



## Operations

We have developed specific capabilities in oil sands, coalbed methane, deep-water technology and international locations. These provide us with world-class capacity for future growth.

**PART I**  
**ITEMS 1 AND 2. BUSINESS AND PROPERTIES**

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## ABOUT US

Nexen Inc. (Nexen, we or our) is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 by the combination of the Canadian crude oil, natural gas, sulphur and chemical operations of two subsidiaries of Occidental Petroleum Corporation (Occidental). We've grown from producing 10,700 boe/d before royalties with revenues of \$26 million in 1971, to 211,700 boe/d before royalties (including Syncrude production) and revenues of \$3.9 billion in 2006. We achieved this growth through exploration success and strategic acquisitions. In more than 30 years of operations, 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.

In the 1980s, we continued to expand in western Canada by acquiring Canada-Cities Service, Ltd. in 1983. This acquisition doubled our size and included an interest in the Syncrude Joint Venture, our entry into the Athabasca oil sands. Acquisitions of Cities Offshore Production Co. in 1984 and Moore McCormack Energy, Inc. in 1988 established our presence in the Gulf of Mexico. 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, and Masila has produced more than 940 million barrels since start up in 1993. 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, the first of several discoveries to date on the block. 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 a non-core divestiture program. 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 more than \$2.6 billion at year-end 2006. We also exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemical operations and we changed our name to Nexen Inc. from Canadian Occidental Petroleum Ltd. 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.

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**We've grown from producing 10,700 boe/d in 1971 to 211,700 boe/d in 2006. In 2007, we expect our net production to grow by 50%.**

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In 2005, we sold Canadian conventional oil and gas properties producing approximately 18,300 boe/d before royalties and monetized 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 our major development project at Buzzard on budget and made significant construction progress at our Long Lake project in the Athabasca oil sands. In early January 2007, Buzzard produced first oil. With Buzzard on stream, followed by Long Lake later in the year, we expect our production after royalties in 2007 to grow by more than 50%, net of declines. Our portfolio of assets, combined with our 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 and offshore West Africa). 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 southeast 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. We define value growth as increasing reserves, production, cash flow and net income over the long term. We believe in developing our competitive advantage, which generates 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, coalbed methane (CBM), deep-water technology and international locations. These 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 are successful deep-water explorers with significant discoveries at Knotty Head in the Gulf of Mexico and at Usan, offshore Nigeria;
- We are skilled project managers with major development projects at Buzzard in the North Sea, and Long Lake in Canada's Athabasca oil sands. In 2006, Buzzard was completed on budget and just days after the original projected start up date. At Long Lake, construction is progressing well and we expect the SAGD production operations to be on stream by the end of the first quarter in 2007, followed by the start up of the upgrader late in the year;
- 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;
- 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 an extended period of time from the capture of opportunities to first production and 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 selling non-core assets into attractive markets.

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**We are building sustainable businesses with major projects in established basins, exploitation of unconventional resources and exploration.**

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Our long-term strategy focuses on building capacity by ensuring we have a sufficient inventory of opportunities for future growth. With Buzzard on stream, followed by Long Lake later this year, we expect to deliver significant production growth. In fact, in 2007 we expect our production after royalties to grow by more than 50%, net of declines. However, the growth does not stop there. Beyond 2007, we have a number of opportunities that are expected to provide production growth and create shareholder value well into the next decade. These opportunities include undeveloped discoveries at Knotty Head in the Gulf of Mexico, Usan and Ukot offshore Nigeria, various discoveries in the UK North Sea, together with development of our CBM and additional oil sands leases in Canada.

In creating sustainable businesses, we are committed to good corporate governance 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 their 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.

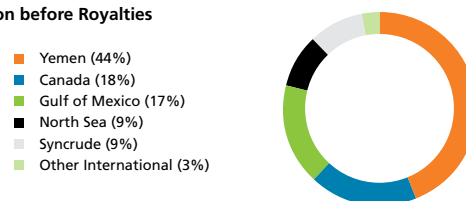
Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash generated from operating activities. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration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

Realized prices 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 significant 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 have a seasonal component that can impact 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, offshore West Africa and Colombia. 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.

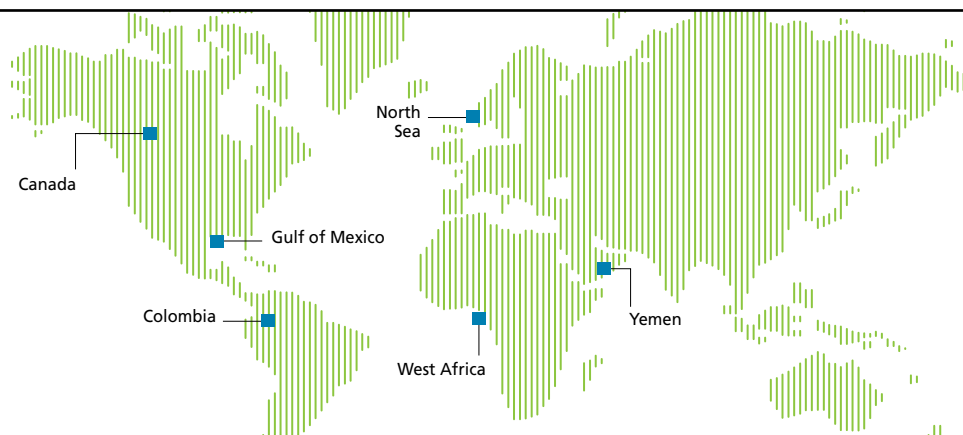
2006 Production before Royalties



In this Form 10-K, we provide estimates of remaining quantities of oil and gas reserves for our various properties. Such estimates are internally prepared. We had 98% of our reserves assessed 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 often differ by significantly more than 10%, either positively or negatively. Refer to the section on Oil and Gas Accounting – Reserves Determination on page 71 for a description of our reserves process.

**North Sea—United Kingdom (UK)**

The UK is one of our key growth areas. 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 focused on exploration and exploitation opportunities near existing infrastructure. We have a number of exploitation opportunities in our existing fields and smaller satellite undeveloped discoveries near infrastructure. Most of our unexplored acreage is near Scott/Telford, Buzzard or Ettrick which is currently being developed. As a result, new discoveries could be tied-in relatively quickly, upon success.

During the year, we produced 20,200 boe/d before royalties (20,200 after royalties) in the UK, which was approximately 10% of Nexen's total production. At year end, the UK had proved reserves of 182 mboe before royalties (182 after royalties) representing about 17% of our total proved oil and gas and Syncrude reserves.

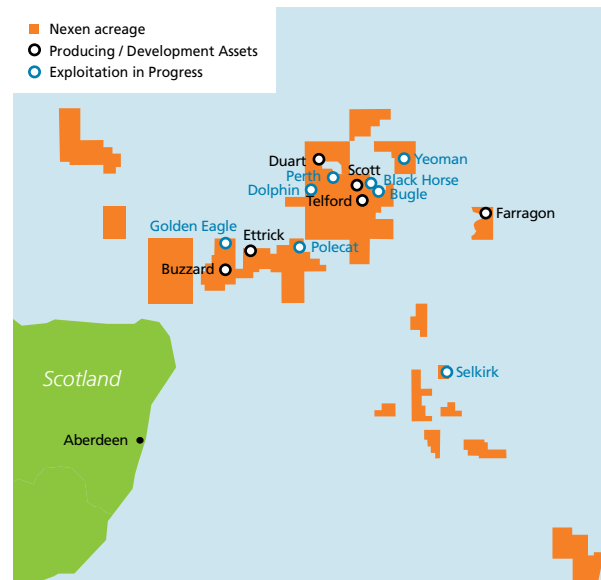
### Buzzard Development

The Buzzard field is located in the Outer Moray Firth, central North Sea, about 60 miles northeast of Aberdeen, in 317 feet of water. The field was discovered in 2001 and construction was completed in 2006, with production commencing early January 2007. During the year, we installed the utilities and production topsides, drilled the initial development wells and completed hook-ups and project commissioning. The facilities have the capacity to process up to 200,000 bbls/d of oil and 60 mmcf/d of gas, including the removal of hydrogen sulphide. Based upon recent drilling results, we have experienced more well-to-well variability in the concentration of hydrogen sulphide than previously seen. We expect existing equipment and processes will allow us to manage this variability for at least the first two to three years of production. As we continue to produce and acquire additional reservoir information, we will determine whether additional equipment will ultimately be required. We anticipate the field will be produced through 27 production wells and reservoir pressure will be maintained through an active water-flood program. Buzzard is one of the largest discoveries in the UK North Sea in the past ten years.

**Buzzard is on stream and ramping up to estimated peak rates of 85,000 boe/d net to us.**

### Ettrick Development

We are progressing development of the Ettrick field which is expected to begin producing in the first half of 2008, with our share expected to average approximately 16,000 boe/d (before and after royalties). Development includes drilling three production wells tied back to a leased floating production, storage and off-loading vessel (FPSO) and is approximately



30% complete. Our share of full-cycle development costs is estimated at \$460 million. In 2007, we plan to invest \$235 million in subsea development including drilling three development wells and one water injection well.

