

OPERATIONS

In 2008, Buzzard delivered exceptional value. Long Lake produced first Premium Synthetic Crude™ in January 2009.

PART I

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PART II

ABOUT US

Nexen Inc. (Nexen, we or our) is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 as Canadian Occidental Petroleum Ltd. when Occidental Petroleum Corporation (Occidental) combined their Canadian crude oil, natural gas, sulphur and chemical operations into one company. We've grown from producing 10,700 boe/d before royalties with revenues of \$26 million in 1971, to producing over 250,000 boe/d before royalties (including Syncrude production) and revenues of \$8.2 billion in 2008. We achieved this growth through exploration success and strategic acquisitions. Operating for more than 35 years, we have been profitable every year, except one, and have been paying quarterly dividends consecutively since 1975.

Where we came from

- | | |
|-------|--|
| 1970s | <ul style="list-style-type: none">• broadened our western Canadian asset base and entered the US Gulf of Mexico• finished the decade with production of about 11,000 boe/d and revenues of \$126 million |
| 1980s | <ul style="list-style-type: none">• grew our western Canadian and Gulf of Mexico assets through acquisitions• acquired Canada-Cities Service doubling our size and captured an interest in Syncrude• finished the decade with production of about 69,000 boe/d and revenues of \$591 million |
| 1990s | <ul style="list-style-type: none">• discovered the first of 17 fields at Masila in Yemen in 1990 and production commenced in 1993• tripled our Canadian production in 1997 by purchasing Wascana Energy Inc.• explored and made several discoveries, such as our 1998 Ukot discovery on block OPL-222, offshore Nigeria• finished the decade with production of about 239,000 boe/d and revenues of \$1.7 billion |

Who we are now

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| 2000–2008 | <ul style="list-style-type: none">• made several significant international discoveries including: Gunnison, Aspen, Knotty Head and Longhorn in the deep-water Gulf of Mexico; Guando in Colombia; Block 51 in Yemen; and Usan, offshore Nigeria• acquired properties in the UK North Sea in 2004, including operatorship of the Buzzard discovery, the producing Scott and Telford fields and 700,000 exploration acres. Buzzard came on stream in 2007 on time and on budget. Made several discoveries including Golden Eagle, Pink and Rochelle• signed a 50/50 joint venture agreement with OPTI Canada Inc. to develop, produce and upgrade bitumen at Long Lake utilizing our patented OrCrude™ technology, in the Athabasca oil sands. Construction of the Long Lake Project was completed in 2008• acquired Occidental's remaining 29% interest in us with Ontario Teachers' Pension Plan Board (Teachers). Teachers purchased 20.2 million common shares and we repurchased the remaining 20 million common shares for \$605 million. We also exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemical operations• divested non-core assets in 2005 by selling Canadian properties producing about 18,300 boe/d before royalties and by monetizing 39% of our chemical business through the initial public offering of Canexus Income Fund• developed our first coalbed methane (CBM) project in the Fort Assiniboine area in western Canada in 2005• captured a significant shale gas position in the Horn River Basin in northeastern BC |
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Where we are going

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| 2009 | <ul style="list-style-type: none">• began producing premium synthetic crude in January 2009 at Long Lake. Increased our interest in the Long Lake Project and joint venture lands by 15% and become the sole operator of both the resource and upgrader• continue to enhance and develop production at Long Lake and move towards first production at Ettrick in the UK North Sea and Longhorn in the US Gulf of Mexico later this year• focusing on oil sands, unconventional gas and select conventional exploration and exploitation properties in our core areas• continue to evaluate and appraise potentially significant recent discoveries in the UK North Sea |
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STRATEGY

Choice—it's what companies and investors value most in challenging times. Whether it's how we allocate capital, fund our growth, or which projects make the most sense in current economic times, choice is key. Our strategy is to build a sustainable energy company focused in three areas: oil sands, unconventional gas and select conventional exploration and exploitation.

To be sustainable we must be better than average. So we operate where we see the greatest opportunity for long-term value creation. Then we invest in solid land positions, developing expertise and applying technology that give us a competitive advantage.

Our goal is to grow long-term value for our shareholders responsibly. Key drivers to growing value include increasing reserves, production, cash flow and net income on a cost-effective basis over the long term. We leverage off our competitive advantages to generate opportunities for long-term success in our evolving industry.

As conventional basins in North America mature, we've developed specific capabilities in oil sands, CBM, deep-water technology and international experience. These skills enable us to focus on specific types of projects, as we transition toward major projects in established basins, exploration in less mature basins and exploitation of unconventional resources.

Today, we are building sustainable businesses in western Canada, the North Sea, Gulf of Mexico, and offshore West Africa, capitalizing on the following corporate strengths:

- diversification—our assets are geographically diverse and we produce oil and gas, onshore and offshore. We have large conventional and unconventional legacy assets in our portfolio;
- significant captured resource—we have key resource plays with a low cost of entry. Our Long Lake Project is developing only 10% of our oil sands leases in the Athabasca oil sands, we hold 195 net sections in the emerging Horn River shale gas play in north east British Columbia and we hold unexplored acreage in the Gulf of Mexico, the North Sea, western Canada and elsewhere;
- focus on growth—we are growing our business through exploration and innovative technology. We are successful explorers with significant undeveloped discoveries at Knotty Head and Vicksburg in the Gulf of Mexico, the Golden Eagle area in the UK North Sea and at Usan, offshore Nigeria. Long Lake is the first oil sands project to use gasification technology to significantly reduce the cost of producing bitumen and we are

advancing new techniques for unconventional production of CBM and enhanced heavy oil recovery in western Canada;

- international expertise—we are an international operator with a proven track record of successful business ventures in Yemen, the United Kingdom, Nigeria, Colombia and Australia;
- strong financial position—we have access to \$3.5 billion of liquidity (after acquiring the additional 15% interest in Long Lake in January 2009) through cash and undrawn committed credit facilities to allow us to proceed with investments at the pace of our choice and to take advantage of opportunities as they arise like we did with our strategic entry into the UK North Sea in 2004 and our recent acquisition of an additional 15% working interest at Long Lake; and
- sustainable business practices—leveraging our strength in business practices such as Health, Safety, Environment and Social Responsibility (HSE&SR) to access opportunities and responsibly create and demonstrate both long-term benefits and value growth for our investors, for the communities in which we operate and for other stakeholders. This makes us a desired business partner and/or joint venture operator.

The location and scale of our operations often result in: 1) an extended period of time from the capture of opportunities to first production and 2) non-linear, year-over-year growth in reserves and production. Significant up-front capital investment is often required prior to realizing production and free cash flows. We fund this investment by maximizing cash flow from our producing assets, issuing long-term debt and/or equity and selling non-core assets into attractive markets.

Our financial position is strong. We have financial flexibility with major capital projects complete at Buzzard and Long Lake, and industry-leading cash netbacks. We have available liquidity of approximately \$3.5 billion (after acquiring the additional 15% interest in Long Lake), split between cash and undrawn committed credit. We have no debt maturities until 2011 and our average term-to-maturity of our long-term debt is approximately 18 years.

In creating sustainable businesses, we are committed to good corporate governance practices and social responsibility. We believe that over the long term, companies that follow sustainable business practices outperform those with narrower priorities. We foster dialogue with stakeholders about our operational opportunities and challenges, from exploration to development to reclamation. Our goal is to help stakeholders become engaged participants in a continuing consultation process, while balancing multiple, and sometimes conflicting goals.



For financial reporting purposes, we report on four main segments:

- oil and gas;
- Syncrude;
- energy marketing; and
- chemicals.

Our oil and gas operations are broken down geographically into the UK North Sea, US Gulf of Mexico, Canada, Yemen and Other International (currently Colombia, offshore West Africa and Norway). Results from our Long Lake Project are included in Canada. Syncrude is our 7.23% interest in the Syncrude Joint Venture. Energy marketing includes our crude oil, natural gas, natural gas liquids and power marketing businesses in North America, Europe and Asia. Chemicals includes operations in North America and Brazil that manufacture, market and distribute sodium chlorate, caustic soda, muriatic acid and chlorine through Canexus Limited Partnership.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 22 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report.

UNDERSTANDING THE OIL AND GAS BUSINESS

The oil and gas industry is highly competitive. With strong global demand for energy, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce the oil or gas, the fiscal terms of the host regime and the price that products command in the market based on quality and marketing efforts. Our goal is to extract the maximum value from each barrel of oil equivalent, so every dollar of capital we invest generates an attractive return.

Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash flow generated from operating activities. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration and development. We attempt to reduce these impacts by investing in projects we believe will generate positive returns at relatively low commodity prices. We maintain liquidity that provides us with the ability to invest in high-quality projects that we believe will generate value over the long term.

The prices we receive for our oil and gas products are determined by global crude oil and natural gas markets, which can be volatile, and by worldwide supply/demand fundamentals. With many alternative customers, the loss of any one customer is not expected to have a significantly adverse effect on the price of

our products or revenues. Oil and gas producing operations are generally not seasonal. However, demand for some of our products can fluctuate season to season, which impacts price. In particular, heavy oil is typically in higher demand in the summer for its use in road construction, and natural gas is generally in higher demand in the winter for heating. We manage our operations on a country-by-country basis, reflecting differences in the regulatory and competitive environments and risk factors associated with each country.

OIL AND GAS OPERATIONS

We have oil and gas operations in the UK North Sea, US Gulf of Mexico, western Canada, Yemen, Colombia, offshore West Africa and Norway. We also have operations in Canada's Athabasca oil sands which produce synthetic crude oil. We operate most of our production and continue to develop new growth opportunities in each area by actively exploring and applying technology.

In this Form 10-K, we provide estimates of remaining quantities of proved oil and gas reserves for our various properties. Such estimates are internally prepared. Additionally, at the end of the year, 98% of our oil and gas reserves before royalties (98% after royalties) and 100% of our Syncrude reserves before royalties (100% after royalties) were assessed (either evaluated or audited as described on page 19) by independent reserves consultants. Their assessments are performed at varying levels of property aggregation, and we work with them to reconcile the differences on the portfolio of properties to within 10% in the aggregate. Estimates pertaining to individual properties within the portfolio may differ by more than 10%, either positively or negatively; however, we believe such differences are not material relative to our total proved reserves. Refer to the section on Critical Accounting Estimates—Oil and Gas Accounting—Reserves Determination on page 70 for a description of our reserves process, and to the section on Reserves, Production and Related Information on page 15 for a description of the nature and scope of the independent assessments performed and the results thereof.

Certain statements in these items 1 and 2 constitute “forward-looking statements” and the reader should refer to the “Special Note Regarding Forward-Looking Statements” set out on page 78 of this 10-K.

North Sea—United Kingdom (UK)

The UK North Sea is a key producing area. Our assets include a 43.2% operated interest in the Buzzard field and facilities, a 41.9% operated interest in the Scott field and production platform, a 71.8% operated interest in the Telford field, interests in several satellite discoveries and more than 750,000 net undeveloped exploration acres. We are a significant regional player with concentrated assets, infrastructure and exploration potential for future growth. Our North Sea properties have high-margin reserves and production, diversify our global portfolio by adding strong assets in a stable jurisdiction, and complement our other longer cycle-time projects.

Our UK strategy is to grow and sustain our existing North Sea production and identify new production hubs with exploration and exploitation opportunities near existing infrastructure. We have a number of exploitation opportunities in our existing fields and smaller undeveloped discoveries near infrastructure. Most of our unexplored acreage is near Scott/Telford, Buzzard or Etrick. As a result, new discoveries can be tied-in quickly.

During the year, we produced 102,700 boe/d before royalties (102,700 after royalties) in the UK, which was approximately 41% of our total production. At year end, our UK proved oil and gas reserves of 175 mmbbl before royalties (175 after royalties) represented about 18% of our total proved oil and gas and Syncrude reserves before royalties (19% after royalties).

Buzzard

Buzzard is the largest discovery in the UK North Sea in over a decade. It was discovered in 2001 and construction of the platforms and facilities was completed in 2006. Production came on stream early 2007 and the project was completed on time and on budget.

The Buzzard field is located about 60 miles northeast of Aberdeen in the Outer Moray Firth, central North Sea, in 317 feet of water. The Buzzard development includes three platforms that can process at least 200,000 bbls/d of oil and 60 mmcf/d of gas. We have drilled 18 development wells and 14 of them are on stream. Development drilling resulted in more well-to-well variability in the concentration of hydrogen sulphide than originally expected. To address this, we are constructing a fourth platform with production sweetening facilities to handle higher levels of hydrogen sulphide. Existing equipment and

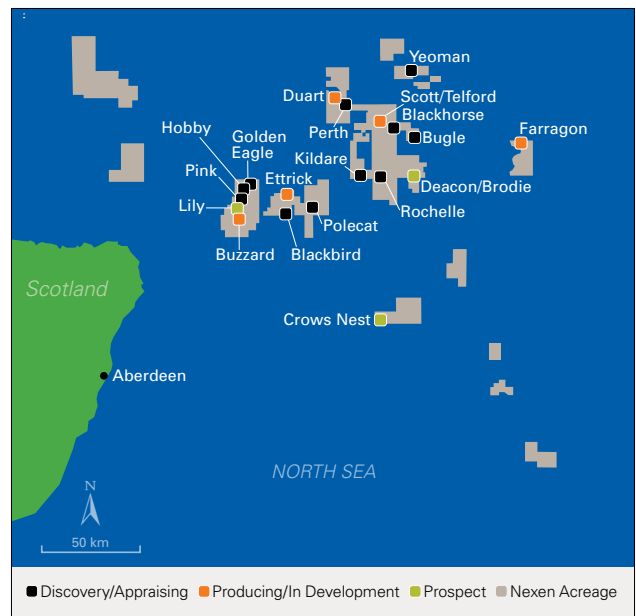
processes can manage current hydrogen sulphide levels and maintain current production deliverability until the additional equipment is commissioned, which is scheduled for 2010.

Oil from Buzzard is exported via the Forties pipeline to the Grangemouth refinery in Scotland. Gas is exported via the Frigg system to the St. Fergus Gas Terminal in northeast Scotland.

We expect to produce the Buzzard field through 27 production wells and maintain reservoir pressure with an active water-flood program. During 2008, the Buzzard field reached a milestone when it exported 100 million barrels of crude oil. In 2009, we plan to drill four production wells, two water injectors and progress work on the fourth platform. During the third quarter of 2009, we plan to install the jackets for this platform and complete tie-in operations, pending installation of the topsides. This will result in about one month of downtime which coincides with a six week planned slowdown of the Forties pipeline.

Scott/Telford

Scott and Telford are producing fields with additional exploitation opportunities and both tie back to the Scott platform. Scott was discovered in 1987 and began producing in September 1993, while Telford was discovered in 1991 and came on stream in 1996. We have a 41.9% working interest in the Scott platform and field, and a 71.8% working interest in Telford. In 2008, our share of production from these fields was approximately 10,500 boe/d. The production is around 90% oil and produced through subsea wells tied back to the Scott platform. Oil is delivered to the Grangemouth refinery in Scotland via the Forties pipeline, while gas is exported via the SAGE pipeline to the St. Fergus Gas Terminal in north-east Scotland. In recent years, the Scott platform underwent a significant maintenance turnaround and facilities upgrade to improve reliability and extend facility life.



