U.S. SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 40-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

☑ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2004

Commission File Number 1-4307

Husky Energy Inc.

(Exact name of Registrant as specified in its charter)

Alberta, Canada	**1311**	**Not applicable.**
(Province or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification No.)*

707 – 8th Avenue S.W.
PO Box 6525 Station D
Calgary, Alberta, Canada T2P 3G7
(403) 298-6111
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 Eighth Avenue, New York, New York 10011
(212) 894-8400
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:
None

Securities registered or to be registered pursuant to Section 12(g) of the Act:
None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
6.15% Notes due 2019

For annual reports, indicate by check mark the information filed with this Form:

☑ Annual information form ☑ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

The Registrant had 423,736,414 Common Shares outstanding at December 31, 2004

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the ''Exchange Act''). If ''Yes'' is marked, indicate the filing number assigned to the Registrant in connection with such Rule. Yes ☐ No ☑

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

This Annual Report on Form 40-F shall be incorporated by reference into the Registrant's Registration Statement on Form F-9 (File No. 333-117972).

Except where otherwise indicated, all dollar amounts stated in this Annual Report on Form 40-F are Canadian dollars.

Principal Documents

The following documents have been included as part of this Annual Report on Form 40-F:

A. Annual Information Form for the year ended December 31, 2004

B. Consolidated audited financial statements for the year ended December 31, 2004, including the report of independent chartered accountants with respect thereto. For a reconciliation of important differences between Canadian and United States generally accepted accounting principles, see Note 20 of the Notes to the Consolidated Financial Statements.

C. Management's Discussion and Analysis for the year ended December 31, 2004.

Controls and Procedures

A. Disclosure Controls and Procedures

The Registrant's Chief Executive Officer and Chief Financial Officer (its principal executive officer and principal financial officer, respectively) have concluded, based on their evaluation as of the end of the period covered by this Annual Report on Form 40-F (the ''evaluation date''), that the Registrant's disclosure controls and procedures are effective to ensure that information required to be disclosed by it in reports filed or submitted by it under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by it in such reports is accumulated and communicated to the Registrant's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

It should be noted that while the registrant's principal executive officer and principal financial officer believe that the registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the registrant's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

B. Changes in Internal Control Over Financial Reporting

There have been no significant changes to the Registrant's internal control over financial reporting or in other factors that could significantly affect internal control over financial reporting subsequent to the evaluation date and prior to the filing date of this Annual Report on Form 40-F.

Audit Committee Financial Expert

The Registrant's Board of Directors has determined that R. Donald Fullerton is an audit committee financial expert (as defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its audit committee. Pursuant to paragraph 8(a)(2) of General Instruction B to Form 40-F, the Board has applied the definition of independence applicable to the audit committee members of the New York Stock Exchange listed companies. Mr. Fullerton is a corporate director and is independent under the New York Stock Exchange standard. For a description of Mr. Fullerton's relevant experience in financial matters, see Mr. Fullerton's five year history in the section ''Directors and officers'' in the Registrant's Annual Information Form for the year ended December 31, 2004, which is included as document A to this Annual Report on Form 40-F.

Code of Ethics

The Registrant's code of ethics is disclosed in its Code of Business Conduct, which is applicable to all its employees, and is posted on its website at www.huskyenergy.ca. In the event that the Registrant:

(i) amends any provision of its Code of Business Conduct that applies to the Registrant's principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to any element of the code of ethics definition enumerated in paragraph (9)(b) of General Instruction B to Form 40-F, or

(ii) grants a waiver, including an implicit waiver, from a provision of its Code of Business Conduct to any of the Registrant's principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to any element of the code of ethics definition as enumerated in paragraph (9)(b) of General Instruction B to Form 40-F,

the Registrant will disclose on its website any amendment to, or waiver of, a provision of its Code of Business Conduct within five business days following the date of any such amendment or waiver that relates to the items set forth above. Such disclosure will specifically describe the nature of the amendment or waiver, and will, in the case of a waiver, name the person to whom the waiver was granted.

Principal Accountant Fees and Services

See ''Audit Committee'' in the Registrant's Annual Information Form for the year ended December 31, 2004, which is included as Document A to this Annual Report on Form 40-F.

Off-Balance Sheet Arrangements

See ''Off-Balance Sheet Arrangement'' in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2004, which is included as Document C to this Annual Report on Form 40-F.

Contractual Obligations and Commercial Commitments

See ''Contractual Obligations and Commercial Commitments'' in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2004, which is included as Document C to this Annual Report on Form 40-F.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when required to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

Consent to Service of Process

A Form F-X signed by the Registrant and its agent for service of process was filed with the Commission together with the Registrant's Annual Report on Form 40-F for the fiscal year ended December 31, 2001.

Any change to the name and address of the agent for service for service of process of the Registrant shall be communicated promptly to the Securities and Exchange Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

SIGNATURE

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

HUSKY ENERGY INC.

By: /s/ Neil D. McGee

Name: Neil D. McGee
Title: Vice President & Chief Financial Officer

By: /s/ James D. Girgulis

Name: James D. Girgulis
Title: Vice President, Legal & Corporate Secretary

March 16, 2005

Document A
Form 40-F

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2004

HUSKY ENERGY INC.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2004

March 16, 2005

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Unless otherwise indicated, all financial information is in accordance with accounting principles generally accepted in Canada. Unless otherwise indicated, gross reserves or gross production are reserves or production attributable to Husky's interest prior to deduction of royalties; net reserves or net production are reserves or production net of such royalties. Gross or net production reported refers to sales volume, unless otherwise indicated. Natural gas volumes are converted to a boe basis using the ratio of six mcf of natural gas to one bbl of oil and natural gas liquids. Unless otherwise indicated, oil and gas commodity prices are quoted after the effect of hedging gains and losses. Natural gas volumes are stated at the official temperature and pressure basis of the area in which the reserves are located. The calculation of barrels of oil equivalent (boe) and thousands of cubic feet equivalent (mcfge) are based on a conversion rate of six thousand cubic feet to one barrel of oil.

Boes or mcfges may be misleading, particularly if used in isolation. A Boe conversion ratio of six mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

EXCHANGE RATE INFORMATION

Except where otherwise indicated, all dollar amounts stated in this Annual Information Form are Canadian dollars. The following table discloses various indicators of the Canadian/United States rate of exchange or the cost of a U.S. dollar in Canadian currency for the three years indicated.

	Year ended December 31,		
	2004	2003	2002
Year end	1.203	1.292	1.580
Low	1.178	1.292	1.519
High	1.397	1.575	1.605
Average	1.302	1.386	1.570

Notes:

(1) The exchange rates were as quoted by the Federal Reserve Bank of New York for the noon buying rate.

(2) The high, low and average rates were either quoted or calculated as of the last day of the relevant month.

DISCLOSURE OF EXEMPTION UNDER NATIONAL INSTRUMENT 51-101

Husky believes that comparability of its disclosures with those required in its major capital market, the United States, is important to many of the investors and prospective investors in its securities. Accordingly, we applied for and were granted an exemption by the Canadian securities regulators under the provisions of National Instrument 51-101 ''Standards of Disclosures for Oil and Gas Activities'' (''NI 51-101''). The exemption, under Section 8.4 of the Companion Policy to NI 51-101, permits us to substitute disclosures required by and consistent with those of the Securities and Exchange Commission (''SEC'') and the Financial Accounting Standards Board (''FASB'') in the United States in place of much of the disclosure expected by NI 51-101. In accordance with the exemption, proved oil and gas reserves data and certain other disclosures with respect to our oil and gas activities in this Annual Information Form are presented in accordance with the following requirements:

- The FASB Statement No. 69 ''Disclosure about Oil and Gas Producing Activities — an amendment of FASB Statements No.'s 19, 25, 33 and 39'' (''FAS 69'');
- FASB Current Text Section Oi5, ''Oil and Gas Producing Activities'' paragraph .103, .106, .107, .108, .112, .160 through .167 and .174 through .184 and .401 through .408;
- SEC Industry Guide 2;
- SEC Item 102 of regulation S-K (17 CFR 229.102);
- SEC Item 302(b) of Regulation S-K (17 CFR 229.302(b)); and
- The definitions and disclosures required by SEC Regulation S-X (CFR 210.4-10).

Proved oil and gas reserves information and other disclosures about oil and gas activities in this Annual Information Form following SEC requirements may differ from corresponding information otherwise required by NI 51-101. Proved reserves disclosed in this Annual Information Form are in accordance with the SEC definitions.

NI 51-101 specifies that proved reserves be determined in accordance with the Canadian Oil and Gas Evaluation Handbook (''COGEH'') definitions. There were no material differences between the oil and gas reserves determined using the SEC definitions and the COGEH definitions. In addition, NI 51-101 requires the inclusion of probable reserves and their associated future net revenue. The SEC does not normally permit the disclosure of probable reserves in documents filed with them.

The SEC requires the evaluation of oil and gas reserves to be based on prices, costs, fiscal regimes and other economic and operating conditions in effect at the time the evaluation is made (''constant prices''). NI 51-101 also requires the evaluation of oil and gas reserves on this basis but also requires an evaluation of oil and gas reserves to be based on a forecast of economic conditions. In establishing the constant prices for bitumen NI 51-101 provides for a different interpretation of the phrase ''price will be the posted price of oil and the spot price of gas, after historical adjustments for transportation, gravity and other factors''. On January 20, 2005 the Canadian Securities Administrators issued Staff Notice 51-315 ''Guidance Regarding the Determination of Constant Prices for Bitumen Reserves under National Instrument 51-101 ''Standards of Disclosure for Oil and Gas Activities''. This guidance stipulates that for establishing the constant prices for bitumen companies should use the posted price for WTI and apply the average annual adjustment for transportation, gravity and other factors that create the difference in price between WTI and bitumen. This method was developed primarily in response to the fluctuations in bitumen prices that, for various reasons, tend to experience the lowest prices at the end of the calendar year. Under the FASB/SEC rules the determination of constant price for bitumen does not permit the use of annual average differentials between WTI and bitumen. These rules require the differentials prevailing on the last day of the period to be used to calculate the constant price. As a result on December 31, 2004 the price for bitumen as established under the FASB/SEC formula was lower than the price established under NI 51-101. There is no difference in determining the constant prices for crude oil classified as heavy oil, 10 to 20 degrees API, under NI 51-101 and FASB/SEC although heavy oil experiences the same pricing patterns as bitumen.

NI 51-101 prescribes a relatively comprehensive set of disclosures in respect of oil and gas reserves and other disclosures about oil and gas activities. In comparison, the SEC prescribes a minimum set of disclosures and advises not to approach the SEC rules and regulations as merely a blank form but encourages registrants to provide such additional information that is necessary to further an investor's understanding of the registrant's business.

Husky believes that its reserves evaluators are qualified and that it has a well established reserves evaluation process that is at least as rigorous as would be the case were we to rely upon independent reserves evaluators. Husky has adopted written evaluation practices and procedures using the COGE Handbook modified to the extent necessary to reflect the definitions and standards under U.S. disclosure requirements.

CORPORATE STRUCTURE

Husky Energy Inc.

Husky Energy Inc. (''Husky Energy'') was incorporated under the *Business Corporations Act* (Alberta) on June 21, 2000. From the date of its incorporation until August 25, 2000, Husky Energy did not carry on any business. On August 25, 2000, Husky Energy was a party to a plan of arrangement under the *Business Corporations Act* (Alberta) (the ''Arrangement'') pursuant to which Husky Oil Limited (''Husky Oil''), Husky Oil Operations Limited (a subsidiary of Husky Oil) and Renaissance Energy Ltd. (''Renaissance'') were amalgamated under the *Business Corporations Act* (Alberta) and continued as one corporation under the name ''Husky Oil Operations Limited'' (''HOOL'') and the securityholders of Renaissance and Husky Oil exchanged their securities for securities of Husky Energy. Under the Arrangement, Husky Energy acquired 100 percent of the common shares of HOOL.

Husky Energy has its registered office and its head and principal office at 707 — 8th Avenue S.W., P.O. Box 6525, Station D, Calgary, Alberta, T2P 3G7.

In this Annual Information Form the term ''Husky'', ''we'', ''our'', ''us'', and ''the Company'', means Husky Energy and its subsidiaries and partnership interests on a consolidated basis including information with respect to predecessor corporations.

Intercorporate Relationships

The principal subsidiaries of Husky and place of incorporation, continuance or place of organization, as the case may be, are as follows. All of the following companies are directly or indirectly 100 percent owned.

Name	Jurisdiction
Subsidiaries of Husky Energy Inc.	
Husky Oil Operations Limited	Nova Scotia
Subsidiaries of Husky Oil Operations Limited	
Husky Oil Limited	Nova Scotia
Husky Energy Marketing Inc.	Alberta
Husky (U.S.A.) Inc.	Delaware
HOI Resources Co.	Nova Scotia
Husky Energy International Sulphur Corporation	Alberta
Canterra Resources Canada Ltd. (formerly 147212 Canada Ltd.)	Canada
Subsidiaries of Husky (U.S.A.) Inc.	
Husky Gas Marketing Inc.	Delaware
Subsidiaries of HOI Resources Co.	
Husky Energy International Corporation	Canada
Subsidiaries of Husky Energy International Corporation	
Husky Oil China Ltd.	Alberta
Husky Oil (Madura) Ltd.	Alberta
Husky Oil Overseas Ltd.	Alberta

GENERAL DEVELOPMENT OF HUSKY

Three Year History

In January 2002, the Terra Nova development project commenced production. This project was the first Grand Banks field to be developed with a floating production, storage and offloading system. We have a 12.51 percent working interest in the Terra Nova oil field.

In June 2002, Husky issued U.S. $400 million of 6.25% senior notes due June 15, 2012. The notes were sold at a discount price of 99.545% per note to yield 6.312%. The notes were issued under a U.S. $1 billion base shelf prospectus dated June 6, 2002. The proceeds were used to repay existing bank indebtedness and for general corporate purposes.

On July 7, 2002, the Wenchang oil fields, 13-1 and 13-2, produced first oil. These oil fields produce light crude oil similar to the benchmark Minas blend from two production platforms into a floating production, storage and offloading vessel stationed between the two fields. We have a 40 percent interest in the Wenchang oil fields.

In September 2002, Husky signed contracts with the China National Offshore Oil Corporation (''CNOOC'') for two exploration blocks in the South China Sea. The 23/15 block comprises 1,327 square kilometres and the 23/20 block comprises 1,543 square kilometres. The contracts require one well to be drilled on each block within three years. CNOOC has the right to participate up to a 51 percent interest in any subsequent development.

In November 2002, we announced a significant discovery of natural gas at Shackleton, Saskatchewan. The Company announced that development of the Shackleton area could add 250 bcf to proved reserves within two to three years. Husky held more than 400 sections of land comprising 300,000 acres in this area in 2002.

In December 2002, Husky signed a contract with CNOOC for the 40/30 exploration block in the South China Sea. The block comprises approximately 6,704 square kilometres and the contract requires one well to be drilled within three years. CNOOC has the right to participate up to a 51 percent interest in any subsequent development.

In December 2002, Husky swapped, with its co-venturer, its working interest in the mining portion of its Kearl oil sands property for its co-venturer's interest in the in-situ portion of the property. As a result Husky now holds 100% working interest in 57,600 acres of lands with in-situ potential. Husky's property has been named ''Sunrise.''

Effective October 1, 2003, Husky purchased all of the outstanding common shares of Marathon Canada Limited (''Marathon'') and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. The total purchase price was U.S.$588 million. In a separate concurrent transaction Husky sold certain of the Marathon properties to another unrelated company for total proceeds of U.S.$320 million. The properties retained by Husky are located throughout western Alberta and north-eastern British Columbia. The acquisition added approximately 39.8 mmboe of gross proved reserves, of which 75% was natural gas, and 729,000 acres of undeveloped lands in Alberta, British Columbia and the Northwest Territories.

In November 2003, Husky announced that it had signed a contract with CNOOC for the 04/35 exploration block in the East China Sea. The block comprises 4,835 square kilometres and requires one well to be drilled within the first three years of the contract. CNOOC has the right to participate up to a 51 percent interest in any subsequent development.

In November 2003, we established a securitization program to sell, on a revolving basis, up to $250 million of its accounts receivable to a third party. The agreement includes a program fee based on Canadian commercial paper rates.

On June 18, 2004 Husky issued U.S. $300 million of 6.15 percent notes due June 15, 2019. The notes were priced to yield 6.194 percent and are redeemable at the option of the Company at any time subject to a make-whole provision. The notes are unsecured and unsubordinated and rank equally with all its other unsecured and unsubordinated indebtedness.

In August 2004 Husky filed a base shelf prospectus that permits issue of up to U.S. $1 billion of debt securities or the equivalent in other currencies during the 25 months that the prospectus is in effect.

Effective July 15, 2004, Husky acquired Temple Exploration Inc. for a cash purchase of $101.5 million plus the assumption of $13.5 million working capital deficit. The acquisition added 21.1 bcf of natural gas and 1.4 million barrels of natural gas liquids to proved reserves as well as undeveloped land.

On August 16, 2004 we signed a production sharing agreement with the CNOOC for the 3,900 square kilometre 29/26 block in the South China Sea. The agreement requires us to drill one exploration well with the option to drill two additional exploration wells before 2011. CNOOC has the right to participate in subsequent development up to 51 percent.

On October 26, 2004 we announced an agreement to acquire our co-venturer's interest in the Madura Strait production sharing agreement in Indonesia. Husky now holds a 100 percent interest in the 2,794 square kilometre exploration block, which contains two discoveries with commercial quantities of recoverable natural gas and natural gas liquids.

In November 2004, Husky acquired three exploration licenses in the Jeanne d'Arc Basin offshore Newfoundland and Labrador. We acquired a 50 percent working interest in 225,100 acres, a 100 percent working interest in 128,800 acres and a 100 percent working interest in 208,200 acres. All three parcels are near Husky's White Rose oil field currently under development.

Business Environment Trends

There are a number of trends that are developing, which may have both long and short-term effects on the oil and gas industry in Canada. Conventional production of crude oil in the Western Canada Sedimentary Basin (''WCSB'') has been in decline since 2000 and will, according to industry forecasts[(1)], continue to decline. Since 2000 increased crude oil production from the WCSB has come from mining and in-situ production of bitumen and heavy crude oils. Non-conventional production of crude oil is forecast[(1)] to increase overall crude oil production from the WCSB beyond current production levels. Natural gas discoveries in the WCSB have, in the past few years, been made in smaller reservoirs. Natural gas exploration efforts in the WCSB are focused on the traditionally less accessible areas in the overthrust belt along the eastern slope of the Rocky Mountains, in the Northwest Territories, offshore the east coast of Canada, smaller shallow gas deposits and coal bed methane.

The trend of volatile commodity prices continues and it is expected will continue. Natural gas prices are sensitive to regional supply/demand imbalances, regional industrial activity levels, weather patterns and access to cheaper sources of energy. Oil prices are clearly dependent on the world economy and stable supply. As a result of numerous supply disruptions and increased demand from China and India oil prices have remained higher than OPEC's U.S. $22.00-$28.00 per bbl price band for more than a year. On January 30, 2005 OPEC announced it was temporarily suspending its price band subject to further consideration.

DESCRIPTION OF HUSKY'S BUSINESS

General

Husky is a publicly held integrated energy and energy related company headquartered in Calgary, Alberta. Our operations include the exploration for and development of crude oil and natural gas properties, as well as the production, purchase, transportation, storage and marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke, and the upgrading and refining of crude oil and marketing of refined petroleum products, including gasoline, diesel, alternative fuels and asphalt products.

Upstream Operations

Husky's portfolio of assets includes properties that produce light (30° API and lighter), medium (between 20° and 30° API) and heavy (below 20° and above 10° API) gravity crude oil, NGL, natural gas and sulphur. As operator of the majority of its properties Husky exercises a high degree of control in its upstream operations. We have production, gathering and processing facilities throughout the WCSB. In the Lloydminster heavy oil prone area Husky has a well established position with concentrated landholdings, production, gathering and processing facilities, as well as heavy crude oil pipeline, upgrading and refining facilities.

At December 31, 2004, we were the operator of properties which accounted for approximately 87 percent of our total gross production in Western Canada. Our undeveloped landholdings in the WCSB totalled 6.7 million net acres or 54 percent of total net land holdings at December 31, 2004.

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(1) ''Canadian Crude Oil Production and Supply forecast'', July 2004, Canadian Association of Petroleum Producers ''Oil Sands Technology Roadmap'', January 30, 2004, Alberta Chamber of Resources.

In the foothills deep basin areas in Alberta, we operate the Ram River gas plant and have interests in properties that supply this plant including: Blackstone, Ricinus, Limestone, Clearwater, Benjamin, Brown Creek and Stolberg. We also have an interest in the Caroline gas plant and field. Further north we have interests in the Valhalla and Wapiti crude oil and natural gas fields near Grand Prairie and properties in the Galloway, Ansell and Edson area. In north-eastern British Columbia, we hold natural gas interests in the Sikanni and Federal area as well as Boundary Lake.

In the plains region of north-west Alberta, we operate the Rainbow Lake Plant, miscible floods and properties in surrounding areas. We have interests in the Peace River Arch, Boyer, Sloat Creek, Marten Hills, Cherpeta and Simons Lake areas. In the east central region of Alberta, we have property holdings east of Calgary and around Red Deer and Edmonton including major properties at Hussar and Provost.

In southern Alberta and Saskatchewan we have extensive property holdings around Taber, Brooks, Jenner and Suffield in southern Alberta and throughout south-west Saskatchewan at Shackleton/Lacadena, Cantaur, Fosterton and Carnduff.

We have extensive experience in development, production, transportation and upgrading of heavy crude oil. We also have experience in enhanced recovery of crude oil and horizontal drilling, as well as in natural gas exploration in the deep basin, foothills and along the eastern slopes of the Canadian Rocky Mountains, also known as the overthrust belt.

On the east coast of Canada we hold a 12.51 percent working interest in the Terra Nova oil field, which began producing light crude oil in January 2002, and a 72.5 percent working interest in the White Rose oil field, which was sanctioned by the co-venturers in March 2002 and is currently under development. First oil from the White Rose oil field is currently expected by the end of 2005 or early 2006. We also hold interests in several exploration and significant discovery licenses in the Jeanne d'Arc Basin and the South Whale Basin.

We hold a 40 percent working interest in the Wenchang oil fields located offshore in the South China Sea. Production at the Wenchang oil fields began in July 2002. We also hold interests in five exploration blocks in the South China Sea with an aggregate areal extent of approximately 17,800 square kilometres and one exploration block in the East China Sea of approximately 4,800 square kilometres.

Husky also holds an interest in a natural gas and liquids production sharing contract located in the Madura strait offshore Java, Indonesia.

Midstream Operations

Husky's midstream operations include upgrading of heavy crude oil feedstock into synthetic crude oil, pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas, and cogeneration of electrical and thermal energy, and marketing of Husky's and third party produced crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.

Refined Products

Husky's refined products operations include refining of heavy and light crude oil, marketing of refined petroleum products, including asphalt and alternate fuels, and processing of grain primarily for ethanol production. Husky sells and distributes transportation fuels including ethanol blended fuels through independently operated Husky and Mohawk branded petroleum outlets, including service stations, truck stops and bulk distribution facilities located from the west coast of Canada to the eastern border of Ontario, some of which include 24 hour restaurants, convenience stores, service bays, car washes, fast food sales, bank machines and propane sales.

Social and Environmental Policy

Husky's environmental policy requires regular environmental audits to be conducted at its sites and facilities. Husky has established procedures designed to anticipate and minimize adverse effects of its operations on the environment and for continued compliance with environmental legislation and minimize future and current costs. Husky's policies apply equally to employees, subsidiaries and contractors.

Risk Factors

The following factors should be considered in evaluating Husky:

Adequacy of crude oil and natural gas prices

Husky's results of operations and financial condition are dependent on the prices received for its crude oil and natural gas production.

Prices for crude oil are based on world supply and demand. Supply and demand can be affected by a number of factors including, but not limited to, actions taken by the OPEC and their adherence to agreed production quotas, non-OPEC crude oil supply, social conditions in oil producing countries, the occurrence of natural disasters, general and specific economic conditions, prevailing weather patterns and the availability of alternate sources of energy.

Husky's natural gas production is located entirely in Western Canada and is, therefore, subject to North American market forces. North American natural gas supply and demand is affected by a number of factors including, but not limited to, the amount of natural gas available to specific market areas either from the well head or from storage facilities, prevailing weather patterns, the price of crude oil, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions.

Demand for Husky's other products and services and the cost of required inputs

Husky's results of operations and financial condition are dependent on the price of refinery feedstock, the price of energy, the demand for refined petroleum products and electrical power and the ability of Husky to recover the increased cost of these inputs from the customer. Husky is also dependent on the demand for Husky's pipeline and processing capacity.

Husky's ability to replace reserves

Husky's future cash flow and cost of capital are dependent on its ability to replace its proved oil and gas reserves in a cost effective manner. Without economic reserve additions through exploration and development or acquisition Husky's production and, therefore, cash flow will decline. Without adequate proved reserves Husky's ability to fund development and other capital expenditures with external sources of funds is diminished.

Competition

The energy industry is highly competitive. Husky competes with others to acquire additional prospective lands, to retain drilling capacity and field operating and construction services, to attract and retain experienced skilled management and oil and gas professionals, to obtain sufficient pipeline and other transportation capacity and to gain access to and retain adequate markets for Husky's products and services. Husky's competitors comprise all types of energy companies, some of which have greater resources.

Environmental risks

All phases of the oil and natural gas business are subject to environmental regulation pursuant to a variety of federal, provincial and municipal laws and regulations, as well as international conventions (collectively, ''environmental legislation'').

Environmental legislation imposes, among other things, restrictions, liabilities, and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that wells, facilities and other properties associated with Husky's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean-up costs and damages. Husky cannot be certain that the costs of complying with environmental legislation in the future will not have a material adverse effect on Husky's financial condition and results of operations.

Husky anticipates that changes in environmental legislation may require, among other things, reductions in emissions from its operations and result in increased capital expenditures. Further changes in environmental legislation

could occur, which may result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on Husky's financial condition and results of operations.

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol, which requires the reduction of greenhouse gas emissions. On December 16, 2002, Canada ratified the Kyoto Protocol. This initiative may require Husky to significantly reduce emissions at its operations of green house gases such as carbon dioxide, which may increase capital expenditures. Details regarding the implementation of the Kyoto Protocol remain unclear.

Uncertainty of oil and gas proved reserves estimates

There are numerous uncertainties inherent in estimating quantities of oil and natural gas reserves, including many factors beyond Husky's control. The reserves information included in and incorporated by reference in this Annual Information Form are Husky's estimates. In general, estimates of economically recoverable oil and natural gas reserves and the estimated future net cash flow therefrom are based on a number of variables in effect as of date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the actual effects of regulation by governmental agencies and the actual future commodity prices and operating costs, all of which may vary considerably from those in effect at the date the reserves were determined. The estimated quantities of reserves expected to be recovered are uncertain and the classification of reserves as proved is only an attempt to define the degree of certainty involved. For these reasons, estimates of economically recoverable oil and natural gas attributable to a particular group of properties, the classification of such reserves as proved and the resultant future net cash flow therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Husky's actual production, revenues, taxes and development, abandonment, and operating expenditures with respect to its estimated oil and natural gas reserves may vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future (proved developed reserves) are often based on volumetric calculations and upon analogy to similar types of reservoirs, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history may result in variations in the estimated reserves, which may be material.

Upstream Operations — Disclosures for Oil and Gas Activities

Production

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
			Crude oil — mbbls/day Natural gas — mmcf/day			
Crude Oil						
Light crude oil and NGL	66.2	32.7	13.7	46.4	19.7	0.1
Medium crude oil	35.0	35.0	—	35.0	—	
Heavy crude oil	108.9	108.9	—	108.9	—	
Total gross	210.1	176.6	13.7	190.3	19.7	0.1
Total net	183.9	153.0	13.2	166.2	17.6	0.1
Natural Gas						
Gross	689.2	689.2	—	689.2	—	—
Net	524.0	524.0	—	524.0	—	—

Production (continued)

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
	Crude oil — mbbls/day Natural gas — mmcf/day					
Crude Oil						
Light crude oil and NGL	71.6	32.2	16.8	49.0	22.4	0.2
Medium crude oil	39.2	39.2	—	39.2	—	
Heavy crude oil	99.9	99.9	—	99.9	—	
Total gross	210.7	171.3	16.8	188.1	22.4	0.2
Total net	186.8	149.5	16.7	166.2	20.4	0.2
Natural Gas						
Gross	610.6	610.6	—	610.6	—	—
Net	473.7	473.7	—	473.7	—	—

	2002					
	Total	Western Canada	East Coast	Canada	China	Libya
	Crude oil — mbbls/day Natural gas — mmcf/day					
Crude Oil						
Light crude oil and NGL	65.4	39.8	13.2	53.0	12.2	0.2
Medium crude oil	44.8	44.8	—	44.8	—	—
Heavy crude oil	95.1	95.1	—	95.1	—	—
Total gross	205.3	179.7	13.2	192.9	12.2	0.2
Total net	179.3	154.8	12.8	167.6	11.5	0.2
Natural Gas						
Gross	569.2	569.2	—	569.2	—	—
Net	426.6	426.6	—	426.6	—	—

Notes:

(1) Light crude oil includes crude oil that is lighter than 30°API, medium crude oil is between 20° and 30°API gravity and heavy crude oil includes crude oil that is lower than 20° API and lighter than 10° API gravity in the Lloydminster area.

(2) Gross volumes are Husky's lessor royalty, overriding royalty and working interest share of production before deduction of royalties. Net volumes are Husky's gross volumes, less royalties.

Revenue

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
	($ millions)					
Crude Oil						
Light crude oil and NGL	967	474	148	622	343	2
Medium crude oil	462	462	—	462	—	—
Heavy crude oil	757	757	—	757	—	—
Total gross	2,186	1,693	148	1,841	343	2
Total net	1,824	1,375	139	1,514	308	2
Natural Gas						
Gross	1,596	1,596	—	1,596	—	—
Net	1,248	1,248	—	1,248	—	—
Processing	48	48	—	48	—	—

Revenue (continued)

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
	($ millions)					
Crude Oil						
Light crude oil and NGL	879	300	238	538	338	3
Medium crude oil	556	556	—	556	—	—
Heavy crude oil	943	943	—	943	—	—
Total gross	2,378	1,799	238	2,037	338	3
Total net	2,082	1,539	233	1,772	307	3
Natural Gas						
Gross	1,346	1,346	—	1,346	—	—
Net	1,058	1,058	—	1,058	—	—
Processing	46	46	—	46	—	—

	2002					
	Total	Western Canada	East Coast	Canada	China	Libya
	($ millions)					
Crude Oil						
Light crude oil and NGL	866	494	171	665	198	3
Medium crude oil	496	496	—	496	—	—
Heavy crude oil	924	924	—	924	—	—
Total gross	2,286	1,914	171	2,085	198	3
Total net	1,974	1,616	169	1,785	186	3
Natural Gas						
Gross	801	801	—	801	—	—
Net	653	653	—	653	—	—
Processing	38	38	—	38	—	—

Note:

(1) Light crude oil includes crude oil that is lighter than 30°API, medium crude oil is between 20° and 30°API gravity and heavy crude oil includes crude oil that is lower than 20° API and lighter than 10° API gravity in the Lloydminster area.

Sales Prices

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
	$/bbl $/mcf					
Crude Oil						
Light crude oil and NGL	48.34	49.35	47.87	49.64	47.66	57.88
Medium crude oil	36.13	36.13	—	36.13	—	—
Heavy crude oil	28.66	28.66	—	28.66	—	—
Total crude oil and NGL (before hedging)	36.07	33.85	47.87	34.90	47.66	57.88
Total crude oil and NGL (after hedging)	28.43	26.19	29.45	26.42	47.66	57.88
Natural Gas						
Before hedging	6.25	6.25	—	6.25	—	—
After hedging	6.24	6.24	—	6.24	—	—

Sales Prices (continued)

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
			$/bbl $/mcf			
Crude Oil						
Light crude oil and NGL	39.53	38.28	38.91	38.49	41.45	40.44
Medium crude oil	31.42	31.42	—	31.42	—	—
Heavy crude oil	25.87	25.87	—	25.87	—	—
Total crude oil and NGL (before hedging)	31.54	29.48	38.91	30.32	41.45	40.44
Total crude oil and NGL (after hedging)	30.93	28.96	36.96	29.67	41.45	40.44
Natural Gas						
Before hedging	5.86	5.86	—	5.86	—	—
After hedging	5.94	5.94	—	5.94	—	—

	2002					
	Total	Western Canada	East Coast	Canada	China	Libya
			$/bbl $/mcf			
Crude Oil						
Light crude oil and NGL	36.17	33.86	35.47	34.26	44.36	40.37
Medium crude oil	30.16	30.16	—	30.16	—	—
Heavy crude oil	26.60	26.60	—	26.60	—	—
Total crude oil and NGL (before hedging)	30.47	29.14	35.47	29.57	44.36	40.37
Total crude oil and NGL (after hedging)	30.50	29.17	35.47	29.61	44.36	40.37
Natural Gas						
Before hedging	3.83	3.83	—	3.83	—	—
After hedging	3.83	3.83	—	3.83	—	—

Note:

(1) Light crude oil includes crude oil that is lighter than 30°API, medium crude oil is between 20° and 30° API gravity and heavy crude oil includes crude oil that is lower than 20° API and lighter than 10° API gravity in the Lloydminster area.

Capital Expenditures

	2004						
	Total	Western Canada	East Coast/ Frontier	Canada	China	Indonesia	Libya
				($ millions)			
Property acquisition (1)	116	54	—	54	—	62	—
Exploration	313	271	24	295	18	—	—
Development	1,728	1,208	515	1,723	5	—	—

	2003						
	Total	Western Canada	East Coast/ Frontier	Canada	China	Indonesia	Libya
				($ millions)			
Property acquisitions (2)	76	76	—	76	—	—	—
Exploration	324	274	24	298	26	—	—
Development	1,378	845	533	1,378	—	—	—

Capital Expenditures (continued)

	2002						
	Total	Western Canada	East Coast/ Frontier	Canada	China	Indonesia	Libya
				($ millions)			
Property acquisitions (3)	108	108	—	108	—	—	—
Exploration	266	216	41	257	9	—	—
Development	1,202	709	417	1,136	66	—	—

Notes:

(1) Does not include the acquisition of Temple Exploration Inc.

(2) Does not include the acquisition of Marathon Canada Limited.

(3) Does not include the acquisition of Titanium Oil & Gas Ltd. and Avid Oil & Gas Ltd.

