TALISMAN ENERGY

2002 ANNUAL REPORT

STRENGTH

VALUE

SKILLS

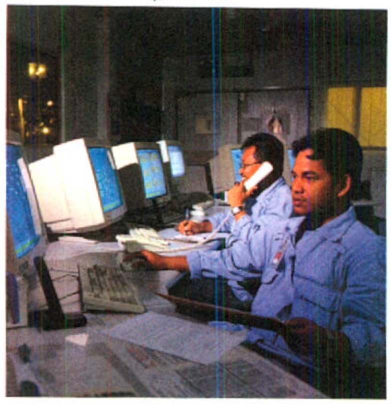
GROWTH

OPPORTUNITY

Western Canada drilling

An $11 billion company, Talisman's **STRENGTH** rests with its people, proven track record and diverse operations. The Company generated $2.6 billion in cash flow in 2002. **Talisman has 1.5 billion boe of proved reserves, predominantly light oil and natural gas.**

Corridor central facility, Indonesia



Creating **VALUE** for shareholders is Talisman's priority. In 2002 and early 2003, Talisman repurchased 5.8 million shares at an average price of approximately $57/share. **Over the past three years, the Company replaced 184% of production for $7.66/boe.**

In Its First 10 Years, Talisman Energy Has Become A Major North American

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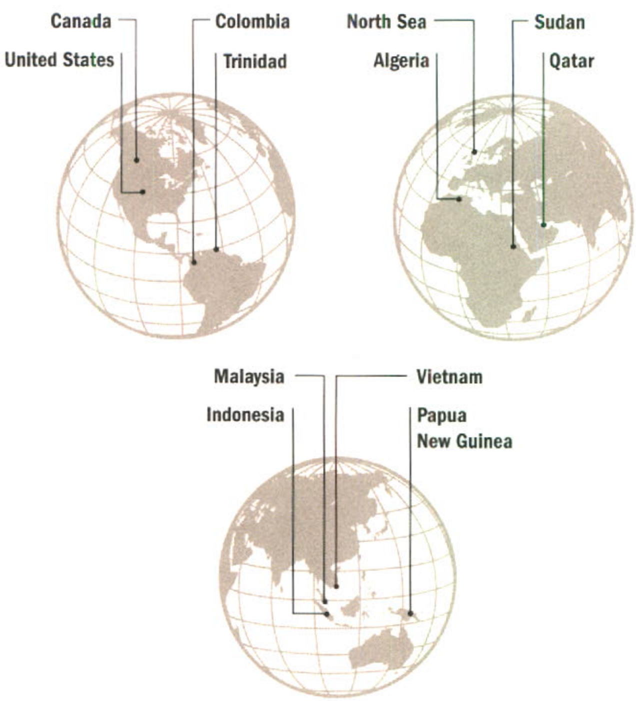
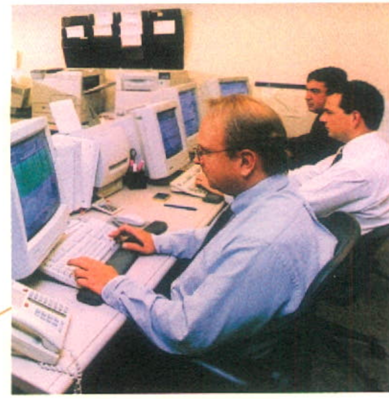


With its head office in Calgary, Alberta, Canada, Talisman is a large independent oil and gas producer with global operations. The Company's common shares are listed on the Toronto and New York stock exchanges under the symbol TLM.

Natural gas marketing, Canada



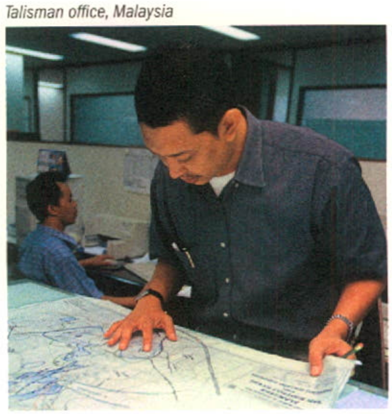
Talisman has demonstrated its SKILLS and track record as a successful North American gas explorer and developer and as an international operator. The Company has consistently achieved drilling success rates of over 85%. **Development of major new projects in Algeria, Malaysia and Vietnam will lead to significant production growth later in 2003.**

The North Sea

Talisman is committed to at least 5-10% GROWTH in production per share going forward. In the Company's 10-year history, it has grown its production per share at a compound annual rate of 13%. **In 2002, Talisman increased production by 6%, setting a new record of 445,000 boe/d.**

Natural Gas Producer and Successful International Operator

Talisman office, Malaysia



The Company has a large OPPORTUNITY inventory in North America, the North Sea, Southeast Asia, the Caribbean & Latin America and the Middle East & North Africa. In 2003, Talisman expects to spend $2.1 billion on exploration and development, participating in over 700 wells. **In 2002, Talisman added significant exploration acreage in the Canadian Foothills, Northeastern US, offshore Nova Scotia, the North Sea, Trinidad, Colombia, Vietnam and Qatar.**

Talisman conducts its operations directly and through subsidiaries. Any reference in this Annual Report to Talisman, includes Talisman's subsidiaries unless otherwise indicated.

A Discussion with Dr. Jim Buckee

President and Chief Executive Officer

Looking back, 2002 had both its highs and lows. How would you characterize the year?

2002 was a good year for Talisman despite some operational difficulties. The Company posted its fourth consecutive year of record cash flow per share and production was up 6% to 445,000 boe per day, also a record high. We expect the sale of Sudan to be completed shortly and we will use the proceeds to create value and grow from our new base. We also initiated a number of large exploration ventures that will provide exciting new opportunities in the coming years.

In the North Sea, we increased production by 15%, brought two new oil fields on stream and made a significant new oil discovery. In Canada, we established a number of area production records and added substantial new Foothills acreage. The successful deep well at Monkman could unlock large gas potential on Talisman acreage. The Company has also started to build a new core gas area in the eastern US.

Our major oil and gas development project in Malaysia and Vietnam is over 60% complete and we expect a significant increase in production later this year. We've continued to prove up our very large Indonesian gas reserves with expectations of significant sales growth over the next five years. The Company added high potential exploration acreage off the east coast of Canada, in Vietnam, Qatar and Trinidad. First production started in Algeria at year end, with first sales in January 2003 and offshore oil and gas development is underway in Trinidad.

At current price levels, I believe Talisman's shares are undervalued. We have repurchased 5.8 million shares since the end of October, in order to achieve our 2003 per share growth targets and because we believe Talisman is a very attractive investment at current prices.

In October 2002, it became apparent that the earlier forecasts of 7-10% organic growth for 2003 would not be achievable on the basis we had planned. In particular, we were affected by drilling problems in the North Sea and production delays in Canada. Most of this production growth has been deferred, not lost, as will be evident in 2004.

Costs were up in 2002 both in North America and internationally. In this, Talisman is not alone; however, we are better positioned than most companies because we can select the best investments from our portfolio of deeper Canadian natural gas opportunities and international oil and gas projects.

What should investors be looking for from Talisman in 2003?

I am excited and optimistic coming into 2003. The benefits of the groundwork done last year will become apparent as we move through the year. Most important for shareholders is our commitment to add value and grow production per share post-Sudan by at least 5% this year and 10% next. We will do this through a combination of share repurchases, acquisitions and organic growth.

The recent acquisitions in the northeastern US will add 60-70 million cubic feet per day of gas production in 2003 and over 50 drilling locations. First oil production from

Algeria started late last year and is expected to grow to over 15,000 barrels per day in the second half of this year. Our oil and gas development project in Malaysia and Vietnam will contribute over 40,000 boe per day to Talisman's production volumes next year.

In Canada, we are embarking on our largest drilling program ever, including record programs in Alberta Foothills and Bigstone/Wild River. We expect to drill three deep wells at Monkman, following up on our success last year, and will explore a large gas prospect off the east coast of Nova Scotia.

In the North Sea, we plan to participate in 35 wells, operating up to five drill strings. Blake flank development is underway with production expected in September 2003. We are drilling a number of exploration targets in the Ross/Blake, Flotta Catchment Area and Clyde/Orion core areas. Individually, these could each contain significant quantities of hydrocarbons.

In Indonesia, we completed the first expansion of our production facilities at Corridor and are actively pursuing new markets. We expect to increase Talisman's net sales from 94 million cubic feet a day in 2002 to over 250 million cubic feet per day in 2006. Evaluation of the giant Suban gas field will be completed this year and we plan to drill a new exploration prospect at Sambar.

Oil and gas development is underway in Trinidad and the program includes five exploration wells. First production of 18,000-25,000 barrels per day (net to Talisman) is expected in early 2005. We will also drill our first exploration wells in Colombia and start seismic work in Qatar.

All in all, Talisman is very strong financially. We possess a wealth of exploration and development opportunities and we continue to seek out acquisition opportunities to enhance shareholder value.

Has your strategy changed post Sudan, particularly at a time when the market is rewarding North American, gas-weighted stocks?

Talisman's strategy has been very successful over the past 10 years and we will continue on course. We like the North American gas business and to that end, we will spend approximately $975 million on Canadian, US and east coast exploration and development in 2003. Our focus on larger, deeper gas targets continues to provide a flow of attractive prospects. In addition, Talisman's international operations provide a scale of opportunity not available in North America. In fact, we are seeing more and more of our peers entering the international arena.

Going forward, how will Talisman achieve its growth targets while still creating shareholder value?

Talisman's growth and success will continue to come from a combination of exploration, acquisition and development. Acquisitions are a legitimate way of adding value, as long as there are next steps in the process, for example, either incremental drilling opportunities, cost reductions or synergies with existing businesses.

As we grow in size, a natural consequence will be to embark on higher potential exploration plays in areas like the offshore east coast of Canada, Trinidad, Vietnam, Qatar and Colombia.

You assert that Talisman is an attractive investment. What are your reasons?

Talisman is a strong company, with high quality assets, a great track record and a proven strategy. We have created substantial value for our shareholders, as measured by reserves, production and cash flow per share over the past 10 years and will continue to do so. The sale of Sudan will improve an already strong balance sheet and also demonstrates our commitment to creating shareholder value. Post Sudan, we expect to grow production per share in the 5-10% range in 2003 and by at least 10% in 2004.

Our core assets, representing almost 90% of Talisman's production, are located in Canada and the North Sea. These are augmented by very large, long life reserves in Southeast Asia and very large exploration upside in a number of areas.

What makes Talisman unique and gives this Company an advantage over its peer group is our international expertise and the diversity of countries in which we operate, hence diversity of opportunities. Talisman has proven that it can bring projects to fruition and successfully deal with the complexities of the international environment.

The world has large, growing energy requirements and Talisman is well positioned to contribute.

The market was disappointed when Talisman lowered its 2003 targets. How confident are you that you will meet your new numbers?

Talisman was one of a number of oil and gas companies to lower its 2003 targets. In our case, it was the cumulative effect of a number of relatively small occurrences, production delays, maintenance issues, deferred drilling and inclement weather, rather than a single event or project which could have been tracked and monitored.

Once a year, Talisman conducts a detailed planning exercise, which involves an economic review and update of hundreds of properties worldwide. As we conducted this review and the results were aggregated, it became apparent that we would not meet our previously announced target of 7-10% growth in 2003. We acted very quickly and responsibly to make this information public and worked to ameliorate the situation. The review also provided an impetus for our share repurchases, which will help achieve at least 5% production per share growth this year, a goal we will easily achieve post Sudan.

Talisman has announced the sale of its 25% interest in Sudan. What are your thoughts on the sale?

As I have said before, I think Talisman's presence was beneficial for the people of Sudan. The wealth generated by the oil development enables a brighter future for the country.

However, our shareholders grew tired of the controversy stemming from the long-standing conflict in the country. This distracted attention away from Talisman's other assets. With a credible buyer offering an attractive price, it was time to sell the property and use the proceeds to create value elsewhere.

What are your thoughts on current oil and gas prices?

During the 1990s, world oil prices averaged US$20 per barrel and NYMEX gas averaged US$2.00 per thousand cubic feet. In the first three years of this decade, the average has been US$27 per barrel and US$4.00 per thousand cubic feet, respectively.

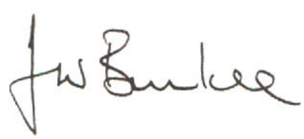
I think prices are now at a point where they better reflect the underlying economics and political uncertainties of the energy business. For a long period, the world economy thrived on the huge oil and gas discoveries made during the 40s and 50s when there was a 20-30 year supply of abundant, low cost, easily producible hydrocarbons.

For the last quarter century, the world has consumed more oil than it has found. In the last decade, this energy deficit widened to the point where supply and demand are very tightly balanced. In North America, despite historically high natural gas prices, the industry is struggling to maintain current production levels.

And in summary?

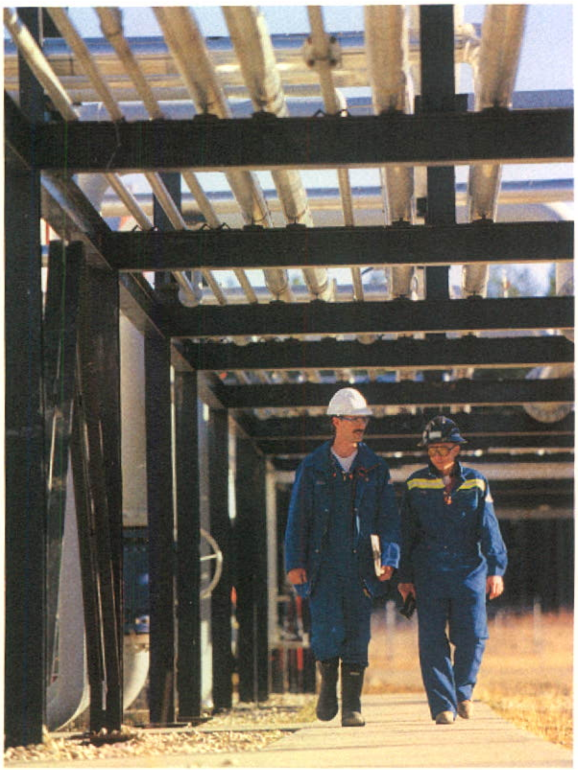
Talisman is a strong company. Our hard work, talents and opportunity set continues to generate significant value and this will become increasingly apparent over the next 18 months. I would like to thank the staff, management team and the Talisman Board of Directors for their hard work and dedication. In particular, I would like to thank David Powell, our retiring Chairman, and Paul Hoenmans, who are leaving the Board this year. They both brought valuable industry experience and provided guidance and support.

In our first 10 years, we have grown from a small Canadian company with a market cap of about $500 million to an $11 billion international company with an extremely successful track record. I believe that Talisman's next 10 years will be as strong as its first decade, providing a bright future for both our shareholders and employees.



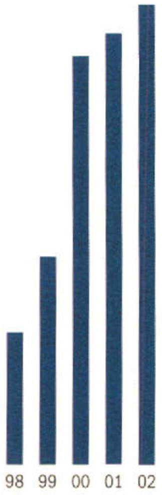
James W. Buckee
President and Chief Executive Officer
March 4, 2003

Highlights



Bigstone gas plant, Canada

Cash Flow Per Share
(dollars)

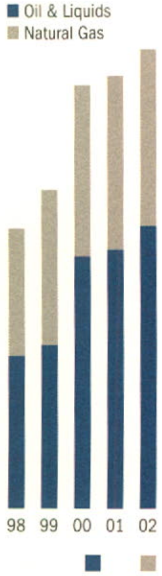


98	5.64
99	8.91
00	17.51
01	18.48
02	**19.73**

Net Income (Loss) Per Share
(dollars)

98	(2.80)
99	1.93
00	6.05
01	5.25
02	**3.73**

Production
(mboe/d)

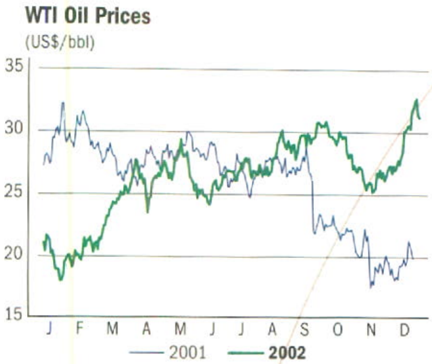


98	147	124
99	158	151
00	244	165
01	251	168
02	**273**	**172**

	2002	2001	2000	1999	1998
FINANCIAL (millions of Canadian dollars)					
Cash flow [1]	**2,645**	2,494	2,413	1,111	631
Net income (loss) [2]	**524**	733	857	255	(314)
EBITDAX [1,2]	**3,036**	2,859	2,853	1,430	758
Exploration and development expenditures	**1,848**	1,882	1,179	996	1,145
Total assets [2]	**11,594**	10,819	8,625	7,806	5,369
Long-term debt	**2,997**	2,983	1,733	2,195	2,086
Shareholders' equity [2]	**4,502**	4,126	3,614	3,621	2,135
PRODUCTION (daily average production)					
Oil and liquids (bbls/d)					
North America	**62,676**	66,056	66,374	58,489	57,585
North Sea	**127,486**	110,828	111,902	59,256	57,480
Southeast Asia	**22,469**	20,873	20,206	28,852	31,684
Sudan	**60,109**	53,257	45,869	11,726	–
Total oil and liquids	**272,740**	251,014	244,351	158,323	146,749
Natural gas (mmcf/d)					
North America	**820**	809	755	681	631
North Sea	**122**	108	122	115	104
Southeast Asia	**94**	93	111	108	13
Total natural gas	**1,036**	1,010	988	904	748
Total mboe/d [3]	**445**	419	409	309	271
Shares outstanding at December 31 (millions)	**131.0**	133.7	135.3	138.3	118.9
Number of permanent employees at December 31	**1,565**	1,358	1,263	1,113	986

1 Non-GAAP measure. See page 18.
2 Prior year's comparative amounts restated for new CICA accounting standard.
3 Six mcf of natural gas equals one boe.

The Business Environment in 2002



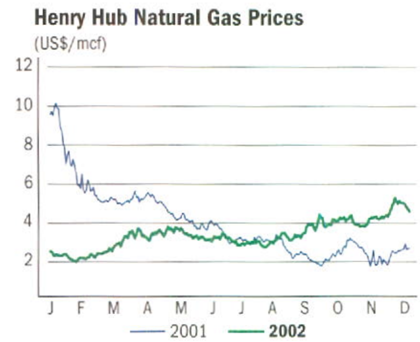
OIL PRICES

Expectations for lower crude oil prices in the first half of 2002 were short lived. A third year of weak demand growth and increasing supply from the Former Soviet Union was more than offset by OPEC's perceived effectiveness, the potential war premium and, towards the end of 2002, a strike by oil workers in Venezuela. As a result, West Texas Intermediate (WTI) oil prices averaged US$26.15/bbl for the year, 1% higher than in 2001.

As the industry heads into 2003, political uncertainty continues to underpin high oil prices, which reached US$37/bbl in February. Once the geopolitical issues are resolved, OPEC discipline and economic growth will ultimately determine where oil prices settle. Talisman currently expects WTI prices to average US$28.50/bbl in 2003.

NATURAL GAS PRICES

Natural gas prices were volatile in 2002 with NYMEX prices averaging US$3.37/mcf, down 21% from 2001, although fundamentals improved during the second half of the year. With high crude oil prices, cold weather and falling storage levels, prices increased to US$9.00/mcf in late February 2003. With industry production in the US and Canada unlikely to increase this year, the outlook for gas prices continues to be positive. Talisman currently expects NYMEX prices to average US$5.00/mcf in 2003.



TALISMAN SHARE PRICE

Geopolitical uncertainty, combined with a lack of investor confidence, made for a difficult year in the broader markets. The oil and gas industry was seen as a relatively safe haven for investor money in the early part of 2002. Accordingly, Talisman's share price performance was strong during the first half of the year, reaching an all time high of $70.09 in May. However, with nervousness over commodity prices and Talisman's revised 2003 production guidance, the stock closed the year at $56.85, down 6% from year end 2001.

SHARE PRICE PERFORMANCE

Weekly Closing Price – January 1998 to February 2003

C$/Share

Talisman in 2002

Platform construction, Malaysia

The Company posted strong financial results on record production volumes in 2002.

- Record cash flow per share of $19.73, an increase of 7% over 2001.
- $2.6 billion in cash flow.
- Production increased 6% to 445,000 boe/d, led by higher North Sea volumes.
- Net income per share was $3.73, down from 2001 due to higher non-cash and exploration expenses and provisions for higher UK taxes.
- Long-term debt at year end was $3 billion. Debt to cash flow at year end was 1.1 times.
- Talisman's average realized price was $32.10/boe, down from $32.91/boe in 2001, due to lower natural gas prices.
- Exploration and development spending was $1.8 billion.
- Unit operating costs increased 12% to $6.48/boe, reflecting both industry pressures and a higher percentage of North Sea volumes.
- During 2002, Talisman repurchased 3.8 million shares and an additional 2.0 million shares early in 2003.

Flotta terminal, UK

FINDING AND DEVELOPMENT COSTS

In 2002, Talisman drilled 439 successful wells, adding 196 mmboe of proved reserves (replacing 121% of production) at a cost of $8.87/boe.

In total, including net revisions, transfers and acquisitions, the Company added 159 mmboe of proved reserves at a cost of $12.15/boe.

Over the past three years, Talisman replaced 184% of production with an average finding, development and acquisition cost of $7.66/boe.

($/boe)	2002	Average 3-year
Finding and development costs [1]	**8.87**	6.98
Total finding and development costs [2]	**11.03**	6.86
Finding, development and acquisition costs	**12.15**	7.66

1 Excludes net revisions and transfers.
2 Total finding and development costs include net revisions and transfers.

Talisman in 2003

Drilling in Indonesia

The Company's objective is to grow production per share by at least 5-10% in both 2003 and 2004 (on a comparable basis, excluding Sudan).

- Production is expected to average between 395,000-415,000 boe/d.
- The Sudan sale is expected to close shortly (US$758 million in gross proceeds).
- The Company has an exploration and development budget of $2.1 billion.
- Talisman expects to participate in over 700 gross exploration and development wells.
- Significant production increases are expected from Algeria, Malaysia and Vietnam in the second half of the year.
- Further pressure on unit operating costs is expected this year both from higher levels of industry activity and the removal of lower cost Sudan production from the weighted average.

The Strategy Works

Jim Buckee
President and Chief Executive Officer

Oil and natural gas demand will continue to increase with population and economic growth. Talisman will concentrate on the upstream hydrocarbon business and is well positioned to create value using its technical and commercial skills.

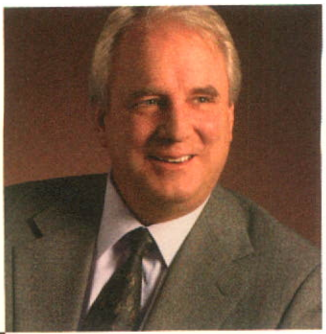
Talisman will continue to develop its large North American gas business, while at the same time growing and adding to its international operations.

Talisman's international assets provide large opportunities outside the mature North American sedimentary basins. The Company continues to build new core assets based on materiality, growth potential and competitive advantage.

Talisman owns, operates and controls key assets and infrastructure where they provide a competitive advantage or add value.

Talisman operates over three-quarters of its production in Canada, 60% in the North Sea and is the operator of a major project currently underway in Southeast Asia. This control has contributed to the Company's success, adds value and enables Talisman to reduce costs and control timing.

Talisman will grow through both exploration and acquisitions, creating opportunities that add significant shareholder value.



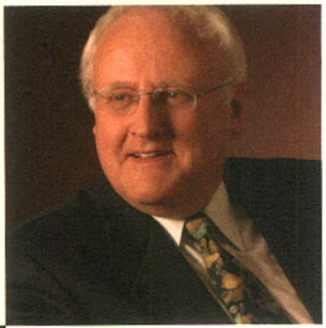
Mike McDonald
Executive Vice-President,
Finance and
Chief Financial Officer

Joe Horler
Executive Vice-President,
Marketing

Nigel Hares
Executive Vice-President,
Frontier and
International Operations

Ted Bogle
Executive Vice-President,
Exploration

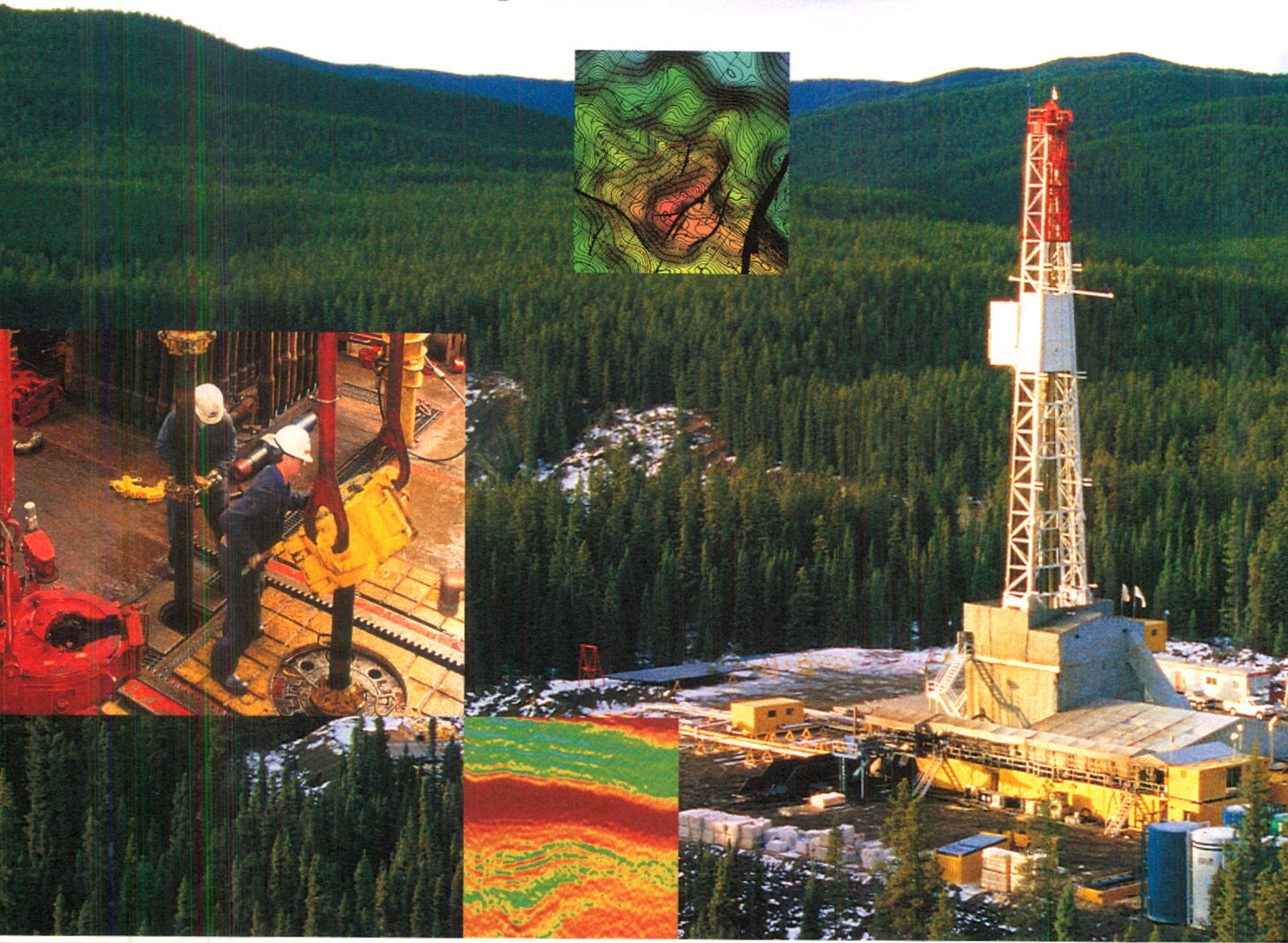
Jackie Sheppard
Executive Vice-President,
Corporate and Legal,
and Corporate Secretary



Bob Mitchell
Executive Vice-President,
North American Operations

Bob Redgate
Executive Vice-President,
Corporate Services

Operations and Exploration Areas



North America

Talisman's large North American natural gas business provides a substantial base of operations, supporting continued growth worldwide. The Company's focus is in the deeper, higher potential gas plays along the Rocky Mountain Foothills. Talisman is also building a new high value, core gas area in upper New York State.

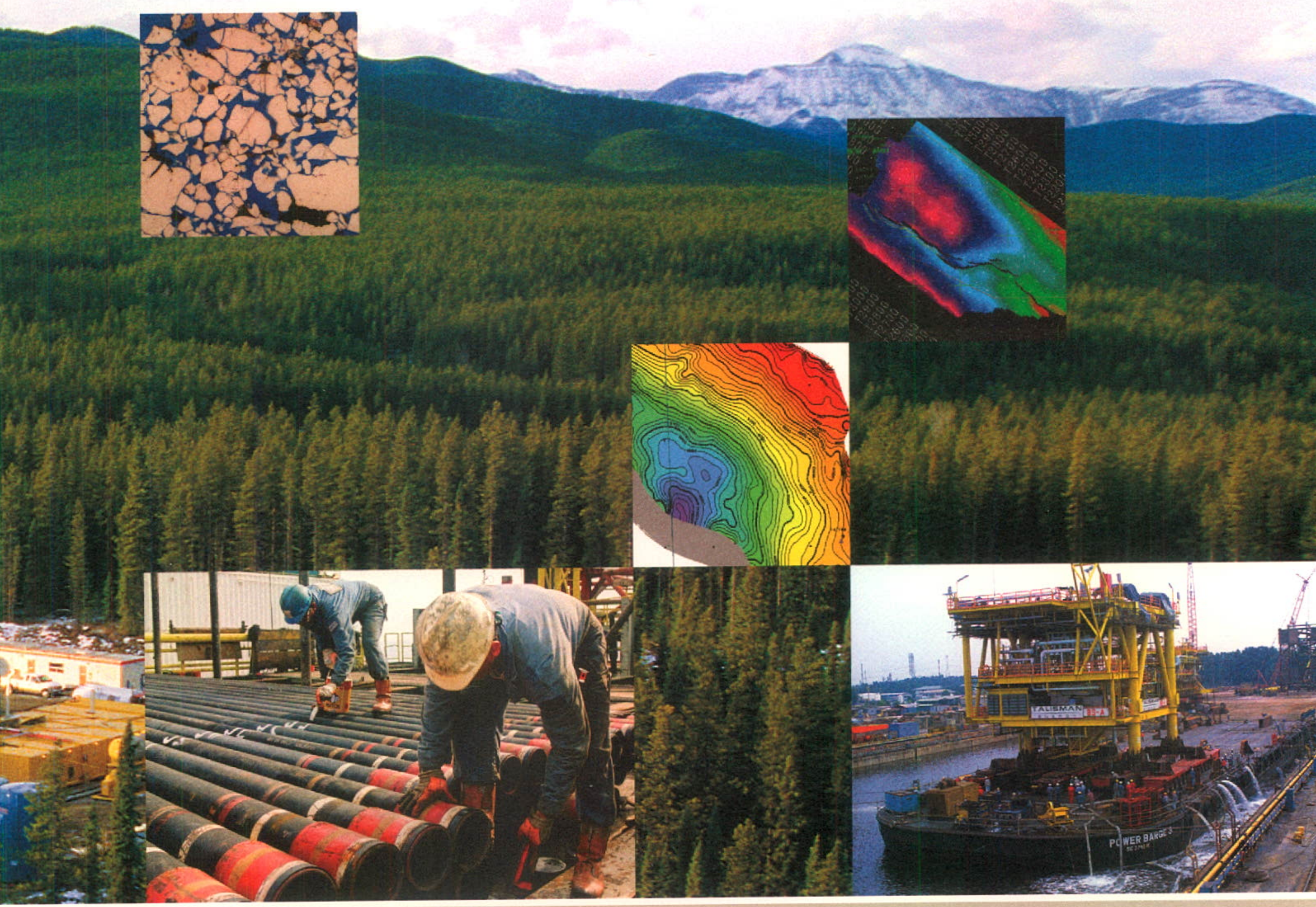
The North Sea

In the Central North Sea, Talisman operates a number of commercial hubs, which provide significant value through low risk development, adjacent exploration opportunities, secondary recovery and third-party tariff receipts. The North Sea is Talisman's highest netback region.

Southeast Asia

Talisman is poised for significant production growth in Southeast Asia. The Company continues to develop its very large gas reserves in Indonesia and is actively discussing new sales opportunities. Development of oil and gas fields in the PM-3 Commercial Arrangement Area in Malaysia/Vietnam is Talisman's largest project in 2003. Talisman acquired a 30% interest in the exploration Block 46/02 offshore Vietnam, contiguous to its PM-3 Block.

Talisman has successfully made a strategic transition to a diversified, international company, exploiting world scale oil and gas opportunities overseas, while increasing its position as one of North America's largest natural gas producers.



The Caribbean & Latin America

Talisman is working in a number of high impact exploration areas utilizing the Company's expertise in thrust and fold belt plays. Talisman's oil and gas development project in Trinidad has been approved and exploration is continuing. The Company is also about to commence exploration drilling in Colombia.

Africa & the Middle East

On October 30, 2002, the Company announced the sale of its Sudan assets for US$758 million. The Company expects the sale to be completed in the near future.

Talisman has non-operated interests in two fields in Algeria. First production from the Ourhoud field commenced in late 2002, with first sales in January 2003. Production from the MLN field is expected later this year.

Talisman has acquired an exploration block offshore Qatar. This acreage contains a number of very large exploration prospects in the midst of a proven hydrocarbon basin.

North America

Bigstone gas plant

2.6 tcf of proved natural gas reserves

Over the past three years, Talisman averaged 6% compound annual growth in gas production in Western Canada and Ontario. The Company has an extensive land base of 14.2 million gross (6.7 million net) acres and maintains a two to three year rolling prospect inventory in Western Canada.

During the year, Talisman entered into a farm-in agreement to acquire a 30% interest in two deep-water exploration licenses offshore Nova Scotia. The acreage contains a number of large natural gas prospects and provides the Company with longer-term growth potential.

Late in 2002 and early 2003, Talisman's wholly-owned subsidiary, Fortuna Energy Inc., acquired natural gas properties, production and facilities in upstate New York for US$309 million. This is a growing new core gas area with low operating costs, 138 bcf of proved gas reserves, production of 60-70 mmcf/d and over 50 drilling locations.

