12384

SUNCOR ENERGY INC.
(Exact name of registrant as specified in its charter)

Canada (Province or other jurisdiction of incorporation or organization)	**1311,1321,2911, 4613,5171,5172** (Primary standard industrial classification code number, if applicable)	**98-0343201** (I.R.S. employer identification number, if applicable)

150 - 6th Avenue S.W.
Box 2844
Calgary, Alberta, Canada T2P 3E3
(403) 296-8000

(Address and telephone number of registrant's principal executive office)

CT Corporation System
111 Eighth Avenue
New York, New York, U.S.A. 10011
(212) 894-8940

(Name, address and telephone number of agent for service in the United States)

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

Title of each class:	Name of each exchange on which registered:
Common shares	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

For annual reports, indicate by check mark the information filed with this form:

ý Annual Information Form ý Annual Audited Financial Statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

Common Shares	**As of December 31, 2013 there were 1,478,315,069 Common Shares issued and outstanding**
Preferred Shares	**None**

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the proceeding 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 in the past 90 days.

Yes ý 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 o No o

INCORPORATION BY REFERENCE

The Registrant's Annual Information Form dated February 28, 2014, included in this annual report on Form 40-F, and Audited Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2013, included as Exhibit 99-1 and Exhibit 99-2, respectively, to this annual report on Form 40-F, are incorporated by reference into and as an exhibit to, as applicable, each of the Registrant's Registration Statements under the Securities Act of 1933: Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-9 (File No. 333-181421).

ANNUAL INFORMATION FORM DATED FEBRUARY 28, 2014

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ADVISORIES

In this Annual Information Form (AIF), references to "we", "our", "us", "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint arrangements, unless the context otherwise requires. References to the "Board of Directors" or the "Board" mean the Board of Directors of Suncor Energy Inc.

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes are presented on a working-interest basis, before royalties, unless otherwise noted. Certain amounts in prior years may have been reclassified to conform to the current year's presentation.

References to our 2013 audited Consolidated Financial Statements mean Suncor's audited Consolidated Financial Statements prepared in accordance with Canadian generally accepted accounting principles (GAAP), which is within the framework of International Financial Reporting Standards (IFRS), the notes and the auditors' report, as at and for each year in the two-year period ended December 31, 2013. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 24, 2014.

This AIF contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this document in the Risk Factors section, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. Refer to the Advisory Forward-Looking Information section of this AIF for information on other risk factors and material assumptions underlying our forward-looking information.

Information contained in or otherwise accessible through Suncor's website www.suncor.com does not form a part of this AIF and is not incorporated into the AIF by reference.

GLOSSARY OF TERMS AND ABBREVIATIONS

Common Industry Terms

Products

Hydrocarbons are solids, liquids or gas made up of compounds of carbon and hydrogen, in varying proportions.

Crude oil is a mixture of pentanes (lighter hydrocarbons) and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained in the processing of natural gas.

> **Bitumen or heavy crude oil** is a naturally occurring viscous mixture, consisting mainly of pentanes and heavier hydrocarbons, which may not be recoverable at a commercial rate in its naturally occurring viscous state through a well without using enhanced recovery methods. After it is extracted, bitumen or heavy crude oil may be upgraded into crude oil and other petroleum products.
>
> **Brent** is a blend of light, sweet crudes sourced from the North Sea used as a global price benchmark for internationally traded crude oil.
>
> **Conventional crude oil** is crude oil produced through wells by standard industry recovery methods.
>
> **Oil sands** are naturally occurring deposits of sand or sandstone, or other sedimentary rocks that contain bitumen.
>
> **Synthetic crude oil (SCO)** is a mixture of hydrocarbons derived by upgrading bitumen from oil sands. Yields of SCO from Suncor's upgrading processes are approximately 80% of bitumen feedstock input, and may vary depending on the source of bitumen. SCO may contain sulphur or other non-hydrocarbon compounds and has many similarities to crude oil. SCO with lower sulphur content is referred to as **sweet synthetic crude oil**, while SCO with higher sulphur content is referred to as **sour synthetic crude oil**.
>
> **Unconventional crude oil** is crude oil produced using techniques other than by standard industry recovery methods.
>
> **Western Canadian Select (WCS)** is a heavy blended crude oil comprised primarily of conventional heavy oil or bitumen blended with diluent that is traded out of Hardisty, Alberta.
>
> **West Texas Intermediate (WTI)** is a type of crude oil used as a benchmark in oil pricing, and is the underlying commodity of futures contracts on the New York Mercantile Exchange (NYMEX).

Natural gas is a mixture of lighter hydrocarbons, which, at atmospheric conditions of temperature and pressure, is in a gaseous state.

> **Associated gas** is the gas cap that overlays a crude oil accumulation in a reservoir.
>
> **Conventional natural gas** is natural gas produced from all geological strata, including associated, non-associated and solution gas, but excluding production from unconventional natural gas formations, such as coal bed methane and shale gas.
>
> **Non-associated gas** is an accumulation of natural gas in a reservoir where there is no crude oil.
>
> **Solution gas** is natural gas that is dissolved in crude oil in the reservoir at original reservoir conditions and that is normally produced with the crude oil.

Natural gas liquids (NGLs) are hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes, plus condensate and small quantities of non-hydrocarbons. **Liquefied petroleum gas (LPG)** includes propane and/or butane.

Oil and gas exploration and development processes

Development costs are costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves.

Exploration costs are costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves.

Field is a defined geographical area consisting of one or more pools containing hydrocarbons.

Reservoir is a porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

Wells:

Development wells are drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

Dry holes are exploratory or development wells found to be incapable of producing either oil or gas in sufficient quantities to justify the completion as an oil or gas well.

Exploratory wells are drilled in a territory without existing proved reserves, with the intention to discover commercial reservoirs or deposits of crude oil and/or natural gas.

Infill wells are drilled between existing development wells to target regions of the reservoir containing bypassed hydrocarbon or to accelerate production.

Observation wells are used to monitor changes in a producing field. Parameters being monitored include fluid saturations and reservoir pressure.

Service wells are development wells drilled or completed for the purpose of supporting production in an existing field, such as wells drilled for the injection of gas or water.

Sidetrack wells are secondary wellbores drilled away from an original wellbore. These enable the bypass of an unusable section of the original wellbore or allow for exploration of a nearby geological feature.

Stratigraphic wells are usually drilled without the intention of being completed for production, which are geologically directed to obtain information pertaining to a specific geologic condition, such as **core hole drilling** or **delineation wells** on oil sands leases, or to measure the commercial potential (i.e. size and quality) of a discovery, such as **appraisal wells** for offshore discoveries.

Production processes

Capacity is the annual average output that may be achieved from a processing facility, such as an upgrader, refinery or natural gas processing plant, under ideal operating conditions and in accordance with current design specifications.

Debottleneck refers to the process of increasing the production capacity of existing facilities through modification of existing equipment to remove throughput restrictions or inefficiencies.

Downstream refers to the refining of crude oil and the selling and distribution of refined products in retail and wholesale channels.

Feedstock generally refers either to i) the bitumen required in the production of SCO for the company's oil sands operations, or ii) crude oil and/or other components required in the production of refined petroleum product for the company's downstream operations.

In situ refers to methods of extracting bitumen or heavy crude oil from deep deposits of oil sands by means other than surface mining.

Overburden is the material overlying oil sands that must be removed before mining, which consists of muskeg, glacial deposits and sand. Overburden is removed before mining and on an ongoing basis to expose ore.

Production sharing contracts (PSC) are a common type of contract, outside North America, signed between a government and a resource extraction company that states how much of the resource produced each party will receive and which parties are responsible for the development and operation of the resource. The resource extraction company does not obtain title to the product; however, the company is subject to the upstream risks and rewards. An **exploration and production sharing agreement (EPSA)** is a form of PSC, which also states which parties are responsible for exploration activities.

Steam-assisted gravity drainage (SAGD) is an enhanced oil recovery technology for producing heavy crude oil and bitumen. It is an advanced form of steam stimulation in which a pair of horizontal wells are drilled into the oil reservoir, a few metres above the other. Low pressure steam is continuously injected into the upper wellbore to heat the oil in the reservoir and reduce its viscosity, causing the heated oil to drain into the lower wellbore, from which it is extracted.

Steam-to-oil ratio (SOR) is a metric used to quantify the efficiency of an in situ oil recovery process, which measures the cubic metres of water (converted to steam) required to produce one cubic metre of oil. A lower ratio indicates more efficient use of steam.

Tailings Reduction Operations (TRO$_{TM}$) is a process involving rapidly converting fluid fine tailings into a solid landscape suitable for reclamation. In this process, mature fine tailings are mixed with a polymer flocculent and deposited in thin layers over sand beaches with shallow slopes. The resulting product is a dry material that is capable of being reclaimed in place or moved to another location for final reclamation.

Utilization is the average use of capacity, and includes the impact of planned and unplanned facility outages and maintenance. More specifically, **refinery utilization** is the amount of crude oil and natural gas plant liquids that are run through crude distillation units, expressed as a percentage of the capacity of these units.

Upgrading is the two-stage process by which bitumen or heavy crude oil is converted into SCO.

> **Primary upgrading,** also referred to as coking or thermal cracking, heats the bitumen in coke drums to remove excess carbon. The superheated hydrocarbon vapours are sent to fractionators where they condense into naphtha, kerosene and gas oil. Carbon residue, or coke, is removed from the coke drums on short intervals and later sold as a byproduct.
>
> **Secondary upgrading,** a purification process also referred to as hydrotreating, adds hydrogen to, and reduces the sulphur and nitrogen of, primary upgrading output to create sweet SCO and diesel.

Upstream refers to the exploration, development and production of conventional crude oil, bitumen or natural gas.

Reserves and resources

Please refer to the Definitions for Reserves Data Tables section of the Statement of Reserves Data and Other Oil and Gas Information in this AIF.

Common Abbreviations

The following is a list of abbreviations that may be used in this AIF:

Measurement

bbl(s)	barrel(s)
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
mmbbls	millions of barrels
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mmboe	millions of barrels of oil equivalent
mcf	thousands of cubic feet of natural gas
mcf/d	thousands of cubic feet of natural gas per day
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
bcf	billions of cubic feet of natural gas
GJ	gigajoules
mmbtu	millions of British thermal units
m^3	cubic metres
m^3/d	cubic metres per day
km	kilometres
MW	megawatts

Places and Currencies

U.S.	United States
U.K.	United Kingdom
B.C.	British Columbia
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

Products, Markets and Processes

WTI	West Texas Intermediate
WCS	Western Canadian Select
NGL(s)	natural gas liquid(s)
LPG	liquefied petroleum gas
SCO	synthetic crude oil
NYMEX	New York Mercantile Exchange
TSX	Toronto Stock Exchange
NYSE	New York Stock Exchange
SAGD	steam-assisted gravity drainage
PSC	production sharing contract
EPSA	exploration and production sharing agreement

Suncor converts certain natural gas volumes to boe, boe/d, mboe, mmboe or mboe/d on the basis of six mcf to one boe. Any figure presented in boe, mboe, mmboe or mboe/d may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or NGL to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Conversion Table(1)(2)

1 m^3 liquids = 6.29 barrels	1 tonne = 0.984 tons (long)
1 m^3 natural gas = 35.49 cubic feet	1 tonne = 1.102 tons (short)
1 m^3 overburden = 1.31 cubic yards	1 kilometre = 0.62 miles
	1 hectare = 2.5 acres

(1) Conversion using the above factors on rounded numbers appearing in this AIF may produce small differences from reported amounts.

(2) Some information in this AIF is set forth in metric units and some in imperial units.

CORPORATE STRUCTURE

Name and Incorporation

Suncor Energy Inc. (formerly Suncor Inc.) was originally formed by the amalgamation under the *Canada Business Corporations Act* on August 22, 1979, of Sun Oil Company Limited, incorporated in 1923, and Great Canadian Oil Sands Limited, incorporated in 1953. On January 1, 1989, we further amalgamated with a wholly owned subsidiary under the *Canada Business Corporations Act*. We amended our articles in 1995 to move our registered office from Toronto, Ontario, to Calgary, Alberta, and again in April 1997 to adopt our current name, "Suncor Energy Inc.". In April 1997, May 2000, May 2002, and May 2008 we amended our article to divide the issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement which was completed effective August 1, 2009, Suncor amalgamated with Petro-Canada to form a single corporation continuing under the name "Suncor Energy Inc.", referred to in this document as the "merger". The arrangement was effected pursuant to the *Canada Business Corporations Act*.

Our registered and head office is located at 150 6th Avenue S.W., Calgary, Alberta, T2P 3E3.

Intercorporate Relationships

Material subsidiaries, each of which was owned 100%, directly or indirectly, by the company as at December 31, 2013 are as follows:

Name	Jurisdiction Where Organized	Description
Canadian operations		
Suncor Energy Oil Sands Limited Partnership	Canada	This partnership holds most of the company's oil sands assets.
Suncor Energy Ventures Partnership	Canada	This partnership holds the company's interest in the Syncrude joint arrangement.
Suncor Energy Products Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds interests in the company's energy marketing and renewable energy businesses, and which is a partner of Suncor Energy Products Partnership.
Suncor Energy Products Partnership	Canada	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	Canada	A subsidiary of Suncor Energy Products Inc. through which production from our upstream North American businesses is marketed. Through this subsidiary, we also administer Suncor's energy trading activities, market certain third-party products, procure crude oil feedstock and natural gas for our downstream business, and procure and market NGLs and LPG for our downstream business.
U.S. operations		
Suncor Energy (U.S.A.) Holdings Inc.	U.S.	A subsidiary of Suncor Energy Inc. that holds the majority of our U.S. interests.
Suncor Energy (U.S.A.) Marketing Inc.	U.S.	A subsidiary of Suncor Energy (U.S.A.) Holdings Inc. that procures and markets third-party crude oil, in addition to procuring crude oil feedstock for the company's refining

		operations.
Suncor Energy (U.S.A.) Inc.	U.S.	A subsidiary of Suncor Energy (U.S.A.) Holdings Inc. through which our U.S. refining and marketing operations are conducted.

International operations

3908968 Canada Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds certain of our international interests.
Suncor Energy UK Holdings Ltd.	U.K.	A subsidiary of 3908968 Canada Inc. that holds certain of our U.K. interests.
Suncor Energy UK Limited	U.K.	A subsidiary of Suncor Energy UK Holdings Ltd. through which certain of our operations are conducted in the U.K.
Petro-Canada Cooperative Holding U.A.	The Netherlands	A subsidiary of 3908968 Canada Inc. that holds certain of our international interests.
Petro-Canada (International) Holdings B.V.	The Netherlands	A subsidiary of Petro-Canada Cooperative Holding U.A. that holds certain of our international interests.
Suncor Energy Germany GmbH	Germany	A subsidiary of Petro-Canada (International) Holdings B.V. that holds the majority of our interests in Libya.
Suncor Energy Oil (North Africa) GmbH	Germany	A subsidiary of Suncor Energy Germany GmbH through which the majority of our Libya operations are conducted.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2013, and (ii) less than 10% of the company's consolidated operating revenues for the fiscal year ended December 31, 2013. In aggregate, the remaining subsidiaries accounted for less than 20% of each of (i) and (ii) described above.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Suncor is an integrated energy company headquartered in Calgary, Alberta, Canada. We are strategically focused on developing one of the world's largest petroleum resource basins Canada's Athabasca oil sands. In addition, we explore for, acquire, develop, produce and market crude oil and natural gas in Canada and internationally; we transport and refine crude oil, and we market petroleum and petrochemical products primarily in Canada. Periodically, we market third-party petroleum products. We also conduct energy trading activities focused principally on the marketing and trading of crude oil, natural gas and byproducts.

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in the Wood Buffalo region of northeast Alberta, recovers bitumen from mining and in situ operations and either upgrades this production into SCO for refinery feedstock and diesel fuel, or blends the bitumen with diluent for direct sale to market. The Oil Sands segment includes:

Oil Sands Operations refer to Suncor's wholly-owned and operated mining, extraction, upgrading, in situ and related logistics and storage assets in the Athabasca oil sands. Oil Sands Operations consist of:

Oil Sands Base operations include the Millennium and North Steepbank mining and extraction operations, integrated upgrading facilities known as Upgrader 1 and Upgrader 2, and the associated infrastructure for these assets including utilities, energy and reclamation facilities, such as Suncor's tailings management (TRO_{TM}) assets.

In Situ operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities, cogeneration units and hot bitumen infrastructure, including an insulated pipeline, diluent import capabilities and a cooling and blending facility, and related storage assets. In Situ production is either upgraded by Oil Sands Base or blended with diluent and marketed directly to customers.

The Oil Sands segment also includes the company's interests in significant growth projects, including its 40.8% interest in the **Fort Hills** mining project where Suncor is the operator and its 36.8% interest in the **Joslyn** North mining project. The company also holds a 12.0% interest in the **Syncrude** oil sands mining and upgrading operation (these assets were formerly known as Oil Sands Ventures prior to an internal reorganization effective January 1, 2014).

EXPLORATION AND PRODUCTION

Suncor's Exploration and Production segment consists of offshore operations off the east coast of Canada and in the North Sea, and onshore operations in North America, Libya and Syria.

East Coast Canada operations include Suncor's 37.675% working interest in Terra Nova, which Suncor operates. Suncor also holds a 20% interest in the Hibernia base project and a 19.5% interest in the Hibernia Southern Extension Unit (HSEU), a 27.5% interest in the White Rose base project and a 26.125% interest in the White Rose Extensions, and a 22.729% interest in Hebron, all of which are operated by other companies.

International operations include Suncor's 29.89% working interest in Buzzard and its 26.69% interest in Golden Eagle. Both projects are located in the U.K. sector of the North Sea and are not operated by Suncor. Suncor also holds interests in several exploration licences offshore the U.K. and Norway. Suncor owns, pursuant to Exploration and Production Sharing Agreements (EPSAs), working interests in the exploration and development of oilfields in the Sirte Basin in Libya. As at the date hereof, production in Libya is shut-in due to political unrest. Suncor also owns, pursuant to a Production Sharing Contract (PSC), an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Due to political unrest in Syria, the company has declared force majeure under its contractual obligations, and Suncor's operations in Syria have been suspended indefinitely.

North America Onshore operations include Suncor's working interests in unconventional natural gas and crude oil assets in Western Canada, including unconventional oil and natural gas properties in central Alberta and northeast B.C.

REFINING AND MARKETING

Suncor's Refining and Marketing segment consists of two primary operations:

Refining and Supply operations refine crude oil into a broad range of petroleum and petrochemical products. Eastern North America operations include refineries located in Montreal, Québec and Sarnia, Ontario, and a lubricants business located in Mississauga, Ontario that manufactures, blends and markets products worldwide. Western North America operations include refineries located in Edmonton, Alberta and Commerce City, Colorado. Other Refining and Supply assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.

Downstream Marketing operations sell refined petroleum products and lubricants to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and other retail stations in Canada and Colorado, a nationwide commercial road transport network in Canada, and a bulk sales channel in Canada.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy marketing, supply and trading activities, and other activities not directly attributable to any other operating segment.

Renewable Energy interests include six operating wind power projects across Canada, two wind power projects under development in Ontario, and the St. Clair ethanol plant in Ontario.

Energy Trading activities primarily involve the marketing, supply and trading of crude oil, natural gas and byproducts, and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.

Corporate activities include stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and the company's captive insurance activities that self-insure a portion of the company's asset base.

Intersegment revenues and expenses are removed from consolidated results in **Group Eliminations**. Intersegment activity includes the sale of product between the company's segments and the provision of insurance for a portion of the company's operations by the Corporate captive insurance entity.

Three-Year History

2011

Exploration and Production segment created. In January, Suncor announced organizational changes that included the former International and Offshore and Natural Gas business divisions merging into a single organization primarily focused on conventional production, which includes both onshore and offshore operations.

Ethanol plant expansion completed. In January, Suncor completed the expansion of its ethanol plant in Ontario that doubled production capacity to 400 million litres per year, making it the largest biofuels production facility in Canada.

Operations in Libya temporarily suspended. In response to political unrest and sanctions in Libya in the first quarter of 2011, the operator of the company's joint operations in Libya shut in production. As a result, Suncor suspended all exploration activities and declared force majeure under its EPSAs. Sanctions in Libya were eventually lifted when the country transitioned to a new government, and the operator was able to restart production from all major producing fields in the first quarter of 2012. Production has since been suspended again due to the closure of export terminal operations at eastern Libyan seaports as a result of political unrest that began earlier in 2013.

Successful completion of the Upgrader 2 turnaround. During the second quarter, the company completed the largest turnaround at its Upgrader 2 facilities in the company's history.

New wind farms commissioned. In May, Suncor commissioned the eight-turbine, 20-MW Kent Breeze wind power project in southwest Ontario. In November, Suncor commissioned the 55-turbine, 88-MW Wintering Hills wind power project in southern Alberta.

Development of Golden Eagle approved. In the third quarter, the field development plan for Golden Eagle in the U.K. sector of the North Sea was approved. The company anticipates first production late in 2014 or early 2015.

North Steepbank extension. In December, the company started mining ore from the North Steepbank area at its Oil Sands Base operations. The opening of this new area enabled Suncor to access additional oil sands ore, decrease overall haul distances and decrease mine congestion.

Operations in Syria suspended. In December, sanctions were introduced that resulted in Suncor declaring force majeure under its contractual obligations and suspending its operations in Syria. Consequently, the company ceased recording all production and revenue associated with its Syrian assets. During 2012, the company received proceeds from risk mitigation instruments related to its Syrian assets, which are subject to a provisional repayment should operations in Syria resume.

2012

Steve Williams appointed as Chief Executive Officer. In December 2011, Steve Williams, formerly Suncor's Chief Operating Officer (COO), was appointed president and a member of the company's Board of Directors, and assumed the role of Chief Executive Officer (CEO) in May 2012. Prior to becoming COO, Mr. Williams served as Executive Vice President, Oil Sands for four years where he was responsible for leading Suncor's Oil Sands Operations through a significant period of growth. Mr. Williams replaced Suncor's long-standing CEO, Rick George, who retired in May after more than 20 years leading the company.