Oil and Gas Netbacks (1)

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
			$/bbl $/mcf			
Crude Oil						
Light crude oil						
Sales revenue	46.95	46.12	47.87	46.63	47.66	57.88
Royalties	5.71	7.76	1.80	6.03	4.91	—
Operating costs	5.82	8.94	3.28	7.29	2.16	16.47
Netback before hedging	35.42	29.42	42.79	33.31	40.59	41.41
Netback after hedging	28.33	22.78	24.37	23.24	40.59	41.41
Medium crude oil						
Sales revenue	36.20	36.20	—	36.20	—	—
Royalties	6.10	6.10	—	6.10	—	—
Operating costs	10.07	10.07	—	10.07	—	—
Net back before hedging	20.03	20.03	—	20.03	—	—
Netback after hedging	20.03	20.03	—	20.03	—	—
Heavy crude oil						
Sales revenue	28.73	28.73	—	28.73	—	—
Royalties	3.38	3.38	—	3.38	—	—
Operating costs	9.33	9.33	—	9.33	—	—
Netback before hedging	16.02	16.02	—	16.02	—	—
Netback after hedging	6.45	6.45	—	6.45	—	—
Total crude oil						
Sales revenue	35.72	33.48	42.87	34.50	47.66	57.88
Royalties	4.58	4.75	1.80	4.54	4.91	—
Operating costs	8.36	9.41	3.28	8.97	2.16	16.47
Netback before hedging	22.78	19.32	42.79	20.99	40.59	41.41
Netback after hedging	15.64	12.25	24.37	13.11	40.59	41.41
Natural Gas						
Sales revenue	6.25	6.25	—	6.25	—	—
Royalties	1.44	1.44	—	1.44	—	—
Operating costs	0.89	0.89	—	0.89	—	—
Netback before hedging	3.92	3.92	—	3.92	—	—
Netback after hedging	3.91	3.91	—	3.91	—	—

Note:

(1) Netbacks reflect the results of operations for leases classified as oil or natural gas. Co-products, such as natural gas produced at an oil property or natural gas liquids produced at a natural gas property, have been converted to equivalent units of oil or natural gas depending on the lease product classification.

Oil and Gas Netbacks [1] ***(continued)***

	2003					
	Total	**Western Canada**	**East Coast**	**Canada**	**China**	**Libya**
			$/bbl $/mcf			
Crude Oil						
Light crude oil						
Sales revenue	40.17	39.91	38.91	39.55	41.45	40.44
Royalties	4.55	7.28	0.81	4.93	3.80	—
Operating costs	5.41	9.27	3.16	7.05	1.94	15.43
Netback before hedging	30.21	23.36	34.94	27.57	35.71	25.01
Netback after hedging	29.49	22.80	32.99	26.50	35.71	25.01
Medium crude oil						
Sales revenue	31.57	31.57	—	31.57	—	—
Royalties	5.28	5.28	—	5.28	—	—
Operating costs	9.53	9.53	—	9.53	—	—
Netback before hedging	16.76	16.76	—	16.76	—	—
Netback after hedging	14.97	14.97	—	14.97	—	—
Heavy crude oil						
Sales revenue	25.98	25.98	—	25.98	—	—
Royalties	2.76	2.76	—	2.76	—	—
Operating costs	9.09	9.09	—	9.09	—	—
Netback before hedging	14.13	14.13	—	14.13	—	—
Netback after hedging	14.13	14.13	—	14.13	—	—
Total crude oil						
Sales revenue	31.70	29.52	38.91	30.53	41.45	40.44
Royalties	3.83	4.14	0.81	3.84	3.80	—
Operating costs	7.97	9.23	3.16	8.68	1.94	15.43
Netback before hedging	19.90	16.15	34.94	18.01	35.71	25.01
Netback after hedging	19.32	15.63	32.99	17.36	35.71	25.01
Natural Gas						
Sales revenue	5.79	5.79	—	5.79	—	—
Royalties	1.29	1.29	—	1.29	—	—
Operating costs	0.79	0.79	—	0.79	—	—
Netback before hedging	3.71	3.71	—	3.71	—	—
Netback after hedging	3.79	3.79	—	3.79	—	—

Note:

(1) Netbacks reflect the results of operations for leases classified as oil or natural gas. Co-products, such as natural gas produced at an oil property or natural gas liquids produced at a natural gas property, have been converted to equivalent units of oil or natural gas depending on the lease product classification.

Oil and Gas Netbacks [1] ***(continued)***

	2002					
	Total	**Western Canada**	**East Coast**	**Canada**	**China**	**Libya**
			$/bbl $/mcf			
Crude Oil						
Light crude oil						
Sales revenue	36.22	33.66	35.47	34.15	44.36	40.37
Royalties	3.25	4.55	0.36	3.41	2.65	—
Operating costs	7.33	10.46	3.62	8.60	2.15	13.13
Netback before hedging	25.64	18.65	31.49	22.14	39.56	27.24
Netback after hedging	25.74	18.82	31.49	22.26	39.56	27.24
Medium crude oil						
Sales revenue	29.92	29.92	—	29.92	—	—
Royalties	5.59	5.59	—	5.59	—	—
Operating costs	7.19	7.19	—	7.19	—	—
Netback before hedging	17.14	17.14	—	17.14	—	—
Netback after hedging	17.33	17.33	—	17.33	—	—
Heavy crude oil						
Sales revenue	26.48	26.48	—	26.48	—	—
Royalties	3.45	3.45	—	3.45	—	—
Operating costs	7.18	7.18	—	7.18	—	—
Netback before hedging	15.85	15.85	—	15.85	—	—
Netback after hedging	15.85	15.85	—	15.85	—	—
Total crude oil						
Sales revenue	30.19	28.81	35.47	29.26	44.36	40.37
Royalties	3.87	4.22	0.36	3.96	2.65	—
Operating costs	7.23	7.84	3.62	7.54	2.15	13.13
Netback before hedging	19.09	16.75	31.49	17.76	39.56	27.24
Netback after hedging	19.16	16.83	31.49	17.84	39.56	27.24
Natural Gas						
Sales revenue	3.97	3.97	—	3.97	—	—
Royalties	0.81	0.81	—	0.81	—	—
Operating costs	0.70	0.70	—	0.70	—	—
Netback before hedging	2.46	2.46	—	2.46	—	—
Netback after hedging	2.46	2.46	—	2.46	—	—

Note:

(1) Netbacks reflect the results of operations for leases classified as oil or natural gas. Co-products, such as natural gas produced at an oil property or natural gas liquids produced at a natural gas property, have been converted to equivalent units of oil or natural gas depending on the lease product classification.

Producing Wells

	Oil Wells		Natural Gas Wells		Total	
	Gross (1)(2)	**Net** (1)	**Gross** (1)(2)	**Net** (1)	**Gross** (1)(2)	**Net** (1)
Canada						
Alberta	5,087	3,501	6,232	3,368	11,319	6,869
Saskatchewan	4,976	3,676	940	673	5,916	4,349
British Columbia	226	78	133	66	359	144
Manitoba	27	1	—	—	27	1
Newfoundland	12	2	—	—	12	2
	10,328	7,258	7,305	4,107	17,633	11,365
International						
China	21	8	—	—	21	8
Libya	2	1	—	—	2	1
	23	9	—	—	23	9
As at December 31, 2004	10,351	7,267	7,305	4,107	17,656	11,376
Canada						
Alberta	5,098	3,410	5,660	2,877	10,758	6,287
Saskatchewan	4,835	3,596	675	422	5,510	4,018
British Columbia	211	63	111	48	322	111
Manitoba	2	1	—	—	2	1
Newfoundland	8	1	—	—	8	1
	10,154	7,071	6,446	3,347	16,600	10,418
International						
China	21	8	—	—	21	8
Libya	2	1	—	—	2	1
	23	9	—	—	23	9
As at December 31, 2003	10,177	7,080	6,446	3,347	16,623	10,427

Notes:

(1) The number of gross wells is the total number of wells in which Husky owns a working interest. The number of net wells is the sum of the fractional interests owned in the gross wells. Producing wells were producing or capable of producing at December 31.

(2) 2004 includes 482 gross, 411 net oil wells and 538 gross, 337 net natural gas wells and 2003 includes 271 gross, 241 net oil wells and 424 gross, 207 net natural gas wells which were completed in two or more formations and from which the production is not commingled. For the purposes of this table, multiple completions are counted as single wells. Where one of the completions in a given well is an oil completion, the well is classified as an oil well.

Landholdings

Developed landholdings

	Developed Acreage	
	Gross	**Net**
	(thousands of acres)	
As at December 31, 2004		
Western Canada		
Alberta	3,200	2,687
Saskatchewan	567	506
British Columbia	186	110
Manitoba	—	—
	3,953	3,303
Northwest Territories and Artic	7	1
Eastern Canada	35	4
Total Canada	3,995	3,308
China	17	7
Libya	7	2
	4,019	3,317
As at December 31, 2003		
Western Canada		
Alberta	3,208	2,684
Saskatchewan	550	485
British Columbia	161	92
Manitoba	1	1
	3,920	3,262
Eastern Canada	35	4
Total Canada	3,955	3,266
China	17	7
Libya	7	2
	3,979	3,275

Undeveloped landholdings

	Undeveloped Acreage	
	Gross	Net
	(thousands of acres)	
As at December 31, 2004		
Western Canada		
Alberta	4,983	4,449
Saskatchewan	1,831	1,669
British Columbia	787	544
Manitoba	7	7
	7,608	6,669
Northwest Territories and Arctic	924	254
Eastern Canada	3,154	2,104
Total Canada	11,686	9,027
International	6,280	3,429
	17,966	12,456
As at December 31, 2003		
Western Canada		
Alberta	5,508	4,852
Saskatchewan	2,057	1,911
British Columbia	713	491
Manitoba	9	8
	8,287	7,262
Northwest Territories and Arctic	527	184
Eastern Canada	2,414	2,104
Total Canada	11,228	9,550
International	4,464	2,066
	15,692	11,616

Drilling Activity

	Year ended December 31					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Western Canada Drilling						
Exploration						
Oil	45	39	12	11	21	20
Gas	234	180	147	124	139	131
Dry	34	33	22	21	15	14
	313	252	181	156	175	165
Development						
Oil	552	499	520	490	497	453
Gas	807	740	540	518	485	453
Dry	57	53	60	57	58	55
	1,416	1,292	1,120	1,065	1,040	961
	1,729	1,544	1,301	1,221	1,215	1,126

Present Activities

Wells Drilling (1)	Exploratory Gross	Exploratory Net	Development Gross	Development Net
Western Canada	11	8.6	29	26.9
East Coast	—	—	1	0.1
China	—	—	—	—
	11	8.6	30	27.0

Note:

(1) Denotes wells that were drilling at December 31, 2004.

Reserves Data and Other Oil and Gas Information

Husky's oil and gas reserves as of December 31, 2004 are based on constant prices and costs as prepared internally by Husky's engineers. Husky uses a formalized process for determining, approving and booking reserves. This process provides for all reserves evaluation to be done on a consistent basis using established definitions and guidelines. Approval of any significant reserve additions and changes requires review by an internal panel of qualified technical experts.

Audit of Oil and Gas Reserves

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the COGEH.

Oil and Gas Reserves Data

The following table presents in summary Husky's proved developed reserves, proved undeveloped reserves and associated future net cash flows as at December 31, 2004. Future revenues, based on constant prices and costs, are presented net of royalties. Estimated future net revenues based on constant prices and costs assume continuation of year end economic conditions including market demand and government policy, which are subject to uncertainty and may differ materially in the future. It should not be assumed that the discounted value of estimated future net reserves is representative of the fair market value of the reserves.

Proved Reserves

	Crude Oil & NGL (1)		Natural Gas (1)		Future Net Cash Flows Before Tax (1)(4)	
	Gross (2)	Net (2)	Gross (2)	Net (2)	0%	10%
	(mmbbls)		(bcf)		($ millions)	
Proved developed (3)	362	317	1,745	1,436	11,891	7,114
Proved undeveloped (3)(5)	67	58	424	352	2,268	1,184
Proved total (3)	429	375	2,169	1,788	14,159	8,298
Heavy oil price revision (6)	120	112	3	3		
	549	487	2,172	1,791		

Notes:

(1) Husky applied for and was granted an exemption from National Instrument 51-101 ''Standards of Disclosure for Oil and Gas Activities'' to provide oil and gas reserves disclosures in accordance with the U.S. Securities and Exchange Commission guidelines and the U.S. Financial Accounting Standards Board disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101. Husky's internally generated oil and gas reserves data was audited by an independent firm of consulting engineers.

(2) Gross reserves are Husky's lessor royalty, overriding royalty and working interest share of reserves, before deduction of royalties. Net reserves are gross reserves, less royalties.

(3) These reserve categories have the same meanings as those set out in SEC Regulation S-X.

(4) The discounted future net cash flows at December 31, 2004 were based on the year-end spot NYMEX natural gas price of U.S. $6.02/mmbtu and on a spot WTI crude oil price of U.S. $43.36/bbl.

(5) Estimated future capital expenditures required to gain access to proved undeveloped reserves as at December 31, 2004 and 2003 were as follows:

	As at December 31, 2004						
	Total	2005	2006	2007	2008	2009	Thereafter
	($ millions undiscounted)						
Western Canada	651	218	210	107	34	13	69
Eastern Canada	352	390	19	9	11	4	(81)
	1,003	608	229	116	45	17	(12)

	As at December 31, 2003						
	Total	2004	2005	2006	2007	2008	Thereafter
Western Canada	697	282	201	76	40	24	74
Eastern Canada	14	12	2	—	—	—	—
	711	294	201	76	40	24	76

(6) On December 31, 2004, the date our oil and gas reserves were evaluated, the calculated price of Lloydminster heavy crude oil was $12.27 per barrel. In accordance with SEC regulation, reserves that were not economic at that price were required to be subtracted as a negative revision from proved reserves until prices increase sufficiently to return those reserves to economic status. For further discussion refer to Management's Discussion and Analysis for the year ended December 31, 2004.

Reconciliation of Proved Reserves

	Canada					International		Total	
	Western Canada				East Coast				
	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Light Crude Oil	Light Crude Oil	Natural Gas	Crude Oil & NGL	Natural Gas
	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)
Proved reserves, before royalties (1)									
Proved reserves at December 31, 2001	182	128	232	1,823	17	40	143	599	1,966
Revision of previous estimate	(4)	9	7	(37)				12	(37)
Purchase of reserves in place			5	6				5	6
Sales of reserves in place	(2)	(14)		(19)				(16)	(19)
Discoveries and extensions	4	1	18	382	8			31	382
Improved recovery	1			5	11	1		13	5
Production	(15)	(16)	(35)	(208)	(5)	(4)		(75)	(208)
Proved reserves at December 31, 2002	166	108	227	1,952	31	37	143	569	2,095
Revision of previous estimate	5	1	6	(132)	1	(5)	(143)	8	(275)
Purchase of reserves in place	9		3	184				12	184
Sales of reserves in place	(1)	(3)	(1)	(23)				(5)	(23)
Discoveries and extensions	5	2	29	300				36	300
Improved recovery	1			1				1	1
Production	(12)	(14)	(37)	(223)	(6)	(8)		(77)	(223)
Proved reserves at December 31, 2003	173	94	227	2,059	26	24	—	544	2,059
Revision of previous estimate	1	1	(114)	(23)	(1)	3		(110)	(23)
Purchase of reserves in place	1			23				1	23
Sales of reserves in place			(1)	(14)				(1)	(14)
Discoveries and extensions	7	2	32	372	24			65	372
Improved recovery	1	2	1	4	3			7	4
Production	(12)	(13)	(40)	(252)	(5)	(7)		(77)	(252)
Proved reserves at December 31, 2004	171	86	105	2,169	47	20	—	429	2,169

Note:

(1) Proved reserves are the estimated quantities of crude oil, natural gas and NGL which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reserves and Production by Principal Area

Crude Oil and NGL (1)	Proved Reserves (mmbbls)	Production (mbbls/day)
Canada		
Western Canada		
British Columbia and Foothills		
Alberta and BC Plains area	31.0	6.6
Foothills Deep Gas area	23.7	6.6
Ram River and Kaybob areas	7.0	2.0
Northwest Alberta Plains		
Rainbow Lake area	83.8	7.7
Peace River Arch area	10.4	4.2
East Central Alberta		
Provost area	23.6	8.2
North area	2.3	0.6
South area	6.5	2.7
Southern Alberta and Saskatchewan		
South Alberta area	20.0	11.2
South Saskatchewan area	72.6	17.4
Lloydminster Area		
Primary production	80.5	81.0
Thermal production	—	18.8
Other	0.8	9.6
	362.2	176.6
East Coast Canada		
Terra Nova	23.6	13.7
White Rose	23.5	—
	409.3	190.3
China		
Wenchang	19.4	19.7
Libya		
Shatirah	0.4	0.1
	429.1	210.1

Note:

(1) Gross crude oil and NGL reserves as at December 31, 2004 and average 2004 daily gross production of crude oil and NGL.

Natural Gas (1)	Proved Reserves (bcf)	Production (mmcf/day)
Western Canada		
British Columbia and Foothills		
Alberta and BC Plains area	181.5	46.9
Foothills Deep Gas area	291.4	94.8
Ram River and Kaybob areas	271.8	84.0
Northwest Alberta Plains		
Rainbow Lake area	373.3	50.7
Peace River Arch	56.4	29.0
Northern Alberta area	269.7	97.4
East Central Alberta		
Provost area	63.7	16.8
North area	148.6	54.0
South area	184.6	55.0
Southern Alberta and Saskatchewan		
South Alberta area	61.7	32.4
South Saskatchewan area	182.9	62.0
Lloydminster Area	75.0	58.0
Other	8.1	8.2
	2,168.7	689.2

Note:

(1) Gross natural gas reserves as at December 31, 2004 and average 2004 daily gross production of natural gas.

Probable Oil and Gas Reserves[1]

	Crude Oil & NGL				Natural Gas			
Probable	Western Canada	East coast	International	Total	Western Canada	International	Total	BOE
		(mmbbls)				(bcf)		(mmboe)
2004 . . .	192.3(2)	155.6	12.7	360.6	388.2	166.6	554.8	453.1
2003 . . .	246.1	182.2	7.0	435.3	381.3	66.5	447.8	509.9
2002 . . .	246.4	201.6	4.2	452.2	383.9	18.9	402.8	519.3

Notes:

(1) The probable reserves presented have been prepared, using constant prices and costs, in accordance with NI 51-101.

(2) Probable bitumen reserves were based on constant prices calculated in accordance with the Canadian Securities Administrators Staff Notice 51-315 ''Guidance Regarding the Determination of Constant Prices for Bitumen Reserves under National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (the ''Staff Notice''). Bitumen reserves at December 31, 2004 remain classified as probable reserves because the pricing formula in the Staff Notice results in an economically viable price as at that date whereas 37 mmbbls of heavy oil reserves were subtracted from probable reserves due to low December 31, 2004 heavy oil prices under the constant pricing calculation applicable to heavy oil, which differed from the bitumen calculation. See ''Disclosure of Exemption under National Instrument 51-101'' for further discussion.

(3) Bitumen probable reserves are included under the caption Western Canada.

(4) The SEC generally permits oil and gas registrants to disclose only reserves that meet the standards for proved reserves. Due to the higher uncertainty associated with probable reserves, disclosure or reference to probable reserves does not meet the standards for the inclusion in a document filed with the SEC. The disclosure of probable reserves is included herein in accordance with certain undertakings made in an exemption order granted to Husky pursuant to Part 8 of the Companion Policy to NI 51-101.

Disclosure about Oil and Gas Producing Activities — Statement of Financial Accounting Standards No. 69

The following disclosures have been prepared in accordance with FASB Statement No. 69 ''Disclosures about Oil and Gas Producing Activities'' (''FAS 69''):

Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

Canadian provincial royalties are determined based on a graduated percentage scale, which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and our estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause our share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2004, no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

Results of Operations for Producing Activities

Results of operations for producing activities (1)(2)	Canada			International			Total		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	($ millions except per boe amounts)								
Oil and gas production revenue	2,866	2,917	2,541	310	310	190	3,176	3,227	2,731
Operating costs									
Lease operating expenses	874	794	676	17	17	10	891	811	686
Production taxes	56	41	66	—	—	—	56	41	66
Asset retirement obligation accretion	23	18	14	—	—	—	23	18	14
	953	853	756	17	17	10	970	870	766
Depreciation, depletion and amortization	1,018	852	784	59	66	38	1,077	918	822
Earnings before taxes	895	1,212	1,001	234	227	142	1,129	1,439	1,143
Income tax	349	491	363	92	91	59	441	582	422
Results of operations	546	721	638	142	136	83	688	857	721
Amortization rate per boe	9.11	8.05	7.47	8.19	8.00	8.33	9.06	8.04	7.50

Notes:

(1) The costs in this schedule exclude corporate overhead, interest expense and other operating costs, which are not directly related to producing activities.

(2) Under U.S. GAAP, the depreciation, depletion and amortization for Canadian producing activities for 2004 amounted to $981 million (2003 — $772 million; 2002 — $727 million). Asset retirement obligation accretion under U.S. GAAP for 2002 is nil. Income taxes for Canadian producing activities under U.S. GAAP for 2004 amounted to $364 million (2003 — $523 million; 2002 — $393 million).

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities [1]

	Canada	International	Total
		($ millions)	
2004			
Property acquisition			
Proved [2]	101	—	101
Unproved [3]	91	62	153
Exploration	295	18	313
Development	1,648	5	1,653
Capitalized interest	75	—	75
	2,210	85	2,295
Less: Proved acquisitions	101	—	101
Capitalized interest	75	—	75
Finding and development costs	2,034	85	2,119
Less: Actual asset retirement Expenditures	26	—	26
Plus: Asset retirement Obligations incurred	90	(1)	89
Total costs incurred	2,098	84	2,182
2003			
Property acquisition			
Proved [4]	541	—	541
Unproved [5]	106	—	106
Exploration	298	26	324
Development	1,326	—	1,326
Capitalized interest	52	—	52
	2,323	26	2,349
Less: Proved acquisitions	541	—	541
Capitalized interest	52	—	52
Finding and development costs	1,730	26	1,756
Less: Actual asset retirement Expenditures	25	—	25
Plus: Asset retirement Obligations incurred	101	2	103
Total costs incurred	1,806	28	1,834

Costs Incurred (1)	Canada	International	Total
		($ millions)	
2002			
Property acquisition			
Proved	20		20
Unproved	88		88
Exploration	257	9	266
Development	1,110	66	1,176
Capitalized interest	26	—	26
	1,501	75	1,576
Less: Proved acquisitions	20	—	20
Capitalized interest	26	—	26
Finding and development costs	1,455	75	1,530
Less: Actual asset retirement Expenditures	18	—	18
Plus: Asset retirement Obligations incurred	33	1	34
Total costs incurred	1,470	76	1,546

Notes:

(1) Costs incurred includes actual retirement expenditures

(2) Property acquisition costs related to corporate acquisitions for proved properties were $98 million

(3) Property acquisition costs related to corporate acquisitions for unproved properties were $40 million

(4) Property acquisition costs related to corporate acquisitions for proved properties were $517 million

(5) Property acquisition costs related to corporate acquisitions for unproved properties were $54 million

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Exploration costs include the costs of geological and geophysical activity, retaining undeveloped properties and drilling and equipping exploration wells.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas.

Exploration and development costs include administrative costs and depreciation of support equipment directly associated with these activities.

The following table sets forth a summary of oil and gas property costs not being amortized at December 31, 2004, by the year in which the costs were incurred:

Withheld Costs	Total	2004	2003	2002	Prior to 2002
			($ millions)		
Property acquisitions					
Canada	328	—	56	26	246
International	75	62	—	—	13
	403	62	56	26	259
Exploration					
Canada	475	249	61	39	126
International	35	13	16	6	—
	510	262	77	45	126
Development					
Canada	1,324	487	466	371	—
International	18	1	1	—	16
	1,342	488	467	371	16
Capitalized interest					
Canada	273	75	52	26	120
	2,528	887	652	468	521

Capitalized Costs Relating to Oil and Gas Producing Activities

	Canada	International	Total
		($ millions)	
2004			
Proved properties	13,289	452	13,741
Asset retirement obligation costs	314	6	320
Unproved properties	2,399	129	2,528
	16,002	587	16,589
Accumulated DD&A	5,722	311	6,033
Net Capitalized Costs (1)	10,280	276	10,556
2003			
Proved properties	11,794	442	12,236
Asset retirement obligation costs	223	7	230
Unproved properties	1,814	54	1,868
	13,831	503	14,334
Accumulated DD&A	4,718	252	4,970
Net Capitalized Costs (1)	9,113	251	9,364
2002			
Proved properties	10,217	432	10,649
Asset retirement obligation costs	122	5	127
Unproved properties	1,318	37	1,355
	11,657	474	12,131
Accumulated DD&A	3,968	186	4,154
Net Capitalized Costs (1)	7,689	288	7,977

Note:

(1) The net capitalized costs for Canadian oil & gas exploration, development and producing activities under U.S. GAAP for 2004 was $9,721 million (2003 — $8,518 million, 2002 — $7,014 million). The net capitalized costs for International property oil & gas exploration,

development and producing activities under U.S. GAAP for 2004 was $274 million (2003 — $249 million, 2002 — $286 million). Please refer to note 20 to the Consolidated Financial Statements.

Oil and Gas Reserve Information

In Canada, our proved crude oil, natural gas liquids, natural gas and sulphur reserves are located in the provinces of Alberta, Saskatchewan and British Columbia, and offshore the East Coast. Our international proved reserves are located in China and Libya.

	Canada			International		Total		
Reserves	**Crude Oil & NGL**	**Natural Gas**	**Sulphur**	**Crude Oil & NGL**	**Natural Gas**	**Crude Oil & NGL**	**Natural Gas**	**Sulphur**
	(mmbbls)	(bcf)	(mmlt)	(mmbbls)	(bcf)	(mmbbls)	(bcf)	(mmlt)
Net proved developed and undeveloped reserves, after royalties (1)(2)(3)(4)								
End of year 2001	503.0	1,558.6	4.7	36.8	115.2	539.8	1,673.8	4.7
Revisions	—	14.7	0.3	(0.8)	(14.3)	(0.8)	0.4	0.3
Purchases	4.2	5.4	—	—	—	4.2	5.4	—
Sales	(14.5)	(16.6)	—	—	—	(14.5)	(16.6)	—
Improved recovery	10.3	3.0	—	—	—	10.3	3.0	—
Discoveries and extensions	26.9	202.4	—	1.1	—	28.0	202.4	—
Production	(61.8)	(155.7)	(0.4)	(4.3)	—	(66.1)	(155.7)	(0.4)
End of year 2002	468.1	1,611.8	4.6	32.8	100.9	500.9	1,712.7	4.6
Revisions	18.4	(88.9)	0.1	(2.8)	(100.9)	15.6	(189.8)	0.1
Purchases	9.2	146.2	—	—	—	9.2	146.2	—
Sales	(4.2)	(15.9)	(0.1)	—	—	(4.2)	(15.9)	(0.1)
Improved recovery	1.2	0.5	—	—	—	1.2	0.5	—
Discoveries and extensions	31.4	245.1	0.1	—	—	31.4	245.1	0.1
Production	(61.1)	(182.2)	(0.5)	(7.5)	—	(68.6)	(182.2)	(0.5)
End of year 2003	463.0	1,716.6	4.2	22.5	—	485.5	1,716.6	4.2
Revisions	(105.4)	(55.1)	(0.4)	2.3	—	(103.1)	(55.1)	(0.4)
Purchases	1.0	17.3	—	—	—	1.0	17.3	—
Sales	(0.7)	(11.6)	—	—	—	(0.7)	(11.6)	—
Improved recovery	5.9	3.4	—	—	—	5.9	3.4	—
Discoveries and extensions	54.7	308.7	0.1	—	—	54.7	308.7	0.1
Production	(61.5)	(191.6)	(0.6)	(6.5)	—	(68.0)	(191.6)	(0.6)
End of year 2004	357.0	1,787.7	3.3	18.3	—	375.3	1,787.7	3.3
Net proved developed reserves, after royalties (1)(2)(3)(4)								
End of year 2001	378.1	1,342.2	4.6	0.6	—	378.7	1,342.2	4.6
End of year 2002	360.9	1,272.8	3.7	28.2	—	389.1	1,272.8	3.7
End of year 2003	372.0	1,422.9	3.8	22.5	—	394.5	1,422.9	3.8
End of year 2004	298.5	1,436.0	3.3	18.3	—	316.8	1,436.0	3.3

Notes:

(1) Net reserves are the Company's lessor royalty, overriding royalty and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.

(2) Reserves are the estimated quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations from a given date forward, by known technology, under existing operating conditions and prices in effect at year end.

(3) Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

(4) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing procedures prescribed by FAS 69 and based on crude oil and natural gas reserve and production volumes estimated by our engineering staff. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating Husky or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of Husky's reserves.

The future cash flows presented below are based on sales prices, cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2004 was based on the NYMEX year-end natural gas spot price of U.S. $6.02/mmbtu (2003 — U.S. $5.96/mmbtu; 2002 — U.S. $4.60/mmbtu) and on crude oil prices computed with reference to the year-end WTI price of U.S. $43.36/bbl (2003 — U.S. $32.5/bbl; 2002 — U.S. $31.21/bbl). The price of WTI in Canadian dollars was lower December 31, 2003 than at December 31, 2002 as a result of the Cdn./U.S. dollar exchange rate, which was $1.29 at December 31, 2003 compared with $1.58 at December 31, 2002.

	Canada (1)			**International** (1)			**Total** (1)		
Standardized Measure	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
					($ millions)				
Future cash inflows	22,681	24,003	25,830	979	928	2,719	23,660	24,931	28,549
Future costs									
Future production and development costs	9,353	8,645	7,239	148	146	502	9,501	8,791	7,741
Future income taxes	4,871	5,696	7,278	266	247	860	5,137	5,943	8,138
Future net cash flows	8,457	9,662	11,313	565	535	1,357	9,022	10,197	12,670
Deduct 10 percent annual discount factor	3,712	4,242	4,966	105	117	518	3,817	4,359	5,484
Standardized measure of discounted Future net cash flows	4,745	5,420	6,347	460	418	839	5,205	5,838	7,186

Note:

(1) The schedules above are calculated using year-end prices, costs, statutory income tax rates and existing proved oil and gas reserves. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Canada (1)			International (1)			Total (1)		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
					($ millions)				
Present value at January 1	5,420	6,347	2,354	418	839	438	5,838	7,186	2,792
Sales and transfers, net of production costs	(1,952)	(2,097)	(1,802)	(294)	(293)	(179)	(2,246)	(2,390)	(1,981)
Net change in sales and transfer prices, net of development and production costs	555	(1,379)	7,752	197	(376)	732	752	(1,755)	8,484
Extensions, discoveries and improved recovery, net of related costs	958	541	676	—	—	40	958	541	716
Revisions of quantity estimates	(1,318)	76	(30)	85	(97)	(28)	(1,233)	(21)	(58)
Accretion of discount	877	1,055	390	61	130	59	938	1,185	449
Sale of reserves in place	(20)	(47)	(189)	—	—	—	(20)	(47)	(189)
Purchase of reserves in place	45	304	45	—	—	—	45	304	45
Changes in timing of future net cash flows and other	(233)	(237)	(191)	17	(49)	80	(216)	(286)	(111)
Net change in income taxes	413	857	(2,658)	(24)	264	(303)	389	1,121	(2,961)
Present value at December 31	4,745	5,420	6,347	460	418	839	5,205	5,838	7,186

Note:

(1) The schedules above are calculated using year-end prices, costs, statutory income tax rates and existing proved oil and gas reserves. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.

INDEPENDENT ENGINEER'S AUDIT OPINION

January 17, 2005

Husky Energy Inc.
707 – 8th Avenue S.W.
Calgary, Alberta
T2P 3G7

Gentlemen:

Pursuant to Husky's request we have conducted an audit of the reserves estimates and the respective present worth value of these reserves of Husky Energy Inc., as at December 31, 2004. The Company's detailed reserves information was provided to us for this audit. Our responsibility is to express an independent opinion on the reserves and respective present worth value estimates, in aggregate, based on our audit tests and procedures.

We conducted our audit in accordance with Canadian generally accepted standards as described in the Canadian Oil and Gas Evaluation Handbook (COGEH) and auditing standards generally accepted in the United States of America. Those standards require that we review and assess the policies, procedures, documentation and guidelines of the Company with respect to the estimation, review and approval of Husky's reserves information. An audit includes examining, on a test basis, to confirm that there is adherence on the part of Husky's internal reserve evaluators and other employees to the reserves management and administration policies and procedures established by the Company. An audit also includes conducting reserves evaluation on sufficient number of Company properties as considered necessary to express an opinion.

Based on the results of our audit, it is our opinion that Husky's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook.

Sincerely,

McDaniel & Associates Consultants Ltd.

/s/ B. H. Emslie

B. H. Emslie, P. Eng.
Senior Vice President

REPORT ON RESERVES DATA BY QUALIFIED RESERVES EVALUATOR

To the Board of Directors of
HUSKY ENERGY INC. (the ''Company''):

1. Our staff has evaluated the Company's oil and gas reserves data as at December 31, 2004. The reserves data consist of the following:

   (a) proved oil and gas reserve quantities estimated as at December 31, 2004 using constant prices and costs; and

   (b) the related standardized measure of discounted future net cash flows.

2. The oil and gas reserves data are the responsibility of the Company's management. As the Corporate Representatives our responsibility is to certify that the reserves data has been properly calculated in accordance with generally accepted procedures for the estimation of reserves data.

3. We carried out our evaluation in accordance with generally accepted procedures for the estimation of oil and gas reserves data and standards set out in the Canadian Oil and Gas Evaluation Handbook (the ''COGEH'') with the necessary modifications to reflect definitions and standards under the applicable U.S. Financial Accounting Standards Board standards (the ''FASB Standards'' and the legal requirements of the U.S. Securities and Exchange Commission (''SEC Requirements''). Our internal reserves evaluators are not independent of the Company, within the meaning of the term ''independent'' under those standards.

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the oil and gas reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGEH as modified or replaced by the FASB Standards and SEC Requirements.

5. The following sets forth the estimated standardized measure of discounted future net cash flows (before deducting income taxes) attributed to proved oil and gas reserve quantities, estimated using constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2004:

Location of Reserves	Discounted Future Net Cash Flows (after income taxes, 10% discount rate)
Canada	4,745
China	447
Libya	13
	5,205

   We have filed the Company's disclosures in accordance with Financial Accounting Standards Board Statement No. 69 reserve disclosure concurrently with this form.