2002 IN REVIEW

Talisman maintained production levels in 2002, despite regulatory issues, lengthening cycle times, infrastructure constraints and drilling delays.

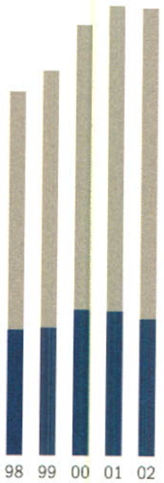
- Natural gas production averaged 820 mmcf/d, up from 809 mmcf/d in 2001.
- Liquids production averaged 62,676 bbls/d, compared to 66,056 bbls/d in 2001.
- In Canada, Talisman drilled 222 natural gas wells and 146 oil wells with an 88% success rate.
- Exploration and development spending totaled $822 million. The Company added 75 mmboe of proved reserves, excluding revisions and transfers, and had 631 mmboe of proved reserves at year end (90% developed).
- Conventional operating costs averaged $4.65/boe, up from $4.41 a year earlier.
- Talisman drilled a successful deep test at Monkman in northeastern British Columbia with one tcf of gas potential in the area.
- Production records were set in the Alberta Foothills (121 mmcf/d) and at Chauvin (14,265 bbls/d).
- The Company commenced a nitrogen injection recovery project at its Turner Valley oil field, which could add an incremental 30-100 mmbbls of oil reserves over the next 20 years.

2003 OUTLOOK

- Major exploration and development programs are planned in the Greater Arch, Alberta Foothills, Monkman, Deep Basin and Edson areas.
- Exploration and development spending is expected to be $975 million, with over 80% directed towards natural gas projects.
- Production targets are 860-880 mmcf/d of natural gas (including US production) and 58,000-60,000 bbls/d of oil and liquids.
- Talisman plans to participate in 590 wells, including 10 in the US.
- Completion of the Erith pipeline, routing gas from the Foothills area to the Edson and Hanlan-Robb gas plants, is scheduled for the fourth quarter.
- An offshore east coast exploration well is planned to spud mid-year.

Production
(mboe/d)

Oil & Liquids
Natural Gas



98	57.5	105.2
99	58.5	113.5
00	66.4	125.8
01	66.0	134.8
02	**62.7**	**136.7**

The North Sea

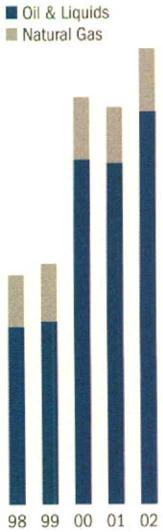
Talisman's highest netback region

The Company creates value through operated commercial hubs with low-risk development opportunities, nearby exploration, secondary recovery, cost reduction and third-party tariff revenues. Talisman is now ranked sixth in UK North Sea liquids production and second in the Central North Sea in oil field operations, as measured by the number of operated producing oil fields.

During the year, Talisman acquired significant new exploration prospects in several blocks adjoining existing core areas.

The J-1 discovery at Buchan is expected to be commercial. Talisman had disappointing results from the Kildrummy and Remus wells, which did not contain commercial quantities of oil. The Drum well in the Flotta Catchment area and the Eta-2 well in the Clyde field were drilling at year end. Commercial evaluation of both wells will be completed in 2003.

Production
(mboe/d)



	Oil & Liquids	Natural Gas
98	57.5	17.3
99	59.3	19.2
00	111.9	20.3
01	110.8	18.0
02	**127.5**	**20.3**

2002 IN REVIEW

Despite some operational difficulties and drilling delays, production was up 15% over 2001.

- Exploration and development spending totaled $431 million.
- Liquids production averaged 127,486 bbls/d and gas production 122 mmcf/d.
- The Halley and Hannay fields started production.
- Blake flank development was approved.
- Development drilling was successful at Claymore, Saltire and MacCulloch.
- Talisman drilled 18 gross (6.4 net) successful oil and gas wells.

2003 OUTLOOK

- Production is expected to be 115,000-120,000 bbls/d of liquids and 125-130 mmcf/d of natural gas.
- Exploration and development spending is expected to be $532 million, with $127 million on exploration and $405 million on development.
- The drilling program includes eight exploration and 27 development wells.
- The Blake flank development is expected to be on production late in the third quarter at 6,000 boe/d net to Talisman.

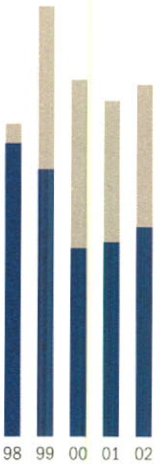
Saltire platform

Flotta Terminal

Southeast Asia

Production
(mboe/d)

■ Oil & Liquids
■ Natural Gas



98	31.7	2.2
99	28.9	18.0
00	20.2	18.5
01	20.9	15.5
02	**22.5**	**15.7**


Corridor central facility, Indonesia


Offshore Malaysia

Poised for significant growth

In Indonesia, Talisman continues to develop its large gas reserves in the Suban and Sumpal fields in the Corridor Block. The infrastructure to supply the Caltex 2 gas contract was completed by year end 2002. The anticipated growth in long-term gas sales will be achieved through development of the Suban field and continued expansion of the Corridor gas plants. Under arrangements with Singapore Power, delivery of gas should commence in early 2004, following completion of the Grissik-Singapore pipeline. Discussions are underway to sell gas to markets in Malaysia and West Java. In Indonesia, Talisman's Corridor Block reserves have been independently evaluated.

Talisman acquired a 15% strategic interest in Transasia Pipeline Company Pvt. Ltd.

In Malaysia/Vietnam, development of the PM-3 Commercial Arrangement Area (PM-3 CAA) project was 60% complete by March 2003. Oil and gas production from this development will increase significantly later in the year and is expected to average over 40,000 boe/d net to Talisman in 2004.

In 2002, Talisman successfully bid for Block 46/02 offshore Vietnam and a petroleum contract was signed in December. This large block is adjacent to the Company's PM-3 CAA project and provides additional exploration and development opportunities.

2002 IN REVIEW

Indonesia

- Production averaged 94 mmcf/d of gas and 16,852 bbls/d of liquids.
- Following continued drilling success at Suban, Talisman had 2.2 tcf of proved and probable gas reserves in Indonesia at year end.
- Exploration and development spending totaled $73 million.

Malaysia & Vietnam

- Production averaged 5,617 bbls/d of liquids.
- Drilling was successful at Bunga Kekwa and W. Bunga Raya, with unsuccessful wells at Chengkeh and E. Seroja
- Exploration and development spending totaled $196 million.

2003 OUTLOOK

Indonesia

- The exploration program includes wells at Suban and Sambar in the Corridor Block.
- Production is estimated to be 95-100 mmcf/d of gas and 14,000-15,000 bbls/d of liquids.
- Exploration and development spending is expected to be $70 million.
- Discussions to supply gas from Corridor to Malaysia and West Java will continue.
- Construction of a gas pipeline to Singapore will continue prior to initial sales in early 2004.

Malaysia & Vietnam

- Completion of the PM-3 CAA development project.
- Production is expected to average 10-15 mmcf/d of gas and 6,000-7,000 bbls/d of liquids.
- Exploration and development spending is estimated at $296 million.
- The drilling program includes 21 development and 9-10 exploration and appraisal wells.
- The first exploration well for Block 46/02 in Vietnam is planned for late 2003.

The Caribbean & Latin America

Trinidad


Eastern Block, Trinidad

Development underway

Talisman holds a 25% interest in Block 2(c) offshore Trinidad where a major oil and gas development project is underway. First production is expected in early 2005 with Talisman's share estimated at 18,000-25,000 bbls/d. Talisman was awarded a 30% interest in a Production Sharing Contract on Block 3(a), which is adjacent and contiguous to its offshore discoveries at Angostura in Block 2(c). The Company relinquished its 50% interest in offshore Block 2(ab).

In 2002, Talisman acquired an operated 65% interest in the onshore Eastern Block. A large 2D and 3D seismic program is planned, with first exploration drilling expected in 2004.

Capital spending in 2003 is expected to be $149 million to fund development of the Angostura discoveries, including four development and five offshore exploration wells.

Colombia

Large exploration upside

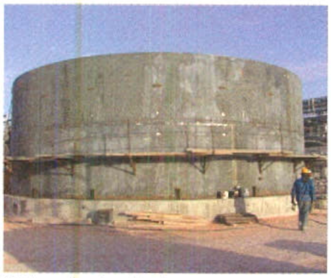
In 2002, Talisman exchanged a 30% interest and operatorship in the Acevedo Block for a 30% non-operated interest in the Altamizal Block. The Company also acquired a 30% non-operated interest in the adjacent Huila Norte Block. Talisman expects to participate in exploration drilling on all three blocks in 2003 and early 2004.

Geophysical operations on the Tangara and Mundo Nuevo Blocks commenced in 2001 and are currently continuing, with plans for Talisman to participate in one exploration well in late 2003 or early 2004.

Capital spending in Colombia in 2003 is expected to be approximately $33 million, including drilling up to four exploration wells.


Calgary visualization centre

Africa & the Middle East



MLN construction, Algeria

Algeria

Production has started

Talisman holds a 35% interest in Block 405a and a 2% interest in the Ourhoud field, a small portion of which extends onto Block 405a. Production from Ourhoud commenced at year end, with first sales in January 2003. Development of the MLN complex of fields on Block 405 continues with first production expected in mid-2003. Talisman's production from Algeria in 2003 is expected to be 9,000-10,000 bbls/d.

In 2003, Talisman plans capital spending of approximately $60 million in Algeria, which includes drilling 10 wells at Ourhoud and three development wells in the MLN area.

Qatar

Large exploration potential

In November 2002, Talisman signed an Exploration and Production Sharing Agreement for a 100% working interest in offshore Block 10 in Qatar. Geophysical work is expected to begin in early 2003, once the agreement is ratified by official decree of the Emir of Qatar.

Sudan

Sale announced

On October 30, 2002, Talisman announced that it had entered into an agreement for the sale of its interests in its oil and gas properties in Sudan for US$758 million. Completion of the sale is subject to certain conditions, primarily relating to obtaining consents from the Government of Sudan and the other consortium members and Talisman expects completion of the transaction in the near future. Until the sale is closed, Talisman will continue to record production volumes from the project.

Commitment to Stakeholders

- ✓ create value for shareholders
- ✓ provide a safe and healthy workplace
- ✓ be a responsible neighbour

CORPORATE RESPONSIBILITY

Talisman conducts its activities in a socially responsible manner. We believe that our operations bring direct benefits to the communities in which we work, such as job creation and support of community projects that create opportunities for a better future. As a responsible company, we also observe and promote ethical business practices and advocate respect and tolerance by and for all people.

In 2002, Talisman contributed over $9 million to several hundred community projects and causes in Canada, the UK, Sudan, Indonesia, Malaysia, Trinidad and Colombia.

Talisman has adopted the International Code of Ethics for Canadian Business and is committed to maintaining high standards of excellence in corporate citizenship and social responsibility wherever it does business.

Talisman's 2002 Corporate Responsibility Report provides an in-depth review of the Company's activities worldwide, in the areas of human rights, community participation, employee relations, ethical business conduct and health, safety and environment. A copy of this report is available on the Talisman website at **www.talisman-energy.com** or by contacting our head office in Calgary.

HEALTH, SAFETY AND ENVIRONMENT

Talisman's performance in the areas of occupational health, employee and public safety and environmental protection is central to the Company's corporate reputation and success worldwide. The Company's Health, Safety and Environment policy commits to providing safe and healthy operations and respect for the interests of the communities in which we operate, as well as our other stakeholders.

Management's Discussion and Analysis

Cash Flow
(millions of dollars)

98	631
99	1,111
00	2,413
01	2,494
02	**2,645**

Cash Flow Per Share
(dollars)

98	5.64
99	8.91
00	17.51
01	18.48
02	**19.73**

Highlights

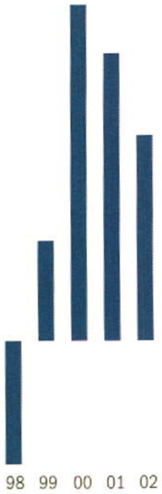
	2002	2001	Change (%)
Cash flow [1]	**2.6 billion**	2.5 billion	6
Net income [2]	**524 million**	733 million	(29)
Per share			
Cash flow [1]	**19.73**	18.48	7
Net income [2]	**3.73**	5.25	(29)
Diluted per share			
Cash flow [1]	**19.43**	18.15	7
Net income [2]	**3.67**	5.16	(29)
Production	**445 mboe/d**	419 mboe/d	6
Average sales price	**32.10/boe**	32.91/boe	(2)
Operating costs	**6.48/boe**	5.79/boe	12
Exploration and development spending	**1.8 billion**	1.9 billion	(2)
Proved reserve additions (including acquisitions)	**159 mmboe**	462 mmboe	(66)
Finding, development and acquisition costs	**12.15/boe**	7.08/boe	72
Production per share	**1.21 boe/share**	1.13 boe/share	7

1 Cash flow and cash flow per share are non-GAAP measures that represent net income before exploration costs, DD&A, future taxes and other non-cash expenses. The components of cash flow are set out in note 14 to the Consolidated Financial Statements.
2 Prior year's comparative has been restated for a new CICA accounting standard (see note 2 to the Consolidated Financial Statements).

This discussion and analysis should be read in conjunction with the audited Consolidated Financial Statements of the Company. In particular, note 16 provides segmented financial information that forms the basis for much of the following discussion and analysis. The calculation of barrels of oil equivalent (boe) is based on a conversion rate of six thousand cubic feet (mcf) of natural gas for one barrel of oil. All comparative percentages are between the years ended December 31, 2002 and December 31, 2001, unless stated otherwise. Reported production represents Talisman's working interest share before royalties unless otherwise noted. Selected quarterly unaudited financial data, including product netbacks, may be found on pages 69 and 70 of this Annual Report.

Included in the Management's Discussion and Analysis (MD&A) are references to terms commonly used in the oil and gas industry such as cash flow, cash flow per share and EBITDAX. These terms are not defined by Generally Accepted Accounting Principles in either Canada or the US. Consequently these are referred to as non-GAAP measures. Cash flow, as commonly used, appears as a separate caption on the Company's cash flow statement and is reconciled to both net income and cash flow from operations. EBITDAX is defined on page 27 of this Annual Report.

Net Income (Loss)
(millions of dollars)



98	(314)
99	255
00	857
01	733
02	**524**

Net Income (Loss) Per Share
(dollars)

98	(2.80)
99	1.93
00	6.05
01	5.25
02	**3.73**

2003 OUTLOOK

Talisman anticipates at least 5% production per share growth in 2003 and 10% in 2004 (after adjusting for Sudan).

- Production is expected to average 395,000-415,000 boe/d, including Sudan volumes in the first quarter.
- Startup of the Malaysia/Vietnam PM-3 CAA Phase 2 and Algeria MLN developments.
- Production of 60-70 mmcf/d in the US.
- Planned exploration and development spending of $2.1 billion ($975 million in North America).
- The Sudan sale is expected to close in the first quarter of 2003.
- Average unit operating costs are expected to increase to $7/boe reflecting the absence of Sudan and a higher operating cost environment.

2002 VARIANCES

The significant variances from 2001 are:

- Increased production volumes contributed $300 million of additional cash flow.
- Lower natural gas prices ($447 million) mostly offset by higher oil and liquids prices ($330 million) and increased hedging gains ($67 million).
- Higher operating expense ($169 million).
- Reduced current taxes ($95 million) mostly on lower natural gas prices in North America.
- Higher DD&A with increased production ($182 million).
- Dry hole and exploration expense increased $99 million.
- Increased future tax due to one time non-cash charge on new UK supplemental oil and gas tax.

Cash flow of $2.6 billion ($19.73/share)[1]
Net income of $524 million ($3.73/share)[1]

NET INCOME AND CASH FLOW VARIANCE (millions)

2001 Net income	733
Favorable (unfavorable)	
Cash flow variance	
Oil and liquids volumes	254
Natural gas volumes	46
Natural gas prices	(447)
Oil and liquids prices	330
Hedging	67
Royalties	62
Other revenue	(2)
Operating expense	(169)
Interest expense	(25)
Current taxes (including PRT)	95
General and administration	(30)
Other	(30)
Total cash flow variance	151
Non-cash items	
Depreciation, depletion and amortization expense	(182)
Dry hole expense	(61)
Exploration expense	(38)
Future taxes (including PRT)	(76)
Other	(3)
Total non-cash items	(360)
2002 Net income[1]	524

1 Net income, cash flow and cash flow per share are before preferred security charges of $24 million, net of tax ($42 million, before tax). The components of cash flow are set out in note 14 to the Consolidated Financial Statements.

TALISMAN'S PERFORMANCE HIGHLIGHTS IN 2002

In 2002, Talisman posted record cash flow of $2.6 billion ($19.73/share). Production also grew to a record 445,000 boe/d.

Progress was made on the Company's key development projects. The Malaysia/Vietnam PM-3 CAA project is expected to come on stream in 2003. Production commenced in Algeria at year end and is expected to increase through 2003. An expansion at the Corridor gas plant facility in Indonesia was completed in 2002 to support additional future sales under gas sales agreements and memoranda of understanding. Project sanction has been received for the Trinidad development with first production expected in early 2005. The Company also announced a North Sea oil discovery at J-1 and is in the process of establishing a natural gas core area in the US.

On October 30, the Company announced an agreement for the sale of its Sudan operations for $1.2 billion. During 2002 and the early part of 2003, 5.8 million shares (4.5% of shares currently outstanding) were repurchased at an average price of $57.05/share.

Cash flow in 2002 was $2.6 billion ($19.73/share), increasing for the fourth straight year and up 6% from last year. Net income was $524 million ($3.73/share), down from 2001, with over half of the decrease due to a one time non-cash expense of $128 million relating to a supplemental 10% tax on UK oil and gas profits. The UK also eliminated government royalties effective January 2003 and accelerated capital allowance deductions. Based on current expected capital expenditures, Talisman anticipates the short term impact of the supplemental tax will be more than offset by the abolition of royalties and accelerated capital allowance deductions and will have a positive impact on cash flow through the end of 2004.

The Company grew production by 6% to average 445,000 boe/d, slightly below the target originally set at the beginning of 2002, due in part to higher than anticipated maintenance in the North Sea. Talisman drilled 439 successful wells in 2002 adding 196 mmboe of reserves, excluding net reserves revisions and acquisitions, replacing 121% of production. Net of revisions and including acquisitions, the Company added 159 mmboe of reserves, replacing 99% of production.

Operating costs were up 12% to $6.48/boe, above the $6/boe target set last year, largely due to higher oil field service and maintenance costs, a higher percentage of North Sea volumes and the strengthening UK Pound Sterling.

SEGMENTED RESULTS REVIEW

Talisman's operations in 2002 were conducted principally in four geographic segments which are North America, North Sea, Southeast Asia and Sudan. Production had also started in Algeria at year end with the first sale in January 2003. Exploration is being conducted in other areas outside the principal geographic segments. On October 30, 2002, the Company signed an agreement for the sale of its operations in Sudan subject to government and consortium member approvals and other closing conditions.

The following is a brief summary of the financial results of each geographic segment. Additional geographic financial results disclosure may be found in note 16 of the Consolidated Financial Statements. More detailed analysis on the Company's results can be found after this Segmented Results Review.

NORTH AMERICA

During 2002, the North American operations contributed $437 million or 32% of the Company's pre-tax segmented income of $1.4 billion, down from $746 million (46% of $1.6 billion) in 2001. The Company's pre-tax segmented income is before corporate G&A, interest, taxes and non-segmented foreign exchange gains and losses. Net revenue in North America decreased 7% to $1.7 billion due principally to lower natural gas revenue as a result of reduced prices. Total North American operating expenses increased by 4% to $357 million due to industry wide cost pressures, higher processing fees and increased natural gas volumes. DD&A increased to $614 million, up from $585 million due to a full year of amortization of the costs associated with the Petromet acquisition. Dry hole expense increased to $128 million due to the expanded exploration budget, the drilling of deeper natural gas targets and a strategic property review.

NORTH SEA

The North Sea pre-tax segmented income increased slightly to $542 million and accounted for 40% of the Company's segmented income during 2002, up from 33% in 2001. North Sea net revenue increased 20% to $1.9 billion on higher production volumes and higher oil and liquids prices. Operating

SEGMENTED PRE-TAX INCOME[1]

	North America		North Sea		Southeast Asia		Sudan		Other[2]		Total	
(millions of dollars)	**2002**	2001	**2002**	2001	2002	2001	**2002**	2001	2002	2001	2002	2001
Revenue	**2,014**	2,332	**1,971**	1,638	**486**	439	**828**	638	**–**	–	**5,299**	5,047
Royalties	**(373)**	(558)	**(96)**	(93)	**(130)**	(90)	**(328)**	(248)	**–**	–	**(927)**	(989)
Other income	**38**	34	**40**	46	**1**	1	**1**	1	**–**	–	**80**	82
Net Revenue	**1,679**	1,808	**1,915**	1,591	**357**	350	**501**	391			**4,452**	4,140
Expenses												
Operating	**(357)**	(343)	**(588)**	(467)	**(86)**	(70)	**(84)**	(66)	**–**	–	**(1,115)**	(946)
DD&A	**(614)**	(585)	**(701)**	(558)	**(87)**	(93)	**(93)**	(77)	**–**	–	**(1,495)**	(1,313)
Dry hole	**(128)**	(54)	**(9)**	(21)	**(4)**	(8)	**(13)**	(16)	**(20)**	(14)	**(174)**	(113)
Exploration	**(66)**	(69)	**(20)**	(30)	**(19)**	(8)	**(6)**	(11)	**(74)**	(29)	**(185)**	(147)
Other	**(77)**	(11)	**(55)**	23	**(11)**	2	**5**	(11)	**7**	(8)	**(131)**	(5)
	437	746	**542**	538	**150**	173	**310**	210	**(87)**	(51)	**1,352**	1,616

1 Segmented pre-tax income is before corporate G&A, interest, taxes and non-segmented foreign exchange gains and losses.
2 Other in 2002 and 2001 primarily relates to exploration activities in Trinidad, Algeria and Colombia.

expense increased to $588 million, up 26% from 2001 with higher volumes, the strengthening Pound Sterling and increased maintenance and well workovers. DD&A increased to $701 million, up from $558 million, due to increased volumes and higher depreciation rates at certain fields. Other expense includes property impairments of $74 million.

SOUTHEAST ASIA

Southeast Asia contributed 11% ($150 million) to the Company's pre-tax segmented income in both 2002 and 2001. An increase in oil revenues, primarily from the inclusion of a full year of production from PM-3 CAA in Malaysia/Vietnam, more than offset higher royalties in Indonesia to increase net revenues to $357 million. Net revenue from natural gas sales were unchanged. Operating costs increased $16 million to $86 million with the inclusion of a full year of operating costs from PM-3 CAA and higher overhead costs at Corridor in Indonesia. DD&A decreased $6 million to $87 million in 2002 due to 2001 including minor asset impairments. Exploration expense increased $11 million due to the increased spending in Malaysia and Vietnam.

SUDAN

The Sudan operations in 2002 generated a pre-tax income of $310 million, up from $210 million in 2001. Higher oil production and prices increased Sudan's corporate contribution to 23%. Operating costs and DD&A increased primarily due to higher volumes.

CORPORATE RESULTS REVIEW

REVENUE

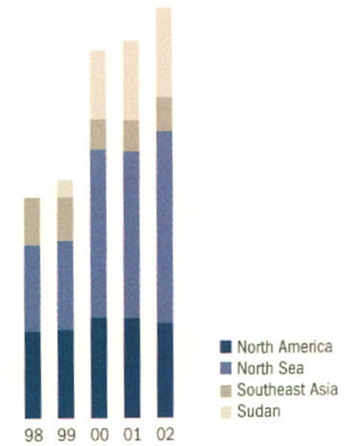
Revenues from oil and natural gas sales in 2002 were $5.3 billion, up $252 million from 2001, on higher oil volumes ($254 million) and oil prices ($330 million), substantially offset by lower natural gas prices ($447 million).

DAILY PRODUCTION VOLUMES

	2002	2001	2000
Oil and liquids (mbbls/d)			
North America	**62.7**	66.0	66.4
North Sea	**127.5**	110.8	111.9
Southeast Asia [1]	**22.5**	20.9	20.2
Sudan	**60.0**	53.3	45.9
	272.7	251.0	244.4
Natural gas (mmcf/d)			
North America	**820**	809	755
North Sea	**122**	108	122
Southeast Asia [1]	**94**	93	111
	1,036	1,010	988
Total (mboe/d @ 6:1)	**445**	419	409

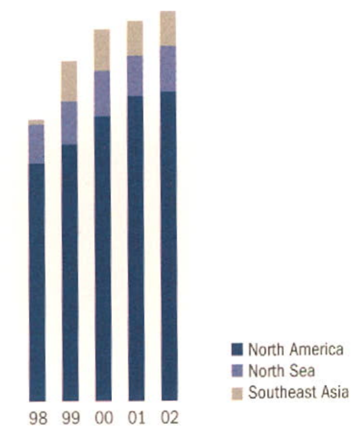
1 Includes operations in Indonesia and Malaysia/Vietnam.

Oil & Liquids Production
(mbbls/d)



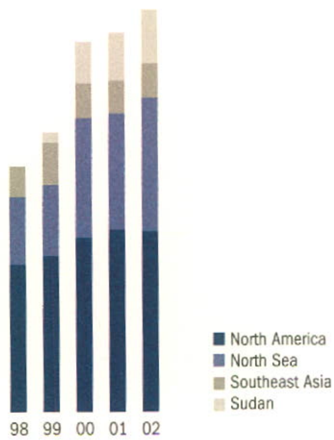
	North America	North Sea	Southeast Asia	Sudan	Total
98	57.5	57.5	31.7	–	146.7
99	58.5	59.3	28.8	11.7	158.3
00	66.4	111.9	20.2	45.9	244.4
01	66.0	110.8	20.9	53.3	251.0
02	**62.7**	**127.5**	**22.5**	**60.0**	**272.7**

Natural Gas Production
(mmcf/d)



	North America	North Sea	Southeast Asia	Total
98	631	104	13	748
99	681	115	108	904
00	755	122	111	988
01	809	108	93	1,010
02	**820**	**122**	**94**	**1,036**

Total Production
(mboe/d)



	North America	North Sea	Southeast Asia	Sudan	Total
98	163	75	34	–	271
99	172	79	47	12	309
00	192	132	39	46	409
01	201	129	36	53	419
02	**199**	**148**	**38**	**60**	**445**

In 2002, Talisman increased its daily production by 6% to 445 mboe/d with oil and liquids production up 9% to 272,740 bbls/d and natural gas increasing 3% to 1,036 mmcf/d.

Talisman's natural gas production in North America averaged 820 mmcf/d, up 11 mmcf/d. A successful drilling program (223 successful gas wells) and the inclusion of a full year of production from the Petromet Resources Limited properties acquired in mid-2001 offset natural declines. Increased lead times to tie in new production, minor property dispositions and localized infrastructure constraints delayed some expected production volumes in 2002. Fourth quarter natural gas production averaged 826 mmcf/d with the tie in of new wells and an acquisition in the Appalachia area of the US which contributed 10 mmcf/d. Canadian oil and liquids production for 2002 averaged 62,676 bbls/d, down 5%, due to natural declines, regulatory delays and minor property dispositions offset by drilling at Chauvin and other core areas (146 successful oil wells).

North Sea oil and liquids production averaged 127,486 bbls/d, up 16,658 bbls/d or 15%. Growth came from the Hannay and Halley developments (on stream in 2002), a full year's production from Beatrice and Blake and development drilling in other core areas. Production at Halley averaged 2,300 bbls/d while Hannay averaged 2,400 bbls/d. Incremental production from Beatrice added 5,250 bbls/d and Ross/Blake increased 11,000 bbls/d over 2001. Beatrice was shut in during the first half of 2001 for pipeline repairs. Ross had been shut in for the second quarter of 2001 to allow production vessel modifications for Blake production. Development program delays, unsuccessful development wells and natural decline in other fields kept volumes below last year's forecast of 144,000-155,000 bbls/d. North Sea fourth quarter production was impacted by maintenance work at the Ross/Blake FPSO and reduced production at Halley pending the drilling of a water injector planned for 2003. Natural gas production in 2002 increased 13% to 122 mmcf/d, slightly above forecast, due to a temporary increase in pipeline capacity available to Talisman and the acquisition of Lundin Oil's carried interest in the Brae Field.

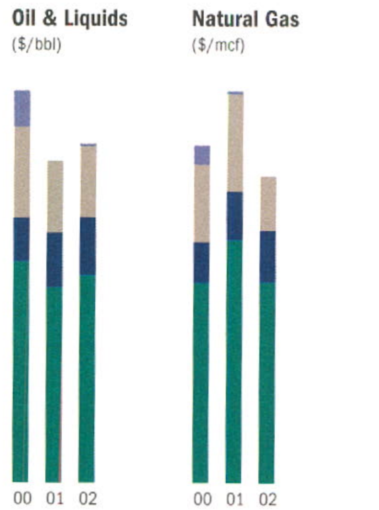
Southeast Asia natural gas production averaged 94 mmcf/d. Production from OK Block (5 mmcf/d), which commenced at the end of the first quarter, offset lower Caltex demand for Corridor natural gas (89 mmcf/d). Caltex is currently the sole purchaser of Corridor natural gas; however, gas sales agreements have been signed with other parties, which will result in additional gas sales in the future. The construction of a pipeline and an expansion of the Corridor gas facilities are currently underway to support the additional anticipated gas sales. As a result of sales to Caltex declining below their committed gas quantity of approximately 100 mmcf/d, Talisman recorded $10 million of deferred revenue for the year ($18 million to date).

NETBACKS

- Hedging (gain)
- Royalties
- Operating Costs
- Netbacks

Netbacks do not include synthetic oil or pipeline operations.

NORTH AMERICA



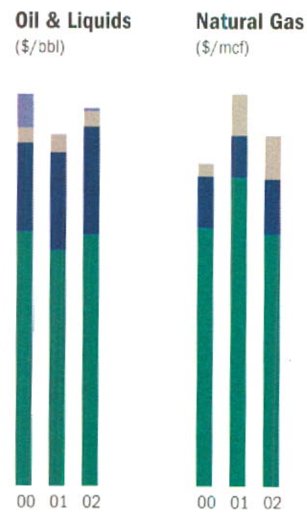
Oil & Liquids

	Netbacks	Operating Costs	Royalties	Hedging (gain)	Price
00	21.29	4.17	8.74	3.44	37.64
01	18.82	5.22	6.88	(0.12)	30.80
02	**19.97**	**5.55**	**6.85**	**0.06**	**32.43**

Natural Gas

00	2.77	0.56	1.07	0.26	4.66
01	3.36	0.67	1.34	0.02	5.39
02	**2.78**	**0.71**	**0.75**	**(0.28)**	**3.96**

NORTH SEA



Oil & Liquids

	Netbacks	Operating Costs	Royalties	Hedging (gain)	Price
00	26.24	9.13	1.57	3.44	40.38
01	24.33	10.06	1.85	(0.17)	36.07
02	**25.93**	**11.11**	**1.60**	**0.12**	**38.76**

Natural Gas

00	2.87	0.57	0.14	–	3.58
01	3.43	0.46	0.46	–	4.35
02	**2.80**	**0.61**	**0.48**	**–**	**3.89**

Southeast Asia liquids production averaged 22,469 bbls/d with PM-3 CAA in Malaysia/Vietnam, acquired from Lundin Oil in 2001, contributing 5,617 bbls/d.

Sudan production averaged 60,109 bbls/d, up 13% with the tie in of new wells, increased pipeline capacity and the increased use of pipeline drag reducing agents and electrical submersible pumps.

COMMODITY PRICES

	2002	2001	2000
Oil and liquids ($/bbl)			
North America	**32.43**	30.80	37.64
North Sea	**38.76**	36.07	40.38
Southeast Asia [1]	**39.46**	35.97	42.50
Sudan	**37.79**	32.66	38.52
	37.20	33.99	39.48
Natural gas ($/mcf)			
North America	**3.96**	5.39	4.66
North Sea	**3.89**	4.35	3.58
Southeast Asia [1]	**4.72**	4.80	5.64
	4.03	5.22	4.63
Company ($/boe)	**32.10**	32.91	34.74

1 Includes operations in Indonesia and Malaysia/Vietnam.
Prices are before hedging activities and do not include synthetic oil.

World oil prices were slightly higher in 2002 and continued to increase throughout 2002 and into 2003, when they surpassed US$35/bbl. Political uncertainty in the Middle East and Venezuela, modest growth in demand and lower US oil inventories have exerted upward pressure on prices.

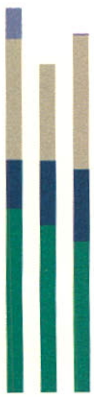
Talisman's North American oil and liquids price averaged $32.43/bbl, up 5% from last year on improved crude oil differentials. The benchmark West Texas Intermediate (WTI) crude oil price averaged US$26.15/bbl in 2002, up 1% from 2001. The Company's natural gas price in North America averaged $3.96/mcf, down 27% from last year. North American natural gas prices were well below 2001 levels early in the year. However, concerns over gas supplies for the winter season led to NYMEX prices approaching US$5/mcf by year end.

The Company's North Sea oil price averaged $38.76/bbl. Both Talisman's average oil price and Brent price are up from 2001. The Company's North Sea natural gas price decreased 11% as a result of higher spot sales during the summer months when gas prices are typically lower.

