global **operations**

In 2007, we added value by bringing Buzzard on stream. Our Long Lake oil sands project is next, expected on stream in mid 2008.

PART I
ITEMS 1 AND 2. BUSINESS AND PROPERTIES

ABOUT US

Nexen Inc. (Nexen, we or our) is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 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 253,600 boe/d before royalties (including Syncrude production) and revenues of $5.6 billion in 2007. 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.

In the 1970s, we expanded our western Canadian assets and entered the US Gulf of Mexico. We finished this decade with production of approximately 11,000 boe/d before royalties and revenues of $126 million.

Buzzard produced first oil early in the year and we made significant construction and commissioning progress at Long Lake.

In the 1980s, we continued to expand in western Canada and the Gulf of Mexico through acquisitions. Acquiring Canada-Cities Services in 1983 doubled our size and included an interest in the Syncrude Joint Venture, our entry into the Athabasca oil sands. We finished this decade with production of approximately 68,600 boe/d before royalties and revenues of $591 million.

In the 1990s, we had two defining events: discovering oil on the Masila block in Yemen and acquiring Wascana Energy Inc. The first of 17 fields at Masila was discovered in 1991. Since start up in 1993, Masila has produced almost a billion barrels of crude oil. Our 1997 purchase of Wascana Energy Inc. almost tripled our Canadian production. In 1998, we entered Australia with an interest in the offshore Buffalo field and Nigeria as the operator of the Ejulebe field. Also in 1998, we discovered Ukot on Block OPL-222, offshore Nigeria. We finished this decade with production of approximately 239,200 boe/d before royalties and revenues of $1.7 billion.

So far in the 21st century, we have made a number of discoveries, two strategic acquisitions and completed non-core asset divestiture programs. In 2000, we discovered Gunnison in the deep-water Gulf of Mexico and Guando in Colombia. We joined with Ontario Teachers' Pension Plan Board (Teachers) to acquire Occidental's remaining 29% interest in us. Teachers purchased 20.2 million common shares. We repurchased the remaining 20 million common shares for $605 million, which would have had a value of almost $2.6 billion at the end of 2007. We also exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemical operations and we changed our name from Canadian Occidental Petroleum Ltd. to Nexen Inc. In 2001, we discovered Aspen in the deep-water Gulf of Mexico and signed a joint venture agreement with OPTI Canada Inc. to develop, produce and upgrade bitumen at Long Lake in the Athabasca oil sands. In 2002, we discovered Usan, the second discovery on OPL-222, offshore Nigeria. In late 2003, we discovered two fields on Block 51 in Yemen.

In 2004, we acquired properties in the UK North Sea, providing us with operatorship of the Buzzard discovery, the producing Scott and Telford fields and 700,000 exploration acres. In 2005, we completed non-core asset divestiture programs by selling Canadian conventional oil and gas properties producing approximately 18,300 boe/d before royalties and by monetizing 39% of our chemical business through the initial public offering of the Canexus Income Fund. We also made a potentially significant discovery in the Gulf of Mexico at Knotty Head and commenced commercial development of our first coalbed methane (CBM) project in the Fort Assiniboine area in western Canada. In 2006, we completed major development projects at Buzzard in the North Sea and the Syncrude Stage 3 expansion in the Athabasca oil sands. In 2007, Buzzard produced first oil early in the year and we made significant construction and commissioning progress at our Long Lake Project. At Long Lake, SAGD steam injection began in the second half of 2007 and the upgrader is scheduled to start up in mid 2008. We also significantly added to our inventory of exploration prospects during the year by securing new Gulf of Mexico deepwater leases, obtaining exploration licences offshore Norway and acquiring additional shale gas opportunities in Canada. Our portfolio of assets, combined with talented people and an active exploration program, are expected to provide future growth for our company.

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 growing crude oil, natural gas, natural gas liquids, ethanol and power marketing business in North America, Europe and Asia.

Chemicals includes operations in North America and Brazil that manufacture, market and distribute sodium chlorate, caustic soda and chlorine through the Canexus Limited Partnership.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 20 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report.

STRATEGY

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 believe in developing a competitive advantage where possible, to assist in generating opportunities for long-term success in our ever-evolving industry. As conventional basins in North America mature, we have 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 new sustainable businesses in western Canada, the North Sea, Gulf of Mexico, and offshore West Africa, capitalizing on the following corporate strengths:

- We have access to resource in our key areas that creates future opportunities. Our Long Lake Project is developing only 10% of our oil sands leases in the Athabasca oil sands and we hold unexplored acreage in the Gulf of Mexico, the North Sea, western Canada and elsewhere;
- We are successful explorers with significant discoveries at Knotty Head and Vicksburg in the Gulf of Mexico, Golden Eagle in the UK North Sea and at Usan, offshore Nigeria;
- We are skilled project managers with major development projects, proven by bringing Buzzard on stream in early 2007;
- We are innovative in our application of technology. Long Lake is expected to be 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;
- We are an international operator with a proven track record of successful business ventures in Yemen, the United Kingdom, Nigeria, Colombia and Australia; and
- From time to time, we supplement our growth with acquisitions, such as our strategic entry into the UK North Sea in 2004.

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 long-term strategy is to build capacity by ensuring we have a sufficient inventory of opportunities for future growth. We have a number of opportunities expected to provide production growth and create shareholder value well into the next decade. They include undeveloped discoveries at Knotty Head and Vicksburg in the Gulf of Mexico, Usan and Ukot offshore Nigeria, various discoveries in the UK North Sea, together with development of CBM, shale gas and additional oil sands leases in Canada.

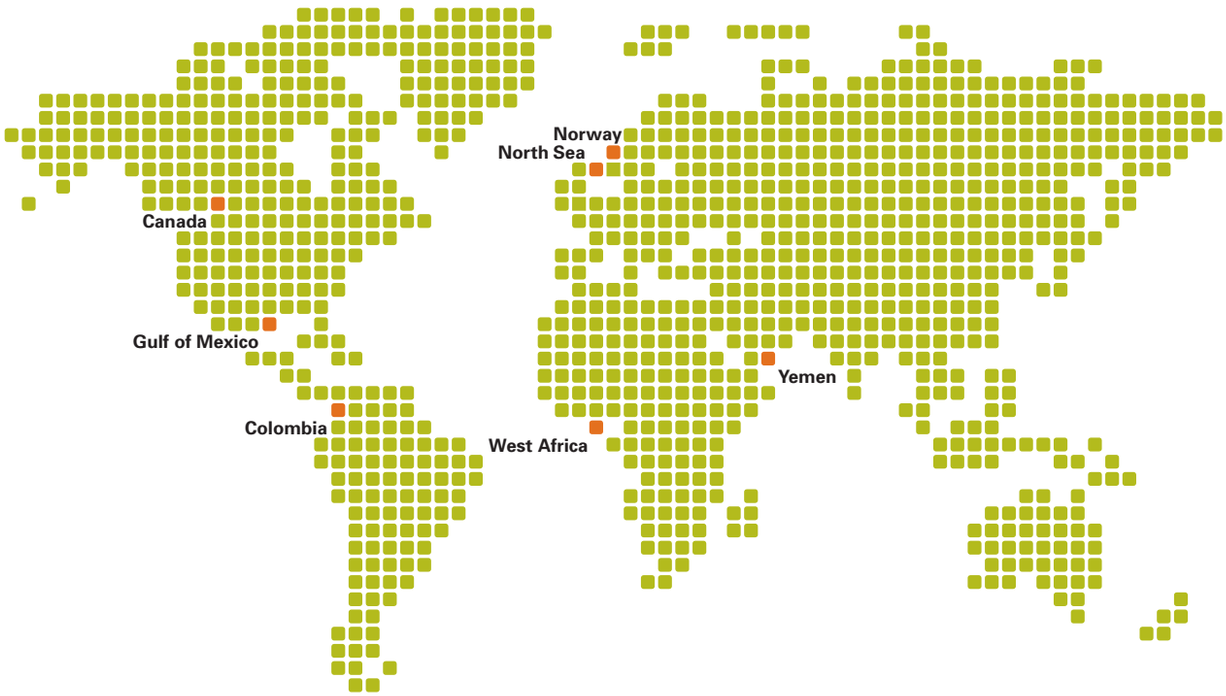
Our goal is to grow long-term value responsibly for our shareholders by building sustainable businesses in western Canada, the North Sea, Gulf of Mexico, and offshore West Africa.

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 production to reclamation. Our goal is to help stakeholders become engaged participants in a continuing consultation process, while balancing multiple, and sometimes conflicting goals.

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 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 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.



The prices we receive for our oil and gas products are mainly determined by volatile global crude oil and natural gas markets. 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 generally 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. We had 98% of our oil and gas reserves before royalties (98% after royalties) and 100% of our Syncrude reserves before royalties (100% after royalties) assessed (either evaluated or audited as described on page 21) 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 68 for a description of our reserves process, and to the section on Reserves, Production and Related Information on page 16 for a description of the nature and scope of the independent assessments performed and the results thereof.