6. In our opinion, the oil and gas reserves data evaluated by us have, in all material respects, been determined in accordance with principles and definitions presented in the COGEH as modified or replaced by the FASB Standards and SEC Requirements.

7. We have no responsibility to update our evaluation for events and circumstances occurring after the date of this report.

8. Oil and gas reserves are estimates only, and not exact quantities. In addition, the oil and gas reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

/s/ PRESTON KRAFT

Preston Kraft P.Eng
Manager of Reservoir Engineering
Calgary, Alberta
January 17, 2005

/s/ LARRY BELL

Larry Bell
Vice President, Exploration & Production Services
Calgary, Alberta
January 17, 2005

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Husky Energy Inc. (the ''Company'') are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes oil and gas reserves data, which consist of the following:

(1) proved oil and gas reserve quantities estimated as at December 31, 2004 using constant prices and costs; and

(2) the related standardized measure of discounted future net cash flows.

Our oil and gas reserves evaluation process involves applying generally accepted procedures for the estimation of oil and gas reserves data for the purposes of complying with the legal requirements of the U.S. Securities and Exchange Commission (''SEC'') and the applicable provisions of the U.S. Financial Accounting Standards Board Statement of Financial Accounting Standards No. 69 (collectively, the ''Oil and Gas Reserves Data Process''). Our Manager of Reservoir Engineering and Vice President, Exploration & Production Services, who are employees of the Company, have evaluated the Company's oil and gas reserves data and certified that the Reserves Data Process has been followed. The Report on Reserves Data of the Manager of Reservoir Engineering and Vice President, Exploration & Production Services will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the Board of Directors has:

(a) reviewed the Company's procedures for providing information to the internal and external qualified oil and gas reserves evaluators;

(b) met with the internal and, if applicable, external qualified oil and gas reserves evaluator(s) to determine whether any restrictions placed by management affect the ability of the internal qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the internal qualified oil and gas reserves evaluators.

The Audit Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Audit Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the Report on Reserves Data of the Manager of Reservoir Engineering and Vice President, Exploration & Production Services; and

(c) the content and filing of this report.

Husky sought and was granted by the Canadian Securities Administrators an exemption from the requirement under National Instrument 51-101 ''*Standards of Disclosure for Oil and Gas Disclosure*'' to involve independent qualified oil and gas reserves evaluators or auditors. Notwithstanding this exemption, we involve independent qualified reserve auditors as part of our corporate governance practices. Their involvement helps assure that our internal oil and gas reserves estimates are materially correct.

In our view, the reliability of the internally generated oil and gas reserves data is not materially different than would be afforded by our involving independent qualified reserves evaluators to evaluate and review the reserves data. A portion of our oil and gas reserves data is international in nature. Husky is an SEC registrant and therefore our reserves data is developed in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as modified or replaced by the applicable U.S. Financial Accounting Standards Board standards and the legal requirements of the SEC. Our procedures, records and controls relating to the accumulation of source data and preparation of reserves data by our internal reserves evaluation staff have been established, refined and documented over many years. Our internal reserves evaluation staff includes 129 individuals, including support staff, of whom 46 individuals are qualified reserves evaluators as defined in the Canadian Oil and Gas Evaluation Handbook, with an average of 10 years of relevant experience in evaluating reserves.

Our internal reserves evaluation management personnel includes 23 individuals with an average of 12 years of relevant experience in evaluating oil and gas and managing the evaluation process.

Reserves data are estimates only, and are not exact quantities. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

/s/ JOHN C. S. LAU	March 16, 2005
John C. S. Lau *President & Chief Executive Officer*	
/s/ NEIL D. MCGEE	March 16, 2005
Neil D. McGee *Vice President & Chief Financial Officer*	
/s/ R. DONALD FULLERTON	March 16, 2005
R. Donald Fullerton *Director*	
/s/ WAYNE E. SHAW	March 16, 2005
Wayne E. Shaw *Director*	

Description of Major Properties and Facilities

Husky's portfolio of assets includes properties that produce light (30° API and lighter), medium (between 20° and 30° API) and heavy (below 20° and above 10° API) gravity crude oil, NGL, natural gas and sulphur.

Lloydminster Heavy Oil and Gas

Husky's heavy oil assets are concentrated in a large producing area covering more than 14,800 square kilometres in the Lloydminster area in the Canadian provinces of Saskatchewan and Alberta. Approximately 85 percent of Husky's proved reserves in the region are contained in the heavy crude oil producing fields of Pikes Peak, Edam, Tangleflags, Celtic, Bolney, Westhazel, Big Gully, Hillmond, Mervin, Marwayne, Lashburn, Baldwinton and Rush Lake, and in the medium gravity crude oil producing fields of Wildmere and Wainwright. These fields contain accumulations of heavy crude oil at relatively shallow depths. We maintain a land position of approximately 1.6 million net acres in the Lloydminster area, of which approximately three-quarters is undeveloped.

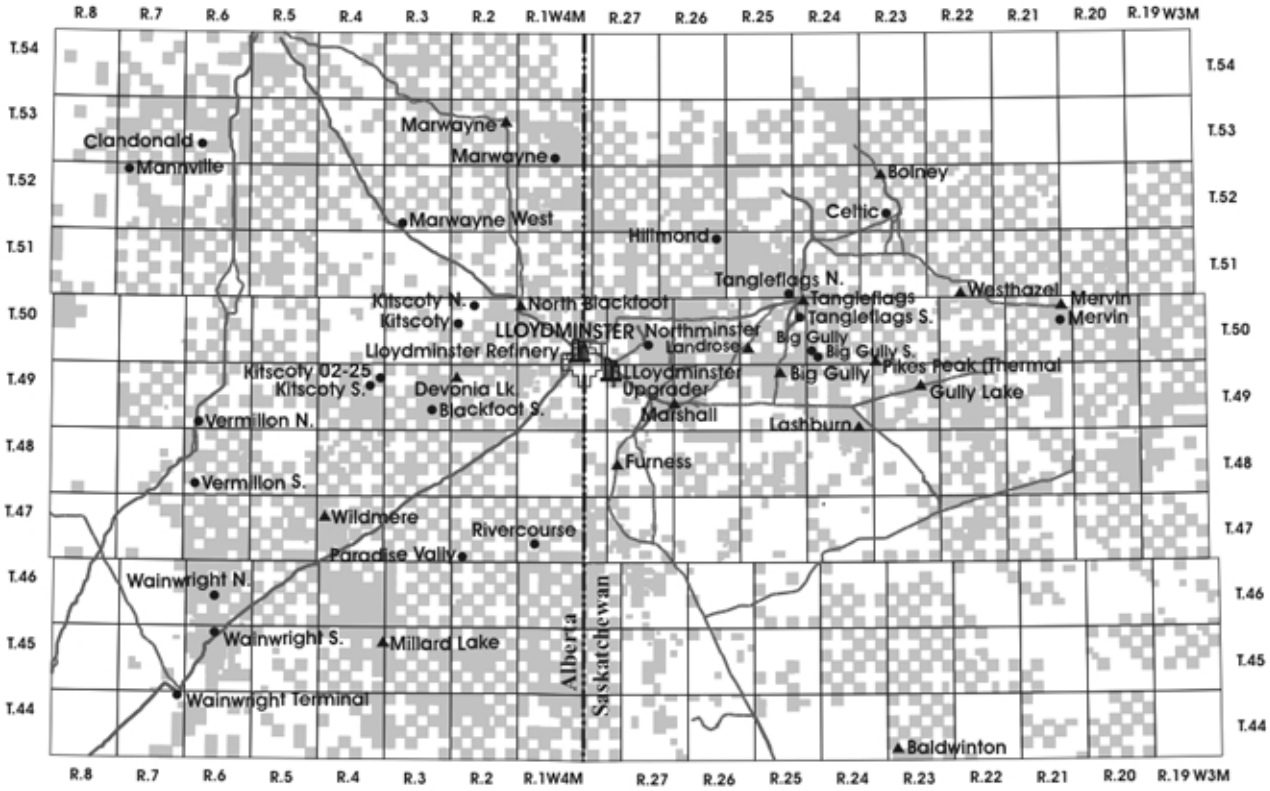
We currently produce from oil and gas wells ranging in depth from 450 to 650 metres and hold a 100 percent working interest in the majority of these wells. We produce heavy oil from the Lloydminster area using a variety of techniques, including standard primary production methods, as well as steam injection, horizontal well technology and steam assisted gravity drainage (''SAGD''). We have increased primary production from the area through cold production techniques which utilize progressive cavity pumps capable of simultaneous production of sand and heavy oil from unconsolidated formations. Our gross heavy and medium crude oil production from the area totalled 99.7 mbbls/day in 2004. Of the total production, 77.3 mbbls/day was primary production of heavy crude oil, 18.8 mbbls/day was production from our thermal operations at Pikes Peak (cyclic steam), Bolney/Celtic (SAGD) and the Lashburn pilot (SAGD), which was started in 2004 and 3.7 mbbls/day was from the medium gravity waterflooded fields in the Wainwright and Wildmere areas. We believe that the future growth from this area will be driven by primary heavy oil production and new thermal projects.

In the Lloydminster area we own and operate 16 oil treating facilities, all of which are tied into our heavy oil pipeline systems. These pipeline systems transport heavy crude oil from the field locations to our Lloydminster asphalt refinery, to the Husky Lloydminster Upgrader and to the Enbridge Pipeline and Express Pipeline systems at Hardisty, Alberta. During 2004, we completed construction of a facility at Landrose, Saskatchewan with an output capacity of 11.3 mbbls/day.

We are focused on increasing our heavy oil production and believe that our undeveloped land position in the Lloydminster area, coupled with the application of improved technologies, a reduced cost structure and increased upgrading capacity, will provide strong growth opportunities for heavy oil production.

We also produce natural gas from numerous small shallow natural gas pools in the Lloydminster area (approximately 76 bcf of proved reserves). Our total gross natural gas production from the area during 2004 was 57.9 mmcf/day.

Lloydminster Area



Northwest Alberta Plains

Rainbow Lake Area

Rainbow Lake, located approximately 700 kilometres north-west of Edmonton, Alberta, is the site of our largest light oil production operation in Western Canada. Husky operates a number of crude oil pools in the Rainbow basin, with an average working interest of 54 percent. Our production in this area is derived from more than 50 oil and gas pools extending over 1,300 square kilometres.

We use secondary and tertiary oil recovery methods extensively in the Rainbow Lake area. These methods include injecting water, natural gas and NGL into the oil reservoirs to enhance crude oil recovery. The use of tertiary recovery programs, such as the miscible flood used at Rainbow Lake, has increased the estimated amount of recoverable crude oil-in-place from 50 to 70 percent of the original crude oil-in-place in certain pools. As a consequence of implementing these natural gas and NGL re-injection programs, historically only small volumes of gas and NGL have been marketed from the Rainbow Lake area prior to 2002. In 2003, we initiated the recovery of natural gas from several pools. NGL recovery is forecast to begin in the 2008-2010 timeframe and is expected to generate revenues as the crude oil production from the pools is completed. We use horizontal drilling techniques, including the re-entry of existing wellbores, to maintain the level of crude oil production and to increase recovery rates. We plan to continue exploration efforts to supplement our development initiatives in the Rainbow Lake area. Husky's gross production from this area averaged 7.2 mbbls/day of light crude oil and NGL and 33.0 mmcf/day of natural gas during 2004.

We hold a 50 percent interest in, and operate, the Rainbow Lake processing plant. The processing design rate capacity of the plant is 69 mbbls/day of crude oil and water and 230 mmcf/day of raw gas. The extraction design capacity is 17 mbbls/day of NGL.

We hold an interest in two significant non-operated properties in the Rainbow area. They include the Ekwan/Sierra property in north-eastern British Columbia and the Bistcho/Cameron Hills property straddling the Alberta and Northwest Territories border. Our gross production from these properties currently averages 11.4 mmcf/day of natural gas and 118 bbls/day of liquid hydrocarbons. We also hold a working interest in the Encana Sierra gas plant and the

Paramount Bistcho gas plant. We are active in both these areas with development and exploration drilling. In these two areas we hold in excess of 200,000 acres of undeveloped land.

Peace River Arch Area

The Peace River Arch area of northern Alberta, which includes the Slave Lake, Sawn Lake, Red Earth, Lubicon, Nipisi, Utikuma and other properties, has been a major light oil producing area located approximately 370 kilometres north-west of Edmonton. We operate and hold an average 80 percent working interest in several properties in this area. Over the last three years, we have maintained net production from properties in this area, at approximately 4.1 mbbls/day of crude oil, through acquisitions, step-out drilling and waterflood optimization. The average working interest in these lands is 80 percent. Infrastructure includes a 100 percent working interest in a 30 mmcf/day sour gas plant and three oil batteries. Husky plans to continue development drilling and waterflood optimization for both crude oil and natural gas targets in this area.

Boyer Area

The Boyer area of Alberta is approximately 600 kilometres north-west of Edmonton, Alberta. We are the operator and hold close to 100 percent working interest in our properties. The area holds shallow Bluesky gas reservoirs that are characterized as low deliverability and low decline that are being developed with a drilling density of three wells per section. We intend to continue to develop this area by drilling undeveloped sections, infill drilling, land acquisitions and step out exploration. Gross production from this area in 2004 averaged 33.0 mmcf/day of natural gas.

Sloat Creek Area

The Sloat Creek or Chinchaga area of Alberta is located close to the British Columbia border approximately 570 kilometres north-west of Edmonton, Alberta. We are the operator and hold an approximate 95 percent working interest in our properties. Natural gas is produced from the Bluesky, DeBolt, Elkton and Shunda zones that lie an average of approximately 1,030 metres deep and the Slave Point zone at an average depth of 1,800 metres. We intend to continue to develop this area with infill, step-out and exploratory drilling so that existing pools can be optimized and new pools can be placed on production.

We own a 30 mmcf/day high pressure booster compression plant that feeds a third party operated sour gas plant and are 50 percent owner in a 12 mmcf/day low pressure booster that feeds a 40 percent owned sweet gas processing facility operated by a third party. Gross production from this area averaged 6.6 mmcf/day of natural gas in 2004.

Marten Hills/Muskwa Area

The Marten Hills and Muskwa areas of Alberta are located 212 kilometres north-west of Edmonton, Alberta. Natural gas is produced from the Clearwater, Colony, McMurray and Wabiskaw zones that lie at an average depth of 600 metres. We operate our properties in this area and intend to continue to develop this area with infill, step-out and exploratory drilling so that existing pools can be optimized and new pools can be placed on production.

We own a 100 percent interest in a series of nine sales gas compressor stations (compressors at sales points) and a number of field booster stations, a 95 percent interest in a compressor station at Rock Island, a 37.5 percent interest in a third party operated facility at Peerless and a 3 percent interest in the third party operated Marten Hills unit. Gross production from this area averaged 34.9 mmcf/day of natural gas in 2004.

Cherpeta and Saleski Areas

The Cherpeta area of Alberta is located 230 kilometres north of Edmonton, Alberta and the Saleski area is located approximately 140 kilometres further north from Cherpeta. Natural gas is produced at Cherpeta from the Nisku, Clearwater, Colony, McMurray and Wabiskaw zones that lie at an average depth of 600 metres. The Grosmont zone that lies between 450 and 500 metres characterizes the Saleski area. We operate our properties in this area and intend to continue to develop this area with infill, step-out and exploratory drilling so that existing pools can be optimized and new pools can be placed on production.

We hold working interests ranging from 60 to 95 percent in the Cherpeta area and 49 percent in the Saleski area and operate a series of sales compressor stations, gas plants and sales pipeline. Gross production from these areas averaged 35.6 mmcf/day of natural gas in 2004.

Simons Lake Area

The Simons Lake area of Alberta is located 386 kilometres north-west of Edmonton, Alberta. Natural gas is produced from the Bluesky, DeBolt, Elkton and Shunda zones that lie at an average depth of 600 metres.

We hold 100 percent working interest in a 10 mmcf/day sour gas processing facility and 34 percent working interest in a high pressure booster station operated by a third party that feeds a separate third party owned sour gas processing facility. Gross production from this area averaged 3.7 mmcf/day of natural gas in 2004.

Northeast British Columbia and Alberta Foothills

Ram River Area

The Ram River area is located in west central Alberta and includes the large Blackstone, Ricinus and Clearwater/Limestone natural gas fields.

The Blackstone field is the most prolific of these fields and contains four high deliverability natural gas wells, capable of combined raw gas production of 80 mmcf/day. We hold a 34 percent interest in two unitized wells, a 24 percent and a 50 percent interest, respectively, in two non-unit wells, and act as the contract operator of the Blackstone wells. Production from these wells is processed at the Ram River gas plant.

We hold an average 72 percent interest in, and are the operator of, the Ram River sour gas plant and related processing facilities. The Ram River plant has the capacity to process 622 mmcf/day of sour gas, resulting in sales gas capacity of 525 mmcf/day. The plant also has the capacity to produce in excess of 2.8 mlt/day of sulphur from raw gas. During 2004, the plant operated at approximately 86 percent of its design rate capacity. The Ram River plant processes in excess of 10 percent of our total gross natural gas production, which includes an average of 50 mmcf/day of our gross production from the Blackstone, Brown Creek, Cordel and Stolberg fields and an average of 18.5 mmcf/day of our gross production from Ricinus and Clearwater/Limestone and Benjamin fields, in addition to processing third-party volumes. In addition, gross production from the Ferrier area, which is processed at another gas plant, averaged 4.4 mmcf/day of natural gas, bringing our total gross production of natural gas from the Ram River area to 71 mmcf/day in 2004.

Our sour gas pipeline network supports the Ram River plant. We operate a network of 845 kilometres of sour gas pipelines in the Ram River area and hold a 30 percent interest in 684 kilometres of this pipeline system. The sour gas processed at the Ram River plant is produced from 18 sour gas fields located as far as 145 kilometres from the Ram River plant.

We believe that the Ram River plant and the extensive infrastructure of gathering pipelines, transmission systems and rail lines, which support the plant, represents a strategic base for the natural gas exploration and development planned by us in this part of the foothills region. In addition, this region is an active exploration and production area for other producers and provides additional opportunities for generating revenue by processing third party natural gas.

Kaybob Area

The Kaybob area consists of land located in the Fox Creek area of Alberta. The Kaybob area consists of four main areas. The Kaybob South Beaverhill Lake Unit 1 (35.6 percent working interest), Kaybob South Trassic Unit 1 (40.5 percent working interest), Kaybob South Trassic Unit 2 (26.8 percent working interest), and non-unit lands (various working interests from gross overriding royalty to 100 percent working interest).

The majority of the gas is gathered and processed through the Kaybob South Amalgamated Gas Plants 1 and 2. We have a 17.8 percent working interest in the sour portion and a 20.4 percent working interest in the sweet gas portion of the plant. We also have various working interests in sweet gas gathering and compression facilities in the area. Our gross production from the area was 635 bbls/day of oil, 400 bbls/day of NGL and 13 mmcf/day of natural gas during 2004.

Boundary Lake Area

We hold a 50 percent working interest in the Boundary Lake Gas Unit and a 34 percent and 19 percent interest in the Boundary Lake oil unit 1 and 2, respectively, in north-east British Columbia. Our natural gas production from this area is derived from five Belloy sour gas pools, and is processed at the nearby Boundary Lake processing plant. Our gross production from this area was 12.0 mmcf/day of natural gas and 1.7 mbbls/day crude oil and NGL from the Boundary Lake units during 2004.

Valhalla and Wapiti Area

We hold a 30 percent interest in three Valhalla oil units, a 100 percent interest in the Valhalla non-unit waterflood wells and a 100 percent interest in the Wapiti property. Production is primarily from the Doe Creek and Cardium zones and consists of light crude oil, NGL and natural gas. Our gross production from these properties averaged 3.7 mbbls/day of crude oil and NGL and 5.0 mmcf/day of natural gas in 2004.

Kakwa Area

We hold an average 60 percent working interest in oil and gas processing facilities and associated oil and gas gathering systems in the Kakwa area. Our gross production from this area was 9.5 mmcf/day of natural gas, 425 bbls/day NGL and 385 bbls/day of oil in 2004. The 2004 acquisition of Temple Exploration Inc. provided us with an average 50 percent interest in properties with gross production of 5.2 mmcf/day and 160 bbls/day of NGL in the vicinity of our Kakwa plant.

Caroline Area

We hold an 11 percent working interest in the 32,000 acre Caroline natural gas field located approximately 97 kilometres north-west of Calgary. The field has a high proportion of NGL and as a result the economics of this field are enhanced.

We also hold an 11 percent interest in the Caroline sour gas processing facility. The plant is presently running at a license limit of 113 percent of design capacity and is processing approximately 124 mmcf/day of total plant sales gas and 39 mbbls/day of NGL. The plant and liquid acceleration gas recycle plant were at 50 percent capacity in 2004 which resulted in Husky gross production of 3.8 mbbls/day NGL and 12.2 mmcf/day natural gas in 2004.

Edson Area

We hold an average 85 percent working interest in two gas processing facilities and associated gas gathering systems in the Edson area. We operate these properties that had average gross production of 34.0 mmcf/day of natural gas and 1.6 mbbls/day of NGL in 2004.

Sikanni Area

We hold interests in properties in the Sikanni and Federal areas of north-east British Columbia, which averaged gross production of 13.5 mmcf/day of natural gas from four wells in 2004. The production flows through Husky owned gathering systems for processing at third party plants at Sikanni and McMahon.

Graham Area

We hold a 40 percent working interest in lands in the Graham area of north-eastern British Columbia. Our gross production from this area averaged 9.7 mmcf/day gross natural gas sales in 2004. Production from the property is from one Halfway and seven Baldonnel pools. We also hold an interest in two 1,500 horsepower compressor stations and the non-operated Cypress gas plant. Plant capacity is 45 mmcf/day and the plant is currently operating at full capacity. We hold a 33.2 percent interest in the gas treating unit, 28.2 percent interest in the amine unit and 28 percent interest in the sulphur unit.

East Central Alberta

Athabasca Area

The Athabasca area extends approximately 175 kilometres north of Edmonton and from the Alberta-Saskatchewan border in the east to the Alberta foothills in the west. The area target is predominantly shallow gas, ranging from 455 to 910 metres, in the multi-zone Palozoic Mannville. The main producing areas are Athabasca, Craigend and Cold Lake. We operate 31 facilities with a pipeline system and an average working interest of 90 percent in the producing wells. We intend to continue to develop this area with infill, stepout and exploratory wells to optimize recovery and develop new pools in order to keep the facilities operating at capacity. Our gross production from this area averaged 54.1 mmcf/day of natural gas and 606 bbls/day of crude oil in 2004.

Red Deer and Hussar Area

The core of the Red Deer and Hussar area is between Calgary, Drumheller and Sylvan Lake. We operate 18 facilities with gas gathering systems in this area. Our gross production from this area averaged 55.2 mmcf/day of

natural gas and crude oil and NGL of 2.7 mbbls/day in 2004. We intend to continue to develop the natural gas potential of this area with infill, stepout and exploratory wells to optimize gas recovery and develop new pools in order to operate the facilities at capacity. In 2003 Husky participated in a coal bed methane pilot project. In 2004, we commenced commercial operations based on the successful results of the pilot project. This project was producing 8.0 mmcf/day from 60 wells by the end of 2004. In 2005 we expect to drill in excess of 250 development wells with our co-venturer.

Provost Area

The centre of the Provost area is approximately 240 kilometres south-east of Edmonton. It is predominantly a medium crude oil area that averaged gross production of 17.5 mbbls/day of crude oil and 16.8 mmcf/day of natural gas in 2004. We intend to selectively drill lower risk oil locations and focus on managing operating costs and improving oil recovery, as well as increasing our focus on natural gas exploration and development. In 2005, we intend to continue to develop several of our 2003 and 2004 natural gas discoveries. There is significant competition in the area for land as well as infrastructure. We have a large land position and maintain close to a 100 percent working interest in most of our facilities.

Southern Alberta and Southern Saskatchewan

As of December 31, 2004, we held 225,000 net developed acres and 850,000 undeveloped acres in Southern Saskatchewan and 279,000 net developed acres and 189,000 net undeveloped acres in Southern Alberta. We also have a small landholding in Manitoba.

Southern Saskatchewan Area

We are a prominent operator in southern Saskatchewan primarily producing medium gravity crude oil, with some natural gas and light crude oil. Gross production from this area averaged 17.3 mbbls/day of crude oil and 62.0 mmcf/day of natural gas during 2004.

We operate 31 oil batteries and six gas facilities in the Southern Saskatchewan area. The oil pools in this area are exploited using pressure maintenance and waterflood recovery operations.

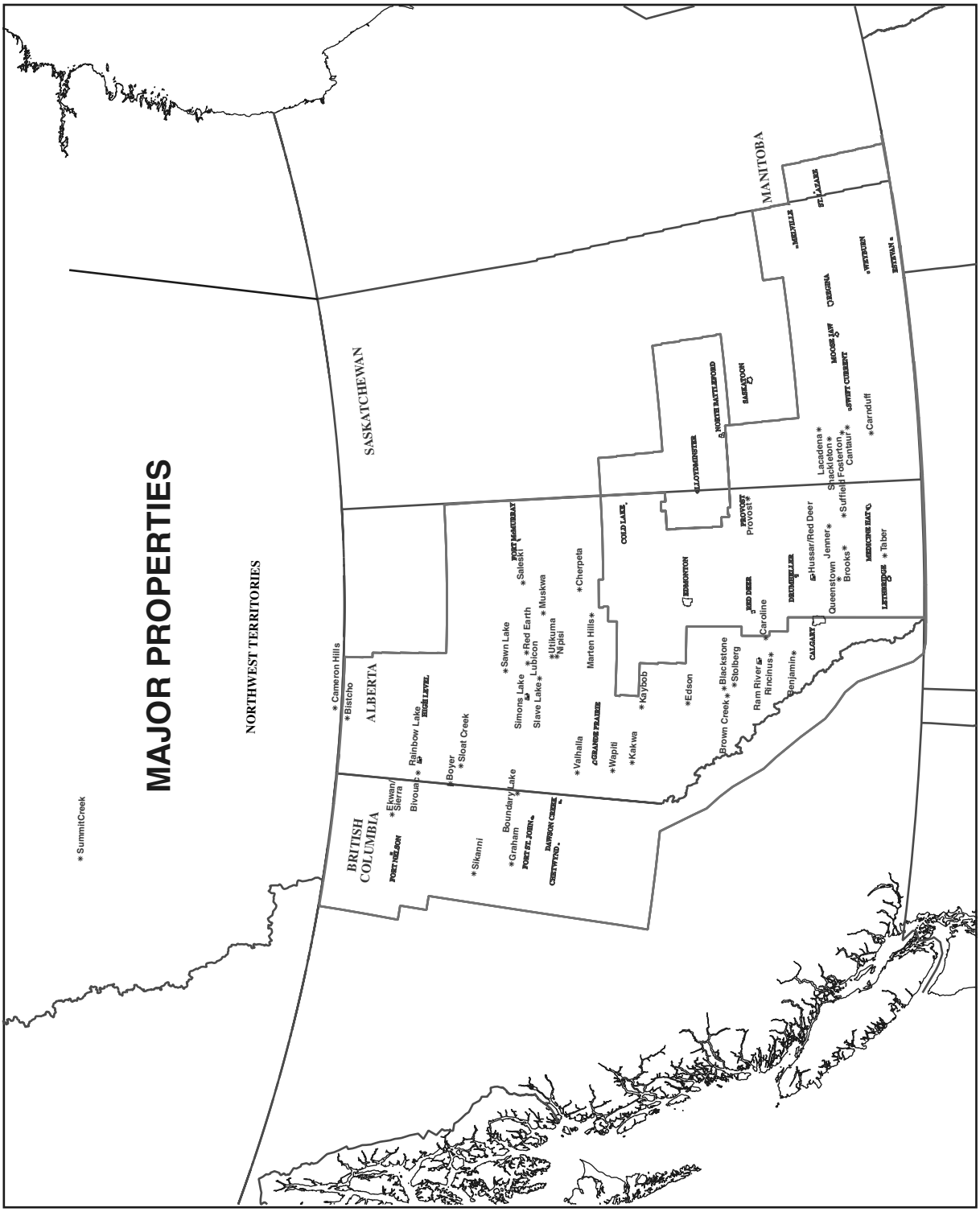
At the Shackleton/Lacadena Milk River shallow gas project, 92 wells were drilled and two new gas facilities were built in 2004. The project was producing at a rate of 48 mmcf/day at December 31, 2004 from a total of 253 wells. In 2005, we plan to drill between 65 and 100 additional stepout and infill wells.

Southern Alberta Area

Taber, Brooks and Jenner/Suffield are our three core areas in southern Alberta. We operate 28 oil facilities and three natural gas facilities with an average working interest of 95 percent. Oil production is mainly medium gravity crude with the majority of reserves being supported by waterfloods or active aquifers. Natural gas production is from a mixture of deep and shallow formations. At Taber, we operate an alkaline-polymer flood to increase recovery from the Cretaceous Mannville reservoir. Our gross production from this area averaged 11.2 mbbls/day of crude oil and 32.4 mmcf/day of natural gas during 2004.

At Queenstown, we intend to complete over 100 wells in 2005 that were drilled in late 2004. We plan to drill another 50 wells in this area in 2005.

Western Canada



Athabasca, Cold Lake and Peace River

Oil Sands

Husky currently holds interests in 433,610 acres in the bitumen prone areas of Athabasca, Cold Lake and Peace River. Recent improvements in fiscal regimes for these types of projects, together with lower costs from technological advances have enhanced their commercial viability.

In addition to interests in the 353,930 net acres in the Cold Lake and Athabasca regions in north-eastern Alberta, Husky holds an interest in 79,680 net acres in the Peace River region of northern Alberta.

Tucker

In May of 2004 we received approval from the Alberta Energy and Utilities Board to develop the Tucker insitu oilsands project. Tucker is located 30 kilometres northwest of Cold Lake, Alberta. The Tucker project will utilize SAGD technology and will have a design rate capacity of 30 mbbls/day. Construction commenced in late 2004 and we expect to commission the facility in late 2006 with production to commence three to six months thereafter.

Sunrise

The Sunrise insitu oil sands project is located in the Athabasca region of Alberta. Stratigraphic delineation drilling over the last three years has confirmed a large recoverable resource base. Additional stratigraphic test wells will be drilled in 2005. In the third quarter of 2004 a commercial project application was submitted to the Alberta Energy and Utilities Board and Alberta Environment. Current plans envision four 50 mbbls/day phases. Front end engineering is expected to be conducted in 2005.

Caribou

Our Caribou oil sands lands are located in the Cold Lake Air Weapons Range and comprise 35,840 acres. Pilot testing was conducted in the early 1990s with encouraging results. Further stratigraphic drilling is planned for 2005.

Saleski

Our largest bitumen deposit is located approximately 120 kilometres west of Fort McMurray, Alberta. Currently, there is no bitumen production in this area. In 2005 we will begin reviewing the geological and reservoir characteristics of this property.

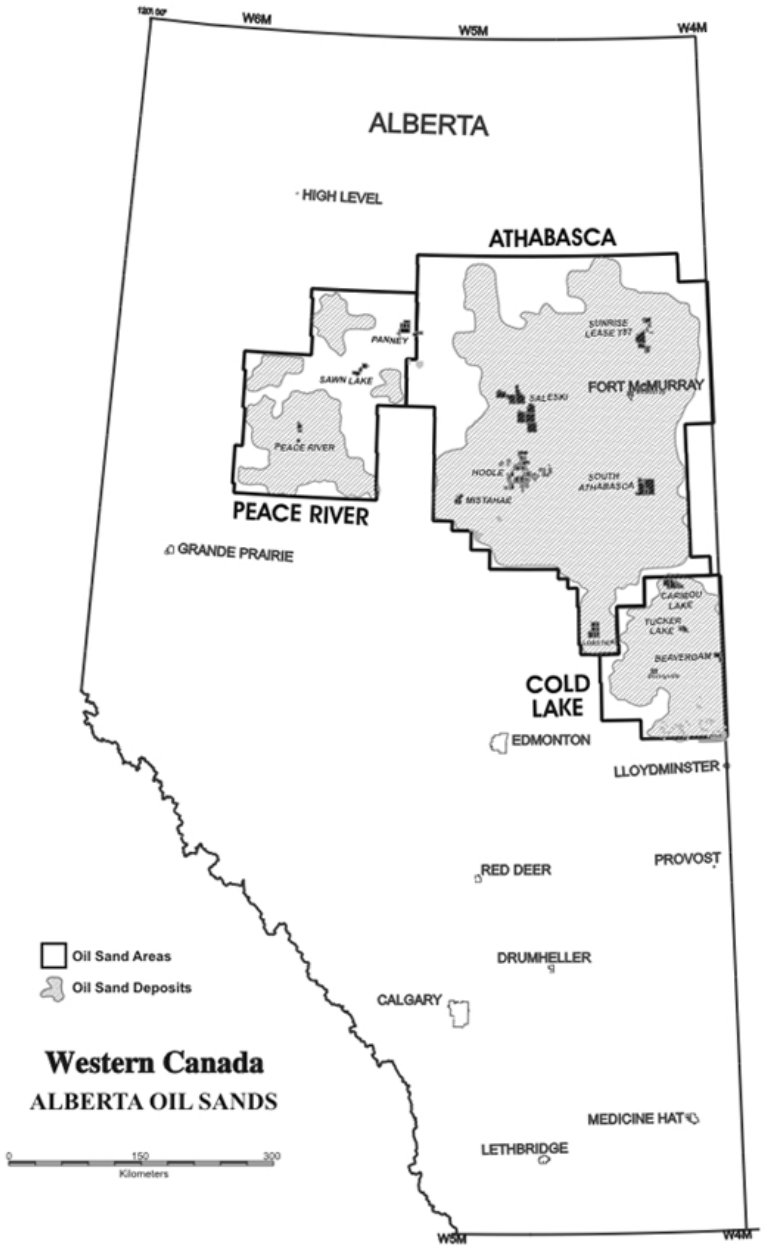
General Location Name	Oil Sands Area	Gross Acres	Net Acres	Husky Operator
South Athabasca — overriding royalty	Athabasca	35,601	—	No
South Athabasca	Athabasca	22,032	11,016	Yes
Sunrise — In situ (1)	Athabasca	64,034	64,034	Yes
Misthae (Drowned, Martin Hills W. & Spur)	Athabasca	28,160	28,160	Yes
Saleski	Athabasca	154,880	154,880	Yes
Hoole — overriding royalty	Athabasca	47,040	—	No
Beaverdam	Cold Lake	11,520	11,520	Yes
Caribou (2)	Cold Lake	35,840	35,840	Yes
Lobstick	Cold Lake	37,120	37,120	Yes
Tucker (3)	Cold Lake	11,360	11,360	Yes
Panny (Senex & Welstead)	Peace River	47,360	47,360	Yes
Peace River (Cadotte Lake)	Peace River	11,840	11,840	Yes
Sawn Lake (Loon)	Peace River	20,480	20,480	Yes
		527,267	433,610	

Notes:

(1) Included in the gross and net amounts are an additional 6,400 acres of petroleum and natural gas rights held as protection acreage for gas over bitumen issues. In 2003, the Alberta regulatory authority issued General Bulletin GB 2003-28 that required natural gas wells within certain bitumen prone areas to be shut-in. The production of natural gas where natural gas reservoirs were believed to be in pressure contact with bitumen reserves was deemed to present an unacceptable risk to future in-situ bitumen production. Sunrise was formerly named Kearl.