The Company's Southeast Asia oil price averaged $39.46/bbl, up 10% over 2001. The natural gas price in Southeast Asia averaged $4.72/mcf, down slightly from 2001. Corridor gas production, which constitutes the majority of the Company's gas sales in Southeast Asia, is exchanged for Duri crude oil on an energy equivalent basis and is sold offshore with payment in US dollars. However, an adjustment to Corridor's gas price in 2002, relating to 2001, decreased Talisman's average Southeast Asia

SOUTHEAST ASIA

Oil & Liquids
($/bbl)



Natural Gas
($/mcf)

Oil & Liquids

					Price
00	20.30	5.40	13.36	3.44	42.50
01	18.45	7.13	10.69	(0.30)	35.97
02	**16.64**	**7.93**	**14.83**	**0.06**	**39.46**

Natural Gas

00	4.87	0.39	0.34	0.04	5.64
01	4.07	0.47	0.24	0.02	4.80
02	**3.88**	**0.59**	**0.25**	**–**	**4.72**

SUDAN

Oil & Liquids
($/bbl)

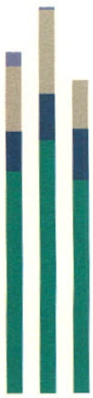
Oil & Liquids

					Price
00	16.28	3.80	15.00	3.44	38.52
01	16.61	3.40	12.78	(0.13)	32.66
02	**18.96**	**3.82**	**14.94**	**0.07**	**37.79**

COMPANY

Oil & Liquids
($/bbl)

Natural Gas
($/mcf)



Oil & Liquids

					Price
00	22.55	6.50	6.99	3.44	39.48
01	20.78	7.15	6.22	(0.16)	33.99
02	**22.29**	**7.99**	**6.83**	**0.09**	**37.20**

Natural Gas

00	3.01	0.54	0.88	0.20	4.63
01	3.43	0.63	1.14	0.02	5.22
02	**2.89**	**0.69**	**0.67**	**(0.22)**	**4.03**

reported gas price by $0.22/mcf. OK Block gas, which came on stream in 2002, is sold under contract at approximately $1.35/mcf and reduced Talisman's average price for the region.

The Sudan oil price increased 16% to $37.79/bbl due to an increase in the Minas benchmark price and reduced transportation costs.

The Company's average sales prices are before a net hedging gain of $75 million, comprised of a $0.22/mcf gain on gas hedges (2001 $0.02/mcf loss) and a $0.09/bbl loss on oil hedges (2001 $0.16/bbl gain). The physical and financial commodity price contracts for 2003 outstanding at year end are disclosed in notes 9 and 10 of the Consolidated Financial Statements with additional discussion in the MD&A section entitled Derivative Financial Instruments and Commodity Sales Contracts. Additional discussion of the expected impact of commodity price contracts on the Company's 2003 results can be found in the Outlook section of this MD&A. The Company's accounting policy with respect to derivative financial instruments and commodity contracts is disclosed in note 1(k) of the Consolidated Financial Statements.

ROYALTIES

Average royalty rates (%)	**2002**	2001	2000
Oil and liquids			
North America	**21**	22	23
North Sea	**4**	5	4
Southeast Asia [1]	**38**	30	31
Sudan	**40**	39	39
	18	18	18
Natural gas			
North America	**19**	25	23
North Sea	**12**	11	4
Southeast Asia [1]	**5**	5	6
	17	22	19
Company	**18**	20	18

1 Includes operations in Indonesia and Malaysia/Vietnam.
Royalty rates do not include synthetic oil or pipeline operations.

The consolidated royalty expense decreased to $927 million in 2002, with lower royalties paid in North America due primarily to lower natural gas prices partially offset by higher royalties in Southeast Asia and Sudan. The overall corporate royalty rate dropped to 18% due to the impact of lower natural gas prices more than offsetting other factors.

North American natural gas royalties, which are largely determined on a sliding scale based on price, averaged 19%, down from 25% in 2001. The Corporate royalty rate for oil and liquids was the same, year-over-year, at 18% with an increase in Southeast Asia offsetting small decreases in other operating areas. Royalties increased in Southeast Asia due to the depletion of a cost recovery pool at Tanjung. Oil from PM-3 CAA in Malaysia/Vietnam has a current royalty rate of 30%. Sudan royalties increased in the fourth quarter to 47%, which resulted in the annual rate being 40%. The fourth quarter Sudan royalties increased due to higher production and prices and the annual royalty adjustment where the average production, price and operating costs for the year are applied in recalculating the total royalty due for 2002.

The UK abolished government oil and gas royalties effective January 2003. Talisman's remaining North Sea royalties are in respect of non-government royalty payments. The Company's North Sea royalty rate is expected to average less than 2%, down from 5% in 2002.

OPERATING EXPENSE

	2002	2001	2000
Oil and liquids ($/bbl)			
North America	**5.55**	5.22	4.17
North Sea	**11.11**	10.06	9.13
Southeast Asia [1]	**7.93**	7.13	5.40
Sudan	**3.82**	3.40	3.80
	7.99	7.15	6.50
Natural gas ($/mcf)			
North America	**0.71**	0.67	0.56
North Sea	**0.61**	0.46	0.57
Southeast Asia [1]	**0.59**	0.47	0.39
	0.69	0.63	0.54
Company ($/boe)	**6.48**	5.79	5.19

1 Includes operations in Indonesia and Malaysia/Vietnam.
Unit operating costs do not include synthetic oil or pipeline operations.

Total operating expense for the Company increased $169 million to $1.1 billion due to increased maintenance and oil field service costs, higher production volumes and the strengthening UK Pound Sterling. On a per unit basis, costs increased 12% to $6.48/boe.

Unit operating costs in North America averaged $4.65/boe, up 5% from 2001. Oil and liquids unit operating costs increased 6% to $5.55/bbl, largely due to lower production and higher oil field service costs. Unit operating costs for natural gas increased to $0.71/mcf with higher processing and maintenance costs.

North Sea oil and liquids unit operating costs increased $1.05/bbl or 10% to average $11.11/bbl. The strengthening UK Pound Sterling accounted for over half of the unit cost increase with the remainder due to higher maintenance and well workover costs. North Sea natural gas costs averaged $0.61/mcf, up from $0.46/mcf in 2001, due to higher maintenance costs at Brae.

Southeast Asia unit operating costs averaged $6.13/boe, up from $5.29/boe in 2001. Operating costs at Corridor averaged $0.60/mcf, up from $0.47/mcf in 2001, partly due to higher overhead allocations from the operator. OK Block natural gas production costs averaged $0.12/mcf. Oil and liquids unit costs were $7.93/bbl in Southeast Asia with operating costs at PM-3 CAA averaging $8.18/bbl. In Indonesia, oil and liquids unit costs increased in 2002 due to declining production.

Sudan operating costs averaged $3.82/bbl, up 12% with the increased use of drag reducing agents and electrical submersible pumps.

DEPRECIATION, DEPLETION AND AMORTIZATION EXPENSE

	2002		2001		2000	
	$/boe	**$millions**	$/boe	$millions	$/boe	$millions
North America	**8.44**	**614**	7.98	585	6.79	478
North Sea	**12.99**	**701**	11.86	558	10.59	512
Southeast Asia [1]	**6.24**	**87**	7.00	93	5.87	83
Sudan	**4.24**	**93**	3.98	77	4.72	80
Company	**9.19**	**1,495**	8.58	1,313	7.70	1,153

1 Includes operations in Indonesia and Malaysia/Vietnam.

The Company's depreciation, depletion and amortization (DD&A) expense increased to $1.5 billion or $9.19/boe, with half the increase due to higher production volumes in the North Sea. The DD&A rate in North America increased with a full year of amortization of the costs associated with the Petromet acquisition. The 2001 DD&A expense in North America included $10 million of goodwill amortization. Goodwill ceased being amortized effective 2002. In the North Sea, higher DD&A, primarily at Beatrice and Ross/Blake, contributed to the $1.13/boe increase. The Southeast Asia rate decreased in 2002 as the 2001 expense included $8 million of minor property impairments. Sudan's DD&A rate increased slightly to $4.24/bbl.

For additional information relating to DD&A refer to the MD&A section entitled Application of Critical Accounting Policies and to note 5 of the Consolidated Financial Statements.

DRY HOLE EXPENSE

(millions of dollars)	**2002**	2001	2000
North America	**128**	54	29
North Sea	**9**	21	15
Southeast Asia [1]	**4**	8	17
Sudan	**13**	16	3
Other [2]	**20**	14	13
	174	113	77

1 Includes operations in Indonesia and Malaysia/Vietnam.
2 Other includes Algeria (2002 – $nil; 2001 – $5 million; 2000 – $13 million) and Trinidad (2002 – $20 million; 2001 – $9 million, 2000 – $nil).

Dry hole expense in North America increased with the write-off of 40 wells, higher exploration expenditures, a strategic property review and the focus on deeper higher value targets. In the North Sea, most of the expense related to the Remus (Beatrice) well. Two wells were written off in each of Malaysia, Indonesia and Trinidad. In Sudan, seven wells were dry resulting in a $13 million expense.

Under the Successful Efforts method of accounting for oil and gas activities, the costs of unsuccessful exploration wells are written-off to dry hole expense in the year such determination is made. Until such determination, the costs are included in non-depleted capital. At year end, $309 million of costs relating to exploration wells, down from $399 million in 2001, were included in non-depleted capital and not subject to DD&A.

EXPLORATION EXPENSE

(millions of dollars)	**2002**	2001	2000
North America	**66**	69	54
North Sea	**20**	30	13
Southeast Asia [1]	**19**	8	7
Sudan	**6**	11	8
Other	**74**	29	18
	185	147	100

1 Includes operations in Indonesia and Malaysia/Vietnam.

Exploration expense consists of geological and geophysical costs, seismic, land lease rentals and indirect exploration expenses. There has been a steady increase in the Company's exploration spending since 1999. Exploration expense is closely tied to the total amount of exploration capital spent in a year. Expenses constituting Other in 2002 relate mostly to activities in Trinidad and Colombia.

CORPORATE EXPENSE

(millions of dollars)	**2002**	2001	2000
G&A expense	**138**	108	95
Interest expense	**164**	139	136
Capitalized interest	**25**	19	16
Preferred securities charges, net of tax	**24**	24	22
Other revenue	**80**	82	99
Other expenses (income) [1]	**113**	78	64

1 Prior year comparatives have been restated for a new CICA accounting standard (see note 2 to the Consolidated Financial Statements)

General and administrative (G&A) expense increased due to higher legal and pension costs, salary increases and additional personnel due to expanding investment and operations. On a per unit basis, G&A was $0.85/boe in 2002, compared to $0.71/boe in 2001.

As a result of higher average debt levels during the year, interest on long-term debt, including capitalized interest, increased to $189 million. Interest capitalized in 2002 is associated with the Malaysia/Vietnam PM-3 CAA development.

Preferred securities charges, net of taxes, have been charged directly to retained earnings and are deducted from net income to determine net income per share. Preferred security charges, before tax, totaled $42 million (2001 – $42 million).

Other revenue includes pipeline and custom treating revenues and miscellaneous income. Other expenses for 2002 include the Kildrummy and Beechnut write-offs ($74 million), foreign exchange losses ($28 million) and losses on property dispositions ($10 million). The 2001 other expenses included foreign exchange losses ($51 million), a write-off associated with the early repayment of the Corridor project loan facility ($17 million) and a gain on property disposition ($11 million). The detailed breakdown of other revenue and other expenses (income) can be found in notes 11 and 12 to the Consolidated Financial Statements.

INCOME TAXES

EFFECTIVE INCOME TAX RATE

(millions of dollars)	**2002**	2001	2000
Income before tax	**1,068**	1,296	1,537
Less PRT	**124**	149	150
	944	1,147	1,387
Income tax expense			
Current	**258**	342	334
Future	**162**	72	196
	420	414	530
Effective income tax rate (%)	**44**	36	38

The Company's effective tax rate for 2002, after deducting Production Revenue Tax (PRT), was 44%, compared to 36% in 2001. This increase over 2001 is due to the UK enacting a 10% supplemental tax on North Sea oil and gas profits. See note 13 of the Consolidated Financial Statements for additional information on the Company's income taxes.

Current income tax expense decreased to $258 million in 2002 from $342 million in 2001, with the largest drop being in North America due to lower natural gas prices. Lower current income tax was incurred in the UK while higher production and oil prices increased current income tax expense in Sudan.

Partially offsetting the impact of the 10% supplemental UK tax was the acceleration of capital allowance deductions. The net effect of these changes is expected to be cash flow positive in the near term as the acceleration of capital allowances will more than offset the new 10% tax. On a non-cash basis, the UK provision for future tax liability was increased $128 million due to the supplemental tax. The 2002 future tax expense is net of a $12 million reduction in North America, which resulted from a decrease in the Alberta corporate tax rate.

The UK Government levies PRT on North Sea fields which received development approval before April 1993, based on gross profit after deducting allowable expenditures, a cost uplift, a portion of losses from certain other fields, abandonment costs and government royalties. PRT is deductible for purposes of calculating corporate income tax.

CAPITAL SPENDING [1]

(millions of dollars)	**2002**	2001	2000
North America	**939**	976	813
North Sea	**518**	664	527
Southeast Asia [2]	**269**	149	69
Sudan	**98**	117	70
Other	**228**	115	50
	2,052	2,021	1,529

1 Includes exploration, development and net asset acquisitions expenditures but excludes corporate acquisitions.

2 Includes operations in Indonesia and Malaysia/Vietnam.

Natural gas continues to be the focus of the Company's exploration activities in North America, supplemented by low risk oil projects. Of the $939 million of capital spending in North America, $321 million related to exploration activities while development accounted for $502 million. The Company participated in 424 wells in North America. Development spending was concentrated in the predominantly gas producing core areas in the Alberta Foothills, Greater Arch and Edson. Other spending included $90 million to acquire additional lands in the US with approximately 10 mmcf/d of production. Subsequent to year end, additional acquisitions were made in the US for $390 million, adding an incremental 55 mmcf/d of gas production.

Total capital spending in the North Sea of $518 million included $134 million for exploration and $297 million for development, with the remainder for property acquisitions. Expenditures included the Halley and Hannay developments, development drilling at Claymore, Buchan, Piper, Saltire, MacCulloch and the Tartan, Highlander and Petronella core area as well as topside refurbishments at Claymore and Tartan. Exploration spending primarily related to drilling the successful J-1 (Buchan) well, the Drum (Claymore) and Eta 2 (Clyde) wells, as well as the Remus (Beatrice) and Kildrummy (Piper) wells. The total North Sea capital spending in 2002 was below plan due to the cancellation of the Kildrummy development and delays in other programs. Interests were acquired in the producing fields Rubie, Renee and Ivanhoe/Rob Roy as well as minor additional working interests in the Claymore and Balmoral fields.

The PM-3 CAA development in Malaysia/Vietnam accounted for $175 million (including $25 million of capitalized interest) or 65% of total capital spending in Southeast Asia. A total of $73 million was spent in Indonesia with the majority on the Corridor gas facilities expansion and development drilling to support additional anticipated gas sales to Singapore. In addition to the $269 million of capital spending in Southeast Asia, a $36 million investment was made to acquire a 15% interest in Transasia Pipeline Company Pvt. Ltd., which owns a 40% interest in PT Transportasi Gas Indonesia, an Indonesian pipeline company that owns and operates the Duri pipeline in Indonesia and is currently building a pipeline from Indonesia to service gas markets in Batam and Singapore. This investment is included in other assets and will be carried at cost.

Capital spending in Sudan of $98 million was focused on ongoing development drilling and the addition of new pipeline pumping stations.

Other areas accounted for $228 million of the 2002 capital spending. Talisman spent $78 million in Trinidad, $107 million in Algeria and $22 million in Colombia. During 2002, five exploration wells were drilled in Trinidad; one on Block 2(ab) and four on Block 2(c). Based on the Company's review of the drilling results and seismic information, a decision was made to proceed with the Greater Angostura Project on Block 2(c) and to relinquish Block 2(ab). The Algeria spending advanced the Ourhoud project to first oil production at the end of 2002, while MLN is expected to come on stream in mid-2003. A 2D seismic program was completed in Colombia and a 3D seismic program is ongoing.

RESERVE REPLACEMENT

Talisman drilled 439 successful wells in 2002, adding 196 mmboe of reserves (before revisions and transfers), replacing 121% of production at a cost of $8.87/boe. Including net revisions and acquisitions, 159 mmboe of reserves were replaced (99% of production) at a cost of $12.15/boe.

During the year, the Company undertook an extensive review of thousands of oil and gas wells on smaller properties in Canada. These reviews, combined with the decision not to develop the Kildrummy field in the North Sea, contributed to a downward revision in total proved reserves of approximately 38 mmboe, or less than 3% of the total.

Finding and development costs in any one year can be misleading due to the long lead times associated with exploration and development. Therefore, five year weighted averages are better indicators. Over the last five years, the Company has replaced approximately 210% of production at a cost of $7.29/boe. Net revisions and transfers over the past five years have resulted in 54 mmboe of reserves being added to the Company's proved reserve base, or approximately 7%.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Proved F&D costs ($/boe)	2002	3-year Average	5-year Average
F&D costs (excluding revisions and transfers)	**8.87**	6.98	7.15
F&D costs	**11.03**	6.86	6.58
Total including acquisitions (FD&A)	**12.15**	7.66	7.29

LIQUIDITY AND CAPITAL RESOURCES

Talisman's long-term debt at year end was $3 billion, including $265 million drawn on the Company's $1,049 million bank lines of credit. The Company also maintains a shelf prospectus under which it may issue up to $500 million of medium term notes in aggregate in the Canadian public debt market. The shelf prospectus expires in March 2004.

During 2002, the Company issued $1,055 million of long-term debt including $325 million of medium term notes under its previous shelf prospectus, a $571 million (£250 million) Eurobond notes offering and a private debt placement in the US for $159 million (US$100 million). Subsequent to year end, the Company spent $390 million on acquisitions to expand the Company's operations and land base in the US Appalachia area. During the first quarter of 2003, the Company expects to complete the Sudan sale. Refer to note 17 of the Consolidated Financial Statements for additional information on the sale of the Sudan operations.

In June 2003, $180 million of medium term notes mature and will be repaid. No amount of the long-term debt has been classified as a current liability as the Company has the ability to refinance amounts due within one year with existing bank facilities.

The Company repurchased 3,847,500 of its common shares under its normal course issuer bid ("NCIB") during 2002 at a cost of $220 million ($57.24/share). Subsequent to year end, an additional 1,986,200 common shares were repurchased for $113 million ($56.70/share). The total common shares repurchased under the existing NCIB represents 87% of the 6,716,781 common shares currently permitted to be repurchased. The NCIB expires on March 25, 2003 and it is expected to be renewed for an additional 5% of the Company's outstanding common shares.

Two dividends of $0.30/share were paid in 2002 (total dividends were $0.60/share). The Company's dividend is determined semi-annually by the Board of Directors.

Talisman maintains targets for long-term debt of less than 2:1 debt to cash flow and 40% debt to debt-plus-equity. At the end of 2002, Talisman met the debt targets with ratios of 1.1:1 for debt to cash flow and 40% for debt to debt-plus-equity. For purposes of these calculations, the Company's preferred securities have been classified as equity.

The projected 2003 year end net debt position of the Company is expected to decrease as a result of the proceeds from the Sudan sale. The 2003 anticipated cash flow is expected to be more than sufficient to fund the $2.1 billion of planned capital expenditures. Significant acquisitions, a prolonged drop in commodity prices and the continuation of share repurchases would impact the anticipated reduction in the Company's projected 2003 year end net debt position.

For additional information regarding the Company's liquidity and capital resources, refer to note 6 of the Consolidated Financial Statements.

Talisman's investment grade corporate credit and senior unsecured long-term debt credit ratings remain unchanged with Dominion Bond Rating Service ("DBRS"), Moody's Investor Service, Inc. ("Moody's") and Standard & Poor's ("S&P") at BBB (high), Baa1 and BBB+ respectively. Due to the subordinated nature of the preferred securities, they have a lower rating. DBRS, Moody's and S&P have rated the preferred securities as Pfd-3 (high), Baa3 and BBB-, respectively.

FINANCIAL LEVERAGE AND COVERAGE RATIOS[1]

	2002	2001	2000
Long-term debt[2] to cash flow[3] (times)	**1.1**	1.2	0.7
Interest coverage – cash flow[3,4] (times)	**16**	19	19
EBITDAX[5] (millions of dollars)	**3,036**	2,859	2,853
Interest coverage – EBITDAX[5,6] (times)	**16**	18	18
Long-term debt to debt-plus-equity[2] (%)	**40**	41	32

1 Preferred securities are classified as equity and the related charges have been excluded from interest expense.
2 Based on balances at December 31.
3 Cash flow is a non-GAAP measure the components of which are set out in note 14 of the Consolidated Financial Statements.
4 Cash flow plus current income taxes and interest expense, divided by the sum of interest expense and capitalized interest.
5 EBITDAX is a non-GAAP measure and represents earnings before interest, income taxes, depreciation, depletion, amortization, impairment writedowns, dry hole and exploration expense.
6 EBITDAX divided by the sum of interest expense and capitalized interest.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

As part of its normal business, the Company entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity, some of which are reflected as liabilities in the Consolidated Financial Statements at year end. The principal commitments of the Company are in the form of: debt repayments; abandonment obligations; settlements of derivative financial instruments; lease commitments relating to corporate offices and vessels; firm commitments for gathering, processing and transmission services; minimum work commitments under various international agreements; other service contracts and fixed price commodity sales contracts.

Additional disclosure of the Company's debt repayment obligations and significant commitments can be found in notes 6 and 10 of the Consolidated Financial Statements. A discussion of the Company's derivative financial instruments and commodity sales contracts can be found in the next section of this MD&A.

DERIVATIVE FINANCIAL INSTRUMENTS AND COMMODITY SALES CONTRACTS

The Company may manage its exposure to fluctuations in foreign exchange rates, interest rates, electricity costs and commodity prices in part through the use of derivative financial instruments and commodity sales contracts. Commodity price derivative financial instruments resulted in a net increase to recorded sales of $75 million (2001 – $8 million increase; 2000 – $377 million decrease). The accounting policy with respect to derivative financial instruments is set out in note 1(k) of the Consolidated Financial Statements.

At December 31, 2002, the Company had outstanding commodity price derivative contracts that cover approximately 60,500 mcf/d (7%) of the Company's anticipated 2003 North American natural gas production and 75,000 bbls/d (35%) of the Company's anticipated 2003 worldwide oil and liquids production. An additional 85,750 mcf/d (10%) of anticipated 2003 North American natural gas production had been committed under commodity sales contracts. At year end, the Company had also committed 48,450 mcf/d of 2004 North American gas production under commodity sales contracts. See notes 9 and 10 of the Consolidated Financial Statements for additional details regarding the contracts outstanding at year end.

Subsequent to year end, the Company entered into natural gas derivative contracts for 57,500 mcf/d at US$4.86/mcf (NYMEX) for the period February 2003 to October 2004. The Company also entered into contracts for the period April to October 2003 for an additional 14,000 mcf/d of collars with ceiling and floor prices referenced to AECO of $7.50/mcf and $6.24/mcf and 9,500 mcf/d referenced to Sumas with ceiling and floor prices of US$4.96/mcf and US$3.92/mcf. In addition, the Company entered into a commodity sales contract to sell 4,800 mcf/d for the period April to October 2003 at $4.24/mcf.

The following table includes the Company's expected future payment commitments and estimated timing of such payments.

			Payments expected[2,3] (millions of dollars)					
Commitments	Recognized in financial statements	**Total**	Due within 1 year	Due within 2-3 years	Due within 4-5 years	Due within 6-10 years	Due within 11-15 years	Due after 15 years
Long-term debt	Yes – Liability	**2,997**	180	695	693	379	576	474
Preferred securities	Yes – Equity	**474**	–	–	–	–	–	474
Office leases	No	**191**	18	30	30	75	38	–
Vessel leases	No	**115**	52	63	–	–	–	–
Transportation and processing commitments	No	**942**	145	173	133	250	203	38
Abandonment obligations[1]	Yes – Partially accrued as liability	**1,731**	24	49	109	232	649	668
Min. work commitments[4]	No	**461**	262	152	47	–	–	–
Other service contracts	No	**160**	16	32	22	30	30	30
Total		**7,071**	697	1,194	1,034	966	1,496	1,684

1 The abandonment obligation represents management's best estimate of the cost and timing of future dismantlement, site restoration and abandonment obligations based on engineering estimates using current costs and technology in accordance with existing legislation and industry practice.

2 Payments exclude ongoing operating costs related to certain leases, interest on long-term debt, preferred securities charges and payments made to settle derivative contracts.

3 Payments denominated in foreign currencies have been translated at the December 31, 2002 exchange rate.

4 Minimum work commitments include contracts awarded for capital projects and those commitments related to exploration or drilling obligations.

The Company also entered into agreements to sell 15,000 mcf/d of North Sea natural gas production for the period April to September 2003 at $4.40/mcf.

Subsequent to the Eurobond notes offering, the Company entered into US dollar cross currency swap contracts and interest rate swap contracts for an equivalent amount of the bond which have in effect converted this indebtedness into US dollars with a floating interest rate based on three month US LIBOR. These swap contracts expire on December 5, 2009. In addition, the Company entered into a forward rate swap agreement to effectively fix the rate of the next three month US LIBOR payment due in March 2003 under the interest rate swap contract.

The Company entered into US dollar/UK Pound Sterling forward swap agreements to purchase £178 million over the first six months of 2003. These swap agreements fix the exchange rate used to convert a portion of the Company's US dollar denominated revenues received in the UK into Pounds Sterling for purposes of paying its operating costs and capital expenditures.

The Company has systems and processes in place to minimize risks associated with its derivatives program and credit risk associated with derivatives counterparties. Management believes its commodity derivatives and fixed priced sales program to be prudent in that it provides a degree of price support during periods of falling commodity prices while providing the ability to participate in price increases and, in the case of certain fixed price sales contracts, guaranteed market access. The US dollar cross currency swap of the Eurobond and the US dollar/UK Pound Sterling forward swap agreements reduce the Company's exposure to foreign exchange movements.

APPLICATION OF CRITICAL ACCOUNTING POLICIES

The preparation of financial statements requires management to make estimates and assumptions that affect reported assets and liabilities, disclosures of contingencies and revenues and expenses. Management is also required to adopt accounting policies that require significant estimates. Actual results could differ from those estimates. A summary of significant accounting policies adopted by Talisman can be found in note 1 to the December 31, 2002, Consolidated Financial Statements. Changes to these policies during the current year are disclosed in note 2. In assisting the Audit Committee's review and approval or recommendations for approval, of the Company's financial statements, management regularly meets and reviews with the committee, the Company's significant accounting policies, estimates and any significant changes thereto including those discussed below.

Management believes the most critical accounting policies, including judgments in their application, that may have an impact on the Company's financial results relate to the accounting for property, plant and equipment, abandonment and goodwill. The rate at which the Company's assets are depreciated or otherwise written-off and the abandonment liability provided for are subject to a number of judgments about future events, many of which are beyond management's control.

RESERVE RECOGNITION

Underpinning Talisman's oil and gas assets and goodwill are its oil and gas reserves. Detailed rules and industry practice to which Talisman adheres have been developed to attempt to provide uniform reserve recognition criteria. However, the process of estimating oil and gas reserves is inherently judgmental. The reserve estimates are made using all available geological and reservoir data as well as production performance data. As new data becomes available, including actual reservoir performance, reserve estimates may change. Reserves can be classified as proved, probable or possible with decreasing levels of certainty as to the likelihood that the reserves will be ultimately produced.

Reserve recognition is also impacted by economic considerations. In order for reserves to be recognized, they must be producible under existing economic and operating conditions, which is viewed as being at year end commodity prices with an operating cost profile based on current operations. As economic conditions change, primarily as a result of changes in commodity prices, and to a lesser extent, operating and capital costs, marginally profitable production, typically experienced in the later years of a field's life cycle, may no longer qualify for reserve recognition.

The Company's reserves and revisions to those reserves, though not separately reported on the Company's balance sheet or income statement, impact the Company's reported net income primarily through the amortization of the Company's Property, Plant and Equipment (PP&E), asset impairments and the provision for future abandonment and reclamation costs. As disclosed in the Historical Proved Reserves table, net revisions during the past three years have resulted in 12 mmbbls of oil equivalent being added to the Company's proved reserve base, or approximately 1%.

DEPRECIATION, DEPLETION AND AMORTIZATION EXPENSE

A significant portion of the Company's Property, Plant and Equipment is amortized based on the unit of production method with the remaining assets being amortized equally over their expected useful lives. The unit of production method attempts to amortize the asset's cost over its reserve base. Accordingly, revisions to reserves or changes to management's view as to the operational life span of an asset will impact the Company's future DD&A expense. As indicated above, the Company's proved estimated reserves have been revised upward 1% over the last three years. This degree of change would have resulted in an insignificant reduction to the DD&A expense during the past year.

As outlined in the Company's DD&A accounting policy and PP&E note (notes 1(d) and 5 of the Consolidated Financial Statements), $1.2 billion of the Company's Property, Plant and Equipment is not currently subject to DD&A. A significant portion of these costs ($730 million) relate to development projects that will soon be on production, at which time amortization will commence. Also included in the $1.2 billion of non-depleted capital is $463 million related to the costs of acquired probable reserves ($154 million) and incomplete drilling activities, including those wells under evaluation or awaiting production to commence ($309 million). Uncertainty exists with these costs, for example, if the evaluation of the acquired probable reserves or recently drilled exploration wells were determined to be unsuccessful, the associated capitalized costs would be expensed in the year such determination is made, except that in the case of acquired probable reserves associated with producing fields, these costs would be amortized over the reserve base of the associated producing field. Accordingly, the rate at which these costs are written-off depends on management's view of the likelihood of the existence of producible reserves.

ASSET IMPAIRMENTS

The Company's oil and gas assets and goodwill are subject to impairment tests. An impairment charge is recorded in the year an asset is determined to be impaired. Individual oil and gas assets are considered impaired under the Successful Efforts method if their undiscounted future cash flows fall below their carrying value. Goodwill is considered to be impaired if its fair value, principally determined based on discounted cash flows, falls below its carrying value. Both tests require management to make assumptions regarding cash flows well into the distant future that are subject to revisions due to changes in commodity prices, costs, recoverable reserves, production profiles and in the case of goodwill, discount rates. During the past three years, isolated asset impairments have occurred (2002 – $74 million; 2001 – $8 million; 2000 – $nil) however, it is possible that future impairments may be material.

As an indication of the volatility of cash flow projections, at December 31, 2002, the estimated undiscounted future net cash flow before tax from proved reserves at year end prices was $28.7 billion and it is estimated that a $1/boe change in the commodity price assumption would change this amount by approximately $1.1 billion. As indicated above, in determining whether an asset is impaired, management uses its best estimate of future prices and costs and risk-adjusted recoverable reserves including those classified as probable.

PURCHASE PRICE ALLOCATIONS

The costs of corporate and asset acquisitions are allocated to the acquired assets and liabilities based on their fair value at the time of acquisition. In many cases the determination of fair value requires management to make certain assumptions and estimates regarding future events. Typically, in determining fair value, management develops a number of possible future cash flow scenarios to which probabilities are judgmentally assigned. The allocation process, including the determination of the appropriate discount rate, is inherently subjective and impacts the amounts assigned to the various individually identifiable assets and liabilities as well as goodwill. The acquired assets and liabilities may span multiple geographical segments and may be amortized at different rates, or not at all as in the case of goodwill or acquired probable reserves. Accordingly, the allocation process impacts the Company's reported assets and liabilities and future net income due to the impact on future depreciation, depletion and amortization expense and impairment tests.

FUTURE ABANDONMENT AND SITE RESTORATION ACTIVITIES

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with abandonment and reclamation activities. Estimates of the associated costs are subject to uncertainty associated with the method, timing and extent of future retirement activities. A liability for these costs is accrued based on estimated future production. Accordingly, the annual expense associated with future abandonment and reclamation activities is impacted by changes in the estimates of the expected costs, timing of abandonment and future production (reserves) over which the remaining unrecorded liability is amortized. During 2002, the abandonment expense included in DD&A was $147 million. The total abandonment liability is currently estimated at $1.7 billion, which is based on current costs and technology and in accordance with existing legislation and industry practice. If this liability had been estimated to be 10% higher, an additional $15 million may have been recorded as DD&A during 2002. Past revisions to the abandonment estimate have not been significant.

FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS UNDER US GAAP

As disclosed in note 1(k) of the Consolidated Financial Statements, the Company's derivative financial instruments are treated as hedges under Canadian GAAP. Accordingly, gains and losses on these instruments are not recorded in the income statement until the hedged transaction is realized. These instruments are carried at cost. For US GAAP purposes, these instruments are recorded on the balance sheet at fair value with changes in fair value being recorded as either income or an expense. The fair value of certain commodity based instruments are highly volatile. The determination of fair value for certain non-market traded instruments requires management to make significant estimates. In addition, the meaningfulness of an instrument's fair value on December 31, 2002 and the appropriateness of recognizing income based on such daily values should be viewed with caution. In determining the fair value of its commodity based instruments, the Company uses an options pricing model based on market determined price forecasts. For other fair values such as those for its interest rate swaps, forward currency contracts and preferred securities, the Company obtains multiple price quotes from external sources.

ACCOUNTING CHANGES DURING THE CURRENT YEAR

CHANGE IN THE COMPANY'S FUNCTIONAL CURRENCY

Talisman's worldwide operations expose the Company to transactions denominated in a number of different currencies, which are required to be translated into one currency for financial statement reporting purposes. Talisman's foreign currency translation policy, as detailed in note 1(i) of the Consolidated Financial Statements, is designed to reflect the economic exposure of the Company's operations to the various currencies.

The adoption of the US dollar, effective for 2002, as the Company's functional currency is a reflection of Talisman's overall exposure to US dollar denominated transactions, assets and liabilities; oil prices are largely denominated in US dollars as is much of the Company's corporate debt and international capital spending and operating costs.

The Company's operations in the UK and Canada are largely self-sufficient (self-sustaining) and their economic exposure is more closely tied to their respective domestic currencies. Accordingly, these operations are measured in UK Pounds Sterling and Canadian dollars, respectively.

Currently, the Company's foreign exchange exposure principally relates to UK oil sales denominated in US dollars and Canadian dollar denominated long-term debt that has not been allocated to the Canadian operations.

The Company adopted the US dollar as its functional currency effective January 1, 2002, due to its increased exposure to the US dollar as a result of the growth in international operations. Prior to January 1, 2002, the functional currency of the Company was the Canadian dollar. The impact of this change was to decrease net income by $15 million during 2002.

ACCOUNTING FOR FOREIGN EXCHANGE GAINS AND LOSSES ON LONG-TERM DEBT

Effective January 1, 2002, as disclosed in note 2 of the Consolidated Financial Statements, in accordance with a Canadian Institute of Chartered Accountants (CICA) accounting standard, the Company no longer defers and amortizes the gains or losses on foreign currency denominated long-term debt. The impact of the change in accounting as a result of the new accounting standard was to decrease net income in 2002 by $3 million. The Company's comparative historical financial results have been restated for this required accounting change. The previously reported net income for 2001 and 2000 was decreased $53 million and $49 million, respectively.