TRO$_{TM}$ operations commissioned. Suncor completed installation of its tailings management assets. Infrastructure included pipes, pumphouses and fluid transfer barges that (a) pump tailings water from extraction plants to a sand placement area, (b) pump mature fine tailings from the sand placement area to a tailings pond for TRO$_{TM}$ treatment, and (c) pump treated water from tailings ponds back to extraction plants for use in production processes. Through the TRO$_{TM}$ process, mature fine tailings are converted more rapidly into a solid material suitable for reclamation. As a result of this new technology and the company's capital investment to reconfigure its tailing operations, Suncor has cancelled plans for five additional tailings ponds.

Off-station maintenance at East Coast Canada assets. The Floating Production, Storage and Offloading (FPSO) vessels for both Terra Nova and White Rose were disconnected and transported to docking facilities for planned maintenance. The water injection swivel was replaced on the Terra Nova FPSO, while the propulsion system was repaired on the White Rose FPSO. The off-station maintenance program for Terra Nova also allowed the company to replace subsea infrastructure to help mitigate hydrogen sulphide (H_2S) issues.

Growth at Firebag. Production from Firebag increased to 104 mbbls/d, approximately 75% higher than the 2011 production level. In 2012, Firebag Stage 3 central processing facilities commissioned in the previous year reached design capacity approximately one year after first oil was brought on-stream. Stage 4 central processing facilities were commissioned in 2012, with first oil from Stage 4 wells brought on-stream in December.

MNU commences operations. The Millennium Naphtha Unit (MNU), which consists of a hydrogen plant and a naphtha hydrotreating unit, began operating at design rates. The MNU has increased sweet SCO production capacity, primarily through a naphtha hydrotreating unit, and stabilized secondary upgrading processes by providing flexibility with respect to hydrogen production during planned or unplanned maintenance.

Oil Sands logistics infrastructure brought into service. The company brought into service the Wood Buffalo pipeline, which connects the company's Athabasca terminal at the base plant in Fort McMurray to other third-party pipeline infrastructure in Cheecham, Alberta, and four storage tanks in Hardisty, Alberta, which are connected to the Enbridge mainline pipeline.

Hebron project receives sanction. In December, the co-owners of the Hebron project located offshore Newfoundland and Labrador sanctioned a development plan that includes a concrete gravity-based structure (GBS) supporting an integrated topsides deck to be used for production, drilling and accommodations. Suncor has a 22.729% interest in the Hebron project. The estimated gross oil production capacity for Hebron is 150 mbbls/d.

2013

Voyageur oil sands upgrader project not proceeding. In March, Suncor announced its intention not to proceed with the Voyageur upgrader project in response to changed market conditions that challenged the project economics. Suncor acquired Total E&P Canada Ltd's (Total E&P) interest in the Voyageur Upgrader Limited Partnership (VULP) for $515 million to gain full control of the partnership's assets, including a hot bitumen blending facility and tankage used to support the company's growing Oil Sands Operations.

Majority of conventional natural gas business in Western Canada sold. Suncor sold its conventional natural gas business in Western Canada with an effective date of January 1, 2013. The transaction closed September 26, 2013 for gross proceeds of $1 billion, before closing adjustments and other closing costs. The sale included properties situated across multiple regions in Alberta, northeast British Columbia and southern Saskatchewan but excluded the majority of Suncor's unconventional natural gas properties in the Kobes region (Montney formation) of northeast British Columbia and unconventional oil properties in the Wilson Creek area (Cardium formation) of central Alberta.

Suncor constructs wetland. A reclamation milestone was reached with the planting of a fen wetland at Oil Sands Base. A fen is a specific type of peat-accumulating wetland. Suncor is one of the first companies in the world to attempt reconstruction of this type of wetland. Construction of the fen's underlying watershed was completed in January 2013, and vegetation was planted during the spring and summer.

Firebag ramp-up completed. Firebag production in 2013 increased by approximately 40% over 2012 production levels as Stage 4 ramp-up was completed. The complex ended 2013 achieving daily production rates of approximately 95% of nameplate capacity of 180 mbbls/d.

Hot bitumen infrastructure commissioned. Suncor initiated a number of debottlenecking projects across Oil Sands Operations, including the completion of an insulated bitumen pipeline from Firebag to the Athabasca terminal. Combined with blending facilities at the Athabasca terminal and diluent import capabilities, Suncor increased the takeaway capacity of bitumen and unlocked production in mining.

Fort Hills project sanctioned. In October, Suncor and project co-owners agreed unanimously to proceed with the Fort Hills oil sands mining project. The project is scheduled to produce first oil by the fourth quarter of 2017 and is expected to achieve 90% of its planned production capacity of 180 mbbls/d (73 mbbls/d net to Suncor) within its first year.

Libya production shut in. Export terminal operations at Libyan seaports were closed during the latter half of 2013 due to political unrest in the country. Production was shut in during this period; however, Suncor was able to continue progress on its exploration program.

Rail offloading facility complete. Construction of a rail offloading facility to enable receipt of inland crudes at the Montreal refinery was completed in the fourth quarter of 2013. The Montreal refinery received its first shipment in early December with volumes expected to increase to approximately 35 mbbls/d in the first quarter of 2014.

Successful completion of Upgrader 1 turnaround. Suncor successfully executed planned maintenance across its operations, including a seven-week turnaround at Upgrader 1, which was the largest turnaround in the company's history. The next scheduled turnaround at Oil Sands Operations is not until 2016.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

Oil Sands

For a discussion of the environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting our Oil Sands segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

Oil Sands Base Operations

Our integrated Oil Sands Base operations, located in the Wood Buffalo region of northeast Alberta, involve numerous activities:

Mining and Extraction

After overburden is removed, open-pit mining operations use shovels to excavate oil sands bitumen ore, which is trucked to sizers and breaker units that reduce the size of the ore. Next, a slurry of hot water, sand and bitumen is created and delivered via a pipeline to extraction plants. The raw bitumen is separated from the slurry using a hot water process that creates a bitumen froth. Naphtha is added to the bitumen froth to form a diluted bitumen, which is subsequently sent to a centrifuge plant that removes most of the remaining impurities and minerals. Coarse tailings produced in this process are placed directly into mine sand dump areas.

Upgrading

After the diluted bitumen is transferred to upgrading facilities, the naphtha is removed and recycled to be used again as diluent in extraction processes. Bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour SCO, is either sold or upgraded further into sweet SCO by removing sulphur and nitrogen using a hydrotreating process. In addition to sweet and sour SCO, upgrading processes also produce diesel and other byproducts.

Utilities

Process water is used in extraction processes and then recycled. Steam and electricity are generated through facilities on site. Steam required for operations is generated by a cogeneration unit or coke-fired boilers. Electricity is generated by turbine generators, some of which are part of the Oil Sands Base cogeneration unit, or provided by cogeneration units at Firebag.

Maintenance

In the normal course of operations, Suncor regularly conducts planned maintenance events at its facilities. Large, planned maintenance events, which require units to be taken offline to be completed, are often referred to as turnarounds. Turnaround maintenance provides opportunities for both preventive maintenance and capital replacement, which are expected to improve reliability and operational efficiency. Production however, is impacted during the turnaround cycle. Planned maintenance events generally occur on routine cycles, determined by historical operating performance, recommended usage factors or regulatory requirements. A turnaround typically involves shutting down the unit, inspecting it for wear or other damage, repairing or replacing components, and then restarting the unit.

Reclamation

Mining processes disturb areas of land that must be reclaimed. Land reclamation activities involve soil salvage and replacement, wetlands research, the protection of fish, waterfowl and other wildlife and re-vegetation.

The extraction process produces tailings that are a mixture of water, clay, sand and residual bitumen. Suncor has developed a tailings management approach, known as TRO$_{TM}$. TRO$_{TM}$ is expected to accelerate and improve the company's tailings management processes, eliminate the need for new tailings ponds at existing mining operations, and, in the years ahead, reduce the number of tailings ponds presently in operation.

Oil Sands Base Assets

Mining and Extraction

Suncor pioneered the commercial development of the Athabasca oil sands beginning in 1962, achieving first production in 1967. The original mining area is essentially depleted, and, for several years, bitumen was mined almost exclusively from the Millennium area, which began production in 2001. The company began mining from the North Steepbank area in 2011. During 2013, the company mined approximately 151 million tonnes of bitumen ore (2012 151 million tonnes). During 2013, Suncor processed an average of 270 mbbls/d of mined bitumen in its extraction facilities (2012 266 mbbls/d).

Upgrading

Suncor's upgrading facilities consist of two upgraders Upgrader 1, which has a primary upgrading capacity of approximately 110 mbbls/d of SCO, and Upgrader 2, which has a primary upgrading capacity of approximately 240 mbbls/d of SCO. Suncor's secondary upgrading facilities consist of three hydrogen plants, three naphtha hydrotreaters, two gas oil hydrotreaters, one diesel hydrotreater and one kero hydrotreater.

During 2013, Suncor averaged 283 mbbls/d of upgraded (SCO and diesel) production, sourced from bitumen provided by both mining and extraction and in situ operations.

Other Mining Leases

Suncor owns several other oil sands leases, including those known as Voyageur South and Audet, which it believes can be developed using mining techniques. Suncor undertakes exploratory drilling programs on such leases from time-to-time, as part of its mine replacement projects. Suncor holds a 100% working interest in both Voyageur South and Audet.

The Voyageur South project is in the early stages of planning and the development timing for the project is currently under assessment. Development options are currently being prepared for review in 2014.

In Situ Operations

Suncor's In Situ operations, Firebag and MacKay River, use SAGD technology to produce bitumen from oil sands deposits that are too deep to be mined economically.

The SAGD process

The SAGD process requires drilling pairs of horizontal wells with one located above the other. To help reduce land disturbance and improve cost efficiency, well pairs are drilled from multi-well pads. Steam is injected into the upper well to create a high-temperature steam chamber underground. This process reduces the viscosity of the bitumen, allowing heated bitumen and condensed steam to drain into the bottom well and flow up to the surface aided by subsurface pumps or circulating gas.

Central processing facilities

The bitumen and water mixture is pumped to separation units at central processing facilities, where the water is removed from the bitumen, treated and recycled for use in steam generation. To facilitate shipment, In Situ operations blend diluent with the bitumen, or transport it on an insulated pipeline as hot bitumen. The bitumen is either upgraded at Oil Sands Base upgrading facilities or blended with internally produced or imported diluent, and sold directly to market.

Power and steam generation

Once Through Steam Generators (OTSGs) are powered by both natural gas and gas vapours recovered at central processing facilities. Cogeneration units are energy-efficient systems, which use natural gas combustion to power turbines that generate electricity and steam used in SAGD operations. Excess electricity generation from cogeneration units is used at Oil Sands Base facilities or sold to the power grid.

Maintenance and feedstock supply

Central processing facilities, steam generation units and well pads are all subject to routine inspection and maintenance cycles.

SAGD production volumes are impacted by reservoir quality and the capacity of central processing facilities and steam generation units to process liquids and generate steam. As with conventional oil and gas properties, SAGD wells will experience natural production declines after several years. In an effort to maintain bitumen supply, Suncor drills new wells from existing well pads or develops and constructs new well pads.

In Situ Assets

Firebag

Production from Suncor's Firebag operations commenced in 2004. Suncor's Firebag complex consists of four central processing facilities with total bitumen processing capacity of approximately 180 mbbls/d. Actual production from Firebag varies based on steaming and ramp-up periods for new wells, planned and unplanned maintenance, reservoir conditions and other factors.

As at December 31, 2013, Firebag had nine well pads in operation with 119 SAGD well pairs and 18 infill wells either producing or on initial steam injection. Central processing facilities have been designed to be flexible as to which well pads supply bitumen. Steam generated at the various facilities can be used at multiple well pads. In addition, Firebag includes five cogeneration units that generate steam, which are capable of producing 425 MW of electricity made up of Firebag site power load of 110 MW and exports of 315 MW. There are also 13 OTSGs at the site for additional steam generation.

As of December 31, 2013, the cumulative SOR at Firebag was 3.3 (2012 3.4).

MacKay River

Production from MacKay River commenced in 2002. As at December 31, 2013, MacKay River included six well pads with 74 well pairs either producing or on initial steam injection. The MacKay River central processing facilities have bitumen processing capacity of approximately 30 mbbls/d. A third party owns the on-site cogeneration unit that is used to generate steam and electricity which Suncor operates under a commercial agreement. There are also four OTSGs at the site for additional steam generation. The company has commenced a debottlenecking project of existing central processing facilities that is expected to increase existing bitumen processing capacity to approximately 38 mbbls/d by 2015.

As at December 31, 2013, the cumulative SOR at MacKay River was 2.6 (2012 2.5).

Suncor has regulatory approval for additional bitumen production from MacKay River and adjacent Dover lands, and is currently evaluating an expansion to increase bitumen processing capacity through an additional central processing facility. Suncor continues to work towards a 2014 sanction decision of an additional central processing facility at MacKay River, which is targeted to have an initial design capacity of approximately 20 mbbls/d and first oil in 2017.

Other In Situ Leases

Suncor owns several other oil sands leases, including those known as Meadow Creek, Lewis, Chard and Kirby. Suncor believes these leases can be developed using in situ techniques on which it may undertake exploratory drilling. In 2013, Suncor drilled 50 core holes at Lewis and 66 gross core holes at Meadow Creek. Plans for winter 2014 drilling include an additional 55 core holes at Lewis and 37 core holes at Meadow Creek. Suncor holds a 100% working interest in Lewis and a 75% working interest in Meadow Creek.

Starting with Meadow Creek, Suncor is commencing a greenfield growth plan with a concept to grow new In Situ reservoirs using a replication strategy to build standardized surface facilities, well pads and infrastructure on a program basis. The winter exploratory drilling programs are designed to identify sufficient resources to fill facilities associated with the replication strategy.

Oil Sands Joint Arrangements

Syncrude

Suncor holds a 12% interest in the Syncrude joint arrangement, located near Fort McMurray, which includes mining operations at Mildred Lake North and Aurora North. Syncrude also has regulatory approval to develop the Aurora South oil sands mining leases. In 2012, the Syncrude co-owners announced a plan to develop two mining areas adjacent to the current mine, subject to final sanctioning and regulatory approvals, which would consequently extend the life of Mildred Lake by approximately ten years. The plan proposes to use existing mining and extraction facilities. Syncrude expects to make regulatory applications for these areas in 2014.

Syncrude began producing in 1978 and is operated by Syncrude Canada Ltd. (SCL). In 2006, SCL entered into a comprehensive management services agreement with Imperial Oil Resources (Imperial Oil) to provide operational, technical and business management services. This agreement has an initial term of ten years and includes renewal provisions.

Syncrude mining operations use truck, shovel and pipeline systems, similar to those at Oil Sands Base. Extraction and upgrading technologies at Syncrude are similar to those used at Oil Sands Base, with the exception that Syncrude uses a fluid coking process that involves the continuous thermal cracking of the heaviest hydrocarbons. At Mildred Lake, electricity is provided by a utility plant fuelled by off-gas from upgrading operations and natural gas. At Aurora North, Syncrude operates two 80-MW gas turbine power plants.

Syncrude produces a single sweet synthetic light crude product. Marketing of this product is the responsibility of the individual co-owners.

Land reclamation activities are similar to those at Oil Sands Base; however, certain aspects of the tailings management processes are different. Syncrude's tailings plan uses the following: freshwater capping, a composite tails mixture of fine tails and gypsum, and plans for centrifuge technology that separates water from tailings.

In 2013, Suncor's share of Syncrude production averaged 32 mbbls/d (2012 34 mbbls/d).

Fort Hills

Fort Hills is an oil sands mining area comprising leases on the east side of the Athabasca River, north of Oil Sands Base operations. Designs for the Fort Hills mining project plan for 180 mbbls/d of bitumen production (gross). Suncor originally acquired a 60% working interest in Fort Hills through the merger with Petro-Canada, but disposed of 19.2% as part of transactions with Total E&P. Suncor now holds a 40.8% working interest in the Fort Hills project. Suncor is the contract operator for the Fort Hills project. The company's share of the post-sanction project costs are estimated to be $5.5 billion. Approximately 15% of the company's 2014 capital budget has been allocated to this project. Project activities in 2014 are expected to focus on detailed engineering, procurement and ramp-up of field construction activities.

Other Assets

Joslyn is the oil sands mining area comprising leases southwest of Fort Hills and on the west side of the Athabasca River. Total E&P is the operator. Preliminary designs for the Joslyn North mining project plan for 157 mbbls/d of bitumen production (gross). Suncor acquired a 36.75% working interest in this asset as a result of transactions with Total E&P. Suncor plans to provide an update on the targeted timing for a sanction decision on the Joslyn project when available.

New Technology

Technology is a fundamental component to Suncor's business. Suncor has pioneered commercial oil sands development and continues to advance technology through innovation and collaboration to improve efficiencies, lower costs and increase environmental performance.

Suncor is working on several new in situ technology projects that are proceeding with the next phase of field testing. Examples of Suncor's new technology projects include:

Electric Submersible Pumps (ESPs) Suncor is working with vendors on technology to improve equipment performance in SAGD.

N-SOLV$_{TM}$ Evolving toward waterless recovery by using a warm solvent to extract bitumen efficiently, sustainably and economically.

Steam Assisted Gravity Drainage Less Intensive Technology Enhanced (SAGD LITE) Field trials are underway to evaluate technologies such as solvent addition, surfactant addition, flow control devices and injection control devices to improve cost, SORs, and timely recovery and productivity.

Suncor is a member of Canada's Oil Sands Innovation Alliance (COSIA) which is a group of oil sands producers brought together to accelerate environmental performance improvement through collaboration.

Sales of Principal Products

Primary markets for SCO and bitumen production from Suncor's Oil Sands segment, which is sold to and subsequently marketed by Suncor's Energy Trading business, include refining operations in Alberta, Ontario, the U.S. Midwest and the U.S. Rocky Mountain regions. Commencing in 2014, production is also being sold to markets in the U.S. Gulf Coast. Diesel production from upgrading operations is sold primarily in Western Canada, marketed by Suncor's Refining and Marketing business.

For bitumen production from In Situ operations, Suncor's marketing strategy allows it to take advantage of changes in market conditions by either: a) upgrading the bitumen directly at our Oil Sands Base facilities; b) upgrading bitumen at Suncor's Edmonton refinery; or c) selling diluted bitumen directly to third parties. Increased bitumen sales may also be required during outages of upgrading facilities. During 2013, approximately 55% or 94 mbbls/d (2012 63% or 83 mbbls/d) of In Situ bitumen production was processed by Oil Sands Base upgrading facilities.

	2013		2012	
Sales Volumes and Operating Revenues Principal Products	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
Sweet Light sweet SCO and diesel (including Syncrude)	**147.9**	**43**	152.7	47
Sour Light sour SCO and bitumen	**241.9**	**51**	205.6	48
Non-proprietary, byproducts and other operating revenues(1)	**n/a**	**6**	n/a	5
	389.8		358.3	

(1) Operating revenues include sales of non-proprietary volumes, primarily third-party diluent purchased to support sales of bitumen that is required when the company is unable to meet diluent demands internally, as well as revenues associated with excess power from cogeneration units.

In the normal course of business, Suncor enters into long-term strategic sales agreements for its proprietary sour SCO, which contain varying terms with respect to pricing, volume, expiry and terminations.

Distribution of Products

Production from Oil Sands Operations is gathered into Suncor's Fort McMurray facilities at the Athabasca Terminal, which is operated by Enbridge Inc. (Enbridge). Suncor has various arrangements with Enbridge at this facility to store SCO, diluted bitumen and diesel. Product moves from the Athabasca Terminal in the following ways:

- To Edmonton via the Oil Sands pipeline, which is owned by Suncor and operated by the Refining and Marketing segment. At Edmonton, the product is sold to local refiners, including Suncor, or transferred onto the Enbridge Mainline system or the TransMountain Pipeline system.
- To Cheecham, Alberta, on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline. From Cheecham, the Enbridge Athabasca Pipeline continues to Hardisty, Alberta.
- To Edmonton via the Enbridge Waupisoo Pipeline, originating at Cheecham.

From Hardisty, where Suncor owns storage capacity with additional capacity under contract, Suncor has various options for delivering product to customers:

- To Suncor's Commerce City refinery via the Express and Platte pipelines. Suncor owns and operates a pipeline that is connected to the Commerce City refinery, which originates from the Guernsey, Wyoming station that is part of the Platte pipeline.
- To Suncor's Sarnia refinery on the Enbridge Mainline and Lakehead systems.
- Through the Enbridge Mainline system, crude can reach most major refining hubs via the Enbridge Mainline, Express/Platte and Keystone pipeline systems.

Commencing in 2014, Suncor has begun shipping heavy crude on TransCanada's Gulf Coast Pipeline, providing the company with more than 50 mbbls/d of heavy crude shipping capacity to the U.S. Gulf Coast and another outlet for the growing bitumen production at Firebag.

Natural gas is used in the production of SCO and bitumen. Natural gas is delivered to Oil Sands Base and In Situ facilities via the Nova Gas Transmission Limited (NGTL) pipeline system. Suncor also transports natural gas to Oil Sands Base facilities on the company-owned and operated Albersun Pipeline, which extends approximately 300 km south of Oil Sands Base facilities and is connected to the NGTL.

Oil Sands Base facilities are readily accessible by public road. MacKay River facilities are accessible by a combination of public and private roads. Firebag facilities are accessible by air and private road.

Royalty Agreements

<u>Oil Sands Base and Syncrude</u>

New oil sands projects are subject to the New Royalty Framework issued by the Government of Alberta, and regulated by the *Oil Sands Royalty Regulation 2009* (OSRR 2009), and supporting regulations, which were approved in 2008.

As part of the New Royalty Framework, Suncor entered into the Suncor Royalty Amending Agreement (Suncor RAA) with the Government of Alberta in January 2008 for royalties pertaining to its Oil Sands Base operations. For the period from January 1, 2010 to December 31, 2015, royalty rates are based on a sliding scale (depending on the Canadian dollar equivalent for WTI) from 25% to 30% of R C (Revenue-Cost), where R is gross revenues, net of bitumen quality adjustments and transportation costs, and C is allowable costs including allowable capital expenditures, which excludes substantially all operating and capital expenditures associated with upgrading facilities. The minimum royalty rate is 1.0% to 1.2% of R. In 2013, Suncor incurred royalties at Oil Sands Base mining operations at a rate of 30% of R C (2012 30% of R C).