Ettrick

We are progressing development of the Ettrick field and first oil is expected in the next few months. The FPSO is currently being commissioned and expected to be on location shortly. Development of the field includes five subsea production wells and three water injectors tied back to a leased FPSO; however, we are developing Ettrick as a new production hub and we expect to tie in new discoveries. We are reviewing our recent exploration success at Blackbird as a potential tie-back to the Ettrick FPSO. The FPSO is designed to handle 30,000 bbls/d of oil, 35 mmcf/d of gas and to re-inject 55,000 bbls/d of water. We operate Ettrick with an 80% working interest.

Other

We have interests in two smaller non-operated fields in the UK North Sea. The Farragon field was brought on stream in late 2005. In 2007, the Duart field began producing oil from a single well tied back to the Tartan platform. Our share of production in 2008 from these properties was 3,900 boe/d before royalties (3,900 after royalties).

Exploration and Undeveloped Assets

We continue to actively explore in the UK North Sea and hold several undeveloped discoveries on operated blocks near Scott, Buzzard and Ettrick as follows:

Field	Interest (%)	Operator Status	Comments
Blackbird	80	operated	discovery near Ettrick; appraisal well planned for 2009
Black Horse	50	operated	discovery near Scott; evaluating development alternatives
Bugle	41	operated	discovery near Scott; evaluating development alternatives
Ferret (Polecat)	40	operated	discovery near Buzzard; appraisal well planned for 2009
Golden Eagle	34	operated	discovery near Buzzard; evaluating development alternatives
Hobby	34	operated	discovery near Buzzard; successful well drilled January 2009
Kildare	50	operated	discovery near Scott; evaluating development alternatives
Perth	42	operated	discovery near Scott; evaluating development alternatives
Pink	46	operated	discovery near Golden Eagle; appraisal well planned for 2009
Rochelle	44	non-operated	discovery near Scott; successful well drilled January 2009

In 2007, we discovered hydrocarbons at Golden Eagle, which was further appraised with a sidetrack well. We are currently evaluating development options and expect to sanction development in 2009. In 2008, we drilled two exploration wells in the UK North Sea that found hydrocarbons at Blackbird and Pink. In early 2009, we discovered hydrocarbons at Rochelle and Hobby.

In 2009, we plan to drill four exploration wells and four appraisal wells. We may modify our current 2009 drilling plans depending on various factors, including our partners' financial situation, the current global economic environment and declining commodity prices.

We are also assessing emerging CBM opportunities onshore in the UK. In 2006, we acquired an 80% working interest in one opportunity and subsequently drilled two successful exploration wells. Both wells encountered coal seams and are being monitored through ongoing production testing.

Fiscal Terms

In the UK, new discoveries pay no royalties and result in cash netbacks that are higher than our company average. Scott is subject to Petroleum Revenue Tax (PRT), although no PRT is payable until available oil allowances have been fully utilized, which isn't expected before 2010. Once payable, PRT is levied at 50% of cash flow after capital expenditures, operating costs and an oil allowance. PRT is applicable to fields receiving development consent prior to March 1993. Buzzard, Ettrick, Farragon, Duart and Telford are not subject to PRT. PRT is deductible for corporate income tax purposes. The UK corporate income tax rate on oil and gas activities is 30% of taxable income and is also subject to a 20% supplemental charge.

Gulf of Mexico—United States (US)

The Gulf of Mexico is an integral part of our growth strategy. Large discoveries, relatively high success rates, expanding production infrastructure and attractive fiscal terms make the deep-water Gulf of Mexico one of the world's most prospective sources for oil and gas. While costs of deep-water exploration are high relative to other basins, deep-water prospects generally have multiple sands and high production rates—factors which improve economics. Technology to find, drill, and develop deep-water discoveries is rapidly progressing and becoming more cost effective. The deep-water Gulf is near infrastructure and continental US markets, so discoveries can be brought on stream in reasonable time.

Our strategy in the Gulf is to explore for new reserves, exploit our existing asset base and acquire assets with upside potential. We focus our exploration program on three strategic play types:

- deep-water prospects near existing infrastructure;
- deep-water, Miocene and Lower Tertiary sub-salt plays with the potential to become new core areas; and
- deep-water, Norphlet targets in the eastern Gulf of Mexico.

These plays are relatively under-explored, hold potential for large discoveries and have attractive fiscal terms. The shorter cycle-times for deep-water prospects near infrastructure complement the longer cycle-times for deep-water sub-salt and Norphlet plays. Although competition in the Gulf is strong, we have built a large inventory of deep-water acreage and are now a significant leaseholder in the deep-water.

In 2009, we plan to further our growth strategies. This includes tying in our four-well subsea tie-back at Longhorn and completing development of Mississippi Canyon 72, both of which are expected on stream in 2009. We also plan to continue to advance our exploration strategy with additional exploratory drilling and seismic evaluation.

US Production

(mboe/d)	2008		2007		2006	
	Before Royalties	After Royalties	Before Royalties	After Royalties	Before Royalties	After Royalties
Deep Water	12.2	10.7	19.4	17.4	19.6	17.5
Shelf	10.1	8.4	13.8	11.5	15.9	13.2
Total	22.3	19.1	33.2	28.9	35.5	30.7

At year end, proved reserves of 49 mmbbl before royalties (43 after royalties) in the Gulf of Mexico represented about 5% of our total proved oil and gas and Syncrude reserves. Our Gulf production and reserves are primarily concentrated in four deep-water and five shallow-water (shelf) areas.

Deep Water

Most of our deep-water production comes from our 30% non-operated Gunnison field and our 100% operated Aspen field. The remainder comes from our 50% non-operated Wrigley field and three 100% operated properties acquired in 2007. In 2009, our 25% non-operated Longhorn field is expected to come on stream and contribute to our Gulf of Mexico production volumes.

Gunnison is in 3,100 feet of water and includes Garden Banks Blocks 667, 668 and 669. Gunnison began production in December 2003 through our truss SPAR platform that can handle 40,000 bbls/d of oil and 200 mmcf/d of gas. Our Gunnison SPAR facility has excess capacity, leaving room for growth from regional exploration and processing of third-party volumes. We achieved payout on Gunnison in December 2005, just two years after first production. In 2008, our share of production before royalties was approximately 4,200 boe/d (3,700 after royalties).

Aspen is on Green Canyon Block 243 in 3,150 feet of water. The project was developed using subsea wells tied back to the Shell-operated Bullwinkle platform 16 miles away and began producing in December 2002. Our share of 2008 production before royalties was approximately 3,100 boe/d (2,800 after royalties).

Wrigley is on Mississippi Canyon Block 506 in 3,300 feet of water. The project consists of a single subsea well tied back to the Shell-operated Cognac platform 17 miles away. Wrigley began gas production in July 2007 and our share before royalties in 2008 was approximately 2,400 boe/d (2,100 after royalties).

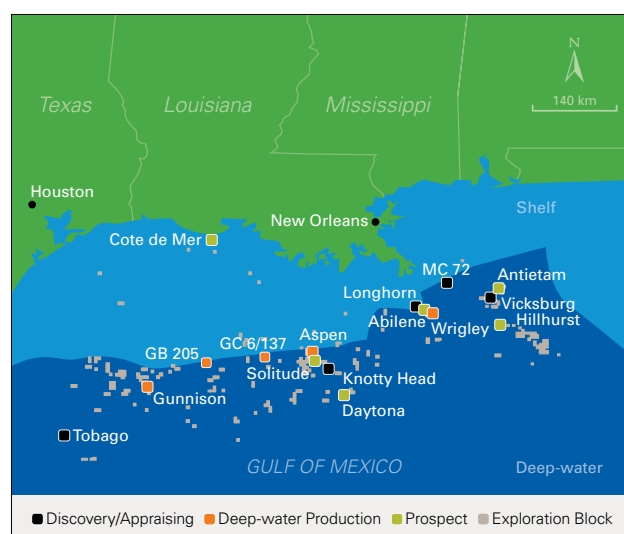
In 2007, we acquired three new deep-water producing fields: 1) Garden Banks Block 205; 2) Green Canyon 137; and 3) Green Canyon 6/50. These fields are in water depths between 700 and 1,100 feet. Production from Green Canyon 6/50/137 has been temporarily suspended as the third-party platform that

processed our oil and gas was destroyed by Hurricane Ike in September 2008. We are currently assessing our options to restore field production.

In 2009, we expect to have two fields begin producing oil and gas. Our non-operated Mississippi Canyon 72 property is designed to come on stream through a single subsea gas well tied back to the BP-operated Pompano Platform five miles northwest of the field. The Longhorn property is on Mississippi Canyon Block 502 in 2,400 feet of water. The project is a non-operated three-well subsea tie-back to the Corral platform located 19 miles north of the field. We expect production from these properties to commence in mid 2009.

Shelf

Our shelf producing assets are offshore Louisiana, primarily in five 100%-owned field areas: Eugene Island 18, Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 320/321/339/340, and Vermilion 76 (consisting of Blocks 65, 66 and 67). We continue to look for opportunities to optimize these assets. In 2009, our shelf development program includes a well at Vermilion 76 to access additional reserves and four recompletion projects.



Exploration and Undeveloped Assets

Our undeveloped deep-water discoveries include:

Well	Interest (%)	Operator Status	Comments
Tobago	10	non-operated	sanctioned; production expected 2010
Knotty Head	25	operated	discovery; further appraisal required
Vicksburg	25	non-operated	discovery; further appraisal required

During the year, we drilled two exploratory dry holes in deep water and acquired additional deep-water acreage. We hold approximately 236 blocks and expect this acreage and future exploration opportunities to position us well for continued growth. In 2009, our expected exploration program includes one exploration well and two appraisal wells, all in deep water. To explore our land inventory and evaluate existing discoveries, we secured two new-build dynamically-positioned fifth-generation semi-submersible drilling rigs. We share access to the rigs that provides us with the ability to use each rig for a total of 24 months over the next four years. We expect the first rig will become available late 2009, followed by the second rig in 2010.

Fiscal Terms

In 2008, royalty rates on our US production averaged 16.5% for shelf volumes and 12.2% for deep-water volumes. The US government increased royalty rates from 12.5% to 16.7% for new deep-water leases awarded after July 2007. We qualify for royalty relief at our deep-water Aspen and Gunnison fields on the first 87.5 mmoeb of production. The US Department of the Interior's Minerals Management Service (MMS) suspended royalty relief on our Gunnison lease and assessed royalties on our production from the field. The oil and gas industry litigated the enforceability of these actions and won a judgement in a US District Court. The MMS subsequently lost their appeal of that judgement in January 2009. Our Aspen field is not subject to a minimum price threshold. US taxable income is subject to federal income tax of 35% and state taxes ranging from 0% to 12%.

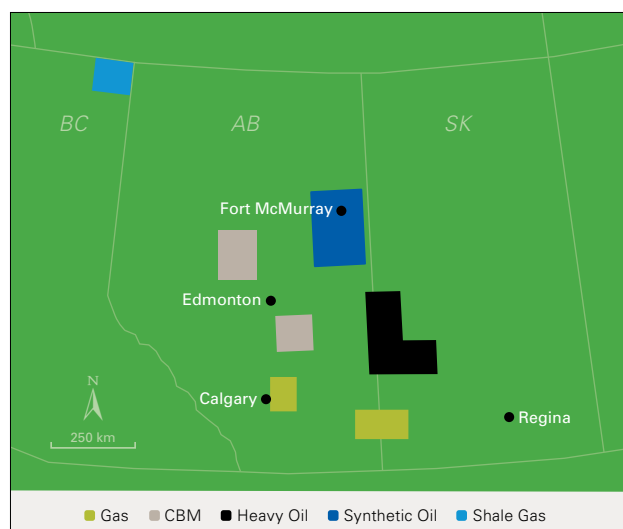
Canada

Our strategy in Canada is two fold: 1) develop unconventional resource opportunities (oil sands, CBM and shale gas) and 2) maximize value from our established operations through disciplined or selective conventional development and enhanced recovery methods. In 2008, we produced 41,900 boe/d before royalties (34,300 after royalties) in Canada, which was approximately 17% of our total production including Syncrude. At year end 2008, Canadian proved reserves (including bitumen and excluding Syncrude) of 375 mmoeb before royalties (362 after royalties) were approximately 38% before royalties (39% after royalties) of our total proved oil and gas and Syncrude reserves.

Our Canadian conventional assets include heavy oil production in east-central Alberta and west-central Saskatchewan, and natural gas near Calgary and in southern Alberta and Saskatchewan. We operate most of our producing properties and hold almost one million net acres of undeveloped land across western Canada. These assets provide predictable production volumes and earnings while we advance the following initiatives for future growth:

- Athabasca oil sands—to produce and upgrade bitumen into synthetic crude;
- shale gas—to evaluate natural gas from organic shales;
- coalbed methane (CBM)—to extract natural gas primarily from Upper Mannville and Horseshoe Canyon coals; and
- enhanced oil recovery (EOR)—to increase recovery in our heavy oil fields.

In 2008, we invested \$1,427 million in Canada including \$1,320 million into these growth initiatives. With the completion of Long Lake Phase 1 in the Athabasca oil sands, we plan to reduce our capital expenditures in 2009 in Canada. Our 2009 capital programs are focused on optimizing and sustaining Long Lake, evaluating and progressing our shale gas opportunities and advancing our CBM strategies.



Athabasca Oil Sands

The Athabasca oil sands in northeast Alberta is a key growth area for Nexen. Our strategy is to economically develop our bitumen resource in phases to provide low-risk, stable, future growth. Our Long Lake Project involves integrating steam-assisted-gravity-drainage (SAGD) bitumen production with field upgrading technology to produce a premium synthetic crude for sale, and a synthetic gas, which significantly reduces our need to purchase natural gas for operations. We also have a 7.23% investment in the Syncrude oil sands mining operation.

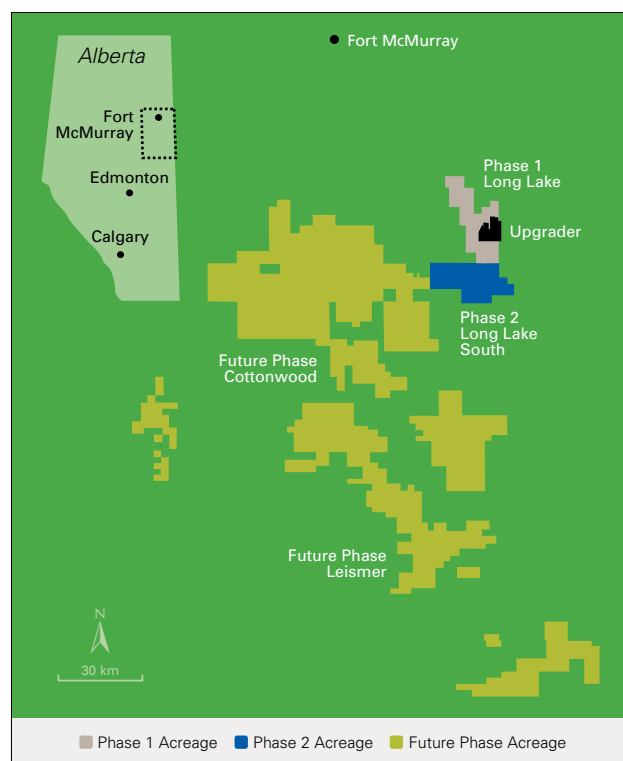
Long Lake Project

In 2001, we formed a 50/50 joint venture with OPTI Canada Inc. (OPTI) to develop the Long Lake lease using SAGD for bitumen production and proprietary OrCrude™ technology for our first stage of upgrading. OPTI has the exclusive Canadian license for the OrCrude™ technology. We acquired the exclusive right to use this technology with OPTI within approximately 100 miles of Long Lake, and the right to use the technology independently elsewhere in the world.

