Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of the significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in note 16 to the Consolidated Financial Statements. Unless otherwise noted, tabular amounts are in millions of Canadian dollars, and sales volumes, production volumes and reserves are before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies. See the Oil and Gas Producing Activities section in the Supplementary Financial Information for our production and reserves after royalties.

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HIGHLIGHTS

(Cdn$ millions)	2002	2001	2000
Net Income	452	450	602
Earnings per Common Share ($/share)	3.34	3.40	4.52
Cash Flow from Operations [1]	1,383	1,423	1,569
Oil & Gas Production (mboe/d) [2]	269	268	256
Capital Expenditures	1,625	1,404	915
Proved Reserve Additions, net of Dispositions (mmboe) [2]	102	135	132
Net Debt [3]	1,775	1,460	1,344
Net Debt to Cash Flow (times) [4]	1.4	1.1	0.9

Notes:

1 We evaluate our performance and that of our business segments based on earnings and cash flow from operations. Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other. We consider it a key measure as it demonstrates our ability and the ability of our business segments to generate the cash flow necessary to fund future growth through capital investment and repay debt.

(Cdn$ millions)	2002	2001	2000
Cash Flow from Operating Activities	1,322	1,566	1,329
Changes in Non-Cash Working Capital	46	(143)	243
Other	15	-	(3)
Cash Flow from Operations	1,383	1,423	1,569

2 Production and reserves include our working interest before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

3 Long-term debt less working capital.

4 Net debt divided by cash flow from operations after dividends on Preferred Securities.

STRATEGY

To succeed in the exploration and production business we must continue to locate and develop economic oil and natural gas reserves. Our capital investments must add new reserves to replace and grow existing production, and also add value. We believe value-based growth is best delivered through full-cycle exploration and development activities.

We pursue a predominantly grassroots, exploration-led strategy, supplemented by targeted, strategic acquisitions and the development of innovative technology to competitively exploit our bitumen resource. This strategy is supported by:

- solid core assets that provide free cash flow to finance new development projects for near-term growth;
- an active exploration program aimed at longer-term growth; and
- a culture based on integrity and social responsibility.

Our fundamental goal is to grow shareholder value. We focus on per-share performance and regularly report on cash flow and earnings per share. We target to grow the physical deliverables to our shareholders that are independent of price volatility. We allocate capital to projects based first on their investment returns and strategic fit, and second on the potential to grow reserves and production. To maximize returns, we try to operate the majority of our core assets and control offsetting acreage and infrastructure for future development.

Our global growth strategy focuses on four major areas: the deep-water Gulf of Mexico, the Middle East, West Africa and the Athabasca region of western Canada. The basins in these areas offer an optimal combination of prospectivity, attractive commercial terms and low costs. In building our portfolio, we target material opportunities with an attractive risk/reward balance and multiple opportunities for organic growth, and those that build on our technical strengths. Our strengths include: operating offshore, extensive experience with oil sands, bitumen and heavy oil, operating in foreign jurisdictions such as the Middle East, managing low pressure reservoirs, constructing and operating large-scale facilities, operating in difficult and remote environments and our strong marketing capabilities.

With our exploration success over the last three years, our focus in 2002 shifted to developing these successes. This included Aspen and Gunnison in the deep-water Gulf of Mexico, Guando in Colombia, our Long Lake Synthetic Crude Project in the Athabasca region of Alberta and the Syncrude expansion. With the exception of Aspen, these projects have yet to contribute significantly to production and cash flow as they are still in the development stage. Annual proved reserve additions fluctuate due to timing of recognizing proved reserves, dispositions and revisions.

Our strategy for maximizing value in our marketing operations is to grow our business with lower-risk opportunities. For our chemicals business, our strategy is to remain a low-cost producer in North America, while capturing an increasing share of the growing markets in South America.

2002 CAPITAL INVESTMENT

We invested a record $1.6 billion in 2002, a 16% increase over 2001 levels:

- 41% was invested in core assets to maintain existing production levels;
- 43% was invested in our major development projects for near-term production growth; and
- 16% was invested in exploration for longer-term production growth.

(Cdn$ millions)	Exploration	Development	Other	Total
Oil & Gas				
Yemen	22	209	-	231
Canada	60	262	-	322
United States	116	541	-	657
Australia	3	46	-	49
Other	58	23	-	81
	259	1,081	-	1,340
Syncrude	-	141	-	141
Chemicals	-	-	45	45
Marketing, Corporate and Other [1]	-	-	99	99
Total Capital	259	1,222	144	1,625

Note:
[1] Includes $67 million for our Balzac power generation facility.

In addition to maintaining production from our core assets (see Production section in this MD&A), our 2002 capital program delivered the following:

United States Gulf of Mexico

Aspen Onstream

- Invested $311 million in 2002 to drill and complete two subsea development wells and tie back to Shell's Bullwinkle production platform.
- First well onstream in early December after a six-week construction delay due to hurricane activity; second well onstream late December 2002; both wells added minimal production in 2002 given late start-up.
- Production is currently ramping up to expected rates of approximately 15,000 boe/d (net to us).
- No significant capital investment required in 2003.

Gunnison Development On-Track

- Invested $111 million in 2002 to complete 55% of the SPAR production facility and drill six development wells with a seventh in progress at year-end.
- Development is on budget and on schedule for first production in early 2004.
- In 2003, we plan to invest $83 million to complete and tie-in the subsea wells to the SPAR production platform arriving from Finland this summer.

Exploitation of 2001 Acquisitions

- Invested $83 million in two offshore producing properties acquired late in 2001 - Vermilion 76 and Eugene Island 295.
- Drilled eight development wells and added compression at Vermilion 76 more than doubling daily gas production to 40 million cubic feet per day in late 2002.
- Drilled one new well and added compression at Eugene Island 295 before the field was extensively damaged by Hurricane Lili; field has been shut-in since October but is expected to return to producing status during the first quarter of 2003.

Exploration for Deep Miocene Gas

- Drilled first well, Fergana (40% interest), as part of our agreement with Shell Exploration & Production Company to jointly explore the continental Shelf for natural gas in Deep Miocene reservoirs.
- Well was abandoned and costs of $23 million were written off in the fourth quarter.
- We plan to drill at least two more wells in the joint venture area in 2003 and 2004.

Canada

Long Lake Pilot Project Commenced

- Invested $80 million in 2002 to expand our recoverable resource potential to 4 billion barrels for the Long Lake and Meadow Creek properties, consulted with communities in support of our regulatory applications, continued detailed design and construction of the SAGD pilot project and carried out project design and cost estimation work.
- In 2003, we plan to invest $130 million to pilot-test SAGD technology at Long Lake and finalize a comprehensive cost assessment based upon detailed engineering design.
- Expect final regulatory approvals in fall 2003 and plan to decide on full-scale commercial project by year-end.

Core Asset Optimization Continues

- Began field testing enhanced extraction technologies in an effort to improve recoveries from some of our heavy oil properties.
- Built a strong land position targeting Coal Bed Methane (CBM) opportunities and commenced CBM pilot project.

Syncrude

Stage 3 Expansion Continues

- Invested $141 million to fund our 7.23% share of Stage 3 expansion.
- Engineering and design is 90% complete for the Mildred Lake upgrader expansion (UE-1) and the second bitumen extraction train at the Aurora mine; construction is 12% complete for UE-1 and 50% complete for the Aurora train.
- In 2003, we plan to invest $150 million for the continued upgrader expansion and completion of the Aurora train.
- Stage 3 is expected to add 101,500 barrels (7,300 barrels net) of daily production in early 2005.

Yemen

Masila Exploitation Continues

- Invested $402 million ($209 million net) to drill and equip 74 new development wells and expand facilities to maintain production at 226,900 barrels per day.

Unsuccessful Well on Block 59

- Drilled the Al Mawarid-1 exploration well on Block 59 without encountering commercial quantities of hydrocarbons.

Australia

- Drilled two successful infill wells at Buffalo offshore Australia.

Other Oil & Gas

Guando Development Commences in Colombia

- Drilled 12 primary-recovery development wells and commenced installation of waterflood pilot facilities to improve recoveries.
- Development drilling increased gross production to 7,300 barrels per day (2,200 net) by year-end.
- In 2003, we plan to invest $35 million to drill 24 wells, complete pipeline construction and evaluate the pilot waterflood performance.

Exploration Success Offshore Nigeria

- Invested $4 million and discovered oil at Usan on Block OPL-222 in the first quarter.
- Discovery well encountered several oil-bearing zones and tested at restricted rates in excess of 5,000 barrels per day.
- Currently appraising Usan and our 1998 discovery at Ukot on the same block.
- In 2003, we are continuing a program to appraise and delineate our discoveries.

Unsuccessful Exploration Well Offshore Brazil

- Drilled an exploration well on Block BC-20 in the Campos Basin which did not encounter commercial hydrocarbons and wrote off $5 million in the third quarter.
- In early 2003, we plan to drill a second exploration well on Block BC-20.

Chemicals

- Expanded low-cost sodium chlorate capacity at Brandon by 60% or 70,000 tonnes per year to 195,000 tonnes per year.
- Expanded our sodium chlorate capacity in Brazil by 70% to 60,000 tonnes per year and chlor-alkali capacity by 30% to 91,160 tonnes.

Other

- In 2002, we paid $67 million to refinance an operating lease related to the construction of a natural gas-fired power generation facility at our Balzac gas plant near Calgary.

FINANCIAL RESULTS

Year to Year Change in Net Income

(Cdn$ millions)	**2002 vs 2001**	**2001 vs 2000**
Net Income for 2001 and 2000	450	602
Favourable (unfavourable) variances:		
Cash Items:		
Production volumes, net of royalties:		
Crude oil	28	123
Natural gas	(18)	30
Commodity prices, net of royalties:		
Crude oil	190	(308)
Natural gas	(114)	22
Oil and gas operating expense:		
Conventional	(65)	(66)
Synthetic	(1)	(16)
Marketing	(23)	48
Chemicals	1	3
General and administrative	(16)	(19)
Interest expense	3	20
Current income taxes	(7)	26
Other	(18)	(9)
Total Cash Variance	(40)	(146)
Non-Cash Items:		
Depreciation, depletion and amortization		
Oil and Gas	(85)	38
Other	(10)	4
Exploration expense	76	(92)
Future income taxes	82	77
Other	(21)	(33)
Total Non-Cash Variance	42	(6)
Net Income for 2002 and 2001	452	450

2002 vs 2001 – Stable earnings year over year

Net income remained strong due to narrow crude oil price differentials, stable production and reduced dry hole expense. Weaker natural gas prices, cost pressures and lower profits from Marketing offset the positive impact of crude oil prices.

2001 vs 2000 – 25% decrease in net income

Net income decreased largely as a result of a US $4.24 per barrel decrease in WTI. Record production levels, excellent results from Marketing and lower costs of financing helped mitigate the impact of crude oil price declines.

Significant variances in net income are explained further in the following sections.

OIL AND GAS

Production

	2002		2001		2000	
	Before Royalties	After Royalties	Before Royalties	After Royalties	Before Royalties	After Royalties
Oil and Liquids (mbbls/d)						
Yemen	118.0	55.8	118.3	55.5	111.9	50.7
Canada	56.3	43.4	58.0	48.3	53.9	44.0
United States	9.9	8.2	10.0	8.3	11.1	9.3
Australia	12.8	10.3	10.2	9.6	12.0	12.0
Other Countries	8.9	5.2	6.2	5.3	6.4	5.4
Syncrude	16.6	16.5	16.1	15.5	14.7	12.1
	222.5	139.4	218.8	142.5	210.0	133.5
Natural Gas (mmcf/d)						
Canada	167	128	174	147	161	135
United States	112	93	121	99	113	92
	279	221	295	246	274	227
Total (mboe/d)	269	176	268	184	256	171

2002 vs 2001 – Production added $10 million to net income

2002 production before royalties grew modestly over 2001 volumes. A 2% increase in crude oil volumes was partially offset by a 5% decrease in natural gas volumes.

MASILA BLOCK IN YEMEN

- Maintained production through our on going development drilling, water handling and throughput expansions.
- Experienced minor delays in tanker loadings but no impact on production or cash flow when the supertanker Limburg was damaged near our Ash Shihr export terminal.
- In 2003, we expect to maintain production through continued infill drilling, facility enhancements and exploration focused on deeper targets.

CANADA

- We invested $240 million or about 15% of our total capital expenditures in 2002 to mitigate production declines.
- We are focused on our highest-return projects including Hay, while we develop new sources of production in synthetic crude and coal bed methane.
- Hay set a new 8,000 barrel per day production record in 2002.

GULF OF MEXICO

- Production decreased due to development delays, weather-related shut-ins and production declines on some of our shelf properties.
- Poor weather in the third and fourth quarters, including tropical storm Isidore and Hurricane Lili, caused temporary shut-in of production, a 6-week delay at Aspen and damage to our Eugene Island 295 production platform.
- All production, except Eugene Island 295, was restored in the fourth quarter.
- Our Eugene Island 295 exploitation program was in progress at the time of the storm; the field has been shut-in since October but is expected to return to producing status during the first quarter of 2003.
- Aspen's first well came onstream in early December and the second well in late December. We are ramping up production to expected rates of 15,000 equivalent barrels per day net to us.
- With Aspen onstream for the full year, we expect 2003 production before royalties to increase by 65% to 46 mboe/d.

BUFFALO OFFSHORE AUSTRALIA

- Completed successful two-well infill drilling program that added incremental production and reserves.
- Exited 2002 at 10,000 barrels per day; we expect Buffalo to be fully depleted in 2004.

EJULEBE OFFSHORE NIGERIA

- Strong 2002 production as the reservoir continued to perform better than anticipated.
- Exited 2002 at 4,700 barrels per day with water-cuts increasing; we expect Ejulebe to be depleted in 2004.

SYNCRUDE

- Extended maintenance turnaround, unplanned coker maintenance and sulfur dioxide emission restrictions reduced volumes during the first half of the year.
- December production of 19,100 barrels per day set a new monthly record.

2001 vs 2000 – 5% production growth added $153 million to net income

- Masila set an annual production record for the sixth consecutive year with gross rates of 227,500 barrels per day.
- In Canada, our exploitation activities included successful optimization of our Hay assets with the doubling of production to an annual average of 5,400 barrels per day.
- Gulf of Mexico natural gas production grew 7% with the fourth quarter acquisitions of Vermilion 76 and Eugene Island 295 and with successful exploitation of our shallow-water assets.
- Australian crude oil production remained stable as the acquisition of the remaining 50% interest in Buffalo offset natural production declines.

Commodity Prices

(Prices based on working interest production before royalties)

	2002	2001	2000
Crude Oil (Cdn$/bbl)			
West Texas Intermediate (US$/bbl)	26.09	25.97	30.21
Differentials (US$/bbl):			
Masila	1.41	3.29	2.82
Heavy Oil	6.49	10.68	8.06
Producing Assets:			
Yemen	38.80	35.05	40.53
Canada	31.13	24.86	33.49
United States	38.88	38.35	44.18
Syncrude	40.89	39.90	44.84
Australia	40.30	38.71	41.05
Other Countries	38.96	37.37	40.12
Corporate Average (Cdn$/bbl)	37.13	33.10	39.23
Natural Gas (Cdn$/mcf)			
New York Mercantile Exchange (US$/mmbtu)	3.37	4.00	4.31
Canada	3.57	5.02	4.38
United States	5.29	6.66	6.90
Corporate Average (Cdn$/mcf)	4.25	5.69	5.42

2002 vs 2001 – Higher realized prices added $76 million to net income

CRUDE OIL PRICES

- Average WTI was largely unchanged but narrow oil differentials added $180 million to net income, increasing our realized price 11%.
- At the beginning of 2002, WTI was US $19.73 per barrel strengthening throughout the year to close at US $31.20.
- Early second quarter strength was driven by uncertainty in the Middle East, OPEC's maintenance of production quotas and the threat of war between Iraq and the US.
- WTI slid modestly early in the fourth quarter as quota cheating by OPEC members increased and the war premium disappeared with Iraq cooperation.
- Despite the reduction of the war premium, WTI strengthened late in the year as supply disruptions took place in Venezuela and OPEC took steps to shore-up production quotas.

NARROW DIFFERENTIALS

- The strength of Brent relative to WTI combined with a short-term premium for Masila mid-year, resulted in a narrower Masila differential. Low inventory levels in Europe kept the Brent-WTI differential narrow throughout most of the year.
- Heavy oil narrowed early in the year due to reduced supply, continued narrow into the summer months due to normal seasonal demand and remained narrow into the winter months due to the Venezuelan supply disruption.
- Realized crude oil prices for Canada and Yemen exceeded 2001 prices by 25% and 11%, respectively.
- We expect the Masila differential to return to historical norms around US $3.00 per barrel in 2003.
- We expect 2003 heavy oil differentials to remain narrow in the near-term due to the ongoing disruptions in Venezuela.

NATURAL GAS PRICES

- Lower gas prices reduced net income by $114 million.
- Prices fell in the first part of 2002 from the record highs of 2001 as gas inventories were higher, but strengthened late in 2002 as cold weather in the eastern US drove up demand and caused supply concerns.
- We expect stronger gas prices in 2003 as production decline rates and a lack of drilling should continue to reduce available supply levels.

2001 vs 2000 – Lower realized prices reduced net income by $286 million

- Lower crude oil prices in 2001.
- At the beginning of 2001, WTI was approximately US $29 per barrel and closed the year at US $19.40 per barrel.
- Sluggish demand after September 11, 2001 and concerns over inventory levels drove prices down late in the year.
- Natural gas prices softened as North American inventories rose.