### UK Production

Buzzard began producing at the beginning of January 2007. We expect to reach peak gross production rates of approximately 200,000 bbls/d of oil and approximately 30 mmcf/d of gas, with our share about 85,000 boe/d (before and after royalties) in the first half of 2007. 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. In 2007, we plan to invest approximately \$130 million to pre-drill and complete 11 future production and injection wells.

Scott and Telford are producing fields with additional exploitation opportunities. Scott, in which we have a 41% working interest, was discovered in 1987 and began producing in September 1993. We have a 54.3% working interest in Telford, which was discovered in 1991 and came on stream in 1996. In 2006, our share of Scott and Telford royalty-free production approximated 16,000 boe/d, of which 80% was oil.

Oil and gas is produced through numerous subsea wells and platform 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 2005, the Scott platform underwent a significant maintenance turnaround and facilities upgrade to improve reliability and extend facility life. In 2006, the flare tip and flare tip supporting structure were upgraded. In 2007, we plan to invest approximately \$45 million to drill, complete and tie-in three development wells.

Our 2004 UK acquisition included a non-operated interest in Farragon, a small satellite discovery, which was brought on stream in November 2005. In 2006, our 20% share of royalty-free production from Farragon was 3,700 boe/d.

Field	Interest (%)	Operator Status	Comments
Duart	50	non-operated	discovery near Scott; first oil expected in late 2007
Black Horse	40	operated	discovery near Scott; evaluating development alternatives
Bugle	82	operated	discovery near Scott; well planned for 2007
Dolphin	42	operated	discovery near Scott; evaluating development alternatives
Golden Eagle	34	operated	discovery near Ettrick; evaluating development alternatives
Perth	42	operated	discovery near Scott; evaluating development alternatives
Polecat	40	operated	discovery near Buzzard; evaluating development alternatives
Selkirk	38	operated	appraisal well planned for 2007
Yeoman	50	operated	discovery near Scott; evaluating development alternatives

Development is progressing at Duart. In 2007, we plan to drill a development well and bring the field on stream before year-end. The other discoveries are in various stages of evaluation.

During 2006, we drilled unsuccessful exploration wells at Zanzibar and Black Cat. These wells encountered non-commercial hydrocarbons and were abandoned. In 2007, we expect to drill five exploration and appraisal wells. The off-shore drilling rig market is currently tight, however, we have secured drilling rigs for most of our 2007 North Sea exploration and development program.

### Coalbed Methane (CBM)

In 2006, we acquired an 80% working interest at an emerging CBM opportunity in the UK. CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by coal in coal deposits rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in reservoir pressure. If the coal deposit is water saturated, water generally needs to be extracted to reduce the pressure and allow gas production to occur. If the coal does not produce water and is "dry", gas will be produced from initial development. Water-producing CBM wells in the United States generally show increasing gas production rates for a period of approximately one to three years before gas rates begin to decline.

### Exploration and Undeveloped Assets

In early 2007, we completed drilling operations at our Golden Eagle prospect and we encountered hydrocarbons. A successful sidetrack was drilled to appraise the accumulation and we are currently evaluating development options. We have a number of smaller discoveries on operated blocks near Scott, Buzzard and third-party facilities as follows:

During 2006, we drilled two exploratory wells at our UK CBM opportunity. The wells encountered all the coal seams expected. In 2007, we plan to continue assessing the potential of this investment by drilling additional wells and production testing them.

### 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 2012. 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. The Buzzard, Telford and Farragon fields are not subject to PRT. PRT is deductible for corporate income tax purposes. The UK corporate income tax rate is 30% of taxable income. Income from oil and gas activities is also subject to a supplemental charge. The UK government increased this charge from 10% to 20%, effective January 1, 2006. The amount and timing of income taxes payable depends on many factors including price, production, capital investment levels and available tax losses.

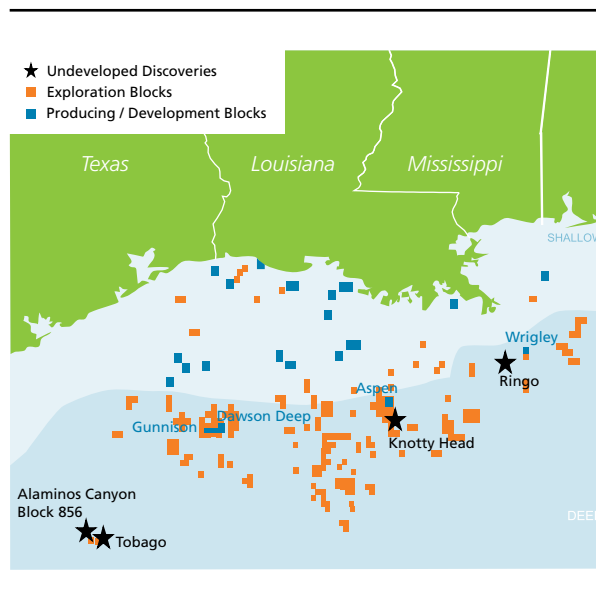
**Gulf of Mexico—United States (US)**

The Gulf of Mexico is an integral part of our growth strategy. Large discoveries, relatively high success rates, 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. The 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 relatively near infrastructure and continental US markets, enabling discoveries to be brought on stream in a reasonable period of time.

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

- deep-shelf gas prospects;
- deep-water prospects near existing infrastructure; and
- deep-water, sub-salt plays with potential to become new core areas.

These plays are relatively under-explored, hold potential for large discoveries and have attractive fiscal terms. The shorter-cycle times for shelf gas and deep-water prospects near infrastructure complement the longer-cycle times for deep-water sub-salt plays. Although competition in the Gulf



is strong, we expect the availability of expiring acreage over the next few years to provide us with access to additional exploration opportunities.

In 2006, we invested \$595 million on exploration and development activities in the Gulf. This resulted in discoveries at Alaminos Canyon Block 856 (Great White West) and Ringo. In 2007, we plan to invest approximately \$585 million in the Gulf to further our strategy.

**US Production**

	2006		2005		2004	
	Before Royalties	After Royalties	Before Royalties	After Royalties	Before Royalties	After Royalties
(mboe/d)						
Deep-water	19.6	17.5	24.0	21.5	32.1	28.7
Shallow-water	15.9	13.2	17.6	14.6	22.6	18.8
Total	35.5	30.7	41.6	36.1	54.7	47.5

In 2006, we produced approximately 35,500 boe/d before royalties (30,700 after royalties), representing approximately 17% of Nexen’s total production including Syncrude. This was less than expected due to timing delays at Aspen and weather-related disruptions. Weather is a risk in the Gulf of Mexico; specifically, tropical storms and hurricanes can damage facilities, drilling rigs and surrounding infrastructure, interrupt production, and delay exploration and development programs. Storms in 2005 caused damage to third-party infrastructure and as a result, approximately 4,000 boe/d of our pre-storm production was shut-in for nine months of

2006. We carry property and business interruption insurance to mitigate losses caused by adverse weather. During 2006, we received \$80 million of insurance proceeds relating to these storms.

At year end, we had proved reserves of 73 mboe before royalties (63 after royalties) representing about 7% of Nexen’s total proved oil and gas and Syncrude reserves. Our production and reserves in the Gulf are primarily concentrated in two deep-water and five shallow-water areas. We operate most of this production.

### Deep-Water Production

The majority of our deep-water production comes from our 100%-operated Aspen field and 30% non-operated Gunnison field. 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. Production began in December 2002 and we achieved payout on our full investment in Aspen in January 2005. Our share of 2006 production before royalties was approximately 8,900 boe/d (8,000 after royalties). In 2006, we drilled an additional development well. This well came on stream in late December. Based on results from this well, we see additional opportunities in the Aspen field and are currently sidetracking the Aspen 1 well to exploit deeper sands. We expect our 2007 production from the Aspen field to average between 15,000 and 20,000 boe/d.

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#### The Wrigley discovery is expected to begin producing in early 2007.

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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. We achieved payout on Gunnison in December 2005, just two years after first production. In 2006, our share of production before royalties was approximately 10,600 boe/d (9,300 after

Well	Interest (%)	Operator Status	Comments
Wrigley	50	non-operated	development underway; expected to begin producing in early 2007
Alaminos Canyon Block 856	30	non-operated	evaluating development alternatives
Tobago	10	non-operated	development approved; expected to begin producing in 2009
Knotty Head	25	operated	further appraisal required
Ringo	50	non-operated	additional appraisal well to be drilled in 2007

During the year, we drilled dry holes at Pathfinder, West Cameron 135, West Cameron 109, Eugene Island 19 and Vermilion 65. We increased our deep-water undeveloped land position by 20 blocks to over 200 blocks and expect this acreage and future exploration opportunities to position us well for continued growth. In 2007, we plan to tie-in our Wrigley discovery to a third-party facility. We also plan to drill nine exploration wells (four in the deep water and five on

royalties). Our Gunnison SPAR production facility has excess capacity, leaving room for growth from exploration and processing of third-party volumes. In 2006, we completed the tie-in of our 15% non-operated Dawson Deep discovery to the Gunnison SPAR.

### Shallow-Water Production

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 opportunities on the shelf. Most of our 2006 shelf activities focused on development drilling at Eugene Island 258/259 and Eugene Island 295.