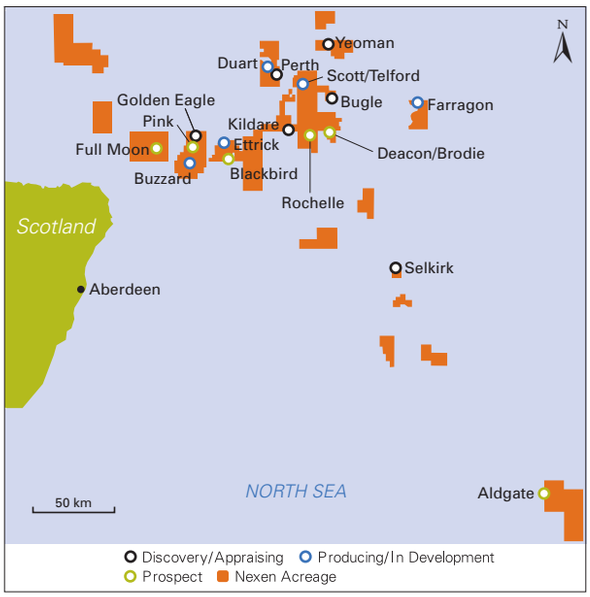
North Sea—United Kingdom (UK)

The UK North Sea is a key producing area. In 2004, we acquired a 43.2% operated interest in the Buzzard development, a 41% operated interest in the Scott field, a 54.3% operated interest in the Telford field, the Scott production platform, interests in several satellite discoveries and more than 700,000 net undeveloped exploration acres for US$2.1 billion. This acquisition established us as a significant regional player with concentrated assets, infrastructure and exploration and development potential for future growth. It added high-margin reserves and production, diversified our worldwide portfolio by adding strong assets in a stable jurisdiction, and complemented our other longer cycle-time projects.

Our UK strategy is to grow and sustain our existing North Sea production and capture 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 Ettrick. As a result, new discoveries can be tied-in quickly.

During the year, we produced 84,000 boe/d before royalties (84,000 after royalties) in the UK, which was approximately one-third of our total production. At year end, our UK proved oil and gas reserves of 207 mmboe before royalties (207 after royalties) represented about 20% of our total proved oil and gas and Syncrude reserves.



Buzzard

Buzzard is the largest discovery in the UK North Sea in the past ten years. It was discovered in 2001 and began producing January 7, 2007. Development of this discovery was 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 facilities can process at least 200,000 bbls/d of oil and 60 mmcf/d of gas. Development drilling has resulted in more well-to-well variability in the concentration of hydrogen sulphide than originally expected. To address this, we plan to construct a fourth platform with production sweetening facilities to handle higher levels of hydrogen sulphide. We believe existing equipment and processes can manage current hydrogen sulphide levels and maintain current production deliverability until the additional equipment is commissioned in 2010.

During the year, we produced 84,000 boe/d in the UK, which was approximately one-third of our total production.

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 Buzzard through 27 production wells and maintain reservoir pressure through an active water-flood program. In 2008, we plan to invest $255 million to drill five production wells, two sidetracks, one water injector and progress work on the fourth platform.

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. In 2007, we increased our interests in these fields and at the end of the year, we have a 41.9% working interest in the Scott platform and field, and a 71.75% working interest in Telford. In 2007, our share of production from these fields was approximately 16,500 boe/d. The production is royalty-free, around 90% oil and produced through numerous subsea wells. 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 northeast 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 we expect it on stream mid 2008. We expect to ramp up to production of approximately 30,000 boe/d gross by the end of the year. Development includes three subsea production wells and one water injector tied back to a leased floating production, storage and off-loading vessel (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. Our share of full-cycle development costs is estimated at $460 million. We operate Ettrick with an 80% working interest.

Other

Our 2004 UK acquisition included a non-operated interest in Farragon, a small satellite discovery, which was brought on stream in late 2005. In 2007, the non-operated Duart field was brought on stream and began producing oil from a single well tied back to the Tartan platform. Our share of production from these non-operated properties was 3,300 boe/d before royalties (3,300 after royalties) in 2007.

Exploration and Undeveloped Assets

In 2007, we discovered hydrocarbons at Golden Eagle and then drilled a successful sidetrack to appraise the accumulation. We are currently evaluating development options and expect to sanction development in 2008. In 2007, we also drilled a successful exploration well at Kildare, and plan to follow up the discovery with an appraisal well. We also completed appraisal of the Selkirk prospect with favourable results. We have a number of discoveries on operated blocks near Scott, Buzzard and third-party facilities as follows:

Field	Interest (%)	Operator Status	Comments
Black Horse	60	operated	discovery near Scott; evaluating development alternatives
Bugle	41	operated	discovery near Scott; appraisal well underway
Dolphin	42	operated	discovery near Scott; evaluating development alternatives
Golden Eagle	34	operated	discovery near Ettrick; evaluating development alternatives
Kildare	50	operated	discovery near Scott; appraisal well planned for 2008
Perth	42	operated	discovery near Scott; evaluating development alternatives
Polecat	40	operated	discovery near Buzzard; evaluating appraisal options
Selkirk	38	operated	discovery near Buzzard; evaluating development alternatives
Yeoman	50	operated	discovery near Scott; evaluating development alternatives

In 2007, we drilled unsuccessful exploration wells at Guinea, Dee and Stag. The three wells encountered non-commercial quantities of hydrocarbons and were abandoned. In 2008, we expect to drill six exploration and two appraisal wells. We have secured drilling rigs for all of our 2008 North Sea exploration and development program.

We have also begun assessing emerging CBM opportunities in the UK. In 2006, we acquired an 80% working interest in one opportunity and have drilled two successful exploration wells so far. Both encountered coal seams as expected and are being monitored through ongoing production testing. In another CBM opportunity, we drilled two unsuccessful exploration wells in 2007. We plan to continue assessing CBM potential in the UK with additional exploratory wells in 2008.

Fiscal Terms

UK fiscal terms are favourable. 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. The amount and timing of income taxes payable depends on many factors including price, production, capital investment levels and available tax losses.

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 reduce risk and improve economics. Technology to find, drill, and develop 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.

We are evaluating development options for Vicksburg, South Marsh Island 257 and Mississippi Canyon 72 and look forward to developing Longhorn in 2008.

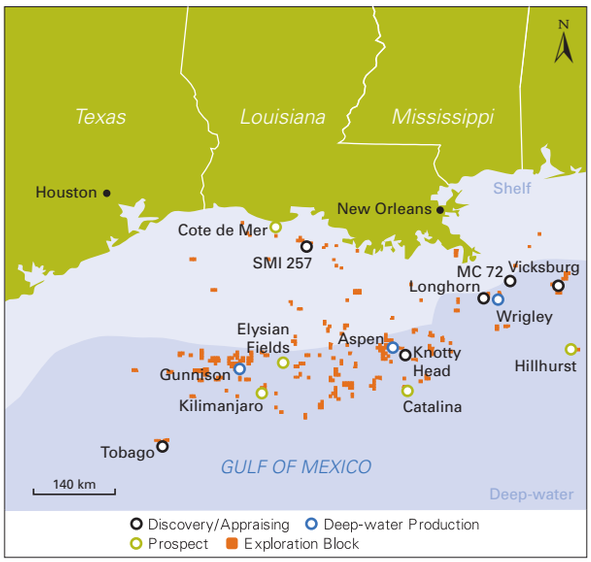
Our strategy in the Gulf is to explore for new reserves, exploit our existing asset base and acquire assets with upside potential. We focus our exploration program on three strategic play types:

- 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 relatively 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 the eighth largest leaseholder in the deep-water.

In 2007, we invested $793 million on exploration, development and acquisitions in the Gulf. This resulted in three discoveries at Desoto Canyon Block 353 (Vicksburg), South Marsh Island 257 and Mississippi Canyon 72 as well as a successful appraisal well at Longhorn. Additionally, we acquired three producing deep-water fields and enhanced our deep-water acreage position. However, some of our development drilling in 2007 did not meet expectations. In 2008, we plan to invest approximately $390 million in the Gulf to further our growth strategies. This includes development of our Longhorn discovery, drilling of proved undeveloped reserves, exploration drilling and land acquisition.



Exploration and Undeveloped Assets

Given our drilling success in 2007, we are evaluating development options for our discoveries at Vicksburg, South Marsh Island 257 and Mississippi Canyon 72 and look forward to developing the Longhorn discovery in 2008. Our undeveloped deep-water discoveries include:

Well	**Interest** (%)	**Operator Status**	**Comments**
Longhorn	25	non-operated	sanctioned; production expected 2009
Tobago	10	non-operated	sanctioned; production expected 2009
Knotty Head	25	operated	discovery; further appraisal required
Vicksburg	25	non-operated	discovery; further appraisal required
South Marsh Island 257	35	non-operated	discovery; production expected 2008
Mississippi Canyon 72	33	non-operated	discovery; production expected 2008

During the year, we drilled ten exploratory dry holes on the shelf. We also converted our interests in Anduin and Great White West to overriding royalty interests to accelerate monetization of the reserves with no further capital investment. We acquired deep-water acreage during the year and hold approximately 200 blocks and expect this acreage and future exploration opportunities to position us well for continued growth. In 2008, we plan to drill seven exploration and appraisal wells and have secured drilling rigs for more than half of the wells. Access to deep-water rigs remains limited. To explore our inventory and evaluate existing discoveries, we have secured two new-build dynamically-positioned fifth-generation semi-submersible drilling rigs. We will have access to each rig for at least two years. We expect the first rig to be available mid 2009, followed by the second rig in 2010.

US Production

	2007		**2006**		**2005**	
(mboe/d)	**Before Royalties**	**After Royalties**	**Before Royalties**	**After Royalties**	**Before Royalties**	**After Royalties**
Deep-water	19.4	17.4	19.6	17.5	24.0	21.5
Shelf	13.8	11.5	15.9	13.2	17.6	14.6
Total	**33.2**	**28.9**	**35.5**	**30.7**	**41.6**	**36.1**

At year end, proved reserves of 62 mmboe before royalties (53 after royalties) in the Gulf of Mexico represented about 6% 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. We operate most of this production.

Deep-water

Most of our deep-water production comes from our 100%-operated Aspen field and our 30% non-operated Gunnison field. The remaining comes from our 50% non-operated Wrigley field and three 100%-operated properties purchased in 2007.

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 2007 production before royalties was approximately 10,400 boe/d (9,500 after royalties).