SAGD bitumen operations started in mid 2008 and we began producing premium synthetic crude from the upgrader in January 2009. Early in 2009, we acquired an additional 15% interest in the Long Lake Project and the joint venture lands from OPTI, increasing our ownership level to 65%. Following this acquisition, we are now responsible for operating both the SAGD bitumen extraction process and the upgrader for Phase 1 as well as for future phases.

SAGD and Upgrader Integration

SAGD involves drilling two parallel horizontal wells, generally between 2,300 and 3,300 feet long, with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. The OrCrude™ technology, using conventional distillation, solvent de-asphalting and thermal cracking, separates the produced bitumen into partially upgraded sour crude oil and liquid asphaltenes. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude is upgraded to light (39° API) premium synthetic sweet crude oil, and the asphaltenes are converted to a low-energy, synthetic fuel gas. This gas is available as a low-cost fuel for generating steam and as a source of hydrogen for the hydrocracking process. The gas is also burned in a cogeneration plant to produce electricity for on-site use and sold to the provincial electricity grid. The energy conversion efficiency for our Long Lake upgrader is



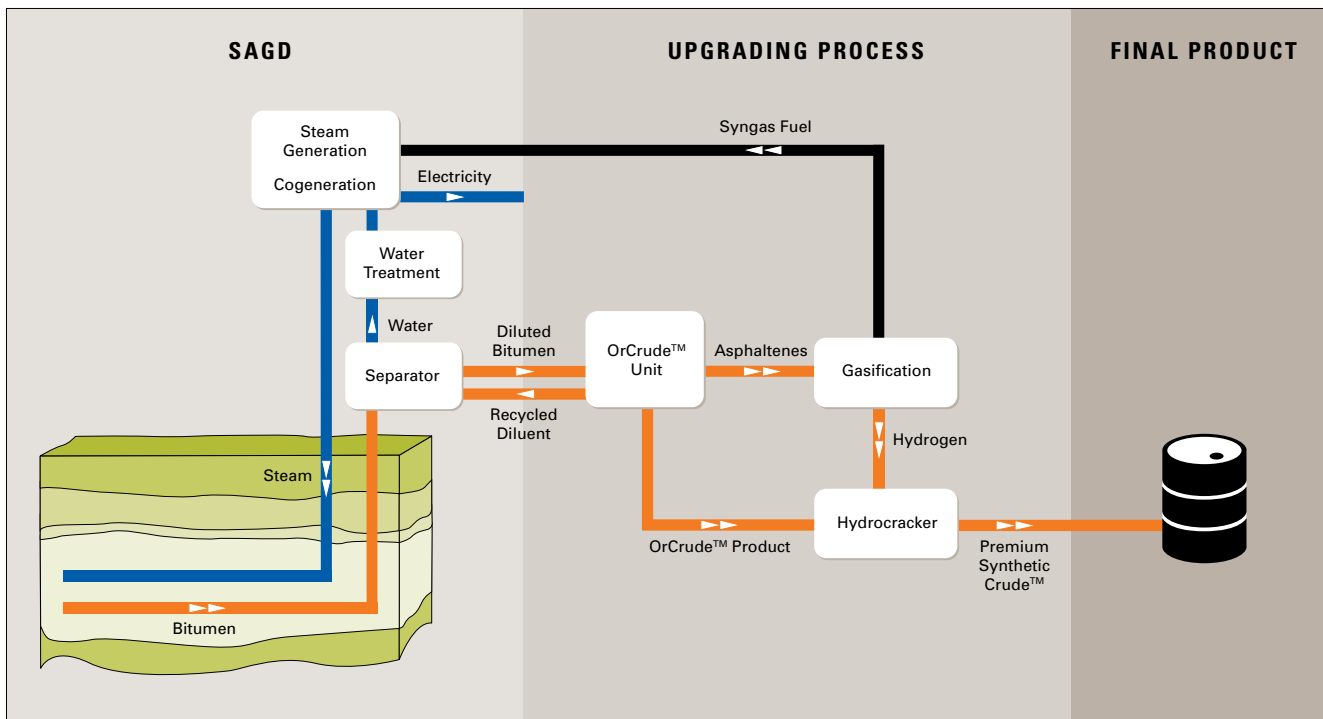
about 90% compared to 75% for a typical bitumen-fed coker, which we expect will provide us with an approximate \$10/bbl operating cost advantage.

Our Strategic Advantage

Our integrated SAGD and upgrading process addresses three main economic hurdles of SAGD bitumen production: 1) the high cost of natural gas; 2) the cost and availability of diluent; and 3) the realized price of bitumen. With synthetic gas from the asphaltenes as fuel, we need to purchase very little additional natural gas. With the upgrading facilities on site, expensive diluent is not required to transport the bitumen to market. By upgrading the bitumen into a highly desirable refinery feedstock or diluent supply, the end product commands light-sweet crude oil premium pricing.

Project Milestones and Costs

The Long Lake Project received regulatory approval in 2003 and Nexen board approval in 2004. Field construction of the SAGD and upgrader facilities began in 2004. In 2006, we substantially completed module and site construction of the SAGD facilities and in 2007, we began injecting steam into the well pads. We continued to steam the SAGD well pairs and began turning wells over to SAGD production in 2008. In 2008, we produced 3,900 bbls/d of bitumen before royalties (3,900 after royalties) and are currently producing approximately 20,000 bbls/d



(13,000 net to us) as of January 2009. The first several months of steam injection largely involves heating the reservoir, followed by a ramp up of bitumen production to peak rates over 12 to 24 months. The reservoir behavior is meeting our expectations. At the start of production, steam-to-oil ratios are high but will decline as bitumen production ramps up to our target rates. We expect the steam-to-oil ratio to average approximately 3.0 over the long-term.

We completed construction of the upgrader in 2008 and began commissioning for commercial operations. Production of premium synthetic crude oil from the upgrader began in late January 2009. We expect that it will take approximately 12 to 18 months to reach the upgrader design capacity. As the upgrader ramps up to full capacity, we expect that there will be periods of downtime as we work through the early stages of operation. This periodic downtime is normal following initial facility start-up and consistent with industry experience. During the bitumen ramp up period, we are purchasing third-party bitumen to take advantage of excess upgrading capacity. Production capacity for the first phase of Long Lake is approximately 60,000 bbls/d (39,000 net at a 65% working interest) of premium synthetic crude. We expect to maintain production over the project's life, estimated at 40 years, by periodically drilling additional SAGD well pairs.

Long Lake's total capital costs increased since project sanctioning due to design enhancements and industry cost pressures. As a result, the final cost of Long Lake increased from \$3.8 billion to \$6.4 billion (\$3.2 billion net to us before acquiring an additional 15% interest in January 2009). Despite capital cost increases, we still expect to achieve positive economic returns which benefit from a significant operating cost advantage. Combined SAGD, cogeneration and upgrading operating costs are expected to average about \$22/bbl, substantially lower than coking or other upgrading processes as a result of the reduced need to purchase natural gas. We expect ongoing capital to average between \$5/bbl and \$10/bbl depending on well spacing, well length and recovery factor. The full-cycle capital costs of producing and upgrading bitumen using this technology are comparable to those for surface mining and coking upgrading on a barrel-of-daily production basis.

Future Phases

We have approximately 281,000 net acres of bitumen-prone lands in the Athabasca region, with plans to acquire more. We plan to continue developing our bitumen lands in phases using our integrated upgrading strategy. In 2008, we invested \$175 million on land acquisition, additional drilling, seismic and engineering to develop our leases and advance regulatory applications for these phases.

During 2007, the federal government announced climate change proposals, however, legislation has not yet been drafted. Due to this regulatory uncertainty and the current global economic crisis, we are delaying certain planned expenditures on Phase 2. Phase 2 is expected to be followed by additional phases every three or four years. Each phase will leverage the knowledge and experience gained from successfully developing Long Lake and subsequent projects will be similar in size and design. By keeping the core team in place and repeating and improving on existing designs and implementation plans, we expect to gain efficiencies in engineering, modular fabrication and on-site construction. We also anticipate enhanced operating efficiencies as we can train and move people easily between the various plants.

Reserves Recognition

Under current SEC rules and regulations, we are currently required to recognize bitumen reserves rather than the upgraded premium synthetic crude oil that we expect to produce and sell. The economic recoverability of bitumen reserves is sensitive to natural gas prices, diluent costs and light/heavy differentials, risks that our integrated project has been designed to virtually eliminate. At December 31, 2008, we recognized proved bitumen reserves of 285 mmbbl before royalties (282 mmbbl after royalties) for our Long Lake Project, representing about 29% before royalties (30% after royalties) of our total proved oil and gas and Syncrude reserves.

Heavy Oil

Approximately 49% of our Canadian conventional production is heavy oil. Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Therefore, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also receives a lower price than light oil, as more expensive and complex refineries are required to refine heavy crude into higher-value petroleum products. To maximize heavy oil returns, it is important to manage capital and operating costs. Our large production base and existing infrastructure are advantageous in managing these costs. Heavy oil reservoirs typically have lower recovery factors than conventional oil reservoirs, leaving substantial amounts of oil in the ground. This creates an opportunity to increase recovery factors by applying new technology. We are continuing to research various technologies to increase our heavy oil recoveries with ongoing pilot projects in west-central Saskatchewan.

Natural Gas

Approximately 32% of our Canadian production is natural gas extracted primarily from shallow sweet reservoirs in southern Alberta and Saskatchewan and from sour gas reservoirs near Calgary. In general, shallower gas targets are cheaper to drill and produce, but have relatively smaller reserves and lower productivity per well. Sour gas is natural gas that contains hydrogen sulphide. Our Balzac field, northeast of Calgary, has been producing sour natural gas since 1961. This sour gas is processed through our operated Balzac plant, which recently went through an extensive maintenance upgrade to improve reliability and efficiency.

Coalbed Methane (CBM)

Approximately 19% of our Canadian production is from our commercial CBM developments at Corbett, Doris and Thunder in the Fort Assiniboine area of central Alberta. We began commercial operations in the Upper Mannville coals in 2005, progressively developing opportunities on our land base. We are applying horizontal well technology to increase gas production rates and reduce de-watering time from water-saturated coal. Upper Mannville coals are generally deeper than the Horseshoe Canyon "dry coal" play, which is also being commercially developed in Alberta.

At the end of 2008, we held more than 725 net sections of land in Alberta with CBM potential, some of which overlay existing conventional producing lands. In 2009, we plan to tie-in existing wells, drill additional wells, fund anticipated partner-initiated development and invest in new potential CBM plays in the Wetaskiwin and Camrose areas.

Shale Gas

As part of our growth strategy in unconventional Canadian resource plays, we have approximately 195 net sections of land in an emerging Devonian shale gas play in the Horn River Basin in northeastern British Columbia. Shale gas is natural gas produced from reservoirs composed of organic shale. The gas is stored in pore spaces, fractures or absorbed into organic matter. Currently, the United States is the largest producer of shale gas.

This shale gas play has the potential to become a significant resource play in North America. It has been compared to the Barnett Shale in Texas as it displays similar rock properties and play characteristics. To date, we have invested \$340 million in land, infrastructure and wells in the Horn River Basin to progress our shale gas strategy toward potential development and reserve recognition. Five horizontal and three vertical wells were drilled on our lands to evaluate the resource potential. Initial production test results are meeting expectations in terms of resource, initial production and decline profile. In 2009, we plan to continue our evaluation program, furthering our technical experience in the play and to test drilling and completion designs for potential commercial development.

We have approximately 88,000 acres in the Dilly Creek area of the Horn River basin with a 100% working interest.

Limited infrastructure of gas pipeline and processing capacity in the Horn River Basin could potentially constrain early development of our lands. To ensure sufficient gathering, processing and transportation capacity for our early development programs, we have contracted gas pipeline capacity of 96 mmcf/d during a five year term. We have entered into additional agreements that will allow us to participate in projects that are expanding infrastructure in the region.

Fiscal Terms

In Canada, we pay two types of royalties to federal and provincial governments on production from lands where they own the petroleum and natural gas rights. The first type of royalty, Net Profits Interest (NPI), applies to our oil sands projects. The second type is a gross royalty (Gross Royalty) system whereby we pay royalties ranging from 5% to 40% depending upon drilling date, production rate and product sales price.

During 2008, the Alberta government legislated a new royalty framework for NPI and Gross Royalty structures effective January 1, 2009. The new NPI royalty rates for oil sands projects will range from 1% to 9% of gross revenue for projects that are pre-payout of costs, and from 25% to 40% of net profit for projects that are post-payout. These royalty rates vary depending on Canadian dollar equivalent of WTI (CAD\$55/bbl to CAD\$120/bbl). The amended Gross Royalty system increases the upper royalty rate limit to 50% and reduces the lower limit for conventional oil to nil, depending on production rates and sales price. Most of our conventional Alberta production qualifies for lower productivity rates and we expect royalties to range between 5% and 25%.

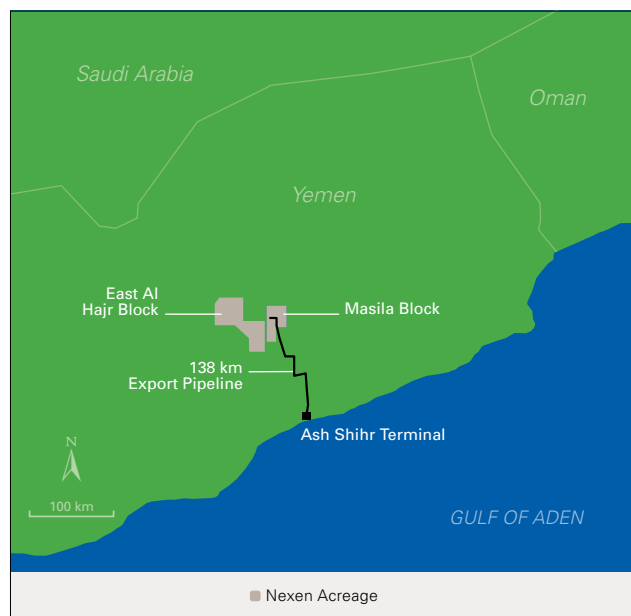
In addition to royalties, some provinces impose taxes on production from lands where they do not own the mineral rights. The Saskatchewan government assesses a resource surcharge on gross Saskatchewan resource sales that are subject to crown royalties, ranging from 1.7% to 3.0%. In Alberta, we are subject to a freehold mineral tax of approximately 4%.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. In 2007, the Federal government reduced the federal corporate income tax rate, ultimately to 15% by 2012. In 2008, federal taxable income is taxed at 19.5%. Provincial income tax rates vary from approximately 10% to 16%.