### Exploration and Undeveloped Assets

Our exploration program in the Gulf of Mexico continues to produce new discoveries. In 2006, we had discoveries at Alaminos Canyon Block 856 (Great White West) and Ringo. We are currently evaluating development options for both of these discoveries. During the year, we also drilled a successful sidetrack well on our 2005 Knotty Head discovery. We are currently proceeding with facility and subsurface studies. Access to deep-water rigs remains limited and we continue to work with partners to find a rig to complete the appraisal of the field. Our undeveloped deep-water discoveries include:

the shelf) and have drilling rigs secured for more than half of these wells. We are actively working with partners to find rigs for the remainder. In 2005, we committed to a deep-water drilling contract, which provides us with access to a new-build fifth generation dynamically positioned semi-submersible drilling rig for two years over a three-and-a-half year period. We expect this new rig to be available in mid 2009.

### Fiscal Terms

In 2006, royalty rates on our US production averaged 16.6% for shallow-water volumes and 11.2% for deep-water volumes. The US government has proposed to increase royalty rates from 12.5% to 16.7% for new deep-water leases awarded after July 2007. We qualify for royalty relief at our deep-water Aspen and Gunnison fields on the first 87.5 mmoeb of production. 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 2006, 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, however, the US government has proposed legislation to include minimum threshold prices for deep-water leases granted in 1998 and 1999. If the legislation is approved, our Aspen field could be subject to a 12.5% government royalty on production after October 1, 2006. 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 to bring our new growth developments into production while we maximize value from our established operations. In 2005, we disposed of approximately 18,300 boe/d before royalties of production, comprising approximately 60% oil and 40% gas. The assets we retained have upside potential for continued conventional development and enhanced recovery with advancements in extraction technology. During the year, we produced 38,000 boe/d before royalties (31,000 after royalties), which was approximately 18% of Nexen's total production including Syncrude. At year end 2006, proved reserves (including bitumen and excluding Syncrude) of 364 mmoeb before royalties (319 after royalties) were approximately 35% of our total proved oil and gas and Syncrude reserves.

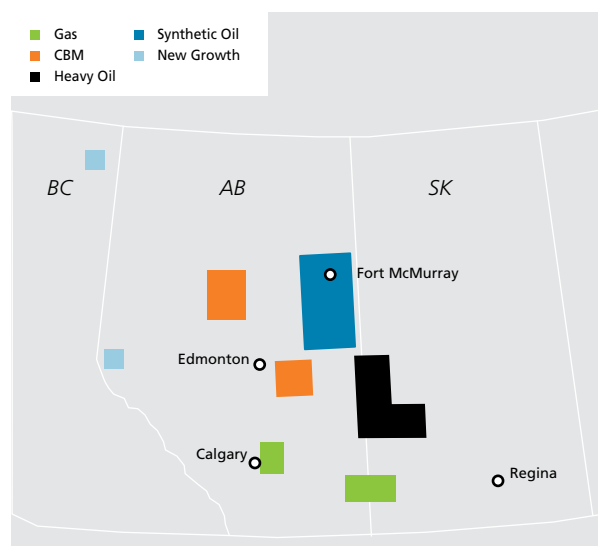
**In Canada, we are increasing our capacity by focusing on unconventional resources such as oil sands, CBM and enhanced oil recovery.**

Our remaining Canadian conventional assets comprise 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 1.1 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; and
- coalbed methane (CBM)—to extract natural gas primarily from Upper Mannville coals.

In 2006, we invested \$1,609 million in Canada; \$1,416 million into these growth initiatives. In 2007, we plan to invest approximately \$1,070 million; \$944 million in these initiatives.



### 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 oil that significantly reduces our need to purchase natural gas. 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 property using SAGD for bitumen production and field upgrading using the proprietary OrCrude™ process. OrCrude™ is a technology to which OPTI has the exclusive Canadian license. 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.

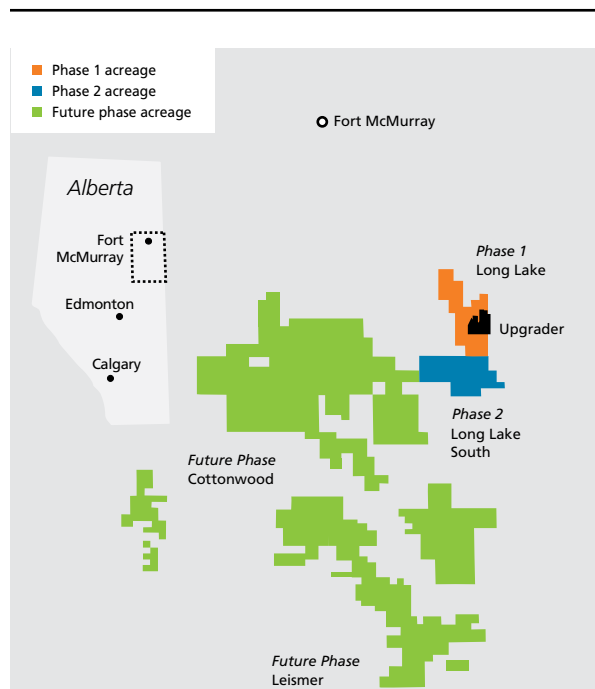
We operate the Long Lake lease bitumen extraction process and are responsible for constructing, developing and operating the SAGD project. OPTI is responsible for the design, construction and operation of the upgrader. We share equally in all project reserves, production, operating and capital costs.

#### *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 asphaltene. 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 asphaltene are converted to a low-energy, synthetic fuel gas. This gas is available as a low-cost fuel source, and as a source for hydrogen required in the hydrocracker. The gas is also to be burned in a co-generation plant to produce steam for the SAGD operations and for 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 SAGD and upgrading integration enables us to overcome 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 asphaltene as a fuel source, we have little need to purchase additional natural gas. With the upgrading facilities on site, expensive diluent is not required

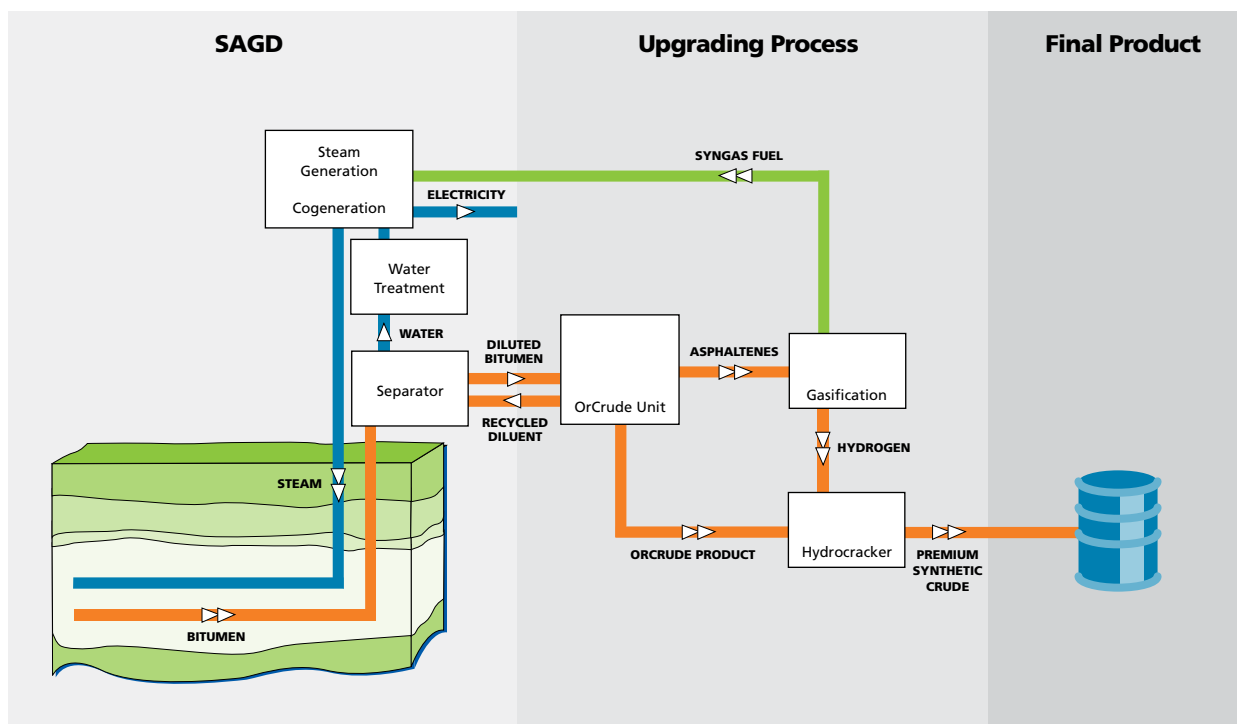


to transport the bitumen to market. And, by upgrading the bitumen into a highly desirable refinery feedstock or diluent supply, the end product commands light-sweet crude oil premium pricing.

**We expect our integrated oil sands strategy will provide us with an approximate \$10/bbl operating cost advantage.**

#### *Project Milestones and Costs*

The Long Lake project received regulatory approval in 2003 and Nexen board approval in 2004. Field construction on the SAGD and upgrader facilities began in 2004. In 2006, we substantially completed module and site construction of the SAGD facilities. Steam injection is expected to commence at the end of the first quarter of 2007, with bitumen production expected to ramp up to peak rates over a 12 to 24 month period. For the first six months of SAGD operation, we will largely be heating the reservoir. During this period, steam to oil ratios will be high but will decline with time as bitumen production ramps up to our target rates. Depending on our actual start up date and the amount of downtime at our facilities, 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 2007, 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.