In 2008, the Alberta government and the co-owners of Syncrude reached an agreement for the implementation of the New Royalty Framework for the Syncrude project (similar to the Suncor RAA). Under the new terms, Syncrude will continue paying the greater of 1% gross revenue, or 25% of net revenue, until the end of 2015. For 2013, the royalty rate was 25% of net revenue (2012 25%). As part of its agreement, Syncrude also exercised its option to transition to a bitumen-based royalty from an SCO-based royalty. In addition, the co-owners of Syncrude agreed to pay an additional royalty of $975 million over a six-year period starting in 2010, which is contingent on achieving certain production levels.

As part of the implementation of the New Royalty Framework, the Alberta government enacted the BVM Regulations effective January 1, 2009 to determine the value of bitumen for royalty purposes. The Crown notified Suncor that the BVM Regulation would apply to Oil Sands base mining operations for purposes of the Suncor RAA (Suncor BVM). In 2009, Suncor provided notice to the Crown that the Suncor BVM was non-compliant with the Suncor RAA. In December 2010, the Alberta Minister of Energy notified Suncor of the modifications to the Suncor BVM, providing for bitumen quality adjustments not previously recognized and adjustments for transportation.

With respect to the bitumen quality adjustments, Suncor filed a Notice of Commencement of Arbitration with the Alberta government on January 29, 2011 pursuant to the dispute resolution provisions of the Suncor RAA. In December 2013, Suncor reached an agreement with the Alberta government to settle all unresolved royalty issues under the Suncor RAA.

The co-owners of Syncrude also filed a non-compliance notice with the Alberta government, citing that reasonable adjustments in the determination of the bitumen value were not considered by the government. In December 2013, the Syncrude co-owners reached an agreement with the Alberta government to settle unresolved royalty issues under the Syncrude RAA.

Under these modified settlement agreements, certain provisions of the BVM Regulation, including the floor price limitations, will apply for the term. A floor price is applied when prices for Canadian heavy oil are discounted relative to heavy oil prices at the U.S. Gulf Coast.

In 2013, Oil Sands royalties (excluding Syncrude) were approximately 7% (2012 6%) of Oil Sands operating revenues (excluding Syncrude). In 2013, Suncor incurred royalties on Syncrude operations averaging approximately 5% of Syncrude operating revenues before royalties (2012 6%).

Beginning on January 1, 2016, Suncor's Oil Sands Base and Syncrude operations will be subject to the generic royalty regime that is currently in place for all other oil sands royalty projects in Alberta, including Suncor's In Situ operations, as described below.

<u>In Situ</u>

Under the New Royalty Framework, royalties on Suncor's Firebag and MacKay River projects are based on a sliding-scale rate of 25% to 40% of R C, subject to a minimum royalty within a range of 1% to 9% of R. Revenues used in royalty formulas are driven primarily by benchmark prices for WCS, while sliding-scale percentages in royalty formulas depend on prices for WTI from Cdn$55/bbl to the maximum rate at a WTI price of Cdn$120/bbl. A project remains subject to the minimum royalty (the pre-payout phase) until the project's cumulative gross revenues exceed its cumulative costs, including an annual investment allowance (the post-payout phase). In 2013, Suncor incurred minimum royalties at a rate of 7% of R for MacKay River (2012 6% of R) and royalties averaging 7% of R for Firebag (2012 6%), which continues in the pre-payout phase.

Exploration and Production

For a discussion of the environmental and other regulatory conditions, competitive conditions, foreign operations and seasonal impacts affecting our Exploration and Production segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

East Coast Canada Assets and Operations

Based in St. John's, Newfoundland and Labrador, this business includes interests in three producing fields and future developments and extensions. Suncor is also involved in exploration drilling for new opportunities. Suncor is the only company in this region with interests in every field currently in production.

<u>Terra Nova</u>

The Terra Nova oilfield is approximately 350 km southeast of St. John's. Terra Nova was discovered in 1984, and was the second oilfield to be developed offshore Newfoundland and Labrador. Operated by Suncor, the production system uses an FPSO vessel that is moored on location, and has gross production capacity of 180 mbbls/d (net 68 mbbls/d to Suncor) and oil storage capacity of 960 mbbls. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Production from Terra Nova began in January 2002. At December 31, 2013, there were 29 wells: 17 oil production wells, nine water injection wells and three gas injection wells. In 2013, Suncor's share of Terra Nova production averaged 14 mbbls/d compared to 9 mbbls/d in 2012. The company commenced off-station maintenance of the Terra Nova facility in late September 2013 for ten weeks to repair a mooring chain and perform preventive maintenance on the remaining eight chains. Production was reinstated in early December 2013. In comparison, the facility was off-line for approximately 27 weeks in 2012 as part of a dockside planned maintenance program.

Current development plans for Terra Nova include a production well and a water injection well that the company anticipates will add production and mitigate natural declines from the reservoir. In addition, in 2014, the company plans to perform maintenance on several production wells and to reinstate a second flowline to a subsea drill centre.

Field production is transported by shuttle tanker from the FPSO and either delivered directly to customers (if tanker schedules permit) or to the Newfoundland transshipment terminal in Placentia Bay, where it is subsequently loaded onto tankers for transport to markets in Eastern Canada or the U.S. Suncor has a 14% ownership interest in the transshipment facility and is part of a group of companies that share the operation of marine transportation assets for East Coast Canada.

Hibernia and the Hibernia Southern Extension Unit (HSEU)

The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is approximately 315 km southeast of St. John's and was the first field to be developed in the Jeanne d'Arc Basin. Operated by Hibernia Management and Development Company Ltd., an ExxonMobil-managed company, the production system is a fixed GBS that sits on the ocean floor, and has gross production capacity of 230 mbbls/d (net 46 mbbls/d to Suncor) and oil storage capacity of 1,300 mbbls. Actual production levels are lower, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Hibernia commenced production in November 1997. At December 31, 2013, there were 62 wells in operation: 37 oil production wells, 14 single-zone water injection wells, six dual-zone water injection wells and five gas injection wells. In 2013, Suncor's share of Hibernia production averaged 27 mbbls/d (2012 26 mbbls/d). Hibernia uses the same transshipment terminal and similar system of shuttle tankers that are used for Terra Nova.

In 2010, final agreements were signed between the Hibernia co-venturers and the Government of Newfoundland and Labrador that established the fiscal, equity and operational principles for the development of the HSEU. During 2011, the first two development wells were completed from the GBS platform and are producing oil. The third production well has been drilled and will commence oil production in the first quarter of 2014. Current development plans include drilling up to two additional production wells from the GBS platform and six water injection wells in a subsea, excavated drill centre. Subsea infrastructure was installed in late 2013 and drilling of the first subsea water injection well began in early 2014. The number of production and injection wells required may be revised as the development proceeds and uncertainties regarding reservoir capability are resolved. Production from the HSEU is not expected to reach higher rates until 2015 when several planned water injection wells are completed.

White Rose and the White Rose Extensions

White Rose is approximately 350 km southeast of St. John's. Operated by Husky Oil Operations Limited, White Rose uses a FPSO vessel and has gross production capacity of 140 mbbls/d (net 39 mbbls/d to Suncor) and oil storage capacity of 940 mbbls. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Production from White Rose began in November 2005. At December 31, 2013, there were 33 wells in operation: 15 oil production wells, 15 water injection wells and three gas storage wells. In 2013, Suncor's share of White Rose production averaged 15 mbbls/d (2012 12 mbbls/d). White Rose uses the same transshipment terminal and the same system of shuttle tankers that are used for Hibernia and Terra Nova.

In 2007, the White Rose co-venturers signed an agreement with the Province of Newfoundland and Labrador for the development of the White Rose Extensions, which include the South White Rose Extension, North Amethyst and West White Rose satellite fields. In May 2010, first oil was achieved in North Amethyst, and development drilling is ongoing. Development of the West White Rose field has been divided into two stages. The first stage was approved in 2010 and first oil was achieved in 2011.

In October 2013, the co-owners reached an agreement with the Government of Newfoundland and Labrador which resulted in amendments to the terms of the 2007 White Rose Expansion Project Framework Agreement, enabling the second stage development of West White Rose using a Wellhead Platform. Detailed engineering design for this project is currently underway and sanction is planned for the second half of 2014. Development of the South White Rose Extension began in 2013 with the installation of subsea gas injection infrastructure. Oil production and water injection infrastructure will be installed in 2014, and first oil for the South White Rose Extension is expected in late 2014 or early 2015.

Hebron

Discovered in 1980, the Hebron oilfield is located 340 km southeast of St. John's. The project is operated by ExxonMobil Canada Properties. On December 31, 2012, the Hebron co-owners announced project sanction. Development of the Hebron project includes the construction of a concrete GBS that supports an integrated topsides deck to be used for production, drilling and accommodations. Development plans include 1,200 mbbls of oil storage capacity and 52 well slots with a gross oil production capacity of 150 mbbls/d (net 34 mbbls/d to Suncor). Detailed engineering and construction of the gravity-based structure and topsides fabrication progressed according to plan during 2013. First oil is expected in 2017. Suncor's share of the post-sanction project cost estimate provided by the project operator is approximately $2.8 billion.

Other Assets

The Ballicatters discovery, located 22 km northeast of Hibernia, was completed in 2011 and is comprised of gas and oil. The licence is operated by Suncor. In September 2013, the Canada-Newfoundland and Labrador Offshore Petroleum Board issued two Significant Discovery Licences (SDL 1051 and SDL 1052) for the Ballicatters discovery. Potential options to commercialize the discovery are currently being evaluated.

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. The company holds interests in 50 other significant discovery licences and six other exploration licences offshore Newfoundland and Labrador.

International Assets and Operations

Buzzard North Sea

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited, a subsidiary of China National Offshore Oil Corporation Limited (CNOOC), the Buzzard facilities have gross installed production capacity of approximately 220 mbbls/d (net 66 mbbls/d to Suncor) of oil and 80 mmcf/d (net 24 mmcf/d to Suncor) of natural gas. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, water injection limits, gas and water production limits, and asset and infrastructure reliability. Buzzard commenced production in January 2007. Buzzard consists of four bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities, and sulphur handling. At December 31, 2013, there were 45 wells: 33 oil and gas production wells and 12 water injection wells. In 2013, Suncor's share of Buzzard production averaged 56 mboe/d (2012 48 mboe/d).

In 2013, Buzzard completed three oil and gas development wells, which are intended to mitigate natural declines from the reservoir.

Crude oil is transported via the third-party operated Forties Pipeline System to the Kinneil terminal in Scotland. Natural gas is transported via the third-party operated Frigg Pipeline to the St. Fergus gas terminal in Scotland.

Golden Eagle North Sea

During 2011, Golden Eagle received regulatory approval from the U.K. Department of Energy and Climate Change and sanction from the project's co-owners. This development is approximately 20 km north of the Buzzard oilfield and consists of the unitization of the Peregrine, Hobby, Golden Eagle and Solitaire areas. The development plan incorporates a combined production, utilities and accommodation platform, linked to a separate wellhead platform, with an initial gross production capacity of 70 mboe/d (net 19 mboe/d to Suncor) from 21 development wells. In 2013, activities at Golden Eagle included the installation of two platform jackets and the wellhead topside, and the start of development drilling. The operator, Nexen Petroleum U.K. Ltd., estimates that the gross development cost will be £2 billion (Cdn$3.5 billion) and £0.6 billion (Cdn$1.0 billion) net to Suncor. First production is expected late in 2014 or early 2015. The Golden Eagle co-owners also hold adjacent exploration licences and continue to explore the region.

Other Assets North Sea

Other Suncor exploration and appraisal initiatives in the North Sea include:

- Beta discovery (Norway) Suncor is the operator for the PL375, PL375b and PL375c licences, in which it has a 70% interest. The company drilled the first exploration well in early 2010, encountering hydrocarbons. An appraisal well was drilled and tested later in 2010 with positive results. However, a third well drilled into a separate fault block did not encounter hydrocarbons. The company will continue to evaluate the Beta discovery by interpreting 3D seismic data acquired in 2013 and with further drilling starting in 2014. The Beta licences also contain other exploration opportunities.

- Butch discovery (Norway) In 2011, Centrica plc, the operator for the PL405 licence in which Suncor has a 30% interest, drilled an exploration well resulting in a discovery, followed by a sidetrack well to assess the lateral extent of the hydrocarbons. Early in 2012, a second sidetrack well was attempted but abandoned, due to well instability, before reaching its intended depth. In December 2013, the operator, began drilling the first of two additional wells on the licence to explore for oil in separate fault blocks from the discovery.

Myrhauk prospect (Norway) Suncor has a 20% interest in the PL539 licence, operated by Premier Oil plc. The operator has planned an exploration well for late 2014.

Romeo discovery (U.K.) During the second half of 2012 and into early 2013, the company was the operator for an exploration well drilled in Block 30/11c, in which Suncor has a 57.857% interest. Drilling was completed early in 2013 and following evaluation, the well was determined to be non-commercial. No further work on this discovery has been planned.

Scotney prospect (U.K.) In 2013, Suncor, as operator, drilled a well in Block 20/05b to comply with a work commitment for the licence, in which it has a 32.86% interest. This well was completed in late April 2013 with no hydrocarbons encountered.

Lily prospect (U.K.) During the fourth quarter of 2013, the operator for the P928 20/1S licence, in which Suncor has a 29.89% interest, drilled an exploration well but did not encounter hydrocarbons.

Blackjack prospect (U.K.) During the second half of 2013, the operator of the P300 14/26a licence, in which Suncor has a 26.69% interest, conducted a site survey for a planned exploration well, which is scheduled to commence drilling during the first quarter of 2014.

Suncor continues to pursue other opportunities in the North Sea, the Norwegian Sea and the Barents Sea. The company holds interests in 30 exploration licences in the U.K. and Norwegian sectors of these areas.

Libya

In Libya, Suncor is signatory to seven EPSAs with the Libya National Oil Corporation (NOC). Five of the seven EPSAs contain producing fields and exploration prospects; the remaining two are exploration EPSAs that do not contain producing fields, one of which is being relinquished because the exploration program was not successful. Together, Suncor and the NOC jointly design and implement the development and redevelopment of existing fields in the Sirte Basin. Existing reserves are associated with five separate agreements which contain five primary producing fields. Under the EPSAs, the company pays 100% of the exploration costs, 50% of the development costs and 12% of the operating costs, and recovers these costs through a 12% share of a production cost recovery mechanism. Any petroleum remaining after cost recovery is referred to as excess petroleum, and is shared between Suncor and the NOC based on several factors. Suncor's share of the excess petroleum can range from 4% to 85%. The EPSAs expire on December 31, 2032, but include an initial five-year extension through the end of 2037. In 2013, Suncor's share of production in Libya averaged 21 mbbls/d, (2012 42 mbbls/d). Libya is a member of the Organization of Petroleum Exporting Countries (OPEC) and is subject to quotas that can affect the company's production in Libya.

For the period from March to September 2011, the operator for the joint operation, Harouge Oil Operations BV (Harouge), shut in production as a result of political unrest that began in February 2011. In March 2011, Suncor declared force majeure under its EPSAs. Suncor exited development force majeure in December 2011 and exploration force majeure in June 2012, and production resumed to previous rates.

In July 2013, operations in Libya were again disrupted as political unrest resulted in the closure of seaport terminals. Production has been shut in since July 2013 and Suncor has not lifted production or recognized a sale since May 2013. Some seaports, largely on the country's western coast, were reopened in late December 2013, but eastern seaports, including the Ras Lanuf and Es Sider terminals through which Suncor's crude is exported, are still closed. As a result of this extended loss of production and uncertainty on timing of return to operations in Libya, Suncor recorded an after-tax impairment charge of $101 million against these assets in the fourth quarter of 2013.

Despite the seaport closures, Suncor continued exploration activities in 2013. During the year, two suspended wells and four additional exploration and appraisal wells were completed. Hydrocarbons were discovered in three of the wells, while the other three wells were assessed as dry holes.

During 2013, exploration force majeure extension agreements were signed by NOC and Suncor, relating to the 2011 force majeure situation, extending the exploration period from December 31, 2012 until April 12, 2014. In early 2014, an additional one-year extension to April 12, 2015, was approved by the NOC, with the formal extension agreements to follow later in 2014. The terms of the ESPAs allow for further extensions to be negotiated. The estimated cost of Suncor's remaining exploration work program commitment at December 31, 2013 is US$349 million.

At December 31, 2013, the company had an outstanding obligation of US$74 million for a signature bonus relating to Petro-Canada's ratification of the Libyan EPSAs in 2008.

Syria

In December 2011, amid continuing unrest in Syria, sanctions were introduced and Suncor declared force majeure under its contractual obligations and suspended its operations in the country. Suncor withdrew its expatriate staff and undertook measures to maintain support for its Syrian employees. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets. Since 2011, Suncor has not been able to monitor the status of any of its assets in the country, including whether certain facilities have suffered damages.

Located in the Central Syrian Gas Basin, the Ebla project includes all hydrocarbons in the Ash Shaer and Cherrife development areas, which cover more than 300,000 acres. Suncor conducts its Syrian operations pursuant to a PSC, under which the company is a co-owner of the Ebla project with the General Petroleum Corporation (GPC). Under the PSC, the company pays 100% of the development costs and recovers these costs from a 40% share of production after deduction for royalties of 12.5%. This petroleum revenue is referred to as Cost Recovery petroleum. The amount by which Cost Recovery petroleum exceeds recoverable cost is referred to as Excess Cost Recovery petroleum; 50% of this amount is due to the GPC and the remaining 50% is shared between Suncor and the GPC according to a profit-sharing schedule. The Ebla PSC expires in April 2035, but includes a five-year extension subject to GPC approval. First commercial gas production from Ebla was achieved in April 2010 and first oil was achieved in December 2010.

The Ebla project comprised six natural gas wells in the Ash Shaer field, a gas gathering and compression station, approximately 80 km of pipeline, and a gas treatment plant. The facility is designed to produce 97 mmcf/d of natural gas, along with related LPG and condensate volumes. The company has a contracted volume of 80 mmcf/d. Natural gas was delivered into the Syrian national gas grid for domestic electrical power generation. The Ebla project also included three crude oil wells.

In 2012, the company recorded an impairment charge against its Syrian assets as a result of the uncertainty about the company's future in the country. Later in the year, the company received proceeds from risk mitigation instruments related to its Syrian assets, which are subject to a provisional repayment should operations in Syria resume and loss of value is determined not to be permanent.

Suncor impaired the remaining carrying value of its Syrian assets in the fourth quarter of 2013, resulting in an after-tax impairment charge of $422 million, as there has been no resolution of the political situation resulting in rising uncertainty with respect to the company's return to operations. Concurrently, the company recognized risk mitigation proceeds, received in 2012, of $300 million ($223 million after-tax) in net earnings. These were previously recorded as a long-term provision.

North America Onshore Assets and Operations

The North America Onshore business explores for, develops and produces natural gas, NGLs, crude oil and byproducts in Western Canada. After the merger with Petro-Canada, the strategy for this business focused on liquids-rich and unconventional sources. As a result, the company divested a number of non-core assets in this business area throughout 2010 and early 2011 and, in 2013, sold the majority of its remaining conventional natural gas business for $1 billion prior to closing adjustments and other closing costs. Following these disposals, the retained assets produce approximately 3 mboe/d of gas and 2 mbbl/d of liquids.

Natural gas extracted from the wellhead requires further processing. Suncor currently operates one natural gas processing plant at Wilson Creek (52.17% working interest ownership), with total licensed capacity of 34.6 mmcf/d, (18.1 mmcf/d net). Capacity not utilized by the company's own production is optimized through processing agreements with third-party producers.

Natural gas production from Alberta is typically sold at the Nova Inventory Transfer point (NIT), which is one of the largest natural gas trading hubs in North America. Natural gas at NIT generally receives a daily or monthly average AECO (Alberta) spot price. Natural gas production from B.C. is typically sold at Station 2, part of the Spectra B.C. transmission system, and receives the Station 2 Gas Daily Index price. Suncor holds firm capacity on the TransCanada PipeLines Gas Transmission Northwest Pipeline (GTN). The GTN firm capacity enables Suncor to deliver natural gas to the Pacific Northwest and California markets.

Crude oil production from North America Onshore assets is shipped on pipelines operated by independent pipeline companies. In most sales arrangements, Suncor is responsible for transportation to the point of sale.

In addition, Suncor holds assets that allow the company to explore long-term supply opportunities in northern frontier areas, such as the Arctic Islands.

Sales of Principal Products

Oil and gas production from East Coast Canada, the North Sea, and from North America Onshore is either marketed by our Energy Trading business, acting as a marketing agent or sold to our Energy Trading business, which then markets the products to customers under direct sales arrangements. Suncor does not typically enter into long-term supply arrangements to sell its production from its Exploration and Production segment. Contracts for these direct sales arrangements are of varied terms, with a majority having terms of one year or less, and incorporate pricing that is generally determined on a daily or monthly basis in relation to a specified market reference price.

In Libya, prior to the shut in of production, crude oil was marketed by the NOC on behalf of Suncor. In Syria, prior to the suspension of operations, the company entered into purchase and sale agreements with the Syrian government for all hydrocarbon production from the Ebla project.

Exploration and Production Sales Summary:

	2013		2012	
Sales Volumes	mboe/d	% operating revenues	mboe/d	% operating revenues
East Coast Canada				
Crude oil	**55.9**	**40**	46.7	33
International				
Crude oil and NGLs	**75.2**	**53**	88.5	59
Natural gas	**1.2**	**0**	1.0	1
North America Onshore				
Crude oil and NGLs	**5.3**	**3**	5.6	3
Natural gas	**32.0**	**4**	48.3	4
Total Exploration and Production				
Crude oil and NGLs	**136.4**	**96**	140.8	95
Natural gas	**33.2**	**4**	49.3	5

Royalties

East Coast Canada

The Terra Nova royalty consists of a sliding-scale, basic royalty payable throughout the project's life, with two tiers of incremental royalties, which became payable upon the achievement of specified levels of profitability. The basic royalty is now capped at 10% of gross field revenue, based on the project reaching a specified cumulative production level. The tier one royalty is 30% of net revenue, and became payable in 2005. Net revenue is gross revenue adjusted for eligible operating and capital costs. The tier two royalty, equal to 12.5% of net revenue, became payable in 2008. During 2013, Terra Nova royalties averaged 12% of gross revenue (2012 36%) and decreased primarily due to higher deductible costs in 2013.