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 2007, our share of production before royalties was approximately 7,000 boe/d (6,200 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 2007 was approximately 1,100 boe/d (1,000 after royalties).

The three new deep-water fields acquired in 2007 are on Garden Banks Block 205, Green Canyon 137 and Green Canyon 6/50—all in water depths between 700 and 1,100 feet. In 2008, we plan to drill a development well at Green Canyon 6/50.

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 302/321/339/340, and Vermilion 76 (consisting of Blocks 65, 66 and 67). We continue to exploit these assets and look for other shelf opportunities. Most of our 2007 shelf activities focused on development drilling at Eugene Island 258/259, Eugene Island 295 and Vermillion 340.

Fiscal Terms

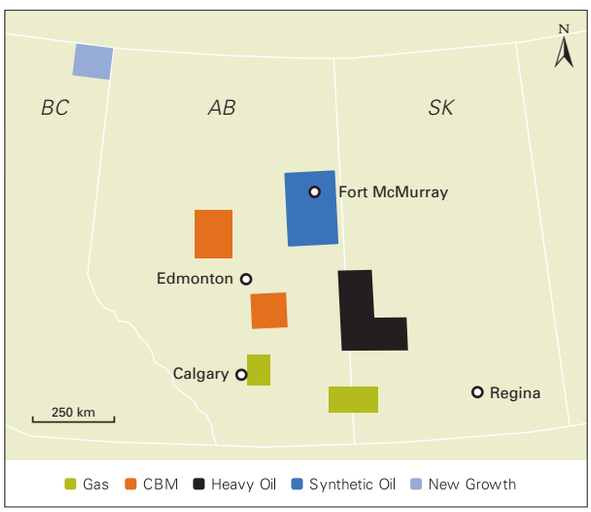
In 2007, royalty rates on our US production averaged 16.5% for shelf volumes and 10.6% for deep-water volumes. The US government has increased royalty rates from 12.5% to 16.7% for new deep-water leases awarded after July 2007. We qualify for royalty relief at our deep-water Aspen and Gunnison fields on the first 87.5 mmboe of production. However, we may be subject to royalties at Gunnison if annual commodity prices are higher than threshold prices set by the US Department of the Interior's Minerals Management Service (MMS). The oil and gas industry is currently litigating the enforceability of these price thresholds. In October 2007, a US District Court ruled that the price thresholds were unenforceable. The MMS has since appealed this ruling and a decision is expected by the end of 2008. In 2007, commodity prices exceeded these thresholds and we were assessed a royalty at Gunnison of 12.5% by the MMS. If the litigation is not successful, royalties that we have accrued on our Gunnison production will be payable. Our Aspen field is not subject to the minimum price threshold. Although several bills were recently proposed burdening leases awarded in 1998 and 1999 with royalties or severance taxes, no such legislation was passed by US Congress.

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 continued conventional development and enhanced recovery methods. In 2007, we produced 36,800 boe/d before royalties (29,700 after royalties) in Canada, which was approximately 14% of our total production including Syncrude. At year end 2007, Canadian proved reserves (including bitumen and excluding Syncrude) of 386 mmboe before royalties (334 after royalties) were approximately 36% 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,



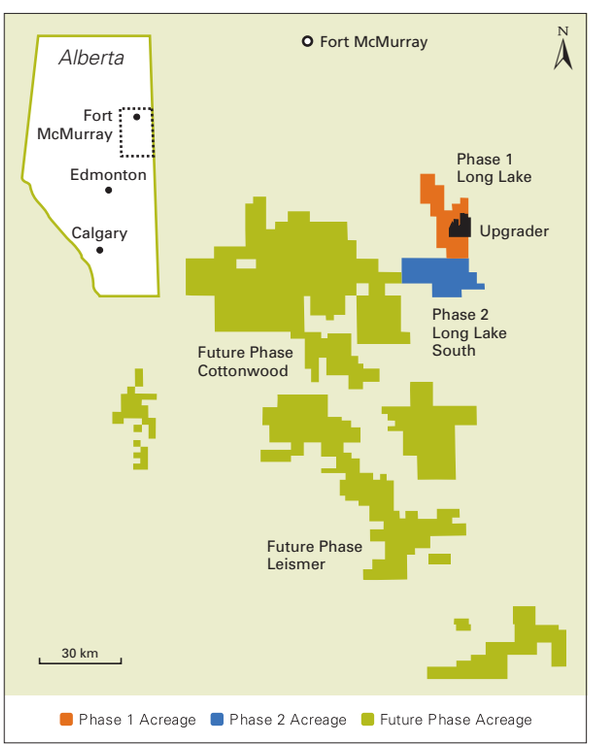
and natural gas near Calgary and in southern Alberta and Saskatchewan. We operate most of our producing properties and hold almost one million net acres of undeveloped land across western Canada. These assets provide predictable production volumes and earnings while we advance the following initiatives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

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

In 2007, we invested $1,505 million in Canada; $1,380 million into these growth initiatives. With the expected completion of Long Lake Phase 1 in the Athabasca oil sands, we plan to reduce our capital investment in 2008 to approximately $770 million. Our 2008 capital programs will focus on completing Phase 1 and work towards sanctioning Phase 2 at Long Lake, advance our CBM strategies and evaluate the potential of shale gas.

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 and 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.

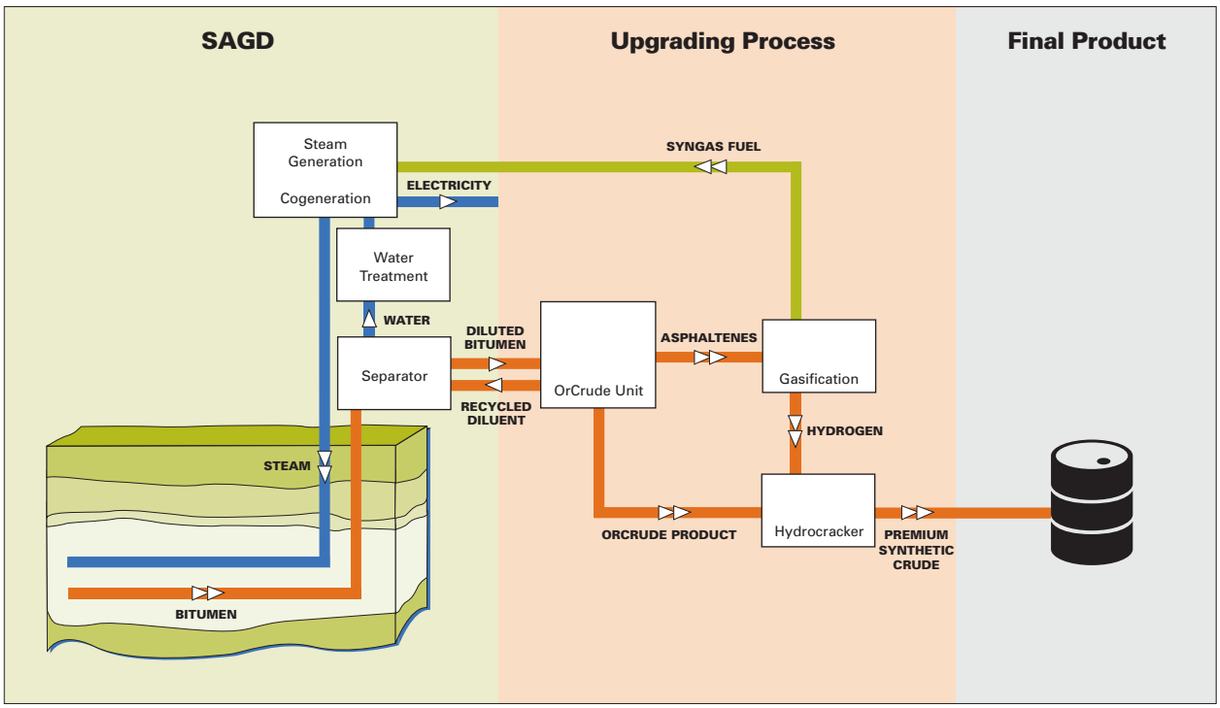
We operate the Long Lake bitumen extraction process and are responsible for constructing, developing and operating the SAGD project. OPTI is responsible for designing, constructing and operating the upgrader. We share equally in all project reserves, production, operating and capital costs.

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 will also be burned in a cogeneration plant to produce electricity to be used on-site 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. And, 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. In 2007, we began injecting steam in all 10 well pads. The first six months of steam injection largely involves heating the reservoir, followed up by a ramp-up of bitumen production to peak rates over 12 to 24 months. At the start of production, steam-to-oil ratios will be high but will decline as bitumen production ramps up to our target rates. Depending on start up issues and any related facility down time, we expect bitumen production before royalties to reach between 35,000 and 45,000 bbls/d (between 17,500 and 22,500 bbls/d net to our share) by the end of 2008, with a steam-to-oil ratio of between 3.5 and 4.0. We expect the steam-to-oil ratio to average approximately 3.0 over the long-term.

Upgrader module fabrication is complete and all modules are on site. Construction of the upgrader was approximately 97% complete at year end and start up is scheduled for mid 2008. Peak output of premium synthetic crude oil is expected within 12 to 18 months of upgrader start up and we expect to exit 2008 with synthetic production rates between 30,000 and 40,000 bbls/d (between 15,000 and 20,000 bbls/d net to our share). Production capacity for the first phase of Long Lake is approximately 60,000 bbls/d (30,000 bbls/d net to our share) of premium synthetic crude, which we expect to reach in 2009. We expect to maintain production over the project's life, estimated at 40 years, by periodically drilling additional SAGD well pairs.

In 2008, we will bring on Long Lake and expect bitumen production to reach between 35,000 and 45,000 bbls/d (17,500 and 22,500 bbls/d net to us).