**Long Lake is on track for start up in 2007 and expected to reach peak production of about 60,000 bbls/d (30,000 bbls/d net) of premium synthetic crude by late 2008 or early 2009.**

Upgrader module fabrication is largely complete and over 95% of the modules are on site. Construction of the upgrader is approximately 80% complete and start up is scheduled for late 2007. Peak output of premium synthetic crude oil is expected within 6 to 18 months of upgrader start up and we expect to exit 2007 with synthetic production rates of between 28,000 and 36,000 bbls/d (between 14,000 and 18,000 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 by late 2008 or early 2009. We also expect production to be maintained over the project's life, estimated at 40 years, by periodically drilling additional SAGD well-pairs.

In 2006, we invested \$1,050 million at Long Lake and expect to invest approximately \$500 million in 2007. The capital cost estimate when our board sanctioned the project in

February 2004 was \$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 certainty and 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). While construction progress has been significant, high activity in the oil sands 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. As a result, the projected costs of Long Lake have increased from \$3.8 billion to \$4.6 billion (\$1.9 billion to \$2.3 billion net). Although we are seeing pressure on capital costs, we expect to benefit from a significant operating cost advantage. Combined SAGD, cogeneration and upgrading operating costs are expected to average between \$12/bbl and \$14/bbl, substantially lower than coking upgrading. We expect ongoing capital to average between \$3/bbl and \$4/bbl. The 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 240,000 net acres of bitumen-prone lands in the Athabasca region and plan to acquire more. We plan to continue developing our bitumen lands in a phased manner using our integrated upgrading strategy. In 2005, we announced our plan to duplicate Long Lake by developing Phase 2. In 2006, we invested \$119 million for future phases and in 2007, we plan to invest approximately \$170 million on land acquisition, additional drilling, seismic and engineering to develop our leases and advance regulatory applications for these phases. Phase 2 SAGD production is expected to be on stream by late 2011, with upgrader start up by the second half of 2012, followed by additional phases every two years or three 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.

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**Phase 2 SAGD production is expected to be on stream by late 2011 followed by upgrader start up in 2012.**

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### Reserves Recognition

Under SEC rules and regulations, we are required to recognize bitumen reserves rather than the upgraded premium synthetic crude oil that we will 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, 2006, we recognized proved bitumen reserves of 246 mmbob before royalties (219 after royalties) for our Long Lake project, representing about 23% of Nexen's total proved oil and gas and Syncrude reserves before royalties.

### Heavy Oil

Approximately 52% 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. Because of these features, 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 the heavy crude into higher-value petroleum products.

Our heavy oil operations are in east-central Alberta and west-central Saskatchewan. To maximize heavy oil returns, it is important to manage capital and operating costs. Our large production base and existing infrastructure are advantageous to us in managing these costs. In 2007, we plan to continue exploiting our existing fields through drilling and optimizing operations.

### Enhanced Oil Recovery

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 48% 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. We have been producing sour natural gas from our Balzac field northeast of Calgary since 1961. This sour gas is processed through our operated Balzac plant.

### Coalbed Methane (CBM)

In 2005, we approved commercial CBM developments at Corbett, Doris and Thunder in the Fort Assiniboine area. Our CBM pilot at Corbett in the Fort Assiniboine area of central Alberta has established techniques to produce natural gas from water saturated Upper Mannville coals. These coals are generally deeper than the Horseshoe Canyon "dry coal" play, which is also being commercially developed in Alberta. We established commerciality of CBM production from the Upper Mannville coals in 2005 by applying horizontal well technology. Commercial production rates and reduced de-watering time has enabled us to confidently develop these coals.

In 2006, we invested approximately \$237 million in exploration and development activities. We have a long-term view of this business and plan to increase our CBM production to at least 150 mmcf/d by 2011, more than doubling our current Canadian natural gas production. At the end of 2006, we held more than 700 net sections of land in Alberta with CBM potential, some of which overlay existing conventional producing lands. We have also established positions in other prospective CBM areas of Alberta. In 2007, we plan to invest \$200 million to develop 98 gross (41 net) sections using single and multi-leg horizontal wells. In addition to our development at Fort Assiniboine, we will continue to evaluate other Mannville and Horseshoe Canyon CBM prospects and pursue new CBM opportunities in 2007.

**Shale Gas**

As part of our growth strategy in unconventional Canadian resource plays, we acquired over 100 sections of land in an emerging shale gas play in western Canada in 2006. Shale gas is natural gas produced from reservoirs composed of organic shale. The gas is stored in pore spaces, fractures or adsorbed into organic matter. Currently, the United States is the largest producer of shale gas. In 2007, we plan to initiate a drilling and evaluation program to demonstrate the feasibility of this resource.

**Fiscal Terms**

In Canada, we pay royalties ranging from 15% to 40% on production from lands owned by the federal and provincial governments. Some provinces also 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 of 3.3%, which is reduced to 1.85% for wells completed after October 1, 2002.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. In 2006, legislation was passed to reduce the federal corporate income tax rate on income from Canadian oil and gas activities from 24% to 19% by 2010.

For our oil sands projects, we elected to pay royalties based on bitumen production, which includes a 1% royalty on gross revenue until all costs have been recovered, at which time the royalty changes to 25% on net revenue. With the combination of low royalties, our expected operating cost advantage and a premium product, our oil sands financial returns are expected to be attractive relative to other oil sands projects.

**Middle East—Yemen**

Yemen has been our most 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 success and reputation in Yemen opens doors elsewhere in the Middle East and around the world.

**Although our Masila fields have matured, we expect to generate approximately 20% of the total project cash flow from the remaining proved resources.**

Our strategy 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 2006, we produced 92,900 bbls/d of oil before royalties (51,800 after royalties), representing approximately 44% of Nexen's total production and 32% of 2006 cash flow. Proved reserves of 66 mmbbl before royalties (38 after royalties) comprise approximately 6% of Nexen's total proved oil and gas and Syncrude reserves before royalties.



**Masila Block (Block 14)**

We have a 52% working interest in and operate the Masila project. Our share of 2006 production was 70,300 bbls/d before royalties (35,500 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 20% of the total project free cash flow from the remaining proved reserves recoverable before the PSA expires in 2011.

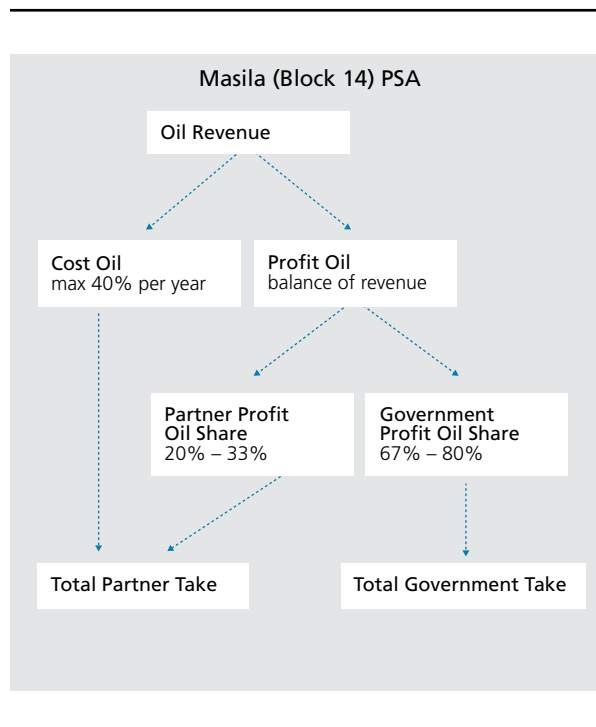
The first successful Masila exploratory well was drilled at Sunah in 1990, with additional discoveries quickly following at Heijah and Camaal. Initial production began in July 1993, with the first lifting of oil in August 1993. Masila Blend oil averages 32° API at very low gas-oil ratios. Most of the 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 and shipped to customers primarily in Asia.

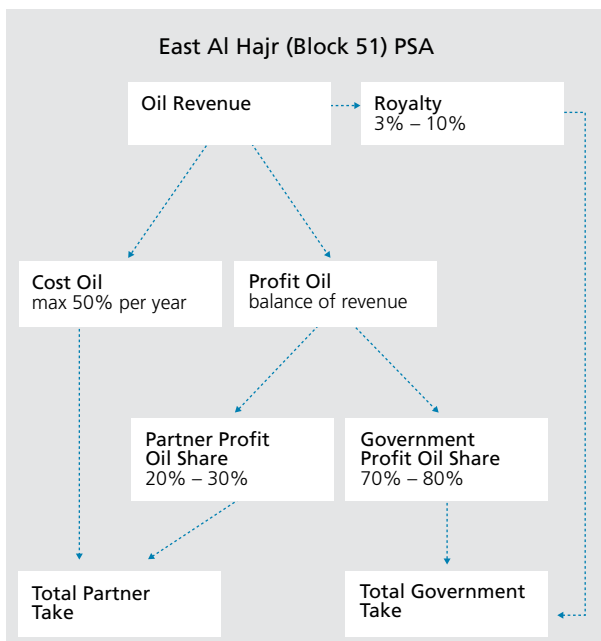
We are managing the pace of our drilling program to ensure we recover the remaining reserves in the most efficient, cost-effective manner. In 2007, we plan to invest approximately \$55 million to drill 14 wells.