The Hibernia royalty agreement for production from the original oilfields and the AA Block consists of a sliding-scale gross royalty, two tiers of incremental royalty, and an additional net profits interest (NPI). The basic royalty is now capped at 5% of gross revenue, as the project has reached a specified cumulative production level. The tier one royalty, which became payable in 2009, is 30% of net revenue. The tier two royalty is 12.5% of net revenue, but has not yet been triggered. Production from the AA Block, which commenced in late 2009, attracts an additional tier three royalty of 12.5% of net revenue. The NPI, which also became payable in 2009, is an additional 10% of net revenue. Limited production from the HSEU began in 2011. The HSEU has a similar royalty structure (gross, tier one and tier two) to that described above for Hibernia. Currently, Suncor is subject to a 5% gross royalty. HSEU production will be subject to an additional tier three royalty that ranges between 2.5% and 7.5% of net revenue, depending on the price for WTI. The HSEU tier three royalty will coincide with the triggering of the tier one net royalty. During 2013, Hibernia (including the HSEU) royalties and NPI combined to average 36% of gross revenue (2012 35%).

The White Rose royalty for the base project consists of a sliding-scale basic royalty payable, with two tiers of incremental royalties, which became payable upon the achievement of specified levels of profitability. The basic royalty is now capped at 7.5% of gross field revenue, based on the base project reaching a specified cumulative production level. The tier one royalty is 20% of net revenue, and became payable in 2007. The tier two royalty, equal to 10% of net revenue, became payable in 2008. The royalty for production from the White Rose Extensions is similar to the base project, except that there is an additional tier three royalty, equal to 6.5% of net revenue, which is payable if WTI is greater than Cdn$50/bbl. Currently, the White Rose Extensions are only subject to a 2.5% gross royalty. During 2013, total White Rose royalties averaged 16% of gross revenue (2012   12%).

International

There are no royalties on oil and gas production from the North Sea; however, in the U.K., oil and gas profits are subject to a 62% income tax rate. For operations in Libya and Syria, all government interests, except for income taxes, are presented as royalties.

North America Onshore

Royalties for Suncor's North America Onshore production in Alberta are regulated primarily by the Natural Gas Royalty Regulation 2009, and by the Petroleum Royalty Regulation

2009. Royalties for natural gas and oil production are set by a sliding-scale formula ranging from 5% to 36% for natural gas, and 0% to 40% for conventional crude oil. Rates are dependent on well depth, production rates, price, and quality of the natural gas and crude oil. New wells receive an initial maximum rate of 5%, subject to volume and credit caps. In Alberta, costs for gathering, compressing, and processing the provincial government share of gas and NGLs are allowable deductions from gross royalties payable. Royalties for NGLs are determined based on the prescribed reference prices multiplied by flat rates of 30% for propane and butane, and 40% for pentanes.

Royalties for Suncor's North America Onshore production in B.C. are regulated primarily by the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. Royalty formulas (rates) for natural gas production are different based on the date the well was drilled. Gas rates start as low as 9%, and are subject to a sliding scale with a maximum royalty rate of 27% as prices increase. B.C. provides royalty adjustments for deep drilling, lower production rates, and unique production methods. In B.C., field expenses (gathering, compression and processing) are allowed as cost of services deductions from gross royalties. Plant processing costs are included as adjustments to the provincial government valuation price. Royalties on NGLs are assessed at a flat rate of 20% of revenues.

During 2013, royalties for North America Onshore production averaged 10% of gross revenue (2012 7%).

Refining and Marketing

For a discussion of the environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting our Refining and Marketing segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

Operations Refining and Product Supply

Eastern North America

The Montreal refinery has a crude oil capacity of 137 mbbls/d, processing primarily foreign conventional crude oil, with a flexible configuration that allows processing of light, sour and heavy grades of crude oil, as well as intermediate feedstock. Crude oil is procured from the market on a spot basis or under contracts that can be terminated on short notice. Crude oil for the refinery is largely supplied via the Portland-Montreal Pipeline and to a lesser extent, by rail and marine transportation. With the commissioning of the rail offloading facility in the fourth quarter of 2013, the Montreal refinery has also started to receive inland crudes. Rail volumes are expected to increase to 35 mbbls/d by the end of the first quarter of 2014.

Production yield from the Montreal refinery includes gasoline, distillate, asphalt and petrochemicals, which are distributed primarily across Quebec and Ontario. The Montreal refinery also produces feedstock for Suncor's lubricants plant. Refined products are delivered to distribution terminals in Ontario via the Trans-Northern Pipeline and delivered to customers directly by truck, rail and marine vessel.

The Sarnia refinery has a crude oil capacity of 85 mbbls/d, processing both SCO from the company's Oil Sands operations and conventional crude oil purchased from third parties on a spot basis or under contracts that can be terminated on short notice. Crude oil is supplied to the Sarnia refinery primarily via the Enbridge Mainline and Lakehead pipeline systems. Suncor procures conventional crude oil feedstock primarily from Western Canada and has the ability to supplement supply with purchases from the U.S.

Production yield from the Sarnia refinery includes gasoline, distillate and petrochemicals, which are primarily distributed in Ontario. Refined products are delivered to distribution terminals in Ontario via the Sun-Canadian Pipeline, or delivered to customers directly via marine vessel and rail. The Sarnia refinery also has limited access to pipelines delivering refined products into the U.S.

To meet the demands of Suncor's marketing network in Eastern North America, the company also purchases gasoline and distillate from other refiners. Suncor enters into reciprocal exchange arrangements with other refiners in Eastern North America, primarily for gasoline and distillate, as a means of minimizing transportation costs and balancing product availability. Specialty products, such as asphalt and petrochemicals, are also exported to customers in the U.S.

Suncor holds a 51% interest in ParaChem Chemicals L.P. (ParaChem), which owns and operates a petrochemicals plant located adjacent to the Montreal refinery. Feedstock for the plant includes xylene and toluene produced by the Montreal and Sarnia refineries. The plant primarily produces paraxylene, which is used by customers to manufacture polyester textiles and plastic bottles. Paraxylene production was approximately 355,000 metric tonnes in 2013 (2012 362,000 metric tonnes). ParaChem also produces benzene, hydrogen and heavy aromatics. Benzene production is delivered back to the Montreal refinery to be marketed with production from that facility.

Suncor's lubricants plant produces specialty lubricants and waxes that are marketed in Canada and internationally. The facility is the largest producer of lubricant base stocks in Canada. In 2013, the plant produced approximately 804 million litres of lubricant base stocks. Feedstock for the lubricants facility comes from Suncor's Montreal refinery and other purchase contracts.

Western North America

Effective January 1, 2014, Suncor increased the nameplate capacity of the Edmonton refinery to 142 mbbls/d from 140 mbbls/d, due to demonstrated reliability and continuous improvement in operating efficiency. The Edmonton refinery has the potential to run entirely on feedstock sourced from oil sands and heavy crude oil from Alberta. Crude oil is supplied to the refinery via company-owned and third-party pipelines.

Feedstock is supplied from Suncor's Oil Sands Operations, Syncrude operations (including volumes purchased by Suncor from other co-owners' share of production) and other producers from the Athabasca and Cold Lake regions of Alberta. The refinery can process approximately 41 mbbls/d of blended feedstock (comprised of 29 mbbls/d of bitumen and 12 mbbls/d of diluent) and process approximately 44 mbbls/d of sour SCO. The refinery can also process approximately 57 mbbls/d of sweet SCO through its synthetic train.

Production yield from the Edmonton refinery includes primarily gasoline and distillate, which are delivered to distribution terminals across Western Canada via the Alberta Products Pipeline, the TransMountain Pipeline and the Enbridge pipeline system, as well as via truck and rail.

The Commerce City refinery has a crude oil capacity of 98 mbbls/d. The refinery processes primarily conventional crude oil, but also has the capability of processing up to 15 mbbls/d of sour SCO from Suncor's Oil Sands Base operations. A majority of crude feedstock is supplied from sources in the U.S., primarily the Rocky Mountain region, while the remainder is purchased from Canadian sources. Crude oil purchase contracts have terms ranging from month-to-month to multi-year. Approximately 58% of crude oil supplied to the refinery is transported via pipeline, with the remainder transported via truck.

Production yield from the Commerce City refinery includes primarily gasoline, distillate and asphalt. The majority of the refined products are sold to commercial and wholesale customers in Colorado and Wyoming, and a retail network in Colorado. Refined products are distributed by truck, rail, and pipeline.

To support the supply and demand balance in the Vancouver area, Suncor imports and exports finished products through its Burrard distribution terminal located on the west coast of B.C. Suncor also enters into reciprocal exchange arrangements with other refiners in Western North America as a means of minimizing transportation costs and balancing product availability.

Refinery Throughputs, Utilizations and Yields

The following tables summarize the crude feedstock, utilizations and production yield mix for Suncor's refineries for the years ended December 31, 2013 and 2012. Refinery utilizations include the impacts of planned and unplanned maintenance events.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	2013	2012	2013	2012	2013	2012	2013	2012
Oil Sands Base sweet synthetic			28.0	14.5	45.5	47.6		0.2
Oil Sands Base sour synthetic			11.3	22.7	59.3	49.9	8.0	8.3
Other synthetic			11.6	8.3	23.6	39.2	8.9	
East Coast Canada light conventional(1)	14.6	21.6						
Other light conventional	94.2	84.8	24.8	0.8	0.5	0.6	72.1	60.2
Sour conventional	0.2	4.7		22.2			11.3	
Heavy conventional	16.7	18.0				0.6		27.0
Total	125.7	129.1	75.7	68.5	128.9	137.9	100.3	95.7
Utilization(2) (%)	92	94	89	81	92	102	102	98

(1) Includes purchases of Suncor and third-party shares of production from East Coast Canada oilfields.

(2) Refinery utilizations based on crude 2013 processing capacities (in mbbls/d): Montreal 137; Sarnia 85; Edmonton 140; and Commerce City 98.

Refined Petroleum Production Yield Mix (%)	Montreal 2013	Montreal 2012	Sarnia 2013	Sarnia 2012	Edmonton 2013	Edmonton 2012	Commerce City 2013	Commerce City 2012
Gasoline	41	41	39	39	43	43	49	47
Distillates	37	35	46	46	52	52	35	34
Other	22	24	15	15	5	5	16	19

Distribution Terminals and Pipelines

Suncor owns and operates 13 major refined product terminals across Canada (including terminals adjacent to refineries) and two product terminals in Colorado. Combined with access to facilities under long-term contractual arrangements with other parties, Suncor's North American assets are sufficient to meet the Refining and Marketing segment's current storage and distribution needs.

Suncor has ownership interests in the following pipelines:

Pipeline	Ownership	Type	Origin	Destinations
Portland-Montreal Pipeline	23.8%	Crude oil	Portland, Maine	Montreal, Quebec
Trans-Northern Pipeline	33.3%	Refined product	Montreal, Quebec	Ontario Ottawa, Toronto & Oakville
Sun-Canadian Pipeline	55.0%	Refined product	Sarnia, Ontario	Ontario Toronto, London & Hamilton
Alberta Products Pipeline	35.0%	Refined product	Edmonton, Alberta	Calgary, Alberta
Rocky Mountain Crude Pipeline	100.0%	Crude oil	Guernsey, Wyoming	Denver, Colorado
Centennial Pipeline	100.0%	Crude oil	Guernsey, Wyoming	Cheyenne, Wyoming

Operations Marketing

Suncor's retail service station network operates nationally in Canada primarily under the Petro-Canada$_{TM}$ brand. As at December 31, 2013, this retail service station network consisted of 1,454 outlets across Canada. In addition to marketing through proprietary retail outlets, refined products are marketed through independent dealers and joint arrangements. Suncor's Canadian retail network had annual sales of gasoline motor fuels averaging approximately 4.8 million litres per site in 2013 (2012 4.8 million litres per site) and attracted an estimated 18% share (2012 17% share) of the national retail market.

Suncor's Colorado retail network consists of 44 owned outlets and product supply agreements with a larger network of Shell®-branded sites and Phillips 66®-branded sites in Colorado.

Marketing activities also generate non-petroleum revenues from convenience stores and car washes.

Suncor's wholesale operations sell refined products into farm, home heating, paving, small industrial, commercial and truck markets. Through its PETRO-PASS network, Suncor is a national marketer to the commercial road transport segment in Canada. Suncor also sells large volumes of refined products directly to large industrial and commercial customers and independent marketers.

Retail Summary:

Locations	As at December 31 2013	2012
Retail Service Stations Canada		
Petro-Canada$_{TM}$-branded	**1 454**	1 458
Sunoco$_{TM}$-branded	**7**	7
	1 461	1 465
Retail Service Stations Colorado		

Shell®-branded retail service stations	**38**	38
Phillips 66®-branded retail service stations	**6**	6
	44	44
Wholesale Cardlock Sites Canada		
Petro-Canada$_{TM}$-branded cardlock sites (PETRO-PASS)	**259**	246

Sales Volumes	2013 thousands of m^3/d	2013 % operating revenues	2012 thousands of m^3/d	2012 % operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**18.4**		19.8	
Western North America	**20.9**		20.4	
	39.3	**46**	40.2	47
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	**14.2**		12.0	
Western North America	**19.2**		19.0	
	33.4	**40**	31.0	39
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	**9.1**		9.8	
Western North America	**4.5**		4.6	
	13.6	**14**	14.4	14
	86.3		85.6	

Sales volumes for specific products are moderately impacted by seasonal cycles: gasoline sales are typically higher during the summer driving season; heating oil sales are typically higher during the winter season; diesel sales are typically higher during the drilling season at the beginning of the year in Western Canada, and during agricultural planting and harvest seasons in early spring and late summer, respectively; and asphalt sales are typically higher during the construction paving period. Suncor has the flexibility to modify refinery inputs and outputs to match production yields with anticipated product demands.

Sales volumes can also be impacted when refineries undergo planned maintenance events, which reduce production. Suncor is able to partially mitigate this impact through its integrated facilities: the Edmonton refinery and Oil Sands Base upgrading facilities, and the Sarnia and Montreal refineries. In addition, Suncor may purchase refined products from third-party suppliers.

Other Suncor Businesses

Energy Trading

Suncor's Energy Trading business is organized around five main commodity groups crude oil, natural gas, sulphur, petroleum coke and electricity. Energy Trading provides commodity supply, transportation and pricing solutions. Our customers include mid-to large-sized commercial and industrial consumers, utility companies and energy producers.

The Energy Trading business supports the company's Oil Sands production by optimizing price realizations, managing inventory levels during unplanned outages at Suncor's facilities and managing the impacts of external market factors, such as pipeline disruptions or outages at refining customers. The Energy Trading business has entered into arrangements for other midstream infrastructure, such as pipeline, storage capacity and rail access, to optimize delivery of existing and future growth production, while generating trading earnings on select strategies and opportunities.

In the fourth quarter of 2013, following the completion of a rail offloading facility in Montreal, the Energy Trading business commenced rail shipments of non-proprietary crude to the Montreal refinery. This enabled the Montreal refinery to take advantage of the price differentials between inland and global crudes. A second rail offloading facility is planned for Tracy, Québec. It is envisioned that this will enable access to eastern tide waters for Oil Sands product and could commence as early as the second quarter of 2014.

Renewable Energy

Since 2006, Suncor has invested in Canada's emerging biofuels industry. Suncor operates Canada's largest ethanol facility, the St. Clair Ethanol plant in the Sarnia-Lambton region of Ontario. The ethanol plant has a production capacity of 400 million litres per year. In 2013, the plant produced 415.0 million litres of ethanol (2012   412.5 million litres).

In addition, Suncor's renewable energy interests include six wind power projects in operation. Suncor's wind farms have a gross generating capacity of 255 MW and avoid carbon dioxide (CO_2) equivalent emissions of approximately 395,000 tonnes each year, compared with traditional power generation sources. Suncor continues to evaluate new opportunities to build its renewable energy portfolio with potential wind power project sites that are in various stages of the evaluation process. In December 2013, the Adelaide project received regulatory approval and construction is expected to commence in the second quarter of 2014. The Cedar Point project will continue to progress through the regulatory process in 2014. The two projects, based in Ontario, are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%.

Suncor's operating wind power projects:

Wind Power Projects		Ownership Interest (%)	Size (MW)	Turbines	Commissioned
Operated by Suncor					
Wintering Hills	Drumheller, Alberta	70.0	88	55	2011
Kent Breeze	Thamesville, Ontario	100.0	20	8	2011
Non-operated					
Ripley	Ripley, Ontario	50.0	76	38	2007
Chin Chute	Taber, Alberta	33.3	30	20	2006
Magrath	Magrath, Alberta	33.3	30	20	2004
SunBridge	Gull Lake, Saskatchewan	50.0	11	17	2002

SUNCOR EMPLOYEES

The following table shows the distribution of employees among Suncor's business units and corporate office.

As of December 31	2013	2012
Oil Sands	**6 310**	6 015
Exploration and Production	**479**	719
Refining and Marketing	**3 265**	3 175
Corporate, Energy Trading and Renewable Energy	**3 892**	4 023
Total	**13 946**	13 932

Corporate includes employees from our Major Projects group, which supports the business units. In addition to our employees, the company also uses independent contractors to supply a range of services.

Approximately 35% of the company's employees were covered by collective agreements at the end of 2013. Unifor, a new union created by the merger of the Communications, Energy and Paperworkers Union and the Canadian Auto Workers Union, represented the majority of these employees. Three-year collective agreements with approximately 4,250 employees in the company's Oil Sands, In Situ, refinery, lubricants and terminal operations were negotiated in 2013. The collective agreement with Unifor covering approximately 60 employees on Terra Nova expired September 30, 2013 and a renewal is currently being negotiated. A second collective agreement with the Teamsters Union, covering approximately 30 employees for the company's British Columbia terminals and warehouses, expired January 31, 2014 and a renewal is currently being negotiated. Collective agreements with the United Steel Workers representing approximately 250 employees at the Commerce City refinery and with the Sunoco Employees' Bargaining Association representing approximately 200 employees at the Sarnia refinery, will expire January 31, 2015 and February 28, 2015, respectively.

SIGNIFICANT POLICIES

Suncor has a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and contract workers. The Code requires strict compliance with legal requirements and sets Suncor's standards for the ethical conduct of our business. Topics addressed in the Code include competition, conflict of interest, the protection and proper use of corporate assets and opportunities, confidentiality, disclosure of material information, trading in shares and securities, communications to the public, improper payments, harassment, fair dealing in trade relations, and accounting, reporting and business controls. The Code is supported by detailed policy guidance and standards and a Code compliance program, under which every Suncor director, officer, employee and contract worker is required to annually read a summary of the Code and affirm that he or she has reviewed the summary, affirm that he or she understands the requirements of the Code, and provide confirmation of his or her compliance with the Code during the preceding year. Compliance is then reported to Suncor's Audit Committee.

Suncor has a Human Rights Policy, which affirms Suncor's responsibility to respect human rights and ensures that Suncor is not complicit in human rights abuses. Suncor is subject to the laws of the countries in which it operates and is committed to complying with all such laws while honouring international human rights principles, such as those described in the Universal Declaration of Human Rights and the Voluntary Principles on Security and Human Rights. The policy includes principles committed to a harassment-free and violence-free working environment, which respects the cultures, customs and values of the communities in which we operate. The policy makes it clear that the scope of Suncor's human rights due diligence includes its own operations and, where we can influence our third-party business relationships, the operations of others.

Suncor has a Stakeholder Relations Policy, which reflects Suncor's values. The policy provides that Suncor is committed to developing and maintaining positive, meaningful relationships with stakeholders in all of its operating areas and provides Suncor's principles for guiding the development of stakeholder relations (respect, responsibility, transparency, timeliness and mutual benefit). The policy makes it clear that successful stakeholder engagement fosters informed decision-making, resolving issues with timely, cost-effective and mutually beneficial solutions and supporting shared learning.

Suncor has an Aboriginal Affairs Policy, which affirms Suncor's desire to work in collaboration with Canada's Aboriginal Peoples to develop a thriving energy industry that allows Aboriginal communities to be vibrant, diversified and sustainable. The policy provides a consistent approach to the company's relationships with Canada's Aboriginal Peoples and outlines Suncor's responsibilities and commitments, and is intended to guide Suncor's business decisions on a day-to-day basis. Suncor is committed to working closely with Canada's Aboriginal Peoples and communities to build and maintain effective, long-term and mutually beneficial relationships. The policy makes it clear that responsible development takes into account Aboriginal issues and concerns about the effects, positive and negative, of energy development on communities and their traditional and current uses of lands and resources.

Suncor remains committed to reducing overall greenhouse gas (GHG) emissions intensity, in addition to other goals related to improving energy efficiency, reducing water use, increasing land reclamation and reducing air emissions. We actively work to mitigate our environmental impact, including taking action to reduce GHG emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emissions abatement equipment, investing in technology research and development and pursuing other opportunities, both internally as well as through joint initiatives, such as our role in COSIA. The Environment, Health, Safety and Sustainable Development Committee of the Board of Directors meets quarterly to review Suncor's effectiveness in meeting its obligations pertaining to EH&S. The committee also reviews the effectiveness with which Suncor establishes appropriate EH&S policies, including environmental performance, given legal, industry and community standards. Management systems are maintained by this committee to implement such policies and ensure compliance.

Suncor has an Environment, Health and Safety (EH&S) policy, which affirms Suncor's aspirations to be a sustainable energy company by meeting or exceeding the environmental, social and economic expectations of our current and future stakeholders. The policy reflects Suncor's belief that our EH&S efforts are complementary and interdependent with our economic and social performance. The policy makes it clear that Suncor management is responsible for ensuring that employees under their direction are competent to manage their EH&S responsibilities and are knowledgeable of the hazards and risks associated with their jobs, and that all Suncor employees and contractors are accountable for compliance with relevant acts, codes, regulations, standards and procedures, and for their own personal safety and the safety of their co-workers. To support and highlight the goals of the EH&S policy, Suncor holds an Annual President's Operational Excellence Awards, which honour employees and contractors who demonstrate an exceptional commitment to health and safety. The awards ceremony highlights progress on safety initiatives and provides educational opportunities for all employees.