At December 31, 2002, the Company's debt was denominated in US and Canadian dollars and UK Pounds Sterling. The UK Pounds Sterling debt has been effectively swapped into US dollars. A portion of the Company's debt (net of cash) is allocated to the self-sustaining Canadian operations based on the Company's net investment in Canada. Foreign exchange gains and losses may result from the debt allocation if the total amount of net debt allocated exceeds or is less than the Company's total Canadian dollar denominated debt.

The Company's foreign exchange accounting policy, including the rationale and implications of adopting the US dollar as the Company's functional currency, was discussed with the Audit Committee of Talisman's Board of Directors.

NEW ACCOUNTING PRONOUNCEMENTS

The CICA has issued a number of accounting pronouncements, some of which may impact the Company's reported results and financial position in future periods. These new pronouncements include the following:

IMPAIRMENTS OF LONG-LIVED ASSETS

Effective for 2004, if a long-term asset is identified as being impaired, as determined by its undiscounted future cash flows, the amount of impairment is to be calculated based on the asset's fair value (present value of expected future cash flows). This is consistent with the US GAAP methodology. Currently, the impairment is calculated based on the asset's undiscounted future cash flows.

DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS

Effective for disposition activities initiated after May 1, 2003, this pronouncement expands the scope of what assets or operations are to be reclassified as Discontinued Operations and the conditions required to reclassify them as such. This treatment eliminates a difference between US and Canadian GAAP.

ASSET RETIREMENT OBLIGATIONS (FUTURE SITE RESTORATION AND ABANDONMENT LIABILITIES)

Effective January 1, 2004, the CICA has adopted a new accounting standard, which will change the method of accruing for costs associated with the retirement of fixed assets. The standard will require entities to record the fair value of a liability for an asset retirement obligation in the period it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Currently, these obligations are provided for using the unit of production method or, for certain assets, using the straight-line method over the estimated remaining lives of the assets. The US has adopted a similar rule commencing January 1, 2003.

SALE OF SUDAN OPERATIONS

As disclosed in note 17 of the Consolidated Financial Statements, the Company has executed an agreement for the sale of its operations in Sudan subject to government and consortium member approvals and other closing conditions. The impact of the sale of Sudan operations is not included in the financial results of the Company as at December 31, 2002. Readers are referred to note 16 in which the Sudan operations are reported as a separate geographic segment.

RISKS AND UNCERTAINTIES

Talisman is exposed to operational risks inherent in exploring for, developing and producing crude oil and natural gas. The process of estimating oil and gas reserves is complex and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data for each reservoir; therefore, reserve estimates are inherently imprecise. The Company may adjust estimates of proved reserves based on production history, results of exploration and development drilling, prevailing oil and gas prices and other factors, many of which are beyond the Company's control. In addition, there are numerous uncertainties in projecting future production, costs and expenses and the results, timing and costs of exploration and development projects. Total amounts or time of production may vary significantly from reserves and production estimates.

The Company's future success depends largely on its ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless produced reserves are replaced through successful development, exploration or acquisition activities at acceptable costs, proved reserves will decline over time. Exploration and development drilling may not result in commercially productive reserves. Successful acquisitions require an assessment of a number of factors, many of which are uncertain. These factors include recoverable reserves, exploration potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain.

Oil and gas drilling and producing operations are hazardous. They are subject to many risks including the possibility of fire, mechanical failure, pipe failure, chemical spills, uncontrollable flows of oil, natural gas or well fluids, and other accidents or occurrences which could result in personal injury or loss of life, damage or destruction of properties, pollution or other environmental damage, interruption of business, regulatory investigations and penalties and liability to third parties. The Company seeks to mitigate risks and to protect against significant losses by maintaining a comprehensive insurance program, while maintaining levels of risk within the Company which management believes to be acceptable. Talisman believes its liability, property and business interruption insurance is appropriate to its business and consistent with common industry practice, although such insurance will not provide coverage in all circumstances.

The energy industry is extremely competitive. This is especially true with regard to exploration for, and development and production of, new sources of oil and natural gas. As an independent producer of oil and natural gas, the Company frequently competes against companies that are larger with greater financial resources to acquire properties suitable for exploration, to contract for drilling equipment and other services and to secure trained personnel.

Talisman is subject to extensive governmental regulation in the countries in which it does business with respect to protection of the environment and responsibility for environmental damage and site remediation. A trend toward stricter environmental regulation and protection controls could increase costs for Talisman and others in the industry. Although Talisman maintains comprehensive programs to control health, safety and environmental risks across its operations and to comply with applicable governmental regulations and standards, accidental discharge of pollutants or other environmental damage or violations of applicable law may occur and may result in significant liability to Talisman. Talisman records provisions for abandonment and restoration of its properties in accordance with generally accepted accounting principles; however, the estimated costs associated with abandonment and restoration are subject to uncertainties and actual costs may exceed Talisman's estimates.

The Company's operations may be adversely affected by changes in governmental policies or social instability or other political, economic or diplomatic developments which are not within the control of Talisman including, among other things, a change in crude oil or natural gas pricing policy, the risks of war, terrorism, abduction, expropriation, nationalization, renegotiation or nullification of existing concessions and contracts, taxation policies, foreign exchange and repatriation restrictions, economic sanctions, changing political conditions, the imposition of specific drilling obligations, the development and abandonment of fields (including restrictions on production), international monetary fluctuations and currency controls. Indonesia, Algeria, Sudan and Colombia have been subject to recent economic or political instability and social unrest, military or rebel hostilities. Although the Company has entered into a definitive agreement for the sale of its interest in the Greater Nile Oil Project in Sudan, as of the date of this document, the transaction was not completed. Accordingly, Talisman continues to have an interest in Sudan. There is civil unrest in Sudan, which apart from short periods of calm, has continued inconclusively since 1956. There have been isolated, politically motivated attacks on the oilfields and pipeline in Sudan. Minor production interruptions occurred as a result of pipeline attacks. Although security measures are in place to reduce the risk of future attacks, the oilfields and pipeline may be targets of future attacks.

The US has imposed comprehensive economic sanctions against Sudan. These sanctions apply to certain Sudan related transactions and activities in the US, activities by US individuals and entities wherever located and transactions by US and non-US persons involving US origin goods, technology or services. With limited exceptions, the sanctions prohibit "US persons" from engaging in or facilitating virtually all direct or indirect commercial, financial or trade transactions of any nature with Sudan or the Government of Sudan, including its entities and agents. As of the date hereof, Talisman (Greater Nile) B.V. ("TGNBV"), a subsidiary of Talisman, holds a 25% interest in the Greater Nile Petroleum Operating Company Limited ("GNPOC") and the Greater Nile Oil Project. GNPOC, which operates the Greater Nile Oil Project, and Sudapet, which is the national oil company of Sudan and holds a 5% interest in GNPOC and the Greater Nile Oil Project, are treated as the Government of Sudan for purposes of the sanctions. Although neither TGNBV nor the Company is a "US person" and therefore are not bound by the sanctions, new laws or regulations could be enacted or the scope of the sanctions could be expanded in a manner that could have an adverse effect upon the Company's business and financial condition. Talisman has implemented comprehensive procedures to identify and avoid potential activities or transactions that may result in a contravention of the Sudanese sanctions by any US person. The Canadian government has not imposed unilateral economic sanctions on Sudan. In addition, in 2001 the United Nations removed its sanctions on Sudan. Those sanctions were diplomatic and not economic.

On October 21, 2002, the President of the United States signed into law the Sudan Peace Act. The legislation is designed to facilitate a comprehensive solution to the civil war in Sudan, but does not contain any capital market sanctions, as were included in an earlier version passed by the US House of Representatives in June 2001.

From time to time, Talisman is the subject of litigation arising out of its operations. Damages claimed under such litigation may be material or may be indeterminate and the outcome of such litigation may materially impact the Company's financial results. A suit, which seeks class action status, was filed against the Company by the Presbyterian Church of Sudan and others on November 8, 2001 in the United States District Court for the Southern District of New York under the Alien Tort Claims Act and has been subsequently amended. The Republic of the Sudan is named in the suit. The suit seeks, among other things, a declaration that Talisman Energy Inc. has violated international law in connection with oil exploration and drilling activities in Sudan, an injunction permanently restraining Talisman from continuing to cooperate with the Government of Sudan, and unquantified compensatory and punitive damages. Talisman intends to fully defend itself against this suit and has filed a motion to dismiss the suit, which is currently under consideration by the United States District Court.

OUTLOOK FOR 2003

Talisman expects production per share, after adjusting for the Sudan sale, to increase 5% in 2003. Production for 2003 is expected to average approximately 395,000-415,000 boe/d with the sale of Sudan expected to close in the first quarter and the commencement of production from Algeria, the PM-3 CAA development project in Southeast Asia and the recently acquired US gas properties.

The Company expects cash flow per share of over $21 in 2003 ($2.8 billion), assuming US$28.50/bbl WTI oil and US$5.00/mcf NYMEX gas. Unit operating costs are expected to average approximately $7/boe, which reflects small increases in Canada and the North Sea, startup costs in Algeria and the sale of Sudan. Net capital spending is expected to be $2.1 billion and excludes corporate and asset acquisitions and the proceeds from the sale of Sudan.

NORTH AMERICA

Natural gas continues to be the focus of the Company's exploration activities in North America supplemented by low risk oil projects. Recently announced acquisitions in northeast US have provided the Company's first US based production in the Appalachia area. North American production in 2003 is expected to average between 860-880 mmcf/d and 58,000-60,000 bbls/d for a total of 200-205 mboe/d.

Estimated total capital spending of $975 million in 2003 will be over 80% directed at natural gas. The Company plans to participate in approximately 590 wells in 2003. Drilling costs are expected to increase in 2003 due to higher rig utilization and the Company's continuing shift in focus from shallow natural gas targets to deeper more technically challenging prospects. Several infrastructure projects are planned to ease capacity constraints in some of the Company's core areas including the Alberta Foothills and Greater Arch. Unit operating costs are expected to increase 5% with higher processing costs, an increase in the number of facilities and higher lifting costs associated with activities designed to maintain or increase production.

NORTH SEA

The Company's North Sea strategy is to focus on low risk development projects and adjacent exploration opportunities around core operated properties and infrastructure. Of the $532 million of planned capital spending, 75% will be related to development projects. A total of eight exploration and 27 development wells are planned for 2003. The Blake Flank development is expected to deliver first oil in the third quarter. Natural decline offsetting the development work is expected to result in North Sea production averaging between 115,000-120,000 bbls/d and 125-130 mmcf/d in 2003, for a total of 136-142 mboe/d. Unit operating costs are expected to increase 7% with the reduced production.

SOUTHEAST ASIA

Natural gas sales in Indonesia have decreased due to reduced demand under the current gas supply contract with Caltex. Indonesian natural gas sales are expected to average 95-100 mmcf/d in 2003. Additional sales are expected in early 2004 when the pipeline to supply Singapore Power with natural gas from Corridor PSC is completed. An expansion of the gas plant facilities at Corridor PSC from 300-700 mmcf/d over the next three years is currently underway in order to accommodate additional anticipated gas sales. Natural gas production from the PM-3 CAA development in Malaysia/Vietnam is expected to commence in the fourth quarter of 2003 with an annualized production rate of 10-15 mmcf/d. The PM-3 CAA natural gas will be sold under a 10-year firm supply contract for approximately 100,000 mcf/d at market price. This contract is extendable on mutual agreement of the parties for an additional 10 years.

Oil and liquids production is expected to average between 20,000-22,000 bbls/d, with production from PM-3 CAA increasing to between 6,000-7,000 bbls/d (annualized) as a result of production from the Phase 2 development scheduled to start in the third quarter. Oil and liquids production in the Indonesian blocks is expected to average 14,000-15,000 bbls/d due to natural decline. Operating costs in Southeast Asia are expected to average $6/boe.

Talisman expects to spend $296 million (including capitalized interest) in Malaysia/Vietnam during 2003, primarily on the PM-3 CAA development project. Malaysia/Vietnam is expected to account for approximately 80% of the $366 million Southeast Asia exploration and development spending in 2003. In addition to the construction of the related facilities, 21 development and six exploration wells will be drilled in PM-3 CAA. Talisman also plans to drill three to four exploration and appraisal wells, two to three on PM-305 in Malaysia and one on Block 46/02 in Vietnam. The $70 million planned spending in Indonesia will primarily relate to the facilities expansion at Corridor and the drilling of additional wells at Corridor and the other Indonesian blocks. Exploration activities will account for $25 million of the $70 million in Indonesia.

ALGERIA

Production in the Ourhoud field commenced at year end. The pipeline has been filled and production is currently averaging 1,800 bbls/d (net to Talisman). Production from the second Algerian field, MLN, is expected to commence mid-year. Total combined production is expected to average 9,000-10,000 bbls/d in 2003. Initial operating costs, which include startup costs, are anticipated to be $8/bbl. A capital budget of $60 million will be used to drill 13 development wells, complete and commission the Central Process Facility and tie in wells.

SUDAN

The sale of the Sudan operations is expected to be completed during the first quarter of 2003. The Sudan operating results will continue to be reported as part of ongoing operations in 2003 until such time as the sales transaction is completed. Additional information regarding the sale is included in note 17 of the Consolidated Financial Statements. Readers are also referred to note 16 where the Sudan operations are disclosed as a separate reporting segment. Production for the first quarter is expected to average 60,000 bbls/d.

REST OF WORLD

Trinidad is expected to account for $149 million of capital spending with $99 million related to the Greater Angostura development project on offshore Block 2(c). First production is expected in early 2005. Talisman expects to spend $50 million in Trinidad to drill five offshore exploration wells and conduct onshore seismic in the Eastern Block.

In Colombia, the exploration program of $33 million is expected to include a seismic program and drilling two wells with the possibility of an additional two wells in the latter part of the year.

COMMODITY PRICES

Management currently expects commodity prices in 2003 will average US$28.50/bbl WTI oil and US$5/mcf NYMEX gas. However, continuing heightened world tension, including the possibility of military conflict in the Middle East and uncertainty over supply, makes price forecasting unusually difficult.

Including those contracts entered into during the early part of 2003, Talisman has committed 25% of its anticipated 2003 North American natural gas production under both commodity sales contracts and commodity price derivative contracts. Approximately 161 mmcf/d has been fixed at an average price of $5.83/mcf and 30 mmcf/d is under collars with an average floor and ceiling price of $6.17/mcf and $7.21/mcf. An additional 26 mmcf/d is under three-way collars that allow the Company to participate in gas prices up to an average $3.56/mcf and will provide a $0.60/mcf premium to spot prices should natural gas prices average below $2.73/mcf.

The Company has hedged 75,000 bbls/d of crude oil for 2003, of which 40,000 bbls/d have been fixed at US$24.45/bbl and 35,000 bbls/d are under crude oil collars with a ceiling price of US$27.53/bbl and a floor price of US$22.82/bbl.

A summary of the contracts outstanding at year end can be found in notes 9 and 10 of the Consolidated Financial Statements.

SENSITIVITIES

Talisman's financial performance is affected by factors such as changes in production volumes, commodity prices and exchange rates. The estimated impact of these factors on 2003 financial performance is summarized in the following table and is based on a WTI oil price of US$28.50/bbl, a NYMEX natural gas price of US$5.00/mcf and an exchange rate of US$0.67/C$1.

APPROXIMATE IMPACT IN 2003

(millions of dollars)	Net Income	Cash Flow [1]
Volume changes		
Oil – 1,000 bbls/d	4	8
Natural gas – 10 mmcf/d	5	13
Price changes [2]		
Oil – US$1.00/bbl		
Increase	38	36
Decrease	(49)	(54)
Natural gas (North America) [3] – C$0.10/mcf	11	17
Exchange rate changes		
US increased by US$0.01	27	44
£ increase by C$0.035	(9)	2

1 Cash flow is a non-GAAP measure, the components of which are set out in note 14 of the Consolidated Financial Statements.

2 The impact of commodity contracts outstanding for 2003 has been included.

3 Price sensitivity on natural gas relates to North American natural gas only. The Company's exposure to changes in North Sea and Malaysia/Vietnam natural gas prices is not material. Most of the Indonesia natural gas price is based on the price of crude oil and accordingly has been included in the price sensitivity for oil except for a small portion which is sold at a fixed price.

Report of Management

THE BOARD OF DIRECTORS IS RESPONSIBLE FOR THE CONSOLIDATED FINANCIAL STATEMENTS BUT HAS DELEGATED RESPONSIBILITY FOR THEIR PREPARATION TO MANAGEMENT.

Management has prepared the Consolidated Financial Statements in accordance with accounting principles generally accepted in Canada (with a reconciliation to accounting principles generally accepted in the United States). If alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has ensured that the Consolidated Financial Statements are presented fairly in all material respects. Management has also prepared the financial information presented elsewhere in the annual report and ensured that it is consistent with information in the Consolidated Financial Statements.

Talisman maintains internal accounting and administrative controls designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that assets are appropriately accounted for and adequately safeguarded.

The Board of Directors is responsible for reviewing and approving the Consolidated Financial Statements and Management's Discussion and Analysis and, primarily through its Audit Committee, ensures that management fulfills its responsibilities for financial reporting.

The Audit Committee is appointed by the Board and is composed entirely of Directors who are not employees of the Company. The Audit Committee meets regularly with management, and with the internal and external auditors, to discuss internal controls and reporting issues and to satisfy itself that each party is properly discharging its responsibilities. It reviews the Consolidated Financial Statements and the external auditors' report. The Audit Committee also considers, for review by the Board and approval by the shareholders, the engagement or reappointment of the external auditors.

Ernst & Young LLP, the external auditors, have audited the Consolidated Financial Statements in accordance with auditing standards generally accepted in Canada on behalf of the shareholders. Ernst & Young LLP have full and free access to the Audit Committee.

James W. Buckee
President and Chief Executive Officer

Michael D. McDonald
Executive Vice-President, Finance and Chief Financial Officer

February 14, 2003

Auditors' Report

TO THE SHAREHOLDERS OF TALISMAN ENERGY INC.

We have audited the Consolidated Balance Sheets of Talisman Energy Inc. as at December 31, 2002 and 2001 and the Consolidated Statements of Income, Retained Earnings and Cash Flows for each of the years in the three year period ended December 31, 2002. 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 Canadian and US generally accepted auditing standards. 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, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles. We also report that, in our opinion, these principles have been applied, except for the change in the method of accounting for goodwill as explained in note 2 to the Consolidated Financial Statements, on a basis consistent with that of the preceding year.

Ernst & Young LLP

Calgary, Canada
February 14, 2003

Ernst & Young LLP
Chartered Accountants

Consolidated Balance Sheets

(December 31)

(millions of Canadian dollars)	2002	2001 restated, see note 2
Assets		
Current		
Cash (note 14)	27	17
Accounts receivable	719	654
Inventories (note 4)	147	99
Prepaid expenses	24	29
	917	799
Accrued employee pension benefit asset (note 15)	67	67
Other assets	99	25
Goodwill (note 2)	469	467
Property, plant and equipment (note 5)	10,042	9,461
	10,677	10,020
Total assets	11,594	10,819
Liabilities		
Current		
Accounts payable and accrued liabilities	803	869
Income and other taxes payable	186	146
Current portion of long-term debt (note 6)	–	189
	989	1,204
Deferred credits	57	87
Provision for future site restoration (note 10)	813	619
Long-term debt (note 6)	2,997	2,794
Future income taxes (notes 2 and 13)	2,236	1,989
	6,103	5,489
Contingencies and commitments (notes 9 and 10)		
Shareholders' equity		
Preferred securities (note 7)	431	431
Common shares (note 8)	2,785	2,831
Contributed surplus	75	77
Cumulative foreign currency translation (note 2)	140	–
Retained earnings	1,071	787
	4,502	4,126
Total liabilities and shareholders' equity	11,594	10,819

On behalf of the board:

David E. Powell
Chairman of the Board

Dale G. Parker
Director

See accompanying notes.

Consolidated Statements of Income

(Years ended December 31)

(millions of Canadian dollars)	2002	2001	2000
Revenue		restated, see note 2	restated, see note 2
Gross sales	**5,299**	5,047	4,836
Less royalties	**927**	989	946
Net sales	**4,372**	4,058	3,890
Other (note 11)	**80**	82	99
Total revenue	**4,452**	4,140	3,989
Expenses			
Operating	**1,115**	946	827
General and administrative	**138**	108	95
Depreciation, depletion and amortization	**1,495**	1,313	1,153
Dry hole	**174**	113	77
Exploration	**185**	147	100
Interest on long-term debt (note 5)	**164**	139	136
Other (note 12)	**113**	78	64
Total expenses	**3,384**	2,844	2,452
Income before taxes	**1,068**	1,296	1,537
Taxes (note 13)			
Current income tax	**258**	342	334
Future income tax	**162**	72	196
Petroleum revenue tax	**124**	149	150
	544	563	680
Net income	**524**	733	857
Preferred security charges, net of tax	**24**	24	22
Net income available to common shareholders	**500**	709	835
Per common share (Canadian dollars)			
Net income	**3.73**	5.25	6.05
Diluted net income	**3.67**	5.16	5.96
Average number of common shares outstanding (millions)	**134**	135	138
Diluted number of common shares outstanding (millions)	**136**	137	140

See accompanying notes.

Consolidated Statements of Retained Earnings

(Years ended December 31)

(millions of Canadian dollars)	2002	2001	2000
		restated, see note 2	restated, see note 2
Retained earnings, beginning of year	**787**	257	212
Net income	**524**	733	857
Adoption of new accounting policies (note 2)	**–**	–	(672)
Common share dividend	**(80)**	(81)	–
Purchase of common shares	**(136)**	(98)	(118)
Preferred security charges, net of tax	**(24)**	(24)	(22)
Retained earnings, end of year	**1,071**	787	257

See accompanying notes.

Consolidated Statements of Cash Flows

(Years ended December 31)

(millions of Canadian dollars)	**2002**	2001	2000
		restated, see note 2	restated, see note 2
Operating			
Net income	**524**	733	857
Items not involving current cash flow (note 14)	**1,936**	1,614	1,456
Exploration	**185**	147	100
Cash flow	**2,645**	2,494	2,413
Deferred gain on unwound hedges	**(43)**	52	–
Changes in non-cash working capital (note 14)	**(163)**	(177)	322
Cash provided by operating activities	**2,439**	2,369	2,735
Investing			
Corporate acquisitions (note 3)	**–**	(1,213)	–
Capital expenditures			
Exploration, development and corporate	**(1,874)**	(1,912)	(1,194)
Acquisitions	**(244)**	(186)	(431)
Proceeds of resource property dispositions	**30**	47	81
Investments	**(36)**	–	–
Changes in non-cash working capital	**2**	52	(407)
Cash used in investing activities	**(2,122)**	(3,212)	(1,951)
Financing			
Long-term debt repaid	**(1,397)**	(568)	(1,294)
Long-term debt issued	**1,417**	1,617	781
Common shares purchased	**(184)**	(117)	(173)
Common share dividends	**(80)**	(81)	–
Preferred security charges	**(42)**	(42)	(40)
Deferred credits and other	**(21)**	(25)	(36)
Cash (used in) provided by financing activities	**(307)**	784	(762)
Net increase (decrease) in cash	**10**	(59)	22
Cash, beginning of year	**17**	76	54
Cash, end of year	**27**	17	76

See accompanying notes.

Notes to the Consolidated Financial Statements

(tabular amounts in millions of Canadian dollars ("$" or "C$") except as noted)

1. SIGNIFICANT ACCOUNTING POLICIES

The Consolidated Financial Statements of Talisman Energy Inc. ("Talisman" or the "Company") have been prepared by management in accordance with accounting principles generally accepted in Canada. A summary of the differences between accounting principles generally accepted in Canada and those generally accepted in the United States ("US") is contained in note 18 to these statements.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

a) CONSOLIDATION

The Consolidated Financial Statements include the accounts of Talisman and its subsidiaries. A substantial portion of Talisman's activities are conducted jointly with others and the Consolidated Financial Statements reflect only the Company's proportionate interest in such activities.

b) INVENTORIES

Product inventories are valued at the lower of average cost and market value. Materials and supplies are valued at the lower of average cost and net realizable value.

c) PROPERTY, PLANT AND EQUIPMENT

The Successful Efforts method is used to account for oil and gas exploration and development costs. Under this method, acquisition costs of oil and gas properties and costs of drilling and equipping development wells are capitalized. Costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. All other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense when incurred. Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its net recoverable amount (undiscounted).

d) DEPRECIATION, DEPLETION AND AMORTIZATION

Capitalized costs of proved oil and gas properties are depleted using the unit of production method. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis.

Successful exploratory wells and development costs are depleted over proved developed reserves while acquired resource properties with proved reserves, including offshore platform costs, are depleted over proved reserves. Acquisition costs of probable reserves are not depleted or amortized while under active evaluation for commercial reserves. Costs are transferred to depletable costs as proved reserves are recognized. At the date of acquisition, an evaluation period is determined after which any remaining probable reserve costs associated with producing fields are transferred to depletable costs; costs not associated with producing fields are amortized over a period not exceeding the remaining lease term.

Costs associated with significant development projects are not depleted until commercial production commences. Unproved land acquisition costs that are individually immaterial are amortized on a straight-line basis over the average lease term until properties are determined to be productive or impaired. Gas plants, net of estimated salvage values, are depreciated on a straight-line basis over their estimated remaining useful lives, not to exceed the estimated remaining productive lives of related fields. Pipelines and corporate assets are depreciated using the straight-line method at annual rates of 7% and 5% to 33%, respectively.

e) FUTURE SITE RESTORATION

Estimated costs of future dismantlement, site restoration and abandonment of oil and gas properties, including offshore production platforms, are provided for using the unit of production method while those of gas plants and facilities are provided for using the straight-line method at rates approximating their useful lives but not exceeding the estimated remaining productive lives of related fields. The annual provision is included within depletion, depreciation and amortization expense and is based on engineering estimates using current costs and technology and in accordance with existing legislation and industry practice. Expenditures are charged against the accumulated provision as incurred. When a property is disposed of, the associated accumulated provision is eliminated and included in determination of the gain or loss on disposal.

f) CAPITALIZED INTEREST

Interest costs associated with major development projects are capitalized until commercial production commences.

g) ROYALTIES

Certain of the Company's foreign operations are conducted jointly with the respective national oil companies. These operations are reflected in the Consolidated Financial Statements based on Talisman's working interest in such activities. All other government stakes, other than income taxes, are considered to be royalty interests. Royalties on production from these joint foreign operations represent the entitlement of the respective governments to a portion of Talisman's share of crude oil, liquids and natural gas production and are recorded using rates in effect under the terms of contracts at the time of production.

h) PETROLEUM REVENUE TAX

United Kingdom Petroleum Revenue Tax ("PRT") is accounted for using the life of the field method whereby total future PRT is estimated using current reserves and anticipated costs and prices and charged to income based on net operating income as a proportion of estimated future net operating income. Changes in the estimated total future PRT are accounted for prospectively.

i) FOREIGN CURRENCY TRANSLATION

Effective January 1, 2002, the Company adopted the US dollar as its functional currency. Prior to January 1, 2002, the functional currency of the Company was the Canadian dollar. The Company's financial results have been reported in Canadian dollars as explained below. See note 2 for additional disclosure regarding the change in functional currency and the treatment of foreign exchange gains and losses on long-term debt.

The Company's self-sustaining operations, which include the Canadian and UK operations, are translated into US dollars using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses on translation to US dollars relating to self-sustaining operations are deferred and included in a separate component of shareholders' equity described as cumulative foreign currency translation.

The remaining foreign operations are not considered self-sustaining and are translated using the temporal method. Under this method, monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Non-monetary assets and liabilities denominated in foreign currencies are translated at rates in effect on the dates the assets were acquired or liabilities were assumed. Revenues and expenses are translated at rates of exchange prevailing on the transaction dates. Gains and losses on translation are reflected in income when incurred.

The Company's financial results have been reported in Canadian dollars with amounts translated to Canadian dollars as follows: assets and liabilities at the rate of exchange in effect at the applicable balance sheet date and revenues and expenses at the average exchange rates for the periods. The Company's share capital accounts including its preferred securities, common shares and contributed surplus are translated at rates in effect at the time of issuance. Unrealized gains and losses resulting from the translation to Canadian dollars are accumulated in the cumulative foreign currency translation account.

j) EMPLOYEE BENEFIT PLANS

The cost of pensions and other retirement benefits earned by employees is determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. The discount rate used to determine the accrued benefit obligation is determined by reference to market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The excess of the net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service life of active employees. The transitional asset and obligations are being amortized over the average remaining service period of active employees expected to receive benefits under the benefit plans.

k) DERIVATIVE FINANCIAL INSTRUMENTS AND COMMODITY CONTRACTS

The Company may enter into derivative financial instruments to hedge against adverse fluctuations in foreign exchange rates, electricity rates, interest rates and commodity prices. Payments or receipts on derivative financial instruments that are designated and effective as hedges are recognized in income concurrently with the hedged transaction and are recorded in the statements of income and cash flows in the line item associated with the hedged transaction. For example, gains and losses on commodity hedges are included in revenues.

If the derivative financial instrument that has been designated as a hedge is terminated, is no longer designated as part of the hedging relationship, or if it is no longer probable that the anticipated transaction will occur substantially as and when identified at the inception of the hedging relationship, the gain or loss at that date is deferred and recognized concurrently with the anticipated transaction. Subsequent changes in the value of the financial instrument are reflected in income. Any derivative financial instrument that does not constitute a hedge is recorded at fair value with any resulting gain or loss reflected in income.

All of the Company's outstanding derivative financial instruments as disclosed in note 9 meet the hedging requirements under Canadian GAAP, including the documentation requirement. The hedging requirements consist of the designation of the instrument as a hedge, the identification of the nature of the risk exposure being hedged and that there is reasonable assurance that the instrument is expected to be an effective hedge throughout its term. In addition, in the case of anticipated transactions, it is also probable that the transaction designated as being hedged will occur. The Company assesses, both at the hedge's inception and on an ongoing basis, whether the derivative financial instruments that have been designated as hedges are highly effective in offsetting changes in fair value or cash flows of the hedged items.

The Company enters into commodity contracts as a normal course of business including ones with fixed or optional pricing terms. The contracts outstanding at December 31, 2002 are disclosed in note 10. The Company's production is expected to be sufficient to deliver all required volumes under these contracts. No amounts are recognized in the financial statements related to these contracts until such time as the associated volumes are delivered.

l) INCOME TAXES

Talisman uses the liability method to account for income taxes. Under the liability method, future income taxes are based on the differences between assets and liabilities reported for financial accounting purposes from those reported for income tax. Future income tax assets and liabilities are measured using substantively enacted tax rates. The impact of a change in tax rate is recognized in net income in the period in which the tax rate is substantively enacted.

m) REVENUE RECOGNITION

Revenues associated with the sale of crude oil, natural gas and liquids represents the sales value of the Company's share of petroleum production during the year (the entitlement method). Differences between production and amounts sold are not significant. Amounts received under take-or-pay gas sales contracts in respect of undelivered volumes is accounted for as deferred income. In accordance with contract provisions, Talisman received upstream capital cost recovery priority in Sudan, which resulted in an accumulation of deferred oil revenue. In 2001, all deferred oil revenues have been realized and commencing in the second quarter of 2001, upstream capital cost recovery reverted to being proportionately shared based on working interest.

n) STOCK OPTION PLANS

Talisman has stock option plans for employees and directors, which are described in note 8. No amount of compensation expense has been recognized in the financial statements. Any consideration paid by employees on exercise of options is credited to share capital.

o) GOODWILL

Goodwill represents the excess purchase price over the fair value of identifiable assets and liabilities acquired in business combinations. Goodwill is no longer amortized and is subject to ongoing annual impairment reviews, or as economic events dictate, based on the fair value of reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's individual assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. See note 2 for additional information on the change in accounting for goodwill.

p) DILUTED EARNINGS PER SHARE

The Company uses the treasury method for calculating diluted earnings per share. This method assumes that any proceeds from the exercise of a convertible instrument would be used to purchase common shares at the average market price during the period. Outstanding stock options are the only instruments that are dilutive to earnings per share. For 2002, 1,080,035 stock options that were antidilutive have been excluded from the computation of diluted earnings per share (2001 – 2,249,145; 2000 – nil).

q) COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the presentation adopted in 2002.

2. CHANGES IN ACCOUNTING

FUNCTIONAL CURRENCY

As disclosed in note 1(i) above, effective January 1, 2002, the Company adopted the US dollar as its functional currency. Prior to January 1, 2002, the functional currency of the Company was the Canadian dollar. The Canadian and UK operations are considered self-sustaining with the Canadian dollar and Pound Sterling as their respective functional currencies. The remaining foreign operations are considered integrated and have the US dollar as their functional currency.

The change in functional currency of the Company is due to the increased exposure to the US dollar as a result of the growth in international operations. The adoption of the Pound Sterling as the functional currency of the UK operations is the result of the increased financial self-sustainability of this operation and its overall exposure to Pound Sterling transactions.

The change in functional currency decreased net income for the year by $15 million, primarily relating to foreign exchange gains on US dollar denominated debt. Had the UK operations continued to be accounted for as being integrated with the parent Company's operations, the Company would have recorded a $130 million reduction to net income, primarily related to foreign exchange losses on its Pound Sterling denominated liabilities.

FOREIGN EXCHANGE GAINS AND LOSSES ON LONG-TERM DEBT

In accordance with a new accounting standard adopted for 2002 by the Canadian Institute of Chartered Accountants (CICA), the Company no longer defers and amortizes the gains or losses on foreign currency denominated long-term debt. Such gains or losses are reflected in the Income Statement in the period incurred. The new standard is being applied retroactively with the financial statements of comparative periods restated. The impact of the new standard on the current year's results was to decrease net income by $3 million.

The effect of the restatement on the prior released financial statements reduced net income, other assets, retained earnings (at time of adoption) and net income per share by the following amounts:

(millions of dollars – except per share amounts)	2001	2000
Net income	53	49
Other assets at December 31	103	51
Retained earnings – adoption of new accounting policies	–	2
Net income per share	0.40	0.36

GOODWILL

In accordance with a new accounting standard of the CICA, the amortization of goodwill ceased January 1, 2002. This change did not have a significant impact on the Company's financial results.