(2) Husky also has the exclusive right to acquire an additional 65,280 acres in the Caribou area.

(3) Included in the gross and net amounts are an additional 1,280 acres of petroleum and natural gas rights held as protection acreage for gas over bitumen issues.


W6M
W5M
W4M
ALBERTA
HIGH LEVEL
ATHABASCA
PANNEY
SAWN LAKE
PEACE RIVER
SUNRISE LEASE 137
SALESKI
FORT McMURRAY
HOOLE
MISTAHAE
SOUTH ATHABASCA
PEACE RIVER
GRANDE PRAIRIE
CARIBOU LAKE
TUCKER LAKE
BEAVERDAM
COLD LAKE
EDMONTON
LLOYDMINSTER
RED DEER
PROVOST
DRUMHELLER
CALGARY
MEDICINE HAT
LETHBRIDGE
Oil Sand Areas
Oil Sand Deposits
Western Canada
ALBERTA OIL SANDS
0
150
300
Kilometers
W5M
W4M

Offshore East Coast — Canada

Husky's offshore East Coast exploration and development program is focused in the Jeanne d'Arc Basin on the Grand Banks offshore the coast of Newfoundland and Labrador, which contains the Hibernia, Terra Nova and White Rose oil fields. We hold ownership interests in the Terra Nova and White Rose oil fields as well as in a number of smaller fields in the central part of the basin. We presently hold working interests ranging from 5.33 to 90 percent in 15 Significant Discovery License (''SDL'') areas in the Jeanne d'Arc Basin. We are also the operator of nine exploration licenses (''EL'') on the Grand Banks and two in the South Whale Basin. In 2004, we acquired 3 ELs. Licenses 1089 and 1090 cover 354,000 square acres between the White Rose SDLs and our EL over the Northern Jeanne d'Arc Basin. We operate both 1089 and 1090 licenses, holding a 100% interest in EL1090 and a 50% interest in EL1089. Husky also holds a 100% interest in EL1091, which flanks the eastern margin of the White Rose field. We believe that our geotechnical expertise, drilling experience and extensive database with respect to offshore the East Coast of Canada provide a strong foundation for future exploration and development. We also believe that there is exploration potential in the area, and that our position off the East Coast of Canada will provide growth opportunities for light crude oil production in the medium to long-term.

We will continue technical evaluation of our East Coast exploration acreage. In 2005, we plan to acquire 3D seismic over several license areas in the Northern Jeanne d'Arc Basin. Depending on drilling rig availability, we also plan to drill one exploration type stratigraphic test well on the EL1059 in the South Whale Basin in 2005.

Terra Nova Oil Field

The Terra Nova oil field is located approximately 350 kilometres south-east of St. John's, Newfoundland and Labrador, 35 kilometres south-east of the Hibernia oil field, in 91 to 100 metres of water. The Terra Nova oil field is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Our current pooled interest in the Terra Nova field is 12.51%. This interest is subject to change, pending re-determination once the field has been further delineated. Production at Terra Nova commenced in January 2002. Our gross production from Terra Nova averaged approximately 10.5 mbbls/day in the fourth quarter of 2004. Husky's gross share of production from Terra Nova was 5.0 mmbbls in 2004.

As at December 31, 2004, there were ten development wells drilled in the Graben area, six producing wells and four injection wells. In the East Flank area there were ten development wells including six production wells and four injection wells. Drilling operations are expected to continue based on a 36 well depletion plan for the Graben and East Flank areas. Subject to regulatory approval, the operator plans to commence production from a portion of the Far East area in 2005 through the use of extended reach wells drilled from the East Flank sub sea template. Drilling additional delineation wells in the Far East area is a high priority for us and we continue to promote locations to be considered as part of the 2005 drilling program. As at December 31, 2004, we had booked 15.6 mmbbls of gross light crude oil in the proved developed category and 8.0 mmbbls of proved undeveloped. These reserves are estimated to be capable of being produced using primary and secondary (waterflood and gasflood) production techniques.

White Rose Oil Field

The White Rose oil field, which is operated by us, is located 354 kilometres off the coast of Newfoundland and Labrador approximately 48 kilometres east of the Hibernia oil field on the eastern section of the Jeanne d'Arc basin. Husky's interest in the White Rose oil field is 72.5%.

Early in 2004, the SeaRose FPSO (floating production storage and offloading vessel) sailed into Marystown, Newfoundland and Labrador following a naming ceremony and 14,000 nautical mile journey from South Korea. At Marystown construction of the topsides modules continued. On July 31, 2004 the White Rose project passed a critical juncture in its development when the final topsides module was lifted from quayside at the fabrication facility in Marystown, onboard the FPSO. A total of 17 modules (a combined weight of approximately 12,000 metric tons) were successfully installed onto the hull. The remainder of the topsides hookup and commissioning work is being carried out in preparation for sailaway during the third quarter of 2005. At that time, the SeaRose FPSO will depart Marystown for the White Rose field and begin preparations for start of production later in 2005 or early in 2006.

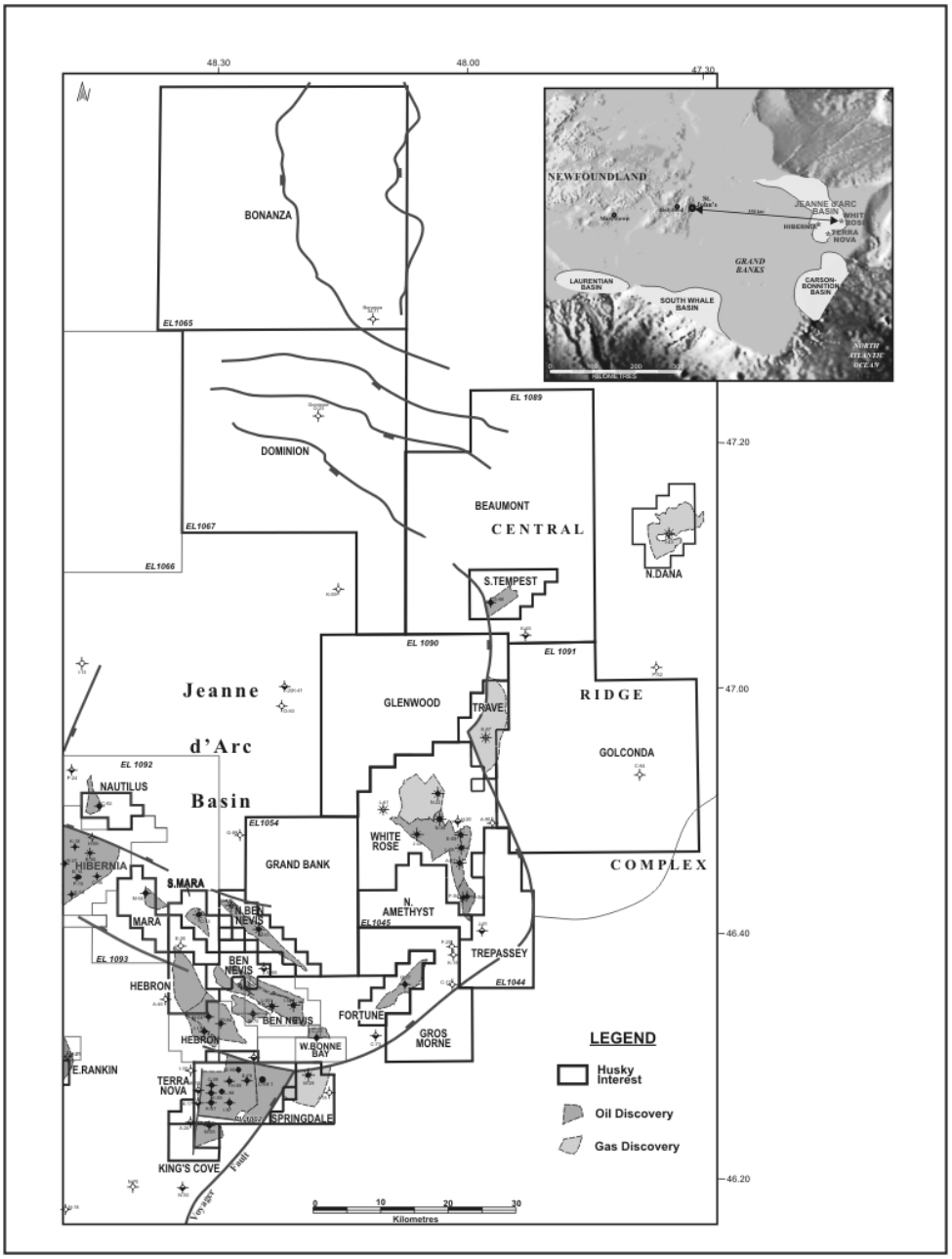
At the White Rose field, the FPSO mooring system, including the riser buoy, was successfully installed. Upon the arrival of the SeaRose FPSO, the riser buoy will be pulled into the turret, providing the anchor point for the FPSO. Development drilling activity at the field is on schedule with six wells drilled as at the end of 2004, including one production well, one gas injection well and four water injection wells. All well results were as predicted, or better. The

first production well was tested, with flow rates of 25-35 mbbls/day, the first gas injection well flowed at 60 mmcf/day and the first water injection well tested at an injection rate of 47 mbbls/day.

In 2004, we commenced studies to evaluate the viability of producing and transporting natural gas from White Rose, and solicited expressions of interest from contractors and engineering firms to assess the key technical, economic and regulatory issues critical to a safe and reliable natural gas development on the Grand Banks, as well as the capital and operating costs of such a development. The solicitation will result in three pre-front end engineering and design studies.

East Coast

Central and Northern Jeanne d'Arc Basin



International

Our international exploration and development program is focused on Southeast Asia. In China, we have a 40 percent interest in one producing oil field and interests in six exploration blocks. The bulk of these interests are in the South China Sea where Husky recently added the deep-water block 29-26, to our South China Sea interests. In Indonesia, we have a 100 percent interest in the Madura block.

South China Sea

Wenchang

The Wenchang oil field is located in the western Pearl River Mouth Basin, approximately 300 kilometres south of Hong Kong and 135 kilometres east of Hainan Island. We hold a 40 percent working interest in the oil fields, which commenced production in July 2002. The Wenchang 13-1 and 13-2 oil fields are producing from 21 wells in 100 metres of water into a floating production, storage and offloading vessel stationed between fixed platforms located in the fields. The blended crude oil from the two fields averages approximately 35° API, similar to the benchmark Minas blend. At December 31, 2004, our proved reserves at Wenchang were 19.4 mmbbls of crude oil. Our gross production averaged 19.7 mbbls/day during 2004.

Block 39/05

We executed a production sharing contract with China National Offshore Oil Corporation (''CNOOC'') for the 5,700 square kilometres 39-05 Exploration Block surrounding the Wenchang fields with a commencement date of October 1, 2001. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. In January 2003, the Qionghai 18-1-3 exploration type stratigraphic well on the block was plugged and abandoned without testing and in February 2003, the Wenchang 8-1-1 exploration type stratigraphic well was plugged and abandoned without testing. In 2004, we relinquished 25 percent of Block 39-05. Husky is evaluating the geological information for the remainder of this block and expects to begin exploration work in late 2005 or early 2006.

Blocks 23/15 and 23/20

We executed production sharing contracts with CNOOC for the 23-15 and 23-20 exploration blocks with a commencement date of December 1, 2002. Both contract areas are located in the South China Sea north of Hainan, within 80 kilometres of the Weizhan oil fields. The 23-15 block is 1,327 square kilometres and the 23-20 block is 1,543 square kilometres. The work program requires Husky to drill a single exploration well on each block within three years. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. In 2003, we completed a 1,000 square kilometre 3-D seismic survey shot over a portion of block 23-15. We have completed our technical evaluation and expect to fulfil our Phase I drilling obligations on both blocks in 2005.

Block 29/26

We executed a production sharing contract with CNOOC for the 29-26 exploration block with a commencement date of October 1, 2004. The block is located in the South China Sea approximately 300 kilometres south east of Hong Kong and 65 kilometres south east of the Panyu gas discovery. The block covers an area of 3,965 square kilometres. The production sharing contract requires the drilling of one exploration well within three years and has a minimum work commitment of U.S. $8 million. CNOOC has the right to participate in development of any discoveries up to a 51% working interest. We are currently conducting a geological evaluation of the block and are working toward drilling an exploration well.

Block 40/30

We executed a production sharing contract with CNOOC for the 40-30 exploration block with a commencement date of February 1, 2003. The block is located in the South China Sea approximately 100 kilometres south of the Wenchang 13-1 and 13-2 oil fields. The block covers an area of 6,704 square kilometres. The production sharing contract requires the drilling of one exploration well within three years and has a minimum work commitment of U.S. $10 million. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. We fulfilled our Phase I obligations of the petroleum contract with the drilling of ChangChang (''CC'') 12-1-1. The CC 12-1-1 is the deepest-water well in the South China Sea to date. The CC12-1-1 well was plugged and abandoned without testing. We expect to complete the geological re-evaluation of the block with information gained from CC12-1-1 well.

East China Sea

Block 04/35

We executed a production sharing contract with CNOOC for the 04-35 exploration block with a commencement date of December 1, 2003. The block is located in the East China Sea approximately 350 kilometres east of the city of Shanghai and covers an area of 4,835 square kilometres. The production sharing contract requires the drilling of a single exploration well in the first exploration phase to a depth of 2,500 metres within three years and a minimum work commitment of U.S. $3 million. Technical evaluations of the hydrocarbon potential are complete and we expect to fulfill our first phase commitments early in 2006. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest.

China

Madura Strait, Indonesia

We have a 100 percent interest in a production sharing contract (''PSC''), which provides for various cost and production sharing arrangements, relating to a 2,794 square kilometre block in the Madura Strait offshore Java, Indonesia. Ten exploration and appraisal wells have been drilled in the block, resulting in discoveries of two natural gas fields. The Indonesian state oil company granted commercial status and approved a plan of development for one of

these fields in order to supply natural gas to a proposed independent power plant near Pasuruan, East Java. Construction of the power plant did not proceed due to economic issues that occurred in Indonesia shortly after the natural gas sales contract was signed. In 2003 the natural gas sales contract was cancelled with the approval of the Indonesian authorities. In January 2003, we signed a memorandum of understanding to begin discussions intended to finalize a new natural gas sales contract for the Madura production. In 2005, we expect to complete negotiation of the gas sales contract, and submit a revised Plan of Development to the Indonesian regulatory authority for approval.

Shatirah, Libya

Husky has an interest in a small crude oil production operation in the Shatirah field, onshore Libya.

Distribution of Oil and Gas Production

Crude Oil and NGL

Husky provides heavy crude oil feedstock to its upgrader and its asphalt refinery, which are located at Lloydminster. The combined dry crude feedstock requirements of the upgrader and asphalt refinery are equal to approximately 75 percent of Husky's heavy crude oil production from the Lloydminster area. Husky also markets heavy crude oil production directly to refiners located in the mid-west and eastern United States and Canada. Husky markets its light and synthetic crude oil production to third party refiners in Canada, the United States and Asia. Natural gas liquids are sold to local petrochemical end users, retail and wholesale distributors and to refiners in North America.

Husky markets third party volumes of light crude oil, heavy crude oil and NGL in addition to its own production.

Natural Gas

The following table shows the distribution of Husky's gross average daily natural gas production for the years indicated:

	Years ended December 31,		
	2004	2003	2002
		(mmcf/day)	
Sales to end users			
United States	407	382	375
Canada	187	156	115
	594	538	490
Sales to aggregators	34	43	49
Internal use (1)	61	30	30
	689	611	569

Note:

(1) Husky consumes natural gas for fuel at several of its facilities.

We also market third party natural gas production in addition to our own production.

Delivery Commitments

The following table shows the future commitments to deliver natural gas from our reserves in Western Canada. Our proved developed reserves of natural gas in Western Canada are more than adequate to meet future delivery commitments.

	Fixed Price		Market Price
	Bcf	$/mmbtu	Bcf
2005	25.5	3.67	47.1
2006	25.5	3.83	44.8
2007	20.0	4.47	39.7
2008	20.0	4.71	16.9
2009	20.0	4.96	4.9
2010	20.0	5.23	0.5
2011	20.0	5.28	—
2012	20.0	5.32	—
2013	20.0	5.37	—
2014	6.2	3.74	—

Midstream Operations

Overview

The midstream operations include:

- Upgrading — the upgrading of heavy crude oil feedstock into synthetic crude oil;
- Infrastructure — pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas, extraction of NGL from natural gas, cogeneration of electrical and thermal energy; and
- Marketing — the purchase and marketing of Husky's and other producers' crude oil, natural gas, NGL, sulphur, petroleum coke and electrical power.

Upgrading Operations

Husky owns and operates the Husky Lloydminster Upgrader, which is a heavy oil upgrading facility located in Lloydminster, Saskatchewan.

The Husky Lloydminster Upgrader is designed to process blended heavy crude oil feedstock into high quality, low sulphur synthetic crude oil. Synthetic crude oil is used as feedstock for the refining of premium transportation fuels in Canada and the United States. In addition, the Husky Lloydminster Upgrader recovers the diluent, which facilitates pipeline transportation of heavy crude oil, and returns it to field to be reused.

The Husky Lloydminster Upgrader provides heavy crude oil access to a new market, which we believe has facilitated, and will continue to stimulate heavy oil production in the area. The market for heavy crude oil previously was either as feedstock for asphalt production or it was sold as blended heavy crude oil for feedstock for specific refineries designed to process or upgrade heavier crude oils. The Husky Lloydminster Upgrader was commissioned in 1992 with an original design capacity of 46 mbbls/day of synthetic crude oil. Actual production has ranged considerably higher than the original design rate capacity as a result of throughput modifications and improved reliability. The upgrader's current rated capacity exceeds 61 mbbls/day of synthetic crude oil. Production at the upgrader averaged 55.2 mbbls/day of synthetic crude oil and 9.4 mbbls/day of diluent in 2004 compared with 61.6 mbbls/day of synthetic crude oil and 10.9 mbbls/day of diluent in 2003. Throughput at the upgrader in 2004 was lower than 2003 due to unplanned outages for repairs during 2004. In addition to synthetic crude oil and diluent, the Husky Lloydminster Upgrader also produced, as by-products of its upgrading operations, approximately 311 lt/day of sulphur and 396 lt/day of petroleum coke during 2004. These products are sold in local and international markets. The profitability of our upgrading operations is primarily dependent upon the differential between the price of synthetic crude oil and the price of heavy crude oil.

The upgrader is currently undergoing a number of debottleneck projects. These projects, upon completion in late 2006, are expected to increase upgrading capacity to 82 mbbls/day of synthetic crude oil and diluent.

Infrastructure and Marketing

Heavy Oil Pipeline Systems and Processing Facilities

Husky has been involved in the gathering, transporting and storage of heavy crude oil in the Lloydminster area since the early 1960s. Our crude oil pipeline systems include approximately 2,050 kilometres of pipeline and are capable of transporting in excess of 575 mbbls/day of blended heavy crude oil, diluent and synthetic crude oil. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through the Husky Lloydminster Upgrader and our asphalt refinery in Lloydminster. Blended heavy crude oil from the field and synthetic crude oil from the upgrading operations are moved south to Hardisty, Alberta to a connection of the Enbridge Pipeline system and the Express Pipeline system. The crude oil is transported to eastern and southern markets on these pipelines. Our crude oil pipeline systems also have feeder pipeline interconnections with the Cold Lake Partnership Pipeline, the Enbridge Athabasca Pipeline and the Talisman Chauvin Pipeline.

The following table shows the average daily pipeline throughput for the periods indicated:

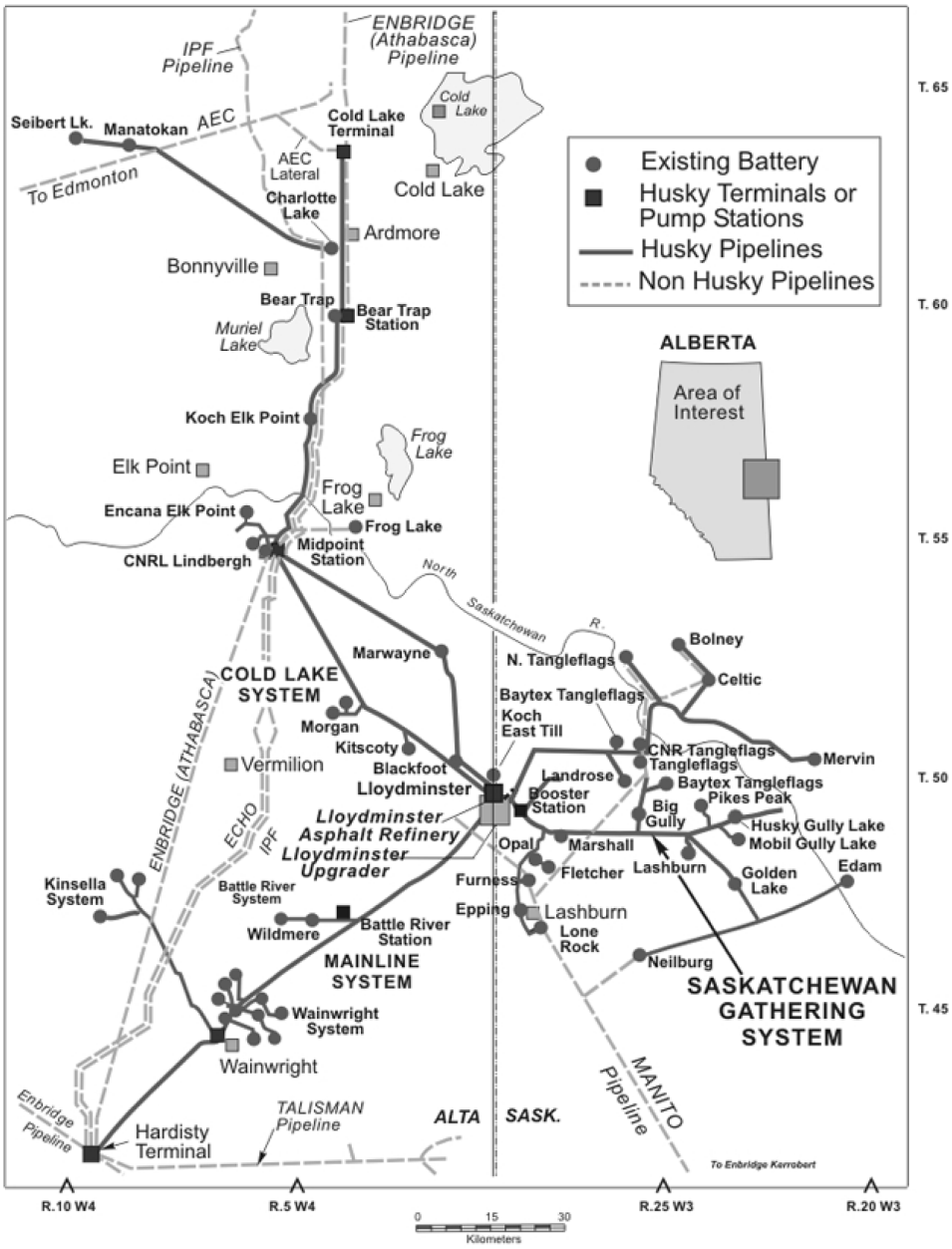
	Years ended December 31,		
	2004	2003	2002
		(mbbls/day)	
Combined pipeline throughput	492	484	457

In recent years Husky has expanded and expects to further expand its heavy crude pipeline systems to capitalize on anticipated increases in heavy oil production from the Lloydminster and Cold Lake areas.

We consider the expansion and optimization of our pipeline systems in the Lloydminster area to be necessary to further our own development objectives in the area. As a result of recent expansion of mainline pipeline systems in the area, competition for throughput volumes has increased.

We operate 16 heavy crude oil processing facilities located throughout the Lloydminster area. These facilities process Husky's and other producers' raw heavy crude oil from the field by removing sand, water and other impurities to produce clean dry heavy crude oil. The heavy crude oil is then blended with a diluent to meet pipeline specifications for transportation.

Heavy Oil Pipeline Systems



Cogeneration

Husky has a 50 percent interest in a 215 MW natural gas fired cogeneration facility at the site of the Husky Lloydminster Upgrader. The plant was commissioned in December 1999. Electricity produced at the facility is being sold to Saskatchewan Power Corporation under a 25 year power purchase agreement effective in 1999. Thermal energy (steam) is sold to the Husky Lloydminster Upgrader.

Husky has a 50 percent interest in a 90 MW natural gas fired cogeneration facility adjacent to Husky's Rainbow Lake processing plant. The cogeneration plant produces electricity for the Alberta Power Pool and thermal energy (steam) for the Rainbow Lake processing plant. It provides power directly to the Alberta Power Pool under an agreement with the Alberta Transmission Administrator to provide additional electricity generating capacity and system stability for north-western Alberta. The power plant has the capability of being expanded to approximately 110 MW in total. Husky is the operator of the facility.

Natural Gas Storage Facilities

Husky has been operating a natural gas storage facility at Hussar, Alberta since April 2000. The facility has a working storage capacity of 17 bcf of natural gas. Husky is continuing to evaluate additional storage opportunities within Western Canada.

Commodity Marketing

Husky is a marketer of both its own and third party production of crude oil, synthetic crude oil, NGL, natural gas and sulphur. We also market petroleum coke, a by-product from the Lloydminster upgrader. We supply feedstock to our upgrader and asphalt refinery from our own and third party heavy oil production sourced from the Lloydminster and Cold Lake areas. We also sell blended heavy crude oil directly to refiners based in the United States and Canada. Our extensive infrastructure in the Lloydminster area supports its heavy crude oil refining and marketing operations.

We market light and medium crude oil and NGL sourced from our own production and third party production. Light crude oil is acquired for processing by third party refiners at Edmonton, Alberta and by our refinery at Prince George, British Columbia. We market the synthetic crude oil produced at our upgrader in Lloydminster to refiners in Canada and the United States.

We market natural gas sourced from our own production and third party production. We are currently committed to gas sales contracts with third parties, which in aggregate do not exceed amounts forecast to be deliverable from our reserves. Our contracts are with customers located in eastern Canada/north-eastern United States (28 percent), mid-west United States (23 percent), Western Canada (46 percent) and west coast United States (3 percent). The natural gas volumes sales contracted are primarily at market prices (90 percent). The terms of the contracts remaining at December 31, 2004 are up to one year (72 percent), one year to five years (20 percent) and over five years (8 percent). Husky has acquired rights to firm pipeline capacity to transport the natural gas to most of these markets.

We have developed our commodity marketing operations to include the acquisition of third party volumes in order to increase volumes and enhance the value of our midstream assets. We plan to expand our marketing operations by continuing to increase marketing activities. We believe that this increase will generate synergies with the marketing of our own production volumes and the optimization of our assets.

Refined Products

Overview

Husky's refined products operations include refining and retail, commercial and wholesale marketing of refined petroleum products. Our retail network provides a platform for substantial non-fuel related businesses.

Light oil refined products are produced at our refinery at Prince George, British Columbia and are also acquired from third party refiners and marketed through Husky and Mohawk branded retail and commercial petroleum outlets and through direct marketing to third party dealers and end users. Asphalt and residual products are produced at Husky's asphalt refinery at Lloydminster and are marketed directly or through Husky's 8 emulsion plants, four of which are also asphalt terminals located throughout Western Canada.

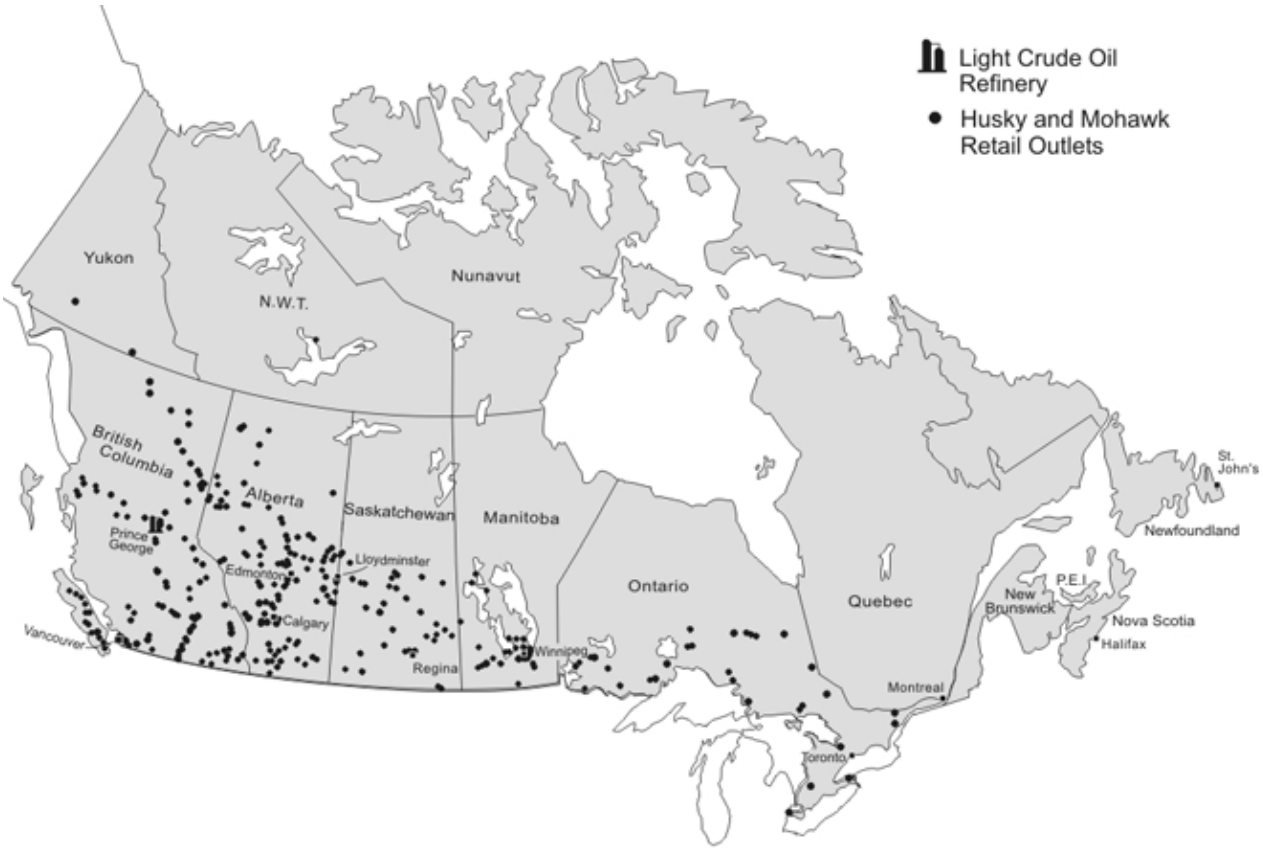
Branded Petroleum Product Outlets and Commercial Distribution

Distribution

As of December 31, 2004, there were 531 independently operated Husky and Mohawk branded petroleum product outlets. These petroleum product outlets include service stations, travel centres and bulk distribution facilities located from Vancouver Island on the West Coast of Canada to the eastern border of Ontario. The travel centre network is strategically located on major highways and serves the retail market and commercial transporters 24 hours per day, 365 a year with quality products and full service Husky House restaurants. At most locations, the travel centre network also features the proprietary ''Route Commander'' cardlock system that enables commercial users to purchase products using a card system that will electronically process transactions and provide detailed billing, sales tax and other information. A variety of full and self serve retail locations under the Mohawk and Husky brand names serve urban and rural markets, while Husky and Mohawk bulk distributors offer direct sales to commercial and farm markets in Western Canada.

Retail Marketing System

Branded Petroleum Product Outlets



Independent retailers or agents operate all Husky and Mohawk branded petroleum product outlets. Branded outlets feature varying services such as 24 hour service, convenience stores, service bays, car washes, Husky House full service family style restaurants, proprietary and co-branded quick serve restaurants, bank machines and alternate fuels such as propane and compressed natural gas. In addition to conventional gasolines, ethanol blended fuels branded as ''Mother Nature's Fuel'' and additive enhanced ''Diesel Max'' are offered in all markets together with Chevron lubricants. Husky supplies refined petroleum products to its branded independent retailers on an exclusive basis and provides financial and other assistance for location improvements, marketing support and related services. Husky's brands are promoted through the Husky Snowstars Program, various national and university athletic sponsorships as well as advertising designed to reach both national and regional audiences.

The following table shows the number of Husky and Mohawk branded petroleum outlets by class of trade and by province as of December 31, 2004:

Retail Outlets	British Columbia & Yukon	Alberta	Sask.	Manitoba	Ontario	Total	2003 Total
Travel Centres	9	8	4	2	13	36	37
Full Serve	12	17	3	3	2	37	46
Full/Self Serve	17	24	6	10	2	59	48
Self Serve	19	11	1	1	2	34	35
Bulk Distributor	1	7	4	1	1	14	14
Card/Key Locks	2	6	—	—	2	10	7
	60	73	18	17	22	190	187
Leased							
Travel Centres	1	—	—	—	—	1	1
Full Serve	3	12	5	4	—	24	30
Full/Self Serve	13	23	4	6	—	46	44
Self Serve	31	20	—	1	—	52	47
Bulk Distributor	3	—	—	—	—	3	3
Card/Key Locks	4	1	—	3	1	9	8
	55	56	9	14	1	135	133
Independent Retailers							
Travel Centres	1	1	—	—	4	6	6
Full Serve	24	21	9	16	7	77	84
Full/Self Serve	18	3	5	1	1	28	40
Self Serve	31	46	3	3	2	85	89
Bulk Distributor	2	4	1	—	—	7	7
Card/Key Locks	—	1	—	—	2	3	4
	76	76	18	20	16	206	230
Total							
Travel Centres	11	9	4	2	17	43	44
Full Serve	39	50	17	23	9	138	160
Full/Self Serve	48	50	15	17	3	133	132
Self Serve	81	77	4	5	4	171	171
Bulk Distributor	6	11	5	1	1	24	24
Card/Key Locks	6	8	—	3	5	22	19
	191	205	45	51	39	531	550
Cardlocks (1)	24	18	4	6	22	74	72
Convenience Stores (1)	179	185	40	47	33	484	507
Restaurants	11	12	4	2	16	45	41

Note:

(1) All of these are located at branded petroleum outlets.