The aforementioned policies are reviewed annually and are available on the company's intranet and external website. Additional workshops and training sessions are also conducted as warranted throughout the year. In addition, information regarding the policies is provided for employees primarily though feature articles on the company's intranet or employee newsletter. The Aboriginal Affairs Policy has Cree and Dene audio translations. Regular training is provided for employees and contract workers whose roles require interaction with the respective stakeholder group.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information outlined below is dated February 28, 2014, with an effective date of December 31, 2013. The preparation date of the information is as of February 21, 2014.

Disclosure of Reserves Data

As a Canadian issuer, Suncor is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves data in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101).

The reserves data set forth in this section of the AIF for Suncor's Mining and In Situ operations is based upon evaluations conducted by GLJ Petroleum Consultants Ltd. (GLJ) with an effective date of December 31, 2013, contained in their reports (the GLJ Reports). The reserves data set forth below for all other reserves, which includes Suncor's interests in its conventional assets offshore Newfoundland and Labrador (East Coast Canada), conventional assets offshore the U.K. (North Sea), conventional assets in Libya (Other International), and its natural gas and tight oil assets primarily located in Western Canada (North America Onshore), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule) with an effective date of December 31, 2013, contained in their reports (the Sproule Reports). Each of GLJ and Sproule (collectively, the Evaluators) are independent qualified reserves evaluators as defined in NI 51-101. All factual data supplied to the Evaluators was accepted as presented.

The reserves data summarizes Suncor's SCO, bitumen, light and medium oil, natural gas and NGL reserves and the net present values of future net revenues for these reserves using forecast prices and costs (unless otherwise indicated) prior to provision for interest, general and administrative expense, and certain abandonment and reclamation costs. Future net revenues are presented on before-tax and after-tax bases.

Advisories Future Net Revenues

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. There is no guarantee that the estimates for SCO, bitumen, light and medium oil, natural gas and NGL reserves provided herein will be recovered. Actual SCO, bitumen, light and medium oil, natural gas and NGL reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in the Notes to Reserves Data Tables, Definitions for Reserves Data Tables and Notes to Future Net Revenues Tables discussion in conjunction with the following notes and tables.

Significant Factors or Uncertainties Affecting Reserves Data

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required as a result of newly acquired technical data, technology improvements, or changes in historical performance, pricing, economic conditions, market availability and regulatory requirements. Additional technical information regarding geology, reservoir properties and reservoir fluid properties are obtained through seismic programs, drilling programs, updated reservoir performance studies and analysis, and production history, and may result in revisions to reserves. Pricing, market availability and economic conditions affect the profitability of reserves exploitation. Depending on the current business environment, higher commodity prices may result in higher reserves by making more projects economically viable or extending their economic life, while lower commodity prices may result in lower reserves, although this generally does not result for assets under PSCs. Regulatory changes, including royalty regimes and environmental regulations, cannot be predicted but may have positive or negative effects on reserves. Future technology improvements would be expected to have a favourable impact on the economics of reserves development and exploitation, and therefore result in an increase to reserves.

While the above factors, and many others, can be considered, certain judgments and assumptions are always required. As new information becomes available, these areas are reviewed and revised accordingly.

For more information as to the risks involved when estimating reserves and resources, see the Risk Factors Uncertainty of Reserves and Resources Estimates section in this AIF.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves[1][2][3]
as at December 31, 2013
(forecast prices and costs)

	SCO[4] (mmbbls)		Bitumen (mmbbls)		Light & Medium Oil (mmbbls)		Natural Gas[5] (bcf)		NGLs (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing												
Mining	1 863	1 670									1 863	1 670
In Situ	151	143	167	152							318	295
East Coast Canada					41	30					41	30
North America Onshore					2	1	42	35	1	1	10	8
Total Canada	2 014	1 812	167	152	43	32	42	35	1	1	2 232	2 003
North Sea					79	79	2	2			79	79
Other International												
Total Proved Developed Producing	**2 014**	**1 812**	**167**	**152**	**121**	**110**	**45**	**38**	**1**	**1**	**2 311**	**2 082**
Proved Developed Non-Producing												
Mining												
In Situ												
East Coast Canada												
North America Onshore							3	3			1	1
Total Canada							3	3			1	1
North Sea					4	4					4	4
Other International					149	54					149	54
Total Proved Developed Non-Producing					**152**	**58**	**4**	**4**			**153**	**58**
Proved Undeveloped												
Mining			845	764							845	764
In Situ	564	497	875	749							1 439	1 245
East Coast Canada					26	18					26	18
North America Onshore					2	1	4	4			2	2
Total Canada	564	497	1 720	1 512	27	20	4	4			2 312	2 029
North Sea					25	25	1	1			25	25
Other International					3	1					3	1
Total Proved Undeveloped	**564**	**497**	**1 720**	**1 512**	**55**	**45**	**5**	**5**			**2 340**	**2 055**
Proved												
Mining	1 863	1 670	845	764							2 707	2 433
In Situ	715	639	1 043	901							1 758	1 540
East Coast Canada					67	48					67	48
North America Onshore					3	3	50	42	1	1	13	11
Total Canada	2 578	2 309	1 887	1 665	70	51	50	42	1	1	4 544	4 033
North Sea					107	107	4	4			108	108
Other International					151	55					151	55

Total Proved	**2 578**	**2 309**	**1 887**	**1 665**	**329**	**213**	**54**	**46**	**1**	**1**	**4 804**	**4 195**
Probable												
Mining	520	459	397	339							916	798
In Situ	1 092	901	457	355							1 550	1 256
East Coast Canada					279	215					279	215
North America Onshore					2	2	36	31	1	1	9	7
Total Canada	1 612	1 360	854	694	281	217	36	31	1	1	2 754	2 277
North Sea					36	36	2	2			37	37
Other International					112	40					112	40
Total Probable	**1 612**	**1 360**	**854**	**694**	**429**	**293**	**39**	**33**	**1**	**1**	**2 902**	**2 354**
Proved Plus Probable												
Mining	2 382	2 129	1 241	1 103							3 624	3 232
In Situ	1 807	1 541	1 500	1 256							3 307	2 797
East Coast Canada					346	263					346	263
North America Onshore					5	4	86	73	2	2	21	18
Total Canada	4 189	3 669	2 741	2 359	351	268	86	73	2	2	7 298	6 310
North Sea					144	144	7	7			145	145
Other International					263	95					263	95
Total Proved Plus Probable	**4 189**	**3 669**	**2 741**	**2 359**	**758**	**506**	**92**	**80**	**2**	**2**	**7 706**	**6 549**

Please see Notes (1) through (5) at the end of the reserves data section for important information about volumes in this table.

Summary of Oil and Gas Reserves[(1)(2)(3)]
as at December 31, 2013
(constant prices and costs)

SCO[(4)] (mmbbls)		Bitumen (mmbbls)		Light & Medium Oil (mmbbls)		Natural Gas[(5)] (bcf)		NGLs (mmbbls)	Total (mmboe)
Gross	Net	Gross	Net	Gross	Net	Gross	Net	1.31	

Gas sales	$ 250,764	$ 128,060
Oil sales	73,355	29,239
Total oil and gas sales	$ 324,119	$ 157,299
Total gas volume-MMcf	50,552	41,300
Gas volume-MMcf per day	138.5	113.2
Average gas price-per Mcf	$ 4.96	$ 3.10
Total oil volume-thousand barrels	2,504	1,171
Oil volume-barrels per day	6,859	3,209
Average oil price-per barrel	$ 29.30	$ 24.97
Marketing sales	$ 130,156	$ 52,350
Marketing purchases	129,503	49,671
Marketing margin	$ 653	$ 2,679
Depreciation, depletion and amortization	$ 88,774	$ 49,231
Production	31,801	19,427
Transportation	7,472	7,918
Taxes other than income	27,485	13,154
General and administrative	17,526	8,568
Stock compensation	1,824	125
Asset retirement obligation accretion	1,009	

We reported net income of $94.6 million, or $2.22 per diluted share in 2003 compared to net income of $39.8 million, or $1.31 per diluted share in 2002. The primary reason for this increase in net income is the increase in revenues from oil and gas sales. These sales for 2003 equaled $324.1 million, compared to $157.3 million in 2002. The $166.8 million increase in sales between the two years consists of $104.8 million related to higher oil and gas prices, and $62.0 million associated with increased production volumes.

Realized gas prices averaged $4.96 per Mcf for 2003, compared to $3.10 per Mcf for 2002. This 60 percent increase had an incremental effect on sales of $94.0 million between the two years. Realized oil prices averaged $29.30 per barrel for 2003, compared to $24.97 per barrel for 2002. The effect on sales between years resulting from this 17 percent improvement in oil prices totaled $10.8 million. Higher prices were the direct result of overall market conditions. We have not entered into any derivative contracts or hedges with respect to our production.

Oil and gas sales also benefited from higher production volumes. Average gas volumes rose 25.3 MMcf per day in 2003 to 138.5 MMcf per day from 113.2 MMcf per day in 2002, resulting in $28.7 million of incremental revenues. Oil volumes averaged 6,859 barrels per day in 2003, compared to 3,209

barrels per day in 2002, resulting in increased revenues of $33.3 million. The increase in overall sales volumes between the two years is due to the Key acquisition and positive drilling results during 2003. Prior to the acquisition, sales volumes for the first three quarters of 2002 averaged 116.4 MMcfe per day. With the inclusion of Key s volumes in the fourth quarter of 2002, production increased to 179.7 MMcfe per day. Average daily production contributed from wells drilled during 2003 totaled 17.2 MMcfe, which largely offset natural declines.

Marketing sales net of related purchases equaled $0.7 million in 2003 compared to $2.7 million in 2002. These sales relate to marketing activities with outside parties conducted by our marketing group. The financial impact from these activities is small relative to our overall results of operations. The marketing margin in 2002 was favorably impacted by wide fluctuations in gas prices. Revenues and costs related to marketing of our own production are eliminated in consolidation.

Costs and Expenses (Other than Income tax expense)

Overall costs and expenses (not including income taxes) were $176.5 million in 2003 compared to $98.6 million in 2002. The largest component of this $77.9 million increase between years is a $39.5 million increase in total depreciation, depletion and amortization expense (DD&A) from $49.2 million in 2002 to $88.8 million in 2003, resulting from a larger asset base following the acquisition of Key and higher costs for reserves added during 2003. On a unit of production basis, DD&A was $1.35 per Mcfe in 2003 compared to $1.02 per Mcfe for 2002.

Taxes other than income were $14.3 million greater, rising from $13.2 million in 2002 to $27.5 million in 2003. This increase resulted from a 106 percent jump in oil and gas sales stemming from higher product prices and volumes.

Production costs rose $12.4 million from $19.4 million in 2002 to $31.8 million in 2003 due to the acquisition of Key s properties and higher workover costs incurred during 2003 for the maintenance of our wells. The mix of Key s wells included proportionately more oil wells, which generally cost more to operate because of additional pumping and electricity charges.

General and administrative (G&A) expenses increased $8.9 million from $8.6 million in 2002 to $17.5 million in 2003, due to the larger organization resulting from the Key acquisition as well as the expanded drilling program that has been implemented.

Stock compensation related to amortization of restricted stock costs increased by $1.7 million between years, because the majority of the restricted stock and stock units were issued in December 2002.

Accretion expense associated with asset retirement obligations was $1.0 million in 2003. Asset retirement obligations were recorded with the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003.

Income tax expense

Income tax expense totaled $55.1 million for 2003 versus $21.6 million for 2002. Tax expense equaled a combined Federal and state effective income tax rate of 37.2 percent and 35.1 percent in 2003 and 2002, respectively. The increase in effective rates results from greater utilization of tax credits in 2002. We estimate that $24.6 million of our 2003 income tax expense is current.

Year Ended December 31, 2002 Compared with Fiscal Year Ended September 30, 2001

On September 30, 2002, we changed our fiscal year end from September 30 to December 31. As a result, we are comparing the year ended December 31, 2002 to the fiscal year ended September 30, 2001. Each annual period discussed includes a full twelve months of operations. The three months ended December 31, 2001 are compared to the three months ended December 31, 2000.

SUMMARY DATA:

(in thousands or as indicated)	For the Years Ended December 31, 2002		For the Years Ended September 30, 2001	
Net income	$	39,819	$	35,253
Per share-basic		1.32		1.33
Per share-diluted		1.31		1.33
Gas sales	$	128,060	$	199,321
Oil sales		29,239		22,815
Total oil and gas sales	$	157,299	$	222,136
Total gas volume-MMcf		41,300		42,387
Gas volume-MMcf per day		113.2		116.1
Average gas price-per Mcf	$	3.10	$	4.70
Total oil volume-thousand barrels		1,171		818
Oil volume-barrels per day		3,209		2,242
Average oil price-per barrel	$	24.97	$	27.88
Marketing sales	$	52,350	$	93,877
Marketing purchases		49,671		87,460
Marketing margin	$	2,679	$	6,417
Reduction to carrying value of oil and gas properties	$		$	78,082
Depreciation, depletion and amortization		49,231		49,699
Production		19,427		13,091
Transportation		7,918		6,359
Taxes other than income		13,154		18,965
General and administrative		8,568		10,068
Financing costs, net		171		(1,784)

On September 30, 2002, Cimarex acquired 100 percent of the outstanding common stock of Key in a tax-free exchange of stock. In the acquisition, we issued approximately 14.1 million shares of our common stock for all the outstanding shares of Key common stock on that date, on a one-for-one basis. The results of operations for Cimarex include Key beginning with the fourth quarter of 2002. The acquisition of Key increased our proved reserves by 94.7 Bcf of gas and 9.1 MMBbls of oil, or an aggregate of 149.4 Bcfe. The purchase price allocated to these proved oil and gas properties was approximately $285.0 million.

We reported net income of $39.8 million, or $1.31 per diluted share for the year ended December 31, 2002 compared to net income of $35.3 million, or $1.33 per diluted share for the year ended

September 30, 2001. Wide variations in gas prices between and during the years contributed both directly and indirectly to the changes in net income. In 2002, net income grew by 13 percent compared to fiscal 2001, despite a 34 percent drop in gas prices, because fiscal 2001 results were negatively affected by a $78.1 million reduction to the carrying value of oil and gas properties stemming from a sharp drop in gas prices on September 30, 2001 compared to average prices for that year.

Oil and gas sales dropped $64.8 million from $222.1 million in fiscal 2001 to $157.3 million in 2002. Gas sales decreased $71.3 million between the two periods. Realized gas prices averaged $3.10 per Mcf for 2002, compared to $4.70 per Mcf for fiscal 2001. This decrease in price had a negative effect on sales of $66.1 million between the two years. Average daily gas volumes decreased 2.9 MMcf in 2002 to 113.2 MMcf from 116.1 MMcf in 2001, reducing revenues by $5.1 million during 2002. Lower gas volumes resulted from natural production declines in existing wells, though partially offset by output from new wells that were completed since September 30, 2001, and gas wells acquired through the Key acquisition.

Oil sales increased from $22.8 million in fiscal 2001 to $29.2 million in 2002. Realized oil prices averaged $24.97 per barrel for 2002, compared to $27.88 per barrel for 2001. The effect on sales between years resulting from this drop in oil prices totaled $3.4 million. The volatility in prices was the result of overall market conditions. Daily oil volumes averaged 3,209 barrels in 2002, compared to 2,242 barrels in 2001, resulting in increased revenues of $9.8 million during 2002. Increase in oil volumes between the two years is due to the acquisition of Key, with Key properties contributing 402 MBbls in the fourth quarter of 2002.

Marketing sales net of related purchases equaled $2.7 million in 2002 compared to $6.4 million in fiscal 2001. The net decrease in 2002 is due to lower average gas prices in 2002 compared to 2001.

Costs and Expenses (Other than Income tax expense)

Overall costs and expenses (not including income taxes) were $98.6 million in 2002 compared to $174.5 million in fiscal 2001. The largest component of this $75.9 million decrease between years is the previously mentioned $78.1 million reduction in carrying value of oil and gas properties in 2001.

DD&A expense dropped slightly to $49.2 million in 2002 from $49.7 million in fiscal 2001.

Taxes other than income decreased to $13.2 million in 2002 from $19.0 million in 2001. These taxes equate to 8.4 percent and 8.5 percent of oil and gas sales for 2002 and 2001, respectively. The expense decreased in 2002 due to lower oil and gas prices realized during the year.

Production costs rose from $13.1 million in fiscal 2001 to $19.4 million in 2002. The biggest contributing factor to the increase was the September 30, 2002 Key acquisition.

Financing costs increased $2.0 million due to the settlement of an ad valorem tax contingency settled for less than originally escrowed, resulting in a portion of the interest component of the settlement being reversed in fiscal 2001.

Smaller variances that effectively offset each other were general and administrative expenses between the two years decreasing $1.5 million and transportation expense increasing $1.5 million.

Income tax expense

Income tax expense totaled $21.6 million for 2002 versus $19.6 million for 2001. Tax expense equaled combined Federal and state effective income tax rates of 35.1 percent in 2002 and 35.7 percent in fiscal 2001.

Three Months Ended December 31, 2001 Compared with Three Months Ended December 31, 2000

SUMMARY DATA:

––(in thousands or as indicated)		**For Three Months Ended December 31, 2001**		**2000 (unaudited)**
Net income	$	4,479	$	27,582
Per share-basic		0.17		1.04
Per share-diluted		0.17		1.04
Gas sales	$	22,750	$	52,004
Oil sales		4,107		7,147
Total oil and gas sales	$	26,857	$	59,151
Total gas volume-MMcf		10,174		10,710
Gas volume-MMcf per day		110.6		116.4
Average gas price-per Mcf	$	2.24	$	4.86
Total oil volume-thousand barrels		206		230
Oil volume-barrels per day		2,236		2,502
Average oil price-per barrel	$	19.97	$	31.04
Marketing sales	$	12,655	$	26,795
Marketing purchases		10,994		22,233
Marketing margin	$	1,661	$	4,562
Depreciation, depletion and amortization	$	8,972	$	9,477
Production		4,197		2,638
Transportation		1,886		1,469
Taxes other than income		2,559		4,194
General and administrative		3,637		2,378

We reported net income of $4.5 million, or $0.17 per diluted share for the fourth quarter ended December 31, 2001 compared to net income of $27.6 million, or $1.04 per diluted share for the three months ended December 31, 2000. The decline in net income is primarily attributable to a decrease in oil and gas sales of $32.3 million. Commodity prices were substantially higher in the quarter ended December 31, 2000.

Realized gas prices averaged $2.24 per Mcf for the fourth quarter of 2001, compared to $4.86 per Mcf for the fourth quarter of 2000. This decrease in price had a negative effect on sales of $26.7 million between the two periods. Realized oil prices averaged $19.97 per barrel for the fourth quarter in 2001, compared to $31.04 per barrel for the same period in 2000, resulting in a decrease in sales between periods of $2.3 million.

Oil and gas sales also decreased due to lower production volumes. Average daily gas volumes decreased 5.8 MMcf in the fourth quarter of 2001 to 110.6 MMcf from 116.4 MMcf for the same period in 2000, resulting in lower revenues of $2.6 million during 2001. Daily oil volumes averaged 2,236 barrels in 2001, compared to 2,502 barrels in 2000, resulting in decreased revenues of $0.7 million during 2001. Lower gas volumes resulted from natural production declines in wells, partially offset by output from new wells that were completed during 2001. Oil volumes between the two periods decreased due to natural production declines.

Marketing sales net of related purchases equaled $1.7 million for the fourth quarter in 2001 compared to $4.6 million for the same period in 2000. Spot market prices were very volatile in November and December 2000, as gas prices were rapidly increasing to relatively high levels. In the three months ended December 31, 2001, gas prices were substantially lower and more stable. The $2.9 million variance in net revenues reflects less volatile market conditions that existed during the fourth quarter of 2001 when spot market sales were accomplished at prices only slightly higher than the cost of gas purchases.

Costs and Expenses (Other than Income tax expense)

Overall costs and expenses (not including income taxes) were $21.3 million in fourth quarter of 2001 compared to $20.1 million for the same period in 2000.

DD&A on oil and gas properties decreased slightly to $9.0 million for the fourth quarter in 2001 from $9.5 million for the same period in 2000.

Transportation expenses increased to $1.9 million from $1.5 million for the fourth quarters of 2001 and 2000, respectively.

Taxes other than income decreased to $2.6 million in the fourth quarter of 2001 from $4.2 million in the same period of 2000, due to lower oil and gas prices realized in 2001.

Production costs increased from $2.6 million in the fourth quarter of 2000 to $4.2 million in the same three months of 2001, due primarily to general cost increases on outside operated wells and additional compression costs.

G&A expenses increased from $2.4 million in the fourth quarter of 2000 to $3.6 million in the fourth quarter of 2001. The increase is primarily due to a $0.9 million impairment of receivables from Enron Corporation and costs associated with legal proceedings. Cimarex has no additional exposure relating to Enron as all sales to Enron were terminated at November 30, 2001.

Income tax expense

Income tax expense totaled $2.8 million for the fourth quarter of 2001 versus $16.5 million for the same period in 2000. Tax expense was calculated using a combined Federal and state effective income tax rate of 38.2 percent in 2001 versus 37.4 percent in 2000. The decrease in the expense between periods was a result of lower revenue resulting from lower oil and gas prices.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

Our primary source of capital is cash flow generated from operating activities. Prices we receive for future oil and gas sales and our level of production will impact these future cash flows. No prediction can be made as to the prices we will receive. Production volumes will in part be dependent upon the amount of future capital expenditures. In turn, actual levels of capital expenditures may vary due to many factors, including drilling results, oil and gas prices, industry conditions, prices and availability of goods and services, and the extent to which proved properties are acquired.

Cash flow provided by operating activities for the year ended December 31, 2003 was $206.3 million, compared to $104.5 million and $162.4 million for the years ended December 31, 2002 and September 30, 2001, respectively. The increase in 2003 from the earlier periods results primarily from higher prices and production.

Higher revenues from oil and gas sales facilitated the payment of our long-term debt, funded our exploration and development expenditure program for the year, and built a larger balance of cash at year end than we held in 2002.

Cash flow used in investing activities for the year ended December 31, 2003 was $159.6 million, compared to $71.7 million and $101.4 million for the years ended December 31, 2002 and September 30, 2001, respectively. The increase in 2003 stems from a larger exploration and development program.