CHANGE IN INCOME TAX ACCOUNTING POLICY IN PRIOR YEAR

Effective January 1, 2000, the Company retroactively adopted without restatement the liability method to account for income taxes. The liability method is explained in note 1(l). Previously, the deferral method was followed, which determined deferred income taxes based on the differences in the timing of income and expenses reported for financial accounting purposes from those reported for income tax purposes. The effect of the accounting change was to increase net income for 2000 by $80 million, increase the January 1, 2000 future tax liability by $670 million and decrease retained earnings on adoption of new accounting policy by $670 million. The adjustment to retained earnings resulted primarily from the recognition of the future tax cost of past corporate acquisitions where the tax basis acquired was less than the purchase price.

3. CORPORATE ACQUISITIONS

PETROMET RESOURCES LIMITED

In May 2001, Talisman acquired Petromet Resources Limited ("Petromet"), an oil and gas exploration and development company, for $765 million and long-term debt assumed of $57 million. The acquisition has been accounted for using the purchase method and the results have been included in these financial statements from the date of acquisition.

Net Assets Acquired	
Property, plant and equipment	795
Goodwill	301
Net non-cash working capital	(6)
Future income tax	(264)
	826
Less acquisition costs	(4)
	822

LUNDIN OIL AB

In August 2001, Talisman acquired Lundin Oil AB ("Lundin"), an oil and gas exploration and development company, for $431 million (net of cash on hand) and long-term debt assumed of $70 million. The acquisition has been accounted for using the purchase method and the results have been included in these financial statements from the date of acquisition.

Net Assets Acquired	
Property, plant and equipment	515
Goodwill	176
Net non-cash working capital	(19)
Future income tax	(158)
	514
Less acquisition costs	(13)
	501

4. INVENTORIES

December 31	**2002**	2001
Materials and supplies	**143**	96
Product	**4**	3
	147	99

5. PROPERTY, PLANT AND EQUIPMENT

December 31, 2002	Cost	Accumulated DD&A	Net book value
Oil and gas properties	**10,198**	**4,264**	**5,934**
Gas plants, pipelines and production equipment	**5,576**	**1,547**	**4,029**
Corporate assets	**213**	**134**	**79**
	15,987	**5,945**	**10,042**
December 31, 2001			
Oil and gas properties	9,033	3,193	5,840
Gas plants, pipelines and production equipment	4,863	1,298	3,538
Corporate assets	194	111	83
	14,063	4,602	9,461

In the year ended December 31, 2002, interest costs of $25 million (2001 – $19 million, 2000 – $16 million) were capitalized. In 2002, capitalized interest relates to the Block PM-3 CAA development in Southeast Asia.

Included in property, plant and equipment are the following costs that were not currently subject to depreciation, depletion or amortization ("DD&A"):

Non-depleted capital at December 31	**2002**	2001
Acquired probable reserve costs[1]		
Canada – associated with producing fields	**102**	229
North Sea – associated with producing fields	**–**	120
North Sea – not associated with producing fields	**13**	22
Southeast Asia – not associated with producing fields	**39**	39
Exploration costs[2]	**309**	399
Development projects[3]		
Southeast Asia	**437**	267
North Sea	**88**	142
Algeria	**175**	21
Trinidad	**30**	–
	1,193	1,239

1 Acquisition costs of probable reserves are not depleted or amortized while under active evaluation for commercial reserves.
2 Exploration costs consist of drilling in progress, wells awaiting determination of proved reserves or commencement of production.
3 Development projects are not depleted pending initial production.

The carrying values of property, plant and equipment, including acquired probable reserve costs, are subject to uncertainty associated with the quantity of oil and gas reserves, future production rates, commodity prices and other factors. Future events could result in material changes to the carrying values recognized in the financial statements.

6. LONG-TERM DEBT

December 31	**2002**	2001
Bank Credit Facilities[1&2]		
Acquisition Credit Facility (2001 – 2.94%)	**–**	625
Bank Credit Facilities (2002 – 3.32%, 2001 – 2.80%)	**265**	639
Debentures and Notes (Unsecured)[3]		
6.625% notes (£250 million), due 2017	**576**	–
7.25% debentures (US$300 million), due 2027	**474**	478
5.80% medium term notes, due 2007	**385**	60
6.96% notes (US$200 million), due 2005	**316**	318
7.125% debentures (US$175 million), due 2007	**276**	279
5.70% medium term notes, due 2003[2]	**180**	180
8.06% medium term notes, due 2009	**174**	175
6.68% notes (US$100 million), due 2008	**158**	–
6.89% notes (US$50 million), Series B, due 2006[4]	**79**	79
9.80% debentures, Series B, due 2004	**75**	75
6.71% notes (US$25 million), Series A, due 2004	**39**	40
9.66% medium term notes, due 2002	**–**	35
	2,997	2,983
Less current portion	**–**	(189)
	2,997	2,794

1 Rates reflect the weighted-average interest rate of instruments outstanding at December 31. Rates are floating rate-based and vary with changes in short-term market interest rates.
2 The amount outstanding at December 31, 2002 has been classified as long-term debt since the Company has both the ability to replace the current portion with long-term borrowings under the revolving bank credit facilities and the intention to extend the terms of the respective credit facilities in 2003.
3 Interest on debentures and notes is payable semi-annually except for the 6.625% notes (£250 million), which is payable annually.
4 Repayable in five equal annual installments commencing 2006.

During 2002, the Company completed a $571 million (£250 million) Eurobond offering of 6.625% notes due December 5, 2017. The Company entered into US dollar cross currency swap contracts and interest rate swap contracts for an equivalent amount of the notes which have in effect converted this indebtedness to US$364 million with a floating interest rate based on US LIBOR. The swap contracts expire December 5, 2009.

BANK CREDIT FACILITIES

Talisman has unsecured credit facilities totaling $1,049 million, consisting of facilities of $437 million ("Facility No. 1"), $512 million ("Facility No. 2") and $100 million ("Facility No. 3"). The maturity date of Facility No. 1 is March 23, 2005, although this date may be extended from time to time upon agreement between the Company and the respective lenders. Prior to the maturity date, the Company may borrow, repay and reborrow at its discretion. The term dates of Facility Nos. 2 and 3 are March 19, 2003 and August 26, 2003, respectively. Until each term date, the Company may borrow, repay and reborrow at its discretion. Annually, upon agreement between the Company and the respective lenders, each term date may be extended for an additional 364 days. Facility No. 2 expires four years after the then current term date and, if the term is not extended, must be repaid in equal semi-annual payments beginning six months after the term date. Facility No. 3 expires one year after the then current term date and, if the term is not extended, must be repaid on the maturity date.

Borrowings under Facility Nos. 1 and 2 are available in the form of prime loans, Canadian or US dollar bankers' acceptances, US dollar base rate loans or LIBOR-based loans. In addition, drawings to a total of $475 million may be made by letters of credit. Borrowings under Facility No. 3 are available in the form of prime loans, Canadian bankers' acceptances, US dollar base rate loans, LIBOR-based loans and letters of credit.

REPAYMENT SCHEDULE

The Company's contractual minimum repayments of long-term debt in the next five years are as follows:

Year	
2003[1]	180
2004	124
2005	571
2006	16
2007	677
Subsequent to 2007	1,429
Total	2,997

1 The portion of long-term debt payable in 2003 has been classified as long-term debt since the Company has both the ability to replace the current portion with long-term borrowings under the revolving bank credit facilities and the intention to extend the terms of the facilities in 2003.

7. PREFERRED SECURITIES

During 1999, Talisman issued 12 million preferred securities ("securities") as unsecured junior subordinated debentures, at US$25 per security, of which six million 9% securities are due February 15, 2048 and six million 8.9% securities are due June 15, 2048. The securities are redeemable, in whole or in part, at par by Talisman through the payment of cash or issuance of common shares at any time on or after February 15, 2004 and June 15, 2004, respectively. The Company has the option to defer the payment of the security charges for up to 20 consecutive three month periods and satisfy such deferred security charges with either cash or the issuance of common shares. Security charges are due quarterly.

8. SHARE CAPITAL

Talisman's authorized share capital consists of an unlimited number of common shares without nominal or par value and first and second preferred shares. No preferred shares have been issued.

Continuity of common shares	**2002**		2001		2000	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Balance, beginning of year	**133,733,182**	**2,831**	135,344,045	2,849	138,346,297	2,901
Issued on exercise of options	**1,154,067**	**36**	1,512,898	49	1,276,048	38
Purchased during year	**(3,847,500)**	**(82)**	(3,036,400)	(65)	(4,278,300)	(90)
Cancelled pursuant to terms of plans of arrangements	**(314)**	**–**	(87,361)	(2)	–	–
Balance, end of year	**131,039,435**	**2,785**	133,733,182	2,831	135,344,045	2,849

During the year ended December 31, 2002, Talisman repurchased 3,847,500 common shares of the Company pursuant to a normal course issuer bid for a total of $220 million (2001 – $166 million; 2000 – $210 million). Subsequent to year end, the Company repurchased an additional 1,986,200 common shares for $113 million pursuant to the normal course issuer bid.

In 2001, Talisman cancelled 87,361 common shares of the Company pursuant to the terms of the offering agreements of certain past corporate acquisitions. As a result of the cancellation of these shares, $2 million was credited to contributed surplus. An additional 314 common shares were cancelled in 2002.

STOCK OPTION PLANS

Talisman has stock option plans that allow employees and directors to receive options to purchase common shares of the Company. Options granted under the plans are generally exercisable after three years and expire 10 years after the grant date. Option exercise prices approximate the market price for the common shares on the date the options are issued.

No amount of compensation expense has been recognized in the Consolidated Financial Statements for stock options granted to employees and directors. The following table provides pro forma measures of net income and net income per common share had stock options been recognized as compensation expense based on the estimated fair value of the options on the grant date.

	2002		2001		2000	
	As Reported	**Pro Forma**	As Reported	Pro Forma	As Reported	Pro Forma
Net income	**524**	**493**	733	709	857	841
Per common share						
Basic	**3.73**	**3.50**	5.25	5.08	6.05	5.93
Diluted	**3.67**	**3.44**	5.16	4.99	5.96	5.85

Stock options granted in 2002 had an estimated weighted-average fair value of $26.19 per option (2001 – $22.80 per option; 2000 – $16.83 per option). All options issued by the Company permit the holder to purchase one common share of the Company at the stated exercise price.

The estimated fair value of stock options issued was determined using the Black-Scholes model using the following weighted-average assumptions:

	2002	2001	2000
Risk-free interest rate (%)	**5.1**	4.9	6.2
Estimated hold period prior to exercise (years)	**5.4**	5.3	5.4
Volatility in the price of the Company's common shares (%)	**41**	39	35
Dividends ($/share)	**0.60**	0.60	–

Continuity of stock options	**2002**		2001		2000	
	Number of Options	**Average Exercise Price**	Number of Options	Average Exercise Price	Number of Options	Average Exercise Price
Outstanding at January 1	**7,497,611**	**41.49**	6,854,806	33.84	7,211,864	32.30
Granted	**1,100,710**	**64.73**	2,301,828	58.39	1,097,427	39.31
Exercised	**1,154,067**	**30.54**	1,512,898	32.19	1,276,048	29.39
Forfeited	**59,150**	**57.53**	146,125	45.24	176,637	36.93
Expired	**1,050**	**57.88**	–	–	1,800	42.55
Outstanding at December 31	**7,384,054**	**46.53**	7,497,611	41.49	6,854,806	33.84
Exercisable at December 31	**3,142,629**	**34.34**	3,246,985	34.87	3,529,921	32.67
Options available for future grants pursuant to the Company's Stock Option Plans	**3,155,889**		4,196,399		2,852,102	

The range of exercise prices of the Company's outstanding stock options is as follows:

December 31, 2002	Outstanding Options			Exercisable Options	
Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Years to Expiry	Number of Options	Weighted Average Exercise Price
$24.25 to $29.99	1,167,871	25.79	5	1,167,871	25.79
$30.00 to $39.99	1,509,492	36.10	6	612,892	33.00
$40.00 to $49.99	1,409,068	42.28	5	1,336,276	41.91
$50.00 to $59.99	2,197,663	58.35	8	15,140	58.55
$60.00 to $68.36	1,099,960	64.73	9	10,450	64.73
$24.25 to $68.36	7,384,054	46.53	7	3,142,629	34.34

At December 31, 2002, 10,539,943 common shares were reserved for issuance related to the stock option plans.

9. FINANCIAL INSTRUMENTS

FINANCIAL CONTRACTS

The following financial contracts were outstanding at December 31:

a) Interest rates

In December 1994, in anticipation of issuing the US$175 million 7.125% debentures, Talisman entered into interest rate swap contracts to hedge against possible adverse interest rate fluctuations. These contracts result in Talisman paying interest at a rate of 8.295% in exchange for receiving the three-month LIBOR rate on notional principal of US$100 million until May 16, 2005. Based on the LIBOR rate at December 31, 2002, these contracts result in an effective rate of interest on the debentures of 10.8%.

b) Cross currency and interest rate swaps

As disclosed in note 6, in conjunction with the Eurobond offering, the Company entered into US dollar cross currency swap contracts and interest rate swap contracts for an equivalent amount of the notes, which have in effect converted the original Pounds Sterling fixed interest rate on this indebtedness into US dollars with a floating interest rate based on three month US LIBOR. The swap contracts expire December 5, 2009. Subsequently in 2002, the Company entered into a forward rate swap agreement to effectively fix the rate of the next three month US LIBOR payment due in March 2003 under the interest rate swap contracts.

c) Foreign exchange forward contracts

During 2002, the Company entered into foreign exchange forward contracts to purchase £178 million for US$275 million during the first six months of 2003. These forward contracts fix the exchange rate used to convert a portion of the Company's US dollar denominated revenues received in the UK into Pounds Sterling for purposes of paying operating costs and capital expenditures.

d) Commodity prices

The Company entered into the following commodity price derivative contracts to reduce the volatility of anticipated natural gas and crude oil revenues. The amounts shown below are the weighted-average of the contracts outstanding.

NATURAL GAS DERIVATIVE CONTRACTS

Fixed price swaps	2003	Two-way collars	2003	Three-way collars	2003
Volumes (mcf/d)	35,600	Volumes (mcf/d)	13,400	Volume (mcf/d)	11,500
Price ($/mcf)	6.54	Ceiling ($/mcf)	6.94	Ceiling ($/mcf)	3.54
		Floor ($/mcf)	6.23	Floor ($/mcf)	3.25
				Sold put ($/mcf)	2.68

The natural gas price reference for the above contracts is AECO. The three-way collars are similar to two-way collars except that should the index price fall below the sold put price, Talisman will receive the index price plus the difference between the floor and sold put prices.

CRUDE OIL DERIVATIVE CONTRACTS

Fixed price swaps (WTI oil index)	2003	Fixed price swaps (Brent oil index)	2003
Volumes (bbls/d)	30,000	Volumes (bbls/d)	10,000
Price (US$/bbl)	25.34	Price (US$/bbl)	21.75
Two-way collars (WTI oil index)	2003	Two-way collars (Brent oil index)	2003
Volumes (bbls/d)	23,000	Volumes (bbls/d)	12,000
Ceiling price (US$/bbl)	28.48	Ceiling price (US$/bbl)	25.71
Floor price (US$/bbl)	23.05	Floor price (US$/bbl)	22.23

CARRYING AMOUNTS AND ESTIMATED FAIR VALUES OF FINANCIAL INSTRUMENTS

Asset (liability) at December 31	**2002**			2001		
	Carrying Value	**Fair Value**	**Unrecognized**	Carrying Value	Fair Value	Unrecognized
Debentures and notes	**(2,732)**	**(3,006)**	**(274)**	(1,719)	(1,767)	(48)
Foreign currency swaps	**–**	**14**	**14**	–	–	–
Cross currency and interest rate swaps	**–**	**72**	**72**	–	(19)	(19)
Natural gas derivatives	**–**	**(10)**	**(10)**	–	69	69
Crude oil derivatives	**–**	**(52)**	**(52)**	–	91	91

Borrowings under bank credit facilities are for short terms and are market rate based, thus, carrying values approximate fair value. The fair value of debentures and notes is based on market quotations, which reflect the discounted present value of the principal and interest payments using the effective yield at December 31 for instruments having the same term and risk characteristics. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at December 31. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices.

The fair values of other financial instruments, including cash, accounts receivable, accounts payable, and income and other taxes payable, approximate their carrying values.

CREDIT RISK

A significant portion of the Company's accounts receivable is due from entities in the oil and gas industry. Concentration of credit risk is mitigated by having a broad domestic and international customer base, which includes a significant number of companies engaged in joint operations with Talisman. The Company routinely assesses the financial strength of its partners and customers, including parties involved in marketing or other commodity arrangements.

The Company is exposed to credit risk associated with possible non-performance by derivative instrument counter parties. The Company actively limits the total exposure to individual counter parties.

10. CONTINGENCIES AND COMMITMENTS

Talisman is party to various legal claims associated with the ordinary conduct of business. These claims are not currently expected to have a material impact on the Company's financial position.

A suit which seeks class action status was filed against Talisman in the United States District Court (Southern District of New York), under the Alien Tort Claims Act relating to the civil conflict in Sudan. Damages sought under the suit are indeterminate.

Talisman's estimated total future dismantlement, site restoration and abandonment liability at December 31, 2002 was $1.7 billion (2001 – $1.5 billion), approximately 80% of which is denominated in UK Pounds Sterling. At December 31, 2002, Talisman had accrued $813 million (2001 – $619 million) of this liability and will continue to accrue the remaining balance in accordance with the Company's policy as set out in note 1(e). The Company has provided letters of credit in 2003 in the amount of £161 million ($411 million) as security for the costs of future dismantlement, site restoration and abandonment costs for certain North Sea fields included in the above total. Estimated future dismantlement, site restoration and abandonment costs and the related provision in the financial statements are subject to uncertainty associated with the method, timing and extent of future dismantlement, site restoration and abandonment. For example, changes in legislation or technology may result in actual future costs that differ materially from those estimated.

Talisman has firm commitments for gathering, processing and transportation services that require the Company to pay tariffs to third parties for processing or shipment of certain minimum quantities of crude oil and liquids and natural gas. The Company has sufficient production to meet these commitments.

Talisman leases certain of its vessels and corporate offices, all of which are accounted for as operating leases. Talisman is under contract to lease two vessels from third parties. The term of the Ross Floating Production, Storage and Offloading vessel ("FPSO") lease depends on the expected life of the Ross and Blake fields. A lease for an FPSO contracted in Malaysia expires in 2004. In addition, Talisman has ongoing operating commitments associated with the vessels.

Estimated future minimum commitments[1]

	2003	2004	2005	2006	2007	Subsequent to 2007	Total
Office leases	18	15	15	15	15	113	191
Vessel leases	52	63	–	–	–	–	115
Transportation and processing commitments[2]	145	97	76	70	63	491	942
Minimum work commitments	262	104	48	22	25	–	461
Abandonment obligations	24	24	25	90	19	1,549	1,731
Other service contracts	16	16	16	16	6	90	160
Total	517	319	180	213	128	2,243	3,600

1 Future minimum payments denominated in foreign currencies have been translated into Canadian dollars based on the December 31, 2002 exchange rate.
2 Certain of the Company's transportation commitments are tied to firm gas sales contracts.

The Company has entered into sales contracts for a portion of its future North American natural gas production. The following are the average volumes under contract and the weighted-average contract price in each of the years shown.

Fixed price sales	2003	2004
Volumes (mcf/d)	71,250	33,200
Average price ($/mcf)	3.91	3.42

Three-way collars	2003	2004
Volumes (mcf/d)	14,500	15,250
Ceiling ($/mcf)	3.59	3.49
Floor ($/mcf)	3.39	3.32
Sold put strike ($/mcf)	2.78	2.67

The three-way collars are similar to two-way commodity collars, except that should the NIT (Nova Inventory Transfer) index fall below the sold put strike price, Talisman will receive NIT plus the difference between the floor and sold put strike prices.

The Company has also sold forward 15,000 mcf/d of North Sea natural gas production for the period April to September 2003 at $4.40/mcf.

11. OTHER REVENUE

Years ended December 31	**2002**	2001	2000
Pipeline and custom treating tariffs	**69**	63	82
Investment income	**8**	15	13
Marketing income	**3**	4	4
	80	82	99

12. OTHER EXPENSES (INCOME)

Years ended December 31	**2002**	2001	2000
Net loss (gain) on asset disposals	**10**	(11)	(12)
Foreign exchange losses[1]	**28**	51	57
Project loan facility deferred costs write-off	**–**	17	–
Property impairments	**74**	–	–
Other expense (income)	**1**	21	19
	113	78	64

1 Foreign exchange gains and losses for 2001 and 2000 have been restated for a new accounting standard. See note 2.

13. TAXES

Income Taxes

The current and future income taxes for each of the three years ended December 31 are as follows:

	2002	2001	2000
Current income taxes (recovery)			
Canada [1]	(20)	45	10
United Kingdom	131	153	233
Netherlands	–	9	4
Southeast Asia [2]	76	83	31
Sudan	68	50	54
Other	3	2	2
	258	342	334
Future income taxes (recovery)			
Canada	67	134	147
United Kingdom	109	(68)	(33)
Netherlands	7	(1)	2
Southeast Asia [2]	(3)	15	89
Sudan	16	3	5
Other	(34)	(11)	(14)
	162	72	196
Income taxes	420	414	530

1 Current Canadian income taxes include the federal tax on large corporations, net of Alberta royalty tax credits.

2 Includes operations in Indonesia and Malaysia/Vietnam.

The components of the net future tax liability at December 31, are as follows:

	2002	2001
Future tax liabilities		
Property, plant and equipment	2,392	2,137
Pension assets	21	22
Other	184	90
	2,597	2,249
Future tax assets		
Provision for future site restoration	297	195
Other	64	65
	361	260
Net future tax liability	2,236	1,989

Future distribution taxes associated with operations in the UK have not been recorded because, based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material amounts of tax expense. Unremitted earnings in other foreign jurisdictions are not material.

Income taxes vary from the amount that would be computed by applying the Canadian statutory income tax rate of 42.08% for the year ended December 31, 2002 (2001 – 42.45%; 2000 – 44.04%) as follows:

Years ended December 31	2002	2001	2000
Income taxes calculated at the Canadian statutory rate	**442**	572	698
Increase (decrease) in income taxes resulting from:			
Non-deductible royalties, mineral taxes and expenses	**138**	207	203
Resource allowances	**(128)**	(168)	(162)
Non-deductible depreciation, depletion and amortization	**–**	4	–
Deductible PRT expense	**(51)**	(62)	(64)
Lower foreign tax rates (net)	**(108)**	(90)	(172)
Provincial rebates and credits	**(10)**	(40)	(1)
Federal tax on large corporations	**9**	9	7
Change in statutory tax rates	**116**	(34)	–
Other	**12**	16	21
Income taxes	**420**	414	530

PETROLEUM REVENUE TAX

Petroleum Revenue Tax (PRT) expense primarily relates to the UK and is comprised of current tax expense of $91 million (2001 – $102 million; 2000 – $165 million) and deferred tax expense of $33 million (2001 – $47 million expense; 2000 – $15 million recovery). The measurement of PRT expense and the related provision in the Consolidated Financial Statements is subject to uncertainty associated with future recovery of oil and gas reserves, commodity prices and the timing of future events, which could result in material changes to deferred amounts.

14. CONSOLIDATED STATEMENTS OF CASH FLOWS

Selected cash flow information:

Years ended December 31	2002	2001	2000
Net income	**524**	733	857
Items not involving current cash flow			
Depreciation, depletion and amortization	**1,495**	1,313	1,153
Property impairments	**74**	–	–
Dry hole	**174**	113	77
Net loss (gain) on asset disposals	**10**	(11)	(12)
Future taxes and deferred PRT	**195**	119	181
Other	**(12)**	80	57
	1,936	1,614	1,456
Exploration	**185**	147	100
Cash flow	**2,645**	2,494	2,413
Cash interest paid (net of capitalized interest)	**156**	137	147
Cash income taxes paid	**274**	365	182

Cash and cash equivalents include short-term investments with maturities of three months or less.

Changes in operating non-cash working capital consisted of the following:

Years ended December 31	2002	2001	2000
Accounts receivable	**(155)**	266	(247)
Inventories	**(42)**	10	(19)
Prepaid expenses	**5**	(9)	2
Accounts payable and accrued liabilities	**(16)**	(323)	385
Income and other taxes payable	**45**	(121)	201
Net source (use) of cash	**(163)**	(177)	322

15. EMPLOYEE BENEFITS

The Company sponsors both defined benefit and defined contribution pension arrangements covering substantially all employees. The Company uses actuarial reports prepared by independent actuaries for funding and accounting purposes. The following significant actuarial assumptions were employed to determine the periodic pension expense and the accrued benefit obligations:

	2002	2001	2000
Expected long-term rate of return on plan assets (%)	**7.5**	7.5	7.5
Discount rate (%)	**6.5**	6.5	6.6
Rate of compensation increase (%)	**4.5**	4.5	4.5

The Company's net benefit plan expense (credit) is as follows:

	2002	2001	2000
Current service cost – defined benefit	**5**	2	1
Current service cost – defined contribution	**6**	5	4
Interest cost	**7**	5	5
Expected return on plan assets	**(11)**	(10)	(10)
Amortization of net transitional asset	**(1)**	(1)	(1)
Net benefit plan expense (credit)	**6**	1	(1)

Information about the Company's defined benefit pension plans is as follows:

	2002		2001	
	Pension plans grouped by funded status		Pension plans grouped by funded status	
	Surplus	**Deficit**	Surplus	Deficit
ACCRUED BENEFIT OBLIGATION				
Accrued benefit obligation, beginning of year	**53**	**42**	48	33
Current service cost	**1**	**4**	1	1
Interest cost	**3**	**3**	4	1
Actuarial losses	**1**	**14**	5	8
Plan participants' contributions	**–**	**1**	–	–
Benefits paid	**(4)**	**(1)**	(5)	(1)
Accrued benefit obligation, end of year	**54**	**63**	53	42
PLAN ASSETS				
Fair value of plan assets, beginning of year	**128**	**21**	136	23
Actual loss on plan assets	**(4)**	**(5)**	(3)	(2)
Employer contributions	**–**	**5**	–	2
Plan participants' contributions	**–**	**1**	4	–
Surplus applied to defined contribution plan	**(6)**	**–**	(4)	–
Benefits paid	**(4)**	**(1)**	(5)	(1)
Fair value of plan assets, end of year	**114**	**21**	128	22
FUNDED STATUS – SURPLUS (DEFICIT)	**60**	**(42)**	75	(20)
Unamortized net actuarial loss	**18**	**21**	4	3
Unamortized net transitional (asset) obligation	**(11)**	**2**	(12)	2
Other	**–**	**–**	–	(1)
Net accrued benefit asset (liability)	**67**	**(19)**	67	(16)

At December 31, 2002, the actuarial net present value of the accrued benefit obligation for other post-retirement benefit plans was $7 million (2001 – $7 million).

16. SEGMENTED INFORMATION

Talisman's activities are conducted in five geographic segments: North America, the North Sea, Southeast Asia, Sudan and other international locations. North America includes operations in Canada and the US. The North Sea includes operations in the UK and the Netherlands. The Southeast Asia segment includes operations in Indonesia, Malaysia and Vietnam. All activities relate to the exploration, development and production of oil, liquids and natural gas.

	North America[2]			North Sea[3]		
	2002	2001	2000	**2002**	2001	2000
Revenue						
Gross sales						
Oil and liquids	**706**	714	799	**1,798**	1,466	1,513
Natural gas	**1,270**	1,583	1,216	**173**	172	159
Synthetic oil	**42**	40	41	**–**	–	–
Sulphur	**(4)**	(5)	3	**–**	–	–
Total gross sales	**2,014**	2,332	2,059	**1,971**	1,638	1,672
Royalties	**373**	558	511	**96**	93	70
Net sales	**1,641**	1,774	1,548	**1,875**	1,545	1,602
Other	**38**	34	19	**40**	46	78
Total revenue	**1,679**	1,808	1,567	**1,915**	1,591	1,680
Segmented expenses						
Operating						
Oil and liquids	**121**	121	97	**517**	407	374
Natural gas	**212**	198	155	**27**	18	26
Synthetic oil	**19**	20	17	**–**	–	–
Pipeline	**5**	4	4	**44**	42	35
Total operating expenses	**357**	343	273	**588**	467	435
DD&A	**614**	585	478	**701**	558	512
Dry hole	**128**	54	29	**9**	21	15
Exploration	**66**	69	54	**20**	30	13
Other	**77**	11	51	**55**	(23)	(4)
Total segmented expenses	**1,242**	1,062	885	**1,373**	1,053	971
Segmented income (loss) before taxes	**437**	746	682	**542**	538	709
Corporate expenses						
General and administrative						
Interest on long-term debt						
Currency translation						
Total corporate expenses						
Income before taxes						
Property, plant and equipment	**4,955**	4,773	3,658	**2,921**	2,831	2,484
Goodwill	**291**	291	–	**46**	41	–
Other	**350**	265	410	**387**	371	389
Segmented assets	**5,596**	5,329	4,068	**3,354**	3,243	2,873
Non-segmented assets						
Total assets						
Capital expenditures						
Exploration	**321**	314	252	**134**	106	46
Development	**501**	562	434	**297**	527	257
Exploration and development	**822**	876	686	**431**	633	303
Acquisitions[1]						
Proceeds on dispositions						
Other non-segmented						
Net capital expenditures						

1 Excluding corporate acquisitions

2

North America		**2002**	2001	2000
Revenues	Canada	**1,674**	1,808	1,567
	US	**5**	–	–
		1,679	1,808	1,567
Property, plant and equipment	Canada	**4,848**	4,769	3,656
	US	**107**	4	2
		4,955	4,773	3,658

3

North Sea		**2002**	2001	2000
Revenues	UK	**1,888**	1,561	1,657
	Netherlands	**27**	30	23
		1,915	1,591	1,680
Property, plant and equipment	UK	**2,875**	2,791	2,436
	Netherlands	**46**	40	48
		2,921	2,831	2,484

	Southeast Asia [4]			Sudan			Other			Total		
	2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000	**2002**	2001	2000
	323	276	289	**828**	638	589	**–**	–	–	**3,655**	3,094	3,190
	163	163	227	**–**	–	–	**–**	–	–	**1,606**	1,918	1,602
	–	–	–	**–**	–	–	**–**	–	–	**42**	40	41
	–	–	–	**–**	–	–	**–**	–	–	**(4)**	(5)	3
	486	439	516	**828**	638	589	**–**	–	–	**5,299**	5,047	4,836
	130	90	113	**328**	248	252	**–**	–	–	**927**	989	946
	356	349	403	**500**	390	337	**–**	–	–	**4,372**	4,058	3,890
	1	1	3	**1**	1	1	**–**	–	(2)	**80**	82	99
	357	350	406	**501**	391	338	**–**	–	(2)	**4,452**	4,140	3,989
	65	54	40	**84**	66	64	**–**	–	–	**787**	648	575
	21	16	15	**–**	–	–	**–**	–	–	**260**	232	196
	–	–	–	**–**	–	–	**–**	–	–	**19**	20	17
	–	–	–	**–**	–	–	**–**	–	–	**49**	46	39
	86	70	55	**84**	66	64	**–**	–	–	**1,115**	946	827
	87	93	83	**93**	77	80	**–**	–	–	**1,495**	1,313	1,153
	4	8	17	**13**	16	3	**20**	14	13	**174**	113	77
	19	8	7	**6**	11	8	**74**	29	18	**185**	147	100
	11	(2)	14	**(5)**	11	(1)	**(7)**	8	4	**131**	5	64
	207	177	176	**191**	181	154	**87**	51	35	**3,100**	2,524	2,221
	150	173	230	**310**	210	184	**(87)**	(51)	(37)	**1,352**	1,616	1,768
										138	108	95
										164	139	136
										(18)	73	–
										284	320	231
										1,068	1,296	1,537
	1,093	924	517	**772**	767	748	**301**	166	94	**10,042**	9,461	7,501
	132	135	–	**–**	–	–	**–**	–	–	**469**	467	–
	205	137	189	**56**	44	77	**18**	7	7	**1,016**	824	1,072
	1,430	1,196	706	**828**	811	825	**319**	173	101	**11,527**	10,752	8,573
										67	67	52
										11,594	10,819	8,625
	36	31	30	**27**	42	33	**110**	74	46	**628**	567	407
	233	110	39	**71**	75	37	**118**	41	5	**1,220**	1,315	772
	269	141	69	**98**	117	70	**228**	115	51	**1,848**	1,882	1,179
										244	186	431
										(40)	(47)	(81)
										26	30	15
										2,078	2,051	1,544

4 Southeast Asia		**2002**	2001	2000
Revenues	Indonesia	**302**	332	406
	Malaysia	**50**	18	–
	Vietnam	**5**	–	–
		357	350	406
Property, plant and equipment	Indonesia	**515**	508	517
	Malaysia	**565**	407	–
	Vietnam	**13**	9	–
		1,093	924	517

17. SALE OF SUDAN OPERATIONS

On October 30, 2002, the Company signed an agreement for the sale of its operations in Sudan subject to government and consortium member approvals and other closing conditions. The impact of the sale of the Sudan operations is not included in the Consolidated Financial Statements of the Company as at December 31, 2002. The Company's Consolidated Financial Statements will continue to include the Sudan operations until closing. Readers are referred to the segmented information in note 16 in which the Sudan operations are reported as a separate operating segment.

The estimated gross proceeds are $1.2 billion (US$758 million), including interest. The gain that will be recorded at the time of closing will be reduced by net cash receipts by Talisman from these operations from September 1, 2002 until closing. The gain on sale will be impacted by the timing of closing, foreign exchange rate movements, closing costs, interest on the sale proceeds and the Sudan operating results during the period to closing.

The gain that would have been recorded had the deal closed on December 31, 2002 is as follows:

Gross proceeds on sale of Sudan operations (US$758 million)	1,197
Less interim adjustments	(91)
	1,106
Property, plant and equipment	772
Other assets	56
Accounts payable and accrued liabilities	(29)
Future income tax liability	(54)
Net carrying value at December 31, 2002	745
Estimated closing costs	(10)
Gain on disposal	351

Assuming the ultimate completion of the Sudan sale, the final adjustments will be increased by the amount of net income recorded by Talisman during 2003 related to the Sudan operations. Accordingly, the amount of gain on disposal that will ultimately be realized by Talisman will be reduced by the amount of net income recorded by Talisman related to the Sudan operations. The amount of net income recorded by Talisman related to the Sudan operations is dependent on the timing of closing and results of the Sudan operations during the period to closing. A longer period to closing will likely result in more income being recorded by Talisman and a lower gain on disposal. Higher prices which generally increase reported income would also reduce the gain on disposal as would lower operating costs.