Middle East—Yemen

Yemen has been a significant international region for us since we first began production at Masila in 1993. We operate the country's largest oil project and have developed strong relationships with the government and local communities.

Our strategy in Yemen is to maximize the value from our existing blocks, prior to contract expiry. We operate from two producing blocks: Masila (Block 14) and East Al Hajr (Block 51). In 2008, we produced 56,600 bbls/d of oil before royalties (30,600 after royalties), representing approximately 23% of Nexen's total production. Proved reserves of 31 mmbobe before royalties (20 after royalties) comprise approximately 3% of Nexen's total proved oil and gas and Syncrude reserves before royalties (2% after royalties).



Masila Block (Block 14)

We operate the Masila Project with a 52% working interest. Our share of 2008 production was 45,900 bbls/d before royalties (24,400 after royalties). The Masila fields are mature, but significant value still remains. As a result of the Production Sharing Agreement (PSA) terms that govern Masila production, we still expect to generate approximately 15% of total project free cash flow before the PSA expires in late 2011.

The first successful Masila exploratory well was drilled at Sunah in 1990, with additional discoveries quickly following at Heijah and Camaal. Initial production began in July 1993, with the first lifting of oil in August 1993. Masila Blend oil averages 32° API at very low gas-oil ratios. Most of the oil is produced from the Upper Qishn formation, but we also produce from deeper formations including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand and Basement formations. Production is collected at our Central Processing Facility (CPF) where water is separated for reinjection and oil is pumped to the Ash Shihr export terminal on the Indian Ocean and shipped to customers, primarily in Asia.

Under the Masila PSA, which was signed between the Government of Yemen and the Masila joint venture partners (Masila Partners), we have the right to produce oil from Masila into 2011 and can negotiate a five-year extension. Production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all exploration, development, and operating costs that are funded by the Masila Partners. Costs are recovered from a maximum of 40% of production each year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for four years
Development	16.7% per year for six years

The remaining production is profit oil that is shared between the Masila Partners and the Government and is calculated on a sliding scale based on production. The Masila Partners' share of profit oil ranges from 20% to 33%. The structure of the agreement moderates the impact on the Masila Partners' cash flows during periods of low prices, as we recover our costs first and then share any remaining profit oil with the Government. The Government's share of profit oil includes a component for Yemen income taxes payable by the Masila Partners at a rate of 35%. In 2008, the Masila Partners' share of production, including recovery of past costs, was approximately 38%.

East Al Hajr Block (Block 51)

The first successful exploratory well was drilled at BAK-A in 2003, with BAK-B discovered shortly after. Block 51 development began in 2004 and included a CPF, gathering system and a 22 km tie-back to our Masila export pipeline. Production began in November 2004. During 2008, production averaged 10,700 bbls/d before royalties (6,200 after royalties).

We operate Block 51, which is also governed by a PSA between the Government of Yemen and the East Al Hajr partners (EAH Partners): The Yemen Company (TYCO) (12.5% carried working interest) and Nexen (87.5% working interest). Under the PSA, TYCO has no obligation to fund capital or operating expenditures and therefore, our effective interest is 100% and for purposes of accounting and reserves recognition, we treat TYCO's 12.5% participating interest as a royalty interest. We recognize both the Government's share and TYCO's share of profit oil under the PSA as royalties and taxes consistent with our treatment of our Masila operations. The PSA expires in 2023, and we have the right to negotiate a five-year extension. Under the PSA, the EAH Partners pay a royalty ranging from 3% to 10% to the Government depending on production volumes. The remaining production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all of the project's exploration, development and operating costs, funded solely by Nexen. Costs are recovered from a maximum of 50% of production each year after royalties, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	75% in year one, 25% in year two
Development	75% in year one, 25% in year two

The remaining production is profit oil that is shared between the EAH Partners and the Government on a sliding scale based on production rates. The EAH Partners' share of profit oil ranges from 20% to 30%. The Government's share of profit oil includes a component for Yemen income taxes payable by the EAH Partners at a rate of 35%. In 2008 the EAH Partners' share of Block 51 production, including recovery of past costs, was approximately 47%.

Offshore West Africa

Offshore West Africa is a core area where we already have discoveries. It offers prolific reservoirs and multiple opportunities to invest in this oil-rich region. Our strategy here is to explore and develop our portfolio for medium- to long-term growth.

Nigeria

In 1998, we acquired a 20% non-operated interest in Block OPL-222, which covers 448,000 acres approximately 50 miles offshore in water depths ranging from 600 to 3,500 feet. In 1998, we discovered the Ukot field and encountered three oil-bearing intervals. This was followed up by a successful appraisal well in 2003. In 2002, the Usan field was discovered and seven more successful wells confirmed that significant hydrocarbons exist on the block. In 2008, we acquired an 18% non-operated interest in Block OPL-223, covering 230,000 acres, which provides us with future exploration potential on the adjacent block.

The Nigerian government approved converting OPL-222 into two OMLs (Oil Mining Lease) that will allow the joint venture partners to develop the Usan and Ukot discoveries. OML-138 consists of 50% of the original acreage and includes the Usan discovery. OML-139 consists of the remaining OPL-222 acreage and includes the Ukot discovery.

Appraisal of the Usan field is complete and development of the field is progressing. Major contracts for construction of the FPSO and subsea facilities were awarded during 2008. The project will have the ability to process an average of 180,000 bbls/d of oil during the initial production plateau period through a new FPSO with a two million barrel storage capacity. We expect our share of development and construction costs will be approximately

US\$2 billion with first production in 2012. In 2009, we plan to progress with the Usan development program. This will include completing detailed engineering, procurement of remaining equipment, fabrication of the FPSO, and initiation of development drilling. At year-end 2008, proved reserves of 28 mmbob before royalties (25 after royalties) comprise approximately 3% of our total proved oil and gas and Syncrude reserves.

Other International Colombia

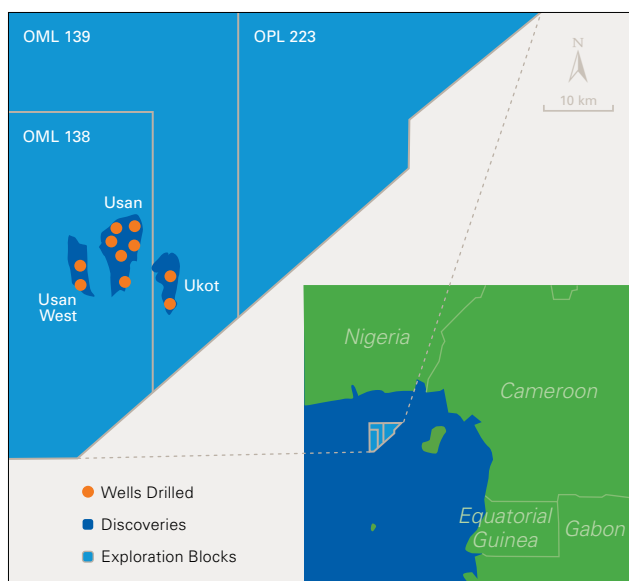
In 2000, we made a discovery at Guando on our 20% non-operated Boqueron Block and production from Guando began in 2001. Boqueron is in the Upper Magdalena Basin of central Colombia, approximately 45 km southwest of Bogota. Our working interest in Guando will decrease to 10% once the field has produced 60 million barrels of oil, which is expected to occur in mid 2009. Our share of 2008 production averaged 5,800 bbls/d before royalties (5,300 after royalties), about 2% of Nexen's total production including Syncrude. We also hold three exploration blocks in the Upper Magdalena Basin that we are assessing for future growth opportunities.

Production from Guando is subject to a royalty between 5% and 25% depending on daily production, and in 2008 averaged 8%. Colombian taxable income is subject to federal income tax of 33% in 2009 and future years.

Norway

Norway is an extension of our conventional offshore growth strategy in the North Sea. The Norwegian North Sea is an established area that has significantly developed infrastructure and relatively unexplored basins that provide the potential for future growth. The Norwegian government created incentives for the oil and gas industry to explore by providing 78% cash tax refunds on qualifying exploration expenditures to companies that do not have a taxable income base. We have ten offshore exploration licences in the Norwegian North Sea with plans to drill our first exploration well in the near future. In 2009, we expect to invest in seismic and geologic studies.

Norwegian oil and gas activities are subject to a general corporate income tax rate of 28% plus an additional 50% special petroleum tax.



RESERVES, PRODUCTION AND RELATED INFORMATION

In addition to the tables below, we refer you to the Supplementary Data in Item 8 of this Form 10-K for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

Net Sales by Product from Oil and Gas Operations (including Syncrude)

<i>(Cdn\$ millions)</i>	2008	2007	2006
Conventional Crude Oil and Natural Gas Liquids (NGLs)	5,534	4,077	2,479
Synthetic Crude Oil	691	545	446
Natural Gas	652	499	553
Total	6,877	5,121	3,478

Crude oil (including synthetic crude oil) and natural gas liquids represent approximately 90% of our oil and gas net sales, while natural gas represents the remaining 10%.

Sales Prices and Production Costs (excluding Syncrude)

	Average Sales Price ¹			Average Production Cost ¹		
	2008	2007	2006	2008	2007	2006
Crude Oil and NGLs (Cdn\$/bbl)						
United Kingdom	96.23	76.30	71.19	6.75	6.94	11.28
Yemen	99.87	76.29	71.57	15.88	12.00	8.11
Canada	74.51	44.07	42.79	22.16	18.67	15.50
United States	104.94	69.83	65.80	13.48	9.69	9.45
Other Countries	98.98	71.29	66.09	4.91	3.76	3.13
Natural Gas (Cdn\$/mcf)						
United Kingdom	6.78	4.71	7.43	1.12	1.16	1.88
Canada	7.73	6.32	6.49	2.09	2.28	1.65
United States	10.07	7.80	7.86	2.25	1.61	1.58

¹ Sales prices and unit production costs are calculated using our working interest production after royalties.

Oil and Gas Acreage

<i>(thousands of acres)</i>	Developed		Undeveloped ¹		Total	
	Gross	Net	Gross	Net	Gross	Net
United Kingdom	197	81	1,107	752	1,304	833
Yemen ²	50	29	756	628	806	657
Canada	817	634	1,865	985	2,682	1,619
United States	215	125	1,260	630	1,475	755
Colombia ⁴	1	–	607	372	608	372
Nigeria ^{2,3}	–	–	678	131	678	131
Norway	–	–	680	383	680	383
Total	1,280	869	6,953	3,881	8,233	4,750⁵

¹ Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.

² The acreage is covered by production sharing contracts.

³ The acreage is covered by a joint venture agreement.

⁴ The acreage is covered by an association contract.

⁵ Approximately 20% of our net oil and gas acreage is scheduled to expire within three years if production is not established or we take no other action to extend the terms. We plan to continue the terms of many of these licences.

Producing Oil and Gas Wells

<i>(number of wells)</i>	Oil		Gas		Total	
	Gross ¹	Net ²	Gross ¹	Net ²	Gross ¹	Net ²
United Kingdom	50	22	–	–	50	22
Yemen	540	327	–	–	540	327
Canada	2,258	1,571	3,124	2,743	5,382	4,314
United States	183	94	202	142	385	236
Colombia	117	24	–	–	117	24
Total	3,148	2,038	3,326	2,885	6,474	4,923

1 Gross wells are the total number of wells in which we own an interest.

2 Net wells are the sum of fractional interests owned in gross wells.

Drilling Activity

<i>(number of net wells)</i>	2008						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United Kingdom	2.5	2.0	4.5	3.3	–	3.3	7.8
Yemen	–	1.0	1.0	17.4	–	17.4	18.4
Canada	9.2	–	9.2	216.4	–	216.4	225.6
United States	0.5	1.0	1.5	1.3	–	1.3	2.8
Colombia	–	–	–	1.6	–	1.6	1.6
Total	12.2	4.0	16.2	240.0	–	240.0	256.2

<i>(number of net wells)</i>	2007						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United Kingdom	2.0	3.2	5.2	4.2	–	4.2	9.4
Yemen	1.0	1.0	2.0	28.0	–	28.0	30.0
Canada	23.2	0.6	23.8	295.6	3.2	298.8	322.6
United States	0.8	2.9	3.7	8.6	1.0	9.6	13.3
Colombia	–	0.9	0.9	7.0	–	7.0	7.9
Total	27.0	8.6	35.6	343.4	4.2	347.6	383.2

<i>(number of net wells)</i>	2006						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United Kingdom	0.8	1.7	2.5	5.5	–	5.5	8.0
Yemen	3.0	5.5	8.5	36.0	1.0	37.0	45.5
Canada	35.4	2.2	37.6	214.3	0.7	215.0	252.6
United States	1.6	2.1	3.7	8.3	2.0	10.3	14.0
Colombia	–	–	–	2.0	–	2.0	2.0
Nigeria	–	0.2	0.2	–	–	–	0.2
Total	40.8	11.7	52.5	266.1	3.7	269.8	322.3

Wells in Progress

At December 31, 2008, we were drilling four wells in Yemen (2.1 net), 16 wells in Canada (10 net), one well in the United States (0.4 net) and seven wells in the United Kingdom (4.5 net). There were no wells drilling in Colombia at December 31, 2008.

Proved Reserves including Proved Undeveloped Reserves

At December 31, 2008, we had 664 mmboe of proved oil and gas reserves before royalties. This is a 10% decrease over the prior year. Including Syncrude, our total proved oil and gas and Syncrude reserves decreased 7% to 988 mmboe. The decrease resulted as additions from our capital program and positive technical revisions of previous estimates did not offset production and negative economic revisions from the decline in year-end oil and gas prices. On an after-royalty basis, our proved oil and gas reserves decreased 3% to 631 mmboe and increased 1% to 926 mmboe when including Syncrude reserves. The changes on an after-royalties basis reflects a reduction in royalties primarily at our oil sands projects where the royalties are sensitive to oil prices.

The following table provides a summary of the changes during 2008 in our proved oil and gas reserves (before royalties) excluding our Syncrude reserves. Refer to page 126 for proved reserves information on an after-royalties basis.

<i>(mmboe)</i>	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2007	386	207	62	41	38	734
Extension and Discoveries	27	5	1	1	–	34
Revisions – Technical	5	17	(1)	11	–	32
Revisions – Economic	(27)	(16)	(5)	–	(2)	(50)
Acquisitions	–	–	–	–	–	–
Divestments	–	–	–	–	–	–
Production	(16)	(38)	(8)	(22)	(2)	(86)
December 31, 2008	375	175	49	31	34	664

Excluding economic revisions, our net oil and gas reserve additions are 66 mmboe (60 after royalties) and including Syncrude are 74 mmboe (67 after royalties).

Extensions and discoveries of 34 mmboe (33 after royalties) are primarily from extending our Long Lake Project by core hole delineation, development drilling at Buzzard, and ongoing development of coalbed methane in Canada. Other increases relate to ongoing exploitation activities in the North Sea, Yemen, the Gulf of Mexico and Canada. No proved reserves will be recognized for exploration discoveries at Golden Eagle, Pink or Blackbird in the UK until we advance our understanding of these discoveries further and demonstrate a commitment to development.

Positive technical revisions of 32 mmboe (27 after royalties) are primarily from additions at Buzzard, Yemen and Canadian coalbed methane where drilling results and production performance supported higher reserve estimates. Negative technical revisions

of 13 mmboe relate primarily to Ettrick where ongoing development drilling and testing did not support previous estimates.