Cash flow used by financing activities in 2003 was $28.6 million versus $17.6 million in 2002, an increase of $11 million. The most significant item that occurred during 2003 was the repayment of $32.0 million of our long-term credit facility afforded by higher oil and gas prices in 2003. Cash flows used by financing activities for the year ended September 30, 2001 were $61.4 million, $43.8 million higher than in 2002. The decrease in cash used by financing activities in 2002 compared to fiscal year 2001 resulted from a reduction in payments to the previous parent company, H&P.

Financial Condition

As of December 31, 2003, stockholders equity totaled $534.7 million, up from $444.9 million at December 31, 2002. The increase resulted primarily from 2003 net income of $94.6 million. During 2003 we repaid all of the $32 million of long-term debt that was outstanding at year end 2002 and increased our cash balance by $18.1 million from $22.3 million at December 31, 2002 to $40.4 million at December 31, 2003.

Working Capital

Working capital at December 31, 2003 totaled $37.7 million, compared to $21.4 million at December 31, 2002. The largest component of this increase was the higher cash balance that resulted from cash flow provided by operating activities. Receivables comprise another significant portion of our working capital, totaling $68.3 million at December 31, 2003. Our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. The collection of receivables has been timely, with associated losses historically not being significant.

Financing

In October 2002, we closed on a three-year $400 million Senior Secured Revolving Credit Facility. The Facility has a borrowing base of $275 million and we have elected a $200 million commitment amount. The borrowing base is subject to redetermination each April and October. Borrowings under this Facility bear interest at a LIBOR rate plus 1.25 percent to 2.00 percent, based on borrowing base usage. Unused borrowings are subject to a commitment fee of 0.375 percent to 0.50 percent, also depending on borrowing base usage. The Credit Facility is secured by mortgages on our oil and gas properties and the stock of our subsidiaries. We are also subject to customary financial and non-financial covenants. We are in compliance with all such covenants. There were no borrowings under the Facility at December 31, 2003. We have not sought a corporate credit rating since we have no outstanding long-term debt.

Contractual Obligations and Material Commitments

At December 31, 2003, we had contractual obligations and material commitments as follows:

		Payments Due by Period			
Contractual obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**
Operating leases	$ 18,172	$ 1,715	$ 3,898	$ 4,236	$ 8,323
Drilling commitments	23,682	23,682			
Deferred income taxes(1)	155,293				155,293
Asset retirement obligation	16,463	2,804	1,786	1,655	10,218
Deferred compensation(2)	11,724	2,444	4,732	2,364	2,184
Other liabilities	1,779	158	120	115	1,386
Total obligations	$ 227,113	$ 30,803	$ 10,536	$ 8,370	$ 177,404

(1) Deferred income taxes are projected not to be paid within the next five years, due to the anticipated drilling expenditures to be incurred during the periods.

(2) The deferred compensation will be paid via the issuance of shares of common stock.

In addition to the items in the table above, we have issued parental guarantees of $9.8 million related to our marketing business for the benefit of companies we purchase gas from.

We have one firm transportation contract to transport 10,000 MMBtus per day, at $0.09 per MMBtu through December 31, 2004. We have a right to extend this contract annually. Maximum amount that would be payable, if deliveries are not made, would be $0.3 million.

Additionally, we have guaranteed to deliver 2.3 Bcf of natural gas from five wells over a three-year period as reimbursement for connection costs to the pipeline. If the minimum delivery is not met, the maximum exposure is $0.2 million. We have also agreed to reimburse another gatherer for connection costs to its pipeline via delivery of 1 Bcf of natural gas per well or a prorated payment based on the total reserves on 17 wells. The maximum amount that would be payable, if we deliver no natural gas, would be $0.6 million.

We also have firm sales contracts to deliver fixed volumes of gas based on an index price. These contracts vary in length from two months to one year. As of December 31, 2003, we had an obligation to deliver approximately 3.8 Bcf of natural gas. If this gas is not delivered, our financial commitment would be approximately $20.7 million based on index prices as of December 31, 2003. This commitment will fluctuate due to price volatility and actual volumes delivered. We believe no financial commitment will be due based on our reserves and current production levels.

All of the commitments were routine and were made in the normal course of our business.

Based on current commodity prices and anticipated levels of production, we believe that the estimated net cash generated from operations, coupled with the cash on hand and amounts available under our existing line of credit will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

Our projected 2004 exploration and development expenditure program of $200 million will require a great deal of coordination and effort. Though there are a variety of factors that could curtail, delay or even cancel some of our drilling operations, we believe our projected program has a high degree of occurrence. The majority of projects are in hand, drilling rigs are being scheduled, and the historical results of our drilling efforts in these areas warrant pursuit of the projects.

Costs of operations on a per Mcfe basis for 2004 are estimated to approximate levels realized in 2003. Should factors beyond our control fluctuate, our program and realized costs will vary from current projections. These factors could include volatility in commodity prices, changes in the supply of and demand for oil and gas, weather conditions, governmental regulations and more.

Estimated production levels for 2004 will range between 195 to 210 MMcfe per day. The revenues to be realized from the sale of this production will be dependent not only on the level of oil and gas actually produced, but also the prices that will be realized from the sales. During 2003, the average price realized from our gas sales was $4.96 per Mcf and $29.30 per barrel from our oil sales. Current indications are that anticipated prices for 2004 should approximate 2003 levels. Prices can be highly volatile, however, and the possibility of realized prices for 2004 to vary from current estimates is high.

ITEM 7A. Qualitative and Quantitative Disclosures about Market Risk

Price Fluctuations

Our results of operations are highly dependent upon the prices we receive for oil and gas production, and those prices are constantly changing in response to market forces. Nearly all of our revenue is from the sale of oil and gas, so these fluctuations, positive and negative, can have a significant impact on our results of operations and cash flows.

Oil and gas price realizations for 2003 ranged from a monthly low of $4.13 per Mcf and $26.34 per barrel, to a monthly high of $7.24 per Mcf and $31.31 per barrel, respectively. It is impossible to predict future oil and gas prices with any degree of certainty.

If we wanted to attempt to smooth out the effect of commodity price fluctuations, we could enter into non-speculative hedge arrangements, commodity swap agreements, forward sale contracts, commodity futures, options and other similar agreements. To date, we have not used any of these financial instruments to mitigate commodity price changes.

Any sustained weakness in prices may affect our financial condition and results of operations, and may also reduce the amount of net oil and gas reserves that we can produce economically. Any reduction in reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities and could cause us to record a reduction in the carrying value of our oil and gas properties.

Interest Rate Risk

Cimarex may be exposed to risk resulting from changes in interest rates as a result of our variable-rate bank credit facility. However, because we presently have no debt outstanding, the potential effect that changes in interest rates would have no affect on our results of operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CIMAREX ENERGY CO.

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES

All other supplemental information and schedules have been omitted because they are not applicable or the information required is shown in the consolidated financial statements or related notes thereto.

Independent Auditors Report

The Board of Directors

Cimarex Energy Co.:

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries as of December 31, 2003 and 2002 and the related consolidated statements of operations, stockholders equity, and cash flows for the years ended December 31, 2003 and 2002 and the three months ended December 31, 2001. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Cimarex Energy Co. and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for the years ended December 31, 2003 and 2002 and the three months ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 5 to the Consolidated Financial Statements, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, as of January 1, 2003.

KPMG LLP

Denver, Colorado

February 9, 2004

REPORT OF INDEPENDENT AUDITORS

The Board of Directors

Cimarex Energy Co.

We have audited the accompanying consolidated statements of operations, stockholder s equity and cash flows of Cimarex Energy Co., (See Note 1) for the year ended September 30, 2001. These financial statements are the responsibility of Cimarex Energy Co. s management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of Cimarex Energy Co. (See Note 1) for the year ended September 30, 2001, in conformity with accounting principles generally accepted in the United States.

ERNST & YOUNG LLP

Tulsa, Oklahoma

May 8, 2002, except as to the first paragraph of Note 1

as to which the date is September 30, 2002.

CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share information)

	December 31, 2003	December 31, 2002
Assets		
Current assets:		
Cash and cash equivalents	$ 40,420	$ 22,327
Accounts receivable:		
Trade, net of allowance	15,847	7,524
Oil and gas sales, net of allowance	21,350	28,222
Marketing, net of allowance	31,096	22,530
Inventories	6,700	3,986
Deferred income taxes	1,631	2,073
Other current assets	6,160	2,949
Total current assets	123,204	89,611
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	1,331,095	1,172,488
Unproved properties and properties under development, not being amortized	39,370	23,941
	1,370,465	1,196,429
Less accumulated depreciation, depletion and amortization	(746,161)	(665,711)
Net oil and gas properties	624,304	530,718
Fixed assets, less accumulated depreciation of $6,422 and $5,163	12,092	6,849
Goodwill	44,967	45,836
Other assets, net	941	1,272
	$ 805,508	$ 674,286
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 11,146	$ 9,500
Marketing	7,248	12,839
Accrued liabilities:		
Exploration and development	16,964	7,415
Taxes other than income	6,362	3,743
Other	25,013	10,734
Revenue payable	18,776	24,022
Total current liabilities	85,509	68,253
Long-term debt		32,000
Deferred income taxes	155,293	127,023
Asset retirement obligation	16,463	
Deferred compensation	11,724	
Other liabilities	1,779	2,130
Total liabilities	270,768	229,406

Commitments and contingencies				
Stockholders equity:				
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued				
Common stock, $0.01 par value, 100,000,000 shares authorized, 41,063,653 and 41,410,308 shares issued and outstanding, respectively		411		414
Paid-in capital		237,430		243,420
Unearned compensation		(9,540)		(10,814)
Retained earnings		306,439		211,860
		534,740		444,880
	$	805,508	$	674,286

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	For the Years Ended			For the Three Months Ended	
	December 31,		September 30,	December 31,	
	2003	2002	2001	2001	2000
					(Unaudited)
Revenues:					
Gas sales	$ 250,764	$ 128,060	$ 199,321	$ 22,750	$ 52,004
Oil sales	73,355	29,239	22,815	4,107	7,147
Marketing sales	130,156	52,350	93,877	12,655	26,795
Other	(63)	(5)	765	84	461
	454,212	209,644	316,778	39,596	86,407
Costs and expenses:					
Depreciation, depletion and amortization	88,774	49,231	49,699	8,972	9,477
Reduction to carrying value of oil and gas properties			78,082		
Accretion expense	1,009				
Production	31,801	19,427	13,091	4,197	2,638
Transportation	7,472	7,918	6,359	1,886	1,469
Taxes other than income	27,485	13,154	18,965	2,559	4,194
Marketing purchases	129,503	49,671	87,460	10,994	22,233
General and administrative	17,526	8,568	10,068	3,637	2,378
Stock compensation	1,824	125			
Financing costs:					
Interest expense	1,285	620	(1,509)	141	107
Capitalized interest	(304)	(206)			
Interest income	(332)	(243)	(275)	(43)	(133)
	306,043	148,265	261,940	32,343	42,363
Income before income tax expense and cumulative effect of a change in accounting principle	148,169	61,379	54,838	7,253	44,044
Income tax expense	55,141	21,560	19,585	2,774	16,462
Income before cumulative effect of a change in accounting principle	93,028	39,819	35,253	4,479	27,582
Cumulative effect of a change in accounting principle, net of tax	1,605				
Net income	$ 94,633	$ 39,819	$ 35,253	$ 4,479	$ 27,582
Earnings per share:					
Basic:					
Income before cumulative effect of a change in accounting principle	$ 2.24	$ 1.32	$ 1.33	$ 0.17	$ 1.04
	0.04				

Cumulative effect of a change in accounting principle, net of tax					
Net income	$ 2.28	$ 1.32	$ 1.33	$ 0.17	$ 1.04
Diluted:					
Income before cumulative effect of a change in accounting principle	$ 2.18	$ 1.31	$ 1.33	$ 0.17	$ 1.04
Cumulative effect of a change in accounting principle, net of tax	0.04				
Net income	$ 2.22	$ 1.31	$ 1.33	$ 0.17	$ 1.04
Weighted average shares outstanding:					
Basic	41,521	30,239	26,591	26,591	26,591
Diluted	42,640	30,317	26,591	26,591	26,591
Pro forma amounts assuming new method of accounting for asset retirement obligations is applied retroactively					
Net income		$ 39,236	$ 34,659	$ 4,300	$ 27,451
Earnings per share:					
Basic		$ 1.30	$ 1.30	$ 0.16	$ 1.03
Diluted		$ 1.29	$ 1.30	$ 0.16	$ 1.03

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

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31, 2003	Years Ended December 31, 2002	September 30, 2001	Three Months Ended December 31, 2001
Cash flows from operating activities:				
Net income	$ 94,633	$ 39,819	$ 35,253	$ 4,479
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization	88,774	49,231	49,699	8,972
Amortization of restricted stock compensation	1,914	125		
Reduction to carrying value of oil and gas properties			78,082	
Cumulative effect of a change in accounting principle, net of taxes	(1,605)			
Deferred income taxes	30,590	21,428	(11,138)	2,805
Asset retirement obligation accretion	1,009			
Income tax benefit related to stock options exercised	1,203			
Other	433	58	(167)	(241)
Change in operating assets and liabilities:				
(Increase) decrease in accounts receivable	(10,123)	(15,996)	9,658	7,387
(Increase) decrease in inventories	(2,714)	1,770	(1,994)	541
(Increase) decrease in other current assets	(3,242)	(934)	6,373	(396)
Decrease in other assets			164	
Increase (decrease) in accounts payable	(9,310)	17,010	5,550	(16,656)
Increase (decrease) in accrued liabilities	15,626	(8,321)	(9,370)	(3,319)
Increase (decrease) in other noncurrent liabilities	(875)	265	248	32
Net cash provided by operating activities	206,313	104,455	162,358	3,604
Cash flows from investing activities:				
Capital expenditures	(150,501)	(66,458)	(100,201)	(14,667)
Acquisition of proved oil and gas properties	(2,032)			
Merger costs		(5,079)		
Cash received in connection with acquisition		2,135		
Proceeds from sale of assets	1,041	313	205	681
Other capital expenditures	(8,149)	(2,596)	(1,387)	(345)
Net cash used by investing activities	(159,641)	(71,685)	(101,383)	(14,331)
Cash flows from financing activities:				
Long-term borrowings		41,016		
Payments on long-term debt	(32,000)	(45,016)		
Financing costs incurred		(927)		
Common stock reacquired and retired	(8)			

Net (distributions to) contributions from Helmerich & Payne, Inc.			(61,430)	4,808
Change in amount due (to) from Helmerich & Payne, Inc.		(13,089)		13,089
Proceeds from issuance of common stock	3,429	403		
Net cash provided by (used in) financing activities	(28,579)	(17,613)	(61,430)	17,897
Net increase (decrease) in cash and cash equivalents	18,093	15,157	(455)	7,170
Cash and cash equivalents at beginning of period	22,327	7,170	455	
Cash and cash equivalents at end of period	$ 40,420	$ 22,327	$	$ 7,170

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In thousands)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Unearned Compensation	Retained Earnings	Total Stockholders Equity
Balance, September 30, 2000	26,591	$ 266	$	$	$ 192,706	$ 192,972
Net income					35,253	35,253
Net distributions to Helmerich & Payne, Inc.					(61,430)	(61,430)
Balance, September 30, 2001	26,591	266			166,529	166,795
Net income					4,479	4,479
Net contributions from Helmerich & Payne, Inc.					3,808	3,808
Balance, December 31, 2001	26,591	266			174,816	175,082
Net income					39,819	39,819
Issuance of restricted stock awards in conjuction with the Cimarex spinoff	38			(156)	156	
Common stock issued for the acquisition of Key Production Company, Inc.	14,079	141	232,212	(159)		232,194
Net distributions to Helmerich & Payne, Inc.					(2,931)	(2,931)
Issuance of restricted stock awards	644	6	10,721	(10,727)		
Common stock reacquired and retired	(13)		(197)			(197)
Amortization of unearned compensation				228		228
Exercise of stock options, net of tax benefit of $282 recorded in paid-in capital	71	1	684			685
Balance, December 31, 2002	41,410	414	243,420	(10,814)	211,860	444,880
Net income					94,633	94,633
Issuance of restricted stock awards	65	1	1,348	(1,349)		
Common stock reacquired and retired			(8)			(8)
Amortization of unearned compensation				2,394		2,394
Exercise of stock options, net of tax benefit of $1,203 recorded in paid-in capital	295	3	4,695			4,698

Net distribution to Helmerich & Payne, Inc.					(54)	(54)
Restricted stock forfeited and retired	(17)		(308)	229		(79)
Shares of restricted stock exchanged for restricted stock units	(689)	(7)	(11,717)			(11,724)
Balance, December 31, 2003	41,064	$ 411	$ 237,430	$ (9,540)	$ 306,439	$ 534,740

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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Cimarex Energy Co. (Cimarex or the Company) was formed in February 2002 as a wholly owned subsidiary of Helmerich & Payne, Inc. (H&P). In July 2002, H&P contributed its oil and gas exploration and production operations and the common stock of Cimarex Energy Services, Inc. (CESI), which is involved in natural gas marketing, to Cimarex. As a result of a dividend declared and paid by H&P on September 30, 2002, in the form of 26,591,321 shares of Cimarex common stock, Cimarex was spun off and became a stand-alone Company. All par value, common stock and per share amounts have been retroactively restated in the accompanying consolidated financial statements to reflect the spin off.

Also on September 30, 2002, Cimarex acquired 100 percent of the outstanding common stock of Key Production Company, Inc. (Key) in a tax-free exchange. Cimarex issued one share of its common stock for each of the 14,079,243 shares of Key common stock outstanding as of that date. The acquisition of Key has been accounted for using the purchase method of accounting. The acquisition of Key is reflected in the accompanying balance sheets and in the results of operations and cash flows for the periods subsequent to the acquisition on September 30, 2002.

On September 30, 2002, Cimarex changed its fiscal year from September 30 to December 31.

The accounts of Cimarex and its subsidiaries are presented in the accompanying consolidated financial statements. All intercompany accounts and transactions were eliminated in consolidation.

We make certain estimates and assumptions to prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. Those estimates and assumptions affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period and in disclosures of commitments and contingencies. Changes in facts and circumstances may result in revised estimates and actual results could differ from those estimates.

The more significant areas requiring the use of management s estimates and judgments relate to preparation of estimated oil and gas reserves, the use of these oil and gas reserves in calculating depletion, depreciation and amortization, the use of the estimates of future net revenues in computing the ceiling test limitations and estimates of abandonment obligations used in such calculations and in recording asset retirement obligations. Estimates and judgments are also required in determining the reserves for bad debts, the impairments of undeveloped properties, the assessment of goodwill and the valuation of deferred tax assets.

Certain amounts in the accompanying consolidated financial statements for prior periods have been reclassified to conform to the current year presentation.

2. DESCRIPTION OF BUSINESS

Cimarex is an independent oil and gas exploration and production company. Our principal areas of operations are located in Oklahoma, Kansas, Texas and Louisiana.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Cash and cash equivalents consist of cash in banks and investments readily convertible into cash which have original maturities within three months at the date of acquisition. Cash equivalents are stated at cost, which approximates market value.

Inventories

Inventories, primarily materials and supplies, are valued at the lower of cost or market.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of oil and gas properties as well as other internal costs that can be directly identified with acquisition, exploration and development activities are also capitalized. Capitalized costs including estimated future development and abandonment costs are amortized using the unit-of-production method.

In accordance with the full cost accounting rules, capitalized costs of proved oil and gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related tax effects (the full cost ceiling limitation). If capitalized costs exceed this limit, the excess must be charged to expense. The expense may not be reversed in future periods, even if higher oil and gas prices subsequently increase the full cost ceiling limitation. The Company recorded a reduction in the carrying value of oil and gas properties of $78.1 million during the year ended September 30, 2001.

The costs of certain unevaluated properties are not being amortized. On a quarterly basis, such costs are evaluated for transfer to the full cost pool resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Abandonments of unproved properties are accounted for as adjustments of capitalized costs to the proved oil and gas properties with no losses recognized.

Expenditures for maintenance and repairs are charged to production expense in the period incurred. Proceeds from the sale of oil and gas properties are credited against capitalized costs, unless such proceeds would significantly alter the amortization base.

Goodwill

Cimarex recorded goodwill in the purchase of Key on September 30, 2002. Statement of Financial Accounting Standard (SFAS) No. 142, *Goodwill and Other Intangible Assets,* states that goodwill and other intangibles determined to have an infinite life are no longer amortized. However, these assets are reviewed for impairment once a year and when circumstances indicate that an impairment may have occurred. The evaluation of the estimated fair value of the goodwill is performed on individual reporting units. The exploration and production segment is considered the only reporting unit to which goodwill has been assigned.

Cimarex uses the estimated fair value approach to value its goodwill. This approach involves evaluating the estimated fair value of the reporting unit, compared to its carrying amount, including goodwill. The estimated fair value of the exploration and production segment of our business is based on numerous factors, each individually weighted, to estimate total reporting unit estimated fair value. If the estimated fair value of the reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. If the carrying amount of a reporting unit exceeds its estimated fair value, then a measurement of any impairment loss must be performed. Measuring any indicated impairment is done by comparing the implied fair value of the reporting unit goodwill with the carrying amount of that goodwill. Any deficiency of the implied goodwill amount compared to the carrying value of goodwill is recorded as an impairment up to the carrying amount. As no deferred taxes have been established for goodwill, any impairment would not be subject to a deferred tax benefit in the income tax provision. Subsequent reversal of a previous goodwill impairment loss is prohibited.

Revenue Recognition

Cimarex recognizes revenues from oil and gas sales based on actual volumes of oil and gas sold to purchasers.

Gas Imbalances

We use the sales method of accounting for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold. Oil and gas reserves are adjusted to the extent there are sufficient quantities of natural gas to make up an imbalance. As of December 31, 2003 and 2002, Cimarex had reduced reserves by 465 MMcf and 420 MMcf, respectively. In situations where there are insufficient reserves available to make-up an overproduced imbalance, then a liability is established. The natural gas imbalance liability at December 31, 2003 and 2002 was $1.4 million and $0.9 million, respectively.

Transportation Costs

Cimarex accounts for transportation costs under Emerging Issues Task Force (EITF) 00-10 *Accounting for Shipping and Handling Fees and Costs,* whereby amounts paid for transportation are classified as an operating expense and not netted against gas sales.