In 2007, we invested $1,025 million at Long Lake Phase 1. Long Lake's total capital costs have increased since project sanctioning due to design enhancements and industry cost pressures. When our board sanctioned the project in February 2004, capital costs were estimated at $3.4 billion ($1.7 billion net). In December 2004, we accelerated the drilling of an additional well pad consisting of 13 well-pairs to ensure reliability of bitumen production at the commencement of upgrader operations at a cost of $98 million ($49 million net). In early 2006, we further modified the project design by adding steam generation capacity and soot handling equipment at a cost of $360 million ($180 million net). These scope changes increased the estimated project cost to $3.8 billion ($1.9 billion net). Since then, high activity in the oil sands has placed ongoing cost pressures on labour and services. As well, lower than anticipated labour productivity has required a larger workforce to maintain progress. As a result, the projected costs of Long Lake have increased from $3.8 billion to between $5.8 billion and $6.1 billion (between $2.9 billion and $3.05 billion net to us). Despite capital cost increases, we still expect to achieve good economic returns which benefit from a significant operating cost advantage. Combined SAGD, cogeneration and upgrading operating costs are expected to average about $17/bbl, substantially

lower than coking or other upgrading processes. We expect ongoing capital to average between $3/bbl and $4/bbl. 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 249,000 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 2005, we announced our plan to duplicate Long Lake by developing Phase 2. In 2007, we invested $114 million on land acquisition, additional drilling, seismic and engineering to develop our leases and advance regulatory applications for these phases.

During 2007, the Alberta government proposed increases to oil sands royalty rates and implemented climate change legislation. The federal government also announced climate change proposals; however, legislation has not been drafted. Due to this regulatory uncertainty, we are delaying certain planned expenditures on Phase 2. Phase 2 will 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 SEC rules and regulations, we are 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, 2007, we recognized proved bitumen reserves of 268 mmboe before royalties (234 after royalties) for our Long Lake Project, representing about 25% of our total proved oil and gas and Syncrude reserves before royalties.

Heavy Oil

Approximately 45% 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. In 2008, we plan to continue exploiting our existing fields through drilling and optimizing operations.

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 several ongoing pilot projects in west-central Saskatchewan.

Natural Gas

Approximately 40% 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 develop, but have relatively smaller reserves and lower productivity per well. Sour gas is natural gas that contains hydrogen sulfide. Our Balzac field, northeast of Calgary, has been producing sour natural gas since 1961. This sour gas is processed through our operated Balzac plant.

At the end of 2007, we held more than 725 net sections of land in Alberta with CBM potential.

Coalbed Methane (CBM)

Approximately 15% 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 development in the Upper Mannville coals in 2005 by 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.

We have a long-term view of this business and plan to increase our CBM production by progressively developing opportunities on our extensive land base. At the end of 2007, we held more than 725 net sections of land in Alberta with CBM potential, some of which overlay existing conventional producing lands. In 2007, we invested approximately $170 million in exploration and development activities. For 2008, we have slowed our pace of program spending until we gain clarity on the impact of Alberta royalty changes. In 2008, we plan to tie-in Upper Mannville development wells drilled in 2007 for production and commence development of our Horseshoe Canyon lands.

Shale Gas

As part of our growth strategy in unconventional Canadian resource plays, we acquired approximately 190 net sections of land in an emerging Devonian shale gas play in north eastern 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. In 2008, we plan to continue our evaluation program to demonstrate the feasibility of this resource.

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 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. The second type of royalty (NPI) applies to our oil sands projects, which includes a 1% royalty on gross revenue prior to the recovery of capital costs. After achieving payout on these costs, the royalty converts to the greater of 1% of gross revenues or 25% of net profits.

During 2007, the Alberta government announced a new royalty framework effective January 1, 2009 that includes proposed increases to Alberta's royalty rates, although it has yet to be passed into legislation. Under the new framework, the upper limit of the Gross Royalty system is expected to increase to 50%, depending on production rate and product sales price. The new framework will also increase the royalty rates for the NPI royalty system that applies to oil sands projects. The new royalty rates for oil sands projects will range from 1% to 9% of gross revenue for projects that are pre-payout of capital costs, and from 25% to 40% of net profit for projects that are post-payout. These royalty rates will vary depending on WTI (US$55/bbl to US$120/bbl).

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 1.75% to 3.3%. In 2008, the rates will reduce slightly to 1.7% and 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 late 2007, the federal government reduced the federal corporate income tax rate from 22% in 2007 to 15% by 2012. Provincial income tax rates vary from approximately 10% to 16%.

Middle East—Yemen

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

Our strategy in Yemen is to maximize the value from our existing blocks, while we continue to search for new reservoirs in deeper horizons. We have two producing blocks: Masila (Block 14) and East Al Hajr (Block 51). In 2007, we produced 71,600 bbls/d of oil before royalties (39,800 after royalties), representing approximately 28% of Nexen's total production. Proved reserves of 41 mmboe before royalties (23 after royalties) comprise approximately 4% of Nexen's total proved oil and gas and Syncrude reserves before royalties (3% after royalties).

Masila Block (Block 14)

We operate the Masila Project with a 52% working interest. Our share of 2007 production was 57,000 bbls/d before royalties (29,900 after royalties). After more than 10 years of growth, our Masila fields have matured, 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 22% of total project free cash flow from the remaining proved reserves recoverable before the PSA expires in 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.

We are managing the pace of our drilling program to ensure we recover the remaining reserves in the most efficient, cost-effective manner. In 2008, we plan to drill ten development wells and sidetracks.

The Masila PSA was signed in 1987 between the Government of Yemen and the Masila joint venture partners (Masila Partners), including Nexen. Under the PSA, we have the right to produce oil from Masila into 2011 and to 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:

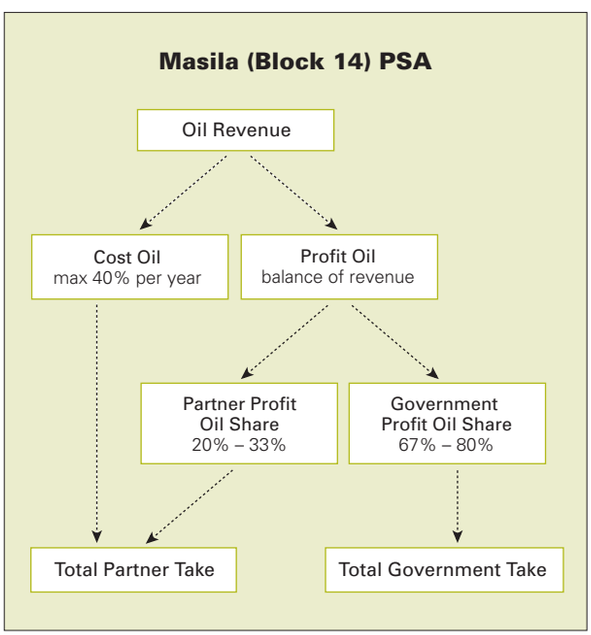
Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for 4 years
Development	16.7% per year for 6 years

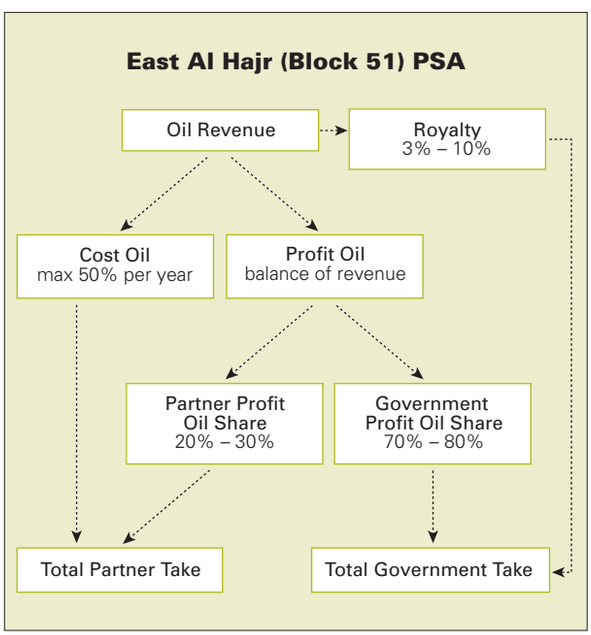
The remaining production is profit oil that is shared between the Masila Partners and the Government and is calculated on a sliding scale based on production. The Masila Partners' share of profit oil ranges from 20% to 33%. The structure of the agreement moderates the impact on the Masila Partners' cash 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 2007, the Masila Partners' share of production, including recovery of past costs, was approximately 39%.

East Al Hajr Block (Block 51)

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. 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:

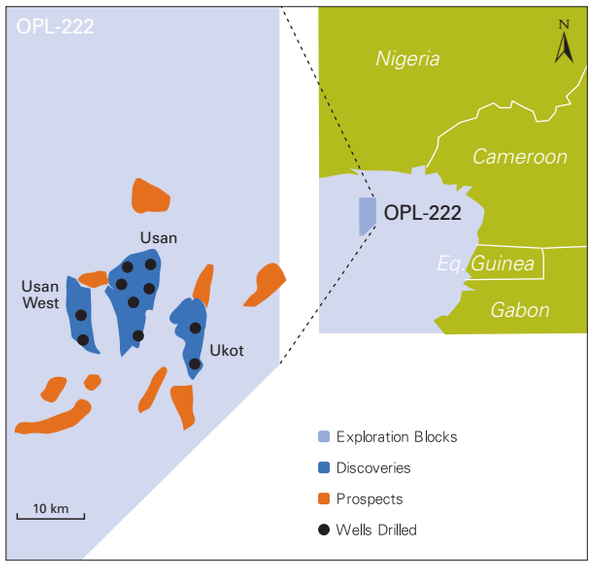
Costs	Recovery
Operating	100% in year incurred
Exploration	75% per year, declining balance
Development	75% per year, declining balance





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 2007, the EAH Partners' share of Block 51 production, including recovery of past costs, was approximately 54%.