Negative economic revisions of 50 mmboe (7 after royalties) are the result of lower commodity prices (primarily oil) and rising costs at year-end. Under SEC regulations, we are required to use year-end prices and costs to estimate our reserves. About 85% of this revision is price related, of which half occurred in our Canadian heavy oil properties, while the remaining changes occurred at our Buzzard, Ettrick, Scott and Telford fields in the UK, and some of our US shelf properties. The majority of the remaining revisions resulted from higher year-end costs, primarily on our Canadian heavy oil properties.

The following provides a summary of the changes in our proved oil and gas reserves (before royalties) excluding Syncrude, for the past three years. Refer to page 126 for proved reserves information on an after-royalties basis for the past three years.

<i>(mmboe)</i>	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2005	117	145	90	105	11	468
Extension and Discoveries	45	40	12	7	30	134
Revisions – Technical	27	78	(21)	4	1	89
Revisions – Economic	228	(13)	(8)	–	(2)	205
Acquisitions	–	1	11	–	–	12
Divestments	–	–	(2)	–	–	(2)
Production	(42)	(76)	(33)	(85)	(6)	(242)
December 31, 2008	375	175	49	31	34	664

Since the end of 2005, we added 440 mmboe (431 after royalties), sold 2 mmboe (2 after royalties) and produced 242 mmboe (191 after royalties). Extensions and discoveries of 134 mmboe (122 after royalties) occurred primarily at our Usan, Ettrick and Buzzard fields, Long Lake Project, Canadian coalbed methane, and the deep-water Gulf of Mexico. The net technical revisions of 89 mmboe (81 after royalties) include 78 mmboe (78 after royalties) of positive revisions in the UK primarily attributed to production performance at Buzzard and increased expected recoveries for our Long Lake Project based on analogous commercial SAGD projects. Negative technical revisions occurred primarily from lower-than-expected production performance at our Aspen field and some Shelf properties in the US Gulf of Mexico. Economic revisions of 205 mmboe (218 after royalties) are related to changes in year-end prices and costs. This includes a positive revision of 246 mmboe (245 after royalties) from reinstatement of Long Lake bitumen reserves that we had removed due to low bitumen prices at the end of 2004. This was partially offset by negative revisions of 41 mmboe (27 after royalties) as a result of substantial decline in oil and gas prices at December 31, 2008 versus 2005 and a rising cost environment that has not yet corrected with the decline in commodity prices.

Proved Undeveloped Reserves

The following table provides a summary of the proved undeveloped reserves (PUDs) for our oil and gas activities at the end of the last two years:

(mmboe)	2008					
	Before Royalties			After Royalties		
	PUDs	Total Proved ¹	% of Total	PUDs	Total Proved ¹	% of Total
United Kingdom	40	175	23%	40	175	23%
Yemen	3	31	8%	1	20	7%
Canada	236	375	63%	234	362	65%
United States	11	49	23%	10	43	23%
Other Countries	28	34	82%	25	31	82%
December 31, 2008	318	664	48%	310	631	49%

(mmboe)	2007					
	Before Royalties			After Royalties		
	PUDs	Total Proved ¹	% of Total	PUDs	Total Proved ¹	% of Total
United Kingdom	54	207	26%	54	207	26%
Yemen	2	41	5%	1	23	4%
Canada	236	386	61%	200	334	60%
United States	20	62	32%	17	53	32%
Other Countries	30	38	79%	25	33	76%
December 31, 2007	342	734	47%	297	650	46%

¹ Excludes proved reserves for our Syncrude operations of 324 mmboe (295 after royalties) in 2008 and 324 mmboe (267 after royalties) in 2007.

In 2008, our PUDs decreased by 24 mmboe (increased by 13 after royalties). We converted 29 mmboe (26 after royalties) with the start-up of our Long Lake SAGD operations, the substantial completion of our Longhorn development project, and the remainder relating to ongoing development of various other properties. We had negative revisions of 14 million boe (13 after royalties) primarily at Ettrick, and we added 19 mmboe (51 after royalties) with the extension of the Long Lake reservoir. After-royalty changes reflect the impact of lower price-sensitive royalties for our Long Lake Project.

In Canada, our PUDs remained at 236 mmboe before royalties (increased 34 to 234 after royalties). At Long Lake, PUDs increased by 4 mmboe (37 after royalties) due to a 19 mmboe (19 after royalties) addition from ongoing delineation drilling,

offset by a 15 mmboe reduction (18 increase after royalties) from conversion to proved with the ongoing start-up of SAGD wells. Other PUDs declined by 4 mmboe (3 after royalties) due to conversions in our coalbed methane properties and revisions in our heavy oil properties. The remaining PUDs are substantially all from Long Lake where we have 232 mmboe (230 after royalties) which are expected to be converted to developed over the next 20 years as we drill additional wells to provide feedstock to run the upgrader at capacity. Other PUDs relate to infill drilling, recompletions or facilities enhancements on our various CBM, heavy oil and natural gas properties. The majority of these PUDs are expected to be converted to producing reserves in 2009 and 2010.

In the United Kingdom, our PUDs decreased from 54 mmboe (54 after royalties) to 40 mmboe (40 after royalties). The decrease primarily reflects the reduction of PUDs at Etrick. About 75% of the PUDs at December 31, 2008 relate to Buzzard while the remainder relate to Etrick. At Buzzard, we converted 5 mmboe of PUDs to producing and added 3 mmboe for increased recovery factors on remaining undrilled locations. The Buzzard PUDs are expected to be converted to producing over the next few years as we drill additional wells and develop increased H₂S handling facilities to keep the platform operating at capacity. We expect to convert the majority of Etrick PUDs to producing when production is initiated in 2009.

In the United States, our PUDs decreased from 20 mmboe (17 after royalties) to 11 mmboe (10 after royalties) largely relating to the completion of the development at Longhorn and conversion and revision of the remaining Gulf of Mexico shelf PUDs. Almost all of the remaining PUDs are located in the deep water of the Gulf of Mexico and relate to suspended production from hurricane damage in our Green Canyon blocks and Gunnison infill drilling. The majority of these PUDs are expected to be converted to producing reserves in 2009 and 2010.

In other countries, PUDs relate primarily to our Usan development, offshore West Africa.

Excluding Long Lake and Usan, we expect to convert over 90% of our PUDs to producing in the next three years. Usan will be converted by 2012 when it is expected to come on stream. Long Lake PUDs will be converted over the next 20 years as new wells are drilled to offset declines from the initial SAGD wells. At the same time, we expect our ongoing exploration and development activities to continue to add new PUDs.

During the past three years, our total PUDs before royalties increased from 180 mmboe to 318 mmboe (165 to 310 after royalties). As a result, our PUDs before royalties as a percent of total proved reserves excluding Syncrude increased from 38% to 48% (42% to 49% after royalties). During this time, we added 206 mmboe (179 after royalties) at our Long Lake Project from the reinstatement of proved reserves previously written off due to low year-end bitumen prices and another 96 mmboe before royalties (119 after royalties), related to our active development projects at Long Lake, Usan, Etrick, CBM and Longhorn. We converted 164 mmboe before royalties (153 after royalties) to developed with the completion of development of our Buzzard, Farragon and Duart fields in the United Kingdom, Block 51 in Yemen, and ongoing development of work elsewhere.

Basis of Reserves Estimates

Reserve estimates in this report are internally prepared. Refer to the section on Critical Accounting Estimates—Oil and Gas Accounting—Reserves Determination on page 70 for a description of our reserves process. As described therein, we have at least 80% of our oil and gas reserve estimates either evaluated or audited annually by independent qualified reserves consultants. The nature and scope of the independent evaluations and audits is determined by agreement between us and the engineering firm. Independent assessments for other companies may, therefore, be different.

The following provides an overview of the nature and scope of the independent evaluations and audits that we have performed. An independent evaluation is a process whereby we request a third-party engineering firm to prepare an estimate of our reserves by assessing and interpreting all available data on a reservoir. An independent audit is a process whereby we request a third-party engineering firm to prepare an estimate of our reserves by reviewing our estimates, supporting working papers and other data as they feel is necessary. The primary difference is that an auditor reviews our work and estimate in preparing their estimate whereas an evaluator uses the reservoir data to prepare their estimate.

In each case, we request their estimate be prepared using standard geological and engineering methods generally accepted by the petroleum industry. Generally accepted methods for estimating reserves include volumetric calculations, material balance techniques, production and pressure decline curve analysis, analogy with similar reservoirs, and reservoir simulation. The method or combination of methods used is based on their professional judgement and experience. In preparing their estimates, they obtain information from us with respect to property interests, production from such properties, current costs of operations, expected future development and abandonment costs, year end prices, agreements relating to current and future operations and sale of production, and various other information and data. They may rely on the information without independent verification. However, if in the course of their evaluation they question the validity or sufficiency of any information, we request that they not rely on such information until they satisfactorily resolve their questions or independently verify such information. We do not place any limitations on the work to be performed. Upon completion of their work, the independent evaluator or auditor issues an opinion as to whether our estimate of the proved reserves for that portfolio of properties is, in aggregate, reasonable relative to the criteria set forth in SEC Rule 4-10(a)(2) of Regulation S-X. These rules define

proved reserves as the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Our estimate may differ from the independent evaluators and auditors as they apply their professional judgement and experience, which may result in applying different estimating methods or interpreting data differently than us. We believe our estimate for a portfolio of properties is reasonable when it is, in aggregate, within 10% of the estimate of the independent evaluator or auditor.

We engaged DeGolyer and MacNaughton (D&M) to evaluate 100% of our reserves before royalties (100% after royalties) for the United Kingdom, Yemen Masila, Yemen Block 51 and Nigeria. A separate opinion was provided on each of these four areas. D&M provided an opinion on each of the areas that the proved reserves estimate prepared by us is, in aggregate, reasonable when compared to their estimate which was prepared in accordance with current SEC Rules.

We engaged McDaniel & Associates Consultants Ltd. (McDaniel) to evaluate 99% of our Canadian conventional, CBM and bitumen reserves before royalties (99% after royalties) and to audit 100% of our Syncrude mining reserves before royalties (100% after royalties). The properties were selected by management and reviewed with the Reserves Review Committee of the Board. All material properties were selected. McDaniel provided their opinions that the proved reserves estimates prepared by us are, in aggregate, reasonable when compared to their estimates which were prepared in accordance with current SEC Rules.

We engaged Ryder Scott Company (Ryder Scott) to evaluate 92% of our US Gulf of Mexico shelf and deep water reserves before royalties (92% after royalties). The properties were selected by management and reviewed with the Reserves Review Committee of the Board. All material properties were selected. Ryder Scott provided an opinion that the difference between their estimate and ours is within the range of reasonable differences and that the estimates have been prepared in accordance with current SEC Rules. In prior years, we engaged William M. Cobb & Associates Inc. to evaluate our deep water reserves. The Reserves Review Committee of the Board was satisfied that the change in evaluator was not the result of a dispute with management.

SYNCRUDE MINING OPERATIONS

We hold a 7.23% participating interest in Syncrude. This joint venture was established in 1975 to mine shallow oil sands deposits using open-pit mining methods, extract the bitumen and upgrade it to a high-quality, light (32° API), sweet, synthetic crude oil. Syncrude's operating strategy is to develop this resource, focusing on safe, reliable and profitable operations.

Syncrude exploits a portion of the Athabasca oil sands that contains bitumen in the unconsolidated sands of the McMurray formation. Ore bodies are buried beneath 50 to 150 feet of over-burden, have bitumen grades ranging from 4 to 14 percent by weight and ore bearing sand thickness of 100 to 160 feet. Syncrude's operations are on eight leases (10, 12, 17, 22, 29, 30, 31, and 34) covering 248,300 hectares, 40 km north of Fort McMurray in northeast Alberta. Syncrude mines oil sands at two mines: Mildred Lake North and Aurora North. These locations are readily accessible by public road. Trucks and shovels are used to collect the oil sands in the open pit mines. The oil sands are transferred for processing using a hydro-transport system.

The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 270 million tons of oil sands per year and between 150 to 160 million barrels of bitumen per year depending on the average bitumen ore grade. To extract bitumen, the oil sands are mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Mildred Lake North Mine uses hot water, steam and caustic soda to create a slurry, while at the Aurora North Mine, the oil sands are mixed with warm water to produce a slurry. Most of the water used in operations is recycled from the upgrader and mine sites. Incremental water is drawn from the Athabasca River in accordance with existing licenses.



The extracted bitumen is fed into a vacuum distillation tower and three cokers for primary upgrading. The resulting products are then separated into naphtha, light gas-oil, and heavy gas-oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities to form light, sweet, synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale.

The high quality of Syncrude's synthetic crude oil allows it to be sold at prices approximating WTI. In 2008, about 40% of the synthetic crude oil was sold to Edmonton area refineries, and the remaining 60% was sold to refineries in eastern Canada and the mid-western United States. Electricity is provided to Syncrude from two generating plants on site: a 270 MW plant and an 80 MW plant.

Since operations started in 1978, Syncrude has shipped more than 1.9 billion barrels of synthetic crude oil to Edmonton by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 to accommodate increased Syncrude production.

At December 31, 2008, our total net book value of property, plant and equipment, including surface mining facilities, transportation equipment, and upgrading facilities, was approximately \$1.1 billion. Based on development plans, our share of future expansion and equipment replacement costs over the next 35 years is expected to be about \$5.2 billion.

In 1999, the Alberta Energy and Utilities Board (AEUB) extended Syncrude's operating license for the eight oil sands leases through to 2035. The license permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the AEUB. There were no known commercial operations on these leases prior to the start up of operations in 1978.

In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude had increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine, which involved extending mining operations to a new location about 25 miles north of the main Syncrude site. The next expansion of Syncrude came on stream in 2006, increasing capacity to 360,000 bbls/d with the completion of the Stage 3 project.

Syncrude pays a royalty to the Alberta government. As of January 2002, this royalty was equal to the greater of 1% of gross revenue or 25% of net synthetic-based profit after deducting new capital expenditures. In connection with the provincial government's review of Alberta royalty rates in 2007, the Syncrude owners entered into negotiations at the request of the government to revise the royalty terms. Effective January 1, 2009, and consistent with the rest of the oil sands industry, Syncrude will begin paying royalties based on bitumen product, rather than paying royalties calculated on fully upgraded synthetic crude oil. As a part of this conversion, the Alberta government will recapture upgrader capital expenses of about \$5 billion (gross) that were deducted against prior royalties payables. The \$5 billion royalty deductions previously received by the Syncrude owners will be recaptured by the Alberta government over a 25 year period. In addition, the Province of Alberta and Syncrude reached agreement to establish new transitional royalty terms. Under the terms of the agreement, until December 31, 2015, Syncrude will continue to pay base

royalty rates (being the greater of 25% of net bitumen-based revenues, or 1% of gross bitumen-based revenues) plus an incremental royalty of up to \$975 million (our share \$70.5 million). The incremental royalty is subject to certain minimum bitumen production thresholds and is to be paid in six annual payments, as indicated in the following table:

<i>(Cdn\$ millions)</i>	2010	2011	2012	2013	2014	2015	Total
Gross	75	75	100	150	225	350	975
Nexen's Share	5	5	7	11	17	25	70

This agreement is in lieu of the Syncrude owners converting to the Province's new royalty framework announced in October 2007, that is effective January 1, 2009. After January 1, 2016, the rates under the new royalty framework will apply to the Syncrude project.