Income Taxes

Deferred income taxes are computed using the liability method. Deferred income taxes are provided on all temporary differences between the financial basis and the tax basis of assets and liabilities. Valuation allowances are established to reduce deferred tax assets to an amount that more likely than not will be realized.

Prior to the spin off of Cimarex from H&P on September 30, 2002, Cimarex s operating results historically had been included in consolidated federal and state income tax returns filed by H&P. A tax sharing agreement exists between Cimarex and H&P to allocate and settle among themselves the

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consolidated tax liability on a shared company basis through September 30, 2002. The allocation was finalized and settled in 2003 with a non-cash distribution to H&P of $0.1 million.

Stock Options

We apply Accounting Principles Board (APB) Opinion 25, *Accounting for Stock Issued to Employees*, and related interpretations to account for all stock option grants and grants of restricted stock. No compensation cost has been recognized for stock options granted as the option prices were the same as the market price of the underlying common stock on the date of grant.

SFAS No. 123, *Accounting for Stock Based Compensation*, as amended by SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*, requires us to provide pro forma information regarding net income as if the compensation cost for our stock option plans had been determined in accordance with the fair value based method prescribed in SFAS No. 123. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. To provide the required pro forma information, we estimate the theoretical fair value of each stock option at the grant date by using the Black-Scholes option-pricing model.

Had compensation cost for the plan been determined based on the fair value at the grant dates for awards to employees under the plan, consistent with the methodology of SFAS No. 123, pro forma net income would have been as indicated below for calendar 2003 and 2002. For periods prior to the spin off and the issuance of stock options in exchange for H&P options held by employees, pro forma compensation expense was based on the estimated fair value of the H&P options (in thousands except per share amounts).

	Years Ended December 31, 2003	Years Ended December 31, 2002	September 30, 2001	Three Months Ended December 31, 2001

Net income, as reported	$	94,633	$	39,819	$	35,253	$	4,479
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects		2,352		1,328		1,270		318
Pro forma net income	$	92,281	$	38,491	$	33,983	$	4,161
Earnings per share:								
Basic as reported	$	2.28	$	1.32	$	1.33	$	0.17
Basic pro forma	$	2.22	$	1.27	$	1.28	$	0.16
Diluted as reported	$	2.22	$	1.31	$	1.33	$	0.17
Diluted pro forma	$	2.16	$	1.27	$	1.28	$	0.16

As required by SFAS No. 123 and amended by SFAS No. 148, the above pro forma data reflects the effect of stock option grants to employees of Cimarex beginning with H&P options issued in 1997. These pro forma amounts may not be representative of future disclosures since the estimated fair value of stock options is amortized to expense over the vesting period and additional options may be granted in future years.

The weighted-average fair values of the Cimarex and H&P stock options granted to employees of Cimarex (adjusted for the spin off conversion ratio) at their grant date during calendar 2003 and 2002, and fiscal 2001 were $7.64, $8.16 and $6.56, respectively, and was $6.21 for grants made in the quarter ended December 31, 2001. The estimated theoretical fair value of each option granted is calculated using the Black-Scholes option-pricing model. The following summarizes the weighted-average assumptions used in the model:

	Years Ended	Three Months Ended December 31, 2001

December 31,	September 30, 2001

2003	2002

Expected years until exercise	7.5	7.5	4.5	4.5
Expected stock volatility	26.7%	38.9%	43.1%	47.7%
Dividend yield	0.0%	0.0%	0.0%	0.0%
Risk-free interest rate	3.2%	3.8%	5.2%	4.0%

Earnings per Share

Basic earnings per share includes no dilution and is computed by dividing net income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects the impact of potentially dilutive securities on weighted average number of shares.

Fair Value of Financial Instruments

The carrying amounts of our cash, accounts receivable, accounts payable and accrued liabilities approximate fair value because of the short-term maturities of these assets and liabilities. At December 31, 2003, the allowance for doubtful accounts for trade, oil and gas sales, and marketing receivables was $0.2 million, $0.4 million and $0.7 million, respectively. At December 31, 2002, the allowance for doubtful trade accounts was $0.3 million and the allowance for marketing receivables was $0.7 million.

Comprehensive Income

Cimarex applies the provisions of SFAS No. 130, *Reporting Comprehensive Income*. Cimarex had no comprehensive income for the periods presented.

4. ACQUISITION OF KEY PRODUCTION COMPANY, INC.

On September 30, 2002, Cimarex acquired 100 percent of the outstanding common stock of Key in a tax-free exchange pursuant to which Key became a wholly owned subsidiary of Cimarex. The acquisition of Key was accounted for using the purchase method of accounting.

Our consolidated balance sheets include the assets and liabilities of Key as well as the adjustments required to record the acquisition in accordance with the purchase method of accounting. The final purchase price and the final allocation of the purchase price were finalized at September 30, 2003 based on the actual fair value of current assets and liabilities, and long-term liabilities. The results of operations of Key are included in our consolidated statements of operations for the period since the acquisition on September 30, 2002.

The following unaudited pro forma financial information presents the combined results of Cimarex and Key, and was prepared as if the acquisition had occurred at the beginning of the periods presented. The unaudited pro forma data presented is based on numerous assumptions and is not necessarily indicative of actual results of operations, had the companies been operating as one. The unaudited pro forma results of operations for the year ended September 30, 2001 includes Key s results of operations for the year ended December 31, 2001. Included in the pro forma results for the year ended December 31, 2002 is $11.0 million of merger related and severance expenses incurred by Key.

	Years Ended		Three Months Ended
	December 31, 2002	September 30, 2001	December 31, 2001
	(In thousands, except per share amounts)		
Total revenues	$ 267,935	$ 425,663	$ 57,493
Net income (loss)	34,474	(6,595)	3,395
Diluted earnings (loss) per share	0.84	(0.16)	0.08

5. ASSET RETIREMENT OBLIGATIONS

On January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* This Statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability upon acquiring or drilling a well.

The adoption of the Statement resulted in recording an increase to the full cost pool of approximately $10.4 million, a decrease to accumulated depreciation, depletion and amortization of approximately $5.9 million, an increase to long-term liabilities for plugging and abandonment costs of approximately $13.8 million, an increase to the deferred tax liability of approximately $0.9 million and income reported as a cumulative effect of a change in accounting principle of approximately $1.6 million, net of income taxes of $1.0 million. On a pro forma basis, the asset retirement obligation would have been approximately $12.6 million as of January 1, 2002.

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The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the year ended December 31, 2003 (in thousands):

Initial adoption amount as of January 1, 2003	$	13,784
Liabilities incurred in the current period		1,929
Liabilities settled in the current period		(259)
Accretion expense		1,009
Balance as of December 31, 2003	$	16,463

6. LONG-TERM DEBT

At December 31, 2003, we had no debt outstanding. We have the capability to borrow on our $400 million Senior Secured Revolving Credit Facility led by Bank One, N.A. This facility presently has a borrowing base of $275 million and we have commitments from our lenders totaling $200 million. The borrowing base is subject to redetermination each April and October.

Borrowings under this facility bear interest at a LIBOR rate plus 1.25 to 2.00 percent, based on borrowing base usage. Unused borrowings are subject to a commitment fee of 0.375 to 0.50 percent, also depending on the borrowing base usage.

The credit facility is secured by mortgages on certain of our oil and gas properties and the stock of our operating subsidiaries. We are also subject to customary financial and non-financial covenants and are in compliance with those covenants. The term of the credit facility expires in October 2005.

7. INCOME TAXES

Federal income tax expense for the years ended December 31, 2003 and 2002, September 30, 2001 and the three months ended December 31, 2001 differ from the amounts that would be provided by applying the U.S. Federal income tax rate, due to the effect of state income taxes, percentage depletion and deductible merger costs.

Key s final tax basis has been determined resulting in an increase of $3.9 million from the original estimate made at the time of the merger with Cimarex. The increase was accounted for at the statutory tax rate of 38 percent and resulted in an adjustment to reduce goodwill by $1.5 million.

The components of the provision for income taxes are as follows (in thousands):

	Years Ended December 31, 2003	Years Ended December 31, 2002	September 30, 2001	Three Months Ended December 31, 2001
Current taxes:				
Federal	$ 21,136	$	$ 27,219	$ 103
State	3,415	132	3,504	(134)
	24,551	132	30,723	(31)
Deferred taxes	30,590	21,428	(11,138)	2,805
	$ 55,141	$ 21,560	$ 19,585	$ 2,774

Reconciliations of the income tax expense at the federal statutory rate to the total income tax expense are as follows (in thousands):

	Years Ended December 31, 2003	Years Ended December 31, 2002	September 30, 2001	Three Months Ended December 31, 2001
Provision at statutory rate	$ 51,859	$ 21,482	$ 19,193	$ 2,539
Effect of state taxes	3,254	1,841	1,024	218
Non-conventional fuel source credits utilized		(313)	(367)	(92)
Excess statutory depletion		(271)	(323)	(81)
Deductible merger related costs		(1,178)		
Other	28	(1)	58	190
Income tax expense	$ 55,141	$ 21,560	$ 19,585	$ 2,774

The components of Cimarex s net deferred tax liabilities are as follows (in thousands):

December 31,

	2003	2002

Long-term:				
Assets -				
Net operating loss carryforwards	$	3,921	$	323
Credit carryforwards		1,207		3,256
Long-term assets and liabilities		4,374		1,756
		9,502		5,335
Liabilities:				
Property, plant and equipment		(164,795)		(132,358)
Net, long-term deferred tax liability		(155,293)		(127,023)
Current:				
Net current deferred tax assets		1,631		2,073
Net deferred tax liabilities	$	(153,662)	$	(124,950)

A net tax operating loss carryforward of approximately $10.3 million exists at December 31, 2003, which expires in the years 2010 through 2022. These net operating losses (NOLs) were acquired as part of an acquisition, and therefore, are subject to annual limitations. We believe all NOLs will be utilized before they expire. An alternative minimum tax credit carryfoward of approximately $1.2 million exists at December 31, 2003.

We have recorded a deferred tax asset of $11.1 million of which $3.9 million is attributable to the NOL carryforward. Realization is dependent on generating sufficient taxable income in the future. Although realization is not assured, we believe it is more likely than not all of the deferred tax asset will be realized.

8. STOCK PLANS

Stock Options

Cimarex s 2002 Stock Incentive Plan reserves seven million shares of common stock for issuance to directors and employees, including officers. Options granted under the plan after December 5, 2002, expire ten years from the grant date and vest in one-fifth increments on each of the first five anniversaries of the grant date. All grants are made at the closing price of our common stock as reported on the New York Stock Exchange on the date of grant. Upon the exercise of the options for shares of common stock, the employee is required to hold at least 50 percent of the profit shares, as defined in the plan, until the eighth anniversary of the grant date.

At the date of distribution on September 30, 2002, H&P stock options held by former H&P employees who became Cimarex employees were converted into Cimarex stock options exercisable for 1,630,269 shares of Cimarex common stock based on the intrinsic value at the date of the distribution. The weighted average exercise price for the new options was $13.24 per share. The tables below show the former H&P stock option activity through September 30, 2002, at which time these options were converted to Cimarex stock options. No accounting charge resulted from this exchange because the economic interest of option holders before and after the spin off was unchanged and the spin off from H&P was for a fixed number of shares of Cimarex common stock. No activity associated with option exercises prior to September 30, 2002, is shown in the statements of stockholders equity.

On September 30, 2002, stock options for 785,501 shares of Key common stock held by former employees of Key were converted to Cimarex stock options on a one-for-one basis. These options vested upon closing of the merger. The weighted average exercise price for these options was $11.06 per share.

The following summary reflects the status of stock options granted to employees and directors as of December 31, 2003, and changes during the year:

	Options Outstanding		Weighted Average Exercise Price	Options Exercisable
H&P Activity:				
Outstanding as of September 30, 2000	643,778	$	23.81	
Granted	216,000		32.31	
Exercised	(190,830)		22.76	
Forfeited/Expired	(6,250)		27.11	
Outstanding as of September 30, 2001	662,698		26.82	160,064
Granted	205,000		29.78	
Exercised	(4,050)		16.15	
Forfeited/Expired	(5,250)		27.94	
Outstanding as of December 31, 2001	858,398		27.56	355,897
Exercised	(68,073)		20.70	
Forfeited/Expired	(23,500)		29.48	
Outstanding on September 30, 2002, pre spin off	766,825		28.15	
Cimarex Activity:				
Incremental options issued for conversion to Cimarex stock options	863,444			
Outstanding on September 30, 2002, post spin off	1,630,269		13.24	
Acquired in Key acquisition	785,501		11.06	
Granted	1,290,800		16.69	
Exercised	(71,294)		5.65	
Forfeited/Expired	(3,189)		14.01	
Outstanding as of December 31, 2002	3,632,087		14.14	1,720,486
Granted	24,000		20.36	
Exercised	(294,921)		11.59	
Forfeited/Expired	(39,867)		16.02	
Outstanding as of December 31, 2003	3,321,299	$	14.39	1,992,360

The following table summarizes information about Cimarex stock options held by employees and directors at December 31, 2003:

	Outstanding Stock Options			Exercisable Stock Options	
Range of Exercise Prices	Options	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
$6.11 to $8.14	182,298	4.7 Years	$ 7.81	182,298	$ 7.81
$8.15 to $10.17	177,500	5.7 Years	9.69	177,500	9.69
$10.18 to $12.21	534,472	4.4 Years	11.52	534,472	11.52
$12.22 to $14.25	579,585	6.9 Years	13.61	379,741	13.40
$14.26 to $16.28	352,923	6.9 Years	15.20	248,745	15.20
$16.29 to $18.32	1,425,521	8.4 Years	16.77	424,604	16.96
$18.33 to $20.36	69,000	8.1 Years	19.32	45,000	18.77

Restricted Stock and Units

We have a long-term incentive program whereby grants of restricted stock and/or units are awarded to certain employees. The restrictions related to these awards are associated with the continued employment of the grantee for one to five years from the date of the original grant, at which time these shares will vest and there is a three year required holding period subsequent to vesting. The restricted stock and stock unit agreements provide that the grantees will be entitled to receive dividends. We do not currently intend to pay dividends on our common stock.

Cimarex awarded 65,000 restricted shares during 2003. On December 1, 2003, certain employees elected to exchange their restricted stock for restricted stock units (Units), in accordance with the provisions of the Stock Incentive Plan. As such, 688,600 restricted shares were cancelled and a like number of Units were issued. The Units issued have been recorded as long-term deferred compensation in an amount equal to the original value attributed to the restricted shares exchanged, with a corresponding adjustment to common stock and paid-in capital. Upon vesting, the Units are exchanged for a like number of shares of common stock and are issued to the employee.

There were 29,087 shares of restricted stock and 688,600 restricted stock units outstanding as of December 31, 2003. There were 674,973 shares of restricted stock outstanding as of December 31, 2002.

Compensation expense for restricted shares or units is based upon the market price of the restricted stock multiplied by the number of shares of restricted stock granted. Compensation cost is being recognized over the associated vesting period. For the year ended December 31, 2003 and 2002, we recorded compensation expense of $1.8 million, net of $0.6 million capitalized to oil and gas properties, and $0.2 million, respectively.

Stockholder Rights Plan

Cimarex has a stockholder rights plan. The plan is designed to improve the ability of our board to protect the interests of our stockholders in the event of an unsolicited takeover attempt.

For every outstanding share of Cimarex common stock, there exists one purchase right (the Right). Each Right represents a right to purchase one one-hundredth of a share of Series A Junior Participating Preferred Stock of the Company. The Rights will become exercisable only in the event a person or group acquires beneficial ownership of 15 percent or more of our common stock, or a person or group commences a tender offer or exchange offer that, if successfully consummated, would result in such person or group beneficially owning 15 percent or more of our common stock. The purchase price for each one one-hundredth of a share of Preferred Stock pursuant to the exercise of a Right is $60.00, subject to adjustment in certain cases to prevent dilution.

Cimarex generally will be entitled to redeem the Rights under certain circumstances at $0.01 per Right at any time prior to the close of business on the tenth business day after there has been a public announcement of the acquisition of the beneficial ownership by any person or group of 15 percent or more of our common stock. The Rights may not be exercised until our board s right to redeem the stock has expired. Unless redeemed earlier, the Rights expire on February 23, 2012.

9. EARNINGS PER SHARE

The calculations of basic and diluted net earnings per common share for the years ended December 31, 2003 and 2002, and September 30, 2001 and the three months ended December 31, 2001 are presented in the table below (in thousands, except per share data):

	Years Ended			Three Months Ended
	December 31,		September 30,	December 31,
	2003	**2002**	2001	2001

Basic earnings per share:								
Income available to common stockholders	$	94,633	$	39,819	$	35,253	$	4,479
Weighted average basic share outstanding		41,521		30,239		26,591		26,591
Basic earnings per share	$	2.28	$	1.32	$	1.33	$	0.17
Diluted earnings per share:								
Income available to common stockholders	$	94,633	$	39,819	$	35,253	$	4,479
Weighted average basic shares outstanding		41,521		30,239		26,591		26,591
Incremental shares assuming the exercise of stock options and vesting of restricted stock units		1,119		78				
Weighted average diluted shares outstanding		42,640		30,317		26,591		26,591
Diluted earnings per share	$	2.22	$	1.31	$	1.33	$	0.17

There were stock options outstanding for 3,321,299 and 3,632,087 shares of Cimarex common stock at December 31, 2003 and 2002, respectively. The weighted average common shares for the diluted earnings per share calculation for the year ended December 31, 2002 excludes the incremental effect related to outstanding stock options exercisable for 1,516,401 shares of Cimarex common stock whose exercise price was in excess of the average price of Cimarex s stock of $15.66 for the period the options were outstanding in 2002 and therefore were antidilutive.

10. EMPLOYEE BENEFIT PLANS

Cimarex maintains and sponsors contributory health care plans and a contributory 401(k) plan. Cimarex employees participate in these plans and costs related to these plans were $3.8 million and $1.9 million, $1.1 million, and $0.3 million in the years ended December 31, 2003 and 2002, and September 30, 2001 and the three months ended December 31, 2001, respectively.

11. RELATED PARTY TRANSACTIONS

H&P provides contract drilling services to Cimarex through its wholly owned subsidiary, Helmerich & Payne International Drilling Company. Drilling costs of approximately $4.6 million and $1.4 million were incurred by Cimarex related to such services for the years ended December 31, 2003 and 2002, respectively. During the fiscal year ended September 30, 2001 and the three months ended December 31, 2001, related drilling costs were $4.5 million and $0.3 million, respectively. Cimarex also reimbursed H&P an additional $0.6 million related to costs incurred by H&P on behalf of Cimarex for the Cimarex stand-alone Oklahoma tax return for the year ended September 30, 2002 and other miscellaneous payments. Hans Helmerich, a director of Cimarex, is President and Chief Executive Officer of H&P.

Additionally, in the years ended December 31, 2003 and 2002 and the three months ended December 31, 2001, non-cash distributions of $0.1 million, $2.9 million and $1.0 million, respectively, were made to H&P pursuant to the tax sharing agreement.

12. MAJOR CUSTOMERS

During 2003, we sold oil and gas production representing 10.3 percent of revenues to OGE Energy Resources, Inc. For the years ended December 31, 2002 and September 30, 2001 and the three months ended December 31, 2001, no purchasers represented more than 10 percent of our revenues. Alternative purchasers are readily available; therefore, we believe the loss of OGE Energy as a purchaser would not have a material adverse effect on our revenues.

Most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. This concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry.

13. SEGMENT INFORMATION

Cimarex operates in the oil and gas industry, and is comprised of an exploration and production segment and a natural gas marketing segment. Exploration and production activities are located primarily in Oklahoma, Kansas, Texas, Louisiana and Wyoming. Information presented for our natural gas marketing segment represents business conducted with third parties, usually incidental to sales of our own production.

Summarized financial information of Cimarex s reportable segments for the years ended December 31, 2003 and 2002, and September 30, 2001 and the three months ended December 31, 2001 is shown in the following table (in thousands):

	External Sales	Operating Profit Before Income Taxes	DD&A and Reduction in Carrying Value of Oil and Gas Properties	Total Assets	Additions to Long-Lived Assets
Year Ended December 31, 2003:					
Exploration and Production	$ 324,119	$ 148,474	$ 88,560	$ 773,041	$ 169,844
Natural Gas Marketing	130,156	407	214	32,467	241
Total	$ 454,275	$ 148,881	$ 88,774	$ 805,508	$ 170,085
Year Ended December 31, 2002:					
Exploration and Production	$ 157,299	$ 59,922	$ 49,040	$ 650,243	$ 419,026
Natural Gas Marketing	52,350	1,633	191	24,043	409
Total	$ 209,649	$ 61,555	$ 49,231	$ 674,286	$ 419,435
Year Ended September 30, 2001:					
Exploration and Production	$ 222,901	$ 51,638	$ 127,611	$ 231,606	$ 101,319
Natural Gas Marketing	93,877	5,254	170	14,606	269
Total	$ 316,778	$ 56,892	$ 127,781	$ 246,212	$ 101,588
Three Months Ended December 31, 2001:					
Exploration and Production	$ 26,941	$ 6,694	$ 8,927	$ 239,882	$ 14,834
Natural Gas Marketing	12,655	459	45	12,084	178
Total	$ 39,596	$ 7,153	$ 8,972	$ 251,966	$ 15,012

The following table reconciles segment operating profit per the above table to income before taxes as reported on the consolidated statements of operations (in thousands).

	Years Ended December 31, 2003	Years Ended December 31, 2002	September 30, 2001	Three Months Ended December 31, 2001
Segment operating profit including depreciation, depletion and amortization	$ 148,881	$ 61,555	$ 56,892	$ 7,153
Unallocated amounts:				
Other revenue (loss)	(63)	(5)		198
General and administrative expense allocated from H&P			(3,839)	
Interest expense, net	(649)	(171)	1,785	(98)
	$ 148,169	$ 61,379	$ 54,838	$ 7,253

14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION (in thousands)

For the Years Ended	Three Months Ended December 31, 2001

December 31,	September 30, 2001

2003	2002

Cash paid during the period for:								
Interest (net of amounts capitalized)	$	830	$	69	$	3,358	$	55
Income taxes (net of refunds received)	$	21,382	$	14	$	30,670	$	

In connection with the acquisition of Key in 2002 for $237.3 million, we acquired assets with a fair value of $367.5 million and assumed liabilities of $130.2 million. This acquisition was a non-cash transaction except for the cash and cash equivalents of $2.1 million received from Key as more fully described in Note 4.