18. INFORMATION FOR US READERS

ACCOUNTING PRINCIPLES GENERALLY ACCEPTED IN THE US

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the US ("US GAAP"). Significant differences between Canadian and US GAAP are as follows:

NET INCOME IN ACCORDANCE WITH US GAAP:

Years ended December 31 (millions of Canadian dollars)	Notes	**2002**	2001	2000
			restated, see note 2	restated, see note 2
Net income – Canadian GAAP		**524**	733	857
Foreign exchange loss	4,6	**(56)**	(44)	(3)
Depreciation, depletion and amortization	1,2,3,6,8	**(26)**	(66)	(66)
(Loss) gain on derivative instruments	4	**(129)**	237	(13)
Preferred security charges	6	**(42)**	(42)	(40)
Deferred income taxes	2,3,4,8	**51**	(95)	7
Loss on adoption of accounting standard	4	**–**	(48)	–
Results of operations held for sale, net of tax	8	**(237)**	(157)	(125)
		(439)	(215)	(240)
Net income before operations held for sale		**85**	518	617
Results of operations held for sale, net of tax	8	**237**	157	125
Net income – US GAAP		**322**	675	742
Net income per common share before operations held for sale (Canadian dollars)				
Basic		**0.64**	3.84	4.48
Diluted		**0.63**	3.77	4.41
Net income per common share (Canadian dollars)				
Basic		**2.40**	5.00	5.39
Diluted		**2.37**	4.91	5.31

COMPREHENSIVE INCOME IN ACCORDANCE WITH US GAAP:

Years ended December 31 (millions of Canadian dollars)	Notes	**2002**	2001	2000
			restated, see note 2	restated, see note 2
Net income – US GAAP		**322**	675	742
Other comprehensive income, net of tax:				
Foreign exchange gain on translation of self-sustaining operations	7	**170**	–	–
Comprehensive income – US GAAP		**492**	675	742

BALANCE SHEET ITEMS IN ACCORDANCE WITH US GAAP ARE AS FOLLOWS:

December 31 (millions of Canadian dollars)	Notes	2002		2001	
				restated, see note 2	restated, see note 2
		Canadian GAAP	**US GAAP**	Canadian GAAP	US GAAP
Current assets	8	**917**	**861**	799	799
Sudan assets held for sale	8	**–**	**842**	–	–
Property, plant and equipment	1,2,3,8	**10,042**	**9,653**	9,461	9,881
Other non-current assets	4,6	**635**	**651**	559	707
		11,594	**12,007**	10,819	11,387
Current liabilities	8	**989**	**960**	1,204	1,204
Sudan liabilities held for sale	8	**–**	**87**	–	–
Long-term debt	4,6	**2,997**	**3,530**	2,794	3,272
Future income taxes	2,3,4,8	**2,236**	**2,127**	1,989	1,971
Other non-current liabilities		**870**	**870**	706	706
		7,092	**7,574**	6,693	7,153
Shareholders' equity					
Preferred securities	6	**431**	**–**	431	–
Common shares		**2,785**	**2,785**	2,831	2,831
Contributed surplus	5	**75**	**92**	77	94
Cumulative foreign currency translation	7	**140**	**(30)**	–	–
Accumulative other comprehensive income	7	**–**	**170**	–	–
Retained earnings	1-8	**1,071**	**1,416**	787	1,309
Total liabilities and shareholders' equity		**11,594**	**12,007**	10,819	11,387

1 **Gains on property exchanges** – Under both US and Canadian GAAP, property exchanges are recorded at the carrying value of the assets given up unless the exchange transaction includes significant cash consideration, in which case it is recorded at fair value. Under US GAAP, asset exchange transactions are recorded at fair value if cash consideration is greater than 25% (10% under Canadian GAAP) of the fair value of total consideration given or received. The resulting differences in the recorded carrying values of these properties result in differences in depreciation, depletion and amortization expense in subsequent years.

2 **Income taxes and depreciation, depletion and amortization expense** – In 2000, the Company adopted the liability method to account for income taxes. The change to the liability method has eliminated a difference between Canadian and US GAAP, however, in accordance with the recommendations of the Canadian Institute of Chartered Accountants (the "CICA"), the effect of the adoption under Canadian GAAP resulted in a charge to retained earnings, whereas, under US GAAP, the future tax costs that gave rise to the Canadian GAAP adjustment have already been reflected in property, plant and equipment. As a result of the implementation method, further differences in depreciation, depletion and amortization expense result in subsequent years.

In connection with the Company's retroactive change in accounting under Canadian GAAP for foreign exchange gains and losses arising from long-term monetary items and the related tax effects as described in note 2, the Company has adjusted its income tax valuation allowance under US GAAP. These valuation allowances of $44 million and $22 million at December 31, 2001 and 2000, respectively, are consistent with the amounts that have now been established for Canadian GAAP. This change increases the US GAAP provision for deferred income taxes and reduces US GAAP net income in 2001 by $22 million (2000 – $21 million).

3 **Impairments** – Under both US and Canadian GAAP, property, plant and equipment must be assessed for potential impairments. Under US GAAP, if the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset, then an impairment loss (the amount by which the carrying amount of the asset exceeds the fair value of the asset) should be recognized. Fair value is calculated as the present value of estimated expected future cash flows. As disclosed in note 1(c), under Canadian GAAP, the impairment loss is the difference between the carrying value of the asset and its net recoverable amount (undiscounted). The resulting differences in recorded carrying values of impaired assets result in further differences in depreciation, depletion and amortization expense in subsequent years. The CICA has adopted a new standard effective for 2003 that will eliminate this US/Canadian GAAP difference.

4 **Forward foreign exchange contracts and other financial instruments** – The Company has designated, for Canadian GAAP purposes, its derivative financial instruments as hedges of anticipated revenue and expenses. In accordance with Canadian GAAP, payments or receipts on these contracts are recognized in income concurrently with the hedged transaction. The fair values of the contracts deemed to be hedges are not reflected in the Consolidated Financial Statements.

Effective January 1, 2001, for US GAAP purposes, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, Accounting for Derivative Instruments and Hedging Activities. Effective with the adoption of this standard, every derivative instrument, including certain derivative instruments embedded in other contracts, is recognized on the balance sheet at fair value. The statement requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Management has not designated any of the currently held derivative instruments as hedges for US GAAP purposes and accordingly these derivatives have been recognized on the balance sheet at fair value with the change in their fair value recognized in earnings. In accordance with the transition provisions of SFAS No. 133, on January 1, 2001, the Company recorded a $48 million after tax non-cash loss in current earnings as a cumulative effect of accounting change.

5 **Appropriation of contributed surplus** – In 1992, concurrent with a change in control of the Company, $17 million of contributed surplus was appropriated to retained earnings to eliminate the deficit at June 30, 1992. This restatement of retained earnings is not permitted under US GAAP as the events that precipitated it did not constitute a quasi-reorganization.

6 **Preferred securities** – Under US GAAP, the Company's preferred securities are treated as debt rather than equity and accordingly are translated at the rates of exchange in effect at the balance sheet date. Under Canadian GAAP, the preferred securities are translated at the historical rate of exchange. In addition, the annual preferred security charges under US GAAP are classified as an expense rather than a direct charge to retained earnings. Under US GAAP, the cost associated with the issuance of the preferred securities is recorded as an asset and is amortized over the term of the preferred securities. Under Canadian GAAP, this cost, net of tax, is charged directly to shareholders' equity. The fair market value of the preferred securities at December 31, 2002 was $494 million (2001 – $485 million).

7 **Foreign exchange gains and losses on translation of self sustaining operations** – Under US GAAP, foreign exchange gains and losses on translation of self-sustaining foreign operations are added, net of tax, to net income in determining comprehensive income. Under Canadian GAAP, such gains and losses are included as a separate component of shareholders' equity referred to as cumulative translation adjustment.

8 **Discontinued operations** – Under US GAAP, effective November 1, 2002, the Sudan assets are classified as Assets Held For Sale with the Sudan operating results, net of tax, classified on the income statement as results of operations held for sale until such date as the assets are sold. No depreciation, depletion or amortization would have been recorded commencing November 1, 2002 related to these assets.

NEWLY ISSUED US ACCOUNTING STANDARDS

SFAS NO. 143 – ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS:

Effective for 2003, this statement significantly changes the method of accruing for costs associated with the retirement of fixed assets for which an entity is legally obligated to incur. This standard requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement costs are to be allocated to expense using a systematic and rational method. The Company is evaluating the impact of this new standard.

SUMMARY US DOLLAR INFORMATION

Unless otherwise noted, all amounts in the Consolidated Financial Statements, including Accounting Principles Generally Accepted in the US above, are reported in millions of Canadian dollars. The following information reflects summary financial information prepared in accordance with US GAAP translated from Canadian dollars to US dollars at the average exchange rate prevailing in the respective year.

US$ million (except as noted)	**2002**	2001	2000
Total revenue	**2,835**	2,673	2,685
Net income	**205**	436	500
Net income per common share (US$/share)	**1.53**	3.23	3.63
Average exchange rate (US$/C$)	**0.6368**	0.6457	0.6732

Supplementary Oil and Gas Information

(unaudited)

The supplemental data on the Company's oil and gas activities on pages 60 to 63 was prepared in accordance with the FASB's SFAS No. 69: Disclosures About Oil and Gas Producing Activities. Activities not directly associated with conventional crude oil and natural gas production, including synthetic oil operations, are excluded from all aspects of this supplementary oil and gas information.

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES

Years ended December 31 (millions of Canadian dollars)		North America	North Sea	Southeast Asia[1]	Sudan	Algeria	Trinidad	Other	Total
2002	Net oil and gas revenue derived from proved reserves[2]	**1,634**	**1,914**	**356**	**500**	**–**	**–**	**–**	**4,404**
	Less: Production costs	**339**	**588**	**86**	**84**	**–**	**–**	**–**	**1,097**
	Exploration and dry hole expense	**194**	**29**	**23**	**19**	**5**	**46**	**43**	**359**
	Depreciation, depletion and amortization	**583**	**701**	**87**	**92**	**–**	**–**	**–**	**1,463**
	Tax expense (recovery)	**205**	**430**	**75**	**85**	**(2)**	**(22)**	**(18)**	**753**
	Results of operations	**313**	**166**	**85**	**220**	**(3)**	**(24)**	**(25)**	**732**
2001	Net oil and gas revenue derived from proved reserves[2]	1,744	1,584	350	389	–	–	–	4,067
	Less: Production costs	323	467	70	66	–	–	–	926
	Exploration and dry hole expense	123	51	16	27	7	15	21	260
	Depreciation, depletion and amortization	549	558	93	77	–	–	–	1,277
	Tax expense (recovery)	273	247	95	52	(3)	(6)	(9)	649
	Results of operations	476	261	76	167	(4)	(9)	(12)	955
2000	Net oil and gas revenue derived from proved reserves[2]	1,527	1,671	403	337	–	–	–	3,938
	Less: Production costs	256	435	55	64	–	–	–	810
	Exploration and dry hole expense	83	28	24	11	17	4	10	177
	Depreciation, depletion and amortization	462	512	83	80	–	–	–	1,137
	Tax expense (recovery)	336	302	126	56	(7)	(2)	(5)	806
	Results of operations	390	394	115	126	(10)	(2)	(5)	1,008

1 Includes operations in Indonesia and Malaysia/Vietnam.

2 Net oil and gas revenue derived from proved reserves is net of applicable royalties.

CAPITALIZED COSTS RELATED TO OIL AND GAS ACTIVITIES

Years ended December 31 (millions of Canadian dollars)		North America	North Sea	Southeast Asia[1]	Sudan	Algeria	Trinidad	Other	Total
2002	Proved properties	**6,939**	**5,592**	**1,422**	**986**	**217**	**45**	**–**	**15,201**
	Unproved properties	**214**	**14**	**156**	**36**	**29**	**9**	**–**	**458**
	Incomplete wells and facilities	**33**	**66**	**22**	**17**	**–**	**–**	**–**	**138**
		7,186	**5,672**	**1,600**	**1,039**	**246**	**54**	**–**	**15,797**
	Less: accumulated depreciation, depletion and amortization	**2,339**	**2,774**	**509**	**271**	**–**	**–**	**–**	**5,893**
	Net capitalized costs	**4,847**	**2,898**	**1,091**	**768**	**246**	**54**	**–**	**9,904**
2001	Proved properties	6,183	4,454	1,092	889	26	–	–	12,644
	Unproved properties	408	284	195	30	94	17	–	1,028
	Incomplete wells and facilities	24	37	56	22	23	6	–	168
		6,615	4,775	1,343	941	143	23	–	13,840
	Less: accumulated depreciation, depletion and amortization	1,926	1,965	419	178	–	–	–	4,488
	Net capitalized costs	4,689	2,810	924	763	143	23	–	9,352
2000	Proved properties	4,783	3,728	759	770	7	–	–	10,047
	Unproved properties	363	227	42	12	76	7	4	731
	Incomplete wells and facilities	12	5	2	27	–	–	–	46
		5,158	3,960	803	809	83	7	4	10,824
	Less: accumulated depreciation, depletion and amortization	1,515	1,476	321	95	–	–	–	3,407
	Net capitalized costs	3,643	2,484	482	714	83	7	4	7,417

1 Includes operations in Indonesia and Malaysia/Vietnam.

COSTS INCURRED IN OIL AND GAS ACTIVITIES

Years ended December 31 (millions of Canadian dollars)		North America	North Sea	Southeast Asia[1]	Sudan	Algeria	Trinidad	Other	Total
2002	Property acquisition costs								
	Proved	**174**	**88**	**–**	**–**	**–**	**–**	**–**	**262**
	Unproved	**50**	**13**	**–**	**–**	**–**	**9**	**–**	**72**
	Exploration costs	**271**	**134**	**36**	**27**	**3**	**54**	**43**	**568**
	Development costs	**478**	**297**	**233**	**71**	**103**	**14**	**–**	**1,196**
	Total costs incurred	**973**	**532**	**269**	**98**	**106**	**77**	**43**	**2,098**
2001	Property acquisition costs								
	Proved	828	213	129	–	–	–	–	1,170
	Unproved	240	19	245	–	–	–	–	504
	Exploration costs	251	106	31	42	22	31	21	504
	Development costs	553	527	110	75	41	–	–	1,306
	Total costs incurred	1,872	865	515	117	63	31	21	3,484
2000	Property acquisition costs								
	Proved	197	70	–	–	–	–	–	267
	Unproved	69	181	–	–	–	–	–	250
	Exploration costs	184	46	30	33	29	7	10	339
	Development costs	426	257	39	37	5	–	–	764
	Total costs incurred	876	554	69	70	34	7	10	1,620

1 Includes operations in Indonesia and Malaysia/Vietnam.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED RESERVES

Future net cash flows were calculated by applying the respective year-end prices to the Company's estimated future production of proved reserves and deducting estimates of future development and production costs and income taxes. Future development and production costs have been estimated based on the assumed continuation of cost levels and economic conditions existing at each year end. Similarly, future income taxes have been estimated based on statutory tax rates enacted at year end. The present values of the estimated future cash flows were determined by applying a 10% discount rate prescribed by the FASB.

In order to increase the comparability between companies, the standardized measure of discounted future net cash flows necessarily employs uniform assumptions that do not necessarily reflect management's best estimate of future events and anticipated outcomes. Accordingly, the Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair market value of the oil and gas properties. Actual future net cash flows will differ significantly from those estimated due to, but not limited to, the following:

- production rates will differ from those estimated both in terms of timing and amount. For example, future production may include significant additional volumes from unproved reserves;
- future prices and economic conditions will differ from those at year end. For example, changes in prices increased the discounted future net cash flows by $9.7 billion in 2002;
- future production and development costs will be determined by future events and will differ from those at year end; and
- estimated income taxes will differ in terms of amounts and timing dependent on the above factors, changes in enacted rates and the impact of future expenditures on unproved properties.

The standardized measure of discounted future net cash flows was prepared using the following prices:

		2002	2001	2000
Crude oil and liquids ($/bbl)	North America	**42.07**	22.48	30.33
	North Sea	**46.84**	29.61	33.14
	Southeast Asia[1]	**49.22**	30.10	33.61
	Sudan	**44.09**	23.89	27.59
	Algeria	**48.37**	29.20	33.29
	Trinidad	**45.72**	–	–
		45.13	26.34	31.04
Natural Gas ($/mcf)	North America	**6.06**	3.49	13.61
	North Sea	**5.59**	4.97	5.19
	Southeast Asia[1]	**4.94**	2.54	3.80
	Trinidad	**1.26**	–	–
		5.43	3.25	10.57

1 Includes operations in Indonesia and Malaysia/Vietnam.

DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED RESERVES

As at December 31 (millions of Canadian dollars)		North America	North Sea	Southeast Asia[1]	Sudan	Algeria	Trinidad	Total
2002	Future cash inflows[2]	**19,639**	**13,160**	**6,627**	**4,090**	**675**	**1,143**	**45,334**
	Future costs							
	Production	**(4,325)**	**(5,577)**	**(1,040)**	**(999)**	**(230)**	**(157)**	**(12,328)**
	Development and site restoration	**(995)**	**(1,873)**	**(709)**	**(313)**	**(64)**	**(368)**	**(4,322)**
	Future net inflows before income taxes	**14,319**	**5,710**	**4,878**	**2,778**	**381**	**618**	**28,684**
	Future income and production revenue taxes	**(5,654)**	**(2,597)**	**(2,011)**	**(744)**	**(31)**	**(370)**	**(11,407)**
	Future net cash flows	**8,665**	**3,113**	**2,867**	**2,034**	**350**	**248**	**17,277**
	10% discount factor	**(3,913)**	**(554)**	**(1,387)**	**(655)**	**(97)**	**(161)**	**(6,767)**
	Discounted future net cash flows	**4,752**	**2,559**	**1,480**	**1,379**	**253**	**87**	**10,510**
2001	Future cash inflows[2]	11,376	9,347	4,026	2,924	493	–	28,166
	Future costs							
	Production	(3,449)	(4,253)	(875)	(991)	(155)	–	(9,723)
	Development and site restoration	(567)	(1,616)	(850)	(217)	(71)	–	(3,321)
	Future net inflows before income taxes	7,360	3,478	2,301	1,716	267	–	15,122
	Future income and production revenue taxes	(2,509)	(1,284)	(929)	(361)	(26)	–	(5,109)
	Future net cash flows	4,851	2,194	1,372	1,355	241	–	10,013
	10% discount factor	(1,797)	(292)	(804)	(478)	(121)	–	(3,492)
	Discounted future net cash flows	3,054	1,902	568	877	120	–	6,521
2000	Future cash inflows[2]	28,716	9,448	2,640	2,726	408	–	43,938
	Future costs							
	Production	(2,711)	(3,423)	(485)	(724)	(62)	–	(7,405)
	Development and site restoration	(292)	(1,403)	(160)	(218)	(46)	–	(2,119)
	Future net inflows before income taxes	25,713	4,622	1,995	1,784	300	–	34,414
	Future income and production revenue taxes	(10,663)	(2,108)	(852)	(362)	(80)	–	(14,065)
	Future net cash flows	15,050	2,514	1,143	1,422	220	–	20,349
	10% discount factor	(6,136)	(481)	(507)	(515)	(118)	–	(7,757)
	Discounted future net cash flows	8,914	2,033	636	907	102	–	12,592

1 Includes operations in Indonesia and Malaysia/Vietnam.
2 Future cash inflows are revenues net of royalties.

PRINCIPAL SOURCES OF CHANGES IN DISCOUNTED CASH FLOWS

Years ended December 31 (millions of Canadian dollars)	2002	2001	2000
Sales of oil and gas produced, net of production costs	**(3,307)**	(3,141)	(3,128)
Net change in prices	**9,709**	(11,795)	8,957
Net change in production costs	**(1,990)**	(692)	(505)
Net change in future development and site restoration costs	**(637)**	(128)	(206)
Development costs incurred during the year	**764**	375	400
Extensions, discoveries and improved recovery	**1,863**	1,542	2,809
Revisions of previous reserve estimates	**37**	216	596
Net purchases and sales of reserves in place	**17**	550	135
Accretion of discount	**972**	2,110	1,057
Net change in taxes	**(3,342)**	4,726	(4,330)
Other	**(97)**	166	(269)
Net change	**3,989**	(6,071)	5,516
Balance, beginning of year	**6,521**	12,592	7,076
Balance, end of year	**10,510**	6,521	12,592

CONTINUITY OF PROVED NET RESERVES[1]

	North America[2]	North Sea	Southeast Asia	Sudan	Algeria	Trinidad	Total
CRUDE OIL AND LIQUIDS (mmbbls)							
TOTAL PROVED							
Proved reserves at December 31, 1999	157.4	187.2	20.0	92.4	6.8	–	463.8
Discoveries, additions and extensions	20.2	20.2	4.1	8.6	5.0	–	58.1
Purchase of reserves	1.4	54.8	–	–	–	–	56.2
Sale of reserves	(1.7)	(0.1)	–	–	–	–	(1.8)
Net revisions and transfers	8.0	10.6	(1.0)	2.4	0.4	–	20.4
2000 Production	(19.4)	(38.9)	(5.2)	(11.0)	–	–	(74.5)
Proved reserves at December 31, 2000	165.9	233.8	17.9	92.4	12.2	–	522.2
Discoveries, additions and extensions	17.9	53.9	15.3	22.5	7.1	–	116.7
Purchase of reserves	8.1	16.2	10.6	–	–	–	34.9
Sale of reserves	(2.9)	(4.8)	–	–	–	–	(7.7)
Net revisions and transfers	4.7	(0.5)	1.1	13.3	(2.4)	–	16.2
2001 Production	(17.9)	(38.4)	(5.3)	(11.9)	–	–	(73.5)
Proved reserves at December 31, 2001	175.8	260.2	39.6	116.3	16.9	–	608.8
Discoveries, additions and extensions	**10.6**	**13.5**	**5.8**	**19.0**	**1.3**	**18.9**	**69.1**
Purchase of reserves	**1.1**	**7.5**	**–**	**–**	**–**	**–**	**8.6**
Sale of reserves	**(3.7)**	**(2.8)**	**–**	**–**	**–**	**–**	**(6.5)**
Net revisions and transfers	**(2.5)**	**13.9**	**(4.2)**	**(27.7)**	**(4.3)**	**–**	**(24.8)**
2002 Production	**(17.2)**	**(44.7)**	**(5.1)**	**(13.3)**	**–**	**–**	**(80.3)**
Proved reserves at December 31, 2002	**164.1**	**247.6**	**36.1**	**94.3**	**13.9**	**18.9**	**574.9**
PROVED DEVELOPED							
December 31, 1999	151.9	150.7	17.3	92.4	–	–	412.3
December 31, 2000	160.9	173.3	15.2	77.4	–	–	426.8
December 31, 2001	168.6	203.8	13.3	89.6	–	–	475.3
December 31, 2002	**157.2**	**210.8**	**11.9**	**84.1**	**2.4**	**–**	**466.4**
NATURAL GAS (bcf)							
TOTAL PROVED							
Proved reserves at December 31, 1999	1,724.4	351.6	536.6	–	–	–	2,612.6
Discoveries, additions and extensions	264.4	10.6	89.0	–	–	–	364.0
Purchase of reserves	27.2	–	–	–	–	–	27.2
Sale of reserves	(53.1)	(19.7)	–	–	–	–	(72.8)
Net revisions and transfers	14.5	(27.5)	(56.9)	–	–	–	(69.9)
2000 Production	(220.3)	(42.4)	(28.5)	–	–	–	(291.2)
Proved reserves at December 31, 2000	1,757.1	272.6	540.2	–	–	–	2,569.9
Discoveries, additions and extensions	293.8	13.7	455.2	–	–	–	762.7
Purchase of reserves	293.6	22.8	125.7	–	–	–	442.1
Sale of reserves	(44.7)	(1.5)	–	–	–	–	(46.2)
Net revisions and transfers	(24.9)	(5.0)	23.4	–	–	–	(6.5)
2001 Production	(222.3)	(35.3)	(32.4)	–	–	–	(290.0)
Proved reserves at December 31, 2001	2,052.6	267.3	1,112.1	–	–	–	3,432.0
Discoveries, additions and extensions	**283.1**	**14.0**	**11.7**	**–**	**–**	**220.0**	**528.8**
Purchase of reserves	**31.5**	**0.4**	**–**	**–**	**–**	**–**	**31.9**
Sale of reserves	**(26.7)**	**–**	**–**	**–**	**–**	**–**	**(26.7)**
Net revisions and transfers	**(110.8)**	**(4.3)**	**(122.6)**	**–**	**–**	**–**	**(237.7)**
2002 Production	**(243.6)**	**(39.5)**	**(32.3)**	**–**	**–**	**–**	**(315.4)**
Proved reserves at December 31, 2002	**1,986.1**	**237.9**	**968.9**	**–**	**–**	**220.0**	**3,412.9**
PROVED DEVELOPED							
December 31, 1999	1,508.4	330.7	163.3	–	–	–	2,002.4
December 31, 2000	1,568.4	215.9	120.0	–	–	–	1,904.3
December 31, 2001	1,804.7	213.8	252.0	–	–	–	2,270.5
December 31, 2002	**1,746.9**	**210.0**	**471.6**	**–**	**–**	**–**	**2,428.5**

1 Net reserves are after deducting royalties. See note 1(g) of the Consolidated Financial Statements for additional disclosure regarding royalties.
2 North American net proved reserves exclude synthetic crude oil reserves: 2000 – 36.9 mmbbls; 2001 – 36.4 mmbbls; 2002 – 36.7 mmbbls.

Supplementary Information

(unaudited)

CONTINUITY OF PROVED GROSS RESERVES

	North America[1]	North Sea	Southeast Asia	Sudan	Algeria	Trinidad	Total
CRUDE OIL AND LIQUIDS (mmbbls)							
TOTAL PROVED							
Proved reserves at December 31, 1999	189.5	196.3	27.3	132.0	12.0	–	557.1
Discoveries, additions and extensions	24.0	21.3	5.8	13.1	8.3	–	72.5
Purchase of reserves	1.8	57.7	–	–	–	–	59.5
Sale of reserves	(2.2)	(0.1)	–	–	–	–	(2.3)
Net revisions and transfers	9.5	11.8	(0.2)	12.4	–	–	33.5
2000 Production	(23.3)	(41.0)	(7.4)	(16.8)	–	–	(88.5)
Proved reserves at December 31, 2000	199.3	246.0	25.5	140.7	20.3	–	631.8
Discoveries, additions and extensions	21.3	54.9	22.6	30.2	14.9	–	143.9
Purchase of reserves	10.7	20.4	14.7	–	–	–	45.8
Sale of reserves	(3.9)	(5.2)	–	–	–	–	(9.1)
Net revisions and transfers	8.0	(1.1)	4.1	4.8	–	–	15.8
2001 Production	(23.1)	(40.5)	(7.6)	(19.4)	–	–	(90.6)
Proved reserves at December 31, 2001	212.3	274.5	59.3	156.3	35.2	–	737.6
Discoveries, additions and extensions	**13.0**	**13.5**	**9.6**	**32.3**	**2.6**	**19.2**	**90.2**
Purchase of reserves	**1.4**	**7.5**	**–**	**–**	**–**	**–**	**8.9**
Sale of reserves	**(4.6)**	**(2.8)**	**–**	**–**	**–**	**–**	**(7.4)**
Net revisions and transfers	**(1.2)**	**3.5**	**–**	**(5.8)**	**(10.4)**	**–**	**(13.9)**
2002 Production	**(21.8)**	**(46.5)**	**(8.3)**	**(21.9)**	**–**	**–**	**(98.5)**
Proved reserves at December 31, 2002	**199.1**	**249.7**	**60.6**	**160.9**	**27.4**	**19.2**	**716.9**
PROVED DEVELOPED							
December 31, 1999	182.5	158.0	23.9	132.0	–	–	496.4
December 31, 2000	192.7	182.4	21.6	117.9	–	–	514.6
December 31, 2001	203.0	215.7	20.4	120.4	–	–	559.5
December 31, 2002	**190.0**	**212.6**	**19.7**	**143.4**	**4.8**	**–**	**570.5**
NATURAL GAS (bcf)							
TOTAL PROVED							
Proved reserves at December 31, 1999	2,169.2	360.4	691.4	–	–	–	3,221.0
Discoveries, additions and extensions	334.4	11.2	126.7	–	–	–	472.3
Purchase of reserves	34.9	–	–	–	–	–	34.9
Sale of reserves	(68.1)	(20.7)	–	–	–	–	(88.8)
Net revisions and transfers	23.4	(20.4)	(8.0)	–	–	–	(5.0)
2000 Production	(277.0)	(44.5)	(40.6)	–	–	–	(362.1)
Proved reserves at December 31, 2000	2,216.8	286.0	769.5	–	–	–	3,272.3
Discoveries, additions and extensions	374.1	14.2	657.5	–	–	–	1,045.8
Purchase of reserves	365.0	57.1	173.9	–	–	–	596.0
Sale of reserves	(57.0)	(1.6)	–	–	–	–	(58.6)
Net revisions and transfers	(6.6)	(14.0)	30.6	–	–	–	10.0
2001 Production	(295.5)	(39.5)	(34.0)	–	–	–	(369.0)
Proved reserves at December 31, 2001	2,596.8	302.2	1,597.5	–	–	–	4,496.5
Discoveries, additions and extensions	**374.2**	**15.4**	**19.7**	**–**	**–**	**223.5**	**632.8**
Purchase of reserves	**37.7**	**0.4**	**–**	**–**	**–**	**–**	**38.1**
Sale of reserves	**(34.9)**	**–**	**–**	**–**	**–**	**–**	**(34.9)**
Net revisions and transfers	**(80.3)**	**(11.3)**	**(54.4)**	**–**	**–**	**–**	**(146.0)**
2002 Production	**(300.1)**	**(44.6)**	**(34.5)**	**–**	**–**	**–**	**(379.2)**
Proved reserves at December 31, 2002	**2,593.4**	**262.1**	**1,528.3**	**–**	**–**	**223.5**	**4,607.3**
PROVED DEVELOPED							
December 31, 1999	1,895.5	339.0	210.5	–	–	–	2,445.0
December 31, 2000	1,972.3	227.0	170.9	–	–	–	2,370.2
December 31, 2001	2,281.8	247.4	358.5	–	–	–	2,887.7
December 31, 2002	**2,278.7**	**232.8**	**723.8**	**–**	**–**	**–**	**3,235.3**

1 North American gross proved reserves exclude synthetic crude oil reserves: 2000 – 43.0 mmbbls; 2001 – 43.4 mmbbls; 2002 – 43.2 mmbbls.