Operating Costs

(Unit operating costs based on working interest production before royalties)

(Cdn$/boe)	2002	2001	2000
Conventional Oil and Gas			
Yemen	1.95	1.62	1.42
Canada	5.70	4.87	4.57
United States	9.09	6.01	5.00
Australia	9.76	13.50	6.92
Other Countries	6.21	8.07	7.58
Total Conventional	4.60	3.92	3.38
Synthetic Crude Oil			
Syncrude	19.09	19.43	18.36
Total Oil and Gas [1]	5.48	4.88	4.22

Note:

[1] Operating costs per equivalent barrel are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies. See Reserves, Production and Other Information in Item 1 and 2 in this 10-K for unit operating costs based on our production after royalties.

2002 vs 2001 – Higher oil and gas operating costs reduced net income by $66 million

Conventional operating costs increased $0.68 per equivalent barrel:

- Gulf of Mexico was a significant contributor as workovers and repairs on the shelf increased costs and temporarily reduced production. Weather-related shut-ins and storm damage also contributed to the increase. One-time workovers and storm-related costs are not expected to continue in 2003.
- Costs are expected to decrease in 2003 with low-cost production from Aspen making up a larger portion of our total Gulf production.
- In Canada, industry cost pressures and a maturing asset base increased per unit costs. In addition, unexpected turnaround costs at our Balzac gas plant caused a one-time increase in operating costs.
- In Yemen, increased water-handling and waterflood costs as well as one time flood-related costs increased per-unit costs.

- In 2002, our floating production and storage off-loading vessel (FPSO) costs in Australia decreased on a per-unit basis as fixed costs were spread over more barrels and increased production levels attracted a lower throughput cost. This decrease in FPSO unit costs was partly offset by one-time field repair costs.

With respect to synthetic crude oil, our operating costs at Syncrude stabilized in 2002 as second quarter maintenance activities improved reliability and performance.

2001 vs 2000 - Higher oil and gas operating costs reduced net income by $82 million

- Conventional operating costs increased $0.54 per equivalent barrel. Industry cost pressures from a sustained period of high commodity prices and maturing assets contributed to the increase.
- Australia's costs increased as fixed costs were spread over fewer barrels of production.
- Maintenance activities and higher energy prices caused an increase in Syncrude's per-unit operating costs.

Depreciation, Depletion and Amortization (DD&A)

(Based on working interest production before royalties)

(Cdn$/boe)	**2002**	**2001**	**2000**
Conventional Oil and Gas			
Yemen	3.47	2.56	2.20
Canada	8.22	7.14	7.89
United States	12.74	10.59	12.70
Australia	10.45	16.61	21.05
Other Countries	13.22	15.11	15.88
Total Conventional	6.84	5.97	6.67
Synthetic Crude Oil			
Syncrude	2.13	2.03	2.23
Total Oil and Gas [1]	6.55	5.73	6.41

Note:
[1] DD&A per equivalent barrel is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2002 vs 2001 – Higher oil and gas DD&A reduced net income by $85 million

Conventional depletion rates increased $0.87 per equivalent barrel:

- Higher 2001 finding and development costs in Canada, Yemen and the Gulf shelf comprise the majority of the increase.
- Changing production mix also contributed as a larger portion of production came from more capital-intensive properties.
- Rates in Australia decreased as reserves were added with our successful infill drilling program.

2001 vs 2000 – Lower oil and gas DD&A added $38 million to net income

- Depletion rates for conventional production decreased as reserves were added at low finding and development costs in 2000.

Exploration Expense

(Cdn$ millions)	**2002**	**2001**	**2000**
Seismic	80	79	74
Unsuccessful Drilling	63	135	54
Other	46	51	45
Total Exploration Expense	189	265	173
Total Exploration Capital	259	411	300

2002 vs 2001 - Lower exploration expense added $76 million to net income

- Pursued exploration activities in Yemen, Nigeria, Brazil, Colombia, the Gulf of Mexico and Canadian natural gas.
- Lower exploration expense as capital spending focused on development of earlier successes.
- Drilled 68% fewer exploration wells.
- Successfully drilled an exploration well at Usan on Block OPL-222.
- Unsuccessful exploration wells include Block 59 in Yemen, Fusa in Colombia, Block BC-20 offshore Brazil and Fergana in the Gulf of Mexico.

2001 vs 2000 – Higher exploration expense reduced net income by $92 million

- Higher exploration expense due to our largest-ever exploration program.
- Unsuccessful drilling costs include two high-risk exploration wells: Scout in the deep-water Gulf of Mexico and Kayu Manis, offshore Indonesia.

OIL AND GAS MARKETING

(Cdn$ millions)	**2002**	**2001**	**2000**
Revenue	496	438	179
Transportation	(423)	(342)	(131)
Net Revenue	73	96	48
Marketing contribution to Income before Income Tax	35	59	23
Physical Sales Volumes (excluding intra-segment transactions)			
Crude Oil (mboe/d)	412	400	294
Natural Gas (mmcf/d)	2,865	2,499	1,664
Value-at-Risk			
Year-end	19	19	13
High	28	24	13
Low	12	6	2
Average	17	13	4

2002 vs 2001 – Lower net marketing revenue reduced net income by $23 million

The energy trading industry experienced many challenges in 2002. Liquidity was at an all-time low following the collapse of Enron and the exposure of questionable accounting and valuation practices by a number of companies. Numerous participants retrenched, consolidated or exited the industry completely. Accounting standard setters and regulators made changes to the rules and practices governing the industry, including improved and more transparent disclosures, as well as changes to the mark-to-market accounting rules, which are described more fully in note 1(r) to our Consolidated Financial Statements.

Our marketing operations had lower net revenue in 2002 compared to 2001 due to:

- Less price volatility in 2002.
- The reduced number of competitors allowed us to increase our marketed volumes over 2001 levels.
- Excluding the one-time gains in the first quarter of 2001, margins grew year over year. We expect margins to continue to grow in 2003 as industry retrenchment continues.

2001 vs 2000 – Higher net marketing revenue adds $48 million to net income

- We successfully capitalized on the significant price volatility early in the year.
- Crude oil volumes increased with the acquisition of Northridge Energy Marketing Ltd., which was purchased on July 31, 2000. Northridge marketed approximately 90,000 barrels of oil per day.

Derivative Energy Contracts

Our marketing operation engages in crude oil and natural gas marketing activities to enhance prices from the sale of our own oil and gas production, and for energy trading. We enter into contracts to purchase and sell crude oil and natural gas. These contracts expose us to commodity price risk between the time contracted volumes are purchased and sold. We actively manage this risk by using energy-related futures, forwards, swaps and options, and by balancing physical and financial contracts in terms of volumes, timing of performance and delivery obligations. However, net open positions may exist, or we may establish them to take advantage of market conditions.

Consistent with our management practices, we account for all derivative energy contracts using mark-to-market accounting, and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is recorded as accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date. On October 25, 2002, as described in note 1(r) to the Consolidated Financial Statements, generally accepted accounting principles followed by energy traders eliminated mark-to-market accounting for inventories. As such, after October 25, 2002, inventories held by our marketing operation are accounted for at the lower of cost or market value.

Fair Value of Derivative Energy Contracts

We value derivative energy trading contracts daily using:

- actively quoted markets such as the New York Mercantile Exchange and the International Petroleum Exchange; and
- other external sources such as independent price publications and over-the-counter broker quotes.

At December 31, 2002, the unrealized fair value of our derivative energy contracts totalled $3 million. The following table shows the valuation methods underlying these contracts together with details of contract maturity:

(Cdn$ millions)	Maturity				
	< 1 year	1-3 years	4-5 years	> 5 years	Total
Prices:					
Actively quoted	63	(40)	(13)	-	10
From other external sources	(67)	45	14	1	(7)
Based on models and other valuation methods	-	-	-	-	-
Total	(4)	5	1	1	3

Contract maturities vary from a single day up to six years. A large number of our contracts mature in less than one year. Those maturing beyond one year are primarily from natural gas related positions. The relatively short maturity position of our contracts lowers our portfolio risk.

Our accounting policy does not permit us to record income on transportation and inventory using option valuation methods. As a result, we have not been subject to write-downs due to the loss of liquidity and volatility caused by the industry retrenchment in 2002.

Changes in Fair Value of Derivative Energy Contracts

(Cdn$ millions)	Contracts Outstanding at Beginning of Year	Contracts Entered Into During Year	Total
Outstanding at December 31, 2001	19	-	19
Change in fair value of contracts:			
Outstanding at January 1, 2002	21	-	21
Entered into during 2002	-	37	37
Net gains realized on positions closed during the year	(44)	(30)	(74)
Changes in valuation techniques and assumptions [1]	-	-	-
Outstanding at December 31, 2002	(4)	7	3

Note:
[1] Our valuation methodology has been applied consistently year over year.

Composition of Net Marketing Revenue

(Cdn$ millions)	
Derivative energy contracts	58
Non-derivative energy contracts	15
Net Marketing Revenue	73

Of the $73 million net marketing revenue recognized during 2002, only a net gain of $3 million is unrealized at December 31, 2002.

Non-derivative Energy Contracts

Our marketing operation also manages various natural gas transportation commitments on behalf of our Canadian oil and gas business and a number of third-party customers. These activities optimize our trading operations. The related commitments are outlined in the Contractual Obligations, Commitments and Contingencies section. We earned $15 million from our non-derivative energy activities in 2002.

CHEMICALS

(Cdn$ millions)	**2002**	**2001**	**2000**
Net Sales	367	373	336
Sales Volumes (thousand short tons)			
Sodium chlorate	454	457	462
Chlor-alkali	375	365	407
Operating Profit [1]	100	99	96
Operating Margin (%)	27	27	29
Chemicals contribution to Income before Income Taxes	27	47	39
Capacity Utilization (%)	85	89	92

Note:
[1] Net sales less operating costs and transportation.

2002 vs 2001 – Chemicals operating profit adds $1 million to net income

We faced many challenges in 2002:

- Slow economic recovery in North America placed downward pressure on sodium chlorate volumes and eroded market prices.
- Increasing energy costs in Louisiana put pressure on our Taft plant, and as a result, the assets have recently been temporarily idled while we review alternatives to manage these costs.

During 2002, margins remained strong due to lower overall energy costs and the shifting of production from higher-cost to lower-cost facilities following the expansion of our Brandon and Brazil facilities. The expansion of these plants and the shifting of production to lower cost facilities increased our depreciation.

Demand in 2003 is expected to improve for sodium chlorate as the economy recovers. We expect to take advantage of the recovery with a full year of production from our Brandon and Brazil expansions. We are continuing to take steps towards improving our overall cost structure in North America.

2001 vs 2000 – Chemicals operating profit adds $3 million to net income

- Sales revenue increased 11% as price increases more than offset recessionary conditions in North America.
- Operating costs as a percentage of sales were consistent with 2000 as high natural gas prices fell late in 2001.

CORPORATE EXPENSES

General and Administrative

(Cdn$ millions)	2002	2001	2000
General and Administrative	152	136	117

2002 vs 2001 – Higher costs reduced net income by $16 million

- 70% of the increase was due to higher staffing levels, associated with our record capital investment program and growth in our marketing operations.
- Increased pension expense due to poor equity market performance.
- We also experienced higher building lease costs and incremental expenses associated with our stock appreciation rights plan.

2001 vs 2000 – Higher costs reduced net income by $19 million

- 60% of the increase related to the expansion of our marketing operations in Calgary and Singapore.
- Remainder was due to increased staffing levels associated with a larger capital investment program.

Interest

(Cdn$ millions)	2002	2001	2000
Interest	140	112	132
Less: Capitalized Interest	(31)	-	-
Net Interest Expense	109	112	132

2002 vs 2001 – Lower interest expense added $3 million to net income

- Total interest costs increased $28 million as a result of the higher borrowing rate on our new 30-year notes.
- Net interest decreased as we capitalized interest on our major development projects.

2001 vs 2000 – Lower interest expense added $20 million to net income

- Lower interest rates and debt levels contributed to decrease from 2000.

Income Taxes

2002 vs 2001 – Effective tax rate declines from 40% to 34%

Rate decreased due to:

- lower federal and provincial statutory tax rates for Canadian non-oil and gas operations;
- higher portions of income coming from international operations where rates are lower; and
- non-taxable capital gain on the sale of our Moose Jaw operations.

The majority of our 2002 current income taxes were paid in Yemen and Australia. Current taxes include cash taxes in Yemen of $207 million (2001 - $191 million; 2000 - $217 million). In 2002, federal and provincial capital taxes were payable in Canada. In 2001 and 2000, alternative minimum tax was payable in the US.

Gain or Loss on Disposition of Assets

Net loss in 2002 includes:

- $13 million gain on the sale of our asphalt operation in Moose Jaw, Saskatchewan for proceeds of $27 million plus working capital; and
- $21 million loss on the sale of a non-operated property by our Canadian oil and gas business segment for proceeds of $14 million.

Gains in 2001 related to the disposition of minor properties in Australia and the United States. In 2000, gains related to the exchange of our 15% interest in oil and gas assets in Ecuador for Occidental's 15% minority interest in our chemicals operations and the disposition of non-core assets in Canada.

LIQUIDITY

Capital Structure

(Cdn$ millions)	2002	2001
Bank Debt	-	424
Senior Public Debt	1,844	1,060
	1,844	1,484
Less: Working Capital	69	24
Net Debt [1]	1,775	1,460
Shareholders' Equity [2]	2,348	1,904

Notes:
1 Long-term debt less working capital.
2 Included in shareholders' equity are preferred securities of $724 million (US $476 million). Under US generally accepted accounting principles, these are considered long-term debt.

Our business strategy is focused on value-based growth through full-cycle exploration and development, supplemented by strategic acquisitions when appropriate. We rely on operating cash flow and borrowings under committed credit facilities and public debt, including preferred securities, for our liquidity and capital requirements. We build our opportunity portfolio to provide a balanced mix of short-term, mid and longer-term growth. This enables us to generate ongoing sustainable operating cash flows.

We enhanced our capital structure in 2002:

Shareholders' equity	Continued to strengthen with strong 2002 operating and financial results.
US $500 million of 7.875% debt	Issued in March 2002 and maturing in 30 years. Proceeds used to repay existing bank debt and fund a portion of our capital investment program.
Committed bank facilities of $1,576 million	All undrawn at year-end and available until 2007.
$500 million Canadian shelf prospectus	Available until May 2003.
US $500 million US shelf prospectus	Available until May 2004.
Favourable debt maturities	Over the next five years, $355 million matures in 2004, $108 million in 2006 and $150 million in 2007.
Increased term to maturity	Increased the average term to maturity of our debt to 18 years, an increase of 8 years from the end of 2001.
$724 million of Preferred Securities	Provide fixed-rate financing for another 45 years but can be redeemed at par commencing in October 2003 ($393 million) and February 2004 ($331 million). The Preferred Securities are subordinated to Senior Debt and interest payments may be deferred for up to five years. Interest and principal can be settled with common shares.

The change in net debt in 2002 and 2001 resulted from:

(Cdn$ millions)	2002	2001
Capital Expenditures	1,625	1,404
Cash Flow from Operations	(1,383)	(1,423)
Dividends on Preferred Securities and Common Shares	109	107
Foreign Exchange	-	57
Proceeds on Disposition of Assets	(49)	(5)
Other	13	(24)
Increase in Net Debt	315	116

2002 - $315 million increase in net debt

- Capital expenditures and dividend payments exceeded cash flow from operations.

2001 - $116 million increase in net debt

- Capital expenditures and dividend payments exceeded cash flow from operations.
- The decline in the Canadian dollar relative to the US dollar also increased net debt.

In 2002, we had working capital of $69 million compared to $24 million in 2001. Our large natural gas storage position at year end caused the increase. The value of this natural gas position has been fixed through financial derivatives. At December 31, 2002, we sold $178 million of accounts receivable proceeds (2001 - $100 million) to minimize our total cost of financing.

Our future debt levels are primarily dependent on our operating cash flows and our capital investment programs. Currently, we expect our 2003 capital program and dividend requirements to be funded by cash flow from operations. Our 2003 operating cash flows assume WTI is US $23 per barrel and natural gas is US $3.50 per mcf for the remainder of year. For every US $1 change in WTI or every US $0.50 change in natural gas, we expect our cash flow from operations to change by $67 million and $61 million, respectively. In addition, we have $1.6 billion of additional unsecured credit facilities to draw on.

We declared common share dividends of $0.30 per common share in each of the last three years.

Leverage Statistics

	2002	2001	2000
Net Debt to Cash Flow [1] (times)	1.4	1.1	0.9
Interest Coverage [2] (times)	10.7	13.7	12.9
Fixed Charge Coverage [3] (times)	7.2	8.4	8.5

Notes:

1 Cash Flow comprises cash flow from operations after dividends on Preferred Securities. Under US regulations, preferred securities are considered long-term debt. Our net debt to cash flow would be 1.9 times (2001 - 1.6; 2000 - 1.4).

2 Cash flow from operations before interest expense divided by total interest.

3 Cash flow from operations before interest expense divided by total interest plus dividends on Preferred Securities.

Our net debt is equal to 1.4 times our 2002 cash flow from operations after dividends on preferred securities. This, together with our coverage ratios, provides us with sufficient financial flexibility and liquidity to pursue our business strategy.

Credit Ratings

Currently, our senior debt is rated BBB-mid by Dominion Bond Rating Service, BBB by Standard and Poor’s and Baa2 by Moody’s Investor Service, Inc. In addition, all rating agencies currently have our rating outlook as stable. Our strong financial results, low historical finding and development costs, ample liquidity and financial flexibility will continue to support our current credit rating.

Financial Assurance Provisions in Commercial Contracts

The commercial agreements our marketing operations enter into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements generally provide for some type of collateral in the event of deterioration in the creditworthiness of the buyer. Credit ratings are frequently used in the agreements to provide an objective measure of creditworthiness, with the agreement typically requiring the posting of collateral (in the form of either cash or a Letter of Credit), if a buyer’s credit rating drops below investment grade. Based on contracts in place and commodity prices at December 31, 2002, we would be required to post collateral of $210 million in the event of a downgrade to non-investment grade. This obligation is reflected in our balance sheet. The posting of collateral merely accelerates the payment of such amounts. Our committed undrawn credit facilities of $1.6 billion adequately cover any potential collateral requirements. Just as we may be required to post collateral in the event of a downgrade below investment grade, we have similar provisions in many of our customer contracts that allow us to demand certain customers post collateral with us if they are downgraded to non-investment grade.