In 2008, Syncrude's production of marketable synthetic crude oil was 289,100 bbls/d. Nexen's share was 20,900 bbls/d before royalties (18,200 after royalties). At year end, Syncrude reserves of 324 mmbob before royalties (295 after royalties) represented about 33% of our total proved oil and gas and Syncrude reserves.

The following table provides some operating statistics for Syncrude operations:

	2008	2007	2006
Total Mined Volume¹			
Millions of Tons	531	470	428
Mined Volume to Oil Sands Ratio ¹	2.5	2.1	2.2
Oil Sands Processed			
Millions of Tons	216	220	192
Average Bitumen Grade (weight %)	11.1	11.6	11.3
Bitumen in Mined Oil Sands			
Millions of Tons	24	26	22
Average Extraction Recovery (%)	90	92	90
Bitumen Production²			
Millions of Barrels	122	133	112
Average Upgrading Yield (%)	86	84	85
Gross Synthetic Crude Oil Shipped³			
Millions of Barrels	105.8	111.3	94.3
Nexen's Share of Marketable Crude Oil			
Millions of Barrels Before Royalties	7.7	8.1	6.8
Millions of Barrels After Royalties	6.6	6.9	6.2

¹ Includes pre-stripping of mine areas.

² Bitumen production in barrels is equal to bitumen in mined oil sands multiplied by the average extraction recovery and the appropriate conversion factor.

³ Approximately 1% of the produced synthetic crude oil is used internally, primarily for diesel that fuels the trucks and shovels at Syncrude. The remaining synthetic crude oil is sold externally.

ENERGY MARKETING

Our marketing group sells proprietary and third-party natural gas, crude oil, natural gas liquids, and power in certain regional global markets. We have built a solid strategic presence within various North American regional markets and have extended our presence into certain global markets. We focus on securing access to transportation, storage and facilities, as well as the commodities we produce or acquire. We optimize the margin on our base business by physically and financially trading around our access to these physical assets. We also trade financially for profit where we see opportunities in the market. We use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes.

Our marketing strategy is to:

- obtain competitive pricing on the sale of our oil and gas production;
- provide market intelligence in support of our oil and gas operations;
- provide superior customer service to producers and consumers;
- capitalize on market opportunities through physical and financial trading; and
- optimize physical assets or contracts to which we have access.

This strategy aligns with our corporate focus on realizing the full value from our assets and provides us with the market intelligence needed to deliver current and future oil and gas production to market at competitive pricing.

Marketing Office Locations



North American Gas Marketing

The marketing and trading of North American natural gas has historically been our marketing group's largest revenue source. We focus on key regional markets where we have a strategic presence, equity production, solid customer relationships, in-depth understanding of the market or established physical assets. We capture regional opportunities by managing supply, transportation and storage assets for producers and end users. In addition to the fee-for-service income we realize from managing these assets, we generate further revenue by:

- capitalizing on location spreads (differences in prices between locations) using our transportation assets;
- offering customized service to our customers that bundle our assets with the commodity;
- utilizing our storage assets where we optimize forward and seasonal pricing differences; and
- leveraging regional knowledge we gain through optimizing our assets.

We have offices in key regions including Calgary, Detroit, Denver and Houston. Our offices provide a variety of services, including supply, storage, and transportation management as well as netback pool arrangements and other customer services. Our customers include producers and consumers (including utilities) in western Canada, eastern Canada, the northeastern US, the

US mid-continent, the Pacific northwest and the US Rockies. We use our access to transportation and storage facilities to optimize returns for ourselves as well as our customers.

Over the years, we focused on growing our asset base by acquiring physical gas purchase and sales contracts, as well as natural gas transportation and storage capacity, on favourable terms. The growth in our underlying physical business was supplemented by an expanding profitable financial trading business with a focus on time and location spreads. In 2008, financial trading proved particularly challenging causing us to reassess the merits of this activity. While we expect to continue to focus on our core physical business, we are reducing our financial trading levels and exposures in an orderly fashion.

Our position as a physical marketer at multiple delivery points in key markets gives us flexibility to capitalize on time and location spreads. With pipeline capacity, we can move gas from producing to consuming regions to take advantage of price differences. At the end of 2008, we held 1.8 bcf/d of pipeline capacity, primarily between western Canada and the eastern US. We also use storage capacity to store normally cheaper summer gas in the ground until the winter heating season arrives. We had access to 38 bcf of natural gas storage facilities at the end of the year.

In addition to transportation and storage assets, we enter into financial contracts that enable us to capture profits around time and location spreads. The risks we assume on these contracts are based on fundamental analysis and knowledge of regional markets. The risk is managed by our product group teams and monitored by our risk group, with regular reporting to Management and the Board of Directors.

North American Crude Oil Marketing

Our crude oil business focuses on marketing physical crude oil to end-use refiners. The crude oil group markets Nexen's production and more than 650,000 bbls/d of third-party production. In addition to physical marketing, we take advantage of quality, time and location spreads.

Our North American operations focus on key regions supported by our offices in Calgary, Houston and Denver. In western Canada, our producer services group concentrates on purchasing from a diversified supply base, while our trading team seeks to optimize the mix for sale to refiners. The Chicago and Denver areas have been key markets for our western Canadian crude, however, we continue to expand our presence into the US Gulf Coast. Our deep-water Gulf of Mexico crude oil production expanded our presence in that market through our Houston office. At the end of 2008, we had access to 2.6 mmbbls of storage and over the course of the year, marketed approximately 656 mbbbls per day.

Our operations also include a North American natural gas liquids (NGLs) business that focuses on buying and selling NGLs. This business acquires and moves product within North America. At the end of 2008, we had access to 1.2 mmbbls of NGL storage and over the course of the year, moved approximately 26 mbbbls per day of product. In 2008, we were active in the ethanol markets in North America but we expect to turn our focus to more traditional NGL markets in 2009.

Our crude oil marketing group also enters into financial contracts intended to capture trading profits around time, quality and location spreads. Like gas marketing, the risks assumed are based on fundamental analysis and proprietary knowledge of regional markets, and are monitored by our risk group.

North American Power Marketing

Our power marketing group is responsible for optimizing our 50% interest in a 120 MW gas-fired, combined-cycle power generation facility at Balzac, Alberta, as well as our 50% interest in the 70 MW Soderglen wind power operation in southern Alberta. We also market the surplus power from the 170 MW cogeneration facility at Long Lake (Nexen 65% interest) that commenced operation in 2008. We market power to larger commercial, industrial and municipal clients in Alberta. We are currently the largest supplier of power to commercial and industrial sectors in the province. Our Balzac facility began operations in 2001 and Soderglen in October 2006.

Europe

Our European operations include a UK-based European gas and power marketing business. Our trading strategies include capitalizing on time and location spreads involving the UK and European gas and power markets, using primarily financial contracts. We are increasing our presence in both the UK and continental Europe physical gas markets. During the year, we secured access to transportation and storage capacity in the UK and Europe. At the end of 2008, we had access to 0.1 bcf/d transportation capacity and 3.7 bcf of storage capacity. Our European marketing operations also physically market our Buzzard crude oil production.

Asia

Our international team in Asia continues to focus on the physical marketing of Masila crude oil. In order to meet customer needs, we occasionally market other regional crude qualities. In addition to our own crude, we sell production for our partners and third parties in the Yemen region. By locating our international crude oil marketing office in Singapore, we are well positioned to serve both the producing region and the Asian refining market.

CHEMICALS

In 2005, we monetized part of our chemicals business through an initial public offering of the Canexus Income Fund. We currently hold a 63.5% interest in our chemicals business, and continue to fully consolidate chemicals in our Consolidated Financial Statements.

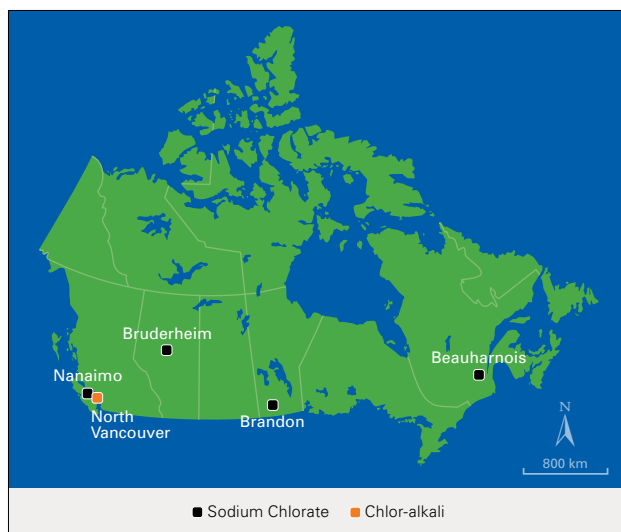
Our chemicals business manufactures sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada and Brazil. This production is sold in North and South America, with some sodium chlorate distributed in Asia. Our manufacturing system is reliable, low-cost and strategically located to capitalize on competitive electricity costs and transportation infrastructure to minimize production and delivery costs.

Electricity is the most significant operating cost in producing sodium chlorate and chlor-alkali products, making up over half our cash costs. Therefore, our current facilities are strategically located to take advantage of economic power sources. Our second highest cost is transportation. The proximity of our manufacturing plants to major customers and competitive freight rates minimize our transportation costs. Labour is also a significant manufacturing cost. Approximately 50% of our workforce is unionized with collective agreements in place at all of our unionized plants.

To grow value in our chemicals business, we focus on reducing our costs while maintaining market share, building a sustainable North American customer base and capturing new offshore opportunities. In 2009, we will fund our current capital projects from undistributed cash, dividend reinvestment and existing credit facilities (which were renewed in 2008).

North America

The North American pulp and paper industry consumes approximately 93% of the continent's sodium chlorate production. We market our sodium chlorate production to numerous pulp and paper mills under multi-year contracts that contain price and volume adjustment provisions. Approximately 27% of this production is sold in Canada, 66% in the US, and the rest is marketed offshore.



We are the third-largest manufacturer of sodium chlorate in North America with four Canadian facilities: Nanaimo, British Columbia; Bruderheim, Alberta; Brandon, Manitoba; and Beauharnois, Quebec.

In 2008, we completed an expansion of our Brandon plant, increasing capacity to over 290,000 tonnes per year. Brandon is the world's largest sodium chlorate facility and has one of the lowest cost structures in the industry, significantly enhancing our competitive position in North America.

Our chlor-alkali facility at North Vancouver, British Columbia, manufactures caustic soda, chlorine and muriatic acid. Almost all of our caustic soda is consumed by local pulp and paper mills, while our chlorine is sold to various customers in the poly-vinyl, chloride, water purification and petrochemicals industries, primarily in the United States. A technology conversion project currently under way will replace existing diaphragm technology and assets with newer, proven membrane technology that is expected to be more cost effective and will expand productive capacity by 35%. This project is progressing on time and on budget with committed financing in place through to August 2011. The project is expected to start up in the first quarter of 2010 and should lower our cost structure and solidify our low-cost position in this regional market.

Average Annual Production Capacity

<i>(short tons)</i>	2008	2007	2006
Sodium Chlorate			
North America	484,800	450,055	446,208
Brazil	68,563	68,563	68,563
Total	553,363	518,618	514,771
Chlor-alkali			
North America	364,500	364,500	356,002
Brazil	109,430	109,430	109,430
Total	473,930	473,930	465,432

Brazil

We entered Brazil in 1999 by acquiring a sodium chlorate plant and a chlor-alkali plant from Aracruz Cellulose S.A. (Aracruz), the leading manufacturer of pulp in Brazil. The majority of the sodium chlorate production is sold to Aracruz under a long-term sales agreement that expires in 2024. Most of the chlorine and about 8% of the sodium chlorate production is sold in the merchant market under short-term contracts. In 2002, we completed an expansion at both facilities to meet Aracruz's growing needs. A 2,000 tonne incremental sodium chlorate expansion project is currently in progress at our Brazil plant and is scheduled for start up in early 2009. A further 4,400 tonne expansion was recently approved, which is estimated to start up in early 2010. The majority of our electricity needs in Brazil are supplied by a long-term supply contract, which expires in February 2013.

GOVERNMENT REGULATIONS

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. Current legislation is generally a matter of public record, and we are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. We participate in many industry and professional associations and monitor the progress of proposed legislation and regulatory amendments.

ENVIRONMENTAL REGULATIONS

Our oil and gas, Syncrude and chemical operations are subject to government laws and regulations designed to protect and regulate the discharge of materials into the environment in countries where we operate. We believe our operations comply, in all material respects, with applicable environmental laws. To reduce our exposure, we apply industry standards, codes and best practices to meet or exceed these laws and regulations. We may conduct activities in countries where environmental regulatory frameworks are in various stages of evolution. Where regulations are lacking, we observe Canadian standards where applicable, as well as internationally accepted industry environmental management practices.

We have an active Health, Safety, Environment and Social Responsibility group (HSE&SR) that ensures our worldwide operations are conducted in a safe, ethical and socially responsible manner. Our HSE&SR practices are reported to our Board of Directors throughout the year. Our overall HSE&SR program is guided by the following 12 element management system:

- Leadership and commitment;
- Regulatory compliance;
- Safety and occupational health management;
- Social responsibility;
- Environmental management;
- Supply chain management;
- Documentation and procedure management;
- Training and awareness;
- Process safety management;
- Emergency preparedness;
- Event reporting, investigation and follow-up; and
- Continuous improvement.

Our performance against this system is reviewed by an external auditor every three years and we have been recognized by the Dow Jones Sustainability Index as a global sustainability leader for eight years in a row. Our progress is publicly reported in our sustainability report which is available on our website at www.nexeninc.com.

Climate Change and Environmental Responsibilities

A growing awareness of possible causes and effects of climate change along with volatile consumer prices have increased concern over the manner by which the world produces and consumes energy. Government and investor expectations continue to converge on sustainable resource development and responsible operating practices, including the preservation of air, water and land. Some jurisdictions in which we operate have already formalized these expectations into regulation while others move closer to doing so. Regardless of how the jurisdictions in which we operate ultimately define their emissions regulation, we expect that our regulatory obligations and the associated cost of compliance will increase. Due to the uncertainty surrounding the future implementation of emissions regulations, we are unable to estimate our costs of compliance.

As a result of our commitment to sustainable development and responsible operating practices, we believe we are well positioned to meet the challenges of climate change and environmental regulation. We have built a corporate culture of integrity and respect for the communities and environments in which we operate, and have developed policies and practices for continuing compliance with all environmental laws and regulations.

Air

To meet our current greenhouse gas (GHG) emissions obligations, we adhere to a five point emissions management strategy:

- reduce emissions by decreasing vent gas and improving energy efficiency;
- self-generate carbon credits from wind power;
- acquire carbon credits through qualified offshore projects, such as the Greenhouse Gas Credit Aggregation Pool (GGCAP);
- participate in eligible international and domestic offset projects such as methane capture from landfills; and
- purchase carbon credits on the spot market.