We also market refined petroleum products directly to various commercial markets, including independent dealers, national rail companies and major industrial and commercial customers in Western Canada and the north-western United States.

The following table shows our average daily sales volumes of light refined petroleum products for the periods indicated:

	Years ended December 31,		
	2004	2003	2002
		(mbbls/day)	
Gasoline	28.3	28.5	26.3
Diesel fuel	23.9	22.1	20.7
Liquefied petroleum gas	1.1	1.2	1.3
	53.3	51.8	48.3

Our strategy in respect of our petroleum product outlets includes continuing to increase profits and sales through the strategic location of new outlets, the enhancement of ancillary non-fuel income streams, the modernization, automation and upgrading of existing petroleum product outlets, expanding customer loyalty programs and the sale of non-core locations. We also plan to continue to enter into strategic alliances with third parties to sell various consumer products at Husky and Mohawk branded petroleum outlets in order to generate revenue and increase demand for other products and services provided at those outlets. We are pursuing acquisitions and joint venture opportunities to further enhance our existing distribution network.

Supply

Prince George Refinery. Husky owns and operates a refinery at Prince George, British Columbia, which has capacity to refine more than 10,000 bbls/day of light crude oil into a full range of refined petroleum products. The crude oil feedstock for the Prince George refinery is produced primarily in north-eastern British Columbia by other producers and delivered to our refinery by pipeline. We are pursuing acquisitions and trading opportunities to further enhance our existing refining capacity. We are currently upgrading the refinery to meet new Federal regulations governing sulphur content in fuel.

Other Supply Arrangements. In addition to the refined petroleum products supplied by the Prince George refinery, Husky has established processing arrangements with major refiners. Processing arrangements allow us to participate in industry refining margins. Primarily Husky crude oil production and some third party purchased crude oil is delivered to major refiners, who process the crude oil into refined products, which are then marketed by us through our retail networks and to our wholesale customers. During 2004, these refiners processed an average of approximately 35.9 mbbls/day of crude oil for us, yielding approximately 33.6 mbbls/day of refined petroleum products. During 2004, we also purchased approximately 9.1 mbbls/day of refined petroleum products from refiners and acquired approximately 5.9 mbbls/day of refined petroleum products pursuant to exchange agreements with third party refiners.

Ethanol Plants. Husky owns an ethanol plant at Minnedosa, Manitoba that produces nine million litres per year of fuel ethanol and one million litres per year of industrial alcohol. We are planning to expand our current capacity to 130 million litres per year of ethanol production at the Minnedosa plant. Ethanol is produced primarily from wheat and other grains. It is an oxygenate, which when added to gasoline, promotes fuel combustion, raises octane levels and inhibits water from freezing in fuel lines. The ethanol blended gasoline (Mother Nature's Fuel) has received federal government recognition for its low combustion emissions. We are currently constructing another ethanol plant at Lloydminster Saskatchewan that will have the capacity to produce 130 million litres per year. Ethanol-blended gasoline is now available at all Husky and Mohawk retail outlets. We also supply E85 (85 percent ethanol content blended gasoline) to some Federal Government fleet vehicles across Western Canada.

Asphalt Products

We have been in the paving and specialty asphalt business for over 50 years. We supply asphalt products to customers across Western Canada and the north-western and midwestern United States. We have a significant market share for paving asphalt, emulsified asphalt and asphalt products sold in Western Canada. Most of the asphalt sold is used for paving and other industrial purposes. Our Pounder Emulsions division manufactures modified and conventional road application emulsion products. Additional non-asphalt based road maintenance products are marketed and distributed through the Western Road Management division of Husky. Demand for higher quality asphalt products has allowed us to increase sales into the United States and Eastern Canada, with products occasionally being shipped as far away as Texas, Florida and New Brunswick. In 2004, 51 percent of our asphalt production was exported

to the United States. We plan to continue our efforts to improve our asphalt business by increasing modified asphalt production capacity to produce better products at a lower cost. We are also studying the feasibility of expanding production and distribution capacity.

Husky's asphalt distribution network consists of four emulsion/asphalt terminals located at Kamloops, British Columbia; Lethbridge, Alberta; Yorkton, Saskatchewan; and Winnipeg, Manitoba and four emulsion plants located at Edmonton, Alberta; Watson Lake, Yukon; Lloydminster and Saskatoon, Saskatchewan. Husky also utilizes an independently operated terminal at Langley, British Columbia.

All of our asphalt requirements are supplied by our Lloydminster, Alberta asphalt refinery. The refinery was commissioned in 1983, replacing a Husky facility that had been operating since 1947. The refinery was designed specifically to produce asphalt from heavy crude oil at a rate of 25 mbbls/day. The crude oil feedstock for the Lloydminster refinery is supplied through Husky's pipeline systems from the supply of heavy crude oil in the region, including Husky's heavy crude oil.

The following table shows our average daily sales volumes of products produced at the Lloydminster refinery, for the years indicated:

	Years ended December 31,		
	2004	2003	2002
		(mbbls/day)	
Asphalt	14.0	12.9	12.7
Residual and other	8.5	9.1	8.1
	22.5	22.0	20.8

Refinery throughput averaged 25.4 mbbls/day of blended heavy crude oil feedstock during 2004. Due to the seasonal demand for asphalt products the refinery historically has operated at full capacity only during the normal paving season in Canada and the northern United States. We have implemented various plans to increase refinery throughput during the other months of the year, such as producing low sulphur diesel, entering into custom processing arrangements and developing other U.S. and international markets for asphalt products.

Human Resources

The number of employees in each business segment was as follows:

	December 31,	
	2004	2003
Upstream	1,822	1,753
Midstream	347	326
Refined Products	358	349
Corporate and business support	505	471
	3,032	2,899

DIVIDENDS

The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31:

	2004	2003	2002
Cash dividends declared per common share	$1.00	$1.38	$0.36

Dividend Policy and Restrictions

The Board of Directors of Husky have established a dividend policy that pays quarterly dividends. From August 2000 to July 2003, Husky has paid a quarterly dividend of $0.09 ($0.36 annually) per common share. From August 2003 to July 2004, Husky paid $0.10 ($0.40 annually) per common share. This policy was reviewed by the Board in April 2004 and the quarterly dividend was increased to $0.12 ($0.48 annually) per common share. The Board has declared special cash dividends in the amount of $1.00 per common share in July, 2003 and $0.54 per common share in

November, 2004. Husky's dividend policy will continue to be reviewed and there can be no assurance that further dividends will be declared.

The declaration and payment of dividends will be at the discretion of the Board, which will consider earnings, capital requirements and financial condition of Husky, the satisfaction of the applicable solvency test in Husky's governing corporate statute, the *Business Corporations Act* (Alberta), and other relevant factors.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

Husky is authorized to issue an unlimited number of common shares. Holders of common shares are entitled to one vote per share at meetings of shareholders of Husky, to receive such dividends as declared by the Board of Directors on the common shares and to receive pro-rata the remaining property and assets of Husky upon its dissolution or winding up, subject to any rights having priority over the common shares.

Preferred Shares

Husky is authorized to issue an unlimited number of preferred shares. Holders of preferred shares shall not be entitled to vote at meetings of Husky, are entitled to receive such dividends as and when declared by the Board of Directors in priority to common shares and shall be entitled to receive pro-rata in priority to holders of common shares the remaining property and assets of Husky upon its dissolution or winding up. There are no preferred shares currently outstanding.

Credit Ratings Summary

	Rating	Last Review	Last Rating Change
Moody's:			
Outlook	Stable	July 27, 2004	—
Senior Unsecured Debt	Baa2	July 27, 2004	April 25, 2001
U.S. Senior Secured Bonds	Baa2	June 4, 2003	April 25, 2001
Capital Securities	Ba1	July 27, 2004	April 25, 2001
Standard and Poor's:			
Outlook	Positive	June 8, 2004	October 3, 2002
Senior Unsecured Debt	BBB	June 8, 2004	—
U.S. Senior Secured Bonds	BBB	June 8, 2004	—
Capital Securities	BB+	June 8, 2004	—
Dominion Bond Rating Service:			
Trend	Stable	May 1, 2003	—
Senior Unsecured Debt	BBB (high)	May 1, 2003	
Capital Securities	BBB	May 1, 2003	—
Fitch:			
Outlook	Stable	June 8, 2004	—
Senior Unsecured Debt	BBB+	June 8, 2004	—
U.S. Senior Secured Bonds	A-	June 8, 2004	
Capital Securities	BBB-	June 8, 2004	—

Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities. The credit ratings accorded to Husky's securities by the rating agencies are not recommendations to purchase, hold or sell the securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

Moody's

Moody's credit rating system ranges from Aaa (highest) to C (lowest). Debt securities rated within the Baa category are considered medium grade debts; they are neither highly protected nor poorly secured. Interest payments and principal security appears to be adequate at the time of the rating however they are subject to potential adverse

circumstances over time. As a result these debt securities possess some speculative characteristics. The addition of a 1, 2 or 3 modifier indicates an additional relative standing within the general rating classification. The addition of the modifier 1 indicates the debt is positioned in the top one third of the general rating classification, 2 indicates the mid one third and 3 indicates the bottom one third.

Standard and Poor's

Standard and Poor's credit rating system ranges from AAA (highest) to D (lowest). Debt securities rated within the BBB category are considered to possess adequate protection parameters. However, they could potentially change subject to adverse economic conditions or other circumstances that may result in reduced capacity of the debtor to continue to meet principal and interest payments. As a result these debt securities possess some speculative characteristics. The addition of the modifier + or – indicates the debt is positioned above (+) or below (–) the mid range of the general category.

Dominion Bond Rating Service

Dominion Bond rating Service's credit rating system ranges from AAA (highest) to D (lowest). Debt securities rated within the BBB category are considered to be of adequate credit quality. Protection of interest and principal is considered acceptable, but the debtor is susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the debtor and its rated debt. The addition of the high or low modifier denotes that the rating is either above or below the mid range or the general rating category.

Fitch

Fitch's credit rating system ranges from AAA (highest) to D (lowest). Debt securities rated within the BBB category indicate that there is currently a low expectation of credit risk. The capacity for timely payment of financial commitments is considered adequate, but adverse changes in circumstances or in economic conditions are more likely to impair this capacity. The addition of the modifier + or – indicates the debt is positioned above (+) or below (–) the mid range of the general category. The A category denotes that the debtor's capacity with regard to the rated debt is strong rather than adequate.

MARKET FOR SECURITIES

Husky's common shares are listed and posted for trading on the Toronto Stock Exchange under the trading symbol ''HSE''.

The following table discloses the trading price range and volume of Husky's common shares traded on the Toronto Stock Exchange during Husky's financial year ended December 31, 2004:

	High	Low	Volume (000's)
January	24.99	22.74	6,757
February	25.55	22.73	6,754
March	28.04	25.50	9,313
April	28.30	25.10	8,118
May	27.90	24.45	7,221
June	26.50	23.74	11,315
July	29.25	25.42	12,552
August	29.35	26.81	11,114
September	31.15	27.65	11,407
October	33.57	30.59	11,638
November	35.65	30.05	13,323
December	34.49	30.90	12,457

DIRECTORS AND OFFICERS

The following are the names and municipalities of residence of the directors and officers of Husky, their positions and offices with Husky and their principal occupations during the past five years. The directors shall hold office until the next annual meeting of Husky shareholders or until their respective successors have been duly elected or appointed.

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
Li, Victor T.K. ..... Hong Kong	Co-Chairman and Director	August 25, 2000	Managing Director of Cheung Kong (Holdings) Limited (an investment holding and project management company) since 1999 and Deputy Chairman since 1994. Mr. Li has also been Deputy Chairman of Hutchison Whampoa Limited (an investment holding company) since 1999 and Executive Director since 1995. Mr. Li has been a Director and Chairman of CK Life Sciences Int'l., (Holdings) Inc. (a biotechnology company) since 2002 and has held the following positions for more than five years: a Director and Chairman of Cheung Kong Infrastructure Holdings Limited (an infrastructure development company), an Executive Director of Hongkong Electric Holdings Limited (a holding company). Mr. Li is also a Director of The Hongkong and Shanghai Banking Corporation Limited. Mr. Li is a member of the Standing Committee of the 10th National Committee of the Chinese People's Political Consultative Conference of the People's Republic of China and he is also a member of the Commission on Strategic Development and the Economic and Employment Council of the Hong Kong Special Administrative Region. Mr. Li holds a Bachelor of Science degree in Civil Engineering and a Master of Science degree in Structural Engineering.
Fok, Canning K.N. ..... Hong Kong	Co-Chairman and Director	August 25, 2000	Group Managing Director of Hutchison Whampoa Limited since 1993 and Executive Director since 1984. Mr. Fok has been a Director and Chairman of Hutchison Telecommunications International Limited (an investment holding company) since 2004 and of Hutchison Global Communications Holdings Limited (formerly Vanda Systems & Communications Holdings Limited) (an investment holdings company) since 2003. Mr. Fok has held the following positions for more than five years: a Director, and since 2002 Chairman of Hutchison Harbour Ring Limited (an investment holding company), a Director and Chairman of Hutchison Telecommunications (Australia) Limited (a telecommunications company), Partner Communications Company Ltd. (a telecommunications company), Deputy Chairman and a Director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited. Mr. Fok is also a director of Cheung Kong (Holdings) Limited and Hutchison Whampoa Finance (CI) Limited (a finance company). Mr. Fok is also a Non-Executive Director of Hanny Holdings Limited and Panvas Gas Holdings Limited. Mr. Fok was a director of VoiceStream Wireless Corporation from 1998 — 2001. Mr. Fok holds a Bachelor of Arts

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
			degree and is a member of the Australian Institute of Chartered Accountants.
Fullerton, R. Donald ..... Toronto, Ontario Canada	Director	May 1, 2003	Corporate Director. Mr. Fullerton has been a Director of George Weston Limited (a holding company) since 1991, Asia Satellite Telecommunications Holdings Limited since 1996 and Partner Communications Ltd. since 2003. Mr. Fullerton was a director of CIBC from 1974 until he retired in February 2004. Mr. Fullerton was also a director of Hollinger Inc. from 1992 to 2003, of Westcoast Energy Inc. from 1993 to 2003 and of IBM Canada Ltd. from 1982 to 2001.
Glynn, Martin J.G. ..... New York, New York U.S.A.	Director	August 25, 2000	President and Chief Executive Officer of HSBC Bank USA since 2003 and a director since 2000. Mr. Glynn has been a director of HSBC Bank Canada since 1999 and was President and Chief Executive Officer from 1999 to 2003. From 1982 Mr. Glynn held various senior executive positions with HSBC Bank Canada (formerly Hongkong Bank of Canada). Mr. Glynn has been a Director of HSBC North America Inc. since 2002, and a Director of HSBC USA Inc. Mr. Glynn is also a director of Wells Fargo HSBC Trade Bank N.A. and Group General Manager of HSBC Holdings plc.
Hui, Terence C.Y. ..... Vancouver, British Columbia Canada	Director	August 25, 2000	Director, President & Chief Executive Officer, Concord Pacific Group Inc. (a real estate development company) since 1997, Director and President of Adex Securities Inc. (a financial services company) since 1992 and Director and Chairman of Maximizer Software Inc. (formerly Multiactive Software Inc.) and Multiactive Technologies Inc. (computer software companies) since 1995. Mr. Hui was President and Chief Executive Officer of Pacific Place Developments Corp. (a real estate development company) from 1992 to 2001. Mr. Hui is a director of abc Multiactive Limited (a software company).
Kinney, Brent D. ..... Dubai, United Arab Emirates	Director	August 25, 2000	Independent businessman. Mr. Kinney is a director of Dragon Oil plc in the United Arab Emirates. Mr. Kinney was also a director of Aurado Energy Inc. from 2003 until 2004.
Kluge, Holger ..... Toronto, Ontario Canada	Director	August 25, 2000	Corporate Director. Mr. Kluge is a director of Hongkong Electric Holdings Limited, Hutchison Telecommunications (Australia) Limited, TOM Group Limited (formerly TOM.COM LIMITED) Loring Ward International Limited (a financial planning company) and Hutchison Whampoa Limited since 2004. Mr. Kluge holds a Bachelor of Commerce degree and a Master's degree in Business Administration.
Koh, Poh Chan ..... Hong Kong	Director	August 25, 2000	Finance Director, Harbour Plaza Hotel Management (International) Ltd.

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
Kwok, Eva L. ..... Vancouver, British Columbia Canada	Director	August 25, 2000	Chairman, a director and Chief Executive Officer, Amara International Investment Corp. (an investment holding company) since 1992 and President from 1992 to 1996. Mrs. Kwok has been a director of Bank of Montreal Group of Companies and since 2002, of CK Life Sciences Int'l., (Holdings) Inc. and Cheung Kong Infrastructure Holdings Limited and Shoppers Drug Mart since 2004. Mrs. Kwok was a director of AirCanada from 1998 to 2003 and of Telesystem International Wireless Inc. from 2002 to 2003.
Kwok, Stanley T.L. ..... Vancouver, British Columbia Canada	Director	August 25, 2000	President, Stanley Kwok Consultants (an architecture, planning and development company) since 1993. Mr. Kwok has been a director since 1997 and President since 1999 of Amara International Investment Corp. Mr. Kwok is a director of Cheung Kong (Holdings) Limited and CTC Bank of Canada.
Lau, John C.S. ..... Calgary, Alberta Canada	President & Chief Executive Officer and Director	August 25, 2000	President & Chief Executive Officer of Husky Energy Inc. since August 2000.
Shaw, Wayne E. ..... Toronto, Ontario Canada	Director	August 25, 2000	Senior Partner, Stikeman Elliott LLP, Barristers and Solicitors.
Shurniak, William ..... Australia	Deputy Chairman and Director	August 25, 2000	Director and Chairman of ETSA Utilities (a utility company) since 2000, Powercor Australia Limited (a utility company) since 2000 and CitiPower Pty Ltd. (a utility company) since 2001. Mr. Shurniak has been a director of Envestra Limited (a natural gas distributor) since 2000, CrossCity Motorways Pty Ltd. (an infrastructure and transportation company) since 2002 and Hutchison Whampoa Limited since 1984. Mr. Shurniak has been a director of Lane Cove Tunnel Company Pty Ltd. (an infrastructure and transportation company) since 2004. Mr. Shurniak holds an Honorary Doctor of Laws degree from the University of Saskatchewan and from The University of Western Ontario.

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
Sixt, Frank J. . . . . Hong Kong	Director	August 25, 2000	Group Finance Director of Hutchison Whampoa Limited since 1998 and Executive Director since 1991. Mr. Sixt hs been Chairman and Director of TOM Online Inc, and a Director of Hutchison Telecommunications International Limited, Hutchison Global Communications Holdings Limited since 2004. Mr. Sixt has held the following positions for more than five years: Chairman and Director of TOM Group Limited, Executive Director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited and a Director of Cheung Kong (Holdings) Limited, Hutchison Whampoa Finance (CI) Limited, Hutchison Telecommunications (Australia) Limited, and Partner Communications Company Ltd. Mr. Sixt was also a director of Orange plc. from 1998 to 2000, VoiceStream Wireless Corp. from 2000 to 2001. Mr. Sixt holds a Master's degree in Arts and a Bachelor's degree in Civil Law and is a member of the Bar and of the Law Society of the Provinces of Quebec and Ontario, Canada.

Name and Municipality of Residence	Office or Position	Principal Occupation During Past 5 Years
McGee, Neil D. . . . . Calgary, Alberta	Vice President & Chief Financial Officer	Vice President & Chief Financial Officer of Husky since August 2000.
Ingram, Donald R. . . . . Calgary, Alberta	Senior Vice President, Midstream & Refined Products	Senior Vice President, Midstream and Refined Products of Husky since August 2000.
Girgulis, James D. . . . . Calgary, Alberta	Vice President, Legal & Corporate Secretary	Vice President, Legal & Corporate Secretary of Husky since August 2000.

The Board of Directors has an Audit Committee (as required by the *Business Corporations Act* (Alberta)) currently consisting of R.D. Fullerton (Chair), M.J.G. Glynn, T.C.Y. Hui, and W.E. Shaw, a Compensation Committee currently consisting of C.K.N. Fok (Chair), H. Kluge, E.L. Kwok and F.J. Sixt, a Health, Safety and Environment Committee currently consisting of H. Kluge (Chair), B. D. Kinney, and S.T.L. Kwok and a Corporate Governance Committee currently consisting of H. Kluge (Chair), E.L. Kwok and W.E. Shaw. Husky does not have an Executive Committee.

As at February 28, 2005, the directors and officers of Husky, as a group, owned beneficially, directly or indirectly, or exercised control or direction over 449,011 common shares of Husky representing less than 1 percent of the issued and outstanding common shares.

Conflicts of Interest

Certain officers and directors of Husky are also officers and/or directors of other companies engaged in the oil and gas business generally and which, in certain cases, own interests in oil and gas properties in which Husky holds or may in future hold an interest. As a result, situations arise where the interests of such directors and officers conflict with their interests as directors and officers of other companies. In the case of the directors the resolution of such conflicts is governed by applicable corporate laws which require that directors act honestly, in good faith and with a view to the best interests of Husky and, in respect of the *Business Corporations Act* (Alberta), Husky's governing statute, that directors declare, and refrain from voting on, any matter in which a director may have a conflict of interest.

Corporate Cease Trade Orders or Bankruptcies

None of those persons who are directors or officers of the Company is or has been within the past ten years, a director or officer of any company, including the Company, that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the Company access to any exemption under securities legislation, for a period of more than 30 consecutive days, or was subject to an event that resulted, after the director or officer ceased to be a director or officer, in the company being subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, for a period of more than 30 consecutive days, or within a year of that person ceasing to act in that capacity became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manger or trustee appointed to hold its assets, other than Eva Kwok who was a director of Air Canada in 2003 at the time it became subject to creditor protection under the *Companies Creditors Arrangement Act* (Canada). In addition, Holger Kluge and Frank Sixt were directors until April 12, 2002 of vLinx Inc., a private Canadian company which was petitioned into bankruptcy on April 15, 2002. vLinx Inc. developed technology and software to facilitate international trade. Mr. Fok acted as a non-executive director of Peregrine Investments Holdings Limited (an investment bank) which was put into compulsory liquidation on March 18, 1998.

Individual Penalties, Sanctions or Bankruptcies

None of the persons who are directors or officers of the Company have, within the past ten years made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold his assets.

None of the persons who are directors or officers of the Company have been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

The members of Husky's Audit Committee are R.D. Fullerton (Chair), M.J.G. Glynn, T.C.Y. Hui and W.E. Shaw. Each of the members of the Company's Audit Committee (the ''Committee'') are independent in that each member does not have a direct or indirect material relationship with the Company. Multilateral Instrument 52-110 — Audit Committees provides that a material relationship is a relationship which could, in the view of the board of directors of Husky (the ''Board''), reasonably interfere with the exercise of a member's independent judgment.

The Committee's Charter provides that the Committee is to be comprised of at least three (3) members of the board of directors, all of whom shall be independent and meet the financial literacy requirements of applicable laws and regulations. Each member of the Committee is financially literate in that each has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements.

The education and experience of each Audit Committee member that is relevant to the performance of his responsibilities as an Audit Committee member is as follows.

R.D. Fullerton (Chair) — Before his retirement Mr. Fullerton served as Chief Executive Officer of CIBC and also served as a director and/or an Audit Committee member of 16 major domestic and international public companies as well as director of a number of affiliates of CIBC.

T.C.Y. Hui — Mr. Hui is the President and Chief Executive Officer of Concord Pacific Group Inc. which three years ago was a public company.

M.J.G. Glynn — Mr. Glynn is currently the Chief Executive Officer of HSBC Bank USA and prior thereto served as Chief Executive Officer of HSBC Bank Canada. He has also served as the Chief Executive Officer of two other public companies and has an M.B.A. from the University of British Columbia.

W.E. Shaw — Mr. Shaw is a senior partner of a major Canadian law firm and in that capacity has developed general business knowledge.

Husky's Audit Committee Charter is attached hereto as Schedule ''A''.

External Auditor Service Fees

The following table provides information about the fees billed to the Company for professional services rendered by KPMG LLP, the Company's external auditor, during fiscal 2004 and 2003:

	Aggregate fees billed by the External Auditor	
	2004	2003
	($ thousands)	
Audit fees	805	743
Audit-related fees	207	40
Tax fees	144	220
All other fees	45	40
	1,201	1,042

Audit Fees. Audit fees consist of fees for the audit of the Company's annual financial statements or services that are normally provided in connection with statutory and regulatory filings.

Audit-Related Fees. Audit-related services included attest services not required by statute or regulation and services with respect to acquisitions and dispositions.

Tax Fees. Tax fees included tax planning and various taxation matters.

All Other Fees. Other services provided by the Company's external auditor, other than audit, audit-related and tax services, included advisory services associated with various aspects of the Sarbanes-Oxley Act of 2002.

The Company's Audit Committee has the sole authority to review in advance, and grant any appropriate pre-approvals, of all non-audit services to be provided by the independent auditors and to approve fees, in connection therewith. The Audit Committee approved all of the audit-related, tax and other services provided by KPMG LLP in 2004.

LEGAL PROCEEDINGS

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these or other matters or amount which may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Company's directors, executive officers or persons or companies that beneficially own directly or indirectly, or exercise control or direction over, more than 10 percent of Husky's common shares, or their associates and affiliates, had any material interest, direct or indirect, in any transaction with the Company within the three most recently completed financial years or during the current financial year that has materially affected or would materially affect the Company except as follows.

Up to and effective July 13, 2004, the Company leased its head office space located in Western Canadian Place in Calgary, Alberta from Western Canadian Place Ltd., which is indirectly controlled by the Company's principal shareholders. The Company's President & Chief Executive Officer and Vice President & Chief Financial Officer are also directors and officers of Western Canadian Place Ltd. The Vice President, Corporate Administration of the Company's subsidiary, Husky Oil Operations Limited, is also a director and officer of Western Canadian Place Ltd. The Company entered into an amended and restated lease for a term ending August 31, 2013 with Western Canadian Place Ltd. on commercial terms consistent with those for leases of comparable space in Class A office buildings in Calgary. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party.

The Company also entered into a management agreement with Western Canadian Place Ltd. for general management of Western Canadian Place. The Company was paid fees of $383,327.69 in 2004 for providing such management services. This management agreement was terminated by the parties effective July 15, 2004.

The Company has also entered into a management agreement effective July 15, 2004 with Western Canadian Place Ltd. for general management of Western Canadian Place Ltd.'s leasehold interest in office space at 635 – 8th Avenue S.W. Calgary, Alberta. The Company was paid fees of $55,836.43 in 2004 for providing such management services.

TRANSFER AGENTS AND REGISTRARS

Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company, Inc. The registers for transfers of the Company's common shares are maintained by Computershare Trust Company of Canada at its principal offices in the cities of Calgary and Toronto. Queries should be directed to Computershare Trust Company at 1-888-267-6555 (toll free in North America).

INTERESTS OF EXPERTS

Certain information relating to the Company's reserves included in this Annual Information Form has been calculated by the Company and audited and opined upon as of December 31, 2004 by McDaniel & Associates Consultants Ltd. (''McDaniel''), independent petroleum engineering consultants retained by Husky, and has been so included in reliance on the opinion and analysis of McDaniel, given upon the authority of said firm as experts in reserve engineering. The partners of McDaniel as a group beneficially own, directly or indirectly, less than 1% of the Company's securities of any class.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal shareholders of Husky's common shares and options to purchase common shares is contained in Husky's Management Information Circular dated March 16, 2005, prepared in connection with the annual meeting of shareholders to be held on April 21, 2005.

Additional financial information is provided in Husky's Consolidated Financial Statements and Management's Discussion and Analysis for the most recently completed fiscal year ended December 31, 2004, contained in Husky's 2004 Annual Report.

Additional information relating to Husky Energy Inc. is available on SEDAR at *www.sedar.com***.**

ABBREVIATIONS AND GLOSSARY OF TERMS

As used in this Annual Information Form, the following terms have the meanings indicated:

Units of Measure

Bbl	-barrel
Bbls	-barrels
mbbls	-thousand barrels
mmbbls	-million barrels
Bbls/day	-barrels per calendar day
mbbls/day	-thousand barrels per calendar day
Boe	-barrels of oil equivalent
boe/day	-barrels of oil equivalent per calendar day
Mcf	-thousand cubic feet
mmcf	-million cubic feet
Bcf	-billion cubic feet
mmcf/day	-million cubic feet per calendar day
mcfge	-thousand cubic feet of gas equivalent
lt	-long ton
mlt	-thousand long tons
lt/day	-long tons per calendar day
mlt/day	-thousand long tons per calendar day
mmbtu	-million British thermal units
MW	-megawatts

Acronyms

API	-American Petroleum Institute
COGE Handbook	-Canadian Oil and Gas Evaluation Handbook
FASB	-Financial Accounting Standards Board
FPSO	-floating production, storage and offloading vessel
LLB	-Lloydminster Blend
NGL	-natural gas liquids
NYMEX	-New York Mercantile Exchange
OPEC	-Organization of Petroleum Exporting Countries
PSC	-production sharing contract
SAGD	-steam assisted gravity drainage
SEC	-Securities and Exchange Commission of the United States
SEDAR	-System for Electronic Document Analysis and Retrieval
WTI	-West Texas Intermediate crude oil

API° gravity

Measure of oil density or specific gravity used in the petroleum industry. The American Petroleum Institute (API) scale expresses density such that the greater the density of the petroleum, the lower the degree of API gravity.

Barrel

A unit of volume equal to 42 U.S. gallons.

Bitumen

A highly viscous oil which is too thick to flow in its native state, and which cannot be produced without altering its viscosity. The density of bitumen is generally less than 10 degrees API.

Bulk Terminal

A facility used primarily for the storage and/or marketing of petroleum products.

Coal Bed Methane

The primary energy source of natural gas is methane (CH_4). Coal bed methane is methane found and recovered from the coal bed seams. The methane is normally trapped in the coal by water that is under pressure. When the water is removed the methane is released.

Cold Production

A non-thermal production process for heavy oil in unconsolidated sand formations. During the cold production process heavy oil and sand are produced simultaneously through the use of progressive cavity pumps, which produce high pressure in the reservoir.

Debottlenecking

To remove restrictions thus improving flow rates and productive capacity.

Delineation well

A well in close proximity to an oil or gas well that helps determine the areal extent of the reservoir.

Developed area

A drainage unit having a well completed thereon capable of producing oil or gas in paying quantities.

Development well

A well drilled within the proved area of an oil and gas reservoir to the depth of a stratigraphic horizon known to be productive.

Diluent

A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to improve the transmissibility of the oil through a pipeline.

Dry and abandoned well

A well found to be incapable of producing oil or gas in sufficient quantities to justify completion as a producing oil or gas well.

Enhanced recovery

The increased recovery from a crude oil pool achieved by artificial means or by the application of energy extrinsic to the pool, which artificial means or application includes pressuring, cycling, pressure maintenance or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of aiding in the lifting of fluids in the well, or stimulation of the reservoir at or near the well by mechanical, chemical, thermal or explosive means.

Exploration licence

A licence with respect to the Canadian offshore or the Northwest or Yukon Territories conferring the right to explore for, and the exclusive right to drill and test for, petroleum; the exclusive right to develop the applicable area in order to produce petroleum; and, subject to satisfying the requirements for issuance of a production licence and compliance with the terms of the licence and other provisions of the relevant legislation, the exclusive right to obtain a production licence.

Exploratory well

A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well as those items are defined herein.

Field

An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Gathering System

Pipeline system and associated facilities used to gather natural gas or crude oil from various wells and deliver it to a central point where it can be moved from there by a single pipeline to a processing facility or sales point.

Horizontal drilling

Drilling horizontally rather than vertically through a reservoir, thereby exposing more of the well to the reservoir and increasing production.

Hydrogen sulphide

A poisonous gas which is colourless and heavier than air and is found in sour gas.

Infill Well

A well drilled on an irregular pattern disregarding normal spacing requirements. These wells are drilled to produce from parts of a reservoir that would otherwise not be recovered through existing wells drilled in accordance with normal spacing.

Liquefied petroleum gas

Liquefied propanes and butanes, separately or in mixtures.

Miscible Flood

An enhanced recovery method which requires that three fluids exist in the reservoir: the mobile oil to be recovered, a displacing fluid (NGL) injected to move as a bank behind the oil, and a fluid injected to propel the displacing fluid (chase gas) through the reservoir.

Multiple completion well

A well producing from two or more formations by means of separate tubing strings run inside the casing, each of which carry hydrocarbons from a separate and distinct producing formation.

Natural gas liquids (''NGL'')

Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and condensate, or a combination thereof.

Oil Battery

An accessible area to accommodate separators, treaters, storage tanks and other equipment necessary to process and store crude oil and other fluids prior to transportation.

Oil Sands

Sands and other rock materials which contain crude bitumen and includes all other mineral substances in association therewith.

Overriding royalty interests

An interest acquired or withheld in the oil and gas produced (or the proceeds from the sale of such oil and gas), received free and clear of all costs of development, operation, or maintenance and in additional to the usual landowner's royalty reserved to the lessor in an oil and gas lease.

Primary recovery

The oil and gas recovered by any method that may be employed to produce the oil or gas through a single well bore; the fluid enters the well bore by the action of native reservoir energy or gravity.

Production Sharing Contract

A contract for the development of resources under which the contractor's costs (investment) are recoverable each year out of the production but there is a maximum amount of production which can be applied to the cost recovery in any year. This annual allocation of production is referred to as cost oil, the remainder is referred to as profit oil and is divided in accordance with the contract between the contractor and the host government.

Raw gas

Gas as produced from a well before the separation therefrom of liquefiable hydrocarbons or other substances contained therein.

Recoverable oil-in-place

The total original oil-in-place which can be expected to be recovered. This quantity is dependent upon recovery efficiency and the economics of operation.

Secondary recovery

Oil or gas recovered by injecting water or gas into the reservoir to force additional oil to the producing wells. Usually, but not necessarily, this is done after the primary recovery phase has passed.

Seismic (survey)

A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations. The rate at which the waves are transmitted varies with the medium through which they pass.

Service well

A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation or injection for in-situ combustion.

Significant discovery licence

A licence with respect to the Canadian offshore or the Northwest Territories or Yukon conferring the right to explore for, and the exclusive right to drill and test for, petroleum; the exclusive right to develop the applicable area in order to produce petroleum; and, subject to satisfying the requirements for issuance of a production licence and compliance with other provisions of the relevant legislation, the exclusive right to obtain a production licence.