OUTLOOK FOR 2003

2003 Capital Investment Program

(Cdn$ millions)	Exploration	Development	Other	Total
Yemen	17	234	-	251
Canada	40	328	-	368
United States	136	182	-	318
Syncrude	-	176	-	176
Australia	3	3	-	6
Other	90	43	-	133
Total Oil & Gas	286	966	-	1,252
Chemicals	-	-	46	46
Marketing, Corporate and Other	-	-	34	34
Total	286	966	80	1,332

Our 2003 capital program of $1.3 billion, our third largest ever, will build on the success of last year. Our solid capital structure and surplus liquidity will support this program. The following items show the expected distribution of our 2003 capital investment program:

- 40% to sustain and grow production and cash flow from our core assets;
- 30% to continue progress on our major development projects for near to mid-term growth; and
- 20% on exploration to test almost 900 million barrels of unrisked resource potential for long-term growth.

This program is consistent with our strategy to grow reserves and production primarily through the drill bit.

Core Asset Maximization

Our focus is to maintain production from our core assets to extract their maximum value without overcapitalizing.

Yemen

- We will continue exploring deeper carbonate sections, further develop the main Qishn horizons and continue waterflood projects on the secondary horizons to maintain production at 226,900 barrels per day.

Gulf of Mexico

- We expect production growth from continued exploitation of our Vermilion 76, Eugene Island 257/258, Eugene Island 295 and Eugene Island 18 properties and a full year of operations from deep-water Aspen.

Canada

- About 14% of our total 2003 investment program will be invested in Canadian conventional exploration and production.
- We will focus on projects that provide the highest returns on invested capital, while we transition to new sources of production growth such as synthetic crude oil, coal bed methane and high-impact gas exploration.

Daily Production

We expect our core assets to generate daily production before royalties of between 270,000 and 280,000 equivalent barrels in 2003. While production before royalties will increase modestly, production after royalties is estimated to grow 6% to 10%, to between 190,000 and 196,000 equivalent barrels per day, with significant new royalty-free production from Aspen. Actual production rates will depend upon numerous factors including commodity prices, the level of capital expenditures, drilling success and well performance.

(mboe/d)	2003 Estimate	
	Before Royalties	After Royalties
Canada	77 - 82	61 - 64
Yemen	118 - 119	60 - 61
United States	46 - 52	39 - 45
Syncrude	17 - 18	17 - 18
Other International	12 - 16	11 - 14
	270 - 280	190 - 196

Over the next five years, production after royalties is expected to grow as our production grows in the deep-water Gulf of Mexico and synthetic crude oil. Since these projects have low or no royalties, lower costs and ultimately higher returns than our current producing assets, this changing production mix will improve profitability, despite lower anticipated oil prices. Using the mid-point of our production range and assuming WTI averages US $23 per barrel and gas prices average US $3.50 per thousand cubic feet in 2003, we expect cash flow from operating activities of approximately $1.3 billion. For every dollar change in WTI in 2003, our cash flow will change by $67 million. For every $0.50 change in our North American natural gas price in 2003, our cash flow will change by $61 million.

Chemicals and Marketing

We expect continuing strong performance from our chemicals and marketing businesses in 2003. In our chemicals operation, increased demand for sodium chlorate, higher margins for chlor-alkali, and operational efficiencies resulting from our Brandon and Brazil expansions should improve cash flow. Our oil and gas marketing business is growing in the fee for service segment and we expect attractive margins, as many competitors have exited the sector.

Major Development Projects

Details of the investment activities for each project are included in the 2002 Capital Investment section in this MD&A. Together these projects are expected to add 55,000 to 65,000 equivalent barrels of daily production by 2007 as they become core assets.

Strong Grass Roots Exploration

Our 2003 exploration program is our highest quality ever as we plan to drill prospects offsetting existing discoveries and extensions of play types we know well. We expect to drill up to 18 high-impact wells. Our plans include:

Gulf of Mexico

- We will invest approximately one-half of our exploration capital here.
- We plan to drill at least five high-impact exploration wells, including the deep-water Gotcha prospect in the Alaminos Canyon area. This prospect directly offsets the recently discovered Great White discovery. We will also drill prospects in the Green Canyon and Garden Banks areas, and a Deep Miocene gas prospect on the shelf.
- We plan to drill additional wells depending upon success and partner priorities.

Other Exploration

- In Yemen, we will continue interpreting seismic data on our exploration blocks and drill at least one exploration well.
- Offshore Brazil, we plan to drill an exploration well on Block BC-20 in the Campos Basin.
- In Canada, we will focus exploration on gas prospects in the foothills of northwestern Alberta and in northeastern British Columbia.

CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

We have assumed various contractual obligations and commercial commitments in the normal course of our operations and financing activities. Contractual obligations include both financial and non-financial obligations. Financial obligations are considered to represent known future cash payments that we are required to make under existing contractual arrangements, such as debt and lease arrangements. Non-financial obligations represent contractual obligations to perform specified activities, such as work commitments. Commercial commitments represent contingent obligations that become payable only if certain pre-defined events occur.

Contractual Cash Obligations and Other Commercial Commitments

(Cdn$ millions)	Payments [1]				
	Total	<1 year	1-3 years	4-5 years	>5 years
Long-Term Debt [1]	1,844	-	355	258	1,231
Operating Leases	257	50	73	34	100
Transportation Commitments	428	180	72	63	113
Work Commitments	166	155	11	-	-
Other	9	7	2	-	-
Total	2,704	392	513	355	1,444

Notes:
1 Payment obligations are not discounted and do not include related interest, accretion or dividends.

- Long-term debt amounts are included in our December 31, 2002 Consolidated Balance Sheet. Under US GAAP, $751 million of Preferred Securities due in 2047 and 2048 would be included in long-term debt. The fair value of these securities is $756 million at December 31, 2002.
- Operating leases include leases for office space, rail cars, vehicles and the lease of the FPSO in Australia.
- Our marketing operation manages various natural gas transportation commitments on behalf of our Canadian oil and gas business and a number of third-party customers. These activities help to optimize our trading operations.
- Work commitments include non-discretionary capital spending related to drilling and seismic commitments in our international operations and development commitments at Gunnison and Syncrude. The remainder of our capital spending in 2003, as discussed in the 2003 Outlook section in this MD&A, is discretionary.

Contingencies

See note 10 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference for a discussion of our contingencies.

BUSINESS RISK MANAGEMENT

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 major integrated oil and gas companies and numerous other independent oil and gas companies.

The pulp and paper chemicals market is also highly competitive. Key success factors are:

- price and product quality;
- logistics and reliability of supply; and
- technical service.

We are one of the largest producers of sodium chlorate in North America and have continent-wide supply capability.

Operational Risk

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, equipment failures and other accidents;
- craterings and sour gas releases;
- uncontrollable flows of oil, natural gas or well fluids;
- adverse weather conditions; and
- environmental risks.

Although we maintain insurance according to customary industry practice, we cannot fully insure against all of these risks. Losses resulting from the occurrence of these risks could have a material adverse impact.

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, our existing 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.

Uncertainty of Reserve Estimates

Oil and gas reserve estimates are integral to making investment decisions regarding oil and gas properties, such as whether development should proceed or enhanced recovery methods should be undertaken. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond our control. The reserve data included in the Supplementary Financial Information in the Form 10-K represents estimates only.

In general, estimates of economically recoverable oil and natural gas reserves and future net cash flows are based on a number of variable factors and assumptions, such as:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe that the factors and assumptions used in estimating reserves are reasonable based on the information available to us at the time the estimates were prepared. Actual results could vary considerably, which could cause material variances in the following:

- estimated quantities of proved oil and natural gas reserves in aggregate and for any particular group of properties;
- reserve classification based on risk of recovery;
- future net revenues, including production, revenues, taxes, and development and operating expenditures; and
- financial results including the annual rate of depletion and recognition of property impairments.

Management is responsible for estimating the quantities of proved oil and natural gas reserves. Estimates are prepared annually for each property by the reservoir engineer associated with the property. Senior management, including the Chief Executive Officer and Chief Financial Officer, meet with the reserves managers for each division to review the estimates and changes therein.

We assess 100% of our reserve estimates internally each year. In addition, our reserve estimates are assessed annually by independent qualified consultants. Generally, the consultants assess at least 80% of our reserves. Given that the reserves are estimates based on numerous assumptions and interpretations, differences within 10% are considered to be immaterial. Differences greater than 10% are resolved.

The Board of Directors has established a Reserves Review Committee (Reserves Committee) to assist the Board and the Audit and Conduct Review Committee of the Board in fulfilling their oversight responsibilities with respect to the annual review of our oil and gas reserves. The Reserves Committee is comprised of three or more directors, the majority of whom must be independent, and each must have a working familiarity with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, results and related disclosures. The Reserves Committee also meets with the consultants independent of management to review such things as the scope of their work, their access to sufficient information, the nature and satisfactory resolution of any differences of opinion, and their independence.

The estimated discounted future net cash flows from estimated proved reserves included in the Supplementary Financial Information in the Form 10-K are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows will also be affected by factors such as actual production levels and timing, and changes in governmental regulation or taxation and may differ materially from such estimates. See the Critical Accounting Policies section of this MD&A for a complete discussion of the impact of changes in our reserve estimates.

Political 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. We conduct our business and financial affairs to protect against political, legal, regulatory and economic risks applicable to operations in the various countries where we operate. However, there can be no assurance that we will be successful in protecting ourselves from the impact of these risks.

In October 2002, there was an explosion and fire aboard the supertanker Limburg, which was inbound for our Ash Shihr export terminal in Yemen. Our Masila block operations were largely unaffected by this. Tanker loadings were delayed while our tugboat secured the Limburg to prevent it from running aground. Loading then resumed and oil exports continued as scheduled. This had no impact on our production or cash flows.

Our Masila operations are important to Yemen, providing 50% of the country's oil production. We are a responsible member of the Yemeni community; we build relationships with its members and involve them in key decisions that impact their lives. We also ensure that they benefit from our presence in their country. Our strong relationship with the people and Government of Yemen has allowed us to operate there without interruptions for almost 13 years and we anticipate this continuing.

Our practices have enabled us to operate successfully, not only in Yemen, but also other parts of the world. We have developed excellent practices to manage the risks successfully.

Environmental Risk

Environmental risks 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.

We manage our environmental risks through a comprehensive and sophisticated Safety, Environmental and Social Responsibility (SESR) Management System that meets or exceeds ISO14001 criteria and those of similar management systems. Overall guidance and direction is provided by the SESR Committee of the Board of Directors. In addition, senior management, including the CEO and CFO, regularly meets with SESR management to review and approve SESR policies and procedures, provide strategic direction, review performance and ensure that corrective action is taken when necessary. We develop and implement proactive and preventative measures designed to reduce or eliminate future environmental liabilities, we are prudent and responsible in our management of existing environmental liabilities, and we continuously seek opportunities for performance improvement. In addition, we maintain an ongoing awareness of external trends and emerging issues. These actions provide assurance that we meet or exceed appropriate environmental standards worldwide.

- At December 31, 2002, $205 million has been provided in the Consolidated Financial Statements for future dismantlement and site restoration costs, which are currently estimated to be approximately $544 million for all of our oil and gas and chemicals facilities.
- During 2002, we recorded a provision for future dismantlement and site restoration costs of $43 million (2001 - $45 million; 2000 - $37 million).
- Actual site remediation expenditures for the year were $20 million (2001 & 2000 - $24 million). We anticipate actual site remediation expenditures in 2003 to approximate 2002 levels.
- We perform periodic internal and external assessments of our operations and adjust our estimates and annual provision accordingly.
- During 2002, we conducted an external audit of our management system for safety, environment and social responsibility issues. In general, the review was very positive and the few minor recommendations for improvement are being implemented.

Kyoto Protocol

Canada was one of 160 countries that adopted the Kyoto Protocol in December 1997. This international treaty establishes commitments to reduce emissions of greenhouse gases (GHG) that are believed to be responsible for increasing the surface temperatures of the Earth and affecting the global climate. The Protocol obliges approximately 38 countries (the Annex 1 countries) to meet national targets that range from an increase of 10% to a reduction of 8% over a 1990 base. The overall reduction averages 5%, and these commitments are to be met during the “first commitment period” of 2008 to 2012. Canada committed to a 6% reduction over the 1990 base when it signed the Kyoto Protocol in April 1998. Economic modelling studies have shown that if emission reductions are met through domestic action in Annex 1 countries alone, there will be severe negative impacts to these countries’ economies, and in particular those such as Canada whose economies are resource and energy intensive. The US Government’s decision to withdraw from the Kyoto Protocol has serious implications for Canada in the context of a continental or hemispheric energy market, but we expect that the US will develop a response to GHG strategies perhaps using the NAFTA model.

Nexen has been continually assessing, for over 8 years, the impact of climate change developments on our various business interests. We have created a senior management committee (The Climate Change Steering Group) to consider national and international developments; hear from leading experts with respect to science, business and risk issues; and consider investment opportunities. As more details of Canada’s domestic program have become available we have undertaken cost analyses based on several carbon price and policy scenarios. While the government has made concessions respecting price (a cap of $15 per tonne) and volumes (a cap of 55 megatonnes for large industrial emitters), much uncertainty remains for those investing in large, capital-intensive projects. We have recreated a 1990 baseline and track and report our direct and indirect emissions and GHG abatement/management activities via the Voluntary Challenge and Registry (VCR). Our 2001 progress report is now posted on the VCR website and the report shows further progress has been made toward reduction of our CO_2 emissions and energy inputs per unit of production.

Nexen has looked to GHG emission reduction and to offset investments. In 1995, we started capturing, compressing and selling methane gas from our Canadian heavy oil operation instead of venting it to the atmosphere. Last year, we captured about 950,000 tons of carbon dioxide equivalent (1,900,000 tons in total since 1995); as a result, emissions in 2001 from our Canadian operations were essentially the same as they were in 1990, despite growing production volumes.

As a Canadian-based international oil and gas exploration and production company, we have worked closely with the Canadian Clean Development Mechanism/Joint Implementation Office of the Department of Foreign Affairs and International Trade to ensure that Canadian companies get access to low cost/high quality carbon offset investments. We continue to investigate carbon-offset opportunities in each of our core countries in the belief that there may be synergies between our oil and gas activities and carbon investments. Investment opportunities considered to date have included biological sequestration, renewable energy, process efficiency, flare and fugitive emission reduction projects and fuel switching. We have invested in a carbon sequestration project in Belize and a gasified power co-generation facility at our Balzac gas plant. Both investments were expected to deliver significant offsets, but may not provide the anticipated results due to evolving domestic and international policies. We are also an investor in several research and development projects investigating the technical and economic issues associated with geological storage of CO_2, including the use of CO_2 for enhanced coal bed methane recovery.

We continue to evaluate emission reduction and CO_2 offset investment opportunities. However, to date we have received no assurances from the federal or provincial governments that credit will be given for actions already taken to reduce direct emissions (i.e. methane previously vented from casing and tankage) and indirect emissions (i.e. electricity from utilities). Further investment opportunities will be considered against the risk of this evolving policy framework and credit for early action. We continuously review the feasibility of new and ongoing projects with respect to current social, political and economic factors and will continue to take policy and requirements with respect to GHG emissions into account when conducting these feasibility reviews.

We are committed to the principles of full disclosure and will continue to keep our stakeholders apprised of how these issues affect us, when reasonably determinable.

MARKET RISK MANAGEMENT

We are exposed to all of the normal market risks inherent within the oil and gas and chemicals business, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We manage our operations in a manner intended to minimize our exposure, as described in note 6 to the Consolidated Financial Statements, which is incorporated by reference here.

Sensitivities

(Cdn$ millions)	Cash Flow	Net Income
Estimated 2003 impact:		
Crude Oil - US $1.00/bbl change in WTI	67	49
Natural Gas - US $0.50/mcf change	61	38
Foreign Exchange - $0.01 change in US to Cdn Dollar	23	11
Interest Rates - 1% change	3	2

Commodity Price Risk

Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals.

To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by North American supply and demand, and to a lesser extent local market conditions.

Non-Trading Activities

The majority of our production is sold under short-term contracts, exposing us to short-term price movements. The other energy contracts, we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. At times, we actively manage these risks by using commodity futures, forwards, swaps and options.

During 2002 and 2001, we purchased fixed-to-floating swaps to modify the terms of certain fixed-price natural gas contracts as we prefer to receive an index-based price for our natural gas. Under the terms of these contracts, we must deliver four million cubic feet per day of natural gas to counterparties at prices ranging from $3.06 to $6.08 per thousand cubic feet. On settlement, we will receive or pay cash for the difference between the contract and floating rates on the affected volumes. These swaps expire in 2003.

During 2001 and 2000, we purchased put options to establish a floor for the price of crude oil, in order to mitigate the impact of potential crude oil price declines. The put options effectively provided a minimum price per barrel equal to the contract strike price for all hedged volumes if WTI crude oil price averaged less than the strike price for the contract period. The contracts expired unexercised, as WTI did not average less than the strike price during the contract period.

Trading Activities

Our marketing operation is involved in the marketing and trading of crude oil and natural gas, through the use of both physical and financial contracts (energy trading activities). These activities expose us to commodity price risk. Open positions exist where not all contracted purchases and sales have been matched, in order to take advantage of market movements. These net open positions allow us to generate income, but also expose us to risk of loss due to fluctuating market prices (market risk) and credit exposure. We control the level of market risk through daily monitoring of our energy-trading portfolio relative to:

- prescribed limits for Value-at-Risk (VaR);
- nominal size of commodity positions;
- periodic loss; and
- stress testing.