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 includes a CPF, gathering system and a 22-km tieback to our Masila export pipeline. Production began in November 2004. During 2007, production averaged 14,600 bbls/d before royalties (9,900 after royalties).



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. Based on the drilling results outlined below, significant hydrocarbons exist on these blocks.

Year	Well	Location	Results
1998	Ukot-1	Ukot field discovery well	encountered three oil-bearing intervals and flowed at restricted rate of 13,900 bbls/d from two intervals
2002	Usan-1	Usan field discovery well	encountered several oil-bearing intervals and flowed at restricted rate of 5,000 bbls/d from one interval
2003	Usan-2	3 km west of discovery	appraised up-dip portion of the fault block
2003	Usan-3	2 km northwest of discovery	appraised separate fault block and flowed at restricted rate of 5,600 bbls/d from one interval
2003	Ukot-2	3.5 km south of discovery	encountered three oil-bearing intervals
2003	Usan-4	5 km south of discovery	flowed at restricted rate of 4,400 bbls/d from first interval and 6,300 bbls/d from second interval
2004	Usan-5	6 km west of discovery	sampled oil in several intervals
2004	Usan-6	4 km south of Usan-5	flowed at restricted rate of 5,800 bbls/d from one interval
2005	Usan-7	9 km southwest of discovery	confirmed an eastern extension of the field
2005	Usan-8	3 km southwest of discovery	confirmed an eastern extension of the field

Appraisal of the Usan field is complete and the field development continues to move forward. We expect the project to advance to the execution phase shortly and this will facilitate the award of the major deep-water facilities contracts. 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 have a 20% interest in exploration and development on this block. In 2008, we plan to invest approximately $165 million to progress development and award the major deep-water facilities contracts. At year-end 2007, proved reserves of 30 mmboe before royalties (25 after royalties) comprise approximately 3% of our total proved oil and gas and Syncrude reserves.

Other International

Colombia

Boqueron Block—Guando

In 2000, we made our first discovery at Guando on our 20% non-operated Boqueron Block. 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 early 2009. Our share of 2007 production averaged 6,200 bbls/d before royalties (5,700 after royalties), about 2% of Nexen's total production including Syncrude.

Production from Guando is subject to a royalty between 5% and 25% depending on daily production, and in 2007 averaged 8%. Colombian taxable income is subject to federal income tax of 34% in 2007 and 33% in 2008 and future years.

Exploration

We have interests in three exploration blocks in the Upper Magdalena Basin: El Queso acquired in 2003, Villarrica Norte Block in 2005 and El Guadual in 2007. In 2007, we drilled two unsuccessful wells; Guaini-1 and Atalea-1. We hold five technical evaluation agreements that each provide approximately one year to evaluate potential prospects. We are also identifying other growth opportunities in Colombia.

Norway

As part of our growth strategy in the North Sea, we participated in the 2006 bid round for exploration rights offshore Norway and were awarded interests in six licences covering nine blocks in early 2007. In 2008, we expect to invest approximately $40 million in additional seismic and geologic studies. In early 2008, we were awarded interests in three additional licences.

Norwegian oil and gas activities are subject to a general corporate income tax rate of 28% plus an additional 50% special petroleum tax. A tax refund of 78% is received on tax losses arising from qualifying exploration expenses in Norway.

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 Continuing Oil and Gas Operations (including Syncrude)

(Cdn$ millions)	2007	2006	2005
Conventional Crude Oil and Natural Gas Liquids (NGLs)	4,077	2,479	2,438
Synthetic Crude Oil	545	446	397
Natural Gas	499	553	671
Total	**5,121**	**3,478**	**3,506**

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]		
	2007	2006	2005	2007	2006	2005
Crude Oil and NGLs (Cdn$/bbl)						
Yemen	76.29	71.57	62.07	12.00	8.11	6.75
Canada [2]	44.07	42.79	40.51	18.67	15.50	14.01
United States	69.83	65.80	57.63	9.69	9.45	7.33
United Kingdom	76.30	71.19	60.55	6.94	11.28	14.90
Other Countries	71.29	66.09	59.96	3.76	3.13	6.08
Natural Gas (Cdn$/mcf)						
Canada [2]	6.32	6.49	7.51	2.28	1.65	0.95
United States	7.80	7.86	10.56	1.61	1.58	1.22
United Kingdom	4.71	7.43	7.86	1.16	1.88	2.48

Notes:

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

2 Includes results of discontinued operations for 2005 (See Note 14 to our Consolidated Financial Statements).

Oil and Gas Acreage

	Developed		Undeveloped [1]		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Yemen [2]	50	29	756	628	806	657
Canada	797	610	1,871	980	2,668	1,590
United States	206	122	1,123	562	1,329	684
United Kingdom	202	83	1,290	846	1,492	929
Colombia [4]	1	–	607	372	608	372
Nigeria [2, 3]	–	–	448	90	448	90
Norway	–	–	280	134	280	134
Total	**1,256**	**844**	**6,375**	**3,612**	**7,631**	**4,456** [5]

Notes:

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

	Oil		Gas		Total	
(number of wells)	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
Yemen	463	274	–	–	463	274
Canada	2,231	1,550	2,884	2,522	5,115	4,072
United States	193	94	202	141	395	235
United Kingdom	48	21	–	–	48	21
Colombia	121	25	–	–	121	25
Total	**3,056**	**1,964**	**3,086**	**2,663**	**6,142**	**4,627**

Notes:

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

2007

(number of net wells)	Net Exploratory			Net Development			Total
	Productive	**Dry Holes**	**Total**	**Productive**	**Dry Holes**	**Total**	
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
United Kingdom	2.0	3.2	5.2	4.2	–	4.2	9.4
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**

2006

(number of net wells)	Net Exploratory			Net Development			Total
	Productive	**Dry Holes**	**Total**	**Productive**	**Dry Holes**	**Total**	
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
United Kingdom	0.8	1.7	2.5	5.5	–	5.5	8.0
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**

2005

(number of net wells)	Net Exploratory			Net Development			Total
	Productive	**Dry Holes**	**Total**	**Productive**	**Dry Holes**	**Total**	
Yemen	0.5	4.6	5.1	33.0	1.6	34.6	39.7
Canada	32.2	8.0	40.2	198.9	0.5	199.4	239.6
United States	–	0.6	0.6	7.2	1.0	8.2	8.8
United Kingdom	0.5	2.1	2.6	1.5	–	1.5	4.1
Colombia	–	–	–	1.8	–	1.8	1.8
Nigeria	0.4	0.2	0.6	–	–	–	0.6
Equatorial Guinea	–	0.5	0.5	–	–	–	0.5
Total	**33.6**	**16.0**	**49.6**	**242.4**	**3.1**	**245.5**	**295.1**

Wells in Progress

At December 31, 2007, we were drilling 3 wells in Yemen (2 net), 2 wells in Canada (2 net), 4 wells in the United States (1.9 net), 3 wells in the United Kingdom (1.4 net), and 1 well in Colombia (0.2 net).

Proved Reserves including Proved Undeveloped Reserves

At December 31, 2007, we had 734 mmboe of proved oil and gas reserves before royalties (650 after royalties). This is a 1% increase over the prior year (2% after royalties). Including Syncrude, our total proved oil and gas and Syncrude reserves increased 1% to 1,058 mmboe (1% to 917 after royalties).

The following table provides a summary of the changes in our proved oil and gas reserves (before royalties) excluding our Syncrude reserves during 2007. Refer to page 120 for proved reserves information on an after-royalties basis.

(mmboe)	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2006	364	182	73	66	40	725
Extension and Discoveries	7	10	4	2	–	23
Revisions	28	44	(12)	1	–	61
Acquisitions	–	1	11	–	–	12
Divestments	–	–	(2)	–	–	(2)
Production	(13)	(30)	(12)	(28)	(2)	(85)
December 31, 2007	**386**	**207**	**62**	**41**	**38**	**734**

Extensions and discoveries contributed 23 mmboe. The majority of the increase results from updip drilling at Buzzard in the North Sea, appraisal drilling at Longhorn in the Gulf of Mexico, 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.

More than half of the 61 mmboe of positive revisions occurred at Buzzard where drilling results and production performance supported higher reserve estimates. About a third of the revisions are from our Long Lake Project where performance of analogous commercial SAGD projects support increased expected recoveries. The remaining positive revisions are primarily from price revisions in Canadian heavy oil properties and the Ettrick field, recovery factor improvements on our Canadian CBM lands and other areas. In the United States, the negative revision mainly relates to our deep-water Gulf of Mexico Aspen property where unsuccessful development drilling and production declines resulted in a reassessment of the property. In addition, four Gulf of Mexico shelf properties recognized negative reserve revisions from unsuccessful recompletions, production declines and increasing operating costs on older platforms reduced their economic life.

Acquisitions and divestments accounted for a net 10 mmboe addition (8 after royalties), primarily in the Gulf of Mexico where we acquired Shelf properties, pooled our deep-water Ringo well within the Longhorn development, and swapped our interest in Great White West for an overriding royalty interest in the entire Great White reservoir. In addition, we acquired additional interests in our operated Scott and Telford properties in the North Sea.

The following provides a summary of the changes in our proved oil and gas reserves (before royalties) excluding Syncrude, during the past three years. Refer to page 120 for proved reserves information on an after royalty basis for the past three years.