Sour gas

Natural gas contaminated with chemical impurities, notably hydrogen sulphide or other sulphur compounds. Such compounds must be removed before the gas can be used for commercial or domestic purposes.

Specific Gravity

The ratio between the weight of equal volumes of water and another liquid measured at standard temperature, weight the weight of water as assigned a value of one (1). However , the specific gravity of oil is normally expressed in degrees of API gravity as follows:

$$\text{Degrees API} = \frac{141.5}{\text{Specific gravity @ F60 degrees}} - 131.5$$

Spot Price

The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased ''on the spot'' at current market rates.

Steam Assisted Gravity Drainage

A recovery method used to produce heavy crude oil and bitumen in-situ. Steam is injected via a horizontal well along a producing formation. The temperature in the formation increases and lowers the viscosity of the crude oil allowing it to fall to a horizontal production well beneath the steam injection well.

Step-out Well

A well drilled adjacent to a proven well but located in an unproven area; a well drilled in an effort to ascertain the extent and boundaries of a producing formation.

Stratigraphic test well

A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) ''exploratory-type'', if not drilled in a proved area, or (ii) ''development-type'', if drilled in a proved area.

Synthetic oil

A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, by through a process that reduces the carbon content and increases the hydrogen content.

Tertiary recovery

The recovery of oil and gas by using exotic or complex recovery schemes involving steam, chemicals, gases or heat. Usually, but not necessarily, this is done after the secondary recovery phase has passed.

Three-D Seismic (survey)

Three dimensional seismic imaging which uses a grid of numerous cable rather than a few lines stretched in one line.

Turnaround

Perform maintenance at a plant or facility which requires the plant or facility to be shut down for the duration.

Undeveloped area

An area in which it has not been established by drilling operations whether oil and/or gas may be found in commercial quantities.

Waterflood

One method of secondary recovery in which water is injected into an oil reservoir for the purpose of forcing oil out of the reservoir and into the bore of a producing well.

Well Abandonment Costs

Costs of abandoning a well (net of any salvage value) and of disconnecting the well from the surface gathering system.

Working interest

An interest in the net revenues of an oil and gas property which is proportionate to the share of exploration and development costs borne until such costs have been recovered, and which entitles the holder to participate in a share of net revenue thereafter.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Information Form are forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to

differ materially from those projected in forward-looking statements made in this Annual Information Form. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as ''will likely result,'' ''are expected to,'' ''will continue,'' ''is anticipated,'' ''estimated,'' ''intends,'' ''plans,'' ''projection'' and ''outlook'') are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form. Among the key factors that have a direct bearing on the Company's results of operation are the nature of the Company's involvement in the business of exploration, development and production of oil and natural gas reserves and the fluctuation of the exchange rate between the Canadian dollar and the United States dollar. These and other factors are discussed herein under ''Management's Discussion and Analysis of Financial Condition and Results of Operations'', incorporated by reference in this Annual Information Form and available on SEDAR at *www.sedar.com*.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Company made by or on behalf of the Company, investors should not place undue reliance on any such forward-looking statements. Further, any forward-looking statement speaks only as of the date on which such statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

Husky Energy Inc.

Audit Committee Charter

The Audit Committee (the ''Committee'') of the Board of Directors (the ''Board'') of Husky Energy Inc. (the ''Company'') will have the oversight responsibility, authority and specific duties as described below.

Composition

The Committee will be comprised of three or more directors as determined by the Board, each of whom shall satisfy the independence and financial literacy requirements of applicable securities regulatory requirements. In addition, one of the members of the Committee will be an audit committee financial expert as defined in applicable securities regulatory requirements. The members of the Committee will be elected annually at the organizational meeting of the full Board on the recommendation of the Corporate Governance Committee to the Co-Chairmen and will be listed in the annual report to shareholders. One of the members of the Committee will be elected Committee Chair by the Board.

Responsibility

The Committee is a part of the Board. Its primary function is to assist the Board in fulfilling its oversight responsibilities with respect to:

(i) the quarterly and annual financial statements and quarterly and annual MD&A be provided to shareholders and the appropriate regulatory agencies;

(ii) earnings press releases before the Company publicly discloses this information;

(iii) the system of internal controls that management has established;

(iv) the internal and external audit process;

(v) the appointment of qualified reserves evaluators or auditors; and

(vi) the filing of statements and reports with respect to the Company's oil and gas reserves.

In addition, the Committee provides an avenue for communication between the Board and each of internal audit, the external auditors, financial management, external qualified reserves evaluators or auditors and internal qualified reserves evaluators. The Committee should have a clear understanding with the external auditors and the external reserve evaluators or auditors that an open and transparent relationship must be maintained with the Committee.

The Committee will make regular reports to the Board concerning its activities.

While the Audit Committee has the responsibilities and powers set forth in this Charter, the role of the Audit committee is oversight. The members of the Committee are not full time employees of the Company and may or may not be accountants or auditors by profession or experts in the fields of accounting or auditing and, in any event, do not serve in such capacity. Consequently, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements are complete and accurate and are in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors and, as to reserves, the external reserve evaluators or auditors. Management and the external auditors shall also have the responsibility to conduct investigations and to assure compliance with laws and regulations and the Company's business conduct guidelines.

Authority

Subject to the prior approval of the Board, the Committee is granted the authority to investigate any matter or activity involving financial accounting and financial reporting, the internal controls of the Company and the reporting of the Company's reserves and oil and gas activities.

The Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensation for any advisors employed by the Committee.

In recognition of the fact that the independent auditors are ultimately accountable to the Committee, the Committee shall have the authority and responsibility to nominate for shareholder approval, evaluate and, where appropriate, replace the independent auditors and shall approve all audit engagement fees and terms and all non-audit engagements with the independent auditors. The Committee shall consult with management and the internal audit group but shall not delegate these responsibilities.

Meetings

The Committee is to meet at least four times annually and as many additional times as the Committee deems necessary. Committee members will strive to be present at all meetings either in person or by telephone. As necessary or desirable, but in any case at least quarterly, the Committee shall meet with members of management and representatives of the external auditors and internal audit in separate executive sessions to discuss any matters that the Committee or any of these groups believes should be discussed privately. Likewise, as necessary or desirable, but in any case at least annually, the Committee shall meet the management and representatives of the external reserve evaluators or auditors and internal reserves evaluators in separate executive sessions to discuss matters that the Committee or any of these groups believes should be discussed privately. In respect of the Committee's oversight regarding reserves, the Committee engages the services of an independent reserves consultant.

Specific Duties

In carrying out its oversight responsibilities, the Committee will:

1. Review and reassess the adequacy of this Charter annually and recommend any proposed changes to the Board for approval.
2. (a) Review with the Company's management, internal audit and external auditors and recommend to the Board for approval the Company's annual financial statements and annual MD&A which is to be provided to shareholders and the appropriate regulatory agencies, including any financial statement contained in a prospectus, information circular, registration statement or other similar document.

   (b) Review with the Company's management, internal audit and external auditors and approve the Company's quarterly financial statements and quarterly MD&A which is to be provided to shareholders and the appropriate regulatory agencies.
3. Review with the Company's management and approve earnings press releases before the Company publicly discloses this information.
4. Recommend to the Board the external auditors to be nominated for the purpose of preparing or issuing an audit report or performing other audit, review or attest services and the compensation to be paid to the external auditors. The external auditors shall report directly to the Committee.
5. Be directly responsible for the oversight of the work of the external auditors, including the resolution of disagreements between management of the Company and the external auditors regarding financial reporting.
6. Review with the Company's management, internal audit and external auditors the Company's accounting and financial reporting controls. Obtain annually in writing from the external auditors their observations, if any, on significant weaknesses in internal controls as noted during the course of their work.
7. Review with the Company's management, internal audit and external auditor's significant accounting and reporting principles, practices and procedures applied by the Company in preparing its financial statements. Discuss with the external auditors their judgements about the quality, not just the acceptability, of the Company's accounting principles used in financial reporting.
8. Review the scope of internal audit's work plan for the year and receive a summary report of major findings by internal auditors and how management is addressing the conditions reported.
9. Review the scope and general extent of the external auditors' annual audit. The Committee's review should include an explanation from the external auditors of the factors considered in determining the audit scope, including the major risk factors. The external auditors should confirm to the Committee whether or not any limitations have been placed on the scope or nature of their audit procedures.
10. Inquire as to the independence of the external auditors and obtain from the external auditors, at least annually, a formal written statement delineating all relationships between the external auditors and the

Company as contemplated by Independence Standards Board Standard No. 1, Independence Discussions with Audit Committees.

11. Have a predetermined arrangement with the external auditors that they will advise the Committee, through its Chair and management of the Company, of any matters identified through procedures followed for the review of interim quarterly financial statements of the Company, and that such notification is to be made prior to the related press release. Also receive a written confirmation provided by the external auditors at the end of each of the first three quarters of the year that they have nothing to report to the Committee, if that is the case, or the written enumeration of required reporting issues.

12. At the completion of the annual audit, review with management, internal audit and the external auditors the following:

    - The annual financial statements and related footnotes and financial information to be included in the Company's annual report to shareholders.
    - Results of the audit of the financial statements and the related report thereon and, if applicable, a report on changes during the year in accounting principles and their application.
    - Significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit. Inquire about the cooperation received by the external auditors during their audit, including access to all requested records, data and information.
    - Inquire of the external auditors whether there have been any material disagreements with management, which, if not satisfactorily resolved, would have caused them to issue a non-standard report on the Company's financial statements.

13. Discuss with the external auditors, without management being present, (a) the quality of the Company's financial and accounting personnel, and (b) the completeness and accuracy of the Company's financial statements. Also, elicit the comments of management regarding the responsiveness of the external auditors to the Company's needs.

14. Meet with management, to discuss any relevant significant recommendations that the external auditors may have, particularly those characterized as 'material' or 'serious'. Typically, such recommendations will be presented by the external auditors in the form of a Letter of Comments and Recommendations to the Committee. The Committee should review responses of management to the Letter of Comments and Recommendations from the external auditors and receive follow-up reports on action taken concerning the aforementioned recommendations.

15. Have the sole authority to review in advance, and grant any appropriate pre-approvals, of all non-audit services to be provided by the independent auditors and, in connection therewith, to approve all fees and other terms of engagement. The Committee shall also review and approve disclosures required to be included in periodic reports filed with Canadian securities regulators and the Securities and Exchange Commission with respect to non-audit services performed by external auditors.

16. Be satisfied that adequate procedures are in place for the review of the Company's disclosure of financial information extracted or derived from the Company's financial statements, and periodically assess the adequacy of those procedures.

17. Establish procedures for (a) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matter, and (b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

18. Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors.

19. Review the appointment and replacement of the senior internal audit executive.

20. Review with management, internal audit and the external auditors the methods used to establish and monitor the Company's policies with respect to unethical or illegal activities by Company employees that may have a material impact on the financial statements.

21. Generally as part of the review of the annual financial statements, receive a report(s), at least annually, from the Company's general counsel concerning legal, regulatory and compliance matters that may have a material impact on the financial statements.

22. Review, with reasonable frequency, the Company's procedures relating to the disclosure of information with respect to the Company's oil and gas reserves, including the Company's procedures for complying with the disclosure requirements and restrictions of applicable regulations.

23. Review with management the appointment of external qualified reserves evaluators or auditors, and in the case of any proposed change in such appointment, determine the reasons for the change and whether there have been disputes between the appointed external qualified reserves evaluators or auditors, and management.

24. Review, with reasonable frequency, the Company's procedures for providing information to the external qualified reserves evaluators or auditors who report on reserves and data for the purposes of compliance with applicable securities laws.

25. Before the approval and the release of the Company's reserves data and the report of the qualified reserve evaluators or auditors thereon, meet with management, the external qualified reserves evaluators or auditors and the internal qualified reserves evaluators to determine whether any restrictions affect their ability to report on reserves data without reservation and to review the reserves data and the report of the qualified reserves evaluators.

26. Recommend to the Board for approval the content and filing of required statements and reports relating to the Company's disclosure of reserve data as prescribed by applicable regulations.

27. Review and approve (a) any change or waiver in the Company's Code of Business Conduct for the chief executive officer and senior financial officers and (b) any public disclosure made regarding such change or waiver.

Calgary, Alberta, Canada
February 16, 2005

Document B
Form 40-F

CONSOLIDATED FINANCIAL STATEMENTS AND AUDITORS' REPORT TO SHAREHOLDERS

For the Year Ended December 31, 2004

MANAGEMENT'S REPORT

The management of Husky Energy Inc. is responsible for the financial information and operating data presented in this annual report.

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgements. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this annual report has been prepared on a basis consistent with that in the consolidated financial statements.

Husky Energy Inc. maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of independent non-management directors, meets regularly with management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy, financial reporting matters and reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with Canadian generally accepted auditing standards on behalf of the shareholders. KPMG LLP have full and free access to the Audit Committee.

John C. S. Lau
President & Chief Executive Officer

Neil McGee
Vice President & Chief Financial Officer

Calgary, Alberta, Canada
January 17, 2005

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Husky Energy Inc., as at December 31, 2004, 2003 and 2002 and the consolidated statements of earnings, retained earnings, and cash flows for each of the years in the three-year period ended December 31, 2004. 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 audit in accordance with Canadian 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, 2004, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

KPMG LLP
Chartered Accountants

Calgary, Alberta, Canada
January 17, 2005

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA U.S. REPORTING DIFFERENCE

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the company's financial statements, such as the change described in Note 3 (l) — Stock-based compensation — to the Company's consolidated financial statements as at December 31, 2004, 2003 and 2002, and for each of the years in the three-year period ended December 31, 2004. Our report to the shareholders dated January 17, 2005 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

KPMG LLP
Chartered Accountants

Calgary, Alberta, Canada
January 17, 2005

CONSOLIDATED BALANCE SHEETS

	As at December 31		
	2004	2003	2002
	(millions of dollars)		
ASSETS			
Current assets			
Cash and cash equivalents	$ 7	$ 3	$ 306
Accounts receivable *(note 4)*	446	618	572
Inventories *(note 5)*	274	198	227
Prepaid expenses	52	33	23
	779	852	1,128
Property, plant and equipment, net *(notes 1, 6)* (full cost accounting)	12,193	10,862	9,421
Goodwill *(note 7)*	160	120	—
Other assets *(note 11)*	106	112	84
	$13,238	$11,946	$10,633
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Bank operating loans *(note 9)*	$ 49	$ 71	$ —
Accounts payable and accrued liabilities *(note 10)*	1,489	1,126	794
Long-term debt due within one year *(note 11)*	56	259	421
	1,594	1,456	1,215
Long-term debt *(note 11)*	1,776	1,439	1,964
Other long-term liabilities *(note 12)*	632	519	304
Future income taxes *(note 13)*	2,758	2,621	2,014
Commitments and contingencies *(note 14)*			
Shareholders' equity			
Capital securities and accrued return *(note 15)*	278	298	364
Common shares *(note 16)*	3,506	3,457	3,406
Retained earnings	2,694	2,156	1,366
	6,478	5,911	5,136
	$13,238	$11,946	$10,633

On behalf of the Board:

JOHN C. S. LAU
Director

R.D. FULLERTON
Director

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2003 and 2002 amounts as restated (note 3).

CONSOLIDATED STATEMENTS OF EARNINGS

	Year ended December 31		
	2004	2003	2002
	(millions of dollars, except per share amounts)		
Sales and operating revenues, net of royalties	$8,440	$7,658	$6,384
Costs and expenses			
Cost of sales and operating expenses *(note 12)*	5,706	4,847	4,026
Selling and administration expenses	135	119	94
Stock-based compensation *(note 16)*	67	—	—
Depletion, depreciation and amortization *(notes 1, 6)*	1,179	1,021	908
Interest — net *(note 11)*	33	73	104
Foreign exchange *(note 11)*	(99)	(215)	13
Other — net	8	3	1
	7,029	5,848	5,146
Earnings before income taxes	1,411	1,810	1,238
Income taxes *(note 13)*			
Current	302	147	66
Future	103	329	358
	405	476	424
Net earnings	$1,006	$1,334	$ 814
Earnings per share *(note 16)*			
Basic	$ 2.37	$ 3.26	$ 1.91
Diluted	$ 2.36	$ 3.25	$ 1.90

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year ended December 31		
	2004	2003	2002
	(millions of dollars)		
Beginning of year	$2,156	$1,366	$ 722
Net earnings	1,006	1,334	814
Dividends on common shares *(note 16)*	(424)	(580)	(151)
Return and foreign exchange on capital securities *(note 15)*	(6)	38	(29)
Related future income taxes *(note 13)*	6	(2)	11
Stock-based compensation — retroactive adoption *(note 16)*	(44)	—	—
Asset retirement obligations — retroactive adoption *(note 12)*	—	—	(1)
End of year	$2,694	$2,156	$1,366

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2003 and 2002 amounts as restated (note 3).

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31		
	2004	2003	2002
	(millions of dollars)		
Operating activities			
Net earnings	$1,006	$1,334	$ 814
Items not affecting cash			
Accretion	27	22	17
Depletion, depreciation and amortization	1,179	1,021	908
Future income taxes	103	329	358
Foreign exchange *(note 11)*	(103)	(242)	—
Other	11	(5)	(1)
Settlement of asset retirement obligations	(40)	(34)	(16)
Change in non-cash working capital *(note 8)*	169	113	(198)
Cash flow — operating activities	2,352	2,538	1,882
Financing activities			
Bank operating loans financing — net	(22)	71	(100)
Long-term debt issue	2,200	598	972
Long-term debt repayment	(1,937)	(971)	(678)
Settlement of cross currency swap	—	(32)	—
Return on capital securities payment	(26)	(29)	(31)
Debt issue costs	(5)	—	(9)
Proceeds from exercise of stock options	18	51	9
Proceeds from monetization of financial instruments	8	44	—
Dividends on common shares	(424)	(580)	(151)
Change in non-cash working capital *(note 8)*	337	48	(9)
Cash flow — financing activities	149	(800)	3
Available for investing	2,501	1,738	1,885
Investing activities			
Capital expenditures	(2,349)	(1,868)	(1,691)
Corporate acquisitions	(102)	(809)	(3)
Asset sales	36	511	93
Other	(19)	5	(20)
Change in non-cash working capital *(note 8)*	(63)	120	42
Cash flow — investing activities	(2,497)	(2,041)	(1,579)
Increase (decrease) in cash and cash equivalents	4	(303)	306
Cash and cash equivalents at beginning of year	3	306	—
Cash and cash equivalents at end of year	$ 7	$ 3	$ 306

The accompanying notes to the consolidated financial statements are an integral part of these statements.
2003 and 2002 amounts as restated (note 3).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 1

***Segmented Financial Information*[1]**

	Upstream			Midstream					
				Upgrading			Infrastructure and Marketing		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
Year ended December 31									
Sales and operating revenues, net of royalties	$ 3,120	$ 3,186	$ 2,665	$1,058	$1,013	$909	$6,126	$4,946	$4,230
Costs and expenses									
Operating, cost of sales, selling and general	967	873	743	884	901	811	5,914	4,747	4,038
Depletion, depreciation and amortization	1,077	918	822	19	20	18	21	21	20
Interest — net	—	—	—	—	—	—	—	—	—
Foreign exchange	—	—	—	—	—	—	—	—	—
	2,044	1,791	1,565	903	921	829	5,935	4,768	4,058
Earnings (loss) before income taxes	1,076	1,395	1,100	155	92	80	191	178	172
Current income taxes	211	95	55	—	1	1	31	27	6
Future income taxes	152	233	346	43	20	25	32	37	59
Net earnings (loss)	$ 713	$ 1,067	$ 699	$ 112	$ 71	$ 54	$ 128	$ 114	$ 107
Capital employed — As at December 31	$ 7,747	$ 6,709	$ 6,100	$ 480	$ 456	$319	$ 255	$ 348	$ 429
Property, plant and equipment — As at December 31									
Cost									
Canada	$16,002	$13,831	$11,657	$1,084	$1,023	$999	$ 647	$ 622	$ 598
International	587	503	474	—	—	—	—	—	—
	$16,589	$14,334	$12,131	$1,084	$1,023	$999	$ 647	$ 622	$ 598
Accumulated depletion, depreciation and amortization									
Canada	$ 5,722	$ 4,718	$ 3,968	$ 409	$ 391	$372	$ 226	$ 203	$ 184
International	311	252	186	—	—	—	—	—	—
	$ 6,033	$ 4,970	$ 4,154	$ 409	$ 391	$372	$ 226	$ 203	$ 184
Net									
Canada	$10,280	$ 9,113	$ 7,689	$ 675	$ 632	$627	$ 421	$ 419	$ 414
International	276	251	288	—	—	—	—	—	—
	$10,556	$ 9,364	$ 7,977	$ 675	$ 632	$627	$ 421	$ 419	$ 414
Capital expenditures — Year ended December 31 (3)	$ 2,157	$ 1,778	$ 1,576	$ 62	$ 25	$ 41	$ 31	$ 18	$ 23
Total assets — As at December 31 (4)									
Canada	$10,897	$ 9,685	$ 7,931	$ 708	$ 650	$659	$ 599	$ 702	$ 851
International	275	264	341	—	—	—	—	—	—
	$11,172	$ 9,949	$ 8,272	$ 708	$ 650	$659	$ 599	$ 702	$ 851

(1) 2003 and 2002 amounts as restated (note 3).

(2) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

(3) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

(4) Includes goodwill on corporate acquisitions related to Upstream.

	Refined Products			Corporate and Eliminations (2)			Total		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
Year ended December 31									
Sales and operating revenues, net of royalties	$1,797	$1,502	$1,310	$(3,661)	$(2,989)	$(2,730)	$ 8,440	$ 7,658	$ 6,384
Costs and expenses									
Operating, cost of sales, selling and general	1,694	1,426	1,224	(3,543)	(2,978)	(2,695)	5,916	4,969	4,121
Depletion, depreciation and amortization	38	26	31	24	36	17	1,179	1,021	908
Interest — net	—	—	—	33	73	104	33	73	104
Foreign exchange	—	—	—	(99)	(215)	13	(99)	(215)	13
	1,732	1,452	1,255	(3,585)	(3,084)	(2,561)	7,029	5,848	5,146
Earnings (loss) before income taxes	65	50	55	(76)	95	(169)	1,411	1,810	1,238
Current income taxes	11	9	4	49	15	—	302	147	66
Future income taxes	13	9	18	(137)	30	(90)	103	329	358
Net earnings (loss)	$ 41	$ 32	$ 33	$ 12	$ 50	$ (79)	$ 1,006	$ 1,334	$ 814
Capital employed — As at December 31	$ 354	$ 315	$ 316	$ (477)	$ (148)	$ 357	$ 8,359	$ 7,680	$ 7,521
Property, plant and equipment — As at December 31									
Cost									
Canada	$ 878	$ 773	$ 706	$ 253	$ 205	$ 172	$18,864	$16,454	$14,132
International	—	—	—	—	—	—	587	503	474
	$ 878	$ 773	$ 706	$ 253	$ 205	$ 172	$19,451	$16,957	$14,606
Accumulated depletion, depreciation and amortization									
Canada	$ 432	$ 392	$ 361	$ 158	$ 139	$ 114	$ 6,947	$ 5,843	$ 4,999
International	—	—	—	—	—	—	311	252	186
	$ 432	$ 392	$ 361	$ 158	$ 139	$ 114	$ 7,258	$ 6,095	$ 5,185
Net									
Canada	$ 446	$ 381	$ 345	$ 95	$ 66	$ 58	$11,917	$10,611	$ 9,133
International	—	—	—	—	—	—	276	251	288
	$ 446	$ 381	$ 345	$ 95	$ 66	$ 58	$12,193	$10,862	$ 9,421
Capital expenditures — Year ended December 31 (3)	$ 106	$ 58	$ 44	$ 23	$ 23	$ 23	$ 2,379	$ 1,902	$ 1,707
Total assets — As at December 31 (4)									
Canada	$ 625	$ 540	$ 537	$ 134	$ 105	$ 314	$12,963	$11,682	$10,292
International	—	—	—	—	—	—	275	264	341
	$ 625	$ 540	$ 537	$ 134	$ 105	$ 314	$13,238	$11,946	$10,633

Note 2

Nature of Operations and Organization

Husky Energy Inc. (''Husky'' or ''the Company'') is a publicly traded, integrated energy and energy-related company headquartered in Calgary, Alberta, Canada.

Management has segmented the Company's business based on differences in products and services and management strategy and responsibility. The Company's business is conducted predominantly through three major business segments — upstream, midstream and refined products.

Upstream includes exploration for, development and production of crude oil, natural gas and natural gas liquids. The Company's upstream operations are located primarily in Western Canada, offshore Eastern Canada, offshore China and offshore Indonesia.

Midstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (upgrading); marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, sulphur and petroleum coke; and pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas and cogeneration of electrical and thermal energy (infrastructure and marketing).

Refined products include refining of crude oil and marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products.

Note 3

Significant Accounting Policies

a) Principles of Consolidation and the Preparation of Financial Statements

These financial statements are prepared in accordance with Canadian generally accepted accounting principles (''GAAP'') which, in the case of the Company, differ in certain respects from those in the United States. These differences are described in note 20, Reconciliation to Accounting Principles Generally Accepted in the United States.

The preparation of financial statements in conformity with Canadian GAAP 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 reported period. Actual results could differ from these estimates.

The consolidated financial statements include the accounts of the Company and its subsidiaries.

Substantially all of the Company's upstream activities are conducted jointly with third parties and accordingly the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flow from these activities.

b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and deposits with a maturity of less than three months at the time of purchase.

c) Inventory Valuation

Crude oil, natural gas, refined petroleum products and purchased sulphur inventories are valued at the lower of cost, on a first-in, first-out basis, or net realizable value. Materials and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead and transportation. Intersegment profits are eliminated.

d) Property, Plant and Equipment

i) Oil and Gas

The Company employs the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves are capitalized and accumulated within cost centres on a country-by-country basis. Such costs include land acquisition, geological and geophysical activity, drilling of productive and non-productive wells, carrying costs directly related to unproved properties and administrative costs directly related to exploration and development activities. Interest is capitalized on certain major capital projects based on the Company's long-term cost of borrowing.

The provision for depletion of oil and gas properties and depreciation of associated production facilities is calculated using the unit of production method, based on gross proved oil and gas reserves as estimated by the Company's engineers, for each cost centre. Depreciation of gas plants and certain other oil and gas facilities is provided using the straight-line method based on their estimated useful lives. Costs subject to depletion and depreciation include both the estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations. In the normal course of operations, retirements of oil and gas interests are accounted for by charging the asset cost, net of any proceeds, to accumulated depletion or depreciation. Gains or losses on the disposition of oil and gas properties are not recognized unless the gain or loss changes the depletion rate by 20 percent or more.

Costs of acquiring and evaluating significant unproved oil and gas interests are excluded from costs subject to depletion and depreciation until it is determined that proved oil and gas reserves are attributable to such interests or until impairment occurs. Costs of major development projects are excluded from costs subject to depletion and depreciation until proved developed reserves have been attributed to a portion of the property or the property is determined to be impaired.

Impairment losses are recognized when the carrying amount of a cost centre exceeds the sum of:

- the undiscounted cash flow expected to result from production from proved reserves;
- the costs of unproved properties, less impairment; and
- the costs of major development projects, less impairment.

The amount of impairment loss is determined to be the amount by which the carrying amount of the cost centre exceeds the sum of:

- the fair value of proved and probable reserves; and
- the cost, less impairment, of unproved properties that do not have probable reserves attributed to them.

ii) Other Plant and Equipment

Depreciation for substantially all other plant and equipment, except upgrading assets, is provided using the straight-line method based on estimated useful lives of assets which range from five to 25 years. Depreciation for upgrading assets is provided using the unit of production method, based on the plant's estimated productive life. Repairs and maintenance costs, other than major turnaround costs, are charged to earnings as incurred. Major turnaround costs are deferred to other assets when incurred and amortized over the estimated period of time to the next scheduled turnaround. At the time of disposition of plant and equipment, accounts are relieved of the asset values and accumulated depreciation and any resulting gain or loss is reflected in earnings.

iii) Asset Retirement Obligations

Effective January 1, 2004, the Company retroactively adopted CICA section 3110, ''Asset Retirement Obligations''. The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period that the asset is put into use, with a corresponding increase to the carrying value of the related asset. The obligations recognized are legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion which is included in cost of sales and operating expenses. The liability will also be adjusted to reflect revisions to the previous estimates of the undiscounted obligation. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion, depreciation and amortization of the underlying asset. Retirement expenditures are charged to the accumulated liability as incurred.

e) Impairment or Disposal of Long-lived Assets

An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value. Testing for recoverability uses the undiscounted cash flows expected from the asset's use and disposition. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent.

A long-lived asset that meets the conditions as held for sale is measured at the lower of its carrying amount or fair value less costs to sell. Such assets are not amortized while they are classified as held for sale. The results of operations of a component of an entity that has been disposed of, or is classified as held for sale, are reported in discontinued operations if: i) the operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction; and, ii) the entity will not have a significant continuing involvement in the operations of the component after the disposal transaction.

f) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill is subject to impairment tests on an annual basis unless certain conditions are met. The Company tests impairment annually in the fourth quarter of each year. To assess impairment, the fair value of the reporting unit is compared with its carrying amount. If any potential impairment is indicated, then it is quantified by comparing the carrying value of goodwill to its fair value, based on the fair value of the assets and liabilities of the reporting unit. Impairment losses would be recognized in current period earnings, if indicated.

g) Derivative Financial Instruments

Derivative financial instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative financial instruments for speculative purposes. The Company may choose to designate derivative financial instruments as hedges.

When applicable, at the inception of the hedge, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between hedged items and hedging items and the method for testing the effectiveness of the hedge which must be reasonably assured over the term of the hedge. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Company may enter into commodity price contracts to hedge anticipated sales of oil and natural gas production to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers in order to retain market prices while meeting customer or supplier pricing requirements. Gains and losses from these contracts are recognized in midstream revenues or cost of sales as the related sales or purchases occur.

The Company may enter into interest rate swap agreements to manage its fixed and floating interest rate mix on long-term debt. These swaps are designated as hedges of the underlying debt. Gains and losses from these contracts are recognized as an adjustment to the interest expense on the hedged debt instrument. The related amount payable or receivable from the counterparties is recorded as an adjustment to accrued interest.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The forward premium or discount on the foreign exchange contract is amortized as an adjustment to interest expense over the term of the contract.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated oil and natural gas sales. Gains and losses on these instruments are recognized as an adjustment to upstream oil and gas revenues when the sale is recorded.

Realized and unrealized gains or losses associated with derivative financial instruments which have been terminated or cease to be effective as a hedge prior to maturity are deferred under current or non-current assets or liabilities on the balance sheet and recognized into income in the period in which the underlying hedged transaction is recognized in income. In the event that a designated hedged item is sold, extinguishes or matures prior to the termination of the related derivative financial instrument, any realized or unrealized gain or loss is recognized into earnings.

h) Employee Future Benefits

The Company provides a defined contribution pension plan and a post-retirement health and dental care plan to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. The cost of the pension benefits earned by employees in the defined contribution pension plan is paid and expensed when incurred. The cost of the benefits earned by employees in the post-retirement health and dental care plan and defined benefit pension plan is charged to earnings as services are rendered using the projected benefit method prorated on service. The cost of the post-retirement health and dental care plan and defined benefit pension plan reflects a number of assumptions that affect the expected future benefit payments. These assumptions include, but are not limited to, attrition, mortality, the rate of return on pension plan assets and salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The plan assets are valued at fair value for the purposes of calculating the expected return on plan assets.

Adjustments arising out of plan amendments, changes in assumptions and experience gains and losses are normally amortized over the expected remaining average service life of the employee group.

i) Future Income Taxes

The Company follows the liability method of accounting for income taxes. Future income tax assets and liabilities are recognized at expected tax rates in effect when temporary differences between the tax basis and the carrying value of the Company's assets and liabilities reverse. The effect of a change to the tax rate on the future tax assets and liabilities is recognized in earnings when substantively enacted.

j) Revenue Recognition

Revenues from the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recorded on a gross basis when title passes to an external party. Sales between the business segments of the Company are eliminated from sales and operating revenues and cost of sales. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided. Effective January 1, 2004, certain transportation costs that were previously netted against revenue are now being recorded as cost of sales on a prospective basis.

k) Foreign Currency Translation

Results of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars at the monthly average exchange rates for revenue and expenses, except for depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Monetary assets and liabilities are translated at current exchange rates and nonmonetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in earnings. Capital securities are adjusted to the current rate of exchange and included in retained earnings.

l) Stock-based Compensation

Effective January 1, 2004, the Company adopted CICA section 3870, ''Stock-based Compensation and Other Stock-based Payments'', retroactively without restatement of prior periods. In accordance with the Company's stock option plan, common share options may be granted to directors, officers and certain other employees. The recommendations require the Company to record a compensation expense over the vesting period based on the fair value of options granted.

Effective June 1, 2004, the Company amended its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for expected cash settlements is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares. The liability is revalued to reflect changes in the market price of the Company's common shares and the net change is recognized in earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital. Accrued compensation for an option that is forfeited is adjusted to earnings by decreasing the compensation cost in the period of forfeiture.

m) Earnings per Share

Basic common shares outstanding are the weighted average number of common shares outstanding for each period. The calculation of basic earnings per common share is based on net earnings after deducting return and foreign exchange on capital securities, net of applicable income taxes, divided by the weighted average number of common shares outstanding.

Diluted common shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. In addition, diluted common shares also include the effect of the potential exercise of any outstanding warrants. Shares potentially issuable on the settlement of the capital securities have not been included in the determination of diluted earnings per common share, as the Company has neither the obligation nor intention to settle amounts due through the issuance of shares.

n) Reclassification

Certain prior years' amounts have been reclassified to conform with current presentation.

Note 4

Accounts Receivable

	2004	2003	2002
Trade receivables	$448	$568	$530
Investment tax credit	—	48	45
Allowance for doubtful accounts	(10)	(12)	(11)
Other	8	14	8
	$446	$618	$572

Sale of Accounts Receivable

In December 2004, the Company increased the ceiling on its securitization program to sell, on a revolving basis, accounts receivable to a third party from $250 million to $350 million. As at December 31, 2004, $350 million (2003 — $250 million) in outstanding accounts receivable had been sold under the program. The agreement includes a program fee. The average effective rate for 2004 was approximately 2.6 percent (2003 — 2.8 percent).

The Company has retained the responsibility for servicing, administering and collecting accounts receivable sold. The servicing liability at December 31, 2004 was not significant.