VaR is a statistical estimate that is reliable when normal market conditions prevail. Our VaR calculation estimates the maximum probable loss given a 95% confidence level that we would incur if we were to unwind our outstanding positions over a two-day period. We estimate VaR using the Variance-Covariance method based on historical commodity price volatility and correlation inputs. Our estimate is based upon the following key assumptions:

- changes in commodity prices are normally distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

If a severe market shock was to occur, the key assumptions underlying our VaR estimate could be violated and the potential loss could be greater than our VaR estimate. There were no changes in the methodology we used to estimate VaR in 2002.

Stress testing complements our VaR estimate and measures the potential impact of low probability extreme market shocks on the value of our energy-trading portfolio. Stress test results are used to ensure that we are not exposed to large losses that might result from infrequent but extreme market conditions that are not captured by VaR.

We also have formal risk management policies relating to our energy trading activities that have been approved by our Board of Directors. Market and credit risks are monitored daily by a risk group that operates independently and ensures compliance with our risk management policies. The Finance Committee of the Board of Directors and our Risk Management Committee monitor our exposure to the above risks and review the results of energy trading activities on a regular basis.

Foreign-Currency Rate Risk

A substantial portion of our operations are denominated in or referenced to US dollars. These activities include:

- prices received for sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses related to our oil and gas and chemicals operations outside Canada; and
- short-term and long-term borrowings.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. Since the timing of cash inflows and outflows is not necessarily interrelated, particularly for capital expenditures, we maintain revolving US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We have designated our long-term US-dollar borrowings as a hedge against our US-dollar net investment in foreign operations.

We do not have any material exposure to highly inflationary foreign currencies.

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. Information regarding our foreign currency net investments, borrowings and related derivative instruments is provided in note 6 to the Consolidated Financial Statements.

Interest Rate Risk

We are exposed to fluctuations in short-term interest rates as a result of the use of floating-rate debt and, to a lesser extent, the use of derivative instruments, as their market value is sensitive to interest rate fluctuations. We maintain a portion of our debt capacity in revolving, floating rate bank facilities with the remainder issued in fixed-rate borrowings. To minimize our exposure to interest rate fluctuations, we occasionally use derivative instruments as described in note 6 to the Consolidated Financial Statements.

At December 31, 2002, we had no floating-rate debt outstanding (2001 - $424 million, 2000 - $430 million).

Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or counterparty. A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. This concentration of risk within the energy industry is mitigated through our broad domestic and international customer base. We are also exposed to possible non-performance by derivative instrument counterparties. We take the following measures to reduce this risk:

- we assess the financial strength of our customer and counterparty base through a rigorous credit process;
- we limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- credit risk exposures, including concentrations of credit, are monitored routinely and reported to our Risk Management Committee and the Finance Committee of the Board;
- we set credit limits based on counterparty credit ratings and internal models, which are based primarily on company and industry analysis;
- we review counterparty credit limits regularly; and
- we use standard agreements that allow for netting of positive and negative exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. At December 31, 2002:

- 90% of our counterparty exposures are investment grade; and
- only four customers individually made up greater than 5% of our exposure from energy trading activities. All are investment grade.

CRITICAL ACCOUNTING POLICIES

As an oil and gas producer, there are a number of critical estimates underlying the accounting policies applied in the preparation of our Consolidated Financial Statements. These critical estimates are discussed below.

Oil and Gas Accounting – Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated reserves we believe are recoverable from our oil and gas assets. The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices and cost change. Our reserve estimates are based on current production forecasts, prices and economic conditions. See Business Risk Management for a complete discussion of our reserve estimation process.

Reserve estimates are critical to many of our accounting estimates, including:

- Determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and if not, we expense the costs immediately. In 2002, $189 million of our total $259 million spent on exploration drilling was expensed in the year. If none of our drilling had been successful, our net income would have decreased by $46 million after tax.
- Calculating our unit-of-production depletion and asset retirement obligation rates. Both proved and proved developed reserve[1] estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense and our provision for dismantlement and site restoration. Proved reserves are used where a property is acquired

[1] "Proved" oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation tests. "Proved developed" oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

and proved developed reserves are used where a property is drilled and developed. In 2002, oil and gas depletion and oil and gas dismantlement and site restoration costs of $604 million and $43 million, respectively, were recorded in depletion, depreciation and amortization expense. If our reserve estimates changed by 10%, our depletion, depreciation and amortization expense would have changed by approximately $45 million, after tax, assuming no other changes to our reserve profile.

- Assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserve estimates, are discussed below.

As circumstances change and additional data becomes available, our reserve estimates also change, possibly materially impacting net income. Estimates made by our engineers are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although we make every reasonable effort to ensure that our reserve estimates are accurate, the subjective decisions, new geological or production information and changing environment may impact these estimates. Revisions to our reserve estimates can arise from changes in year end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative. During the past three years, revisions have been less than 10% of our total reserves and have been largely related to price changes. Reserves information is shown in the Supplementary Financial Information set out in Item 8 of this 10-K.

It would take a very significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in Liquidity.

Oil and Gas Accounting - Impairment

We evaluate our oil and gas properties for impairment if an adverse event or change occurs. Among other things, this might include falling oil and gas prices, a significant revision to our reserve estimates, or significant or adverse political changes. If one of these occurs, we estimate undiscounted future cash flows for affected properties to determine if they are impaired. If the undiscounted future cash flows for a property are less than the carrying amount of that property, we calculate its fair value using a discounted cash flow approach. The property is then written down to its fair value. Our cash flow estimates require assumptions about two primary elements - future prices and reserves.

Our estimates of future prices require significant judgements about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility - over the last five years, prices for WTI and NYMEX gas have ranged from US $10.35/bbl to US $37.80/bbl and US $1.61/mmbtu to US $10.10/mmbtu, respectively. Our forecasts for oil and gas revenues are based on a US $23 per barrel WTI and a US $3.50 per mcf gas price. These prices are derived from a consensus of future price forecasts amongst industry analysts. Our estimates of future cash flows generally assume our long-term price forecast and current operating costs per barrel plus an inflation factor. Given the significant assumptions required and the strong possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in this estimate would impact all except our chemicals business.

We review all of our oil and gas properties for indications of impairment. Based on this review, we have tested certain oil and gas properties for impairment over the last two years. In each year, we determined that the sum of the expected future cash flows, undiscounted, was greater than the carrying amount of the properties. As a result, no impairment charges were recognized in net income.

If we decreased our US $23 per barrel long-term forecast for WTI crude oil prices by US $1.00-1.50/bbl at December 31, 2002, our initial assessment of impairment indicators would not change. Furthermore, current crude oil prices would have to fall over US $10 per barrel before our assessment would change. Although oil and gas prices fluctuate a great deal in the short-term, they are typically stable over a longer-time horizon. This mitigates the potential for impairment.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserve estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test, is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment. We do, however, have confidence in our reserve estimates and we do not expect significant downward revisions in the future.

A substantial increase in our estimated impairment provision would lower our net income. We do not expect any significant impairment given that we expense all unsuccessful exploration wells as they are drilled. This leaves us with very little excess carrying value on our balance sheet.

We have discussed the development and selection of the critical accounting estimates described above with the Audit and Conduct Review Committee of our Board of Directors. The above disclosures have also been discussed with this committee.

NEW ACCOUNTING PRONOUNCEMENTS

In December 2001, the Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, "Hedging Relationships" (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied. The guideline is effective for fiscal years beginning on or after July 1, 2003. Adoption of AcG-13 is not expected to have a material impact on our financial position or results of operations.

In September 2002, the CICA approved Section 3063, "Impairment of Long-Lived Assets" (S.3063). S.3063 establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets, and applies to long-lived assets held for use. An impairment loss is recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The new Section is effective for fiscal years beginning on or after April 1, 2003. Adoption of this Section is not expected to have a material impact on our financial position or results of operations.

In December 2002, the CICA approved Section 3110, "Asset Retirement Obligations" (S.3110). S.3110 requires liability recognition for retirement obligations associated with our property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation. S.3110 is effective for fiscal years beginning on or after January 1, 2004. The total impact on our financial statements has not yet been determined.

The following standards and revisions issued by the CICA do not impact us:

- Amendments to S.3025 - "Impaired Loans", effective for asset foreclosures on or after May 1, 2003
- Section 3475 - "Disposal of Long-Lived Assets and Discontinued Operations", effective for disposal activities initiated by commitments to plans on or after May 1, 2003.

In June 2001, the US Financial Accounting Standards Board (FASB) issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 requires liability recognition for retirement obligations associated with our property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation. FAS 143 is effective for all fiscal years beginning after June 15, 2002. The impact of adopting this standard is described in note 16(f) to the Consolidated Financial Statements.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 elaborates on the disclosures we must make about our obligations under certain guarantees that we have issued. It also requires us to recognize, at the inception of a guarantee, a liability for the fair value of the obligations we have undertaken in issuing the guarantee. The initial recognition and initial measurement provisions are to be applied only to guarantees issued or modified after December 31, 2002. Adoption of these provisions will not have a material impact on our financial position or results of operations. The disclosure requirements are effective for annual or interim periods ending after December 15, 2002.

In January 2003, the FASB issued Statement No. 148 "Accounting for Stock-Based Compensation - Transition and Disclosure, an Amendment of FASB Statement No. 123" (FAS 148). FAS 148 amends FAS 123 "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair-value based method of accounting for stock-based employee compensation. In addition, FAS 148 amends the disclosure requirements of FAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. FAS 148 has no material impact on us, as we do not plan to adopt the fair-value method of accounting for stock options at the current time. We have included the required disclosures in note 8 to the Consolidated Financial Statements.

The following standards issued by the FASB do not impact us:

- Statement No. 145 – "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" effective for financial statements issued on or after May 15, 2002;
- Statement No. 146 – "Accounting for Costs Associated with Exit or Disposal Activities" effective for exit or disposal activities initiated after December 31, 2002;
- Statement No. 147 – "Acquisitions of Certain Financial Institutions - an Amendment of FASB Statements No. 72 and 144 and FASB Interpretation No. 9" effective for acquisitions on or after October 1, 2002; and
- Interpretation No. 46 – "Consolidation of Variable Interest Entities" effective for financial statements issued after January 31, 2003.

Item 7(A). Quantitative and Qualitative Disclosures about Market Risk

Please refer to the Business and Marketing Risk Management sections of Item 7 for the required disclosures about Market Risk.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in Items 1 and 2 - Business and Properties and Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements.[1] Forward-looking statements are generally identifiable by terms such as "plan", "expect", "estimate", "budget" or other similar words.

These statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. These risks, uncertainties and other factors include:

- market prices for oil, natural gas and chemicals products;
- our ability to produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions that increase taxes, change environmental and other laws and regulations;
- renegotiations of contracts; and
- political uncertainty, including actions by terrorists, insurgent groups or war.

The above items and their possible impact are discussed more fully in the section, titled "Business Risk Management" and "Market Risk Management" in Item 7.

The impact of any one risk, uncertainty or factors on a particular forward-looking statement is not determinable with certainty as these factors are interdependent and management's future course of action depends upon our assessment of all information available at that time. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future cost recovery oil revenues and our share of production from our operations in Yemen;
- future capital expenditures and their allocation to exploration and development activities;
- future sources of funding for our capital program;
- future debt levels;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of reserves;
- expected finding and development costs;
- expected operating costs;
- future demand for chemicals products;
- future expenditures and future allowances relating to environmental matters; and
- dates by which certain areas will be developed or will come onstream.

We believe that the forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements.

[1] Within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended.

Item 8. Financial Statements and Supplementary Financial Information

REPORT OF MANAGEMENT

To the Shareholders of Nexen Inc.:

We are responsible for the preparation and integrity of all the information contained in the accompanying consolidated financial statements. Fulfilling this responsibility requires the preparation and presentation of our consolidated financial statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US. We have established disclosure controls and procedures, internal controls and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly.

Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all the required regulatory disclosures.

To gather and control financial data, we have established accounting and reporting systems supported by internal controls and an internal audit program. We believe that the existing internal controls provide reasonable assurance that assets are safeguarded against loss from unauthorized use or disposition and that the records are reliable for preparing consolidated financial statements and other financial information. Financial information displayed in other sections of this report has been reviewed to ensure consistency with the consolidated financial statements.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization including a written ethics and integrity policy that applies to all employees including the chief executive officer, chief financial officer and chief accounting officer or controller.

Our Board of Directors approves the consolidated financial statements. Their financial statement related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (the Audit Committee) with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves and from the Finance Committee regarding the assessment and mitigation of risk. The Audit Committee is composed entirely of independent directors, and includes three directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors, and external auditors, to discuss reporting and control issues and ensures each party is properly discharging its responsibilities. The Audit Committee also considers the independence of the external auditors and reviews their fees. The internal and external auditors have access to the Committee without the presence of management.

On June 3, 2002, the Canadian firm of Deloitte & Touche LLP (Deloitte Canada) completed a transaction with the Canadian firm of Arthur Andersen LLP (Andersen Canada) to integrate the partners and staff of Andersen Canada into Deloitte Canada. On July 11, 2002, Deloitte Canada, an independent firm of chartered accountants, was appointed by the Board to audit the consolidated financial statements, and to provide an independent professional opinion thereon.

(signed) "Charles W. Fischer"
President and Chief Executive Officer

(signed) "Marvin F. Romanow"
Executive Vice President,
and Chief Financial Officer

REPORT OF INDEPENDENT AUDITORS

To the Shareholders of Nexen Inc.:

We have audited the consolidated balance sheet of Nexen Inc. as at December 31, 2002 and the consolidated statements of income, cash flows and shareholders' equity for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Nexen Inc. as at December 31, 2002 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements of Nexen Inc. as at December 31, 2001 and for each of the two years in the period ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an opinion without reservation on those consolidated financial statements in their report dated January 23, 2002. As described in Note 1(r), certain amounts in these consolidated financial statements have been reclassified to give effect to a change in generally accepted accounting principles in 2002. We audited the reclassification of amounts described in Note 1(r) that relate to the 2001 and 2000 consolidated financial statements. In our opinion, such reclassification is appropriate and has been properly applied. However, we were not engaged to audit, review or apply any procedures to the 2001 and 2000 consolidated financial statements of Nexen Inc. other than with respect to such reclassification and, accordingly, we do not express an opinion or any other form of assurance on the 2001 and 2000 financial statements taken as a whole.

Calgary, Alberta
January 23, 2003

(signed) "Deloitte & Touche LLP"
Chartered Accountants

THIS REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS IS A COPY OF THE REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP AND HAS NOT BEEN REISSUED.

REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS

To the Shareholders of Nexen Inc.:

We have audited the consolidated balance sheet of Nexen Inc. as at December 31, 2001 and 2000 and the consolidated statements of income, cash flows and shareholders' equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in accordance with generally accepted accounting principles in Canada.

Calgary, Alberta
January 23, 2002

(signed) "Arthur Andersen LLP"
Chartered Accountants

Nexen Inc.
Consolidated Statement of Income
For the Three Years Ended December 31, 2002
Cdn$ millions

	2002	2001	2000
Revenues			
Net Sales	2,606	2,593	2,705
Marketing and Other (Notes 1(r) and 12)	504	475	220
Gain (Loss) on Disposition of Assets	(8)	5	42
	3,102	3,073	2,967
Expenses			
Operating	782	781	687
Transportation and Other (Note 1(r))	469	400	182
General and Administrative	152	136	117
Depreciation, Depletion and Amortization	720	625	667
Exploration	189	265	173
Interest (Note 7)	109	112	132
	2,421	2,319	1,958
Income before Income Taxes	681	754	1,009
Provision for Income Taxes (Note 13)			
Current	223	216	242
Future	6	88	165
	229	304	407
Net Income	452	450	602
Dividends on Preferred Securities, Net of Income Taxes (Note 8)	43	39	37
Net Income Attributable to Common Shareholders	409	411	565
Earnings Per Common Share ($/share)			
Basic (Note 9)	3.34	3.40	4.52
Diluted (Note 9)	3.30	3.36	4.46

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Consolidated Balance Sheet
December 31, 2002 and 2001
Cdn$ millions

	2002	2001
Assets		
Current Assets		
Cash and Short-Term Investments	59	61
Accounts Receivable (Note 3)	988	609
Inventories and Supplies (Note 4)	256	189
Other	26	20
Total Current Assets	1,329	879
Property, Plant and Equipment (Note 5)	4,863	4,170
Goodwill (Note 1)	36	36
Future Income Tax Assets (Note 13)	263	212
Deferred Charges and Other Assets	69	28
	6,560	5,325
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-Term Borrowings (Note 7)	18	51
Accounts Payable and Accrued Liabilities	1,194	773
Accrued Interest Payable	39	22
Dividends Payable	9	9
Total Current Liabilities	1,260	855
Long-Term Debt (Note 7)	1,844	1,484
Future Income Tax Liabilities (Note 13)	873	869
Dismantlement and Site Restoration	191	182
Other Deferred Credits and Liabilities	44	31
Shareholders' Equity (Note 8)		
Preferred Securities	724	724
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2002 - 122,965,830 shares		
2001 - 121,202,444 shares	440	389
Retained Earnings	1,069	697
Cumulative Foreign Currency Translation Adjustment	115	94
Total Shareholders' Equity	2,348	1,904
Commitments and Contingencies (Note 10)		
	6,560	5,325

See accompanying notes to Consolidated Financial Statements.