The PSA governing Masila production 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 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. At current production, the Government is entitled to approximately 73% of the profit oil, which includes a component for Yemen income taxes payable by the Masila Partners at a rate of 35%. In 2006, the Masila Partners' share of production, including recovery of past costs, was approximately 37%.



**East Al Hajr Block (Block 51)**

We have an 87.5% working interest and operate Block 51. This block is 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 terms of 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 2006, the EAH Partners' share of Block 51 production, including recovery of past costs, was approximately 61%.

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 and we achieved payout on the project in the first quarter of 2006. During the year, production averaged 22,600 bbls/d before royalties (16,300 after royalties).

**We achieved payout on Block 51 in the first quarter of 2006.**

In 2006, we drilled three exploration wells on the block and two of these wells were abandoned. In 2007, we plan to invest approximately \$80 million to drill nine development wells, construct additional facilities and continue exploring with three exploration wells.

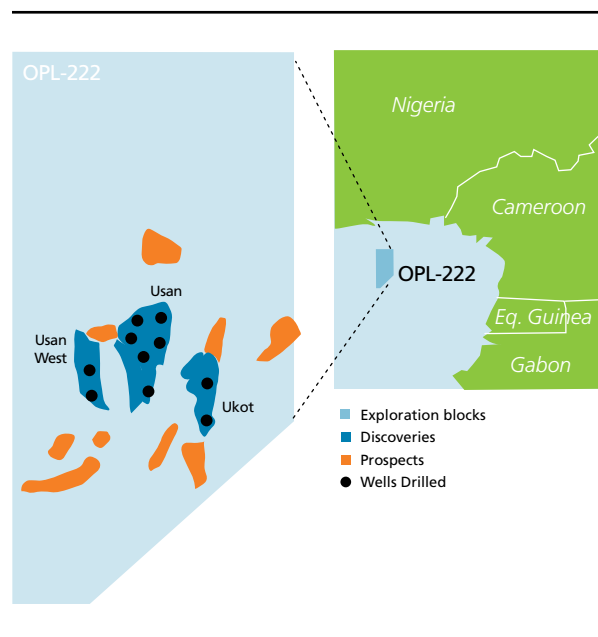
### Offshore West Africa

Offshore West Africa is a growing 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

##### Block OPL-222

In 1998, we acquired a 20% non-operated interest in Block OPL-222, which includes 448,000 acres and is approximately 50 miles offshore in water depths ranging from 600 to 3,500 feet. The ongoing appraisal of the block indicates significant hydrocarbon accumulations based on the drilling results outlined below:



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 this field is complete. The Nigerian authorities have provisionally approved the preliminary Usan field development plan. We expect the Usan development to be formally sanctioned in 2007, with first production as early as 2010.

**Usan is expected to be producing by 2011, adding about 30,000 bbls/d to our production.**

The development will include a FPSO with storage capacity of two million barrels, capable of handling peak production rates of 160,000 bbls/d of oil. In 2007, we plan to invest approximately \$140 million to progress development by completing our cost estimate. We have a 20% interest in this develop-

ment program. Proved reserves of 30 mmbob before royalties (25 after royalties) comprise approximately 3% of Nexen's total proved oil and gas and Syncrude reserves.

In 2006, we drilled the deep-water Ukot South well. This well was unsuccessful and the capital costs were expensed.

##### Block OML-115

We relinquished this block during the year.

##### Block OML-109—Ejulebe

In 2005, we sold our producing assets and terminated our contractual interest in this block.

**Equatorial Guinea—Block K**

We relinquished this block during the year.

**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 share of 2006 production averaged 6,300 bbls/d before royalties (5,700 after royalties), about 3% of Nexen's total production including Syncrude.

Production from Guando is subject to a 5% to 25% royalty depending on daily production. In 2006, legislation was introduced to reduce the corporate income tax rate from 38.5% in 2006 to 34% in 2007, and to 33% in 2008 and future years.

**Exploration Blocks**

We have interests in three exploration blocks in the Upper Magdalena Basin. Villarrica was acquired in 2000, El Queso in

2003 and Boqueron Deep in 2003. In 2005, we relinquished the Villarrica Block and acquired the Villarrica Norte Block under improved fiscal terms. In 2006, we drilled a well on the El Queso block which we are currently evaluating. We are currently participating in a well on Boqueron Deep and plan to drill a well on Villarrica Norte later in 2007. In addition, we are assessing potential drilling opportunities in other areas of the Upper Magdalena Basin.

**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 four licenses in early 2007. In 2007, we expect to invest approximately \$30 million in additional seismic and geologic studies there.

**Australia—Buffalo**

Field abandonment began in November 2004 and was completed in 2005.

**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.

**Oil and Gas Acreage**

(thousands of acres)	2006					
	Developed		Undeveloped <sup>1</sup>		Total	
	Gross	Net	Gross	Net	Gross	Net
Yemen <sup>2</sup>	50	29	756	628	806	657
Canada	781	578	2,081	1,095	2,862	1,673
United States	183	103	1,396	650	1,579	753
United Kingdom	83	27	1,822	1,031	1,905	1,058
Colombia <sup>4</sup>	1	–	604	463	605	463
Nigeria <sup>2,3</sup>	–	–	448	90	448	90
<b>Total</b>	<b>1,098</b>	<b>737</b>	<b>7,107</b>	<b>3,957</b>	<b>8,205</b>	<b>4,694</b>

*Notes:*

<sup>1</sup> 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.

<sup>2</sup> The acreage is covered by production sharing contracts.

<sup>3</sup> The acreage is covered by a joint venture agreement.

<sup>4</sup> The acreage is covered by an association contract.

## Producing Oil and Gas Wells

(number of wells)	2006					
	Oil		Gas		Total	
	Gross <sup>1</sup>	Net <sup>2</sup>	Gross <sup>1</sup>	Net <sup>2</sup>	Gross <sup>1</sup>	Net <sup>2</sup>
Yemen	428	249	–	–	428	249
Canada	2,196	1,519	2,627	2,279	4,823	3,798
United States	191	91	199	138	390	229
United Kingdom	39	17	–	–	39	17
Colombia	91	19	–	–	91	19
<b>Total</b>	<b>2,945</b>	<b>1,895</b>	<b>2,826</b>	<b>2,417</b>	<b>5,771</b>	<b>4,312</b>

Notes:

<sup>1</sup> Gross wells are the total number of wells in which we own an interest.

<sup>2</sup> Net wells are the sum of fractional interests owned in gross wells.

## Drilling Activity

(number of net wells)	2006						
	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
<b>Total</b>	<b>40.8</b>	<b>11.7</b>	<b>52.5</b>	<b>266.1</b>	<b>3.7</b>	<b>269.8</b>	<b>322.3</b>

(number of net wells)	2005						
	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
<b>Total</b>	<b>33.6</b>	<b>16.0</b>	<b>49.6</b>	<b>242.4</b>	<b>3.1</b>	<b>245.5</b>	<b>295.1</b>

(number of net wells)	2004						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
Yemen	–	2.0	2.0	37.3	0.5	37.8	39.8
Canada	13.4	1.0	14.4	202.9	–	202.9	217.3
United States	0.3	1.8	2.1	11.0	1.0	12.0	14.1
United Kingdom	–	–	–	–	–	–	–
Colombia	–	–	–	7.0	–	7.0	7.0
Nigeria	0.4	1.0	1.4	–	–	–	1.4
Equatorial Guinea	–	0.5	0.5	–	–	–	0.5
<b>Total</b>	<b>14.1</b>	<b>6.3</b>	<b>20.4</b>	<b>258.2</b>	<b>1.5</b>	<b>259.7</b>	<b>280.1</b>

## Wells in Progress

At December 31, 2006, we were drilling 5 wells in Yemen (3.6 net), 5 wells in Canada (5 net), 2 wells in the United States (1.6 net), 3 wells in the United Kingdom (1.6 net), and 1 well in Colombia (0.5 net).

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

(Cdn\$ millions)	2006	2005	2004
Conventional Crude Oil and Natural Gas Liquids (NGLs)	2,479	2,438	1,697
Synthetic Crude Oil	446	397	321
Natural Gas	553	671	534
<b>Total</b>	<b>3,478</b>	<b>3,506</b>	<b>2,552</b>

Crude oil (including synthetic crude oil) and natural gas liquids represent approximately 84% of our oil and gas net sales, while natural gas represents the remaining 16%.

### Sales Prices and Production Costs (excluding Syncrude)

	Average Sales Price <sup>1</sup>			Average Production Cost <sup>1</sup>		
	2006	2005	2004	2006	2005	2004
<b>Crude Oil and NGLs</b> (Cdn\$/bbl)						
Yemen	71.57	62.07	47.59	8.11	6.75	5.64
Canada <sup>2</sup>	42.79	40.51	36.60	15.50	14.01	11.76
United States	65.80	57.63	46.60	9.45	7.33	6.09
United Kingdom	71.19	60.55	46.81	11.28	14.90	8.26
Australia <sup>2</sup>	–	–	51.22	–	–	35.73
Other Countries	66.09	59.96	43.07	3.13	6.08	4.09
<b>Natural Gas</b> (Cdn\$/mcf)						
Canada <sup>2</sup>	6.49	7.51	5.76	1.65	0.95	0.85
United States	7.86	10.56	7.89	1.58	1.22	1.02
United Kingdom	7.43	7.86	8.28	1.88	2.48	–

Notes:

- <sup>1</sup> Sales prices and unit production costs are calculated using our working interest production after royalties.
- <sup>2</sup> Includes results of discontinued operations for 2005 and 2004. (See Note 14 to our Consolidated Financial Statements.)