Proceeds from revolving sales between the third party and the Company in 2004 totalled approximately $2.5 billion.

In 2002, the Company had an agreement to sell up to $200 million of net trade receivables on a continual basis. The agreement called for purchase discounts which were based on Canadian commercial paper rates. The average effective rate for 2002 was approximately 2.8 percent.

Note 5

Inventories

	2004	2003	2002
Crude oil and refined petroleum products	$159	$115	$160
Natural gas	100	69	50
Materials, supplies and other	15	14	17
	$274	$198	$227

Note 6

Property, Plant and Equipment

Refer to note 1, Segmented Financial Information, which presents the Company's property, plant and equipment by segment.

Costs of oil and gas properties, including major development projects, excluded from costs subject to depletion and depreciation at December 31 were as follows:

	2004	2003	2002
Canada	$2,399	$1,814	$1,318
International	129	54	37
	$2,528	$1,868	$1,355

The future cash flow used in the computation of the full cost ceiling test at December 31, 2004 was based on the following reference prices:

Western Canada	2005	2006	2007	2008	2009	2010	Annual Increase Thereafter
							(percent)
Light oil @ Edmonton *($/bbl)*	$ 52.60	$47.52	$42.56	$39.78	$38.44	$38.47	1.6
Medium oil @ Hardisty *($/bbl)*	47.08	42.55	37.96	35.52	34.24	34.27	1.7
Heavy oil @ Lloydminster *($/bbl)*	34.21	30.93	27.73	26.08	24.88	24.92	1.7
Alberta natural gas *($/mcf)*	7.25	6.87	6.39	5.91	5.69	5.69	1.6
Fixed price contract adjustment *($/mcf)*	(0.36)	(0.36)	(0.22)	(0.17)	(0.14)	(0.11)	

Note 7

Corporate Acquisitions

Effective July 15, 2004, the Company acquired all of the issued and outstanding shares of Temple Exploration Inc. (''Temple'') for total cash consideration of $102 million.

Effective October 1, 2003, the Company acquired all of the issued and outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. (''Marathon Canada'') for cash consideration of U.S. $611 million (Cdn. $831 million).

The results of Temple and Marathon Canada are included in the consolidated financial statements of the Company from their acquisition dates.

The allocation of the aggregate purchase price based on the estimated fair values of the net assets of Temple and Marathon Canada on their acquisition dates was as follows:

	Temple	Marathon Canada
Net assets acquired		
Working capital (1)	$ (17)	$ (15)
Property, plant and equipment	138	1,008
Goodwill (2)	20	140
Asset retirement obligations	—	(38)
Future income taxes	(39)	(264)
	$102	$ 831

(1) Working capital of Marathon Canada acquired included cash of $22 million.

(2) Allocated to the Company's upstream segment and not deductible for income tax purposes. Refer to note 1, Segmented Financial Information.

In conjunction with the above acquisition of Marathon Canada, the Company sold certain of the Marathon Canada oil and gas properties to a third party for cash consideration of U.S. $320 million (Cdn. $431 million).

Note 8

Cash Flows — Change in Non-cash Working Capital

a) Change in non-cash working capital was as follows:

	2004	2003	2002
Decrease (increase) in non-cash working capital			
Accounts receivable	$209	$ (7)	$(153)
Inventories	(77)	28	(2)
Prepaid expenses	(12)	(10)	1
Accounts payable and accrued liabilities	323	270	(11)
Change in non-cash working capital	443	281	(165)
Relating to:			
Financing activities	337	48	(9)
Investing activities	(63)	120	42
Operating activities	$169	$113	$(198)

b) Other cash flow information:

	2004	2003	2002
Cash taxes paid	$213	$ 69	$ 20
Cash interest paid	$116	$134	$139

Note 9

Bank Operating Loans

At December 31, 2004, the Company had short-term borrowing lines of credit with banks totalling $195 million (2003 and 2002 — $195 million). As at December 31, 2004, $49 million (2003 — $71 million; 2002 — nil) had been used for bank operating loans and $23 million (2003 — $18 million; 2002 — $12 million) had been used for letters of credit. Interest payable is based on Bankers' Acceptance, money market, or prime rates. During 2004, the weighted average interest rate on short-term borrowings was approximately 3.4 percent (2003 — 3.7 percent; 2002 — 2.9 percent).

Note 10

Accounts Payable and Accrued Liabilities

	2004	2003	2002
Trade payables	$ 110	$ 58	$ 87
Accrued liabilities	751	794	562
Dividend payable	280	42	38
Commodity contract settlements	50	8	—
Stock-based compensation	49	—	—
Current income taxes	119	117	51
Other	130	107	56
	$1,489	$1,126	$794

Note 11

Long-term Debt

	Maturity	2004	2003	2002	2004	2003	2002
		Cdn. $ Amount			U.S. $ Amount		
Long-term debt							
Syndicated credit facility	2007	$ 70	$ —	$ —	$ —	$ —	$ —
Bilateral credit facilities	2006-7	40	—	—	—	—	—
6.875% notes		—	—	237	—	—	150
7.125% notes	2006	181	194	237	150	150	150
6.25% notes	2012	481	517	632	400	400	400
7.55% debentures	2016	241	258	316	200	200	200
6.15% notes	2019	361	—	—	300	—	—
Private placement notes	2005	18	41	107	15	32	68
8.45% senior secured bonds	2005-12	140	188	256	117	145	162
Medium-term notes	2007-9	300	500	600	—	—	—
Total long-term debt		1,832	1,698	2,385	$1,182	$927	$1,130
Amount due within one year		(56)	(259)	(421)			
		$1,776	$1,439	$1,964			

Required debt repayments for the following periods are:

	Amount
2005	$ 56
2006	226
2007	219
2008	19
2009	214
Thereafter	1,098
	$1,832

Interest — net for the years ended December 31 was as follows:

	2004	2003	2002
Long-term debt	$106	$129	$128
Short-term debt	3	2	3
	109	131	131
Amount capitalized	(75)	(52)	(26)
	34	79	105
Interest income	(1)	(6)	(1)
	$ 33	$ 73	$104

Foreign exchange for the years ended December 31 was as follows:

	2004	2003	2002
Gain on translation of U.S. dollar denominated long-term debt	$(129)	$(315)	$—
Cross currency swaps	27	73	—
Other losses	3	27	13
	$ (99)	$(215)	$13

As at December 31, 2004, other assets included $22 million (2003 — $19 million; 2002 — $23 million) of deferred debt issue costs.

Credit Facilities

The revolving syndicated credit facility allows the Company to borrow up to $950 million in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a one-year committed revolving credit facility, extendible annually. In the event that the lenders do not consent to such extension, the revolving credit facility will convert to a two-year non-revolving amortizing term loan. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected, credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt and whether the Company borrows under the revolving or non-revolving condition.

The Company's $150 million revolving bilateral credit facilities have substantially the same terms as the syndicated credit facility.

Notes and Debentures

The 7.125 percent notes and the 7.55 percent debentures represent unsecured securities issued under a trust indenture dated October 31, 1996. These securities mature in 2006 and 2016, respectively. The 7.125 percent notes are not redeemable prior to maturity. Interest is payable semi-annually.

The 6.25 percent and the 6.15 percent notes represent unsecured securities issued under a trust indenture dated June 14, 2002. Interest is payable semi-annually.

On August 12, 2004, the Company filed a base shelf prospectus with securities regulatory authorities in Canada and the United States. The prospectus permits Husky to offer for sale, from time to time, up to U.S.$1 billion of debt securities during the 25 months from August 12, 2004. No notes have been issued under the base shelf prospectus as of December 31, 2004.

The private placement notes represent unsecured securities under a master shelf agreement dated January 31, 2001 and have an interest rate of 6.89 percent. Interest is payable quarterly.

The 8.45 percent senior secured bonds represent securities issued by a subsidiary under a trust indenture dated July 20, 1999. These securities amortize semi-annually. Such securities were issued in connection with the financing of the Company's share of the costs for the exploration and development of the Terra Nova oil field located off the East Coast of Canada. Interest is payable semi-annually. The Company has the option of delaying the repayment schedule by one year. The Company, through a wholly owned partnership, owns 12.51 percent of the Terra Nova oil field and associated facilities. The repayment of the securities is contracted to be made solely from revenue from the Terra Nova oil field. There is also a charge created by the partnership on its interest in the assets of the Terra Nova oil field and associated facilities in favour of the security holders. Certain related financial obligations require collateral of letters of credit and/or cash equivalents. As at December 31, 2004, letters of credit totalling $54 million (2003 — $54 million; 2002 — $38 million) were outstanding.

The medium-term notes Series B represent unsecured securities issued under a trust indenture dated February 3, 1997 and the Series E notes represent unsecured securities issued under a trust indenture dated May 4, 1999. The amounts, rates and maturities are as follows:

Issue	Amount	Interest Rate	Maturity Date
Series B	$100	6.85%	February 2007
Series E	200	6.95%	July 2009
	$300		

Interest is payable semi-annually on all series.

The notes and debentures disclosed above are redeemable (unless otherwise stated) at the option of the Company, at any time, at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate (for U.S. dollar denominated securities) or Government of Canada Bond rate (for Canadian dollar denominated securities) plus an applicable spread.

Note 12

Other Long-term Liabilities

	2004	2003	2002
Asset retirement obligations	$509	$432	$286
Cross currency swaps	68	41	—
Interest rate swaps	18	26	—
Employee future benefits	23	20	17
Stock-based compensation	14	—	—
Other	—	—	1
	$632	$519	$304

Asset Retirement Obligations

The Company adopted the new recommendations for the recognition of the obligations to retire long-lived tangible assets. The change was effective January 1, 2004 and the revision was applied retroactively.

The impact of the retroactive revision was as follows:

	2003			2002		
	As Reported (1)	Change	As Restated	As Reported (1)	Change	As Restated
Consolidated Balance Sheets						
Assets						
Property, plant and equipment, net	$10,698	$ 164	$10,862	$9,363	$ 58	$9,421
Liabilities and Shareholders' Equity						
Other long-term liabilities	390	129	519	266	38	304
Future income taxes	2,608	13	2,621	2,003	11	2,014
Retained earnings	2,134	22	2,156	1,357	9	1,366
Consolidated Statements of Earnings						
Cost of sales and operating expenses	$ 4,825	$ 22	$ 4,847	$4,009	$ 17	$4,026
Depletion, depreciation and amortization	1,058	(37)	1,021	939	(31)	908
Future income taxes	327	2	329	354	4	358
Net earnings	1,321	13	1,334	804	10	814
Earnings per share						
Basic	$ 3.23	$0.03	$ 3.26	$ 1.88	$0.03	$ 1.91
Diluted	$ 3.22	$0.03	$ 3.25	$ 1.88	$0.02	$ 1.90

(1) Certain amounts have been reclassified to conform with current presentation.

At December 31, 2004, the estimated total undiscounted amount required to settle the asset retirement obligations was $2.9 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend up to 50 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2 percent to 6.4 percent.

Changes to the asset retirement obligations were as follows:

	2004	2003	2002
Asset retirement obligations, beginning of year	$432	$286	$247
Liabilities incurred	13	158	38
Liabilities settled	(40)	(34)	(16)
Revisions	77	—	—
Accretion	27	22	17
Asset retirement obligations, end of year	$509	$432	$286

Note 13

Income Taxes

The combined provision for income taxes in the Consolidated Statements of Earnings and Retained Earnings reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31 were accounted for as follows:

	2004	2003	2002
Earnings before income taxes			
Canadian	$1,171	$1,587	$1,084
Foreign jurisdictions	240	223	154
	1,411	1,810	1,238
Statutory income tax rate (*percent*)	39.3	40.2	41.6
Expected income tax	555	728	515
Effect on income tax of:			
Royalties, lease rentals and mineral taxes payable to the crown	153	175	159
Resource allowance on Canadian production income	(156)	(183)	(212)
Rate benefit on partnership earnings	(42)	(23)	—
Change in statutory tax rate	(40)	(161)	(31)
Return on capital securities	(6)	2	(11)
Non-deductible capital taxes	20	22	18
Gains and losses on foreign exchange	(20)	(45)	—
Foreign jurisdictions	(13)	(16)	(13)
Other — net	(52)	(21)	(12)
	$ 399	$ 478	$ 413
Charged (credited) to:			
Income tax expense	$ 405	$ 476	$ 424
Retained earnings	(6)	2	(11)
	$ 399	$ 478	$ 413

The future income tax liability at December 31 comprised the tax effect of temporary differences as follows:

	2004	2003	2002
Future tax liabilities			
Property, plant and equipment	$2,949	$2,826	$2,226
Foreign exchange gains taxable on realization	56	32	—
Other temporary differences	5	2	30
	3,010	2,860	2,256
Future tax assets			
Asset retirement obligations	180	160	121
Loss carry forwards	11	2	7
Foreign exchange losses deductible on realization	—	—	28
Provincial royalty rebates	14	52	48
Other temporary differences	47	25	38
	252	239	242
	$2,758	$2,621	$2,014

Note 14

Commitments and Contingencies

Certain former owners of interests in the upgrading assets retained a 20-year upside financial interest expiring in 2014 which requires payments to them when the average differential between heavy crude oil feedstock and synthetic crude oil exceeds $6.50 per barrel. The calculation is based on a two-year rolling average of the differential. During 2004, the Company capitalized $27 million (2003 — $10 million; 2002 — $23 million) of payments under this arrangement.

At December 31, 2004, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

	2005	2006	2007	2008	2009	After 2009	Total
Operating leases	$ 68	$ 76	$ 76	$ 78	$ 73	$183	$ 554
Firm transportation agreements	213	202	173	143	119	211	1,061
Unconditional purchase obligations	593	428	256	63	24	117	1,481
Lease rentals	44	44	44	44	44	110	330
Exploration work agreements	27	5	10	—	—	8	50
Engineering and construction commitments	572	241	142	12	—	—	967
	$1,517	$996	$701	$340	$260	$629	$4,443

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and future income taxes.

Note 15

Capital Securities

The Company issued U.S. $225 million unsecured capital securities under an indenture dated August 10, 1998. Such securities rank junior to all senior debt and other financial debt of the Company. They yield an annual return of 8.9 percent, payable semi-annually until August 15, 2008 and mature in 2028. The capital securities are redeemable, in whole or in part, by the Company at any time prior to August 15, 2008 at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate plus an applicable spread. They are redeemable at par, in whole but not in part, by the Company on or after August 15, 2008. If not redeemed in whole, commencing on August 15, 2008, the annual return changes to a floating rate equal to U.S. LIBOR plus 5.50 percent payable semi-annually. The Company has the right at any time prior to maturity to defer payment of the return on the securities. Since the Company also has the unrestricted ability to settle its deferred return, principal and redemption obligations through the issuance of common or preferred shares, the principal amount of the capital securities, net of issue costs, has been classified as equity. The return and foreign exchange on capital securities, net of income taxes, are classified as a distribution of equity.

The amounts disclosed as capital securities and accrued return in shareholders' equity at December 31 were as follows:

	2004	2003	2002
Capital securities — U.S. $225	$271	$291	$355
Unamortized costs of issue	(2)	(3)	(3)
Accrued return	9	10	12
	$278	$298	$364

In November 2003, the Accounting Standards Board revised recommendations in CICA section 3860, ''Financial Instruments -Disclosure and Presentation'', on the classification of obligations that must or could be settled with an entity's own equity instruments. The new recommendations will be effective January 1, 2005 and will result in the Company's capital securities being classified as liabilities instead of equity. The accrued return on the capital securities and the issue costs will be classified outside of shareholders' equity. The return on the capital securities will be a charge to

earnings. The revision will be applied retroactively effective January 1, 2005 and will result in the following changes to the Company's financial statements:

	2004			2003			2002		
	As Reported	Change	Pro Forma	As Reported	Change	Pro Forma	As Reported	Change	Pro Forma
Consolidated Balance Sheets									
Assets									
Other assets	$ 106	$ 2	$ 108	$ 112	$ 3	$ 115	$ 84	$ 3	$ 87
Liabilities and Shareholders' Equity									
Accounts payable and accrued liabilities	1,489	9	1,498	1,126	10	1,136	794	12	806
Long-term debt	1,776	271	2,047	1,439	291	1,730	1,964	355	2,319
Capital securities and accrued return	278	(278)	—	298	(298)	—	364	(364)	—
Consolidated Statements of Earnings									
Interest — net	$ 33	$ 27	$ 60	$ 73	$ 29	$ 102	$ 104	$ 32	$ 136
Foreign exchange	(99)	(21)	(120)	(215)	(67)	(282)	13	(3)	10
Future income taxes	103	(6)	97	329	2	331	358	(11)	347
Net earnings	1,006	—	1,006	1,334	36	1,370	814	(18)	796

Effective January 1, 2005, the Company will be required to include the capital securities in the determination of diluted earnings per common share.

Note 16

Share Capital

The Company's authorized share capital is as follows:

Common shares — an unlimited number of no par value.

Preferred shares — an unlimited number of no par value, none outstanding.

Common Shares

Changes to issued share capital were as follows:

	Number of Shares	Amount
January 1, 2002	416,878,093	$3,397
Options and warrants exercised	995,508	9
December 31, 2002	417,873,601	3,406
Options and warrants exercised	4,302,141	51
December 31, 2003	422,175,742	3,457
Stock-based compensation — adoption	—	23
Options and warrants exercised	1,560,672	26
December 31, 2004	423,736,414	$3,506

Stock Options

At December 31, 2004, 23.2 million common shares were reserved for issuance under the Company stock option plan. As described in note 3 l), on June 1, 2004, the Company modified its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the average market price of the Company's common shares during the five trading days prior to the date of the award. When the option is surrendered for cash, the cash payment is the difference between the average market price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. Under the stock option plan the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year.

A downward adjustment of $0.48 was made to the exercise price of all outstanding stock options effective November 29, 2004, pursuant to the terms of the stock option plan under which the options were issued as a result of the special $0.54 per share dividend that was declared in November 2004. A similar downward adjustment of $0.82 was made to the exercise price of all outstanding stock options effective September 3, 2003, as a result of the special $1.00 per share dividend that was declared in July 2003.

The following options to purchase common shares have been awarded to directors, officers and certain other employees:

	Number of Options	Weighted Average Exercise Prices	Weighted Average Contractual Life	Options Exercisable
	(thousands)		(years)	(thousands)
December 31, 2001	8,602	$13.78	4	2,853
Granted	568	$16.11	5	
Exercised for common shares	(608)	$13.63	2	
Forfeited	(642)	$14.37	3	
December 31, 2002	7,920	$13.91	3	4,822
Granted	591	$19.17	5	
Exercised for common shares	(3,789)	$13.45	2	
Forfeited	(125)	$14.71	2	
December 31, 2003	4,597	$13.88	2	3,564
Granted	8,200	$25.10	4	
Exercised for common shares	(1,350)	$13.11	1	
Surrendered for cash	(1,269)	$13.32	1	
Forfeited	(214)	$22.73	4	
December 31, 2004	9,964	$22.61	4	1,417

	As at December 31, 2004				
	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options	Weighted Average Exercise Prices	Weighted Average Contractual Life	Number of Options	Weighted Average Exercise Prices
	(thousands)		(years)	(thousands)	
$9.86-$14.99	1,443	$12.75	1	1,320	$12.57
$15.00-$23.99	475	$18.40	3	97	$19.39
$24.00-$32.14	8,046	$24.62	4	—	$ —
	9,964	$22.61	4	1,417	$13.04

Warrants

In 2000, the Company granted 1.4 million Renaissance Energy Ltd. (''Renaissance'') replacement options to purchase common shares of Husky in exchange for certain share purchase options to purchase common shares of Renaissance previously held by employees of Renaissance. The former shareholders of Husky Oil Limited were also granted warrants to acquire, for no additional consideration, 1.86 common shares of the Company for each common share issued on the exercise of a Renaissance replacement option. The warrants are exercisable only if and when the Renaissance replacement options are exercised and provide for the issue of a maximum of 2.5 million common shares. During 2004, 113,600 warrants were exercised (2003 — 276,500; 2002 — 208,500). As at December 31, 2004, there were 51,068 common shares remaining which could potentially be issued as a result of the exercise of these warrants. The Renaissance replacement options had a weighted average contractual life of 0.2 years at December 31, 2004.

Earnings per Common Share

	2004	2003	2002
Net earnings	$1,006	$1,334	$ 814
Return and foreign exchange on capital securities (net of related taxes)	—	36	(18)
Net earnings available to common shareholders	$1,006	$1,370	$ 796
Weighted average number of common shares outstanding			
Basic *(millions)*	423.4	419.5	417.4
Effect of dilutive stock options and warrants	2.3	2.0	1.9
Weighted average number of common shares outstanding			
Diluted *(millions)*	425.7	421.5	419.3
Earnings per share			
Basic	$ 2.37	$ 3.26	$ 1.91
Diluted	$ 2.36	$ 3.25	$ 1.90

Stock-based Compensation

As described in note 3 l), beginning January 1, 2004, stock-based compensation is being recognized in earnings. This change was adopted retroactively without restatement of prior periods and resulted in a decrease to retained earnings of $44 million, an increase to contributed surplus of $21 million and an increase to share capital of $23 million on January 1, 2004. If the Company had applied the fair value method retroactively with restatement of prior periods for all options granted, the Company's net earnings and earnings per share for the years ended December 31, 2003 and 2002 would have been as follows:

	2003	2002
Compensation cost — all options granted (1)	$ 14	$ 13
Net earnings available to common shareholders		
As reported	$1,370	$ 796
As restated	$1,356	$ 783
Weighted average number of common shares outstanding *(millions)*		
Basic	419.5	417.4
Diluted	421.5	419.3
Basic earnings per share		
As reported	$ 3.26	$ 1.91
As restated	$ 3.23	$ 1.88
Diluted earnings per share		
As reported	$ 3.25	$ 1.90
As restated	$ 3.22	$ 1.87

(1) Includes options modified.

As described in note 3 l), effective June 1, 2004, the Company modified the stock option plan to a tandem plan, resulting in an increase to current liabilities of $34 million, a decrease to contributed surplus of $16 million and an increase to stock-based compensation expense of $18 million. Prior to the modification, the fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The grant date fair values and assumptions used prior to June 1, 2004 were:

	2004	2003	2002
Weighted average fair value per option	$5.67	$4.00	$5.19
Risk-free interest rate *(percent)*	3.1	3.9	3.6
Volatility *(percent)*	21	23	43
Expected life *(years)*	5	5	5
Expected annual dividend per share	$0.44	$0.36	$0.36

As a result of the downward adjustment of $0.82 to the exercise price of all outstanding options effective September 3, 2003, the fair values of all common share options granted prior to that date were revalued on September 3, 2003 using the Black-Scholes option-pricing model. The weighted average fair value of outstanding stock options as at September 3, 2003 and the assumptions used are noted below:

Weighted average fair value per option	$7.14
Risk-free interest rate *(percent)*	2.8
Volatility *(percent)*	20
Expected life *(years)*	2.3
Expected annual dividend per share	$0.40

Dividends

During 2004, the Company declared dividends of $1.00 per common share (2003 — $1.38 per common share; 2002 — $0.36 per common share), including a special dividend of $0.54 per common share (2003 — $1.00 per common share).

Contributed Surplus

Changes to contributed surplus were as follows:

	2004
January 1, 2004	$ —
Stock-based compensation — adoption	21
Stock-based compensation cost	1
Stock options exercised	(6)
Modification of stock option plan — June 1, 2004	(16)
December 31, 2004	$ —

Note 17

Employee Future Benefits

The Company currently provides a defined contribution pension plan for all qualified employees. The Company also maintains a defined benefit pension plan, which is closed to new entrants, and all current participants are vested. The Company also provides certain health and dental coverage to its retirees which is accrued over the expected average remaining service life of the employees.

Weighted average long-term assumptions are based on independent historical and projected references and are noted below:

	2004	2003	2002
Discount rate (percent)	6.0	6.0	6.3
Long-term rate of increase in compensation levels (percent)	5.0	5.0	5.0
Long-term rate of return on plan assets (percent)	8.0	8.0	8.0

The discount rate used at the end of 2004 to determine the accrued benefit obligation was 5.75 percent.

The long-term rate of return on the assets was determined based on management's best estimate and the historical rates of return, adjusted periodically. The rate at the end of 2004 was 7.5 percent.

The average health care cost trend used was eight percent, which is reduced by 0.50 percent until 2009. The average dental care cost trend used was four percent, which remains constant.

Defined Benefit Pension Plan

The status of the defined benefit pension plan at December 31 was as follows:

Benefit Obligation

	2004	2003	2002
Benefit obligation, beginning of year	$118	$108	$ 95
Current service cost	2	2	2
Interest cost	7	7	7
Benefits paid	(6)	(6)	(6)
Actuarial losses	3	7	10
Benefit obligation, end of year	$124	$118	$108

Fair Value of Plan Assets

	2004	2003	2002
Fair value of plan assets, beginning of year	$85	$77	$85
Contributions	10	8	2
Benefits paid	(6)	(6)	(6)
Expected return on plan assets	7	6	7
Gain (loss) on plan assets	1	2	(11)
Foreign exchange losses	(1)	(2)	—
Fair value of plan assets, end of year	$96	$85	$77

Funded Status of Plan

	2004	2003	2002
Fair value of plan assets	$ 96	$ 85	$ 77
Benefit obligation	(124)	(118)	(108)
Excess obligation	(28)	(33)	(31)
Unrecognized past service costs	1	1	1
Unrecognized losses	32	32	27
Accrued benefit asset (liability)	$ 5	$ —	$ (3)

Husky, under the purview of its Board of Directors, adheres to a Statement of Investment Policies and Procedures (the ''Policy'') that conforms to applicable government regulation. The assets are allocated in accordance with the long-term nature of the obligation and comprise a balanced investment based on interest rate and inflation sensitivities. The Policy explicitly prescribes diversification parameters for all classes of investment.

The date of the last actuarial valuation for the Company was December 31, 2002 and the next scheduled actuarial valuation will take place January 1, 2005.

The composition of the defined benefit pension plan assets was as follows:

	2004	2003	2002
U.S. common equities	15%	15%	15%
Canadian common equities	25	28	29
International equity mutual funds	11	10	7
Canadian equity mutual funds	—	2	2
Canadian government bonds	25	29	26
Canadian corporate bonds	16	12	14
Cash and receivables	8	4	7
Total	100%	100%	100%

During 2004, Husky contributed $10 million to the defined benefit pension plan assets, $8 million of which was in respect of additional contributions as a result of the plan's deficiency. Husky currently plans to contribute a similar amount in 2005.

The Company amortizes the portion of the unrecognized actuarial gains or losses that exceed 10 percent of the greater of the accrued benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets. The gains or losses that are in excess of 10 percent are amortized over the expected future years of service, which is currently eight years.

The past service costs are amortized over the expected future years of service.

Post-retirement Health and Dental Care Plan

The status of the post-retirement health and dental care plan at December 31 was as follows:

Benefit Obligation

	2004	2003	2002
Benefit obligation, beginning of year	$23	$21	$16
Current service cost	2	2	1
Interest cost	1	1	1
Benefits paid	(1)	(1)	—
Actuarial losses	—	—	3
Benefit obligation, end of year	$25	$23	$21

Funded Status of Plan

	2004	2003	2002
Benefit obligation	$(25)	$(23)	$(21)
Unrecognized losses	2	3	4
Accrued benefit liability	$(23)	$(20)	$(17)

The assumed health care cost trend can have a significant effect on the amounts reported for Husky's post-retirement health and dental care plan. A one percent increase and decrease in the assumed trend rate would have the following effect:

	1% Increase	1% Decrease
Effect on total service and interest cost components	$ 1	$ —
Effect on post-retirement benefit obligation	$ 4	$ (3)

Pension Expense and Post-retirement Health and Dental Care Expense

The expenses for the years ended December 31 were as follows:

Pension Expense

	2004	2003	2002
Defined benefit pension plan			
Employer current service cost	$ 2	$ 2	$ 2
Interest cost	7	7	7
Expected return on plan assets	(7)	(6)	(7)
Amortization of net actuarial losses	2	2	—
	4	5	2
Defined contribution pension plan	12	11	10
Total expense	$ 16	$ 16	$ 12

Post-retirement Health and Dental Care Expense

	2004	2003	2002
Employer current service cost	$ 2	$ 2	$ 1
Interest cost	1	1	1
Total expense	$ 3	$ 3	$ 2

Future Benefit Payments

The following table discloses the current estimate of future benefit payments:

	Defined Benefit Pension Plan	Post-retirement Health and Dental Care Plan
2005	$ 7	$ 1
2006	7	1
2007	7	1
2008	7	1
2009	8	1
2010-2014	45	6

Note 18

Related Party Transactions

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, Husky paid approximately $10 million for office space in Western Canadian Place during 2004.

Note 19

Financial Instruments and Risk Management

Carrying Values and Estimated Fair Values of Financial Assets and Liabilities

The carrying value of cash and cash equivalents, accounts receivable, bank operating loans, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of these instruments.

The fair value of the long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. The estimated fair value of the long-term debt at December 31 was as follows:

	2004		2003		2002	
	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$1,832	$1,991	$1,698	$1,869	$2,385	$2,579

Unrecognized Gains (Losses) on Derivative Instruments

	2004	2003	2002
Commodity price risk management			
Natural gas	$(9)	$ (8)	$(4)
Crude oil	—	(109)	6
Power consumption	(1)	2	—
Interest rate risk management			
Interest rate swaps	52	31	86
Foreign currency risk management			
Foreign exchange contracts	(30)	(19)	(7)
Foreign exchange forwards	—	15	(5)

Commodity Price Risk Management

Natural Gas Production

During 2004 the impact of the 2004 hedge program was a gain of $8 million (2003 — gain of $24 million).

At December 31, 2004, the Company had hedged 7.5 mmcf of natural gas per day at NYMEX for 2005 at an average price of U.S. $1.92 per mcf. During 2004 the impact was a loss of $9 million (2003 — loss of $8 million; 2002 — insignificant).

Crude Oil Production

The impact of the 2004 hedge program was a loss of $560 million (2003 — loss of $36 million; 2002 — gain of $5 million).

Power Consumption

At December 31, 2004, the Company had hedged power consumption of 197,100 MWh from January to December 2005 at an average fixed price of $49.94 per MWh and 65,160 MWh from January to June 2005 at an average fixed price of $48.00 per MWh. The impact of the 2004 hedge program was a gain of $3 million.

Natural Gas Contracts

The Company has a portfolio of fixed and basis price offsetting physical forward purchase and sale natural gas contracts relating to marketing of other producers' natural gas. The objective of these contracts is to ''lock in'' a positive spread between the physical purchase and sale contract prices. At December 31, 2004, the Company had the following offsetting physical purchase and sale contracts:

	Volumes (mmcf)	Unrecognized Gain (Loss)
Physical purchase contracts	14,276	$(2)
Physical sale contracts	(14,276)	$ 3

Interest Rate Risk Management

The majority of the Company's long-term debt has fixed interest rates and various maturities. The Company periodically uses interest rate swaps to manage its financing costs. At December 31, 2004, the Company had entered into interest rate swap arrangements whereby the fixed interest rate coupon on certain debt was swapped to floating rates with the following terms:

Debt	Amount	Swap Maturity	Swap Rate (percent)
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps
7.55% debentures	U.S. $200	November 15, 2011	U.S. LIBOR + 194 bps
6.15% notes	U.S. $300	June 15, 2019	U.S. LIBOR + 63 bps

During 2004 the Company realized a gain of $22 million (2003 — gain of $17 million; 2002 — gain of $29 million) from interest rate risk management activities.

In 2003, the Company unwound three interest rate swaps for proceeds of $44 million. The proceeds have been deferred and are being amortized to income over the remaining term of the underlying debt.

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange rate fluctuations by balancing the U.S. dollar denominated cash flows with U.S. dollar denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency.

At December 31, 2004, the Company had the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate (percent)
7.125% notes	U.S. $150	$218	November 15, 2006	8.74
6.25% notes	U.S. $150	$212	June 15, 2012	7.41

The Company hedged U.S. dollar revenues for various amounts and maturities through 2005 using foreign exchange forwards. On November 10, 2004, the Company unwound its long-dated forwards totalling U.S. $36 million, which resulted in a gain of $8 million that has been deferred and will be recognized into income on the dates that the underlying hedged transactions are to take place.

During 2004 the Company recognized a loss of $13 million (2003 — loss of $56 million; 2002 — loss of $11 million) from foreign currency risk management activities.

Credit Risk

Accounts receivable are predominantly with customers in the energy industry and are subject to normal industry credit risks.

In addition, the Company is exposed to credit related losses in the event of non-performance by counterparties to its derivative financial instruments. The Company primarily deals with major financial institutions and investment grade rated entities to mitigate these risks.

Husky did not have any customers that constituted more than five percent of total sales and operating revenues during 2004.