Approved on behalf of the Board:

(Signed) "Charles W. Fischer"
Director

(Signed) "David A. Hentschel"
Director

Nexen Inc.
Consolidated Statement of Cash Flows
For the Three Years Ended December 31, 2002
Cdn$ millions

	2002	2001	2000
Operating Activities			
Net Income	452	450	602
Charges and Credits to Income not Involving Cash (Note 14)	742	708	794
Exploration Expense	189	265	173
Changes in Non-Cash Working Capital (Note 14)	(46)	143	(243)
Other	(15)	-	3
	1,322	1,566	1,329
Financing Activities			
Proceeds from Long-Term Debt	882	315	2,467
Repayment of Long-Term Debt	(511)	(400)	(2,284)
Proceeds from (Repayment of) Short-Term Borrowings, Net	(33)	(17)	59
Dividends on Preferred Securities	(72)	(70)	(68)
Dividends on Common Shares	(37)	(37)	(37)
Issue of Common Shares	51	39	45
Repurchase of Common Shares (Note 8)	-	-	(605)
Changes in Non-Cash Working Capital (Note 14)	-	-	(2)
Other	(23)	-	(2)
	257	(170)	(427)
Investing Activities			
Capital Expenditures			
Exploration and Development	(1,477)	(1,162)	(822)
Chemicals, Corporate and Other	(144)	(120)	(58)
Proved Property Acquisitions	(4)	(122)	(35)
Acquisition (Note 2)	-	-	(39)
Proceeds on Disposition of Assets	49	5	42
Changes in Non-Cash Working Capital (Note 14)	7	(18)	42
Other	-	(52)	(27)
	(1,569)	(1,469)	(897)
Effect of Exchange Rate Changes on Cash and Short-Term Investments	(12)	24	12
Increase (Decrease) in Cash and Short-Term Investments	(2)	(49)	17
Cash and Short-Term Investments – Beginning of Year	61	110	93
Cash and Short-Term Investments – End of Year	59	61	110

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Consolidated Statement of Shareholders' Equity
For the Three Years Ended December 31, 2002
Cdn$ millions

	Preferred Securities (Note 8)	Common Shares (Note 8)	Contributed Surplus	Retained Earnings	Cumulative Foreign Currency Translation Adjustment
December 31, 1999	724	358	14	666	36
Exercise of Stock Options	-	25	-	-	-
Issue of Common Shares	-	20	-	-	-
Repurchase of Common Shares (Note 8)	-	(53)	(14)	(535)	-
Adoption of Liability Method of Accounting for Income Taxes (Note 13)	-	-	-	(336)	-
Net Income	-	-	-	602	-
Dividends on Preferred Securities, Net of Income Taxes	-	-	-	(37)	-
Dividends on Common Shares	-	-	-	(37)	-
Translation Adjustment, Net of Income Taxes	-	-	-	-	27
December 31, 2000	724	350	-	323	63
Exercise of Stock Options	-	16	-	-	-
Issue of Common Shares	-	23	-	-	-
Net Income	-	-	-	450	-
Dividends on Preferred Securities, Net of Income Taxes	-	-	-	(39)	-
Dividends on Common Shares	-	-	-	(37)	-
Translation Adjustment, Net of Income Taxes	-	-	-	-	31
December 31, 2001	724	389	-	697	94
Exercise of Stock Options	-	27	-	-	-
Issue of Common Shares	-	24	-	-	-
Net Income	-	-	-	452	-
Dividends on Preferred Securities, Net of Income Taxes	-	-	-	(43)	-
Dividends on Common Shares	-	-	-	(37)	-
Translation Adjustment, Net of Income Taxes	-	-	-	-	21
December 31, 2002	724	440	-	1,069	115

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Notes to Consolidated Financial Statements
Cdn$ millions except as noted

1. ACCOUNTING POLICIES
The Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and US GAAP on the Consolidated Financial Statements is disclosed in Note 16. Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Actual results can differ from those estimates.

(a) Principles of Consolidation
The Consolidated Financial Statements include the accounts of Nexen Inc. and our subsidiary companies and partnerships in which we have a controlling interest (Nexen, we or our). All subsidiary companies and, effective April 18, 2000 all partnerships, are wholly owned. All material intercompany accounts and transactions have been eliminated. Substantially all exploration, development and production activities related to our oil and gas business and the Syncrude Joint Venture (Syncrude) are conducted jointly with others and our accounts reflect only Nexen's proportionate interest.

(b) Accounts Receivable
Accounts receivable are recorded based on our revenue recognition policy (see Note 1(i)). Our allowance for doubtful accounts provides for specific doubtful receivables.

(c) Inventories and Supplies
Inventories and supplies for our oil and gas and chemicals segments are stated at the lower of cost or market value. Cost is determined on the first-in first-out method or average basis.

After October 25, 2002, inventories held by our marketing operation are accounted for at the lower of cost or market value determined on an average basis. Prior to that these inventories were accounted for on a mark-to-market basis. On October 25, 2002, generally accepted accounting principles followed by energy traders eliminated mark-to-market accounting for inventories (see Note 1(r)).

(d) Property, Plant and Equipment
Property, plant and equipment is recorded at cost. Improvements that increase capacity or extend the useful lives of the related assets are capitalized. Major maintenance or turnaround costs are expensed as incurred.

We follow successful efforts accounting for our oil and gas business. Under this method, we capitalize the costs of resource property acquisitions, exploratory drilling and all development. The cost of exploratory wells that are dry and all other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to earnings.

We periodically evaluate our property, plant and equipment for impairment. If an adverse event or change indicates possible impairment, we estimate the undiscounted future cash flow for the related property. If the total undiscounted future cash flow is less than the carrying amount of the property, we calculate the fair value of the property using a discounted cash flow approach and write down the property to that amount. The cash flow estimates require assumptions about future commodity prices, operating costs and other factors. Actual results can differ from those estimates.

(e) Depreciation, Depletion and Amortization (DD&A)
Under successful efforts accounting, oil and gas costs are depleted using the unit-of-production method. Development costs are depleted over remaining proved developed reserves and acquisition costs over proved reserves. Other plant and equipment costs are depreciated using the straight-line method based on the estimated useful lives of the assets, which range from 3 years to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

(f) Dismantlement and Site Restoration
We provide for dismantlement and site restoration costs on our resource properties, facilities, production platforms and pipelines and our chemicals facilities. We estimate the total future dismantlement and site restoration costs required to comply with current legislation and industry practices. We then provide for those costs annually based on proved reserves or estimated remaining asset lives. The annual provision is included in depreciation, depletion and amortization. Expenditures are charged against the provision as incurred.

(g) Goodwill

On January 1, 2002, we adopted the new recommendations of the Canadian Institute of Chartered Accountants (CICA). Under the new standard, goodwill and intangible assets with an indefinite useful life are no longer amortized, but are tested for impairment at least annually based on estimated future cash flows. No goodwill impairment writedowns were required during the year. Our unamortized goodwill at January 1, 2002 was $36 million. The following shows the adjusted net income and earnings per common share had the new standard been applied in 2001 and 2000:

	2002	2001	2000
Net Income Attributable to Common Shareholders			
As Reported	409	411	565
Add: Goodwill Amortization	-	6	5
Adjusted	409	417	570
Earnings Per Common Share ($/share)			
Basic as Reported	3.34	3.40	4.52
Adjusted	3.34	3.46	4.56
Diluted as Reported	3.30	3.36	4.46
Adjusted	3.30	3.42	4.50

(h) Carried Interest

According to our Masila Block agreement in Yemen (the Agreement), production generated from the Masila Block (the Project) is shared between the Government of Yemen (the Government), Nexen and the other Project participants. Production is divided into cost recovery oil and profit oil.

Cost recovery oil provides for the recovery of operating, exploration and development costs, based on a formula, and is limited to a maximum of 40% of production during each fiscal year. Nexen and the other participants fund the Government's share of exploration and development costs. Cost recovery oil received by us is recorded as revenue, and includes a carried interest component which allows us to recover the Government's share of exploration and development costs we have incurred. Costs not recovered in the year may be recovered in future years, and are included in property, plant and equipment. Recoveries of capitalized carried costs are shown as depreciation or depletion expense.

Profit oil is the production remaining after deducting cost recovery oil. Profit oil is shared by the Government and the Project participants on a sliding scale based on production rates, and is accounted for using successful efforts accounting. The Government's portion of profit oil includes an amount for Nexen's income taxes payable under the laws of Yemen.

(i) Revenue Recognition

Crude Oil, Natural Gas and Chemicals

Revenue is recognized when title passes to the customer. When we produce or sell crude oil and natural gas above or below our working interest, production overlifts and underlifts occur. Overlifts are recorded as liabilities, and underlifts are recorded as assets. We settle these over time as liftings are equalized, or in cash when production ceases.

Marketing

Financial and physical commodity contracts (collectively derivative instruments) held by our marketing operation are marked-to-market. Under mark-to-market accounting, these contracts are recorded at fair value at the balance sheet date. We record the net gain or loss on these contracts in marketing and other. Prior to October 25, 2002 non-derivative instruments, including transportation contracts, were also marked-to-market. As of October 25, 2002, costs relating to these instruments are expensed as incurred. These costs are now recorded in transportation and other (see Note 1(r)).

(j) Income Taxes

Effective January 1, 2000, we began following the liability method of accounting for income taxes (see Note 13). This method recognizes income tax assets and liabilities at enacted rates, based on differences between financial statement reporting and tax amounts. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income in the period that the change occurs.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, since we intend to invest such earnings indefinitely in foreign operations.

(k) Petroleum Resource Rent Tax

Petroleum Resource Rent Tax with respect to our Australian oil and gas operations is accounted for on the liability basis with a future liability or asset recognized on temporary differences at the current enacted rate. Temporary differences mainly relate to depletion, dismantlement and site restoration. We treat the related cost as a royalty and deduct it from sales.

(l) Foreign Currency Translation

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars as follows:

- assets and liabilities using exchange rates at the balance sheet dates; and
- revenues and expenses using the average exchange rates throughout the year.

Gains and losses resulting from this translation are included in the cumulative foreign currency translation adjustment in shareholders' equity.

Monetary balances denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from translation, except on our US-dollar debt, are included in income. We have designated our US-dollar debt as a hedge against our net investment in US-dollar based self-sustaining foreign operations. Gains and losses resulting from the translation of the US-dollar debt, to the extent they do not exceed our investment in foreign operations, are included in the cumulative foreign currency translation adjustment in shareholders' equity.

(m) Capitalized Interest

We capitalize interest on qualifying assets until they are put into service, using the weighted-average interest rate on all our borrowings.

(n) Derivative Instruments

Non-Trading Activities

We use derivative instruments for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates, as described in Note 6. Hedge accounting is used when there is a high degree of correlation between price movements in the derivative instrument and the item designated as being hedged. We recognize gains and losses in the same period as the hedged item. If correlation ceases, hedge accounting is terminated and future changes in the market value of the derivative instruments are recognized as gains or losses in the period of change.

Trading Activities

Our marketing operation uses derivative instruments for marketing and trading crude oil and natural gas. Derivative instruments used include:

- exchange-traded futures and options;
- non-exchange traded forwards, swaps and options; and
- commodity contracts settled with physical delivery.

We account for these instruments using mark-to-market accounting, and record the net gain or loss in marketing and other. The fair value of these instruments is recorded as accounts receivable or payable. They are classified as long term or short term based on their anticipated settlement date.

(o) Employee Benefits

The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and management's best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses which exceed 10% of the greater of the benefit obligation and the fair value of plan assets, are amortized on a straight-line basis over the expected average remaining service life of the employee group.

(p) Stock-Based Compensation

We use the intrinsic value based method of accounting for stock options. Under this method, no compensation expense has been recognized for stock options granted to employees and directors. On January 1, 2002, we adopted the new CICA recommendations. The new standard requires companies that do not recognize the compensation expense determined under the fair-value based method to make pro forma disclosures of net income and earnings per common share as if that method of accounting had been applied (see Note 8).

We provide stock appreciation rights to employees as described in Note 8. Obligations are accrued as compensation expense over the vesting period of the stock appreciation rights.

(q) Cash and Short-Term Investments

Cash and short-term investments are instruments that mature within three months of their purchase.

(r) Changes in Accounting Policies – Marketing Activities

Mark-to-Market

On October 25, 2002, regulators changed accounting principles, eliminating mark-to-market accounting for our marketing inventories and our non-derivative energy contracts. Under the new principles:

- we measure marketing inventories at the lower of cost or market; and
- we record non-derivative energy contracts, including our transportation and storage capacity contracts, at cost as incurred.

We recorded the change to inventory prospectively as the effects on previous periods cannot be determined. Inventories at October 25, 2002 have been attributed a cost based on their market value on that date. Inventories purchased after October 25, 2002 are recorded at cost. We removed the mark-to-market on our transportation contracts from earnings retroactively to the beginning of the year. The impact on previous years is immaterial. Under the previous method, our results would have been:

	2002
Net Income Attributable to Common Shareholders	
As Reported	409
Mark-to-Market on inventory and transportation, net of income taxes	4
Adjusted	413
Earnings per Common Share ($/share)	
Basic as Reported	3.34
Adjusted	3.37
Diluted as Reported	3.30
Adjusted	3.34

Presentation of Transportation

During the year, we adopted the new interpretation of the Emerging Issues Committee relating to the presentation of costs for which we are reimbursed. We pay for the transportation of the crude oil, natural gas and chemicals products that we market, and then bill our customers for the transportation. Under the new interpretation, this transportation should be presented as a cost to us. Previously, we netted this cost against our revenue. Effective October 1, 2002, we show these costs as transportation and other on the consolidated statement of income, resulting in the following increases:

	2002	2001	2000
Net Sales	35	32	31
Marketing and Other	423	342	131
Transportation and Other	458	374	162

2. ACQUISITION

Effective July 31, 2000, our marketing business acquired Northridge Energy Marketing Ltd. for cash consideration of $39 million. We used the purchase method to account for the acquisition and included the results in our financial statements from the acquisition date. The purchase consisted of the following:

Current Assets	172
Current Liabilities	(155)
Goodwill	13
Property, Plant and Equipment	9
	39

3. ACCOUNTS RECEIVABLE

	2002	2001
Trade		
Oil and Gas		
Marketing	574	305
Other	330	220
Chemicals and Other	59	57
	963	582
Non-Trade	34	36
	997	618
Allowance for Doubtful Accounts	(9)	(9)
	988	609

4. INVENTORIES AND SUPPLIES

	2002	2001
Finished Products		
Oil and Gas		
Marketing	130	56
Other	-	15
Chemicals and Other	13	15
	143	86
Work in Process	6	6
Field Supplies	107	97
	256	189

5. PROPERTY, PLANT AND EQUIPMENT

	2002			2001		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Yemen	2,054	1,646	408	1,839	1,491	348
Canada	3,098	1,137	1,961	2,867	913	1,954
United States	2,186	959	1,227	1,636	848	788
Australia	209	184	25	167	144	23
Other Countries	305	198	107	271	166	105
Marketing	86	40	46	89	32	57
	7,938	4,164	3,774	6,869	3,594	3,275
Syncrude	628	139	489	487	127	360
Chemicals	789	345	444	744	296	448
Corporate and Other	213	57	156	137	50	87
	9,568	4,705	4,863	8,237	4,067	4,170

The above table includes capitalized costs of $585 million (2001 - $251 million) relating to unproved properties and projects under construction or development. These costs are not being depreciated, depleted or amortized.

6. DERIVATIVE INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The nature of our operations and long-term debt expose us to fluctuations in commodity prices, foreign-currency exchange rates, interest rates and credit risk. We recognize these risks and manage our operations to minimize our exposure to the extent practical and, to a lesser extent, using derivative instruments. Our marketing operation uses derivative instruments to manage its exposure to commodity price fluctuations and for trading purposes. We use exchange-traded futures and options and non-exchange traded forwards, swaps and options, which may be settled in cash or by delivery of the physical commodity. The Finance Committee of the Board of Directors and our Risk Management Committee monitor our exposure to the above risks and regularly review our derivative activities and all outstanding positions.

(a) Commodity price risk management

Non-Trading Activities

We generally sell our crude oil and natural gas under short-term market based contracts. During 2001 and 2000, we purchased put options to establish a minimum price for our crude oil to mitigate the impact of any price declines. This minimum price per barrel equaled the contract strike price for all hedged volumes if the West Texas Intermediate crude oil price (WTI) averaged less than the strike price for the contract period. In 2001, we paid a US $13 million premium for the put options. The contracts expired unexercised in 2002, as WTI did not average less than the strike price during the contract period.

During 2002 and 2001, we purchased fixed-to-floating swaps to modify the terms of certain fixed-price natural gas contracts as we prefer to receive an index-based price for our natural gas. Under the terms of these contracts, we must deliver 4 million cubic feet per day of natural gas to counterparties at prices ranging from $3.06 to $6.08 per thousand cubic feet. On settlement, we either pay or receive cash for the difference between the contract and floating rates. These swaps expire in 2003.

Trading Activities

Our marketing operation engages in crude oil and natural gas marketing activities to enhance prices from the sale of our own oil and gas production, and for energy trading. We enter into contracts to purchase and sell crude oil and natural gas. These contracts expose us to commodity price risk between the time contracted volumes are purchased and sold. We actively manage this risk by using energy-related futures, forwards, swaps and options, and by balancing physical and financial contracts in terms of volumes, timing of performance and delivery obligations. However, net open positions may exist, or we may establish them to take advantage of market conditions.

Open positions enable our marketing operation to generate income based on competitive information from marketing activities, but also expose us to risks of loss from fluctuating market prices. Our exposure is restricted to prescribed limits and is monitored daily using value-at-risk, stress testing and scenario analysis. The value-at-risk calculation estimates the maximum probable loss, given a 95% confidence level, that we would incur if our open positions were unwound over two days. Our net margin from trading activities is as follows:

	2002	2001	2000
Net Revenue	496	438	179
Less: Transportation	423	342	131
	73	96	48
Value-at-Risk			
Year End	19	19	13
Average	17	13	4

(b) Foreign currency exchange rate risk management

A substantial portion of our activities are transacted in or referenced to US dollars. These activities include:

- prices received for sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses related to our oil and gas and chemicals operations outside Canada; and
- short-term and long-term borrowings.

We manage our exposure to fluctuations between the US and Canadian dollars by minimizing the need to convert between the two currencies. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. Our US-dollar debt has been designated as a hedge against our net investment in foreign operations. The foreign exchange gains or losses realized on this debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. Our net investment in foreign operations and our US-dollar long-term debt at December 31 are as follows:

(US$ millions)	2002	2001
Net Investment in Foreign Operations	1,389	887
Long-Term Debt	962	728

We do not have any material exposure to highly inflationary foreign currencies.