(mmboe)	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2004	164	130	103	133	12	542
Extension and Discoveries	30	41	24	17	31	143
Revisions	283	79	(33)	(4)	1	326
Acquisitions	2	1	11	–	–	14
Divestments	(49)	–	(2)	–	–	(51)
Production	(44)	(44)	(41)	(105)	(6)	(240)
December 31, 2007	**386**	**207**	**62**	**41**	**38**	**734**

Since the end of 2004, we added 483 mmboe, sold 51 mmboe and produced 240 mmboe. Extensions and discoveries of 143 mmboe occurred primarily at our Usan, Ettrick and Buzzard fields, Canadian CBM and heavy oil, and the deep-water Gulf of Mexico. Our net positive revisions of 326 mmboe include economic revisions of 261 million boe, related to changes in year-end prices and costs. This includes 246 mmboe from reinstatement of Long Lake bitumen reserves that we had removed due to low bitumen prices at the end of 2004. The net technical revisions of 65 mmboe includes 77 mmboe of positive revisions in the UK primarily attributed to production performance at our Buzzard property and increased expected recoveries for our Long Lake Project. Negative technical revisions occurred primarily from lower-than-expected production performance at our Aspen field and some Shelf properties in the U.S. Gulf of Mexico. Our divestments are primarily from the 2005 sale of various Canadian properties.

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:

2007

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

2006

	Before Royalties			After Royalties		
(mmboe)	**PUDs**	**Total Proved [1]**	**% of Total**	**PUDs**	**Total Proved [1]**	**% of Total**
Canada	216	364	59%	188	319	59%
United Kingdom	50	182	27%	50	182	27%
United States	9	73	12%	7	63	11%
Yemen	9	66	14%	5	38	13%
Other Countries	31	40	78%	25	35	71%
December 31, 2006	**315**	**725**	**43%**	**275**	**637**	**43%**

Note:
1 Excludes proved reserves for our Syncrude operations of 324 mmboe (267 after royalties) in 2007 and 324 mmboe (274 after royalties) in 2006.

In 2007, our PUDs increased by 27 mmboe (22 after royalties). We added 22 mmboe (14 after royalties) at Long Lake primarily relating to increased recovery factors on proved reserves outside of the initial 81 well-pair SAGD development area. We also added PUDs from ongoing activities at Buzzard, Ettrick, Longhorn and CBM. We converted 18 mmboe (14 after royalties) of PUDs to developed, with the majority relating to Buzzard, Masila, Block 51 and CBM development activities. Other small additions and conversions occurred from ongoing development activities in Canada, United States, United Kingdom and Colombia.

In Canada, our PUDs increased from 216 mmboe (188 after royalties) to 236 mmboe (200 after royalties). Substantially all of the increase relates to Long Lake. Long Lake PUDs of 228 mmboe (194 after royalties) 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. The remaining PUDs relate to infill drilling, recompletions or facilities enhancements on our various heavy oil and natural gas fields. The majority of these PUDs are expected to be converted to producing reserves in 2008 and 2009. Also, a small portion of the PUDs relate to our CBM properties, which are expected to be converted to producing by infill drilling and field development planned for 2008 and 2009.

In the United Kingdom, our PUDs increased from 50 mmboe (50 after royalties) to 54 mmboe (54 after royalties). About 60% of the PUDs relate to Buzzard while the remainder relate to Ettrick. At Buzzard, we converted 6 mmboe of PUDs to producing and added 6 mmboe for increased recovery factors on remaining undrilled locations. The Buzzard PUDs are expected to be converted to proved over the next few years as we drill additional wells to keep the platform operating at capacity. We expect to convert the majority of Ettrick PUDs to producing when production is initiated in 2008.

In the United States, our PUDS increased from 9 mmboe (7 after royalties) to 20 mmboe (17 after royalties) largely as a result of the Green Canyon 6 acquisition, and activities at Longhorn and Great White, which are expected to be producing in the next two years. Almost all of the remaining PUDs are located in the deep water of the Gulf of Mexico.

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

Excluding Long Lake and Usan, we expect to convert over 80% 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 190 mmboe to 342 mmboe (165 to 297 after royalties). As a result, our PUDs before royalties as a percent of total proved reserves excluding Syncrude increased from 35% to 47% (37% to 46% after royalties). During this time, we converted 164 mmboe before royalties (148 after royalties) to developed. These conversions relate to completion of development of our Buzzard, Farragon and Duart fields in the United Kingdom and Block 51 in Yemen, and ongoing development of work elsewhere. We also added 316 mmboe before royalties (280 after royalties), primarily related to our active development projects at Long Lake, Usan, Ettrick and Longhorn.

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 68 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, current prices for production, 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 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 an opinion that the proved reserves estimate prepared by us is, in aggregate, within 10% of their estimate which was prepared in accordance with SEC Rules.

We engaged Ryder Scott Company (Ryder Scott) to evaluate 79% of our US Gulf of Mexico shelf reserves before royalties (79% 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 SEC Rules.

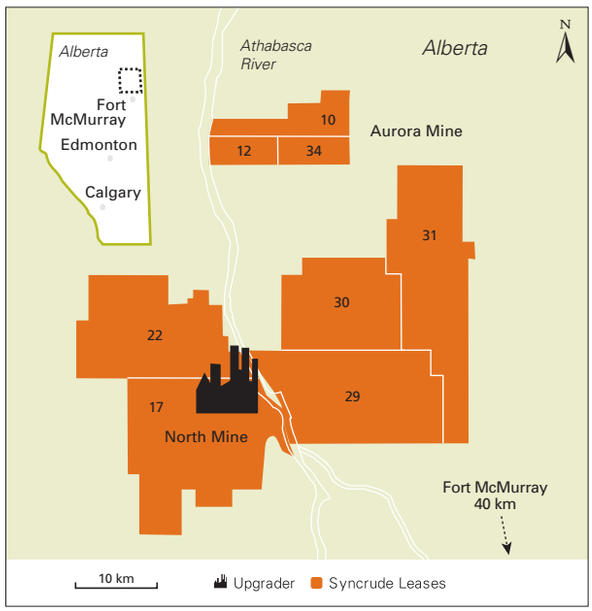
We engaged William M. Cobb & Associates, Inc. (Cobb) to evaluate 98% of our US Gulf of Mexico deep-water reserves before royalties (98% after royalties). The properties were selected by management and reviewed with the Reserves Review Committee of the Board. All material properties were selected. Cobb 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 SEC Rules.

SYNCRUDE MINING OPERATIONS

We hold a 7.23% participating interest in Syncrude Canada Ltd. (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 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 three mines: Base, 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 from 150 to 160 mmbbls 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 Base Mine uses hot water, steam and caustic soda to create a slurry, while at the North and Aurora North Mines, 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. In late 2007, the Base Mine was shut down after Syncrude recovered all of the available oil sands in the final pit.

Our Syncrude production increased to 22,100 bbls/d in 2007, following completion of the Stage 3 expansion in 2006.

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 2007, about 35% of the synthetic crude oil was sold to Edmonton area refineries, and the remaining 65% 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 1.8 billion barrels of synthetic crude oil to Edmonton, Alberta, by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 to accommodate increased Syncrude production.

At December 31, 2007, our total investment in the property, plant and equipment, including surface mining facilities, transportation equipment, and upgrading facilities, was approximately $1.3 billion. Based on development plans, our share of future expansion and equipment replacement costs over the next 35 years is expected to be about $2.8 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 profit after deducting new capital expenditures. In connection with the government's review of Alberta royalty rates in 2007, the Syncrude owners entered into negotiations at the end of 2007 at the request of the government that may result in revised royalty terms. These negotiations may result in higher royalties paid to the Alberta government in the future.

In 2007, Syncrude's production of marketable synthetic crude oil was 305,000 bbls/d. Nexen's share was 22,100 bbls/d before royalties (18,800 after royalties).

The following table provides some operating statistics for Syncrude operations:

	2007	2006	2005
Total Mined Volume [1]			
Millions of Tons	470	428	353
Mined Volume to Oil Sands Ratio [1]	2.1	2.2	2.1
Oil Sands Processed			
Millions of Tons	220	192	169
Average Bitumen Grade (weight %)	11.6	11.3	11.1
Bitumen in Mined Oil Sands			
Millions of Tons	26	22	19
Average Extraction Recovery (%)	92	90	89
Bitumen Production [2]			
Millions of Barrels	133	112	94
Average Upgrading Yield (%)	84	85	85
Gross Synthetic Crude Oil Shipped [3]			
Millions of Barrels	111.3	94.3	78.1
Nexen's Share of Marketable Crude Oil			
Millions of Barrels Before Royalties	8.1	6.8	5.7
Millions of Barrels After Royalties	6.9	6.2	5.6

Notes:

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 1.0% 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, ethanol 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.

North American Gas Marketing

The marketing and trading of North American natural gas is our marketing group's largest revenue source. We focus on key regional markets where we have a strategic presence—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;
- capitalizing on time spreads (differences in prices between summer and winter) using our storage assets; and
- financial trading of location and time spreads.

We have offices in key regions including Calgary, Detroit and Houston. Our Calgary office provides 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 in western Canada as well as consumers (including utilities) in eastern Canada, the north-eastern United States and the US mid-continent. Our Detroit office works closely with Calgary to provide services to our customers and our presence in Houston has established us in the Gulf Coast region. We use our access to transportation and storage facilities to optimize returns for ourselves as well as our customers.

Marketing Office Locations

In 2003 and 2004, we grew our asset base by acquiring physical gas purchase and sales contracts, as well as natural gas transportation capacity, on favourable terms. This gave us access to new third party gas supply until the end of 2008, pipeline capacity to 2016 and new relationships that have enabled us to negotiate new gas purchase and sales contracts. We continue to pursue opportunities to grow our storage and transportation positions by reviewing acquisitions and participating in the normal bidding processes. 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 regions to take advantage of price differences. At the end of 2007, we held 2 bcf/d of pipeline capacity, primarily between western Canada and the eastern US, and we continue to expand our presence into other markets within North America. We also use storage capacity to store normally cheaper summer gas in the ground until the winter heating season arrives. We had access to 39 bcf of natural gas storage facilities at the end of the year.