Water

We are developing a company-wide water management strategy to limit water use. An external consulting firm compiled information on water issues relevant to Nexen's projects and operations, reviewed key business drivers related to water, and surveyed Nexen's business units with respect to their water policies and practices. Benchmarking of oil and other industry related water policies, strategies and programs was also completed. This information was used as the starting point for our HSE&SR group to begin the process of developing corporate water management principles that are aligned with our stated objective to "grow value responsibly".

Land

Our land use practices are based upon principles of minimal disturbance and a commitment to return land to its natural state after responsibly producing oil and gas resources. We also recognize our ability to effectively access land is directly linked to the way in which we manage potential environmental effects and in how we cooperate with other industries to reduce our cumulative impact.

For many stakeholders, a company's ability to meet environmental expectations is a significant criteria upon which their decision to invest or conduct business is based. A failure to meet those expectations can limit access to exploration, development and partnership opportunities. We therefore believe that superior environmental and social responsibility performance is directly linked to economic performance.

We have outlined and more fully discussed our environmental practices and policies in our sustainability report, available on our website at www.nexeninc.com.

Environmental Provisions and Expenditures

Meeting the challenges of climate change and environmental regulation and our commitment to sustainable resource development increases the cost of our operations. The ultimate financial impact of our sustainability practices and compliance with environmental laws and regulations is not clearly known and cannot be reasonably estimated as new standards continue to evolve in the countries in which we operate. We estimate our future environmental costs based on past experience and current regulations. At December 31, 2008, \$1,059 million (\$2,393 million, undiscounted, adjusted for inflation) has been provided in our Consolidated Financial Statements for asset retirement obligations. In 2008, we increased our retirement obligations for future dismantlement and site restoration by over \$200 million primarily from ongoing development of the

Long Lake Project in the Athabasca oil sands, our CBM wells in Canada and from industry cost pressures in the North Sea and the US Gulf of Mexico.

In 2008, our expenditures for environmental-related matters, including environment control facilities, were approximately \$55 million. In 2009, we estimate these expenditures to range between \$35 and \$50 million.

EMPLOYEES

We had 4,254 employees on December 31, 2008, of which 309 were employed under collective bargaining schemes. Information on our executive officers is presented in Item 10 of this report.

ITEM 1A. Risk Factors

RISK FACTORS

Our operations are exposed to various risks, some of which are common to others in the oil and gas industry and some of which are unique to our operations. Certain risks set out below constitute “forward-looking statements” and the reader should refer to the “Special Note Regarding Forward Looking Statements” set out on page 78 of this 10-K.

Our profitability and liquidity is highly dependent on the price of crude oil and natural gas.

Our operations and performance depend significantly on the price of crude oil and natural gas. Crude oil and natural gas are commodities which are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Historically, these prices have been very volatile, and are likely to remain volatile in the future. Current worldwide economic conditions have depressed crude oil and natural gas prices significantly, which may materially and adversely affect our results of operations and revenue generated from operating activities should those price levels persist for an extended period of time. The current price environment has also affected the value of our oil and gas properties and our level of spending for oil and gas exploration and development.

Our crude oil prices are based on various reference prices, which generally track the movement of Brent and WTI. Adjustments are made to the reference price to reflect quality differentials and transportation. Brent, WTI and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and geopolitical events.

The continued and unprecedented disruptions in the credit markets may negatively impact our liquidity.

While we generally rely upon cash flow from operations to fund our activities, a sustained depression in the prices of crude oil and natural gas may require us to draw upon existing credit facilities or issue new debt or equity to satisfy our funding needs. The current financial turmoil affecting the banking system and financial markets, and the possibility that financial institutions may consolidate or go out of business has resulted in a tightening of the credit markets, a low level of liquidity in many financial markets, and extreme volatility in fixed income, credit, currency and equity markets. There could be a number of follow-on effects from the credit crisis on our business which could negatively impact our liquidity and operations, and which may materially affect our business, including: a reduced ability to access credit or issue new public or private debt; higher costs of borrowing; lower returns on invested cash; and a negative change to our ratings outlook or even a reduction in our credit ratings by one or more credit rating agencies. A downgrade could limit our access to private and public credit markets and increase the costs of borrowing under existing facilities that could be available. If our credit ratings were downgraded, we could be required to provide additional liquidity to our marketing division if further collateral is required to be placed with counterparties, or reduce some of our marketing activities.

The inability of counterparties and joint operating partners to fulfill their obligations to us could adversely impact our results of operations.

Credit risk affects both our trading and non-trading activities and there is the risk of loss and additional burden if counterparties and joint venture partners do not or cannot fulfill their contractual obligations. In particular in 2008, the credit crisis that impacted world financial markets caused some of our counterparties to restructure, declare bankruptcy or sell assets to fund liquidity requirements. In 2009, we may experience similar developments. Most of our receivables and partners are with counterparties in the energy industry and are subject to normal industry credit risk. The inability of any one or more of these parties to fulfill their obligations to us may adversely impact our results of operations.

Competitive forces may limit our access to natural resources, and create labour and equipment shortages.

The oil and gas industry is highly competitive, particularly in the following areas:

- gaining access to areas or countries known to have available resources;
- searching for and developing new sources of crude oil and natural gas reserves;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include national oil companies, major integrated oil and gas companies and various other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers. The pulp and paper chemicals market is also highly competitive. Key success factors in each of these markets are price, product quality, logistics and reliability of supply.

Competitive forces may result in shortages of prospects to drill, labour, drilling rigs and other equipment to carry out exploration, development or operating activities, and shortages of infrastructure to produce and transport production. It may also result in an oversupply of crude oil and natural gas. Each of these factors could negatively impact our costs and prices and, therefore, our financial results.

We operate in harsh and unpredictable climates and locations where our access is regulated which could adversely impact our operations.

Some of our facilities are located in harsh and unpredictable climates and locations which can experience extreme weather conditions and natural disasters such as: sustained ambient temperatures above 40°C or below -35°C, flooding, droughts, wind and dust storms, difficult terrain, high seas, monsoons and hurricanes. These conditions are difficult to anticipate and cannot be controlled. In these conditions, operations can become difficult or unsafe and are often suspended. Some of our facilities and those upon which our facilities rely (such as pipelines, power, communications and oilfield equipment) are vulnerable to these types of extreme weather conditions and may suffer extensive damage as a result. If any such extreme weather were to occur, our ability to operate certain facilities and proceed with exploration or development programs could be seriously or completely impaired or destroyed, and could have a material adverse effect on our business, financial condition

and results of operations. The insurance we maintain may not be adequate to cover our losses resulting from disasters or other business interruptions.

In some areas of the world, access and operations can only be conducted during limited times of the year due to weather or government regulation. These adverse conditions can limit our ability to operate in those areas and can intensify competition during periods of good weather for oil field equipment, services, and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs, and could have a material adverse effect on our business, financial condition and results of operations.

Exploration, development and production activities may not be successful and carry a risk of loss.

Acquiring, developing and exploring for oil and natural gas involves many risks. There is a risk that we will not encounter commercially productive oil or gas reservoirs, and that wells we drill may not be productive, or not sufficiently productive to recover all or any portion of our investment in those wells. Seismic data and other exploration technologies we use do not provide conclusive proof prior to drilling a well that crude oil or natural gas is present or may be produced economically. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- encountering unexpected formations or pressures;
- blow-outs, well bore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- accidents and equipment failures;
- uncontrollable flows of oil, natural gas or well fluids; and
- environmental risks.

We may not achieve production targets should our reservoir production decline sooner than expected. Also, we operate two facilities that are located in close proximity to populated areas, and each processes materials of potential harm to the local populations. We may not be fully insured against all of these risks. Losses resulting from the occurrence of these risks may materially impact our operational activities and financial results.

Unconventional gas resource plays carry additional risks and uncertainties.

Part of Nexen's growth strategy is unconventional Canadian gas resource plays, such as CBM and shale gas. Exploitation techniques and practices for these resources in Canada generally remain in the early stages of development and it is very difficult to determine whether or not these resource plays will prove commercially viable, or to what degree.

CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by the coal itself rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in pressure in the coal. Some of the uncertainties associated with development of CBM resources are as follows:

- if the coalbed is water saturated, such as the Mannville coals in the Fort Assiniboine region of Alberta, water generally needs to be extracted to reduce the pressure and allow gas production to occur. A significant period of time may be required to dewater these wet coals and determine if commercial production is feasible. We may also have to invest significant capital in these assets before they achieve commercial rates of production, if ever;
- some coalbeds may not have sufficient natural permeability in the coalbed to recover the gas in place and can therefore require more extensive, and expensive, completion technologies which can increase the cost of drilling and production;
- the public may react negatively to certain water disposal practices related to water saturated CBM projects, even though these water disposal practices are regulated to ensure public safety and water conservation. Negative public perception around water saturated CBM production could impede our access to the resource;
- CBM wells typically have lower producing rates and reserves per well than conventional gas wells, although this varies by area; and
- regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain.

Shale gas is an unconventional gas produced from reservoirs composed of organic rich shales. The gas is stored in pore spaces, fractures or adsorbed into organic matter. Some of the uncertainties associated with development of shale gas resources are as follows:

- shale gas wells typically have higher production decline rates, lower producing rates and reserves per well than conventional gas wells, although this varies by area;
- regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain; and
- shales are typically less permeable than conventional gas reservoirs, and can therefore require more extensive, and expensive, completion technologies which can increase the cost of drilling and production.

Our heavy oil production is more expensive and yields lower prices than light oil and gas.

Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also yields a lower price relative to light oil and gas, as a smaller percentage of high-value petroleum products can be refined from heavy oil. As a result, our heavy oil operations are exposed to the following risks:

- additional costs may be incurred to purchase diluent to transport heavy oil;
- there could be a shortfall in the supply of diluent which may cause its price to increase; and
- the market for heavy oil is more limited than for light oil making it more susceptible to supply and demand fundamentals which may cause the price to decline.

Any one or a combination of these factors could cause some of our heavy oil properties to become uneconomic to produce and/or result in negative reserve revisions.

Without reserve additions, our reserves and production will decline over time and we require capital to produce remaining reserves.

Our future crude oil and natural gas reserves and production, and therefore our future operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, development or acquisitions, our reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves and production will be impaired.

Discovered oil and natural gas reserves are generally only produced when they are economically recoverable. As such, oil and gas prices, and capital and operating costs have an impact on whether reserves will ultimately be produced. As required by SEC rules, our proved reserves represent the quantities that we expect to economically recover using existing prices and costs at the end of the year. Proved reserves can increase or decrease under different price and cost scenarios. Our bitumen reserves are particularly sensitive to year end prices and costs. Under current SEC rules, we are required to recognize our oil sands as bitumen reserves rather than the upgraded premium synthetic crude oil that we produce from the Long Lake Project. We expect price-related revisions, both positive and negative, to occur in the future as the economic producibility of our bitumen reserves are sensitive to year-end prices. We recognize our oil sands as bitumen reserves and they are related to one project. All or none of the reserves will likely be considered economic depending on the year-end prices for bitumen, diluent and natural gas, even though the Long Lake Project has minimal exposure to these factors.

Our proved reserves include undeveloped properties that require additional capital to bring them on stream.

Under SEC rules, the definition of proved undeveloped reserves includes reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells begin production. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates. At December 31, 2008, 48% of our proved reserves before royalties (49% after royalties) were undeveloped. Refer to page 18 for information on our PUDs.

The Long Lake Project faces additional risks compared to conventional oil and gas production.

The Long Lake Project is a fully integrated production, upgrading and cogeneration facility. We use steam assisted gravity drainage (SAGD) technology to recover bitumen from oil sands. The bitumen is partially upgraded using the proprietary OrCrude™ process, followed by conventional hydrocracking to produce a sweet, premium synthetic crude oil. The OrCrude™ process also yields liquid asphaltenes that will be gasified into synthetic gas. This syngas is used as fuel for the SAGD process, a source of hydrogen in the upgrading process, and to generate electricity through a cogeneration facility.

We have a 65% working interest in this project. Given the initial investment and operating costs to produce and upgrade bitumen, the payout period for the project is longer and the economic return is lower than a conventional light oil project with an equal volume of reserves.

In addition to the risks associated with heavy oil production stated above, risks associated with our Long Lake Project include the following:

Application of Relatively New SAGD Bitumen Recovery Process

SAGD has been used in western Canada to increase recoveries from conventional heavy oil reservoirs for over a decade; however, application of SAGD to the insitu recovery of bitumen from oil sands is relatively new. Some of the SAGD oil sands applications to date have been pilot projects, although several commercial SAGD projects have been in steady state operation for over six years.

Our estimates for performance and recoverable volumes for the Long Lake Project are based primarily on our three well-pair SAGD pilot, the initial performance of our first commercial well phase, and industry performance from SAGD operations in like reservoirs in the McMurray formation in the Athabasca oil sands. Using this data, our assumptions included average well-pair productivity of 900 bbls/d of bitumen and a long-term steam-to-oil ratio of 3.0. While some of our wells have achieved these levels, there can be no certainty that our overall SAGD operation will produce bitumen at the expected levels or steam-to-oil ratio. If the assumed production rates or steam-to-oil ratio are not achieved, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity, purchase natural gas for additional steam generation, and/or make short-term bitumen purchases. These could have an adverse impact on the future activities and economic return of the Long Lake Project.

Application of New Bitumen Upgrading Process

The proprietary OrCrude™ process we are using to upgrade raw bitumen to synthetic crude is the first commercial application of the process although we have operated it in a 500 bbl/d demonstration plant and initial upgrader operations which began in January 2009 have produced the desired products. There can be no certainty that the commercial upgrader at Long Lake will sustain or achieve the results which are now being seen or forecast. If we are unable to continue to upgrade the bitumen for any reason we may decide to sell it as bitumen without upgrading, which would expose us to the following risks:

- the market for bitumen is limited;
- additional costs would be incurred to purchase diluent for blending and transporting bitumen;

- there could be a shortfall in the supply of diluent which may cause its price to increase;
- the market price for bitumen is relatively low reflecting its quality differential;
- the market price for bitumen fluctuates over the course of the year; and
- additional costs would be incurred to purchase natural gas for use in generating steam for the SAGD process since we would not be producing syngas from the upgrading process.

These factors could have a significant adverse impact on the future activities and economic returns of the Long Lake Project.

If any of these factors arise, our operating costs would increase and our revenues would decrease from those we have assumed. This would materially decrease expected earnings from the project and the project may not be profitable under these conditions.

Dependence upon Proprietary Technology

The success of the project and our investment depends highly on the proprietary technology of OPTI and proprietary technology of third parties that has been, or is required to be, licensed by OPTI. OPTI currently relies on intellectual property rights and other contractual or proprietary rights, including (without limitation) copyright, trademark laws, trade secrets, confidentiality procedures, contractual provisions, licenses and patents, to secure the rights to utilize its proprietary technology and the proprietary technology of third parties. OPTI may have to engage in litigation to protect the validity of its patents or other intellectual property rights, or to determine the validity or scope of patents or proprietary rights of third parties. Litigation can be time-consuming and expensive, whether OPTI is successful or not. The process of seeking patent protection can itself be long and expensive, with no assurance that any pending or future patent applications of OPTI or such third parties will actually result in issued patents, or that, if patents are issued, they will be of sufficient scope or strength to provide meaningful protection or any commercial advantage to OPTI. Others may develop technologies that are similar or superior to: 1) the technology of OPTI or third parties; or 2) the design around the patents owned by OPTI and/or third parties. There is also a risk that OPTI may not be able to enter into licensing arrangements with third parties for additional technologies required to possibly further expand the Long Lake upgrader.