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. At December 31, 2002, we held a foreign currency derivative instrument that obligates us and the counterparty to exchange principal and interest amounts. In November 2006, we will pay US $37 million and receive Cdn $50 million (see Note 7).

(c) Interest rate risk management

We use fixed and floating rate debt to finance our operations. The floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings. At December 31, 2002, fixed-rate borrowings comprised 100% (2001 – 69%) of our long-term debt at an effective average rate of 7.4% (2001 - 7.0%). During the year we periodically drew on our unsecured syndicated term credit facilities. We had no interest rate swaps outstanding in 2002 or 2001.

(d) Credit risk management

A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international customers. We are also exposed to possible non-performance by derivative instrument counterparties. We assess the financial strength of our customer and counterparty base, including those involved in marketing and other commodity arrangements and we limit the total exposure to individual counterparties. As well, a number of our contracts contain provisions that allow us to demand the posting of collateral in the event downgrades to non-investment grade occur. Credit risk, including credit concentrations are routinely reported to our Risk Management Committee. We also use standard agreements that net positive and negative exposures of a single counterparty. We believe this minimizes our overall credit risk.

(e) Carrying value and estimated fair value of derivative instruments

Assets/(Liabilities)	2002			2001		
	Carrying Value	Fair Value	Unrealized Gain/(Loss)	Carrying Value	Fair Value	Unrealized Gain/(Loss)
Long-Term Debt	(1,844)	(1,948)	(104)	(1,484)	(1,465)	19
Currency Swap	-	(3)	(3)	-	-	-
Preferred Securities	(724)	(756)	(32)	(724)	(769)	(45)
Crude Oil Put Options	-	-	-	2	-	(2)
Natural Gas Swaps	-	2	2	-	(7)	(7)

The estimated fair value of all derivative instruments is based on quoted market prices and if not available, on estimates from third-party brokers or dealers or amounts derived from valuation models. The carrying value of cash and short-term investments, amounts receivable and short-term obligations approximates their fair value because the instruments are near maturity. Amounts receivable and payable by our marketing operations related to derivative instruments are equal to fair value as we use the mark-to-market method to value them. Amounts related to derivative instruments included in deferred charges and other assets and other deferred credits and liabilities are $14 million and $7 million, respectively. These derivative instruments are held by our marketing operation and settle beyond 2003.

7. LONG-TERM DEBT AND SHORT-TERM BORROWINGS

	2002	2001
Unsecured Syndicated Term Credit Facilities (a)	-	424
Unsecured Redeemable Notes, due 2004 (b)	355	358
Unsecured Redeemable Debentures, due 2006 (c)	108	109
Unsecured Redeemable Medium Term Notes, due 2007 (d)	150	150
Unsecured Redeemable Medium Term Notes, due 2008 (e)	125	125
Unsecured Redeemable Notes, due 2028 (f)	316	318
Unsecured Redeemable Notes, due 2032 (g)	790	-
	1,844	1,484

(a) Unsecured syndicated term credit facilities
Nexen has committed unsecured revolving term credit facilities totalling $1,576 million available for 5 years, and each lender has the option to extend them on an annual basis. No repayments are required until the end of the availability period. Borrowings are available in the form of Canadian bankers' acceptances, LIBOR-based loans, Canadian prime loans or US-dollar base rate loans. Interest is payable monthly at a floating rate. During 2002, the weighted average interest rate was 2.5% (2001 – 6.0%).

(b) Unsecured redeemable notes, due 2004
During February 1999, we issued US $225 million of notes. Interest is payable semi-annually at a rate of 7.125%, and the principal is to be repaid in February 2004. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes.

(c) Unsecured redeemable debentures, due 2006
During November 1996, we issued $100 million of unsecured 10-year redeemable debentures. Interest is payable semi-annually at a rate of 6.85% and the principal is to be repaid in November 2006. In December 1996, $50 million of this obligation was effectively converted through a currency exchange contract with a Canadian chartered bank to a US $37 million liability bearing interest at 6.75% for the term of the debentures. We may redeem part or all of the debentures at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the debentures plus 0.1%.

(d) Unsecured redeemable medium term notes, due 2007
During July 1997, we issued $150 million of notes. Interest is payable semi-annually at a rate of 6.45% and the principal is to be repaid in July 2007. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

(e) Unsecured redeemable medium term notes, due 2008

During October 1997, we issued $125 million of notes. Interest is payable semi-annually at a rate of 6.3% and the principal is to be repaid in June 2008. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

(f) Unsecured redeemable notes, due 2028

During April 1998, we issued US $200 million of notes. Interest is payable semi-annually at a rate of 7.4% and the principal is to be repaid in May 2028. We may redeem part or all of the notes any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.25%.

(g) Unsecured redeemable notes, due 2032

During March 2002, we issued US $500 million of notes. Interest is payable semi-annually at a rate of 7.875% and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.375%. Included in deferred charges and other assets is a debt discount of US $14 million.

(h) Debt repayments

2003	-
2004	355
2005	-
2006	108
2007	150
Thereafter	1,231
	1,844

(i) Debt covenants

The majority of our debt instruments contain covenants regarding certain financial ratios and our ability to grant security. At December 31, 2002, we were in compliance with all covenants.

(j) Short-term borrowings

Nexen has unsecured operating loan facilities of approximately $301 million. Interest is payable at floating rates and the facilities are subject to periodic reviews. During 2002, the weighted average interest rate on short-term borrowings was 2.3% (2001 - 5.5%).

Occasionally we sell the future proceeds of our accounts receivable; however, we retain a 10% exposure to related credit losses. At December 31, 2002, we sold $178 million (2001 - $100 million) of accounts receivable. The retained credit exposure of $18 million (2001 - $10 million) is included in short-term borrowings.

(k) Interest expense

	2002	**2001**	**2000**
Long-Term Debt	134	106	125
Other	6	6	7
Total	140	112	132
Less: Capitalized	31	-	-
	109	112	132

Capitalized interest relates to and is included as part of the cost of oil and gas properties. The capitalization rates are based on our weighted-average cost of borrowings.

8. SHAREHOLDERS' EQUITY

(a) Preferred Securities

	Principal Amount	Interest Rate	Maturity Date	Call Date
	(US$ millions)	(%)		
Preferred Securities	259	9.75	October 30, 2047	October 30, 2003
Preferred Securities	217	9.375	March 31, 2048	February 9, 2004

Nexen may redeem part or all of the preferred securities on or after their redemption or call date. We may defer, subject to certain conditions, up to 20 consecutive quarterly interest payments and may satisfy our interest, principal or redemption payments by issuing common shares. Interest is payable quarterly.

Since we have the unrestricted ability to settle the interest, principal and redemption payments by issuing common shares, the preferred securities are classified as equity. We record the principal amount in shareholders' equity and interest payments, net of income taxes, are classified as dividends and charged directly to retained earnings.

(b) Authorized Capital

Authorized share capital consists of an unlimited number of common shares of no par value, and an unlimited number of Class A preferred shares of no par value, issuable in series.

(c) Issued common shares and dividends

(thousands of shares)	**2002**	**2001**	**2000**
Beginning of Year	121,202	119,855	138,145
Issue of Common Shares for Cash:			
Exercise of Stock Options	1,090	648	1,129
Dividend Reinvestment Plan	500	533	433
Employee Flow-through Shares	174	166	148
Repurchase of Common Shares	-	-	(20,000)
End of Year	122,966	121,202	119,855
Dividends per Common Share ($/share)	0.30	0.30	0.30
Cash Consideration (Cdn$ millions)			
Exercise of Stock Options	27	16	25
Dividend Reinvestment Plan	17	17	14
Employee Flow-through Shares	7	6	6
	51	39	45

At December 31, 2002, there were 1,783,968 (2001 – 489,329; 2000 – 1,022,545) common shares reserved for issuance under the Dividend Reinvestment Plan.

In March 2000, Nexen, Ontario Teachers' Pension Plan Board (Teachers) and Occidental Petroleum Corporation (Occidental) entered into an agreement where Occidental would sell its 29% interest in Nexen. The agreement was approved by a majority of Nexen shareholders other than Occidental and Teachers at a meeting of shareholders on April 17, 2000. Under the agreement, Teachers purchased 20.2 million of Nexen's common shares. Nexen repurchased 20 million common shares for $605 million, including associated fees. When repurchased, the common shares were cancelled.

(d) Stock Options Granted, Exercised and Forfeited

We have granted options to purchase common shares to directors, officers and employees. Each option permits the holder to purchase one common share of Nexen at the stated exercise price. Options granted prior to February 2001 vest over 4 years and are exercisable on a cumulative basis over 10 years. Options granted after February 2001 vest over 3 years and are exercisable on a cumulative basis over 5 years. At the time of grant, the exercise price is equal to the market price. The following options have been granted:

	Options	Weighted-Average Exercise Price
	(thousands)	($/option)
December 31, 1999	6,206	24
Granted	3,016	36
Exercised	(1,129)	22
Forfeited	(117)	25
December 31, 2000	7,976	29
Granted	1,645	31
Exercised	(648)	24
Forfeited	(142)	30
December 31, 2001	8,831	30
Granted	1,788	31
Exercised	(1,090)	25
Forfeited	(53)	30
December 31, 2002	9,476	30
Options exercisable at December 31		
2000	2,741	24
2001	4,232	27
2002	5,113	29

Common shares reserved for issuance under the stock option plan were 9,759,545 at December 31, 2002 (2001 - 10,896,060; 2000 – 8,044,680).

(e) Exercise Price Range

	Outstanding Options			**Exercisable Options**	
	Number of Options	Weighted-Average Exercise Price	Weighted-Average Years to Expiry	Number of Options	Weighted-Average Exercise Price
	(thousands)	($/option)	(years)	(thousands)	($/option)
$12.13 to $19.99	823	18	5	820	18
$20.00 to $24.99	272	23	4	272	23
$25.00 to $29.99	2,126	28	6	1,787	28
$30.00 to $34.99	3,474	33	4	624	31
$35.00 to $40.35	2,781	36	8	1,610	36
	9,476			5,113	

(f) Estimated Fair-Value of Stock Options

We determine the estimated fair value of stock options issued using the Generalized Black-Scholes model under the following assumptions:

	2002	**2001**	**2000**
Weighted-Average Fair Value ($/option)	9.08	12.24	13.06
Risk-Free Interest Rate (%)	3.6	5.1	5.8
Estimated Hold Period Prior to Exercise (years)	3	5	5
Volatility in the Price of Nexen's Common Shares (%)	35	40	34
Dividends per Common Share ($/share)	0.30	0.30	0.30

(g) Pro Forma Net Income – Fair-Value Based Method of Accounting for Stock Options

The following shows pro forma net income and earnings per common share had we applied the fair-value based method of accounting to all stock options outstanding.

	2002	2001	2000
Net Income Attributable to Common Shareholders			
As Reported	409	411	565
Less: Fair Value of Stock Options	22	25	14
Pro Forma	387	386	551
Earnings Per Common Share ($/share)			
Basic as Reported	3.34	3.40	4.52
Pro Forma	3.16	3.20	4.41
Diluted as Reported	3.30	3.36	4.46
Pro Forma	3.13	3.16	4.35

(h) Stock Appreciation Rights

We established a stock appreciation rights plan in 2001. Under this plan, employees are entitled to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. The vesting period and other terms of the plan are similar to the stock option plan. The total rights granted and outstanding at any time cannot exceed 10% of Nexen's total outstanding common shares.

(millions of rights)	2002	2001
Rights Granted	0.9	0.9
Rights Outstanding	1.8	0.9
Weighted Average Exercise Price ($/right)	33.94	31.17
Rights Expensed ($ millions)	2	-

9. EARNINGS PER COMMON SHARE

We calculate earnings per common share using Net Income Attributable to Common Shareholders and the weighted average number of common shares outstanding. We calculate diluted earnings per common share using Net Income Attributable to Common Shareholders and the weighted-average number of diluted common shares outstanding.

(millions of shares)	2002	2001	2000
Weighted-average number of common shares outstanding	122.4	120.7	125.0
Shares issuable pursuant to stock options	8.1	4.7	5.5
Shares to be purchased from proceeds of stock options	(6.7)	(3.3)	(3.7)
Weighted-average number of diluted common shares outstanding	123.8	122.1	126.8

In calculating diluted earnings per common share for the year ended December 31, 2002, we excluded 46,167 options (2001 - 2,992,903; 2000 - 42,000), because the exercise price was greater than the average market price of our common shares in those periods. During these three years, outstanding stock options were the only dilutive instrument.

10. COMMITMENTS AND CONTINGENCIES

	2003	2004	2005	2006	2007	Thereafter
Operating leases	50	39	34	18	16	100
Transportation commitments	180	40	32	32	31	113
	230	79	66	50	47	213

In November 2000, we committed to enter into a lease agreement when construction of a natural-gas-fired generating facility in Alberta was completed. On June 28, 2002, we exercised our option to buy out the lease for $67 million, which was the cost of construction plus interest on advances during the construction phase. We included this amount in capital expenditures for the year ended December 31, 2002.

There are a number of lawsuits and claims pending including income tax reassessments as described in Note 13, the ultimate results of which cannot be ascertained at this time. We record costs as they are incurred or become determinable. Management believes the resolution of these matters would not have a material adverse effect upon our consolidated financial position or results of operations.

11. PENSION AND OTHER POST RETIREMENT BENEFITS

Nexen has contributory and non-contributory defined benefit and defined contribution pension plans, which together cover substantially all employees. Syncrude has a defined benefit plan for its employees, and all of the Syncrude information in this note is Nexen's proportionate interest. Under these plans, we provide benefits to retirees based on their length of service and final average earnings.

(a) Defined Benefit Pension Plans

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund this plan according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds.

	2002		2001	
Change in Benefit Obligation	Nexen	Syncrude	Nexen	Syncrude
Beginning of Year	163	63	131	54
Service Cost	7	3	5	2
Interest Cost	10	4	9	4
Plan Participants' Contributions	2	-	2	-
Actuarial Loss/(Gain)	(11)	-	18	5
Benefits Paid	(7)	(2)	(6)	(2)
Plan Amendment	-	-	4	-
End of Year	164	68	163	63
Change in Fair Value of Plan Assets				
Beginning of Year	136	41	148	43
Actual Return on Plan Assets	(7)	(3)	(12)	(2)
Employer's Contribution	3	1	4	2
Plan Participants' Contributions	2	-	2	-
Benefits Paid	(7)	(2)	(6)	(2)
End of Year	127	37	136	41
Reconciliation of Funded Status				
Funded Status [1]	(37)	(31)	(27)	(22)
Unamortized Transitional Obligation	1	-	2	-
Unamortized Prior Service Costs	6	1	6	1
Unamortized Net Actuarial Loss	19	23	13	17
Pension Liability	(11)	(7)	(6)	(4)
Assumptions (%)				
Discount Rate	6.75	6.50	6.25	6.50
Long-Term Rate of Employee Compensation Increase	4.00	4.00	4.00	4.00
Long-Term Annual Rate of Return on Plan Assets	7.00	9.00	7.00	9.00

Note:
[1] Included in the above amounts are unfunded obligations for supplemental benefits to the extent that the benefit under the defined benefit pension plan is limited by statutory guidelines. At December 31, 2002, the projected benefit obligation for supplemental benefits was $26 million (2001 - $25 million).

Net Pension Expense Under Our Defined Benefit Pension Plans

	2002	2001	2000
Nexen			
Cost of Benefits Earned by Employees	7	5	5
Interest Cost on Benefits Earned	10	9	9
Expected Return on Plan Assets	(10)	(10)	(9)
Net Amortization and Deferral	1	-	-
Net	8	4	5
Syncrude			
Cost of Benefits Earned by Employees	3	2	2
Interest Cost on Benefits Earned	4	4	3
Expected Return on Pension Plan Assets	(4)	(4)	(4)
Net Amortization and Deferral	1	-	-
Net	4	2	1
Total	12	6	6

(b) Defined Contribution Pension Plans

Under these plans, pension benefits are based on plan contributions. During 2002, Canadian pension expense for these plans was $3 million (2001 - $3 million; 2000 - $2 million). During 2002, US pension expense for these plans was $3 million (2001 – $3 million; 2000 - $2 million).

(c) Post-Retirement Benefits

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. These costs are fully accrued as compensation in the period employees work; however, these future obligations are not funded.

12. MARKETING AND OTHER

	2002	2001	2000
Marketing Net Revenue (including Transportation)	496	438	179
Interest	7	17	21
Foreign Exchange Gains (Losses)	(3)	-	3
Other	4	20	17
	504	475	220

13. INCOME TAXES

(a) Change in Accounting Policy

Effective January 1, 2000, we adopted the CICA's new recommendations on accounting for income taxes and applied it retroactively without restating prior periods. The new recommendations use the liability method. The change in accounting policy increased (decreased) the following items on the Consolidated Financial Statements as at January 1, 2000:

Future Income Tax Assets	450
Future Income Tax Liabilities	786
Retained Earnings	(336)

Retained earnings decreased because of the future income tax cost of the Wascana Energy Inc. (Wascana) acquisition in 1997, in which the acquired tax basis was less than the purchase price.

(b) Temporary Differences

	2002		2001	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Property, Plant and Equipment, Net	23	704	111	721
Tax Losses Carried Forward	226	-	34	-
Deferred Income	-	177	-	139
Foreign Exchange	-	-	1	3
Recoverable Taxes	14	-	101	-
Other	-	(8)	9	6
	263	873	256	869
Valuation Allowance [1]	-	-	(44)	-
	263	873	212	869

Note:
[1] The future income tax asset valuation allowance related to foreign tax credits being carried forward.