At year end, we had access to 39 bcf of natural gas storage facilities.

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 pro-actively 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. Traditionally, 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 has expanded our presence in that market through our Houston office. At the end of 2007, we had access to 2.7 mmbbls of storage and over the course of the year, marketed approximately 655 mbbls per day.

Our operations also include North American natural gas liquid (NGL) and ethanol businesses that focus on buying and selling NGLs, as well as ethanol and natural gasoline. These businesses acquire and move product within North America. They also provide natural gasoline as a denaturant for ethanol production and market the finished ethanol in the US. At the end of 2007, we had access to 550 mbbls of NGL storage and over the course of the year, moved approximately 26 mbbls per day of product.

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 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. We expect to increase our power generation capacity with a 170 MW cogeneration facility at Long Lake in 2008. We have a 50% interest in this project.

Europe

In 2006, we acquired Foundation Energy, a UK-based European gas and power marketing business. Our trading strategies include capitalizing on time and location spreads involving the UK and German 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. We recruited an experienced crude oil marketing team and established an office in London, UK in 2006 to maximize the value of our North Sea production. The team began successfully marketing Buzzard crude oil production in 2007.

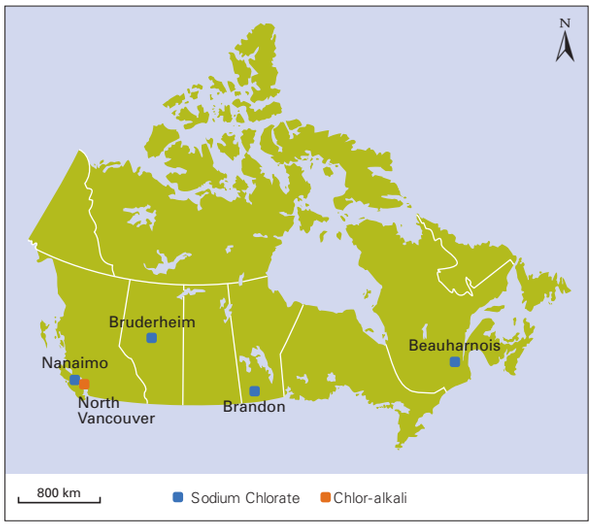
Asia

Our international team in Asia continues to focus on the physical marketing of Masila crude oil. In order to meet customer needs, we may occasionally market other regional crude types. In addition to our own crude, we market 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 have retained a 61.4% interest in our chemicals business, and we 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 facilities are modern, reliable and strategically located to capitalize on competitive power costs or transportation infrastructure to minimize production and delivery costs. This enables us to have reliable supplies and low costs—key factors for marketing bleaching chemicals.



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.

North America

The North American pulp and paper industry consumes approximately 95% 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 32% of this production is sold in Canada, 61% 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 October 2004, we completed an expansion of our Brandon plant, increasing capacity to 260,000 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. In late 2006, we began another expansion at Brandon which is expected to increase capacity by 33,000 tonnes per year, by mid 2008.

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 polyvinyl chloride, water purification and petrochemicals industries, primarily in the United States. In early 2008, a technology conversion project for the North Vancouver facility was sanctioned. The conversion project 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%. The project is expected to be completed early 2010.

Average Annual Production Capacity

(short tons)	2007	2006	2005
Sodium Chlorate			
North America	450,055	446,208	446,208
Brazil	68,563	68,563	68,563
Total	**518,618**	**514,771**	**514,771**
Chlor-alkali			
North America	364,500	356,002	356,002
Brazil	109,430	109,430	109,430
Total	**473,930**	**465,432**	**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 15% of the sodium chlorate production is sold in the merchant market under shorter-term contracts. In 2002, we completed an expansion at both facilities to meet Aracruz's growing needs. The majority of our electricity needs are supplied by a long-term supply contract in Brazil.

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. Occasionally, 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 safety, environment and social responsibility group that ensures our worldwide operations are conducted in a safe, ethical and socially responsible manner. We have developed policies for continuing compliance with environmental laws and regulations in the countries in which we operate.

Environmental Provisions and Expenditures

The ultimate financial impact of 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, 2007, $832 million ($2,165 million, undiscounted, adjusted for inflation) has been provided in our Consolidated Financial Statements for asset retirement obligations. In 2007, we increased our retirement obligations for future dismantlement and site restoration by $105 million primarily from ongoing development of the Long Lake Project in the Athabasca oil sands and from industry cost pressures in the North Sea.

In 2007, our capital expenditures for environmental-related matters, including environment control facilities, were approximately $23 million. Our operating expenditures for environmental-related matters were approximately $4 million. In 2008, we estimate these expenditures to be approximately $27 million.

EMPLOYEES

We had 4,058 employees on December 31, 2007, of which 326 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 our industry and some of which are unique to our operations.

A substantial or extended decline in oil and natural gas prices could have a material adverse effect on us.

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. Changes in world crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect 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, primarily Brent and West Texas Intermediate (WTI) crude oil reference prices and other 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 political events. Quality differentials are affected by local supply and demand factors.

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, and logistics and reliability of supply.

Competitive forces may result in shortages of prospects to drill, shortages of labour and 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.

Exploration, development and production risks and natural disasters could result in liability exposure or loss of production or reserves.
Acquiring, developing and exploring for oil and natural gas involves many risks. These include:

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

We operate two facilities that are located in close proximity to populated areas, and each processes materials of potential harm to the local populations. At Balzac, just north of Calgary, we operate a gas plant that has been producing sour gas for over 45 years. Through our ownership in Canexus Limited Partnership, we operate a chlor-alkali plant in North Vancouver that has been producing chlorine for almost 50 years.

We may not be fully insured against all of these risks. Losses resulting from the occurrence of these risks may materially impact our financial results.

Our offshore operations are subject to unique operating risks.
Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production.

Our operations in the Gulf of Mexico have been suspended, from time to time, due to hurricanes or tropical storms. In the last five years, we have had a few instances where production was suspended for an extended period of time and damage to facilities was incurred. In late August 2005, we shut-in all of our production in the Gulf of Mexico, consisting of approximately 50,000 boe/d before royalties, and ceased drilling operations in anticipation of Hurricane Katrina. Production was restored in early September for most of our fields. In late September 2005, we again shut-in all of our production and ceased drilling operations in anticipation of Hurricane Rita. While we incurred minimal damage to most of our facilities, extensive damage was incurred to the third party infrastructure necessary to accommodate our production. As a result, our 2005 annualized production was reduced by approximately 6,000 boe/d. These storms also resulted in damage to rigs under contract with us, which increased our costs and delayed our drilling schedule. In each of these instances, there was no significant financial impact after business interruption and property insurance claims.

Our exploration and development capital programs in our offshore operations are exposed to risk of delay or additional costs by limited access to drilling rigs. Recent industry pressure in the Gulf of Mexico has reduced the availability of drilling rigs. Our profitability and success at finding reserves or bringing new production on stream may be reduced by extended delays and/or higher costs of obtaining drilling rigs.

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 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 prices and costs at the end of the year. Accordingly, 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 SEC rules, we are required to recognize our oil sands as bitumen reserves rather than the upgraded premium synthetic crude oil that we expect to produce from the Long Lake Project. As a result, 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. In particular, since 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 may begin production. Such 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, 2007, 47% of our proved reserves before royalties (46% after royalties) were undeveloped. Refer to page 20 for information on PUDs.

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.

The Long Lake Project faces additional risks compared to conventional oil and gas production.
The Long Lake Project is planned as a fully integrated production, upgrading and cogeneration facility. We intend to use steam assisted gravity drainage (SAGD) technology to recover bitumen from oil sands. As designed, the bitumen will be 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 asphaltines that will be gasified into syngas. This syngas will be 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 50% working interest in this project, and our share of the capital costs is estimated to be between $2.9 billion and $3.05 billion ($5.8 billion and $6.1 billion gross). This includes a contingency reserve of $150 million ($300 million gross) for cost and productivity pressures over and above current trends. 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:

Uncertain Time Line and Cost of the Project

The Long Lake Project is currently in the construction and commissioning stage. There is a risk that actual costs to construct and develop may be higher than expected or that the project may not be completed on time or at all due to many factors, including:

- construction performance falling below expected levels of output or efficiency;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- inability to attract sufficient numbers of qualified workers;
- design errors;
- contractor or operator errors;
- non-performance by third-party contractors;
- changes in project scope;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- breakdown or failure of equipment or processes;
- violation of permit requirements;
- catastrophic events such as fires, earthquakes, storms or explosions; and
- disruption in the supply of energy.

The capital cost estimate at the time our board sanctioned the project in February 2004 was $3.4 billion (gross). In December 2004, we accelerated the drilling of an additional well pad consisting of 13 well-pairs to increase certainty and reliability of bitumen production at the commencement of upgrader operations at a cost of $98 million (gross). In early 2006, we further modified the project design by adding steam generation capacity and soot handling equipment at a cost of $360 million (gross). These scope changes increased the estimated project cost to $3.8 billion. High activity in the oil sands region is placing ongoing pressure on the costs of labour and services. In addition, labour productivity has been lower than anticipated, requiring a larger workforce to maintain progress. In October 2007, we announced that the projected cost estimate for Phase 1 ranges from $5.8 to $6.1 billion ($2.9 to $3.05 billion net to Nexen). We are on track to complete the construction and commence commissioning of all units in sufficient time for first production of synthetic crude oil in mid 2008.

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 in-situ recovery of bitumen from oil sands is relatively new. Some of the SAGD oil sands applications to date have been pilot projects, however several commercial SAGD projects have been in steady state operation for over five years.