Operational Hazards

The operation of the project is subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. We may not carry insurance with respect to all potential casualty occurrences and disruptions, and our insurance may not sufficiently cover casualty occurrences or disruptions that occur. The project could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the project and on our business, financial condition and results of operations.

Recovering bitumen from oil sands and upgrading the recovered bitumen into synthetic crude oil and other products involve particular risks and uncertainties. The project is susceptible to loss of production, slowdowns or restrictions on its ability to produce higher-value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. The costs associated with synthetic crude oil production are largely fixed and, as a result, operating costs per unit depend largely on production levels.

The Long Lake Project processes large volumes of hydrocarbons at high pressure and temperatures and will handle large volumes of high-pressure steam. Equipment failures could result in damage to the project's facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Certain components of the Long Lake Project produce sour gas, which is gas containing hydrogen sulphide. Sour gas is a colourless, corrosive gas that is toxic at relatively low levels to plants and animals, including humans. The project includes integrated facilities for handling and treating the sour gas, including the use of gas sweetening units, sulphur recovery systems and emergency flaring systems. Failures or leaks from these systems or other exposure to sour gas produced as part of the project could result in damage to other equipment, liability to third parties, adverse effect to humans, animals and the environment, or the shutdown of operations.

The Long Lake Project produces carbon dioxide emissions. Risk factors relating to environmental regulation are provided separately in this document.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the city of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the Long Lake Project and on us.

Some of our production is concentrated in a few producing assets.

A significant portion of our production is generated from highly productive individual wells or central production facilities. Examples include:

- Scott and Buzzard production platforms in the North Sea;
- central processing facilities, oil pipelines, and export terminal at our Yemen operations;
- our Long Lake synthetic crude oil operations; and
- upgrading facilities at Syncrude in the Athabasca oil sands.

As significant production is generated from each asset, any single event that interrupts one of these operations could result in the loss of production.

Our energy marketing operations expose us to the risk of trading losses and liquidity constraints.

Our trading operations expose us to the risk of financial losses from various sources which may have a material and adverse effect on our financial performance. The commodity markets in which we trade have experienced unanticipated volatility relative to historical variances, resulting in unusual and significant pricing changes, and deviations from anticipated seasonal pricing trends and pricing levels. Our energy marketing division maintains a trading portfolio comprised of both long and short physical and financial positions which may be at any time significant in size or number, and which are predicated on a trading thesis for expected pricing levels and trends in forward or regional markets. Unanticipated volatility in the commodity price level and trends upon which those trading positions are based may cause those positions to decrease in value.

Significant changes in the commodities and financial markets could require us to provide additional liquidity if additional collateral is required to be placed with counterparties, or reduce some of our activities. Adverse credit-related events such as a downgrade of our credit rating to non-investment grade could require additional collateral to be placed with counterparties. Adverse credit-related events could also negatively affect trading counterparties who fail to fulfill their contractual obligations.

The transportation and storage assets and contracts owned by our energy marketing business may decrease in value due to changes in temporal and regional commodity pricing.

Use of marine transportation may expose us to the risk of financial loss and damaged reputation.

From time to time, we may choose to charter marine vessels for the transportation of crude oil. This may expose us to the risk of financial loss and damaged reputation in the event of oil spills.

We operate in countries with political, economic and security risks.

We operate in numerous countries, some of which may be considered politically and economically unstable. A portion of our revenue is derived from operations in these countries. As a result, our financial condition and operating results could be significantly affected by risks associated with international activities, including:

- civil unrest and general strikes;
- political instability, the risk of war and acts of terrorism;
- taxation policies, including royalty and tax increases and retro-active tax claims, and investment restrictions;
- expropriation or forced renegotiation or modification of existing contracts;
- exchange controls, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licenses to operate and concession rights in countries where we currently operate; and
- difficulties in enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

The impact that future terrorist attacks or regional hostilities may have on the oil and gas industry in general, and on our operations in particular, is not known at this time. Uncertainty surrounding military strikes or a sustained military campaign may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities.

There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequence.

We may be affected by changes in government rules and regulations.

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. Current legislation is generally a matter of public record, and we cannot predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. Changes in government regulations could adversely affect our results of operations and financial condition.

Increased environmental regulation could increase our operating costs.

The Kyoto Protocol came into force in 2005 and Canada ratified the Kyoto Protocol in December 2002. In 1997, Canada committed to an emission reduction of 6% below 1990 levels during the First Commitment period from 2008 to 2012. In 2007, the Canadian Federal government introduced a paper titled "Regulatory Framework for Air Emissions" which proposes that the Federal government regulate greenhouse gases (GHGs) and air pollutants beginning as early as 2010, with progressively more stringent reductions applied through 2050. GHGs are regulated based on CO₂ equivalent (CO₂e) intensity per unit of production until 2020–2025, when a cap and trade system may be imposed. The reduction obligations are contemplated

to be met through internal reductions, purchasing offsets or making payments into a technology fund (with escalating but defined costs). The purchasing of offsets was predicated on the establishment of a domestic emissions trading market. Offsets can be obtained from approved projects within Canada and from international projects approved by the Clean Development Mechanism Executive Board subject to certain limitations.

The Federal government was to publish proposed regulations in late 2008, however, no definitive regulation has been published to date. The Federal government's recent announcements indicating an interest in pursuing a bi-lateral cap and trade system with the United States has created further uncertainty about the implementation of their "Regulatory Framework for Air Emissions".

The Canadian Federal government has also indicated their intent to regulate air pollutants concurrent with GHGs but their schedule and long-term objectives remain unclear. We could face technical challenges in meeting some of the criteria for certain pollutants. Any required reductions in the GHGs emitted from our operations could result in increases in our capital or operating expense, or reduced operating rates, especially at the Long Lake Project, which could have an adverse effect on our results of operations and financial condition. As a "new facility" Long Lake will have three years to establish an emissions baseline before having a reduction obligation assigned. In 2008, our Canadian operations, including Syncrude, accounted for 25% of our production before royalties.

Alberta became the first jurisdiction in Canada to enact and implement binding emission reductions (a one time from base, 12% reduction in carbon intensity) on facilities emitting more than 100 kilo-tonnes of CO₂ equivalent. Facilities unable to achieve internal reductions have unlimited ability to pay into a technology fund at the rate of \$15 per tonne of CO₂ equivalent. This amount must be paid annually until such time as internal reduction is achieved unless other approved offsets are acquired from projects in Alberta.

British Columbia enacted legislation in November 2007 entitled the Greenhouse Gas Reduction Targets Act which targets a 33% reduction in current provincial GHG emissions by 2020. Regulations affecting this reduction target have yet to be finalized and we are monitoring progress in that regard.

During the period 2010 to 2020, the Canadian carbon market could be short of supply leading to high carbon prices. It remains to be seen if the Federal and Alberta Provincial levels of government will harmonize their compliance regimes and how the revenue in the technology funds will be allocated.

Our three installations in the UK North Sea have allocations from the regulator and are part of the European Union Emission Trading System. The allocations cover emissions from combustion equipment and flaring from 2008 until 2012. Our installations are expected to have emissions in excess of allowances which will be covered by eligible offsets from the Clean Development Mechanism and purchases of EU Allowances.

Environmental liabilities inherent in the oil and gas and chemicals industries are becoming increasingly sensitive as related laws and regulations become more stringent worldwide. Many of these laws and regulations impose stringent controls on the manner in which we operate and our impact on the environment, and require us to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by disposing or releasing specified substances. Significant changes in the environmental laws and regulations governing our operations could have an adverse financial consequence on us.

Certain operations require the use of fresh and saline water which we currently obtain from both sub-surface and surface sources. Additional costs may be incurred if allocation limits are placed on our water usage, if our water needs exceed allocated amounts or if existing water allocations are reduced.

ITEM 1B.

Unresolved Staff Comments

There are no unresolved staff comments with the SEC.

ITEM 3.

Legal Proceedings

There are a number of lawsuits and claims pending against Nexen, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts assessed against us would not have a material adverse effect on our consolidated financial position or results of operations. We believe we have made adequate provisions for such lawsuits and claims.

Certain of our US oil and gas operations have received, over the years, notices and demands from the US Environmental Protection Agency (EPA), state environmental agencies, and certain third parties for certain sites seeking to require investigation and remediation under federal or state environmental statutes. In addition, notices, demands, and lawsuits have been received for certain sites related to historical operations and activities in the US for which, although no assurances can be made, we believe that certain assumption and indemnification agreements protect our US operations from any present or future material liabilities that may arise from these particular sites.

ITEM 4.

Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of Nexen's security holders during the fourth quarter of 2008.

PART II

ITEM 5.

Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Nexen's common shares are traded on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol NXY.

On December 31, 2008, there were 1,624 registered holders of common shares and 519,448,590 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings.

Issuer Purchases of Equity Securities during the Fourth Quarter¹

Period	(a) Total number of shares (or units) purchased	(b) Average price paid per share (or unit)	(c) Total number of shares (or units) purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares (or units) that may yet to be purchased under the plans or programs
October 1–31, 2008	1,093,900	\$16.44	1,093,900	41,833,346
November 1–30, 2008	1,056,200	\$18.92	1,056,200	40,777,146
December 1–31, 2008	–	–	–	40,777,146

¹ On July 30, 2008, we announced that Nexen received approval from the TSX for a Normal Course Issuer Bid that allows us to repurchase up to a maximum of 52,914,046 common shares in the period of August 6, 2008 to August 5, 2009.

Trading Range of Nexen's Common Shares

(\$/share)	TSX (Cdn\$)		NYSE (US\$)	
	High	Low	High	Low
2008				
First Quarter	34.20	26.00	34.57	25.11
Second Quarter	43.45	29.69	42.71	28.87
Third Quarter	41.47	21.12	40.99	20.56
Fourth Quarter	29.10	13.33	23.99	10.81
2007				
First Quarter	37.60	29.66	31.88	25.18
Second Quarter	36.51	31.25	32.21	29.08
Third Quarter	36.32	27.21	34.79	25.25
Fourth Quarter	32.63	27.88	34.37	27.58

Quarterly Dividends Declared on Common Shares

(\$/share)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2008	0.025	0.050	0.050	0.050
2007	0.025	0.025	0.025	0.025

Payment date for dividends was the first day of the next quarter. All dividends paid to holders of common shares in 2008 have been designated as "eligible dividends" for Canadian tax purposes. This designation will apply to all such dividends paid in the future unless otherwise notified by us.

The Income Tax Act of Canada requires us to deduct a withholding tax from all dividends remitted to non-residents. According to the Canada-US Tax Treaty, we have deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock, where the withholding tax is 5%.

The Investment Canada Act requires that a "non-Canadian", as defined, file notice with Investment Canada and obtain government approval prior to acquiring control of a Canadian business, as defined. Otherwise, there are no limitations, either under the laws of Canada or in Nexen's charter on the right of a non-Canadian to hold or vote Nexen's securities (refer to the table of securities authorized for issuance under equity compensation plans on page 161).

On February 3, 2000, at a Special Meeting of Shareholders, a Shareholder Rights Plan was approved. On May 2, 2002, at the Annual General and Special Meeting of Shareholders, an Amended and Restated Shareholder Rights Plan (Plan) was approved. According to the Plan, a right is attached to each present and future outstanding common share, entitling the holder to acquire additional common shares during the term of the right. Prior to the separation date, the rights are not separable from the common shares, and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our board can defer the separation date.

Rights created under the Plan, which can only be exercised when a person acquires 20% or more of our common shares (a Flip-In Event), entitle each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. The Plan must be reapproved by shareholders on or before our annual general meeting in 2011 to remain effective past that date. A copy of the Plan is available on our web site at www.nexeninc.com.

ITEM 6.

Selected Financial Data

Five-Year Summary of Selected Financial Data in Accordance with US GAAP

<i>(Cdn\$ millions, except otherwise indicated)</i>	2008	2007	2006	2005	2004
Oil & Gas and Syncrude Production					
Production Before Royalties (mboe/d) ¹	250	254	212	242	250
Production After Royalties (mboe/d) ¹	210	207	156	173	174
Results of Operations					
Revenue					
Oil & Gas and Syncrude ²	6,907	5,174	3,656	3,535	2,573
Marketing	522	926	1,373	864	625
Chemicals	427	447	413	413	383
Other	364	(26)	(47)	(193)	59
Total Revenue	8,220	6,521	5,395	4,619	3,640
Net Income from Continuing Operations	1,704	1,012	579	658	705
Basic Earnings per Common Share from Continuing Operations (\$/share)	3.24	1.92	1.10	1.26	1.37
Diluted Earnings per Common Share from Continuing Operations (\$/share)	3.20	1.88	1.08	1.23	1.35
Net Income	1,704	1,012	579	1,110	788
Basic Earnings per Common Share (\$/share)	3.24	1.92	1.10	2.13	1.53
Diluted Earnings per Common Share (\$/share)	3.20	1.88	1.08	2.08	1.51
Financial Position					
Total Assets ¹	22,048	17,982	17,079	14,493	12,339
Long-Term Debt ³	6,578	4,610	4,618	3,630	4,214
Shareholders' Equity	6,946	5,449	4,614	3,961	2,892
Capital Investment, including Acquisitions	3,066	3,401	3,408	2,638	4,264
Dividends per Common Share (\$/share) ⁴	0.175	0.10	0.10	0.10	0.10
Common Shares Outstanding (thousands) ⁵	519,449	528,305	525,026	522,281	516,798

1 In late 2004, we acquired North Sea assets and began production from Block 51 in Yemen. In 2005, we sold producing properties in Canada and suffered hurricane-related downtime in the Gulf of Mexico. A full year's production from the North Sea and Block 51 in Yemen offset declines caused by these events. In early 2007, the Buzzard field came on stream and offset declines from Masila in Yemen.

2 In the third quarter of 2005, we sold Canadian conventional oil and gas properties in Saskatchewan, British Columbia and Alberta producing 18,300 bbls/d. The results of these operations have been shown as discontinued operations.

3 In December 2004, we drew US\$1.5 billion on unsecured acquisition credit facilities to finance the purchase of North Sea assets. The remainder of the purchase price was funded from cash on hand. The acquisition credit facility was repaid in 2005 with proceeds from the issuance of US\$1.04 billion in senior notes in the first quarter and from asset dispositions in the third quarter. Our long-term debt increased in 2006 as a result of our capital investments, primarily at Buzzard and Long Lake. In May 2007, we issued US\$1.5 billion of senior notes with US\$250 million maturing in 10 years and US\$1,250 million maturing in 30 years. In June 2007, we filed a universal base shelf prospectus in the US and Canada allowing us to potentially raise US\$2.5 billion of debt, equity or other hybrid securities, should the need arise.

4 Quarterly dividends were increased to 5¢ per share in the second quarter of 2008.

5 During the third quarter of 2008, we received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid that allows us to repurchase up to a maximum of 52,914,046 common shares for the period of August 6, 2008 to August 5, 2009. In 2008, we repurchased and cancelled 12,136,900 common shares for \$338 million.