PROBABLE RESERVES[1]

	North America	North Sea	Southeast Asia	Sudan	Algeria	Trinidad	Total
CRUDE OIL AND LIQUIDS (mmbbls)							
Probable reserves at December 31, 2001	88.4	142.6	62.8	56.1	59.6	61.0	470.5
Discoveries, additions and extensions	2.5	6.2	11.4	5.2	(12.6)	–	12.7
Dispositions and acquisitions	(1.5)	6.0	–	–	–	–	4.5
Net revisions and transfers	(3.1)	(12.9)	(17.5)	(9.0)	(6.6)	(41.7)	(90.8)
Probable reserves at December 31, 2002	**86.3**	**141.9**	**56.7**	**52.3**	**40.4**	**19.3**	**396.9**
NATURAL GAS (bcf)							
Probable reserves at December 31, 2001	1,428.4	75.5	1,338.7	–	–	288.5	3,131.1
Discoveries, additions and extensions	131.5	10.6	83.7	–	–	–	225.8
Dispositions and acquisitions	(7.8)	1.2	–	–	–	–	(6.6)
Net revisions and transfers	(153.8)	14.0	(33.9)	–	–	(196.5)	(370.2)
Probable Reserves at December 31, 2002	**1,398.3**	**101.3**	**1,388.5**	**–**	**–**	**92.0**	**2,980.1**
BOE[2] (mmboe)							
Probable reserves at December 31, 2001	326.5	155.2	285.9	56.1	59.6	109.1	992.4
Discoveries, additions and extensions	24.5	8.0	25.4	5.2	(12.6)	–	50.5
Dispositions and acquisitions	(2.8)	6.2	–	–	–	–	3.4
Net revisions and transfers	(28.9)	(10.7)	(23.2)	(9.0)	(6.6)	(74.5)	(152.9)
Probable reserves at December 31, 2002	**319.3**	**158.7**	**288.1**	**52.3**	**40.4**	**34.6**	**893.4**

1 Gross probable reserves, excluding sulphur and synthetic oil.
2 Six mcf of natural gas equals one boe.

HISTORICAL PROVED RESERVES[1]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	**2002**
CRUDE OIL AND LIQUIDS (mmbbls)										
Opening balance	40.5	95.0	167.8	167.9	225.9	300.3	416.5	557.1	631.8	**737.6**
Discoveries, additions and extensions	11.0	8.8	15.4	33.8	68.7	83.3	62.0	72.5	143.9	**90.2**
Dispositions and acquisitions	53.8	69.9	0.9	35.6	29.0	67.3	111.3	57.2	36.7	**1.5**
Net revisions and transfers	(0.3)	12.2	11.2	24.3	23.2	18.2	24.1	33.5	15.8	**(13.9)**
Production	(10.0)	(18.1)	(27.4)	(35.7)	(46.5)	(52.6)	(56.8)	(88.5)	(90.6)	**(98.5)**
Closing balance	95.0	167.8	167.9	225.9	300.3	416.5	557.1	631.8	737.6	**716.9**
NATURAL GAS (bcf)										
Opening balance	734.7	1,267.9	1,852.1	1,901.8	2,301.7	2,663.5	2,834.4	3,221.0	3,272.3	**4,496.5**
Discoveries, additions and extensions	125.3	186.0	195.3	263.9	407.6	396.0	301.0	472.3	1,045.8	**632.8**
Dispositions and acquisitions	530.1	564.1	9.5	34.2	289.6	(51.7)	368.6	(53.9)	537.4	**3.2**
Net revisions and transfers	1.4	15.1	82.0	338.7	(95.2)	100.2	47.4	(5.0)	10.0	**(146.0)**
Production	(123.6)	(181.0)	(237.1)	(236.9)	(240.2)	(273.6)	(330.4)	(362.1)	(369.0)	**(379.2)**
Closing balance	1,267.9	1,852.1	1,901.8	2,301.7	2,663.5	2,834.4	3,221.0	3,272.3	4,496.5	**4,607.3**
BOE[2] (mmboe)										
Opening balance	163.0	306.3	476.5	485.0	609.5	744.2	888.8	1,094.0	1,177.2	**1,487.0**
Discoveries, additions and extensions	31.9	39.8	47.9	77.7	136.6	149.2	112.0	151.1	318.2	**195.7**
Dispositions and acquisitions	142.3	163.9	2.5	41.3	77.3	58.7	172.8	48.1	126.2	**2.1**
Net revisions and transfers	(0.1)	14.8	25.0	80.7	7.4	34.9	32.2	32.8	17.5	**(38.4)**
Production	(30.8)	(48.3)	(66.9)	(75.2)	(86.6)	(98.2)	(111.8)	(148.8)	(152.1)	**(161.7)**
Closing balance	306.3	476.5	485.0	609.5	744.2	888.8	1,094.0	1,177.2	1,487.0	**1,484.7**

1 Gross reserves, excluding sulphur and synthetic oil.
2 Six mcf of natural gas equals one boe.

FIVE YEAR FINDING AND DEVELOPMENT COSTS

	1998	1999	2000	2001	**2002**	3-year	5-year
PROVED RESERVES ADDITIONS [1]							
North America (mmboe)	70.4	55.1	93.2	90.6	**60.7**	244.5	370.0
International (mmboe)	113.7	89.1	90.7	245.1	**96.6**	432.4	635.2
Total	184.1	144.2	183.9	335.7	**157.3**	676.9	1,005.2
PROVED NET ACQUISITIONS [2]							
North America (mmboe)	(12.4)	95.2	(6.0)	58.1	**(2.7)**	49.4	132.2
International (mmboe)	71.2	77.6	54.1	68.1	**4.8**	127.0	275.8
Total	58.8	172.8	48.1	126.2	**2.1**	176.4	408.0
CAPITAL SPENDING (millions of dollars) [3]							
Exploration and development							
North America	381.3	300.5	658.7	821.2	**753.9**	2,233.8	2,915.6
International	670.7	621.1	459.6	971.1	**980.7**	2,411.4	3,703.2
Total Company	1,052.0	921.6	1,118.3	1,792.3	**1,734.6**	4,645.2	6,618.8
Net acquisitions and divestitures	214.1	1,581.5	209.5	1,478.1	**203.4**	1,891.0	3,686.6
Total Capital	1,266.1	2,503.1	1,327.8	3,270.4	**1,938.0**	6,536.2	10,305.4
PROVED F&D COST ($/boe)							
North America	5.41	5.45	7.07	9.06	**12.42**	9.14	7.88
International	5.90	6.97	5.06	3.96	**10.15**	5.58	5.83
Total	5.71	6.39	6.08	5.34	**11.03**	6.86	6.58
PROVED + 1/2 PROBABLE F&D COST ($/boe)							
North America	5.82	4.65	7.34	10.09	**12.89**	9.73	8.10
International	6.10	6.14	2.59	3.69	**20.60**	4.94	5.30
Total	6.00	5.56	4.19	5.21	**16.35**	6.48	6.25
PROVED FD&A COST ($/boe)							
North America	5.78	8.35	7.39	11.75	**15.00**	11.10	9.66
International	5.03	7.49	4.72	4.86	**10.53**	5.85	5.99
Total	5.21	7.90	5.72	7.08	**12.15**	7.66	7.29
PROVED + 1/2 PROBABLE FD&A COST ($/boe)							
North America	5.88	6.45	7.81	10.57	**16.00**	10.79	8.76
International	4.45	6.38	2.75	3.78	**19.23**	4.63	4.90
Total	4.76	6.42	4.01	5.75	**17.63**	6.47	6.19

1 Proved discoveries and revisions only, excluding acquisitions, conventional oil only.
2 Reserve purchases less dispositions, includes asset sales, dispositions, swaps and corporate acquisitions.
3 Exploration and development spending excludes indirect exploration expenses, Syncrude, enhanced oil recovery, Chauvin pipeline, Canadian Midstream and capitalized interest.
Six mcf of natural gas equals one boe.

HISTORICAL OPERATIONS SUMMARY

Years ended December 31	**2002**	2001	2000	1999	1998	1997	1996	1995	1994	1993
DAILY AVERAGE PRODUCTION										
Crude oil (bbls/d)										
North America	**46,287**	50,424	51,005	44,806	45,103	40,627	34,169	31,019	29,801	22,542
North Sea	**124,965**	108,163	109,096	57,267	54,988	48,065	30,675	16,987	7,114	–
Southeast Asia [1]	**21,925**	20,326	19,627	28,286	31,684	28,458	22,621	18,121	5,919	–
Sudan	**60,109**	53,257	45,869	11,726	–	–	–	–	–	–
Other	**–**	–	–	–	–	–	–	–	473	116
Natural gas liquids (bbls/d)										
North America	**13,521**	12,851	12,829	10,918	9,818	8,054	7,598	7,097	5,512	4,810
North Sea	**2,521**	2,665	2,806	1,989	2,492	2,437	2,363	1,791	538	–
Southeast Asia [1]	**544**	547	579	566	–	–	–	–	–	–
Synthetic oil (Canada) (bbls/d)	**2,868**	2,781	2,540	2,765	2,664	2,536	2,534	2,527	2,425	1,517
Total oil and liquids	**272,740**	251,014	244,351	158,323	146,749	130,177	99,960	77,542	51,782	28,985
Natural gas (mmcf/d)										
North America	**820**	809	755	681	631	558	557	581	481	338
North Sea	**122**	108	122	115	104	100	90	69	15	–
Southeast Asia [1]	**94**	93	111	108	13	–	–	–	–	–
Total natural gas	**1,036**	1,010	988	904	748	658	647	650	496	338
Total (mboe/d)	**445**	419	409	309	271	240	208	186	134	85
AVERAGE UNIT PRICES [2]										
Crude oil ($/bbl)										
North America	**33.74**	30.57	38.29	24.82	15.87	22.68	25.31	21.00	19.04	17.61
North Sea	**38.97**	36.24	40.51	28.70	18.69	26.25	28.41	23.63	22.43	–
Southeast Asia [1]	**39.46**	35.92	42.50	26.20	18.01	26.27	27.83	23.76	22.40	–
Sudan	**37.79**	32.66	38.52	31.24	–	–	–	–	–	–
Other	**–**	–	–	–	–	–	–	–	10.17	7.24
Natural gas liquids ($/bbl)										
North America	**27.90**	31.69	35.03	19.84	15.07	22.39	21.13	18.04	16.56	16.18
North Sea	**28.16**	29.46	35.15	18.42	15.22	24.19	21.41	18.90	17.61	–
Southeast Asia [1]	**39.53**	37.47	42.66	26.70	–	–	–	–	–	–
Synthetic oil (Canada) ($/bbl)	**40.07**	39.54	44.41	28.01	20.53	27.78	29.09	23.81	21.71	20.59
Total oil and liquids	**37.22**	34.05	39.53	26.58	17.41	24.89	26.52	21.99	19.65	17.49
Natural gas ($/mcf)										
North America	**3.96**	5.39	4.66	2.54	2.02	1.98	1.67	1.34	1.88	1.68
North Sea	**3.89**	4.35	3.58	3.06	3.90	3.88	3.35	3.63	3.78	–
Southeast Asia [1]	**4.72**	4.80	5.64	3.18	1.65	–	–	–	–	–
Total natural gas	**4.03**	5.22	4.63	2.68	2.26	2.27	1.91	1.58	1.94	1.68
Total ($/boe)	**32.15**	32.95	34.80	21.48	15.66	19.73	18.70	14.72	14.75	12.60

1 Includes operations in Indonesia and Malaysia/Vietnam.
2 Average unit prices are before hedging activities.

HISTORICAL FINANCIAL SUMMARY

(millions of Canadian dollars unless otherwise stated)

Years ended December 31	**2002**	2001	2000	1999	1998	1997	1996	1995	1994	1993
BALANCE SHEETS [1]										
Current assets	**917**	799	1,042	730	272	471	362	256	426	130
Other assets	**166**	92	82	93	100	88	63	51	61	42
Goodwill	**469**	467	–	–	–	–	–	–	–	–
Property, plant and equipment	**10,042**	9,461	7,501	6,983	4,997	4,441	3,333	2,733	2,772	909
Total assets	**11,594**	10,819	8,625	7,806	5,369	5,000	3,758	3,040	3,259	1,081
Current liabilities	**989**	1,204	1,311	1,060	576	497	338	225	241	130
Deferred credits and other liabilities	**3,106**	2,695	1,997	968	587	601	426	280	235	91
Long-term debt	**2,997**	2,794	1,703	2,157	2,071	1,739	899	906	1,203	246
Shareholders' equity	**4,502**	4,126	3,614	3,621	2,135	2,163	2,095	1,629	1,580	614
Total liabilities and shareholders' equity	**11,594**	10,819	8,625	7,806	5,369	5,000	3,758	3,040	3,259	1,081
RESULTS OF OPERATIONS [1]										
Revenue	**4,452**	4,140	3,989	1,975	1,371	1,430	1,213	899	613	330
Expenses	**3,384**	2,844	2,452	1,531	1,738	1,248	949	800	519	296
Income (loss) before taxes	**1,068**	1,296	1,537	444	(367)	182	264	99	94	34
Taxes (recovery)	**544**	563	680	189	(53)	130	170	61	55	32
Net income (loss)	**524**	733	857	255	(314)	52	94	38	39	2
Preferred security charges, net of tax	**24**	24	22	13	–	–	–	–	–	–
Income from discontinued operations	**–**	–	–	–	–	–	–	6	25	24
Net income (loss) available to common shareholders	**500**	709	835	242	(314)	52	94	44	64	26
Cash flow	**2,645**	2,494	2,413	1,111	631	797	697	502	362	189
Capital expenditures	**2,118**	2,098	1,625	1,495	1,224	1,066	765	489	429	179
Proceeds on property dispositions	**(40)**	(47)	(81)	(133)	(157)	(49)	(40)	(100)	(230)	(18)
Net capital expenditures	**2,078**	2,051	1,544	1,362	1,067	1,017	725	389	199	161
Per common share (dollars)										
Cash flow	**19.73**	18.48	17.51	8.91	5.64	7.29	6.71	5.21	4.63	3.17
Net income (loss)	**3.73**	5.25	6.05	1.93	(2.80)	0.48	0.90	0.46	0.82	0.43

1 Comparative amounts of prior years have been restated for a new CICA accounting standard (See Note 2 to the Consolidated Financial Statements).

CONSOLIDATED FINANCIAL RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium term notes pursuant to the short form prospectus dated March 27, 2002, and a prospectus supplement dated March 28, 2002, and are based on the corporation's consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

The asset coverage ratios are calculated as at December 31, 2002. The interest coverage ratios are for the 12-month period then ended.

December 31, 2002	Preferred Securities as Equity [5]	Preferred Securities as Debt [6]
Interest coverage (times)		
Income [1]	**5.86**	**4.79**
Cash flow [2]	**16.23**	**13.27**
Asset coverage (times)		
Before deduction of future income taxes and deferred credits [3]	**3.54**	**3.05**
After deduction of future income taxes and deferred credits [4]	**2.50**	**2.16**

1 Net income plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.
2 Cash flow plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.
3 Total assets minus current liabilities; divided by long-term debt.
4 Total assets minus current liabilities and long-term liabilities excluding long-term debt; divided by long-term debt.
5 The Company's preferred securities are classified as equity and the related charges have been excluded from interest expense.
6 Reflect adjusted ratios, had the preferred securities been treated as debt and the related charges been included in interest expense.

SELECTED QUARTERLY FINANCIAL DATA

(millions of Canadian dollars unless otherwise stated)		Total Year	Three months ended Dec. 31	Sept. 30	June 30	March 31
2002	Total revenue	**4,452**	**1,242**	**1,110**	**1,111**	**989**
	Net income	**524**	**182**	**151**	**90**	**101**
	Net income available to common shareholders	**500**	**176**	**145**	**84**	**95**
	Cash flow	**2,645**	**759**	**657**	**652**	**577**
	Total assets	**11,594**	**11,594**	**11,471**	**10,996**	**11,032**
	Total long-term liabilities	**6,103**	**6,103**	**5,763**	**5,655**	**5,658**
	Capital expenditures					
	Exploration	**628**	**174**	**146**	**130**	**178**
	Development	**1,220**	**283**	**297**	**256**	**384**
	Acquisitions	**244**	**175**	**49**	**15**	**5**
	Per common share (dollars)					
	Net income	**3.73**	**1.33**	**1.08**	**0.62**	**0.71**
	Diluted net income	**3.67**	**1.31**	**1.06**	**0.61**	**0.70**
	Cash flow	**19.73**	**5.72**	**4.87**	**4.84**	**4.31**
	Daily average production					
	Oil and liquids (bbls/d)	**272,740**	**270,582**	**267,393**	**275,157**	**277,971**
	Natural gas (mmcf/d)	**1,036**	**1,028**	**1,024**	**1,051**	**1,044**
	Total (mboe/d)	**445**	**442**	**438**	**450**	**452**
2001	Total revenue	4,140	937	999	1,014	1,190
	Net income	733	40	121	289	283
	Net income available to common shareholders	709	33	116	283	277
	Cash flow	2,494	502	587	641	764
	Total assets	10,819	10,819	11,058	9,991	8,922
	Total long-term liabilities	5,489	5,489	5,432	4,745	3,851
	Capital expenditures					
	Exploration	567	171	146	130	120
	Development	1,315	374	343	344	254
	Acquisitions	186	39	16	3	128
	Per common share (dollars)					
	Net income	5.25	0.25	0.86	2.09	2.05
	Diluted net income	5.16	0.24	0.85	2.05	2.01
	Cash flow	18.48	3.75	4.35	4.73	5.64
	Daily average production					
	Oil and liquids (bbls/d)	251,014	280,711	258,190	224,085	240,550
	Natural gas (mmcf/d)	1,010	1,079	986	980	993
	Total (mboe/d)	419	460	422	387	406

SELECTED QUARTERLY FINANCIAL DATA

PRODUCT NETBACKS

		2002					2001				
			Three months ended					Three months ended			
		Total Year	Dec. 31	Sept. 30	June 30	March 31	Total Year	Dec. 31	Sept. 30	June 30	March 31
North America	Oil and liquids ($/bbl)										
	Sales price	**32.43**	**34.57**	**35.57**	**32.76**	**26.82**	30.80	21.58	32.81	33.70	35.14
	Hedging (gain)	**0.06**	**0.36**	**0.52**	**0.11**	**(0.77)**	(0.12)	(0.72)	(0.03)	0.12	0.13
	Royalties	**6.85**	**7.42**	**7.74**	**6.35**	**5.90**	6.88	4.56	7.34	7.58	8.05
	Operating costs	**5.55**	**6.20**	**5.91**	**4.64**	**5.48**	5.22	5.84	5.12	5.02	4.91
		19.97	**20.59**	**21.40**	**21.66**	**16.21**	18.82	11.90	20.38	20.98	22.05
	Natural gas ($/mcf)										
	Sales price	**3.96**	**5.21**	**3.26**	**4.08**	**3.29**	5.39	3.20	3.56	5.99	9.06
	Hedging (gain)	**(0.28)**	**(0.11)**	**(0.37)**	**(0.21)**	**(0.42)**	0.02	(0.37)	(0.22)	0.17	0.54
	Royalties	**0.75**	**1.04**	**0.55**	**0.73**	**0.67**	1.34	0.58	0.74	1.64	2.47
	Operating costs	**0.71**	**0.78**	**0.74**	**0.65**	**0.66**	0.67	0.75	0.62	0.68	0.63
		2.78	**3.50**	**2.34**	**2.91**	**2.38**	3.36	2.24	2.42	3.50	5.42
North Sea	Oil and liquids ($/bbl)										
	Sales price	**38.76**	**41.77**	**41.89**	**37.71**	**33.87**	36.07	30.15	37.16	40.48	38.98
	Hedging (gain)	**0.12**	**0.38**	**0.75**	**0.11**	**(0.74)**	(0.17)	(0.72)	(0.02)	0.13	0.14
	Royalties	**1.60**	**1.72**	**1.68**	**1.41**	**1.60**	1.85	1.60	2.06	1.80	1.99
	Operating costs	**11.11**	**12.00**	**12.74**	**9.51**	**10.27**	10.06	9.66	9.92	11.31	9.71
		25.93	**27.67**	**26.72**	**26.68**	**22.74**	24.33	19.61	25.20	27.24	27.14
	Natural gas ($/mcf)										
	Sales price	**3.89**	**4.51**	**3.13**	**3.05**	**5.04**	4.35	4.48	3.40	3.92	5.35
	Hedging (gain)	**–**	**–**	**–**	**–**	**–**	–	–	–	–	–
	Royalties	**0.48**	**0.27**	**0.46**	**0.41**	**0.79**	0.46	0.84	0.43	0.23	0.20
	Operating costs	**0.61**	**0.92**	**0.61**	**0.49**	**0.45**	0.46	0.66	0.27	0.29	0.50
		2.80	**3.32**	**2.06**	**2.15**	**3.80**	3.43	2.98	2.70	3.40	4.65
Southeast Asia [1]	Oil and liquids ($/bbl)										
	Sales price	**39.46**	**45.04**	**41.27**	**38.77**	**32.84**	35.97	27.63	37.87	42.81	38.22
	Hedging (gain)	**0.06**	**0.36**	**0.53**	**0.11**	**(0.76)**	(0.30)	(1.04)	(0.19)	0.12	0.14
	Royalties	**14.83**	**17.13**	**16.13**	**13.76**	**12.34**	10.69	7.74	11.41	12.73	11.83
	Operating costs	**7.93**	**8.67**	**8.30**	**7.61**	**7.15**	7.13	6.89	6.82	8.04	6.89
		16.64	**18.88**	**16.31**	**17.29**	**14.11**	18.45	14.04	19.83	21.92	19.36
	Natural gas ($/mcf)										
	Sales price	**4.72**	**6.00**	**4.12**	**4.92**	**3.96**	4.80	4.06	4.88	5.60	4.74
	Hedging (gain)	**–**	**–**	**–**	**–**	**–**	0.02	0.01	0.01	0.01	0.02
	Royalties	**0.25**	**0.31**	**0.24**	**0.25**	**0.20**	0.24	0.21	0.24	0.27	0.23
	Operating costs	**0.59**	**0.80**	**0.69**	**0.49**	**0.42**	0.47	0.61	0.50	0.41	0.35
		3.88	**4.89**	**3.19**	**4.18**	**3.34**	4.07	3.23	4.13	4.91	4.14
Sudan	Oil ($/bbl)										
	Sales price	**37.79**	**46.30**	**38.33**	**36.64**	**29.35**	32.66	24.87	33.36	40.22	32.54
	Hedging (gain)	**0.07**	**0.37**	**0.52**	**0.11**	**(0.75)**	(0.13)	(0.73)	(0.03)	0.12	0.14
	Royalties	**14.94**	**21.74**	**12.45**	**13.96**	**11.32**	12.78	9.01	11.62	18.28	12.41
	Operating costs	**3.82**	**3.72**	**4.07**	**4.55**	**2.89**	3.40	3.25	2.78	3.93	3.71
		18.96	**20.47**	**21.29**	**18.02**	**15.89**	16.61	13.34	18.99	17.89	16.28
Total Company	Oil and liquids ($/bbl)										
	Sales price	**37.20**	**41.47**	**39.64**	**36.46**	**31.27**	33.99	26.94	35.33	38.66	36.54
	Hedging (gain)	**0.09**	**0.37**	**0.63**	**0.11**	**(0.75)**	(0.16)	(0.75)	(0.04)	0.12	0.14
	Royalties	**6.83**	**8.85**	**6.66**	**6.32**	**5.52**	6.22	4.29	6.18	8.34	6.58
	Operating costs	**7.99**	**8.53**	**8.89**	**7.17**	**7.38**	7.15	7.27	6.96	7.45	6.94
		22.29	**23.72**	**23.46**	**22.86**	**19.12**	20.78	16.13	22.23	22.75	22.88
	Natural gas ($/mcf)										
	Sales price	**4.03**	**5.20**	**3.32**	**4.02**	**3.55**	5.22	3.45	3.66	5.74	8.24
	Hedging (gain)	**(0.22)**	**(0.09)**	**(0.30)**	**(0.16)**	**(0.33)**	0.02	(0.28)	(0.18)	0.13	0.43
	Royalties	**0.67**	**0.89**	**0.51**	**0.65**	**0.63**	1.14	0.58	0.66	1.37	2.01
	Operating costs	**0.69**	**0.80**	**0.72**	**0.62**	**0.61**	0.63	0.73	0.58	0.62	0.59
		2.89	**3.60**	**2.39**	**2.91**	**2.64**	3.43	2.42	2.60	3.62	5.21

1 Includes operations in Indonesia and Malaysia/Vietnam.
Netbacks do not include synthetic oil or pipeline operations.

Additional Information for US Readers

The following information is for US readers. Production, finding and development costs, finding, development and acquisition costs as well as netbacks and the recycle ratio have been calculated net of royalties and have been translated to US$ at the average exchange rate for each of the years shown. (2002 US$1=C$1.57; 2001 US$1=C$1.55; 2000 US$1=C$1.49; 1999 US$1=C$1.49; 1998 US$1=C$1.48).

NET PRODUCTION (after royalties)

	2002	2001	2000	1999	1998
Crude Oil and Liquids (bbls/d)					
North America	**47,182**	49,145	49,018	44,114	44,128
North Sea	**122,231**	105,138	107,554	58,039	56,722
Southeast Asia [1]	**14,025**	14,667	13,853	17,149	20,230
Sudan	**36,346**	32,422	28,001	9,079	–
Synthetic Oil (Canada)	**2,788**	2,387	1,927	2,556	2,502
Total oil and liquids	**222,572**	203,759	200,353	130,937	123,582
Natural Gas (mmcf/d)					
North America	**665**	608	582	552	539
North Sea	**107**	97	117	111	103
Southeast Asia [1]	**89**	89	104	103	–
Total natural gas	**861**	794	803	766	642
Total mboe/d	**366**	337	335	259	232

1 Includes operations in Indonesia and Malaysia/Vietnam.

FINDING AND DEVELOPMENT COSTS (net of royalties) [1]

US$/boe	1998	1999	2000	2001	**2002**	3-Year	5-Year
Proved F&D Cost, Net							
North America	4.59	6.01	5.49	7.69	**12.97**	7.86	6.95
International	5.02	9.17	6.27	3.39	**11.54**	5.42	5.74
Total	4.87	7.92	5.81	4.51	**12.11**	6.33	6.19
Proved FD&A Cost, Net							
North America	5.16	7.91	7.31	9.71	**14.36**	9.74	8.52
International	4.90	7.25	4.65	4.28	**11.27**	5.45	5.65
Total	4.97	7.59	5.79	6.12	**12.52**	7.06	6.77

1 Property acquisition, exploration and development costs are set out in the Supplementary Oil and Gas Information under the heading Costs Incurred in Oil and Gas Activities.

RECYCLE RATIO

	1998	1999	2000	2001	**2002**	3-Year	5-Year
Netback (US$/boe)	6.05	9.53	17.04	16.64	**15.78**	16.47	13.72
Finding and development	1.2	1.2	2.9	3.7	**1.3**	2.6	2.2
Finding, development and acquisition	1.2	1.3	2.9	2.7	**1.3**	2.3	2.0

The 2002 year end net reserves used in the above calculations have been determined by applying prices in effect on December 31, 2002.

Year end oil and natural gas prices may be subject to significant volatility in the future, in which case large year-to-year price induced revisions to reported year end net reserves would occur. Consequently, future finding and development costs and recycle ratio calculations, which are impacted by net reserve additions and net production, may also be subject to significant volatility.

US Readers:
PRODUCT NETBACK

(Net of Royalties) – US$			2002	2001	2000
North America	Oil and Liquids (US$/bbl)				
		Sales Price	**20.65**	19.89	25.34
		Hedging (gain)	**0.04**	(0.10)	3.01
		Operating costs	**4.48**	4.33	3.66
			16.13	15.66	18.67
	Natural Gas (US$/mcf)				
		Sales Price	**2.52**	3.48	3.14
		Hedging (gain)	**(0.22)**	0.02	0.22
		Operating costs	**0.56**	0.57	0.49
			2.18	2.89	2.43
North Sea	Oil and Liquids (US$/bbl)				
		Sales Price	**24.68**	23.29	27.19
		Hedging (gain)	**0.08**	(0.12)	2.41
		Operating costs	**7.38**	6.83	6.40
			17.22	16.58	18.38
	Natural Gas (US$/mcf)				
		Sales Price	**2.48**	2.81	2.41
		Hedging (gain)	**–**	–	–
		Operating costs	**0.44**	0.33	0.40
			2.04	2.48	2.01
Southeast Asia [1]	Oil and Liquids (US$/bbl)				
		Sales Price	**25.13**	23.22	28.61
		Hedging (gain)	**0.06**	(0.28)	3.37
		Operating costs	**8.09**	6.53	5.30
			16.98	16.97	19.94
	Natural Gas (US$/mcf)				
		Sales Price	**3.01**	3.10	3.80
		Hedging (gain)	**–**	0.01	0.03
		Operating costs	**0.40**	0.32	0.28
			2.61	2.77	3.49
Sudan	Oil and Liquids (US$/bbl)				
		Sales Price	**24.06**	21.09	25.93
		Hedging (gain)	**0.08**	(0.14)	3.79
		Operating costs	**4.02**	3.60	4.19
			19.96	17.63	17.95
Total Company	Oil and Liquids (US$/bbl)				
		Sales Price	**23.74**	21.95	26.58
		Hedging (gain)	**0.07**	(0.13)	2.81
		Operating costs	**6.25**	5.64	5.32
			17.42	16.44	18.45
	Natural Gas (US$/mcf)				
		Sales Price	**2.57**	3.37	3.12
		Hedging (gain)	**(0.17)**	0.01	0.17
		Operating costs	**0.53**	0.52	0.45
			2.21	2.84	2.50

1 Includes operations in Indonesia and Malaysia/Vietnam.
Netbacks do not include synthetic oil or pipeline operations.

US Readers:

CONTINUITY OF PROVED NET RESERVES – Alternate Price Scenario

Net reserves, after deducting royalties, will fluctuate with changes in prices. Management does not view the net reserves calculated based on year end prices (as required by FAS 69) as the best estimate of future events and anticipated outcomes. The following net reserves have been calculated after deducting royalties based on oil and natural gas prices of US$20/bbl (WTI) and US$3/mcf (NYMEX) in 2002, escalated at 2% per year thereafter.

NET RESERVES (after royalties)

	North America	North Sea	Southeast Asia	Sudan	Algeria	Trinidad	Total
BOE (mmboe)							
Proved reserves at December 31, 2001	514.5	305.3	220.3	113.3	17.0	–	1,170.4
Discoveries, additions and extensions	58.9	15.7	8.9	23.7	1.2	56.5	164.9
Purchase of reserves	6.4	7.6	–	–	–	–	14.0
Sale of reserves	(8.3)	(2.8)	–	–	–	–	(11.1)
Net revisions and transfers	(8.6)	6.4	(2.6)	(6.1)	(4.8)	–	(15.7)
2002 Production	(57.8)	(51.3)	(10.5)	(13.3)	–	–	(132.9)
Proved reserves at December 31, 2002	**505.1**	**280.9**	**216.1**	**117.6**	**13.4**	**56.5**	**1,189.6**

Canadian oil and gas industry practice, when calculating Finding and Development (F&D) costs, is to exclude indirect and midstream costs, capitalized interest and costs associated with non-conventional oil and gas exploration and development activities. In addition, reserve additions are net of disposals with the corresponding adjustment for the related proceeds in the determination of reserve replacement costs. The following F&D costs have been calculated using the Canadian industry conventions and the above reserves.

RESERVE REPLACEMENT COSTS – Reconciliation of Cost Used to FAS 69 Disclosures (US$ millions)

	2002	2001
Exploration and development costs (FAS 69)	**1,123**	1,169
Add: Land costs included in E&D	**37**	41
Less: Indirect cost and capitalized interest	**(41)**	(34)
Midstream costs	**(14)**	(18)
Exploration and development costs	**1,105**	1,158
Acquisition costs (FAS 69)	**213**	1,081
Less: Sales proceeds on dispositions	**(26)**	(105)
Land costs included in E&D	**(37)**	(41)
Add: Additional costs on corporate acquisitions	**(21)**	20
Acquisition costs	**129**	955
Total exploration, development and acquisition cost	**1,234**	2,113

PROVED FINDING AND DEVELOPMENT COSTS (US$/boe)

	2002	2001
North America	**9.53**	8.18
International	**6.32**	3.40
Total	**7.40**	4.64

PROVED FINDING, DEVELOPMENT AND ACQUISITION COSTS (US$/boe)

	2002	2001
North America	**11.44**	10.19
International	**6.56**	4.25
Total	**8.11**	6.18

Detailed Property Review

2002 LANDHOLDINGS

(thousands of acres)	Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net	Total Gross	Total Net
Canada						
Western Canada	2,646.6	1,368.2	5,301.4	3,461.3	7,948.0	4,829.5
Oil Sands	8.2	1.0	405.7	32.6	413.9	33.6
Total Western Canada	2,654.8	1,369.2	5,707.1	3,493.9	8,361.9	4,863.1
Ontario	539.4	357.8	681.6	469.1	1,221.0	826.9
Other[1]	2.0	–	3,599.6	243.9	3,601.6	243.9
United States	3.5	3.4	993.2	812.2	996.7	815.6
Total North America	3,199.7	1,730.4	10,981.5	5,019.1	14,181.2	6,749.5
North Sea	194.1	93.2	1,791.2	761.4	1,985.3	854.6
Southeast Asia						
Indonesia	292.6	127.1	1,585.3	524.0	1,877.9	651.1
Malaysia and Vietnam	224.4	92.5	3,696.9	1,285.8	3,921.3	1,378.3
Papua New Guinea	–	–	1,686.0	614.8	1,686.0	614.8
Sudan	598.4	149.6	11,488.0	2,872.0	12,086.4	3,021.6
Algeria	76.8	5.2	750.5	262.7	827.3	267.9
Trinidad	–	–	320.9	134.5	320.9	134.5
Other	–	–	1,637.3	793.3	1,637.3	793.3
Total International	1,386.3	467.6	22,956.1	7,248.5	24,342.4	7,716.1
Total Worldwide	4,586.0	2,198.0	33,937.6	12,267.6	38,523.6	14,465.6

1 Includes Yukon Territory, Northwest Territories and Arctic Islands.

2002 DRILLING

Year Ended December 31, 2002		Exploration Oil	Exploration Gas	Exploration Dry	Exploration Total	Development Oil	Development Gas	Development Dry	Development Total	Total Oil	Total Gas	Total Dry	Total Total
North America													
Canada	Gross	17.0	95.0	35.0	147.0	129.0	127.0	15.0	271.0	146.0	222.0	50.0	418.0
	Net	14.8	66.4	26.4	107.6	88.9	70.9	10.9	170.7	103.7	137.3	37.3	278.3
United States	Gross	–	1.0	5.0	6.0	–	–	–	–	–	1.0	5.0	6.0
	Net	–	1.0	3.4	4.4	–	–	–	–	–	1.0	3.4	4.4
North Sea	Gross	1.0	–	3.0	4.0	15.0	2.0	3.0	20.0	16.0	2.0	6.0	24.0
	Net	0.9	–	1.6	2.5	5.4	0.1	2.2	7.7	6.3	0.1	3.8	10.2
Southeast Asia													
Indonesia	Gross	–	3.0	2.0	5.0	5.0	–	1.0	6.0	5.0	3.0	3.0	11.0
	Net	–	0.9	1.0	1.9	2.5	–	0.4	2.9	2.5	0.9	1.4	4.8
Malaysia and Vietnam	Gross	1.0	1.0	2.0	4.0	3.0	4.0	–	7.0	4.0	5.0	2.0	11.0
	Net	0.4	0.4	0.8	1.6	1.2	1.7	–	2.9	1.6	2.1	0.8	4.5
Sudan	Gross	17.0	–	7.0	24.0	6.0	–	1.0	7.0	23.0	–	8.0	31.0
	Net	4.3	–	1.8	6.1	1.5	–	0.3	1.8	5.8	–	2.1	7.9
Algeria	Gross	–	–	–	–	9.0	–	–	9.0	9.0	–	–	9.0
	Net	–	–	–	–	1.2	–	–	1.2	1.2	–	–	1.2
Trinidad	Gross	2.0	1.0	2.0	5.0	–	–	–	–	2.0	1.0	2.0	5.0
	Net	0.5	0.3	0.9	1.7	–	–	–	–	0.5	0.3	0.9	1.7
Total	Gross	38.0	101.0	56.0	195.0	167.0	133.0	20.0	320.0	205.0	234.0	76.0	515.0
	Net	20.9	69.0	35.9	125.8	100.7	72.7	13.8	187.2	121.6	141.7	49.7	313.0

Water injection, source and disposal wells are not included.