### Proved Reserves including Proved Undeveloped Reserves

At December 31, 2006, we had 725 mmboe of proved oil and gas reserves before royalties (637 after royalties). This is a 55% increase over the prior year (62% after royalties). Including Syncrude, our total proved oil and gas and Syncrude reserves increased 34% to 1,049 mmboe (39% to 911 after royalties).

The following table provides a summary of the changes in our proved oil and gas reserves (before royalties) excluding our Syncrude reserves. Refer to page 131 for proved reserves information on an after-royalties basis.

(mmboe)	Canada	United Kingdom	United States	Yemen	Other Countries	Total
December 31, 2005	117	145	90	105	11	468
Extension and Discoveries	11	25	7	4	30	77
Revisions	249	20	(11)	(8)	1	251
Production	(13)	(8)	(13)	(35)	(2)	(71)
<b>December 31, 2006</b>	<b>364</b>	<b>182</b>	<b>73</b>	<b>66</b>	<b>40</b>	<b>725</b>

Extensions and discoveries contributed 77 mmboe (67 after royalties). The majority of the increase results from new development projects at Usan, offshore West Africa, the Ettrick and Duart fields in the North Sea, Ringo in the Gulf of Mexico, and coalbed methane in Canada. Other increases relate to ongoing exploitation activities in the North Sea, Yemen, the Gulf of Mexico and Canada.

The revisions relate primarily to our Long Lake project. Under SEC rules, we are required to recognize bitumen reserves rather than the upgraded synthetic crude oil that we will produce and sell. As such, proved reserves recognition depends on year end oil prices, light/heavy differentials, diluent prices and natural gas prices. We initially recognized proved bitumen reserves at Long Lake in early 2004 when

we sanctioned development of the project. The reserves were, however, written off at the end of the year due to wide light/heavy differentials and high natural gas costs. At the end of 2006, narrow light/heavy differentials and low natural gas costs allowed us to recognize proved bitumen reserves of 246 mmboe (219 after royalties). In the North Sea, the additions reflect increases at Buzzard as a result of development drilling and an increase in the proved recovery factor. In Canada, the additions relate primarily to our heavy oil properties where narrow light/heavy differentials increased the amount of economically recoverable reserves. Negative revisions occurred on Block 51 in Yemen and the Aspen field in the Gulf of Mexico as a result of lower than expected production performance.

### Proved Undeveloped Reserves

The following table provides a summary of our proved undeveloped reserves (PUDs) for our oil and gas activities at December 31, 2006 and 2005:

(mmboe)	Before Royalties			After Royalties		
	PUDs	Total Proved <sup>1</sup>	% of Total	PUDs	Total Proved <sup>1</sup>	% of Total
Canada	216	364	59%	188	319	59%
United Kingdom	50	182	27%	50	182	27%
Yemen	9	66	14%	5	38	13%
United States	9	73	12%	7	63	11%
Other Countries	31	40	78%	25	35	71%
<b>December 31, 2006</b>	<b>315</b>	<b>725</b>	<b>43%</b>	<b>275</b>	<b>637</b>	<b>43%</b>
Canada	13	117	11%	11	101	11%
United Kingdom	128	145	88%	128	145	88%
Yemen	23	105	22%	13	59	22%
United States	15	90	17%	13	77	17%
Other Countries	1	11	5%	–	11	5%
<b>December 31, 2005</b>	<b>180</b>	<b>468</b>	<b>38%</b>	<b>165</b>	<b>393</b>	<b>42%</b>

Note:

<sup>1</sup> Excludes proved reserves for our Syncrude operations of 324 mmboe (274 after royalties) in 2006 and 318 mmboe (264 after royalties) in 2005.

In 2006, our PUDs increased by 135 mmboe (110 after royalties). We added 206 mmboe (179 after royalties) at Long Lake relating to proved reserves outside of the initial 81 well-pair SAGD development area. We also added PUDs from our new development projects at Usan, Ettrick, Ringo, Duart and CBM. We converted 117 mmboe (112 after royalties) of PUDs to developed, with the majority relating to the completion of the Buzzard development project. Other small additions and conversions occurred from ongoing development activities at Canada, the United States, Yemen, the United Kingdom and Colombia.

In Canada, our PUDs increased from 13 mmboe (11 after royalties) to 216 mmboe (188 after royalties). Substantially

all of the increase relates to Long Lake where we added 206 mmboe (179 after royalties). These PUDs 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 2007 and 2008. 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 2007 and 2008.

In the United Kingdom, our PUDs decreased from 128 mmboe (128 after royalties) to 50 mmboe (50 after royalties) primarily from completing the Buzzard development, which converted 80% of the related PUDs to developed. The remaining 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. PUDs were added by our Ettrick development, which we expect to convert to producing in 2008.

In Yemen, the PUDs are split relatively equally between our Masila and East Al Hajr Blocks. These reserves relate entirely to infill drilling, which we plan to carry-out during 2007 and 2008.

In the United States, our PUDs decreased from ongoing development of our Gulf of Mexico deep-water and shelf properties. In 2006, additions principally relate to the Ringo and Tobago developments, which are expected to be producing within the next two years.

In other countries, our PUDs increased by 30 mmboe (25 after royalties), resulting from recognizing proved reserves associated with our Usan development, offshore West Africa.

Excluding Long Lake and Usan, we expect to convert about 80% of our PUDs to producing in 2007 and 2008. Usan will be converted by 2011 when it is expected to come on stream. Long Lake PUDs will be converted over the next 20 years as initial SAGD wells deplete. At the same time, we expect our ongoing exploration and development activities to continue to add new PUDs.

**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 from the oil sands, and upgrade the bitumen to produce a high-quality, light (32° API), sweet, synthetic crude oil.

The Syncrude operation exploits a portion of the Athabasca oil sands deposit 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 258,000 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

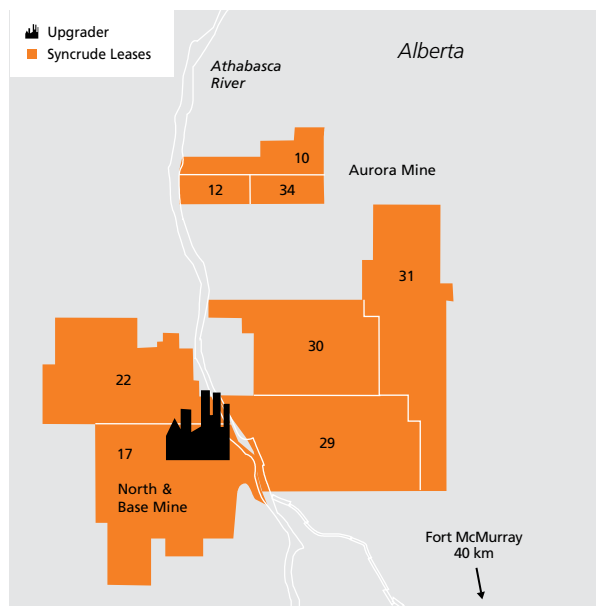
road. Trucks and shovels are used to collect the oil sands in the open pit mines. The oil sands are transferred for processing using a hydro-transport system.

The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 270 million tons of oil sands per year and about 160 mmbbls of bitumen per year. 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 Mine and the Aurora North Mine, the oil sands are mixed with warm water to produce a slurry.

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 2006, about 40% of the synthetic crude oil was sold to Edmonton area refineries, and the remaining 60% was sold to refineries in Eastern Canada and the mid-western United States.

Electricity is provided to Syncrude from two generating plants on site: a 270 MW plant and an 80 MW plant.



Since operations started in 1978, Syncrude has shipped more than 1.7 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, 2006, 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 more than \$2.5 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.

Syncrude pays a royalty to the Province of Alberta. Subsequent to 1987, this royalty was equal to 50% of Syncrude's deemed net profits after deduction of capital expenditures. In 1995, the Province of Alberta announced

generic royalty terms for new oil sands projects that provide for a royalty rate of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. In 1997, the Province of Alberta and the Syncrude owners agreed to move to the generic royalty terms when the total of all allowed capital costs incurred after December 31, 1995 equalled \$2.8 billion (gross). That total was surpassed at the end of 2001. In 2006, we realized full recovery of allowed capital costs and, as a result, Syncrude royalties are assessed at 25% of net revenues.

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. Our share of capital spending in 2007 is expected to be \$50 million.

In 2006, Syncrude's production of marketable synthetic crude oil was 258,400 bbls/d. Nexen's share was 18,700 bbls/d before royalties (16,900 after royalties).