(c) Canadian and Foreign Income Taxes

	2002	2001	2000
Income before Income Taxes			
Canadian	140	225	240
Foreign	541	529	769
	681	754	1,009
Provision for Income Taxes			
Current			
Canadian	4	6	7
Foreign	219	210	235
	223	216	242
Future			
Canadian	38	81	119
Foreign	(32)	7	46
	6	88	165

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to Yemen, the United States and Australia, and included Yemen cash taxes of $207 million (2001 - $191 million; 2000 - $217 million).

(d) Reconciliation of Effective Tax Rate to the Canadian Federal Tax Rate

	2002	2001	2000
Income before Income Taxes	681	754	1,009
Provision for Income Taxes Computed at the Canadian Statutory Rate	269	317	449
Add (Deduct) the Tax Effect of:			
Royalties and Rentals to Provincial Governments	57	66	79
Resource Allowance and Provincial Tax Rebates	(67)	(68)	(81)
Lower Tax Rates on Foreign Operations	(37)	(15)	(45)
Additional Canadian Tax on Canadian Resource Income	8	2	-
Federal and Provincial Capital Tax	4	5	6
Other	(5)	(3)	(1)
Provision for Income Taxes	229	304	407

During 2002 and 2001, the federal and some provincial governments in Canada reduced statutory income tax rates. This reduced our liability and provision for future income taxes by $1 million (2001 - $5 million). The federal rate reduction does not apply to our earnings from Canadian resource properties.

(e) Available Unused Tax Losses and Tax Contingencies

At December 31, 2002, we had unused tax losses totalling $534 million (2001 - $71 million) of which the majority relate to our US operations.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some that may increase our tax liability. In addition, we have filed Notices of Objection with respect to certain issues. While the results of these items cannot be ascertained at this time, management believes there is adequate provision for income taxes based on available information.

At the time of acquisition, Wascana had outstanding taxation issues in dispute from prior taxation years. Wascana disagreed with issues raised and has filed Notices of Objection. The value of the tax pools acquired at the time of acquisition reflected management's evaluation of the potential impact of these issues.

14. CASH FLOWS

(a) Charges and credits to income not involving cash

	2002	2001	2000
Depreciation, Depletion and Amortization	720	625	667
Loss (Gain) on Disposition of Assets	8	(5)	(42)
Future Income Taxes	6	88	165
Other	8	-	4
	742	708	794

(b) Changes in non-cash working capital

	2002	2001	2000
Operating Activities			
Accounts Receivable	(388)	471	(521)
Inventories and Supplies	(73)	73	(120)
Other Current Assets	(6)	(5)	3
Accounts Payable and Accrued Liabilities	407	(399)	390
Accrued Interest Payable	17	1	(1)
Dividends Payable	-	-	(1)
Effect of Foreign Exchange Rate Changes on Non-Cash Working Capital	(3)	2	7
	(46)	143	(243)
Financing Activities			
Accounts Payable and Accrued Liabilities	-	-	(2)
Investing Activities			
Accounts Payable and Accrued Liabilities	7	(18)	42
Total	(39)	125	(203)

(c) Other cash flow information

	2002	2001	2000
Interest Paid	117	106	133
Income Taxes Paid	238	211	236

15. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has three operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and Australia. Our other operations are primarily in Nigeria, Colombia, and Brazil. Oil and gas also includes our marketing operations. Marketing sells our own crude oil and natural gas, markets third party crude oil and natural gas and engages in energy trading.

Syncrude: We own 7.23% of the Syncrude Joint Venture, which develops and produces synthetic crude oil from oil sands in northern Alberta, Canada.

Chemicals: We manufacture, market and distribute industrial chemicals, principally sodium chlorate, chlorine and caustic soda. We produce sodium chlorate at five facilities in Canada, one in the United States and one in Brazil. We produce chlorine and caustic soda at chlor-alkali facilities in Canada and Brazil.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

2002 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas						Syncrude	Chemicals	Corporate and Other[a]	Total
	Yemen	Canada	United States	Australia	Other Countries[b]	Marketing				
Net Sales [j]	789	656	296	165	78	-	245	367[c]	10	2,606
Marketing and Other	-	2	-	-	-	496	-	2	4	504
Gain (Loss) on Disposition of Assets	-	(21)[d]	-	-	-	-	-	-	13[e]	(8)
Total Revenues	789	637	296	165	78	496	245	369	27	3,102
Operating	86	176	94	50	22	-	115	229	10	782
Transportation and Other	-	-	3	-	-	423	-	40	3	469
General and Administrative	4	22	11	1	19	30	1	21	43	152
Depreciation, Depletion and Amortization	149	253	133	53	46	8	13	52	13	720
Exploration	21	38	82	3	45[f]	-	-	-	-	189
Interest	-	-	-	-	-	-	-	-	109	109
Income (Loss) before Income Taxes	529	148	(27)	58	(54)	35	116	27	(151)	681
Less: Provision for (Recovery of) Income Taxes[g]	188	59	(10)	19	(18)	12	37	9	(67)	229
Net Income (Loss)	341	89	(17)	39	(36)	23	79	18	(84)	452
Identifiable Assets	600	2,124	1,452	63	159	811[h]	536	538	277	6,560
Capital Expenditures										
Development and Other	209	258	541	46	23	2	141	45	97[i]	1,362
Exploration	22	60	116	3	58	-	-	-	-	259
Proved Property Acquisitions	-	4	-	-	-	-	-	-	-	4
	231	322	657	49	81	2	141	45	97	1,625
Property, Plant and Equipment										
Cost	2,054	3,098	2,186	209	305	86	628	789	213	9,568
Less: Accumulated DD&A	1,646	1,137	959	184	198	40	139	345	57	4,705
Net Book Value [j]	408	1,961	1,227	25	107	46	489	444	156	4,863
Goodwill										
Cost	-	-	-	-	-	60	-	-	-	60
Less: Accumulated DD&A	-	-	-	-	-	24	-	-	-	24
Net Book Value	-	-	-	-	-	36	-	-	-	36

Notes:

(a) Includes results of operations from a natural gas-fired generating facility in Alberta.

(b) Includes results of operations from producing activities in Nigeria and Colombia.

(c) Net sales for our chemicals operations include:

Canada	$ 251
United States	56
Brazil	60
	$ 367

(d) On December 30, 2002, we disposed of non-operated oil and gas properties for proceeds of $14 million.

(e) On January 2, 2002, we disposed of our Moose Jaw Asphalt operation for proceeds of $27 million plus working capital.

(f) Includes exploration activities primarily in Nigeria, Colombia and Brazil.

(g) The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

(h) Approximately 70% of Marketing's identifiable assets are accounts receivable.

(i) Includes $67 million related to the buy out of lease agreement related to the construction of a natural gas-fired generating facility in Alberta.

(j) Net sales made from all segments originating in Canada. $ 1,162
Property, plant and equipment located in Canada. $ 2,908

2001 Operating and Geographic Segments

(Cdn$ millions)

	Oil and Gas						Syncrude	Chemicals	Corporate and Other[a]	Total
	Yemen	Canada	United States	Australia	Other Countries[b]	Marketing				
Net Sales [g]	711	647	358	141	61	-	225	373[c]	77	2,593
Marketing and Other	-	10	1	-	6	438	-	3	17	475
Gain on Disposition of Assets	-	-	1	3	-	-	-	-	1	5
Total Revenues	711	657	360	144	67	438	225	376	95	3,073
Operating	71	155	66	52	19	-	114	243	61	781
Transportation and Other	-	-	-	-	-	342	-	34	24	400
General and Administrative	3	25	8	1	21	23	1	18	36	136
Depreciation, Depletion and Amortization	111	227	116	65	31	14	12	34	15	625
Exploration	25	44	101	13	82 [d]	-	-	-	-	265
Interest	-	-	-	-	-	-	-	-	112	112
Income (Loss) before Income Taxes	501	206	69	13	(86)	59	98	47	(153)	754
Less: Provision for (Recovery of) Income Taxes [e]	185	90	27	5	(24)	26	32	16	(53)	304
Net Income (Loss)	316	116	42	8	(62)	33	66	31	(100)	450
Identifiable Assets[f]	520	2,123	880	47	179	470	399	534	173	5,325
Capital Expenditures										
Development and Other	185	367	120	(4)	23	-	60	73	47	871
Exploration	44	84	197	12	74	-	-	-	-	411
Proved Property Acquisitions	-	7	115	-	-	-	-	-	-	122
	229	458	432	8	97	-	60	73	47	1,404
Property, Plant and Equipment										
Cost	1,839	2,867	1,636	167	271	89	487	744	137	8,237
Less: Accumulated DD&A	1,491	913	848	144	166	32	127	296	50	4,067
Net Book Value [g]	348	1,954	788	23	105	57	360	448	87	4,170
Goodwill										
Cost	-	-	-	-	-	60	-	-	-	60
Less: Accumulated DD&A	-	-	-	-	-	24	-	-	-	24
Net Book Value	-	-	-	-	-	36	-	-	-	36

Notes:

(a) Includes results of our Moose Jaw Asphalt operation, which was disposed of on January 2, 2002.
(b) Includes results of operations from producing activities in Nigeria.
(c) Net sales for our chemicals operations include:

Canada	$ 241
United States	90
Brazil	42
	$ 373

(d) Includes exploration activities primarily in Nigeria, Indonesia, and Colombia.
(e) The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.
(f) Approximately 65% of Marketing's identifiable assets are accounts receivable.
(g) Net sales made from all segments originating in Canada. $ 1,190
Property, plant and equipment located in Canada. $ 2,709

2000 Operating and Geographic Segments

(Cdn$ millions)

	Oil and Gas						Syncrude	Chemicals	Corporate and Other[a]	Total
	Yemen	Canada	United States	Australia	Other Countries[b]	Marketing				
Net Sales[h]	752	698	382	167	78	-	199	336[c]	93	2,705
Marketing and Other	6	2	-	-	1	179	-	7	25	220
Gain on Disposition of Assets	-	23	1	-	18[d]	-	-	-	-	42
Total Revenues	758	723	383	167	97	179	199	343	118	2,967
Operating	58	135	55	27	22	-	98	213	79	687
Transportation and Other	-	-	-	-	-	131	-	34	17	182
General and Administrative	3	21	6	1	17	12	-	17	40	117
Depreciation, Depletion and Amortization	90	233	139	86	40	13	12	40	14	667
Exploration	14	40	60	23	36[e]	-	-	-	-	173
Interest	-	-	-	-	-	-	-	-	132	132
Income (Loss) before Income Taxes	593	294	123	30	(18)	23	89	39	(164)	1,009
Less: Provision for (Recovery of) Income Taxes[f]	219	129	50	11	(5)	9	29	16	(51)	407
Net Income (Loss)	374	165	73	19	(13)	14	60	23	(113)	602
Identifiable Assets[g]	427	1,956	699	91	179	1,015	327	506	351	5,551
Capital Expenditures										
Development and Other	98	297	81	-	9	2	37	31	25	580
Exploration	15	65	143	19	58	-	-	-	-	300
Proved Property Acquisitions	-	28	4	3	-	-	-	-	-	35
	113	390	228	22	67	2	37	31	25	915
Property, Plant and Equipment										
Cost	1,555	2,497	1,242	151	245	88	429	667	89	6,963
Less: Accumulated DD&A	1,314	729	723	90	126	25	118	261	37	3,423
Net Book Value[h]	241	1,768	519	61	119	63	311	406	52	3,540
Goodwill										
Cost	-	-	-	-	-	60	-	-	-	60
Less: Accumulated DD&A	-	-	-	-	-	18	-	-	-	18
Net Book Value	-	-	-	-	-	42	-	-	-	42

Notes:

(a) Includes results of our Moose Jaw Asphalt operation which was disposed of on January 2, 2002.

(b) Includes results of operations from producing activities in Nigeria and Ecuador.

(c) Net sales from our chemicals operations include:

Canada	$ 237
United States	76
Brazil	23
	$ 336

(d) On April 18, 2000, Nexen exchanged its oil and gas operations in Ecuador for Occidental's 15% interest in our chemicals operations. The exchange was valued at $55 million. Results of operations from producing activities in Ecuador have been included to April 18, 2000, and operations from the 15% interest in our chemicals operations has been included since April 18, 2000.

(e) Includes exploration activities primarily in Nigeria and Indonesia.

(f) The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

(g) Approximately 70% of Marketing's identifiable assets are accounts receivable.

(h) Net sales made from all segments originating in Canada. $ 1,227
Property, plant and equipment located in Canada. $ 2,472

16. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. Canadian principles differ from US GAAP as follows:

(a) Consolidated Statement of Income

	2002	2001	2000
Net Income - Canadian GAAP	452	450	602
Impact of US Principles:			
Dividends on Preferred Securities (i)	(72)	(70)	(68)
Less: Associated Future Income Taxes	29	31	31
Depreciation (ii)	(53)	(46)	(43)
Fair Value of Currency Swap, Net of Income Tax (v)	(4)	-	-
Net Income - US GAAP (viii)	352	365	522
Earnings per Common Share – US GAAP ($/share)			
Basic	2.88	3.03	4.17
Diluted	2.84	2.99	4.12
Pro forma Earnings – Fair-value Based Method of Accounting for Stock Options			
Net Income			
As Reported	352	365	522
Less: Fair Value of Stock Options	22	25	14
Pro Forma	330	340	508
Earnings Per Common Share ($/share)			
Basic as Reported	2.88	3.03	4.17
Pro Forma	2.70	2.81	4.07
Diluted as Reported	2.84	2.99	4.12
Pro Forma	2.67	2.79	4.01

(b) Consolidated Statement of Comprehensive Income

	2002	2001	2000
Net Income - US GAAP	352	365	522
Translation Adjustment, Net of Income Tax (i); (iv)	34	(3)	-
Minimum Unfunded Pension Liability, Net of Income Tax (vii)	(2)	-	-
Comprehensive Income	384	362	522

(c) Consolidated Balance Sheet

	2002		2001	
	Canadian GAAP	US GAAP	Canadian GAAP	US GAAP
Assets				
Accounts Receivable (iii)	988	990	609	616
Property, Plant and Equipment, Net (ii)	4,863	5,064	4,170	4,424
Deferred Charges and Other Assets (i); (vi)	69	70	28	51
Liabilities and Shareholders' Equity				
Accounts Payable and Accrued Liabilities (iii); (v)	1,194	1,200	773	780
Long-Term Debt (i); (vi)	1,844	2,575	1,484	2,242
Future Income Tax Liabilities (i); (ii)	873	876	869	878
Preferred Securities (i)	724	-	724	-
Retained Earnings (i); (ii); (v)	1,069	1,280	697	965
Cumulative Foreign Currency Translation Adjustment (iv)	115	-	94	-
Accumulated Other Comprehensive Income (i);(iv)	-	92	-	60

(d) Consolidated Statement of Cash Flows

Under US principles, dividends on preferred securities of $72 million (2001 - $70 million; 2000 - $68 million) that are included in financing activities would be reported in operating activities.

Under US principles, geological and geophysical costs of $80 million (2001 - $79 million; 2000 - $74 million) that are included in investing activities would be reported in operating activities.

(e) Changes in Accounting Principles

Mark-to-Market

On October 25, 2002, we adopted EITF 02-03, which eliminated mark-to-market accounting as previously defined by EITF 98-10. Mark-to-market accounting was eliminated for our marketing inventories and transportation contracts. We have adopted this change as described in note 1(r). Under EITF 98-10 our results would have been:

	2002
Net Income	
As Reported	352
Mark-to-Market on inventory and transportation, net of income taxes	4
Adjusted	356
Earnings per Common Share ($/share)	
Basic as Reported	2.88
Adjusted	2.91
Diluted as Reported	2.84
Adjusted	2.88

Goodwill

On January 1, 2002, we adopted Financial Accounting Standards Board (FASB) Statement No.142, which eliminates goodwill amortization but instead requires annual impairment testing. No goodwill impairment writedowns were required during the year. Our unamortized goodwill at January 1, 2002 was $36 million. The following shows the adjusted net income and earnings per common share had the new standard been applied in 2001 and 2000:

	2002	**2001**	**2000**
Net Income			
As Reported	352	365	522
Add: Goodwill Amortization	-	6	5
Adjusted	352	371	527
Earnings Per Common Share ($/share)			
Basic as Reported	2.88	3.03	4.17
Adjusted	2.88	3.07	4.22
Diluted as Reported	2.84	2.99	4.12
Adjusted	2.84	3.04	4.16

(f) Recent Developments in US Accounting Standards

In June 2001, FASB issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 requires recognition of a liability for the future retirement obligations associated with our property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation. FAS 143 is effective for all fiscal years beginning after June 15, 2002. The impact on our financial statements at January 1, 2003, is as follows:

(Cdn$ millions)	Increase /(Decrease)
Consolidated Balance Sheet	
Property, Plant and Equipment	123
Asset Retirement Obligation	185
Future Income Tax Liability	(25)
Consolidated Statement of Income	
Cumulative Effect of Change in Accounting Principle, Net of Income Taxes	37
Depreciation, Depletion and Amortization, Net of Income Taxes	2

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 elaborates on the disclosures we must make about our obligations under certain guarantees that we have issued. It also requires us to recognize, at the inception of a guarantee, a liability for the fair value of the obligations we have undertaken in issuing the guarantee. The initial recognition and initial measurement provisions are to be applied only to guarantees issued or modified after December 31, 2002. Adoption of these provisions will not have a material impact on our financial position or results of operations. The disclosure requirements are effective for annual or interim periods ending after December 15, 2002.

In January 2003, the FASB issued Statement No. 148 "Accounting for Stock-Based Compensation - Transition and Disclosure, an Amendment of FASB Statement No. 123" (FAS 148). FAS 148 amends FAS 123 "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, FAS 148 amends the disclosure requirements of FAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. FAS 148 has no material impact on us, as we do not plan to adopt the fair value method of accounting for stock options at the current time. We have included the required disclosures in Note 8 to these financial statements.