PROPERTY REVIEW: NORTH AMERICA[1]

Property		Average WI (%)	**2002**	2001	2000
Greater Arch					
Production:	Oil & Liquids (bbls/d)	84	**8,842**	10,347	11,047
	Natural Gas (mmcf/d)	76	**166.9**	204.2	202.9
	Total Production (boe/d)		**36,654**	44,379	44,867
Drilling:	Number of wells		**79**	96	136
	Success Rate (%)		**71**	76	78
Capital Expenditures:	(C$ million)		**114**	136	155
Alberta Foothills					
Production:	Oil & Liquids (bbls/d)		**167**	139	439
	Natural Gas (mmcf/d)	85	**121.1**	102.4	79.6
	Total Production (boe/d)		**20,353**	17,210	13,709
Drilling:	Number of wells		**22**	21	22
	Success Rate (%)		**95**	100	95
Capital Expenditures:	(C$ million)		**118**	142	119
Chauvin					
Production:	Oil & Liquids (bbls/d)	97	**14,265**	12,578	11,376
	Natural Gas (mmcf/d)		**18.3**	16.7	13.8
	Total Production (boe/d)		**17,312**	15,361	13,681
Drilling:	Number of wells		**60**	90	89
	Success Rate (%)		**93**	99	100
Capital Expenditures:	(C$ million)		**48**	76	65
Northern Plains					
Production:	Oil & Liquids (bbls/d)	79	**1,642**	2,810	3,440
	Natural Gas (mmcf/d)	73	**33.0**	43.1	46.5
	Total Production (boe/d)		**7,142**	9,988	11,183
Drilling:	Number of wells		**6**	8	16
	Success Rate (%)		**50**	75	88
Capital Expenditures:	(C$ million)		**25**	18	28
Ontario					
Production:	Oil & Liquids (bbls/d)	97	**2,664**	3,056	2,731
	Natural Gas (mmcf/d)	76	**20.2**	18.9	19.0
	Total Production (boe/d)		**6,034**	6,198	5,891
Drilling:	Number of wells		**29**	35	38
	Success Rate (%)		**79**	94	84
Capital Expenditures:	(C$ million)		**41**	43	30
Monkman-BC Foothills					
Production:	Oil & Liquids (bbls/d)		**–**	11	–
	Natural Gas (mmcf/d)	71	**82.7**	90.0	102.9
	Total Production (boe/d)		**13,770**	15,016	17,142
Drilling:	Number of wells		**2**	5	2
	Success Rate (%)		**100**	80	100
Capital Expenditures:	(C$ million)		**44**	17	31
Carlyle					
Production:	Oil & Liquids (bbls/d)	81	**7,657**	9,421	10,141
	Natural Gas (mmcf/d)		**1.0**	0.9	0.9
	Total Production (boe/d)		**7,824**	9,576	10,297
Drilling:	Number of wells		**13**	17	47
	Success Rate (%)		**100**	89	81
Capital Expenditures:	(C$ million)		**13**	15	29

NORTH AMERICA[1] (continued)

Property		Average WI (%)	**2002**	2001	2000
Edson Area (includes West Whitecourt, Bigstone/Wild River)					
Production:	Oil & Liquids (bbls/d)	69	**4,189**	3,449	2,391
	Natural Gas (mmcf/d)	78	**199.7**	162.7	106.8
	Total Production (boe/d)		**37,465**	30,565	20,188
Drilling:	Number of wells		**79**	95	59
	Success Rate (%)		**96**	85	85
Capital Expenditures:	(C$ million)		**192**	169	82
Lac La Biche					
Production:	Natural Gas (mmcf/d)	86	**56.3**	63.9	70.7
	Total Production (boe/d)		**9,383**	10,647	11,780
Drilling:	Number of wells		**12**	17	24
	Success Rate (%)		**83**	100	88
Capital Expenditures:	(C$ million)		**6**	19	14
Central Alberta (includes Acme)					
Production:	Oil & Liquids (bbls/d)	75	**2,632**	2,981	3,094
	Natural Gas (mmcf/d)	60	**19.2**	22.2	22.1
	Total Production (boe/d)		**5,832**	6,676	6,776
Drilling:	Number of wells		**6**	11	19
	Success Rate (%)		**100**	100	90
Capital Expenditures:	(C$ million)		**18**	35	25
Turner Valley					
Production:	Oil & Liquids (bbls/d)	96	**2,264**	2,105	2,002
	Natural Gas (mmcf/d)		**10.3**	6.8	6.2
	Total Production (boe/d)		**3,978**	3,231	3,037
Drilling:	Number of wells		**4**	5	2
	Success Rate (%)		**100**	100	100
Capital Expenditures:	(C$ million)		**22**	23	3
Shaunavon					
Production:	Oil & Liquids (bbls/d)	92	**3,724**	3,813	3,428
Drilling:	Number of wells		**7**	4	6
	Success Rate (%)		**86**	100	100
Capital Expenditures:	(C$ million)		**4**	6	4
Other (includes United States)					
Production:	Oil & Liquids (bbls/d)		**10,198**	11,384	12,653
	Natural Gas (mmcf/d)		**53.1**	58.7	69.2
	Total Production (boe/d)		**19,050**	21,048	24,202
Drilling:	Number of wells		**65**	115	118
	Success Rate (%)		**87**	60	94
Capital Expenditures:	(C$ million)		**130**	133	73
Syncrude	Synthetic oil (bbls/d)	1.25	**2,868**	2,781	2,540
Deep Basin					
Production:	Oil & Liquids (bbls/d)		**1,564**	1,181	1,092
	Natural Gas (mmcf/d)		**38.2**	18.5	15.0
	Total Production (boe/d)		**7,937**	4,264	3,592
Drilling:	Number of wells		**40**	37	32
	Success Rate (%)		**100**	97	91
Capital Expenditures:	(C$ million)		**47**	44	28
Total Production:	Oil & Liquids (bbls/d)		**62,676**	66,056	66,374
	Natural Gas (mmcf/d)		**820.0**	809.0	755.6
	(boe/d)		**199,326**	200,753	192,313
Total Capital Expenditures:	(C$ million)		**822**	876	686

1 In Canada, Talisman operates approximately 72% of its oil and liquids production and approximately 76% of its natural gas production. Average working interest at December 31, 2002 in Talisman-operated properties only. Certain properties have been reallocated between core areas and, accordingly, figures have been restated to conform to current year presentation. The average crude oil gravity of Talisman's Canadian production is 35° API. Capital expenditures exclude acquisition and disposition activity.

NORTH SEA [1]

Property		Average WI (%)	2002	2001	2000
Ross/Blake		54-56			
Production:	Oil & Liquids (bbls/d)		**27,017**	16,029	13,288
	Natural Gas (mmcf/d)		**7.7**	3.0	3.5
	Total Production (boe/d)		**28,294**	16,524	13,868
Drilling:	Number of wells		**–**	4	2
Capital Expenditures:	(C$ million)		**4**	163	122
Clyde/Orion/Halley		13-95			
Production:	Oil & Liquids (bbls/d)		**14,688**	15,112	16,015
	Natural Gas (mmcf/d)		**4.5**	7.1	8.2
	Total Production (boe/d)		**15,446**	16,297	17,389
Drilling:	Number of wells		**2**	2	2
Capital Expenditures:	(C$ million)		**94**	77	40
Flotta Catchment Area		20-100			
Production:	Oil & Liquids (bbls/d)				
	Tartan/Highlander/Petronella		**10,008**	9,447	7,873
	Piper		**16,009**	19,070	22,236
	MacCulloch		**6,184**	4,761	5,891
	Claymore		**20,045**	17,496	18,863
	Natural Gas (mmcf/d)				
	MacCulloch and Piper		**1.4**	0.9	0.9
	Total Production (boe/d)		**52,488**	50,926	55,019
Drilling:	Number of wells		**8**	5	2
Capital Expenditures:	(C$ million)		**186**	145	42
Buchan/Hannay		86			
Production:	Oil & Liquids (bbls/d)		**8,062**	5,990	5,498
	Natural Gas (mmcf/d)		**0.7**	1.0	0.9
	Total Production (boe/d)		**8,178**	6,165	5,649
Drilling:	Number of wells		**4**	3	–
Capital Expenditures:	(C$ million)		**89**	89	32
Beatrice		100			
Production:	Oil & Liquids (bbls/d)		**7,406**	2,160	2,998
Drilling:	Number of wells		**1**	3	1
Capital Expenditures:	(C$ million)		**16**	104	15
Brae		17-18			
Production:	Oil & Liquids (bbls/d)		**8,801**	9,221	10,762
	Natural Gas (mmcf/d)		**93.2**	79.3	74.5
	Total Production (boe/d)		**24,330**	22,440	23,183
Drilling:	Number of wells		**1**	4	6
Capital Expenditures:	(C$ million)		**4**	11	11
Netherlands		4-15			
Production:	Oil & Liquids (bbls/d)		**199**	176	122
	Natural Gas (mmcf/d)		**12.4**	13.8	14.3
	Total Production (boe/d)		**2,269**	2,482	2,507
Drilling:	Number of wells		**2**	3	2
Capital Expenditures:	(C$ million)		**13**	6	5
Other		2-30			
Production:	Oil & Liquids (bbls/d)		**9,067**	11,366	8,356
	Natural Gas (mmcf/d)		**2.3**	3.0	19.4
	Total Production		**9,436**	11,848	11,584
Drilling:	Number of wells		**6**	9	5
Capital Expenditures:	(C$ million)		**25**	38	36
Total Production:	Oil & Liquids (bbls/d)		**127,486**	110,828	111,902
	Natural Gas (mmcf/d)		**122.2**	108.1	122
	(boe/d)		**147,847**	128,842	132,197
Total Capital Expenditures:	(C$ million)		**431**	633	303

1 In the North Sea, Talisman operates approximately 77% of its oil and liquids production and approximately 11% of its natural gas production. Average working interest at December 31, 2002 in Talisman-operated properties only. The average crude oil gravity of Talisman's North Sea production is 40° API. Capital expenditures include capitalized interest and financing costs and exclude acquisition and disposition activity.

SOUTHEAST ASIA[1]

Property			Average WI (%)	2002	2001	2000
Corridor						
Production:	Oil & Liquids (bbls/d)					
		Corridor Technical Assistance Contract	40	**4,329**	5,344	5,351
		Corridor Production Sharing Contract	36	**2,031**	2,081	2,320
	Natural Gas (mmcf/d)					
		Corridor Production Sharing Contract	36	**89.4**	93.3	110.8
	Total Production (boe/d)			**21,254**	22,971	26,138
Drilling:	Number of wells			**1**	41	35
Capital Expenditures:	(C$ million)			**59**	65	25
Tanjung Raya			100			
Production:	Oil & Liquids (bbls/d)			**6,617**	6,414	6,884
Drilling:	Number of wells			**2**	3	10
Capital Expenditures:	(C$ million)			**8**	8	17
Ogan Komering[2]			50			
Production:	Oil & Liquids (bbls/d)			**2,721**	3,340	3,938
	Natural Gas (mmcf/d)			**5.0**	–	–
	Total Production (boe/d)			**3,563**	3,340	3,938
Drilling:	Number of wells			**6**	12	9
Capital Expenditures:	(C$ million)			**3**	7	4
Jambi			40			
Production:	Oil & Liquids (bbls/d)			**1,154**	1,420	1,713
Drilling:	Number of wells			**–**	9	12
Capital Expenditures:	(C$ million)			**0.5**	3	3
Malaysia/Vietnam PM-3 CAA			41			
Production:	Oil & Liquids (bbls/d)			**5,617**	2,273	–
Drilling:	Number of wells			**11**	3	–
Capital Expenditures:[3]	(C$ million)			**161**	56	–
Other			25-60			
Drilling:	Number of wells			**2**	–	1
Capital Expenditures:	(C$ million)			**37.5**	2	20
Total Production:	Oil & Liquids (bbls/d)			**22,469**	20,872	20,206
	Natural Gas (mmcf/d)			**94.4**	93.3	110.8
	(boe/d)			**38,205**	36,419	36,673
Total Capital Expenditures:	(C$ million)			**269**	141	69

1 In Indonesia, Talisman operates approximately 33% of its oil and liquids production. The average crude oil gravity of Talisman's Indonesia production is 34° API. Capital expenditures include capitalized interest and financing costs and exclude acquisition and disposition activity.

2 Effective January 1, 2001, the Indonesia national oil company, Pertamina, elected to convert its previously reported royalty interest to a 50% equity interest.

3 Malaysia/Vietnam capital expenditures include PM305 expenditures.

SUDAN

		Average WI (%)	2002	2001	2000
Production:	Oil & Liquids (bbls/d)	25	**60,109**	53,257	45,869
Drilling:	Number of wells		**31**	49	17
Capital Expenditures:	(C$ million)		**98**	117	70

EXPLORATION AREAS

			2002	2001	2000
Algeria		35			
Drilling:	Number of wells		**9**	14	12
Capital Expenditures:	(C$ million)		**107**	63	34
Trinidad		25-65			
Drilling:	Number of wells		**5**	3	1
Capital Expenditures:	(C$ million)		**78**	31	7
Colombia		30-70			
Drilling:	Number of wells		**–**	–	–
Capital Expenditures:	(C$ million)		**22**	7	–
Other International					
Drilling:	Number of wells		**–**	–	–
Capital Expenditures:	(C$ million)		**21**	–	–

Corporate Governance

TALISMAN'S APPROACH TO CORPORATE GOVERNANCE

Talisman's approach to corporate governance aligns with the existing guidelines for effective corporate governance established by The Toronto Stock Exchange ("TSX"). The Company addresses TSX guidelines through Board composition, stated responsibilities of the Board and through various committees of the Board, as outlined below.

INDEPENDENCE OF THE BOARD

Talisman is in full compliance with the TSX recommendation that "The Board of Directors of every corporation should be constituted with a majority of individuals who qualify as unrelated directors. An unrelated director is a director who is independent of management and is free from any interest and any business or other relationship which could, or reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the corporation, other than interests and relationships arising from shareholding." The Board of Directors of Talisman comprises 10 directors, nine of whom, including the Chairman of the Board, qualify as unrelated directors as defined by the TSX. The only related director is James W. Buckee, President and Chief Executive Officer of the Company.

The composition of the Board, including the independence of the Chairman and his specified role, ensures that the Board has "in place appropriate structures and procedures to ensure that the Board can function independently of management" and that "committees of the Board of Directors are composed of outside directors, the majority of whom are unrelated directors".

The Chairman of the Board is specifically charged with responsibility for leading and managing the Board in discharging its responsibilities and acts as the Board's spokesman to management.

RESPONSIBILITIES OF THE BOARD

The Board of Directors of Talisman sees its principal role as stewardship of the Company and its fundamental objective the creation of shareholder value, including the protection and enhancement of the value of the Company's assets. The Board's stewardship responsibility means that it oversees the conduct of the business and management, which is responsible for the day-to-day conduct of the business. The Board assesses and ensures systems are in place to manage the risks of the Company's business with the objective of preserving the Company's assets. The Board, through the Chief Executive Officer, sets the attitude and disposition of the Company towards compliance with applicable laws, environmental, safety and health policies, financial practices and reporting. In addition to its primary accountability to shareholders, the Board is also accountable to employees, government authorities, other stakeholders and the public.

In fulfilling its primary responsibilities, the Board ensures that the Company has:

- established long-term goals and a strategic planning process,
- identified the principal risks of the Company's business and implemented appropriate systems to monitor and manage those risks,
- undertaken sufficient succession planning to manage and monitor management's performance and, in particular the Chief Executive Officer's performance, in achieving the Company's stated objectives,
- established internal controls and management information systems which have sufficient integrity to effectively monitor the Company's operations and ensure compliance with applicable laws, regulations and policies,
- implemented processes to properly oversee Company sponsored pension plans, and
- developed and implemented a communications policy for effectively communicating with and receiving feedback from shareholders, employees, government authorities, other stakeholders and the public.

The Board of Directors may delegate power over certain matters to a committee of the Board, provided that certain responsibilities of the Board are sufficiently important to warrant the attention of the full Board and, accordingly, are not delegated or are only delegated in a qualified or partial manner, including:

- submitting to shareholders any matter requiring their approval,
- filling vacancies among the directors or appointing additional directors,
- issuing securities, declaring dividends or purchasing the Company's own shares,
- approving management proxy circulars,
- approving annual financial statements, and
- adopting, amending or repealing by-laws.

The Board of Directors has developed a mandate for the Board embodying the foregoing. To assist Board members in performing their responsibilities, the Company has adopted a policy whereby, with the approval of the Governance and Nominating Committee, a Board member may engage an outside advisor at the Company's expense.

The Board of Directors met eight times during the 2002 fiscal year. Two directors were each unable to attend one meeting of the Board.

COMMITTEES OF THE BOARD

The Board of Directors has established five committees: the Audit Committee, the Executive Committee, the Governance and Nominating Committee, the Management Succession and Compensation Committee and the Pension Funds Committee. In accordance with the TSX guidelines, and as a result of the composition of the Board, all committees comprise a majority of unrelated directors. The President and Chief Executive Officer is a member of the Executive Committee and the Pension Funds Committee and is the only inside and related director on these committees. The Governance and Nominating Committee, the Audit Committee and the Management Succession and Compensation Committee are composed exclusively of unrelated directors. With the exception of the Executive Committee, for which there are no regularly scheduled meetings, the committees of the Board convene in accordance with an annually developed schedule.

Audit Committee

Members: The Audit Committee consists of **Douglas D. Baldwin**, **Al L. Flood**, **Paul J. Hoenmans**, **Dale G. Parker**[1] and **Charles W. Wilson**, all of whom are unrelated directors.

Mandate: The primary roles and responsibilities of the Audit Committee include:

- reviewing and recommending to the Board for approval, the Company's annual financial statements,
- reviewing and approving the Company's interim financial statements,
- reviewing and approving, as prescribed, other financial information,
- recommending to the Board the auditors who will be proposed at the annual shareholders' meeting for appointment as the Company's external auditors for the ensuing year,
- evaluating and ensuring the independence of the Company's auditors,
- reviewing and pre-approving the terms of the annual external audit engagement plan, as well as non-audit services the auditors are to perform,
- reviewing results of external audit activities,
- reviewing the Company's ongoing relationship with its auditors,
- maintaining direct access to the Company's internal and external auditors and meeting separately with each group,
- overseeing the internal audit function of the Company and its relationship with the Company's auditors and management,
- reviewing and obtaining reasonable assurance that the Company's internal financial control and information systems are operating effectively to produce accurate, appropriate and timely financial information,
- reviewing insurance coverage of significant business risks,
- receiving a report on the Company's material subsidiaries concerning any material non-routine structures,
- reviewing corporate policies within the scope of its responsibility and monitoring compliance with such policies,
- directing and supervising the investigation into any matter brought to the Committee's attention within the scope of its duties, and
- reporting to the Board at each regularly scheduled meeting following any Audit Committee meeting.

Activities: The Audit Committee met five times in 2002. All members attended each meeting of the Committee, with the exception of Charles W. Wilson, who was not appointed to the Committee until March 4, 2003.

Executive Committee

Members: The Executive Committee consists of **James W. Buckee**, **Al L. Flood**, **David E. Powell**[1] and **Roland Priddle**, of whom only James W. Buckee is a related director.

Mandate: The Executive Committee is an extension of the full Board and convenes to take action when it is not practicable to call a meeting of the full Board. Consequently, the Executive Committee has no regularly scheduled meetings. The Executive Committee may exercise, subject to applicable laws, all of the powers and discretions of the full Board, provided that the powers of the Committee do not include those listed previously as warranting the attention of the full Board.

Activities: The Executive Committee did not meet during 2002.

1 Denotes Committee Chairman

Governance and Nominating Committee

Members: The Governance and Nominating Committee consists of **Douglas D. Baldwin** [1], **David Powell**, **Roland Priddle** and **Lawrence G. Tapp**, all of whom are unrelated directors.

Mandate: The primary roles and responsibilities of the Governance and Nominating Committee include:

- developing the Company's approach to corporate governance and reviewing and approving the Company's annual disclosure of corporate governance compliance,
- establishing a long-term plan for composition of the Board,
- establishing a process for identifying, recruiting and appointing new directors and recommending nominees for election to the Board,
- reviewing and recommending the education and orientation program for new Board members,
- reviewing the size and assessing the composition and effectiveness of the Board, its committees and its individual members,
- assessing the effectiveness of and ensuring there is a succession plan for the Chairman of the Board,
- reviewing and determining director compensation,
- considering and recommending to the Board stock option grants to directors of the Company who are not employed on a permanent basis by the Company,
- reviewing the purpose of and recommending grants under the Deferred Share Unit Plan,
- reviewing the general responsibilities and function of the Board, its committees and the roles of the Chairman of the Board and the Chief Executive Officer,
- assessing the needs of the Board in terms of frequency, location and conduct of Board and committee meetings, and
- considering requests from individual directors or committees to engage outside advisors.

Activities: The Governance and Nominating Committee met six times in 2002. One director was unable to attend one meeting of the Committee.

Management Succession and Compensation Committee

Members: The Management Succession and Compensation Committee consists of **Paul J. Hoenmans** [1], **David E. Powell**, **Lawrence G.Tapp** and **Stella M. Thompson**, all of whom are unrelated directors.

Mandate: The primary roles and responsibilities of the Management Succession and Compensation Committee include:

- reviewing succession plans for key management positions within the Company,
- reviewing management development and staffing plans, compensation, pension and benefit plans,
- leading the process for assessing the performance of the Chief Executive Officer,
- reviewing the employment agreements and annual performance contracts of the Company's Chief Executive Officer and executive officers and the compensation paid to the Company's Chief Executive Officer and executive officers,
- reviewing employee stock option grants,
- reviewing human resource strategies and policies, and
- reviewing the Company's disclosure of executive compensation.

Activities: The Management Succession and Compensation Committee met five times in 2002. All members attended each meeting of the Committee.

Pension Funds Committee

Members: The Pension Funds Committee consists of **James W. Buckee**, **Dale G. Parker**, **Roland Priddle** and **Stella M. Thompson** [1], of whom only James W. Buckee is a related director.

Mandate: The primary roles and responsibilities of the Pension Funds Committee include:

- approving the investment objectives and policy of the Company's pension plans,
- reviewing the investment strategy, risk profile and performance of the plans and approving the asset class allocations of the plans,
- approving the appointment and termination of investment managers and reviewing costs associated with the plan administration, and
- reviewing and approving annual financial statements and management reports of each plan.

Activities: The Pension Funds Committee met twice in 2002. All members attended each meeting of the Committee.

1 Denotes Committee Chairman

ROLES AND RESPONSIBILITIES OF THE CHAIRMAN OF THE BOARD

The principal role of the Chairman of the Board is to manage and to provide leadership to the Board of Directors. The Chairman is accountable to the Board and acts as a direct liaison between the Board and management of the Company. In addition, the Chairman acts as a spokesman for Board decisions where appropriate.

Other duties and responsibilities of the Chairman include:

- providing independent advice and counsel to the Chief Executive Officer,
- ensuring that the directors are properly informed and that sufficient information is provided to enable the directors to form appropriate judgments,
- ensuring appropriate committees of the Board are struck and recommending the appointment of members to the committees, and
- assessing and making recommendations regarding the effectiveness of the Board, committees of the Board and individual directors.

DIRECTOR SHARE OWNERSHIP POLICY

In August 1998, the Board adopted a policy regarding director ownership of Company shares. The policy prescribes that directors should own at least 2,500 Talisman shares and sets out a timeframe over which that accumulation should occur. All directors currently own Talisman shares that meet or exceed the levels of ownership set by the internal policy.

MANAGEMENT PERFORMANCE

The terms of the mandate of the Board ensure that the Company annually confirms or redetermines its long-term strategy and strategic objectives and sets its budget and development plan for the ensuing year. This process produces specific annual goals for the Company that are further developed into specific contracts for each of the officers of the Company based upon that officer's role in the Company. Through this process, each officer (including the President and Chief Executive Officer) individually, and the officers as a whole, are made directly responsible for achieving the annual goals of the Company. A significant portion of the annual compensation of each officer is based upon achieving these Company and individual goals.

SHAREHOLDER COMMUNICATIONS

Talisman's shareholder communications policy specifically adopts the principles of timely, accurate and efficient disclosure of information concerning the Company to all shareholders. In addition to the required annual, quarterly and timely reporting of information, the Company regularly makes presentations to industry analysts and investors. The Company also meets informally upon request with investors and analysts, provided however, that in any such meeting, the Company strictly adheres to applicable laws relating to selective disclosure of material information. The Company's Investor Relations and Corporate Communications Department has the specific mandate of responding in a timely manner to all inquiries received from shareholders, analysts and potential investors. Shareholder inquiries or suggestions are forwarded to the appropriate person or to senior management. Shareholders may also obtain corporate information on the Company's external website at www.talisman-energy.com.

Investor Information

COMMON SHARES

Transfer agent: Computershare Trust Company of Canada
Calgary, Toronto, Montreal, Vancouver

Co-transfer agent: Computershare Trust Company, Inc.

Authorized: Unlimited number of common shares and unlimited number of first and second preferred shares

Issued: 131,039,435 common shares at December 31, 2002

PREFERRED SECURITIES

Trustee: JP Morgan Chase Bank, New York

Issued: TLM PrA 6,000,000 9% Preferred Securities each having principal amount of US$25

Issued: TLM PrB 6,000,000 8.9% Preferred Securities each having principal amount of US$25

Talisman's Preferred Securities are currently rated as:
Dominion Bond Rating Service – Pfd-3 (high);
Moody's – Baa3; S&P – BBB-

STOCK EXCHANGE LISTINGS

COMMON SHARES

Symbol: **TLM**
Canada: The Toronto Stock Exchange
United States: New York Stock Exchange

PREFERRED SECURITIES

Symbol: **TLM PrA, TLM PrB**
United States: New York Stock Exchange

PUBLIC DEBT

Trustee: Computershare Trust Company of Canada
7.125% (US$) unsecured debentures
9.80% unsecured debentures, Series B
7.25% (US$) unsecured debentures
5.70% unsecured medium term notes
8.06% unsecured medium term notes
5.80% unsecured medium term notes
Trustee: JP Morgan Chase, London
6.625% (£) unsecured notes
Talisman's commercial paper is currently rated as:
Moody's – P-2
Talisman's public long-term debt is currently rated as:
Dominion Bond Rating Service – BBB (high);
Moody's – Baa1; S&P – BBB+

PRIVATE DEBT

6.71% (US$) unsecured notes, Series A
6.96% (US$) unsecured notes
6.89% (US$) unsecured notes, Series B
6.68% (US$) unsecured notes

DIVIDENDS

In June and December 2002, the Company paid a semi-annual dividend of $0.30 per share on Talisman's common shares.

MARKET INFORMATION

COMMON SHARES		2002		2001		2000	
		TSX (C$)	**NYSE (US$)**	TSX (C$)	NYSE (US$)	TSX (C$)	NYSE (US$)
Share Price (dollars)	High	**70.09**	**45.70**	65.77	42.30	58.85	39.75
	Low	**51.30**	**32.10**	46.51	29.76	34.40	23.88
	Close	**56.85**	**36.17**	60.50	37.85	55.65	37.06
Shares Traded (millions)	First quarter	**26.4**	**7.9**	42.2	7.9	43.3	4.3
	Second quarter	**28.0**	**8.6**	44.5	9.4	40.6	7.9
	Third quarter	**29.7**	**10.8**	35.3	8.5	40.3	7.7
	Fourth quarter	**51.3**	**15.4**	39.2	10.8	35.4	8.3
	Year	**135.4**	**42.7**	161.2	36.7	159.6	28.2
Year end shares outstanding (millions)		**131.0**		133.7		135.3	
Weighted average shares outstanding (millions)		**134.0**		134.9		137.8	
Year end stock options outstanding (millions)		**7.4**		7.5		6.9	

Corporate Information

EXECUTIVE OFFICE

Talisman Energy Inc.
3400, 888 - 3rd Street S.W.
Calgary, Alberta, Canada T2P 5C5
Telephone: (403) 237-1234
Facsimile: (403) 237-1902

WEBSITE

www.talisman-energy.com
E-mail: tlm@talisman-energy.com

SELECTED FIELD OFFICES

Talisman Energy (UK) Limited
Talisman House
163 Holburn Street
Aberdeen AB10 6BZ
Scotland
Telephone: (1224) 352-500
Facsimile: (1224) 353-400

Talisman (Asia) Limited
Setiabudi Atrium Office, Suite 410
Jl. H.R. Rasuna Said Kav.62
Jakarta, 12920, Indonesia
Telephone: (021) 521-0654
Facsimile: (021) 521-0660

Talisman Malaysia Limited
Level 31
Menara Citibank
165 Jalan Ampang
50450 Kuala Lumpur, Malaysia
Telephone: (603) 2162 6970
Facsimile: (603) 2162 6972

Talisman (Trinidad) Petroleum Ltd.
4th Floor, PWC Building
11-13 Victoria Avenue
Port of Spain
Trinidad, West Indies
Telephone: (868) 625-1515
Facsimile: (868) 624-7999

INVESTOR RELATIONS CONTACTS

M. Jacqueline Sheppard
Executive Vice-President,
Corporate and Legal,
and Corporate Secretary
(403) 237-1183

David Mann
Manager, Investor Relations
and Corporate Communications
(403) 237-1196

ANNUAL MEETING

The annual meeting of shareholders of Talisman Energy Inc. will be held at 11:00 a.m. on Tuesday, May 6, 2003 in the Imperial Ballroom of the Hyatt Regency Calgary Hotel, 700 Centre Street South, Calgary, Alberta. Shareholders are encouraged to attend the meeting, but those who are unable to do so are requested to participate by voting, using one of three available methods: (i) by telephone, (ii) by Internet, or (iii) by signing and returning the form of proxy or voting instruction form mailed with this report.

Directors and Executive

BOARD OF DIRECTORS

David E. Powell [1,3,5]
Calgary, Alberta
Chairman, Talisman Energy Inc.

Douglas D. Baldwin [2,5]
Calgary, Alberta
Corporate Director

James W. Buckee [1,4]
Calgary, Alberta
President and Chief Executive Officer
Talisman Energy Inc.

Al L. Flood, C.M. [1,2]
Thornhill, Ontario
Corporate Director

Paul J. Hoenmans [2,3]
Aspen, Colorado
Corporate Director

Dale G. Parker [2,4]
Vancouver, British Columbia
Public Administration and Financial Institution Advisor

Roland Priddle [1,4,5]
Victoria, British Columbia
Consultant

Lawrence G. Tapp [3,5]
London, Ontario
Dean of Richard Ivey School of Business of University of Western Ontario

Stella M. Thompson [3,4]
Calgary, Alberta
Principal, Governance West Inc.
President, Stellar Energy Ltd.

Charles W. Wilson [6]
Evergreen, Colorado
Corporate Director

1 Member of Executive Committee
2 Member of Audit Committee
3 Member of Management Succession and Compensation Committee
4 Member of Pension Funds Committee
5 Member of Governance and Nominating Committee
6 Member of Audit Committee effective March 4, 2003

EXECUTIVE

James W. Buckee
President and Chief Executive Officer

Edward W. Bogle
Executive Vice-President, Exploration

T. Nigel D. Hares
Executive Vice-President, Frontier and International Operations

Joseph E. Horler
Executive Vice-President, Marketing

Michael D. McDonald
Executive Vice-President, Finance and Chief Financial Officer

Robert W. Mitchell
Executive Vice-President, North American Operations

Robert M. Redgate
Executive Vice-President, Corporate Services

M. Jacqueline Sheppard
Executive Vice-President, Corporate and Legal, and Corporate Secretary

Forward-Looking Statements

This Annual Report contains statements that constitute "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995.

How to recognize forward-looking statements

Forward-looking statements are included throughout this Annual Report including, among other places, under the headings "A Discussion with Dr. James Buckee" and "Management's Discussion and Analysis" and in the descriptions of the Company's worldwide properties. These statements include, among others, statements regarding:

- outlook of oil and gas prices,
- estimates of future sales and production,
- business plans for drilling, exploration and production,
- the estimated amounts and timing of capital expenditures,
- anticipated operating costs,
- anticipated future debt levels,
- royalty rates and exchange rates, or
- other expectations, beliefs, plans, goals, objectives, assumptions and statements about future events or performance.

Statements concerning oil and gas reserves contained in this Annual Report involve the implied assessment that the resources described can be profitably produced in the future, based on certain estimates and assumptions. Consequently, statements about oil and gas reserves may also be deemed to be forward-looking statements.

Often, but not always, forward-looking statements use words or phrases such as: "expects" or "does not expect", "is expected", "anticipates" or "does not anticipate", "plans", "estimates" or "estimated", "projected", "forecasts" or "intends", or state that certain actions, events or results "may", "could", "would", "might" or "will" be taken, occur or be achieved.

Risks related to forward-looking statements

Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements. These risks include the risks of the oil and gas industry, such as:

- operational risks in exploring for, developing and producing crude oil and natural gas,
- risks and uncertainties involving geology of oil and gas deposits,
- the uncertainty of reserve estimates,
- the uncertainty of estimates and projections relating to production, costs and expenses,
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures,
- fluctuations in oil and gas prices and foreign currency exchange rates, and
- health, safety and environmental risks.

Relevant risks also include, but are not limited to:

- uncertainties as to the availability and cost of financing,
- risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action in countries such as Indonesia, Malaysia, Vietnam, Sudan, Algeria or Colombia),
- the effect of United States sanctions against Sudan,
- the conditions that must be met before the Company's sale of its interest in the Greater Nile Oil Project in Sudan will close,
- general economic conditions,
- the effect of acts of, or actions against international terrorism, and
- the possibility that government policies may change or governmental approvals may be delayed or withheld.

Additional information on these and other factors which could affect the Company's operations or financial results are included in this Annual Report under the headings "Management's Discussion and Analysis – Liquidity and Capital Resources", "– Risks and Uncertainties" and "– Outlook". Additional information may also be found in the Company's other reports on file with Canadian securities regulatory authorities and the United States Securities and Exchange Commission ("SEC").

No obligation to update forward-looking statements

Forward-looking statements are based on the estimates and opinions of the Company's management at the time the statements are made. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Note to US Readers

The SEC normally permits oil and gas companies to disclose in their filings with the SEC only proved reserves that have been demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Accordingly, the probable reserves and the calculations with respect thereto included in this report do not meet the SEC's standards for inclusion in documents filed with the SEC.

Unless otherwise indicated, the financial statements and other Canadian financial information included in this Annual Report are presented in accordance with Canadian generally accepted accounting principles which differ from generally accepted accounting principles in the US. See note 18 to the consolidated financial statements for information concerning significant differences between Canadian and US generally accepted accounting principles.

Abbreviations

API	American Petroleum Institute
bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian dollars
EBITDAX	Earnings before interest, preferred security charges, income taxes, depreciation, depletion and amortization, impairment write downs, exploration and dry hole expense
FPSO	Floating, Production, Storage and Offloading Vessel
FSO	Floating, Storage and Offloading Vessel
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbls	million barrels
mmboe	million barrels of oil equivalent
mmcf	million cubic feet
Moody's	Moody's Investor Service
NYMEX	New York Mercantile Exchange
OECD	Organization of Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
S&P	Standard & Poor's Ratings Group
tcf	trillion cubic feet
UK	United Kingdom
US	United States of America
US$	United States dollars
WTI	West Texas Intermediate
£	Pound Sterling

CONVERSION & EQUIVALENCY FACTORS

Imperial		Metric
1 ton	=	0.907 tonnes
1 acre	=	0.40 hectares
1 barrel	=	0.159 cubic metres
1 cubic foot	=	0.0282 cubic metres

Barrels of oil equivalent have been calculated on the basis of six mcf of natural gas equals one barrel of oil equivalent.

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Algeria photographs on page 16 courtesy Burlington Resources Inc.

TALISMAN

ENERGY

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