The following table provides some operating statistics for Syncrude operations:

	2006	2005	2004
<b>Total Mined Volume <sup>1</sup></b>			
Millions of Tons	428	353	389
Mined Volume to Oil Sands Ratio <sup>1</sup>	2.2	2.1	2.1
<b>Oil Sands Processed</b>			
Millions of Tons	192	169	188
Average Bitumen Grade (weight %)	11.3	11.1	11.1
<b>Bitumen in Mined Oil Sands</b>			
Millions of Tons	22	19	21
Average Extraction Recovery (%)	90	89	87
<b>Bitumen Production <sup>2</sup></b>			
Millions of Barrels	112	94	103
Average Upgrading Yield (%)	85	85	86
<b>Gross Synthetic Crude Oil Shipped <sup>3</sup></b>			
Millions of Barrels	94	78	87
<b>Nexen's Share of Marketable Crude Oil</b>			
Millions of Barrels Before Royalties	6.8	5.7	6.3
Millions of Barrels After Royalties	6.2	5.6	6.1

Notes:

<sup>1</sup> Includes pre-stripping of mine areas.

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

<sup>3</sup> Approximately 1.2% 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 extended our presence into certain global markets as well. We focus on securing access to transportation, storage and facilities, as well as 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 extracting 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:

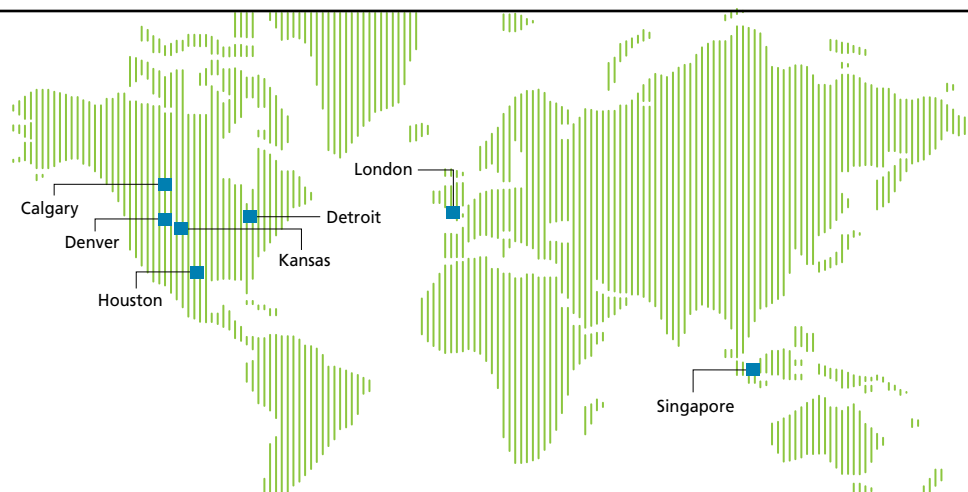
- capitalizing on location spreads (differences in prices between locations) using our transportation assets;
- capitalizing on time spreads (differences in prices between summer and winter) using our storage assets; and
- financial trading of location and time spreads.

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. Our presence in Houston has established us in the Gulf Coast region where we have our own production.

We use our access to transportation and storage facilities to optimize returns for ourselves as well as our customers.

In 2003 and 2004, we grew our asset base by acquiring physical gas purchase and sales contracts, as well as natural

**Marketing Office Locations**



gas transportation capacity, on favourable terms. This gives us access to new third party gas supply until 2008, pipeline capacity to 2016 and new relationships that have enabled us to negotiate new gas purchase and sales contracts. In 2006, we continued to grow our storage and transportation positions through acquisitions as well as bidding processes. Our position as a physical marketer at multiple delivery points in key markets gives us the 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 2006, we held 3.3 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 typically cheaper summer gas in the ground until the winter heating season arrives. We had access to 50 bcf of natural gas storage facilities at the end of the year.

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**We use our access to transportation and storage facilities to optimize returns, capitalizing on location and time spreads.**

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In addition to transportation and storage assets, we hold 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 proactively by our product group teams and monitored by our risk group, with regular reporting to management and the board of directors.

### **International Crude Oil Marketing**

Our crude oil business focuses on marketing physical crude oil to end-use refiners. The crude oil group markets our own production and more than 500,000 bbls/d of third-party field production to refiners from producing regions where we operate. In addition to physical marketing, we take advantage of quality differentials and time 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 the procurement of 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 given

us the opportunity to expand our presence in that market through our Houston office. At the end of 2006, we had access to 1.7 mmbbls of storage and over the course of the year, moved approximately 705 mmbbls per day.

In the last two years, we acquired two North American natural gas liquid (NGL) and ethanol businesses that focus on buying and selling NGLs as well as diesel, ethanol and natural gasoline. These businesses acquire and move NGLs into the US midwest and Gulf Coast from Canada, as well as providing denaturant for ethanol production and the marketing of finished ethanol in the US. At the end of 2006, we had access to 550 mmbbls of storage and over the course of the year, moved approximately 25 mmbbls per day of product.

Internationally, we focus on the physical marketing of our Yemen 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. We established an office in London, United Kingdom to maximize the value of our North Sea production. With Buzzard crude on stream in early 2007, we expect to increase our presence in various global markets, ensuring we maximize the value of this production.

Our crude oil marketing group also holds 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 the use of our 50% interest in a 100 MW gas-fired, combined-cycle power generation facility at Balzac, Alberta, as well as our recently completed 70 MW Soderglen wind power operation in southern Alberta. We also market power to larger commercial, industrial and municipal clients in Alberta. With the 2005 acquisition of a commercial/industrial marketing business in Alberta, we became the largest supplier of power to the 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 co-generation facility at Long Lake in 2007. We have a 50% interest in this project.

### European Gas and Power Marketing

In 2006, we acquired a UK-based European gas and power marketing business that focuses on UK gas and power as well as German power. In 2007, we expect to increase our presence in both the UK and continental Europe gas and power markets.

### 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.

### Average Annual Production Capacity

(short tons)	2006	2005	2004
<b>Sodium Chlorate</b>			
North America	446,208	446,208	446,617
Brazil	68,563	68,563	68,563
<b>Total</b>	<b>514,771</b>	<b>514,771</b>	<b>515,180</b>
<b>Chlor-alkali</b>			
North America	356,002	356,002	356,002
Brazil	109,430	109,430	109,430
<b>Total</b>	<b>465,432</b>	<b>465,432</b>	<b>465,432</b>

### 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 plant in Brandon, Manitoba increasing capacity to 260,000 tonnes per year. This expansion replaced higher-cost capacity idled in 2002 at Taft, Louisiana. 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 of our plant in Brandon which is expected to increase capacity by 32,300 tonnes per year, early in 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.

### **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. This agreement had an initial six-year take-or-pay component that ended in 2005. Most of the chlorine and about 20% of the sodium chlorate production is sold in the merchant market under shorter-term contractual arrangements. 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, 2006, \$704 million (\$1,770 million, undiscounted) has been provided in our Consolidated Financial Statements for asset retirement obligations. In 2006, we increased our retirement obligations for future dismantlement and site restoration by \$75 million primarily from the development of the Buzzard field in the North Sea.

In 2006, our capital expenditures for environmental-related matters, including environment control facilities, were approximately \$44 million. Our operating expenditures for environmental-related matters were approximately \$6 million. In 2007, we estimate these expenditures to be approximately \$21 million.

### **EMPLOYEES**

We had 3,687 employees on December 31, 2006, of which 266 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.

#### **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:

- 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 have a negative impact on 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 40 years. In North Vancouver, we operate, indirectly through ownership in Canexus Limited Partnership a chlor-alkali plant 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 have a material impact on 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 2002, our facilities at Eugene Island 295 were damaged during Hurricane Lili. Production from this field was suspended for about four months while temporary production facilities were put in place. During this period, production volumes were reduced by approximately 2,500 boe/d. Production was restored at a reduced rate through temporary facilities for approximately six months while installation of new permanent facilities was completed. It is estimated that volumes were reduced by approximately 1,800 boe/d during this period. 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 following storm damage sustained in the 2005 hurricane season has reduced the availability of drilling rigs. Our profitability and success at finding reserves 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 will be impaired.

Over the past three years, we experienced net negative revisions of 19 million boe to our proved reserves (before royalties). This includes net negative revisions of 25 million boe, representing about 2% of worldwide proved reserves (including Syncrude), related to technical revisions primarily on our producing properties, partially offset by 6 million boe of net positive economic revisions related to changes in year-end prices and costs. In Yemen, negative revisions of 27 million boe occurred largely in 2004 and resulted primarily from lower-than-expected production performance, drilling results and updated geological mapping. In the United States, negative revisions of 29 million boe occurred largely in 2005 and 2006 and resulted primarily from lower-than-expected production performance at our deep-water Aspen property and at various properties on the shelf. These negative revisions were somewhat offset by positive revisions of 37 million boe in our Buzzard field due to updated geological mapping.

Under SEC rules, we must recognize our oil sands as bitumen reserves rather than the upgraded premium synthetic crude oil that we expect to produce from Long Lake. As a result, we expect price-related revisions, both positive and negative, to occur in the future as the economic producibility of our bitumen and heavy oil 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 integrated project has virtually no 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.

During the past three years, our total proved undeveloped reserves before royalties have increased from 124 mmboe to 315 mmboe (87 mmboe to 275 mmboe after royalties). As a result, our proved undeveloped reserves have increased from 23% to 43% of our proved reserves excluding Syncrude (22% to 43% after royalties). Proved undeveloped reserves increased primarily at our Long Lake oil sands project and various other worldwide development projects, partially offset by the completion of the Buzzard development and ongoing development activities elsewhere.