The following standards issued by the FASB do not impact us:

- Statement No. 145 – "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections", effective for financial statements issued on or after May 15, 2002;
- Statement No. 146 – "Accounting for Costs Associated with Exit or Disposal Activities", effective for exit or disposal activities initiated after December 31, 2002;
- Statement No. 147 – "Acquisitions of Certain Financial Institutions - an Amendment of FASB Statements No. 72 and 144 and FASB Interpretation No. 9", effective for acquisitions on or after October 1, 2002; and
- Interpretation No. 46 – "Consolidation of Variable Interest Entities", effective for financial statements issued after January 31, 2003.

Notes:

i. Under US principles, the preferred securities are classified as long-term debt rather than shareholders' equity. The pre-tax dividends are included in interest expense, and the related income tax is included in the provision for income taxes in the Consolidated Statement of Income. The related pre-tax issue costs are included in deferred charges and other assets rather than as an after-tax charge to retained earnings. The foreign-currency translation gains or losses are included in other comprehensive income in the Consolidated Balance Sheet. The pre-tax dividends are included in operating activities in the Consolidated Statement of Cash Flows.

ii. Under US principles, the liability method of accounting for income taxes was adopted in 1993 rather than January 1, 2000, as described in Note 13. Under US principles, the adjustment on initial adoption was included in property, plant and equipment rather than retained earnings. This increases depreciation expense under US principles.

iii. On January 1, 2001, Nexen adopted FASB Statement No. 133 “Accounting for Derivative Instruments and Hedging Activities”, as modified by Statement No. 138 “Accounting for Certain Derivative Instruments and Certain Hedging Activities” (FAS 133). FAS 133 requires us to recognize all derivative instruments on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met. For cash flow hedges, changes in the fair value of derivatives that are designated as hedges are recognized in earnings in the same period as the hedged item. Any fair value change in a derivative before that period is recognized on the balance sheet and in other comprehensive income. For fair value hedges, both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value. Any changes in the fair value are reflected net in earnings. Included in both accounts receivable and accounts payable at December 31, 2002 is $2 million (2001 - $7 million) related to fair value hedges. The hedges convert fixed prices for physical delivery of natural gas into a floating price through a fixed to floating swap. The impact on earnings is immaterial.

iv. Under US principles, exchange gains and losses arising from the translation of our net investment in self-sustaining foreign operations are included in comprehensive income. Additionally, exchange gains and losses from translation of our US-dollar long-term debt, net of income taxes, is included in comprehensive income as it has been designated as a hedge of the our foreign net investment. Cumulative amounts are included in accumulated other comprehensive income in the Consolidated Balance Sheet.

v. Under US principles, a derivative and a cash instrument cannot be designated in combination as a net investment hedge. Changes in fair value and foreign exchange gains and losses on our US $37 million currency swap (see note 6) are included in earnings.

vi. Under US principles, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred charges and other assets.

vii. Under US principles, the amount by which our accrued pension cost is less than the unfunded accumulated benefit obligation is included in comprehensive income and accrued pension liabilities.

viii. Under US principles, gains and losses on the disposition of assets are shown as operating expenses rather than revenues.

SUPPLEMENTARY FINANCIAL INFORMATION (Unaudited)

Quarterly Financial Data in Accordance with Canadian and US GAAP

(Cdn$ millions)

	Quarter Ended							
	March 31		June 30		September 30		December 31	
	2002	2001	2002	2001	2002	2001	2002	2001
Net Sales	541	729	644	692	716	666	705	506
Operating Profit								
Oil and Gas [1]	97	304	184	278	223	152	185	28
Syncrude [2]	20	26	9	23	47	23	40	26
Chemicals	3	6	4	13	11	17	9	11
	120	336	197	314	281	192	234	65
Interest and Other Corporate [3]	24	45	43	40	36	33	48	35
Income Tax Expense [4]	31	116	53	114	88	74	57	-
Net Income in Accordance with Canadian GAAP	65	175	101	160	157	85	129	30
US GAAP Adjustment	(23)	(22)	(22)	(21)	(23)	(21)	(32)	(21)
Net Income in Accordance with US GAAP	42	153	79	139	134	64	97	9
Per Common Share ($/share)								
Net Income (Canadian GAAP)	0.44	1.38	0.74	1.25	1.20	0.62	0.96	0.16
Net Income (US GAAP)	0.35	1.27	0.65	1.15	1.09	0.53	0.79	0.08
Dividends Declared [5]	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Common Share Prices ($/share)								
Toronto Stock Exchange								
High	39.75	39.90	42.50	40.65	42.18	41.50	37.78	35.21
Low	29.70	31.00	37.20	32.40	34.34	28.10	31.00	29.51
New York Stock Exchange								
High (US$)	25.11	25.77	28.04	26.61	27.71	26.12	23.85	22.39
Low (US$)	18.57	20.69	23.30	20.60	21.70	17.95	19.79	18.73

Notes:

[1] A loss of $21 million was recorded on the disposition of non-operated oil and gas properties during the fourth quarter of 2002.

[2] Plant turnarounds and unplanned coker maintenance in the second quarter of 2002 increased operating costs.

[3] A gain of $13 million was recorded on the disposition of our Moose Jaw Asphalt operation during the first quarter of 2002.

[4] The fourth quarter of 2001 includes a statutory tax rate adjustment for provincial rate reductions in Canada.

[5] In February 2003, the Board of Directors declared a regular quarterly dividend of $0.075 per common share, payable April 1, 2003, to shareholders of record on March 10, 2003.

[6] At December 31, 2002, there were 1,372 registered holders of common shares and 122,965,830 common shares outstanding.

Oil and Gas Netbacks

(Sales prices, per unit costs and netbacks are calculated using our working interest production before royalties.)

($/boe)	2002						
	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	38.80	27.90	34.21	40.30	38.96	40.89	35.14
Royalties and other	(20.45)	(6.53)	(5.82)	(7.88)	(16.48)	(0.36)	(12.56)
Operating expense	(1.95)	(5.70)	(9.09)	(9.76)	(6.21)	(19.09)	(5.48)
In-country taxes	(4.81)	-	-	-	-	-	(2.10)
Cash netback	11.59	15.67	19.30	22.66	16.27	21.44	15.00

($/boe)	2001						
	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	35.05	26.60	39.42	38.71	37.37	39.90	33.28
Royalties and other	(18.66)	(6.26)	(6.85)	(2.36)	(7.07)	(1.72)	(11.40)
Operating expense	(1.62)	(4.87)	(6.01)	(13.50)	(8.07)	(19.43)	(4.88)
In-country taxes	(4.40)	-	-	-	-	-	(1.95)
Cash netback	10.37	15.47	26.56	22.85	22.23	18.75	15.05

($/boe)	2000						
	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	40.53	31.10	42.43	41.05	40.12	44.84	38.05
Royalties and other	(22.14)	(7.48)	(7.70)	-	(8.62)	(7.75)	(13.67)
Operating expense	(1.42)	(4.57)	(5.00)	(6.92)	(7.58)	(18.36)	(4.22)
In-country taxes	(5.30)	-	-	-	-	-	(2.34)
Cash netback	11.67	19.05	29.73	34.13	23.92	18.73	17.82

OIL AND GAS PRODUCING ACTIVITIES (Unaudited)

The following oil and gas information is provided in accordance with the US Financial Accounting Standards Board Statement No. 69 “Disclosures about Oil and Gas Producing Activities”.

A. Reserve Quantity Information

Our net proved reserves and changes in those reserves are disclosed below. The net proved reserves represent management’s best estimate of proved oil and natural gas reserves after royalties. We assess 100% of our reserves estimates internally each year and at least 80% of the reserves have been assessed by independent consultants.

Estimates of conventional crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, demonstrating with reasonable certainty that they are recoverable from known oil and gas fields under economic and operating conditions that exist at year-end. See Critical Accounting Policies and Business Risk Management sections in Item 7 for a discussion of reserves estimation and the related risks.

	Total			Yemen [1]	Canada		United States		Australia	Other Countries [2]
Oil reserves are in mmbbls and natural gas reserves in bcf	Conventional Oil	Gas	Syncrude [3]	Oil	Oil	Gas	Oil	Gas	Oil	Oil
Proved Developed and Undeveloped Reserves [4]										
December 31, 1999	291	614	188	104	150	455	19	159	8	10
Revisions of Previous Estimates	26	39	-	20	6	18	1	21	(1)	-
Purchases of Reserves in Place	7	3	-	-	5	-	-	3	2	-
Sales of Reserves In Place	(5)	(1)	-	-	(1)	(1)	-	-	-	(4)
Extensions and Discoveries	26	101	19	2	22	86	2	15	-	-
Production	(45)	(83)	(4)	(19)	(16)	(49)	(4)	(34)	(4)	(2)
December 31, 2000	300	673	203	107	166	509	18	164	5	4
Revisions of Previous Estimates	1	-	-	7	(14)	(1)	2	1	1	5
Purchases of Reserves in Place	2	64	-	-	2	3	-	61	-	-
Sales of Reserves in Place	-	(2)	-	-	-	(2)	-	-	-	-
Extensions and Discoveries	53	146	34	17	21	91	11	55	-	4
Production	(47)	(90)	(6)	(20)	(18)	(54)	(3)	(36)	(4)	(2)
December 31, 2001	309	791	231	111	157	546	28	245	2	11
Revisions of Previous Estimates	(6)	(10)	(12)	(14)	7	(6)	1	(4)	-	-
Purchases of Reserves in Place	-	1	-	-	-	1	-	-	-	-
Sales of Reserves in Place	(6)	(1)	-	-	(2)	(1)	-	-	-	(4)
Extensions and Discoveries	72	103	13	23	10	31	32	72	5	2
Production	(45)	(81)	(6)	(20)	(16)	(47)	(3)	(34)	(4)	(2)
December 31, 2002	324	803	226	100	156	524	58	279	3	7
Proved Developed Reserves [5]										
December 31, 2000	223	613	183	77	120	463	17	150	5	4
December 31, 2001	223	676	212	70	126	505	18	171	2	7
December 31, 2002	246	702	196	61	131	487	46	215	3	5

Notes:

1 Under the terms of the Masila production sharing contract, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all our costs and those of our partners. Remaining production is profit oil, which is shared between the partners and the Government of Yemen based on production rates, with the partners’ share ranging from 20% to 33%. The Government’s share of profit oil represents their royalty interest and an amount for income taxes payable in Yemen. Yemen’s net proved reserves include our share of future cost recovery and profit oil after the Government’s royalty interest but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) since the barrels necessary to achieve cost recovery change with prevailing oil prices.

2 Represents reserves in Nigeria and Colombia. (2001 – Nigeria and Colombia; 2000 – Nigeria; 1999 – Nigeria and Ecuador.)

3 US Securities and Exchange Commission regulations define these reserves as mining-related and not part of conventional oil and gas reserves. For management purposes, we view these reserves and their development as integral to our oil and gas operations. These reserves are not considered in the standardized measure of discounted future net cash flows, which follows. In 2002, Syncrude moved to generic royalty terms that provide for a royalty of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. Under this royalty regime, reported reserves will increase as oil prices decrease (and vice versa) since the barrels necessary to recover costs change with prevailing oil prices.

4 “Proved” oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered “proved” if they can be produced economically, as demonstrated by either actual production or conclusive formation tests.

5 “Proved developed” oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

B. Capitalized Costs

(Cdn$ millions)	Proved Properties	Unproved Properties	Accumulated Depreciation, Depletion and Amortization	Capitalized Costs
December 31, 2002				
Yemen	2,024	30	1,646	408
Canada	2,882	216	1,137	1,961
United States	2,061	125	959	1,227
Australia	209	-	184	25
Other Countries	251	54	198	107
Syncrude	628	-	139	489
Total	8,055	425	4,263	4,217
December 31, 2001				
Yemen	1,808	31	1,491	348
Canada	2,750	117	913	1,954
United States	1,522	114	848	788
Australia	167	-	144	23
Other Countries	267	4	166	105
Syncrude	487	-	127	360
Total	7,001	266	3,689	3,578
December 31, 2000				
Yemen	1,544	11	1,314	241
Canada	2,344	153	729	1,768
United States	1,154	88	723	519
Australia	151	-	90	61
Other Countries	184	61	126	119
Syncrude	429	-	118	311
Total	5,806	313	3,100	3,019

C. Costs Incurred

(Cdn$ millions)	Total		Conventional Oil and Gas				
	Conventional Oil and Gas	Syncrude	Yemen	Canada	United States	Australia	Other Countries
Year Ended December 31, 2002							
Property Acquisition Costs							
Proved	4	-	-	4	-	-	-
Unproved	31	-	-	-	31	-	-
Exploration Costs	228	-	22	60	85	3	58
Development Costs	1,077	141	209	258	541	46	23
	1,340	141	231	322	657	49	81
Year Ended December 31, 2001							
Property Acquisition Costs							
Proved	122	-	-	7	115	-	-
Unproved	37	-	19	-	18	-	-
Exploration Costs	374	-	25	84	179	12	74
Development Costs	691	60	185	367	120	(4)	23
	1,224	60	229	458	432	8	97
Year Ended December 31, 2000							
Property Acquisition Costs							
Proved	35	-	-	28	4	3	-
Unproved	39	-	-	-	31	-	8
Exploration Costs	261	-	15	65	112	19	50
Development Costs	485	37	98	297	81	-	9
	820	37	113	390	228	22	67

D. Results of Operations for Producing Activities

(Cdn$ millions)	Total		Conventional Oil and Gas				
	Conventional Oil and Gas	Syncrude	Yemen	Canada	United States	Australia	Other Countries
Year Ended December 31, 2002							
Net Sales	1,984	245	789	656	296	165	78
Production Costs	428	115	86	176	94	50	22
Exploration Expense	189	-	21	38	82	3	45
Depreciation, Depletion and Amortization	634	13	149	253	133	53	46
Other Expenses (Income)	79	1	4	41	14	1	19
	654	116	529	148	(27)	58	(54)
Income Tax Provision (Recovery)	238	37	188	59	(10)	19	(18)
Results of Operations	416	79	341	89	(17)	39	(36)
Year Ended December 31, 2001							
Net Sales	1,918	225	711	647	358	141	61
Production Costs	363	114	71	155	66	52	19
Exploration Expense	265	-	25	44	101	13	82
Depreciation, Depletion and Amortization	550	12	111	227	116	65	31
Other Expenses (Income)	37	1	3	15	6	(2)	15
	703	98	501	206	69	13	(86)
Income Tax Provision (Recovery)	283	32	185	90	27	5	(24)
Results of Operations	420	66	316	116	42	8	(62)
Year Ended December 31, 2000							
Net Sales	2,077	199	752	698	382	167	78
Production Costs	297	98	58	135	55	27	22
Exploration Expense	173	-	14	40	60	23	36
Depreciation, Depletion and Amortization	588	12	90	233	139	86	40
Other Expenses (Income)	(3)	-	(3)	(4)	5	1	(2)
	1,022	89	593	294	123	30	(18)
Income Tax Provision (Recovery)	404	29	219	129	50	11	(5)
Results of Operations	618	60	374	165	73	19	(13)

E. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

The following disclosure includes estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying year-end prices to our after royalty share of estimated annual future production from proved conventional oil and gas reserves (excluding Syncrude). Future development and production costs to be incurred in producing and further developing the proved reserves are based on year-end cost indicators. Future income taxes are computed by applying year-end statutory-tax rates. These rates reflect allowable deductions and tax credits and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proven to be the case in the past. Other assumptions could give rise to substantially different results.

We believe that this information does not in any way reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from year-end levels.

(Cdn$ millions)	Total	Yemen	Canada	United States	Australia	Other Countries
December 31, 2002						
Future Cash Inflows	18,687	4,662	9,067	4,516	144	298
Future Production and Development Costs	4,892	1,177	2,568	913	108	126
Future Income Tax	3,650	790	1,976	863	-	21
Future Net Cash Flows	10,145	2,695	4,523	2,740	36	151
10% Discount Factor	3,776	819	2,081	818	1	57
Standardized Measure	6,369	1,876	2,442	1,922	35	94
December 31, 2001						
Future Cash Inflows	10,337	3,068	5,034	1,880	64	291
Future Production and Development Costs	4,123	880	1,943	1,000	64	236
Future Income Tax	1,520	661	751	96	-	12
Future Net Cash Flows	4,694	1,527	2,340	784	-	43
10% Discount Factor	1,607	385	1,004	202	-	16
Standardized Measure	3,087	1,142	1,336	582	-	27
December 31, 2000						
Future Cash Inflows	15,173	3,552	8,113	3,166	220	122
Future Production and Development Costs	3,574	741	2,103	550	112	68
Future Income Tax	3,783	897	2,093	760	18	15
Future Net Cash Flows	7,816	1,914	3,917	1,856	90	39
10% Discount Factor	2,825	507	1,835	474	4	5
Standardized Measure	4,991	1,407	2,082	1,382	86	34

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(Cdn$ millions)	**2002**	**2001**	**2000**
Beginning of Year	3,087	4,991	3,801
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(1,158)	(2,012)	(1,425)
Net Changes in Prices and Production Costs Related to Future Production	3,083	(2,871)	1,255
Extensions, Discoveries and Improved Recovery, Less Related Costs	1,929	691	536
Development Costs Incurred during the Period	322	61	341
Revisions of Previous Quantity Estimates	267	(33)	670
Accretion of Discount	409	736	534
Purchases of Reserves in Place	2	161	119
Sales of Reserves in Place	(109)	(1)	(47)
Net Change in Income Taxes	(1,463)	1,364	(793)
End of Year	6,369	3,087	4,991

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

On June 3, 2002, the Canadian firm of Deloitte & Touche LLP (Deloitte Canada) completed a transaction with the Canadian firm of Arthur Andersen LLP (Andersen Canada) to integrate partners and staff of Andersen Canada into Deloitte Canada. On July 11, 2002, our Board accepted the resignation of Andersen Canada and appointed Deloitte Canada as our auditors until the next Annual General Meeting.

There were no disagreements with accountants on accounting and financial disclosure.