15. COMMITMENTS AND CONTINGENCIES

Litigation

Cimarex is a defendant to certain claims relating to drainage of gas from two properties that it operates. The royalty owner plaintiffs have filed suit on behalf of themselves and a class of similarly situated royalty owners in two 640-acre-spacing units. The plaintiffs allege that the two units have suffered approximately 20 Bcf of gross gas drainage. Cimarex denies that the drainage, if any, was in an amount that significant. The plaintiffs have stated that the royalty owner class has sustained actual damages of approximately $20 million exclusive of interest and costs. We estimate that the share of such alleged damages attributable to its working interest ownership would total approximately $3.0 million exclusive of interests and costs. Plaintiffs further allege that, as a former operator, Cimarex is liable for all damages attributable to the drainage. We believe that our liability, if any, should not exceed our working interest share of any actual damages attributable to the alleged drainage. We have received confirmation from the court that any claim against Cimarex will be limited to our proportionate interest in the two properties. We cannot predict the outcome of this litigation, and accordingly, no accrual has been recorded in connection with this action.

Cimarex has other various litigation matters in the normal course of business, none of which are material, individually or in aggregate. We are also party to certain litigation items as plaintiffs that could result in potential gains of between $2.5 million to $3.0 million, net to our interest.

Leases

Cimarex has noncancelable operating leases for office and parking space in Denver and Tulsa and for small district and field offices. Rental expense for the operating leases totaled $2.1 million and $0.6 million for the years ended December 31, 2003 and 2002, respectively, and $0.3 million for the year ended September 30, 2001 and $0.1 million for the three months ended December 31, 2001.

The following table summarizes the future minimum lease payments under all noncancelable operating lease obligations.

Year Ending December 31,	**Future Minimum Lease Payments**

	(In thousands)
2004	$ 1,715
2005	1,826
2006	2,072
2007	2,106
2008	2,130
2009 and thereafter	8,323
	$ 18,172

Transportation and Gas Deliveries

We have one firm transportation contract to transport 10,000 MMBtus per day, at $0.09 per MMBtu through December 31, 2004. We have a right to extend this contract annually. The maximum amount that would be payable, if deliveries are not made, would be $0.3 million.

Additionally, we have guaranteed to deliver 2.3 Bcf of natural gas from five wells over a three-year period as reimbursement for connection costs to the pipeline. If the minimum delivery is not met, our maximum exposure is less than $0.2 million. We have also agreed to reimburse another gatherer for connection costs to its pipeline via delivery of 1 Bcf of natural gas per well or a prorated payment based on the total reserves on 17 wells. The maximum amount that would be payable, if no gas is delivered, would be $0.6 million.

We also have firm sales contracts to deliver fixed volumes of gas based on an index price. These contracts vary in length from two months to one year. As of December 31, 2003, we had an obligation to deliver approximately 3.8 Bcf of natural gas. If this gas is not delivered, our financial commitment would be approximately $20.7 million based on index prices as of February 1, 2004. This commitment will fluctuate due to price volatility and actual volumes delivered. We believe no financial commitment will be due based on our reserves and current production levels.

Tax Sharing Agreement

On September 30, 2002, Cimarex entered into an agreement with H&P that imposes certain restrictions on Cimarex s ability to redeem or issue a material number of shares of its common stock or to undergo a change of control. These restrictions expire on October 1, 2004. Such actions by Cimarex could cause the spin off of Cimarex by H&P to be deemed a taxable event, potentially resulting in a substantial amount of taxable income to H&P. Under the terms of the agreement, if Cimarex takes or permits an action to be taken that causes the spin off to be taxable, Cimarex would generally be liable for all or a portion of the resultant tax liability. It is expected that any such taxes allocated to Cimarex would be material.

Cimarex has also provided indemnification of H&P in connection with any future tax claims that may be made relating to the oil and gas exploration and production assets contributed to Cimarex by H&P.

Other

The Company has contractual commitments on oil and gas wells approved for drilling or in the process of being drilled at December 31, 2003 of approximately $23.7 million.

Parental Guarantees

Cimarex has approximately $9.8 million of parental guarantees outstanding. These guarantee the credit of various CESI agreements and are for the benefit of counterparties from which CESI purchases gas.

16. SUPPLEMENTAL OIL AND GAS DISCLOSURES

Oil and Gas Operations The following tables contain direct revenue and cost information relating to our oil and gas exploration and production activities for the periods indicated. We have no long-term supply or purchase agreements with governments or authorities in which we act as producer. Income taxes related to our oil and gas operations are computed using the statutory tax rate for the period.

	Years Ended December 31, 2003	Years Ended December 31, 2002	September 30, 2001	Three Months Ended December 31, 2001
	(In thousands, except per Mcfe data)			
Oil and gas revenues from production	$ 324,119	$ 157,299	$ 223,026	$ 26,857
Less operating costs and income taxes:				
Depletion	86,390	48,272	48,931	8,792
Asset retirement obligation accretion	1,009			
Reduction to carrying value of oil and gas properties			78,082	
Production	31,801	19,427	13,091	4,197
Transportation	7,472	7,918	6,359	1,886
Taxes other than income	27,485	13,154	18,965	2,559
Income taxes	63,226	25,356	20,574	3,357
	217,383	114,127	186,002	20,791
Results of operations from oil and gas producing activities	$ 106,736	$ 43,172	$ 37,024	$ 6,066
Amortization rate per Mcfe	$ 1.32	$ 1.00	$ 1.03	$ 0.77

Costs Incurred The following table sets forth the capitalized costs incurred in our oil and gas production, exploration, and development activities (in thousands).

	Year Ended December 31, 2003	Year Ended December 31, 2002	September 30, 2001	Three Months Ended December 31, 2001
Costs incurred during the year:				
Acquisition of properties				
Proved	$ 2,032	$ 286,041	$ 738	$
Unproved	9,330	16,008	18,612	850
Exploration	50,350	29,181	44,166	7,296
Development	100,915	37,273	41,459	6,279
Oil and gas expenditures	162,627	368,503	104,975	14,425
Property sales	(694)	(151)	(977)	
Asset retirement obligation (Adoption)	10,428			
Asset retirement obligation (Additions)	1,675			
	$ 174,036	$ 368,352	$ 103,998	$ 14,425

Costs Not Being Amortized The following table summarizes oil and gas property costs not being amortized at December 31, 2003, by year that the costs were incurred (in thousands):

2003	$ 29,743
2002	4,838

2001		3,393
2000 and prior		1,396
	$	39,370

We expect the majority of these costs to be evaluated, and to become subject to amortization within the next five years.

Oil and Gas Reserve Information (Unaudited) Proved oil and gas reserve quantities are based on estimates prepared by Cimarex in accordance with guidelines established by the Securities and Exchange Commission (SEC). Ryder Scott Company, L.P., independent petroleum engineers, has reviewed the proved reserve estimates associated with approximately 80 percent of the discounted future net cash flows before income taxes for the years ended December 31, 2003 and 2002. Netherland, Sewell & Associates, Inc., independent petroleum engineers, prepared the proved reserve estimates as of September 30, 2001. The estimates of proved reserves as of December 31, 2001 were prepared by H&P.

Proved reserves are estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those that are expected to be recovered through existing wells with existing equipment and operating methods. There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and the timing of development expenditures. The following reserve data at December 31, 2003, 2002 and 2001 and at September 30, 2001 represents estimates only and should not be construed as being exact. All of our reserves are located in the continental United States or the Gulf of Mexico.

	December 31, 2003		**December 31, 2002**		**December 31, 2001**		**September 30, 2001**	
	Gas (MMcf)	**Oil (MBbl)**	**Gas (MMcf)**	**Oil (MBbl)**	**Gas (MMcf)**	**Oil (MBbl)**	**Gas (MMcf)**	**Oil (MBbl)**
Total proved reserves - Developed and undeveloped								
Beginning of year	318,627	15,025	212,326	5,304	216,337	5,932	262,498	6,305
Revisions of previous estimates	6,699	41	31,153	1,094	1,260	(432)	(17,018)	(700)
Extensions and discoveries	61,545	1,625	21,064	643	4,903	10	12,748	1,145
Purchases of reserves	1,320	43	95,388	9,155			496	
Production	(50,552)	(2,504)	(41,300)	(1,171)	(10,174)	(206)	(42,387)	(818)
Sales of properties	(295)	(93)	(4)					
End of year	337,344	14,137	318,627	15,025	212,326	5,304	216,337	5,932
Proved developed reserves	336,230	13,876	318,452	14,765	211,874	4,607	213,931	5,213

Standardized Measure of Future Net Cash Flows (Unaudited) The Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Standardized Measure) is a disclosure requirement under FASB Statement No. 69, *Disclosures About Oil and Gas Producing Activities*. The Standardized Measure does not purport, nor should it be interpreted, to present the fair value of a company s proved oil and gas reserves. Fair value would require, among other things, consideration of expected future economic and operating conditions, a discount factor more representative of the time value of money, and risks inherent in reserve estimates.

Under the Standardized Measure, future cash inflows are estimated by applying year-end prices to the forecast of future production of year-end proved reserves. Future cash inflows are then reduced by estimated future production and development costs to determine net pre-tax cash flow. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash flow over our tax

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basis in the associated oil and gas properties. Tax credits and permanent differences are also considered in the future income tax calculation. Future net cash flow after income taxes is discounted using a 10 percent annual discount rate to arrive at the Standardized Measure.

The following summary sets forth the Company s Standardized Measure (in thousands):

	December 31, 2003	December 31, 2002	December 31, 2001	September 30, 2001
Cash inflows	$ 2,258,337	$ 1,742,435	$ 560,439	$ 467,886
Production costs	(562,124)	(511,168)	(189,216)	(167,914)
Development costs	(16,014)	(6,909)	(3,961)	(6,789)
Income tax expense	(554,746)	(361,423)	(89,562)	(81,253)
Net cash flow	1,125,453	862,935	277,700	211,930
10% annual discount rate	(413,872)	(329,076)	(95,135)	(67,891)
Standardized measure of discounted future net cash flow	$ 711,581	$ 533,859	$ 182,565	$ 144,039
Discounted future net cash flow before income taxes	$ 1,030,340	$ 741,209	$ 241,150	$ 191,240

The following are the principal sources of change in the Standardized Measure (in thousands):

	December 31, 2003	December 31, 2002	December 31, 2001	September 30, 2001
Standardized measure, beginning of period	$ 533,859	$ 182,565	$ 144,039	$ 488,071
Sales, net of production costs	(257,362)	(116,801)	(18,215)	(179,776)
Net change in sales prices, net of production costs	202,135	200,935	52,126	(400,679)
Extensions, discoveries, and improved recovery, net of future production and development costs	266,128	62,648	9,669	29,387
Net change in future development costs	2,120	4,039	3,691	27,978
Revision of quantity estimates	16,038	70,532	(1,305)	(15,298)
Accretion of discount	74,121	24,115	19,124	68,021
Change in income taxes	(111,409)	(148,765)	(11,385)	160,776
Purchases of reserves in place	4,174	297,394		619
Sales of properties	(837)	(1)		
Settlement of asset retirement obligation	(259)			
Change in production rates and other	(17,127)	(42,802)	(15,179)	(35,060)
Standardized measure end of period	$ 711,581	$ 533,859	$ 182,565	$ 144,039

Impact of Pricing (Unaudited) The estimates of cash flows and reserve quantities shown above are based on year-end oil and gas prices, except in those cases where future gas sales are covered by contracts at specified prices. Fluctuations are largely due to the seasonal pricing nature of natural gas, supply perceptions for natural gas and significant worldwide volatility in oil prices.

The following average prices were used in determining the Standardized Measure as of:

	December 31, 2003	December 31, 2002	December 31, 2001	September 30, 2001
Price per Mcf	$ 5.54	$ 4.22	$ 2.23	$ 1.90
Price per Bbl	$ 30.49	$ 28.56	$ 18.10	$ 20.25

Under SEC rules, companies that follow full cost accounting methods are required to make quarterly ceiling test calculations. Under this test, capitalized costs of oil and gas properties, net of accumulated DD&A, and deferred income taxes, may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, as adjusted for related tax effects. We calculate the projected income tax effect using the year-by-year method for purposes of the supplemental oil and gas disclosures and use the short-cut method for the ceiling test calculation. Application of these rules during periods of relatively low oil and gas prices, even if of short-term duration, may result in write-downs.

17. UNAUDITED SUPPLEMENTAL QUARTERLY FINANCIAL DATA

	First		Second		Third		Fourth	
	(In thousands, except for per share data)							
2003								
Revenues	$	136,559	$	99,270	$	112,762	$	105,621
Expenses, net		105,416		78,230		90,221		87,317
Income before cumulative effect of change in accounting principle		31,143		21,040		22,541		18,304
Cumulative effect of change in accounting principle, net		1,605						
Net income	$	32,748	$	21,040	$	22,541	$	18,304
Earnings per common share:								
Basic:								
Income before cumulative effect of change in accounting principle	$	0.75	$	0.51	$	0.54	$	0.44
Cumulative effect of change in accounting principle, net		0.04						
Net income	$	0.79	$	0.51	$	0.54	$	0.44
Diluted:								
Income before cumulative effect of change in accounting principle	$	0.74	$	0.50	$	0.53	$	0.43
Cumulative effect of change in accounting principle, net		0.04						
Net income	$	0.78	$	0.50	$	0.53	$	0.43

	First		Second		Third		Fourth	
	(In thousands, except for per share data)							
2002								
Revenues	$	34,575	$	46,134	$	51,809	$	77,126
Expenses, net		**30,317**		**36,290**		**41,879**		**61,339**

Net income	**$**	**4,258**	**9,844**	**9,930**	**15,787**

Earnings per common share:

Basic	$ 0.16	$ 0.37	$ 0.37	$ 0.39
Diluted	$ 0.16	$ 0.37	$ 0.37	$ 0.38

The sum of the individual quarterly net income per common share amounts may not agree with year-to-date net income per common share because each period s computation is based on the weighted average number of shares outstanding during that period.

ITEM 9. CHANGES IN AND DISAGREEMENT WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, with the participation of management, Cimarex s Chief Executive Officer and Chief Financial Officer carried out an evaluation of the effectiveness of the design and operation of Cimarex s disclosure controls and procedures (as defined in Securities Exchange Act Rules 13a-14(c) and 15(d)-14(c)) to ensure that information required to be disclosed by Cimarex under the Securities Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that Cimarex s disclosure controls and procedures are effective.

There were no significant changes in Cimarex s internal controls or in other factors that could significantly affect these controls subsequent to the Evaluation Date.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF CIMAREX

Information concerning the directors of Cimarex is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2004 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2004. Information concerning the executive officers of Cimarex is set forth under Item 4A in Part I of this report.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2004 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2004.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2004 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2004.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2004 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2004.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2004 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2004.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) (1) The following financial statements are included in Item 8 to this 10-K/A:

Consolidated balance sheets as of December 31, 2003 and 2002

Consolidated statements of operations for the years ended December 31, 2003 and 2002, September 30, 2001 and for the three months ended December 31, 2001 and 2000

Consolidated statements of cash flows for the years ended December 31, 2003 and 2002, September 30, 2001 and for the three months ended December 31, 2001

Consolidated statements of stockholders equity for the year ended December 31, 2003 and 2002, the three months ended December 31, 2001, and the year ended September 30, 2001

Notes to consolidated financial statements

(2) Financial statement schedules None

(3) Exhibits:

Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated by reference to a prior SEC filing as indicated.

Exhibits designed by a plus sign (+) are management contracts or compensatory plans or arrangements required to be filed herewith pursuant to Item 15.

2.1 Agreement and Plan of Merger, dated as of February 23, 2002, among Helmerich & Payne, Inc., Cimarex Energy Co., Mountain Acquisition Co. and Key Production Company, Inc. (filed as Exhibit 2.1 to the Registrant s Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

3.1 Amended and Restated Certificate of Incorporation of Cimarex Energy Co. filed as Exhibit 3.1 to the Registrant s Registration Statement on Form S-4, dated May 9, 2002 (Registration No. 333-87948), and incorporated herein by reference.

3.2 By-laws of Cimarex Energy Co. filed as Exhibit 3.2 to the Registrant s Registration Statement on Form S-4, dated May 9, 2002 (Registration No. 333-387948) and incorporated herein by reference.

4.1 Specimen Certificate of Cimarex Energy Co. common stock (filed as Exhibit 4.1 to Amendment No. 1 to Registration Statement on Form S-4 dated July 2, 2002 (Registration No. 333-87948) and incorporated herein by reference).

4.2

Rights Agreement, dated as of February 23, 2002, by and between Cimarex Energy Co. and UMB Bank, N.A. (filed as Exhibit 4.2 to dated May 9, 2002 the Registration Statement on Form S-4 (Registration No. 333-87948) and incorporated herein by reference).

10.1	Credit Agreement, dated October 2, 2002, among Cimarex Energy Co., the lenders party thereto, Bank One, NA, as Administrative Agent, Royal Bank of Canada, as Co-Documentation Agent, Wachovia Bank, National Association, as Co-Documentation Agent, and Banc One Capital Markets, Inc., as Lead Arranger and Sole Book Runner. (Incorporated by reference to Exhibit 10.1 to the Registrant s Form 10-Q for the quarter ended September 30, 2002, file no. 001-31446).
10.2	First Amendment to Credit Agreement, dated as of April 21, 2003, among Cimarex Energy Co., BankOne, NA, as Administrative Agent, and the Lenders under the Credit Agreement (incorporated by reference to Exhibit 10.1 to the Registrant s Form 10-Q for the quarter ended June 30, 2003, file no. 001-31446).
10.3	Distribution Agreement, dated as of February 23, 2002, by and between Helmerich & Payne, Inc. and Cimarex Energy Co. (filed as Exhibit 10.1 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.4	Tax Sharing Agreement, dated as of February 23, 2002, by and between Helmerich & Payne, Inc. and Cimarex Energy Co. (filed as Exhibit 10.2 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.5	Employee Benefits Agreement, dated as of February 23, 2002, by and between Helmerich & Payne, Inc. and Cimarex Energy Co. (filed as Exhibit 10.3 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.6	First Amendment to Employee Benefits Agreement, dated August 2, 2002, by and among Helmerich & Payne, Inc., Cimarex Energy Co. and Key Production Company, Inc. (filed as Exhibit 10.3.1 to Amendment No. 2 to the Registration Statement on Form S-4 dated August 2, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.7	Employment Agreement dated September 1, 1992 between Key Production Company, Inc. and F.H. Merelli (filed as Exhibit 10.5 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).+
10.8	Employment Agreement, dated September 7, 1999, by and between Paul Korus and Key Production Company, Inc. (filed as Exhibit 10.6 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).+
10.9	Employment Agreement, dated October 25, 1993, by and between Thomas E. Jorden and Key Production Company, Inc. (filed as Exhibit 10.7 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).+
10.10	Employment Agreement, dated February 2, 1994, by and between Stephen P. Bell and Key Production Company, Inc. (filed as Exhibit 10.8 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).+
10.11	Employment Agreement, dated March 11, 1994, by and between Joseph R. Albi and Key Production Company, Inc. (filed as Exhibit 10.9 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).+

10.12	Change of Control Agreement, dated April 11, 2002, by and between Steven R. Shaw and Helmerich & Payne, Inc. (filed as Exhibit 10.10 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).+
10.13	Key Production Company, Inc. Income Continuance Plan, dated effective June 1, 1994 (incorporated by reference to Exhibit 10.18 to Key Production Company, Inc. s Form 10-K for the fiscal year ended December 31, 1992, file no. 0-17162).+
10.14	Amended and Restated 2002 Stock Incentive Plan of Cimarex Energy Co. (incorporated by reference to Exhibit 10.14 to the Registrant s From 10-K for the fiscal year ended December 31, 2002, file no. 001-31446).+
10.15	Cimarex Energy Co. Supplemental Savings Plan (amended and restated, effective March 3, 2003). (incorporated by reference to Exhibit 10.15 to the Registrant s Form 10-K for the fiscal year ended December 31, 2002, file no. 001-31446). +
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers*
21.1	Subsidiaries of the Registrant*
23.1	Consent of KPMG LLP.*
23.2	Consent of Ernst & Young LLP.*
23.3	Consent of Ryder Scott Company, LP.*
23.4	Consent of Netherland, Sewell & Associates, Inc.*
24.1	Power of Attorney of directors of the Registrant.*
31.1	Certification of F.H. Merelli, Chief Executive Officer of Cimarex Energy Co. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32.1	Certification of F.H. Merelli, Chief Executive Officer of Cimarex Energy Co. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
32.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

(b) Form 8-K filed October 8, 2003, provided an update of operations.

Form 8-K filed November 5, 2003, announcing financial and operating results for the third quarter and first nine months of 2003.

SIGNATURE

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

Date: March 11, 2004

CIMAREX ENERGY CO.

By: /s/ F.H. Merelli
F.H. Merelli
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date

/s/ F.H. Merelli F.H. Merelli	Director, Chairman, President and Chief Executive Officer (Principal Executive Officer)	March 11, 2004
/s/ Paul Korus Paul Korus	Vice President, Chief Financial Officer Corporate Secretary and Treasurer (Principal Financial Officer)	March 11, 2004
/s/ James H. Shonsey James H. Shonsey	Controller, Chief Accounting Officer (Principal Accounting Officer)	March 11, 2004
/s/ F.H. Merelli Attorney-in-Fact Glenn A. Cox	Director	March 11, 2004
/s/ F.H. Merelli Attorney-in-Fact Cortlandt S. Dietler	Director	March 11, 2004
/s/ F.H. Merelli Attorney-in-Fact Hans Helmerich	Director	March 11, 2004
/s/ F.H. Merelli Attorney-in-Fact David A. Hentschel	Director	March 11, 2004
/s/ F.H. Merelli Attorney-in-Fact Paul D. Holleman	Director	March 11, 2004
/s/ F.H. Merelli Attorney-in-Fact L.F. Rooney, III	Director	March 11, 2004

/s/ F.H. Merelli Attorney-in-Fact Michael J. Sullivan	Director	March 11, 2004
/s/ F.H. Merelli Attorney-in-Fact L. Paul Teague	Director	March 11, 2004