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

### **Our Long Lake project faces additional risks compared to conventional oil and gas production.**

Our Long Lake project is planned as a fully integrated production, upgrading and co-generation 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 a syngas. This syngas will be used as a fuel source for the SAGD process, a source of hydrogen for use in the upgrading process, and to generate electricity through a co-generation facility.

We have a 50% working interest in this project, and our share of the capital costs is estimated to be \$2.3 billion (\$4.6 billion gross). 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 oil sands project include the following:

#### **Uncertain Timeline and Cost of the Project**

The Long Lake project is currently in the construction 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 of our board's sanctioning 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. After a review of all trends, the projected cost of Long Lake has been increased to \$4.6 billion (gross).

#### **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 assurance 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 assurance 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 cause a material decrease in 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 the creation of 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 to a significant extent 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 in order to protect the validity of its patents or other intellectual property rights, or to determine the validity or scope of the patents or proprietary rights of third parties. This kind of litigation can be time-consuming and expensive, regardless of whether or not OPTI is successful. 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, even 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 the technology of OPTI or such third parties or design around the patents owned by OPTI and/or such third parties. There is also a risk that OPTI may not be able to enter into licensing arrangements with third parties for the additional technologies required for the possible further expansion of 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. It cannot be assured that our insurance will be sufficient to cover any such casualty occurrences or disruptions. 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 devel-

opment 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 are largely dependent on levels of production.

The Long Lake SAGD operation and upgrader 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. Carbon dioxide is a greenhouse gas that will be regulated by the Kyoto Protocol, which may come into effect in Canada. Risk factors relating to environmental regulation are provided separately herein.

### 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 project and on us.

### Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of petroleum interests and the distribution 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 of the 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 enter the oil sands business and begin production of synthetic crude oil, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of synthetic crude oil and other competing crude oil products in the marketplace. Depending on the levels of 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:

- central processing facilities, oil pipelines, and export terminal at our two Yemen operations;
- Gunnison SPAR production platform in the Gulf of Mexico;
- highly productive Aspen wells tied-in to a third-party processing facility in the Gulf of Mexico;
- upgrading facilities at Syncrude in the Athabasca oil sands; and
- Scott and Buzzard production platforms in the North Sea.

As significant production is generated from each of these assets, any single event causing an interruption to any one of these operations could result in the loss of production.

### We may not achieve commercial production rates in our coalbed methane operations.

Coalbed methane (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. If the coal is water saturated, water generally needs to be extracted to reduce the pressure and allow gas production to occur. CBM wells typically have 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.

The Mannville coals in the Fort Assiniboine region of Alberta are generally deeper than other commercial CBM projects in the Horseshoe Canyon and are water saturated. A significant period of time may be required to sufficiently dewater the coals to determine if commercial production is feasible. As a result, we may have to invest significant capital in CBM assets before they achieve commercial rates of production. The wells may never achieve commercial rates of production as there are no other commercially proven Mannville CBM projects in operation.

CBM projects in some areas of the United States have had negative public reaction due to certain water disposal practices. In Canada, as in the United States, water disposal practices are regulated to ensure public safety and water conservation. Nevertheless, negative public perception around CBM production could impede our access to the resource.

**We have significant upfront 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 is expected to commence at the end of first quarter of 2007. With respect to the Long Lake upgrader, module fabrication is largely complete and over 95% of the modules are on site. Construction of the upgrader is approximately 80% complete and start up is scheduled for late 2007. 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.

**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 are continuing 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. 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. Changes in government regulations could have an adverse effect on 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 the disposal or release of specified substances. This could have an adverse financial consequence.

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.

**Our operations could be subject to changes in regulations related to climate change.**

The Kyoto Protocol came into force on February 16, 2005. 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). Since that time, the Canadian federal government and various provincial governments have grappled with the issue of climate change and a number of proposals have come and gone. Bill C-30 (Canada's Clean Air Act) has been sent to

a special parliamentary committee that intends to report back to parliament by the end of March 2007. This Bill contains proposals to deal with criteria air contaminants (CACs) and greenhouse gases (GHGs) and outlines proposed changes to the Canadian Environmental Protection Act 1999, the Energy Efficiency Act and the Motor Vehicle Fuel Conservation Standards Act. The proposals seek to apply intensity-based targets for GHGs and absolute caps on CACs in the period up to 2020–2025, ultimately leading to absolute caps on GHGs. It is unclear if and when Bill C-30 will become law.

Any required reductions in the GHGs emitted for our operations could result in increases in our capital or operating expense, or reduced operating rates, especially those related to the Long Lake project, which could have an adverse effect on our results of operations and financial condition.

**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 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 counter-parties. Any significant loss of liquidity may result in delays and/or cancellation of our development plans.

**Use of marine transportation may expose us to the risk of financial loss and reputational damage.**

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 reputational damage in the event of oil spills.

### ITEM 1B. UNRESOLVED STAFF COMMENTS

There are no unresolved staff comments with the SEC that have been outstanding for more than 180 days before December 31, 2006.

### 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 with respect to 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.

In June 2003, a subsidiary of Occidental Petroleum Corporation (Occidental) initiated an arbitration against us at the International Court of Arbitration in the International Chamber of Commerce (ICC Court) regarding an Area of Mutual Interest agreement relating to certain portions of Block 51 in the Republic of Yemen. In April 2006, the ICC Court concluded that we breached this agreement and as a result, Occidental was entitled to monetary damages. In late 2006, we agreed to settle the arbitration with Occidental for US\$135 million. This amount was accrued and included in other expenses in our Consolidated Statement of Income during 2006. No further amounts are expected to be payable under the settlement.

On September 5, 2005, there was a gas release on the Scott Platform in the North Sea. No-one was harmed as a result of the incident, but Nexen was fined £400,000 under the UK Health and Safety at Work Act, 1974 and the Offshore Installation (Prevention of Fire and Explosion, and Emergency Response) Regulations, 1995.

### 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 2006.

## 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, 2006, there were 1,454 registered holders of common shares and 262,513,206 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

(\$/share)	TSX (Cdn\$)		NYSE (US\$)	
	High	Low	High	Low
<b>2006</b>				
First Quarter	68.10	54.34	59.94	46.98
Second Quarter	69.50	50.82	61.68	45.63
Third Quarter	71.22	52.13	63.65	46.70
Fourth Quarter	65.79	52.91	58.37	46.90
<b>2005</b>				
First Quarter	35.50	23.55	29.18	19.44
Second Quarter	39.85	29.53	32.32	23.28
Third Quarter	60.67	40.25	51.73	31.95
Fourth Quarter	59.54	43.77	51.69	36.80

### Quarterly Dividends Declared on Common Shares

(\$/share)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2006	0.05	0.05	0.05	0.05
2005	0.05	0.05	0.05	0.05

Payment date for dividends was the first day of the next quarter. All dividends paid to holders of common shares in 2006 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.

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 website at [www.nexeninc.com](http://www.nexeninc.com).

## ITEM 6. SELECTED FINANCIAL DATA

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

(Cdn\$ millions, except per share amounts)	2006	2005	2004	2003	2002
<b>Oil &amp; Gas and Syncrude Production</b>					
Production Before Royalties (mboe/d) <sup>2</sup>	212	242	250	269	269
Production After Royalties (mboe/d) <sup>2</sup>	156	173	174	185	176
<b>Results of Operations</b>					
Revenue					
Oil & Gas and Syncrude <sup>1</sup>	3,656	3,535	2,573	2,261	1,966
Marketing	1,373	864	625	586	496
Chemicals	413	413	383	377	369
Other	(47)	(193)	59	31	8
Total Revenue	5,395	4,619	3,640	3,255	2,839
Net Income from Continuing Operations	579	658	705	419	270
Basic Earnings per Common Share from Continuing Operations (\$/share)	2.21	2.52	2.74	1.69	1.10
Diluted Earnings per Common Share from Continuing Operations (\$/share)	2.15	2.47	2.71	1.68	1.09
Net Income	579	1,110	788	420	352
Basic Earnings per Common Share (\$/share)	2.21	4.26	3.06	1.70	1.44
Diluted Earnings per Common Share (\$/share)	2.15	4.17	3.03	1.68	1.42
<b>Financial Position</b>					
Total Assets <sup>2</sup>	17,079	14,493	12,339	7,703	6,764
Long-Term Debt <sup>3</sup>	4,618	3,630	4,214	2,470	2,575
Shareholders' Equity	4,614	3,961	2,892	2,131	1,812
Capital Investment, including Acquisitions	3,408	2,638	4,264	1,432	1,545
Dividends per Common Share (\$/share) <sup>4</sup>	0.20	0.20	0.20	0.163	0.15
Common Shares Outstanding (thousands)	262,513	261,141	258,399	251,212	245,932

## Notes:

- 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.
- In 2003, production increased from our deep-water Aspen development in the Gulf of Mexico in the United States. In 2004, production declined from our maturing assets in Yemen at Masila, in Canada and in the United States on the 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 2006, declines in Yemen at Masila reduced production volumes.
- 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 our asset disposition program in the third quarter. Our long-term debt increased in 2006 as a result of our investment in capital projects, primarily at Buzzard and Long Lake.
- Quarterly dividends were increased to 5¢ per share in the fourth quarter of 2003.