Our estimates for performance and recoverable volumes for the Long Lake Project are based primarily on our three well-pair SAGD pilot 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. There can be no certainty that our 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 a significant 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 will be the first commercial application of the process although we have operated it in a 500 bbl/d demonstration plant. There can be no certainty that the commercial upgrader being constructed at Long Lake will achieve the same or similar results as the demonstration plant or the results which are forecast. If we are unable to upgrade the bitumen for any reason we may decide to sell it as bitumen without upgrading it, 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 on OPTI Canada Inc.

We are undertaking the Long Lake Project jointly with OPTI Canada Inc. (OPTI) pursuant to a joint venture agreement governing the construction, ownership and joint operation of the project. The agreement provides for a management committee that is responsible for the supervision and direction of the management and operation of the project, the supervision and control of the operators and all other matters relating to the development of the project. If our interest in any element of the project falls below 25%, OPTI may be able to make decisions respecting that element without our input, which may adversely affect our operations.

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. This kind of 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, and there can be no assurance that any currently 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. Furthermore, 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 will be 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 will process 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 will 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 will include 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 shut down of operations.

The Long Lake Project will produce 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.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including exploring for, and developing, new sources of supply, acquiring petroleum interests and distributing and marketing of petroleum products. The Long Lake Project competes with other producers of synthetic crude oil blends and other producers of conventional crude oil. Some conventional producers have lower operating costs than the project is anticipated to have. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies, other than OPTI and us, have announced plans to: 1) enter the oil sands business and begin producing synthetic crude oil, or 2) expand existing operations. Either plan could materially increase the supply of synthetic crude oil and other competing crude oil products in the marketplace. Depending on future demand, increased supplies could have a negative impact on prices.

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 two Yemen operations;
- Gunnison SPAR production platform in the Gulf of Mexico;
- Aspen wells tied-in to a third-party processing facility in the Gulf of Mexico; 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 operations could be subject to changes in regulations related to air emissions.

The Kyoto Protocol came into force on February 16, 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 (2008 to 2012). Alberta became the first jurisdiction in Canada to enact and implement binding emission reductions (a 12% reduction in carbon intensity) on facilities emitting more than 100 kilo-tonnes of CO_2 equivalent. Facilities unable to make internal reductions have unlimited access to a technology fund at the rate of $15 per tonne of CO_2 equivalent. In 2007, the Federal government introduced a Regulatory Framework for Air Emissions which indicates that the government intends to regulate both greenhouse gases and air pollutants beginning as early as 2010, with progressively more stringent reductions applied out to 2050. Greenhouse gases (GHGs) will be regulated based on intensity until 2020 – 2025, when a cap and trade system may be imposed. The intent appears to offer companies the option of making internal reductions, purchasing offsets or making payments into a technology fund (with escalating fixed costs). During the period 2010 to 2020 there will be increasing exposure to a Canadian carbon market which could be short of supply leading to very high carbon prices. It remains to be seen if the two levels of government will harmonize their compliance regimes and how the revenue in the technology funds will be allocated. The federal government has also indicated their intent to regulate air pollutants concurrent with greenhouse gases but their schedule and long-term objectives are less clear. Based on what is known today, there could be 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" starting operations in 2008, Long Lake will have three years to establish an emissions baseline before having a reduction obligation assigned. In 2007 our Canadian operations, including Syncrude, accounted for 23% of our production before royalties.

Our two installations in the UK sector of the 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. The installations are both expected to have emissions in excess of allowances which will be covered by eligible offsets from the Clean Development Mechanism and over-the-counter trades.

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. The markets in which we trade are susceptible to significant changes, which could expose us to the risk of material financial losses. Significant changes in the commodities and financial markets could require us to provide additional liquidity to support our energy marketing operations.

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. Any significant loss of liquidity could adversely affect our financial condition.

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.

Fluctuations in exchange rates give rise to foreign currency exposure.
Many of our activities are transacted in or referenced to US dollars. Revenues, expenses, capital expenditures and related net assets of our oil and gas and chemicals operations outside Canada are primarily US-dollar denominated. Prices received in Canada for sales of our crude oil, natural gas and some chemicals products are referenced to US-dollar denominated prices. Also, we have the ability to borrow on a short-term and long-term basis in US dollars. Fluctuations in exchange rates between the US and the Canadian dollar, and between US or Canadian dollar and other foreign currencies, including but not limited to the British pound and the Euro, could adversely affect our financial condition.

Increases in interest rates could give rise to increased debt servicing obligations.
We use both fixed and floating rate debt to finance our operations. Our floating rate debt obligations expose us to changes in interest payments due to fluctuating interest rates. This could adversely affect our financial condition.

The inability of counterparties 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 if counterparties do not fulfill their contractual obligations. Most of our receivables are with counterparties in the energy industry and are subject to normal industry credit risk. The inability of any one or more of these counterparties to fulfill their obligations to us may adversely impact our results of operations.

We may not achieve commercial production rates in our coalbed methane or shale gas operations.
Part of Nexen's growth strategy is unconventional Canadian gas resource plays, including coalbed methane (CBM) and shale gas. Both gas resource plays have significant potential; however, 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 commercial, 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. Nevertheless, 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.

We have significant up-front commitments related to our current development projects.
We have significant commitments in connection with various development activities currently underway. At Long Lake, we essentially completed module and site construction of the SAGD facilities in 2006 and steam injection began in 2007. Module fabrication of the Long Lake Upgrader is complete and all modules are on site. Construction of the upgrader is approximately 97% complete and start up is scheduled for mid 2008. At Long Lake, we are exposed to the possibility of cost overruns and/or delays in the commencement of commercial production, which may be significant. Specific risk factors relating to our Long Lake oil sands project are provided separately. See "The Long Lake Project faces additional risks compared to conventional oil and gas production".

We operate in countries with political and economic risk.
We operate in numerous countries, some of which may be considered politically and economically unstable. Our operations and related assets are subject to the risks of actions by governmental authorities, insurgent groups or terrorists which may have material adverse financial consequences. For instance, on September 15, 2006 our oil export terminal in Yemen was assaulted by two explosive laden vehicles. One worker was killed and two others received minor injuries. The ability of the terminal to receive and export oil was not affected and operations continued as normal. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

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. For example, the US government has proposed increases to the royalty rates for new deep-water Gulf of Mexico leases and has proposed amendments to deep-water leases issued in 1998 and 1999. In 2007, the Alberta government proposed changes to royalty rates effective 2009. 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.

Our operations are exposed to environmental liabilities.
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 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. This could have an adverse financial consequence on us.

Certain operations require the use of fresh and saline water. We currently use sub-surface sources of water for these operations. Additional costs may be incurred if allocation limits are placed on our saline water usage, if our sub-surface fresh water needs exceed allocated amounts or if existing sub-surface fresh 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 2007.

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, 2007, there were 1,569 registered holders of common shares and 528,304,813 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings. During the year, we made no purchases of our own equity securities.

Trading Range of Nexen's Common Shares

	TSX (Cdn$)		**NYSE** (US$)	
($/share)	**High**	**Low**	**High**	**Low**
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
2006				
First Quarter	34.05	27.17	29.97	23.49
Second Quarter	34.75	25.41	30.84	22.82
Third Quarter	35.61	26.07	31.82	23.35
Fourth Quarter	32.90	26.46	29.19	23.45

Quarterly Dividends Declared on Common Shares

($/share)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
2007	0.025	0.025	0.025	0.025
2006	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 2007 have been designated as "eligible dividends" for Canadian tax purposes.

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 154).

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 2008 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

(Cdn$ millions, except otherwise indicated)	2007	2006	2005	2004	2003
Oil & Gas and Syncrude Production					
Production Before Royalties (mboe/d) [1]	254	212	242	250	269
Production After Royalties (mboe/d) [1]	207	156	173	174	185
Results of Operations					
Revenue					
Oil & Gas and Syncrude [2]	5,174	3,656	3,535	2,573	2,261
Marketing	926	1,373	864	625	586
Chemicals	447	413	413	383	377
Other	(26)	(47)	(193)	59	31
Total Revenue	6,521	5,395	4,619	3,640	3,255
Net Income from Continuing Operations	1,012	579	658	705	419
Basic Earnings per Common Share from Continuing Operations ($/share) [3]	1.92	1.10	1.26	1.37	0.85
Diluted Earnings per Common Share from Continuing Operations ($/share) [3]	1.88	1.08	1.23	1.35	0.84
Net Income	1,012	579	1,110	788	420
Basic Earnings per Common Share ($/share) [3]	1.92	1.10	2.13	1.53	0.85
Diluted Earnings per Common Share ($/share) [3]	1.88	1.08	2.08	1.51	0.84
Financial Position					
Total Assets [1]	17,982	17,079	14,493	12,339	7,703
Long-Term Debt [4]	4,610	4,618	3,630	4,214	2,470
Shareholders' Equity	5,449	4,614	3,961	2,892	2,131
Capital Investment, including Acquisitions	3,401	3,408	2,638	4,264	1,432
Dividends per Common Share ($/share) [3,5]	0.10	0.10	0.10	0.10	0.08
Common Shares Outstanding (thousands) [3]	528,305	525,026	522,281	516,798	502,424

Notes:

1 *In 2004, production declined from our maturing assets in Yemen at Masila, in Canada and in the US Gulf of Mexico Shelf. 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 *During 2003, we sold non-core conventional light oil assets in southeast Saskatchewan in Canada producing 9,000 bbls/d. In late 2004, we concluded production from our Buffalo field, offshore Australia, as anticipated. 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 *Our shareholders approved a split of our issued and outstanding common shares on a two-for-one basis at our annual and special meeting on April 26, 2007. All common share and per common share amounts presented have been retroactively restated to reflect this share split.*

4 *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.*

5 *Quarterly dividends were increased to 2.5¢ per share in the fourth quarter of 2003.*