Note 20

Reconciliation to Accounting Principles Generally Accepted in the United States

The Company's consolidated financial statements have been prepared in accordance with GAAP in Canada, which differ in some respects from those in the United States. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described below:

Consolidated Statements of Earnings

	2004	2003	2002
Net earnings under Canadian GAAP	$1,006	$1,334	$ 814
Adjustments:			
Full cost accounting (a)	37	80	88
Related income taxes	(13)	(30)	(37)
Foreign exchange on capital securities (b)	21	67	3
Related income taxes	(3)	(12)	(1)
Return on capital securities (b)	(27)	(29)	(32)
Related income taxes	9	11	11
Derivatives and hedging (c)	—	(1)	22
Related income taxes	—	1	(9)
Energy trading contracts (c)	(1)	(15)	(2)
Related income taxes	—	6	1
Asset retirement obligations (d)	—	—	(14)
Related income taxes	—	—	4
Stock-based compensation (e)	2	(46)	—
Accounting for income taxes (f)	—	—	(37)
Earnings before cumulative effect of change in accounting principle under U.S. GAAP	1,031	1,366	811
Cumulative effect of change in accounting principle, net of tax (d)	—	9	—
Net earnings under U.S. GAAP	$1,031	$1,375	$ 811
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
Basic	423.4	419.5	417.4
Diluted	425.7	421.5	419.3
Earnings per share before cumulative effect of change in accounting principle under U.S. GAAP			
Basic	$ 2.44	$ 3.26	$ 1.94
Diluted	$ 2.42	$ 3.24	$ 1.93
Earnings per share under U.S. GAAP			
Basic	$ 2.44	$ 3.28	$ 1.94
Diluted	$ 2.42	$ 3.26	$ 1.93

Condensed Consolidated Balance Sheets

	2004		2003		2002	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets (c)	$ 779	$ 837	$ 852	$ 911	$ 1,128	$ 1,276
Property, plant and equipment, net (a)(d)	12,193	11,633	10,862	10,264	9,421	8,686
Other assets (b)(j)	266	269	232	236	84	89
	$13,238	$12,739	$11,946	$11,411	$10,633	$10,051
Current liabilities (b)(c)(j)	$ 1,594	$ 1,663	$ 1,456	$ 1,635	$ 1,215	$ 1,301
Long-term debt (b)(c)	1,776	2,099	1,439	1,761	1,964	2,406
Other long-term liabilities (d)	632	632	519	519	304	266
Future income taxes (a)(b)(c)(d)(f)(j)	2,758	2,555	2,621	2,372	2,014	1,772
Capital securities and accrued return (b)	278	—	298	—	364	—
Share capital (e)(g)(h)	3,506	3,740	3,457	3,737	3,406	3,640
Retained earnings	2,694	2,085	2,156	1,478	1,366	683
Accumulated other comprehensive income						
Cash flow hedges, net of tax (c)	—	(20)	—	(76)	—	(7)
Minimum pension liability, net of tax (j)	—	(15)	—	(15)	—	(10)
	$13,238	$12,739	$11,946	$11,411	$10,633	$10,051

Condensed Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income

	2004		2003		2002	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Retained earnings, beginning of year	$2,156	$1,478	$1,366	$ 683	$ 722	$ 23
Net earnings	1,006	1,031	1,334	1,375	814	811
Dividends on common shares	(424)	(424)	(580)	(580)	(151)	(151)
Return and foreign exchange on capital securities, net of tax (b)	—	—	36	—	(18)	—
Stock-based compensation — retroactive adoption (e)	(44)	—	—	—	—	—
Asset retirement obligations — retroactive adoption (d)	—	—	—	—	(1)	—
Retained earnings, end of year	$2,694	$2,085	$2,156	$1,478	$1,366	$ 683
Accumulated other comprehensive income, beginning of year	$ —	$ (91)	$ —	$ (17)	$ —	$ 3
Cash flow hedges, net of tax (c)	—	56	—	(69)	—	(10)
Minimum pension liability, net of tax (j)	—	—	—	(5)	—	(10)
Accumulated other comprehensive income, end of year	$ —	$ (35)	$ —	$ (91)	$ —	$ (17)

Condensed Consolidated Statements of Earnings and Comprehensive Income

	2004		2003		2002	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Sales and operating revenues (c)(i)	$8,440	$7,038	$7,658	$6,823	$6,384	$5,635
Costs and expenses (b)(c)(e)(i)	5,790	4,366	4,732	3,892	4,117	3,345
Accretion expense (d)	27	27	22	22	17	—
Depletion, depreciation and amortization (a)(d)	1,179	1,142	1,021	941	908	851
Interest — net (b)	33	60	73	102	104	136
Earnings before income taxes	1,411	1,443	1,810	1,866	1,238	1,303
Income taxes (a)(b)(c)(d)(f)	405	412	476	500	424	492
Earnings before cumulative effect of change in accounting principle	1,006	1,031	1,334	1,366	814	811
Cumulative effect of change in accounting principle, net of tax (d)	—	—	—	9	—	—
Net earnings	1,006	1,031	1,334	1,375	814	811
Other comprehensive income (c)(j)	—	(56)	—	74	—	20
Comprehensive income	$1,006	$ 975	$1,334	$1,449	$ 814	$ 831

Condensed Consolidated Statements of Cash Flows

	2004	2003	2002
Cash flow — operating activities — Canadian GAAP	$2,352	$2,538	$1,882
Adjustments:			
Return on capital securities payment	(26)	(29)	(31)
Settlement of asset retirement liabilities	—	—	16
Cash flow — operating activities — U.S. GAAP	2,326	2,509	1,867
Cash flow — financing activities — Canadian GAAP	149	(800)	3
Adjustments:			
Return on capital securities payment	26	29	31
Cash flow — financing activities — U.S. GAAP	175	(771)	34
Cash flow — investing activities — Canadian GAAP	(2,497)	(2,041)	(1,579)
Adjustments:			
Settlement of asset retirement liabilities	—	—	(16)
Cash flow — investing activities — U.S. GAAP	(2,497)	(2,041)	(1,595)
Change in cash and cash equivalents	$ 4	$ (303)	$ 306

The increases or decreases noted above refer to the following differences between U.S. GAAP and Canadian GAAP:

(a) Under Canadian GAAP the ceiling test has been modified by Accounting Guideline 16, ''Oil and Gas Accounting — Full Cost'' (''AcG-16''). Under AcG-16 the ceiling test is performed by comparing the carrying value of the cost centre based on the sum of the undiscounted cash flows from proved reserves using future prices and costs expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach of proved plus probable reserves using

future prices. Previously, the Company performed the cost recovery ceiling test for each cost centre which limited net capitalized costs to the undiscounted estimated future net revenue from proved reserves plus the cost of unproved properties and major development projects less impairment, using year-end prices or average prices in that year if appropriate. In addition, the aggregate value of all cost centres were previously further limited by including financing costs, administration expenses, future removal and site restoration costs and income taxes. Under U.S. GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved reserves using a discount factor of 10 percent. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end. Financing and administration costs are excluded from the calculation under U.S. GAAP. At December 31, 2001, the Company recognized a U.S. GAAP ceiling test write down of $334 million after tax. Depletion expense for U.S. GAAP is reduced by $76 million (2003 — $80 million; 2002 — $88 million), net of tax of $27 million (2003 — $30 million; 2002 — $37 million).

Under U.S. GAAP, prices used in determining proved reserves are those in effect at the applicable year-end. For Canadian GAAP, commencing in 2004, future prices and costs are used in determining proved reserves. The different prices result in lower proved reserves for U.S. GAAP. Additional depletion of $39 million, net of taxes of $14 million has been recorded under U.S. GAAP in 2004.

(b) The Company records the capital securities as a component of equity and the return and foreign exchange gains or losses thereon as a charge to retained earnings. Under U.S. GAAP, the capital securities, the accrued return thereon and costs of issue would be classified outside of shareholders' equity and the related return and foreign exchange gains or losses would be charged to earnings. See note 15, Capital Securities.

(c) The Company records all derivative instruments as assets and liabilities on the balance sheet based on their fair values as required under FAS 133, ''Accounting for Derivative Instruments and Hedging Activities''. At December 31, 2004, the Company recorded additional assets and liabilities for U.S. GAAP purposes of $52 million (2003 — $52 million; 2002 — $111 million) and $93 million (2003 — $172 million; 2002 — $122 million), respectively, for the fair values of derivative financial instruments. The Company also recorded a loss of less than $1 million, net of tax (2003 — loss of $2 million; 2002 — gain of $1 million), in revenue for U.S. GAAP purposes with respect to derivatives designated as fair value hedges relating to commodity price risk. In addition, the amount included in other comprehensive income was reduced by $51 million net of tax (2003 — increased by $69 million; 2002 — reduced by $10 million), for changes in the fair values of the derivatives designated as hedges of cash flows relating to commodity price risk and foreign exchange risk and the transfer to income of amounts applicable to cash flows occurring in 2004. On November 10, 2004, the Company unwound its long-dated foreign exchange forwards. The unrealized gain of $5 million, net of tax continues to be deferred in other comprehensive income and will be recognized at the dates that the underlying transactions are to take place. In prior years, the gains net of tax (2003 — $1 million; 2002 — $11 million) on foreign currency derivatives and natural gas basis swaps that did not qualify for hedge accounting under FAS 133 were included in income for U.S. GAAP purposes.

Under U.S. GAAP, energy trading contracts entered into and physical energy trading inventories purchased on or before October 26, 2002 were recorded at fair value. These contracts include derivatives as well as energy trading contracts that do not meet the definition of derivatives. Effective October 26, 2002, inventories and the associated natural gas purchase and sale contracts entered into after the effective date are no longer recorded at fair value in accordance with Emerging Issues Task Force 02-03, ''Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities''. Under Canadian GAAP, the impact of energy trading contracts is recorded as they settle. Under U.S. GAAP, at December 31, 2004 the Company recorded additional assets and liabilities of $4 million (2003 — $7 million; 2002 — $37 million) and $3 million (2003 — $5 million; 2002 — $19 million), respectively, and included the resulting unrealized loss, net of tax of $1 million (2003 — loss of $9 million; 2002 — loss of $1 million) in earnings for the year. Under U.S. GAAP, gains and losses on energy trading contracts have been netted against sales and operating revenues.

(d) In 2003, the Company adopted FAS 143, ''Accounting for Asset Retirement Obligations'', which requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related tangible long-lived asset. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the asset. The liability is accreted at the end of each period through charges to accretion expense. The change was effective January 1, 2003, and the related cumulative effect of change in accounting principle to net earnings to December 31, 2002 was an increase of $20 million, net of tax of $11 million or $0.02 per share (diluted). Effective January 1, 2004, under Canadian GAAP the Company adopted CICA section 3110, ''Asset Retirement Obligations'', which is substantially the same as the recommendations in FAS 143. CICA section 3110 was adopted retroactively with restatement. The application of asset retirement obligations did not have a material impact on the Company's depletion, depreciation and amortization rate. There was no impact on the Company's cash flow as a result of adopting asset retirement obligations.

The following table shows the effect on the Company's net earnings and earnings per share as if FAS 143 had been in effect in prior years. There would have been a $10 million increase to net earnings for the year ended December 31, 2002.

	As at and for the year ended December 31, 2002
As reported	
Net earnings under U.S. GAAP	$ 811
Earnings per share under U.S. GAAP	
Basic	$1.94
Diluted	$1.93
Pro forma	
Net earnings under U.S. GAAP	$ 821
Earnings per share under U.S. GAAP	
Basic	$1.97
Diluted	$1.96
Asset retirement obligations	
Beginning of year	$ 269
End of year	$ 286

(e) On September 3, 2003, the Company modified the exercise price of all outstanding options. Under U.S. GAAP these options are required to be accounted for using variable accounting where the in-the-money portion of the vested stock options outstanding is adjusted through the statement of earnings as compensation expense over the remaining vesting period. The amount of stock-based compensation expense charged to earnings for the year ended December 31, 2003 was $46 million. The compensation expense is revalued at each reporting date based on the share price and the number of vested stock options outstanding. In 2003, under Canadian GAAP no compensation expense was recorded for modified options.

Effective January 1, 2004, under Canadian GAAP, the Company adopted CICA section 3870, ''Stock-based Compensation and Other Stock-based Payments'', retroactively without restatement of prior periods, which requires the Company to record a compensation expense over the vesting period of the options based on the fair value of the options granted. CICA section 3870 is consistent with the recommendations in FAS 123, ''Accounting for Stock-Based Compensation''.

(f) The liability method under Canadian GAAP requires the measurement of future income tax liabilities and assets using income tax rates that reflect substantively enacted income tax rate reductions provided it is more likely than not that the Company will be eligible for such rate reductions in the period of reversal. U.S. GAAP allows recording of such rate reductions only when enacted.

(g) As a result of the reorganization of the capital structure which occurred in 2000, the deficit of Husky Oil Limited of $160 million was eliminated. Elimination of the deficit would not be permitted under U.S. GAAP.

(h) The Company recorded interest waived on subordinated shareholders' loans and dividends waived on Class C shares as a reduction of ownership charges. Under U.S. GAAP, waived interest and dividends in those years would be recorded as interest on subordinated shareholders' loans and dividends on Class C shares and as capital contributions.

(i) Under U.S. GAAP, transportation costs are included in cost of sales. Effective January 1, 2004, for Canadian purposes, certain transportation costs that were previously netted against revenue are now being recorded as cost of sales on a prospective basis. Transportation costs for 2003 and 2002 were $112 million and $113 million, respectively.

(j) The Company amortizes the portion of the unrecognized gains or losses that exceed 10 percent of the greater of the projected benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets. Under U.S. GAAP, an additional minimum liability is recognized if the unfunded accumulated benefit obligation exceeds the unfunded pension cost already recognized. If an additional minimum liability is recognized, an amount equal to the unrecognized prior service cost is recognized as an intangible asset and any excess is reported in other comprehensive income. At December 31, 2004, the additional minimum liability was decreased by $1 million (2003 — increase of $6 million; 2002 — increase of $19 million) with a decrease to other comprehensive income of less than $1 million (2003 — decrease of $5 million; 2002 — decrease of $10 million), net of tax.

Additional U.S. GAAP Disclosures

Corporate Acquisitions

As described in note 7, Corporate Acquisitions, the Company purchased all of the outstanding shares of Temple Exploration Inc. and Marathon Canada Limited. The Company also purchased the Western Canadian assets of Marathon International Petroleum Canada, Ltd. These transactions increased the reserve base and created cost efficiencies, increasing shareholder value.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2001, the Company adopted the provisions of FAS 133, which require that all derivatives be recognized as assets and liabilities on the balance sheet and measured at fair value. Gains or losses, including unrealized amounts, on derivatives that have not been designated as hedges are included in earnings as they arise.

For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with equal or lesser amounts of changes in the fair value of the hedged item. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

For derivatives designated as cash flow hedges, the portion of the changes in the fair value of the derivatives that are effective in hedging the changes in future cash flows are recognized in other comprehensive income until the hedged items are recognized in earnings. Any portion of the change in the fair value of the derivatives that is not effective in hedging the changes in future cash flows is included in earnings. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

Stock Option Plan

FAS 123 establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by FAS 123, Husky has elected to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board (''APB'') Opinion 25. Since all options were granted with exercise prices equal to the market price, no compensation expense has been charged to income at the time of the option grants. On September 3, 2003, the Company modified the exercise price of all outstanding options, resulting in the use of variable accounting for these modified stock options. The table below provides pro forma amounts prior to the application of variable accounting which required recognition of compensation expense on September 3, 2003. Effective January 1, 2004, the Company adopted CICA section 3870 which requires the Company to record a compensation expense over the vesting period of the options based on the fair value of the options granted. CICA section 3870 is consistent with the recommendations in FAS 123. Had compensation cost for Husky's stock options been determined based on the fair market value at the grant dates of the awards, and amortized on a straight-line basis over the vesting period, consistent with methodology prescribed by FAS 123, Husky's net earnings and earnings per share for the years ended December 31, 2003 and 2002 would have been the pro forma amounts indicated below:

	2003		2002	
	As Reported	Pro Forma	As Reported	Pro Forma
Net earnings under U.S. GAAP	$1,375	$1,407	$ 811	$ 798
Earnings per share — Basic	$ 3.28	$ 3.35	$1.94	$1.91
— Diluted	$ 3.26	$ 3.34	$1.93	$1.90

The fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair market value of options granted during the years 2003 and 2002 and the assumptions used in their determination are the same as described in note 16.

In December 2004, the Financial Accounting Standards Board (''FASB'') issued FAS 123(R), ''Share-Based Payment'', which replaces FAS 123 and supersedes APB Opinion 25. FAS 123(R) requires compensation cost related to share-based payments be recognized in the financial statements and that the cost must be measured based on the fair value of the equity or liability instruments issued. Under FAS 123(R) all share-based payment plans must be valued using option-pricing models. For U.S. GAAP, the liability related to the options issued under the Company's tandem plan will be measured at fair value using an option pricing model. Under Canadian GAAP, the liability will be measured based on the intrinsic value of the option. Over the life of the option the amount of compensation expense recognized will differ under U.S. and Canadian GAAP, creating a temporary GAAP timing difference. At exercise or surrender of the option, the compensation expense to be recorded will be equal to the cash payment which will be identical under U.S. and Canadian GAAP and there will no longer be a GAAP difference. FAS 123(R) is effective for the third quarter of 2005.

Depletion, Depreciation and Amortization

Upstream depletion, depreciation and amortization per gross equivalent barrel is calculated by converting natural gas volumes to a barrel of oil equivalent (''boe'') using the ratio of 6 mcf of natural gas to 1 barrel of crude oil (sulphur volumes have been excluded from the calculation). Depletion, depreciation and amortization per boe as calculated under U.S. GAAP for the years ended December 31 were as follows:

	2004	2003	2002
Depletion, depreciation and amortization per boe	$8.76	$7.35	$6.96

Accounting for Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation 46, ''Accounting for Variable Interest Entities'' (''FIN 46'') that requires the consolidation of Variable Interest Entities (''VIEs''). VIEs are entities that have insufficient equity or their equity investors lack one or more of the specified elements that a controlling entity would have. The VIEs are controlled through financial interests that indicate control (referred to as ''variable interests''). Variable interests are the rights or obligations that expose the holder of the variable interest to expected losses or expected residual gains of the entity. The holder of the majority of an entity's variable interests is considered the primary beneficiary of the VIE and is required to consolidate the VIE. In December 2003, the FASB issued FIN 46(R) which superseded FIN 46 and restricts the scope of the definition of entities that would be considered VIEs that require consolidation. The Company does not believe FIN 46(R) results in the consolidation of any additional entities.

SAB 106

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin 106 (''SAB 106'') regarding the application of FAS 143 by oil and gas producing entities that follow the full cost accounting method. SAB 106 states that after the adoption of FAS 143 the future

cash flows associated with the settlement of asset retirement obligations that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling test calculation. The Company excludes the future cash outflows associated with settling asset retirement obligations from the present value of estimated future net cash flows and does not reduce the capitalized oil and gas costs by the asset retirement obligation accrued on the balance sheet. Costs subject to depletion and depreciation include estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations. The adoption of SAB 106 in the fourth quarter of 2004 did not have a material effect on the results of the ceiling test or depletion, depreciation and amortization calculations.

Accounting for Inventory Costs

In November 2004, the FASB issued FAS 151 which clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material as they relate to inventory costing. FAS 151 requires these items to be recognized as current period expenses. Additionally, the allocation of fixed production overheads to the cost of inventory should be based on the normal capacity of the production facilities. FAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company does not believe that the application of FAS 151 will have an impact on the financial statements.

Accounting for Exchanges of Nonmonetary Assets

In December 2004, the FASB issued FAS 153 which deals with the accounting for the exchanges of nonmonetary assets. FAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. FAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for nonmonetary exchanges of similar productive assets and introduces a broader exception for exchanges of nonmonetary assets that do not have commercial substance. FAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not believe that the application of FAS 153 will have an impact on the financial statements.

Document C
Form 40-F

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2004

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 16, 2005

Management's Discussion and Analysis is management's explanation of Husky's financial performance for the period covered by the financial statements along with an analysis of the Company's financial position and prospects. It should be read in conjunction with the Consolidated Financial Statements and Notes thereto and the Statement of Reserves Data and Other Information in the Company's Annual Information Form. The Consolidated Financial Statements and all financial information included and incorporated by reference in this Annual Report have been prepared in accordance with accounting principles generally accepted in Canada. The effect of significant differences between Canadian and United States accounting principles is disclosed in Note 20 of the Consolidated Financial Statements. The following discussion and analysis refers primarily to 2004 as compared with 2003, unless otherwise indicated. Refer to the section ''Results of Operations for 2003 Compared with 2002'' for an abridged discussion. All dollar amounts are in millions of Canadian dollars, unless otherwise indicated. Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties. Prices quoted include or exclude the effect of hedging as indicated. Crude oil has been classified as the following: light crude oil has an API gravity of 30 degrees or more; medium crude oil has an API gravity of 21 degrees or more and less than 30 degrees; heavy crude oil has an API gravity of less than 21 degrees.

Management's Discussion and Analysis contains the term ''cash flow from operations'', which should not be considered an alternative to, or more meaningful than ''cash flow from operating activities'', as determined in accordance with generally accepted accounting principles as an indicator of the Company's financial performance. The Company's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations generated by each business segment represents a measurement of financial performance for which each reporting business segment is responsible. The items reported under the caption ''Corporate and eliminations'' are required to reconcile to the consolidated total and are not considered to be attributable to a business segment.

OVERVIEW

Summary of Results

Husky's operations are organized into three major business segments:

- The upstream segment includes the exploration for and the development and production of crude oil and natural gas in Western Canada, offshore the Canadian East Coast and offshore China and other international areas.
- The midstream segment is organized into two reportable business segments: heavy crude oil upgrading operations and infrastructure and commodity marketing operations. The infrastructure and commodity marketing segment comprises heavy crude oil pipeline and processing operations, natural gas storage, cogeneration operations, and marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.
- The refined products segment includes the refining of crude oil and the marketing of refined petroleum products including asphalt products.

Selected Annual Information

	Year ended December 31				
	2004	Percent Change	2003 (1)	Percent Change	2002 (1)
	($ millions, except where indicated)				
Sales and operating revenues, net of royalties	$ 8,440	10	$ 7,658	20	$ 6,384
Segmented earnings					
Upstream	$ 713	(33)	$ 1,067	53	$ 699
Midstream	240	30	185	15	161
Refined Products	41	28	32	(3)	33
Corporate and eliminations	12	(76)	50	163	(79)
Net earnings	$ 1,006	(25)	$ 1,334	64	$ 814
Per share — Basic	$ 2.37	(27)	$ 3.26	71	$ 1.91
— Diluted	$ 2.36	(27)	$ 3.25	71	$ 1.90
Dividends declared per common share	$ 0.46	21	$ 0.38	6	$ 0.36
Special dividend per common share	$ 0.54	(46)	$ 1.00	—	$ —
Total assets	$13,238	11	$11,946	12	$10,633
Total long-term debt and capital securities	$ 2,047	18	$ 1,730	(25)	$ 2,319
Return on equity *(percent)*	16.2		24.1		16.9
Return on average capital employed *(percent)*	12.8		18.1		12.3

(1) 2003 and 2002 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.

Business Environment

Husky's financial results are significantly influenced by its business environment. Risks include, but are not limited to:

- crude oil and natural gas prices
- the price differential and demand related to various crude oil qualities
- cost to find, develop, produce and deliver crude oil and natural gas
- availability of pipeline capacity
- the exchange rate between the Canadian and U.S. dollars
- refined products margins
- demand for Husky's pipeline capacity
- demand for refined petroleum products
- government regulations
- cost of capital

Average Benchmark Prices and U.S. Exchange Rate

	2004	2003	2002
WTI crude oil (1) *(U.S. $/bbl)*	$41.40	$31.04	$26.08
Canadian par light crude 0.3% sulphur *($/bbl)*	$52.91	$43.56	$40.28
Lloyd @ Lloydminster heavy crude *($/bbl)*	$28.75	$26.44	$26.71
NYMEX natural gas (1) *(U.S. $/mmbtu)*	$ 6.14	$ 5.39	$ 3.25
NIT natural gas *($/GJ)*	$ 6.44	$ 6.35	$ 3.86
WTI/Lloyd crude blend differential *(U.S. $/bbl)*	$13.65	$ 8.55	$ 6.47
U.S./Canadian dollar exchange rate *(U.S. $)*	$0.769	$0.716	$0.637

(1) Prices quoted are near-month contract prices for settlement during the next month.

Commodity Price Risk

Our earnings depend largely on the profitability of our upstream business segment, which is significantly affected by fluctuations in oil and gas prices. Commodity prices have been, and are expected to continue to be, volatile due to a number of factors beyond our control. Refer to the section ''Financial and Derivative Instruments'' for a discussion of our use of hedging contracts.

Crude Oil

The prices received for our crude oil and NGL are related to the price of crude oil in world markets. These prices are further affected by the use of hedging contracts, which provide for payments or receipts depending on whether the underlying commodity price is higher or lower than an agreed upon strike price. Prices for heavy crude oil and other lesser quality crudes trade at a discount or differential to light crude oil.

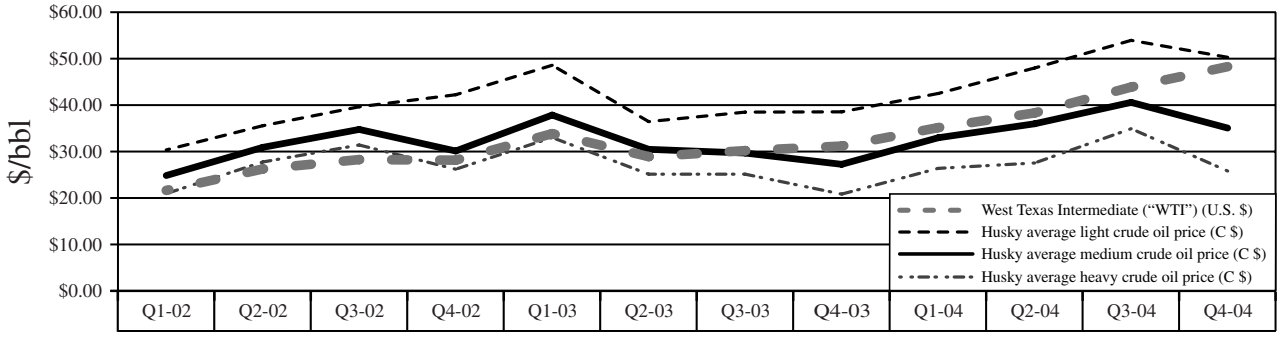
Benchmark crude oil prices averaged higher in 2004 compared with 2003. The price for West Texas Intermediate (''WTI'') crude oil averaged U.S. $34.22/bbl in January 2004 and fluctuated between monthly averages of U.S. $34.50/bbl and U.S. $53.09/bbl during the remainder of the year.

During 2004 record high world crude oil prices resulted from a number of factors. The year started off with low crude oil inventories in the United States followed by uncertainty as to Iraqi production; damaged infrastructure caused by hurricanes Charley, Frances and Ivan; higher demand for crude oil spurred by increasing demand from China and India; and continued instability in Venezuela, Nigeria and Russia.

Numerous factors could affect world crude oil prices in 2005. We expect prices to fluctuate with weather forecasts, announcements by the Organization of Petroleum Exporting Countries oil ministers or any perceived threat of supply disruptions. However, in the longer term, supply and demand will be the key in determining price factors with an emphasis on demand.

During 2004 heavy crude oil differentials averaged U.S. $13.65/bbl for WTI/Lloyd crude blend compared with U.S. $8.55/bbl during 2003. However, in December 2004 the average price for Lloydminster crude oil with an API gravity of 12 to 14 degrees averaged $12.27/bbl while light crude oil averaged above the $50.00/bbl level. The wider differential tends to reduce Husky's overall financial results as our crude oil production is weighted toward heavier gravity crudes. In periods of wider differentials, our heavy oil upgrader partially offsets the impact of the lower heavy oil value compared with light oil.

WTI and Husky Average Crude Oil Prices



	Q1-02	Q2-02	Q3-02	Q4-02	Q1-03	Q2-03	Q3-03	Q4-03	Q1-04	Q2-04	Q3-04	Q4-04
West Texas Intermediate (''WTI'') (U.S.$)	$21.64	$26.25	$28.27	$28.15	$33.86	$28.91	$30.20	$31.18	$35.15	$38.32	$43.88	$48.28
Husky average light crude oil price (C$)	$30.35	$35.56	$39.64	$42.23	$48.58	$36.45	$38.49	$38.55	$42.50	$47.99	$53.94	$50.29
Husky average medium crude oil price (C$)	$24.84	$30.90	$34.76	$30.12	$37.86	$30.48	$29.68	$27.25	$32.97	$35.98	$40.59	$35.06
Husky average heavy crude oil price (C$)	$20.95	$27.75	$31.41	$26.20	$33.02	$25.13	$25.13	$20.84	$26.38	$27.54	$34.92	$25.81

Natural Gas

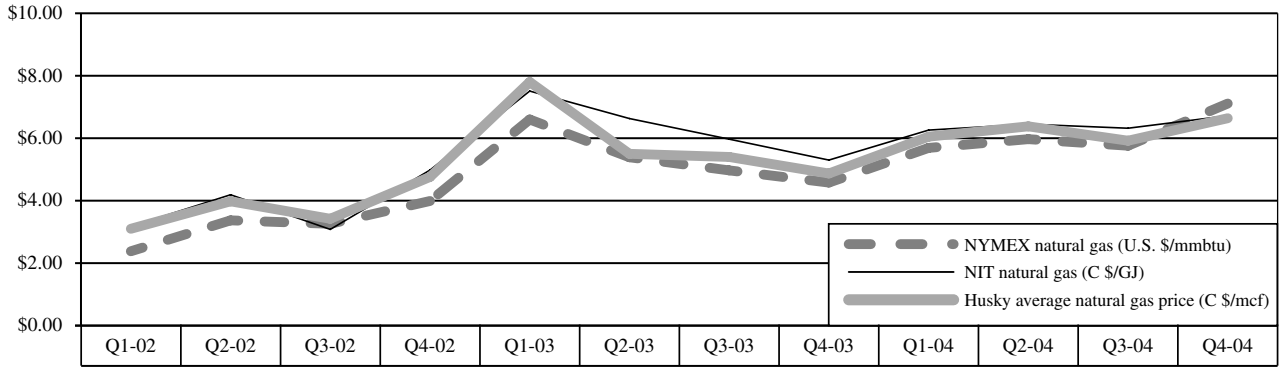
The price of natural gas in North America is affected by regional supply and demand factors, particularly those affecting the United States such as weather conditions, pipeline delivery capacity, production disruptions, the

availability of alternative sources of less costly energy supply, inventory levels and general industry activity levels. Periodic imbalances between supply and demand for natural gas are common and result in volatile pricing.

Throughout 2004 natural gas prices on the New York Mercantile Exchange (''NYMEX'') fluctuated just below the U.S. $6.00/mmbtu level ending the year on the U.S. $6.00/mmbtu level and fluctuating with weather conditions.

The prices received for Husky's natural gas are based either on fixed price contracts, spot prices, NYMEX or other regional market prices. The prices received are further affected by the use of hedging contracts, which provide for payments or receipts depending on whether the underlying commodity price is higher or lower than an agreed upon strike price.

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices



	Q1-02	Q2-02	Q3-02	Q4-02	Q1-03	Q2-03	Q3-03	Q4-03	Q1-04	Q2-04	Q3-04	Q4-04
NYMEX natural gas (U.S.$/mmbtu)	$2.38	$3.37	$3.26	$3.99	$6.60	$5.39	$4.97	$4.58	$5.69	$5.97	$5.76	$7.11
NIT natural gas (C$/GJ)	$3.17	$4.19	$3.08	$4.98	$7.51	$6.63	$5.97	$5.30	$6.26	$6.45	$6.32	$6.72
Husky average natural gas price (C$/mcf)	$3.10	$3.98	$3.42	$4.76	$7.80	$5.50	$5.40	$4.87	$6.05	$6.38	$5.92	$6.64

Upgrading Differential

The profitability of Husky's heavy oil upgrading operations is dependent upon the amount by which revenues from the synthetic crude oil produced exceed the costs of the heavy oil feedstock plus the related operating costs. An increase in the price of blended heavy crude oil feedstock that is not accompanied by an equivalent increase in the sales price of synthetic crude oil would reduce the profitability of our upgrading operations. We have significant crude oil production that trades at a discount to light crude oil, and any negative effect of a narrower differential on upgrading operations would be more than offset by a positive effect on revenues in the upstream segment from heavy oil production.

Refined Products Margins

The margins realized by Husky for refined products are affected by crude oil price fluctuations, which affect refinery feedstock costs, and third-party light oil refined product purchases. Husky's ability to maintain refined products margins in an environment of higher feedstock costs is contingent upon the ability to pass on higher costs to our customers.

Integration

Husky's production of light, medium and heavy crude oil and natural gas and the efficient operation of our upgrader, refineries and other infrastructure provide opportunities to take advantage of any fluctuation in commodity prices while assisting in managing commodity price volatility. Although we are predominantly an oil and gas producer, the nature of our integrated organization is such that the upstream business segment's output provides input to the midstream and refined products segments.

Foreign Exchange Risk

Our results are affected by the exchange rate between the Canadian and U.S. dollars. The majority of our revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to

U.S. benchmark prices. The majority of Husky's expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities and correspondingly a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense. At December 31, 2004, 80 percent or $1.7 billion of our long-term debt and capital securities were denominated in U.S. dollars. The Cdn./U.S. exchange rate at the end of 2004 was $1.20. The percentage of our long-term debt and capital securities exposed to the Cdn./U.S. exchange rate decreases to 61 percent when the cross currency swaps are included. Refer to the section ''Financial and Derivative Instruments.''

Interest Rates

Husky maintains a portion of its debt in floating rate facilities which are exposed to interest rate fluctuations. We will occasionally fix our floating rate debt or create a variable rate for our fixed rate debt using derivative financial instruments. Refer to the section ''Financial and Derivative Instruments''.

Environmental Regulations

Most aspects of Husky's business are subject to environmental laws and regulations. Similar to other companies in the oil and gas industry, we incur costs for preventive and corrective actions. Changes to regulations could have an adverse effect on our results of operations and financial condition.

International Operations

In addition to commodity price risk, Husky's international upstream operations may be affected by a variety of factors including political and economic developments, exchange controls, currency fluctuations, royalty and tax increases, import and export regulations and other foreign laws or policies affecting foreign trade or investment.

Sensitivity Analysis

The following table is indicative of the relative effect on pre-tax cash flow and net earnings from changes in certain key variables in 2004. The analysis is based on business conditions and production volumes during 2004. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis

Item	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
		($ millions)	($/share) (4)	($ millions)	($/share) (4)
WTI benchmark crude oil price					
Excluding commodity hedges	U.S.$1.00/bbl	$87	$0.20	$59	$0.14
Including commodity hedges	U.S.$1.00/bbl	46	0.11	30	0.07
NYMEX benchmark natural gas price (1)					
Excluding commodity hedges	U.S.$0.20/mmbtu	38	0.09	25	0.06
Including commodity hedges	U.S.$0.20/mmbtu	36	0.09	23	0.06
Light/heavy crude oil differential (2)	Cdn.$1.00/bbl	(30)	(0.07)	(20)	(0.05)
Light oil margins	Cdn.$0.005/litre	15	0.04	10	0.02
Asphalt margins	Cdn.$1.00/bbl	8	0.02	5	0.01
Exchange rate (U.S. $ per Cdn. $) (3)					
Including commodity hedges	U.S.$0.01	(54)	(0.13)	(35)	(0.08)

(1) Includes decrease in earnings related to natural gas consumption.

(2) Includes impact of upstream and upgrading operations only.

(3) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $10 million in net earnings based on December 31, 2004 U.S. dollar denominated debt levels.

(4) Based on December 31, 2004 common shares outstanding of 423.7 million.

RESULTS OF OPERATIONS

Upstream

Upstream Earnings Summary[1]

	Year ended December 31		
	2004	2003	2002
		($ millions)	
Gross revenues	$4,392	$3,796	$3,120
Royalties	711	584	460
Hedging (gain) loss	561	26	(5)
Net revenues	3,120	3,186	2,665
Operating and administration expenses	967	873	743
Depletion, depreciation and amortization	1,077	918	822
Income taxes	363	328	401
Earnings	$ 713	$1,067	$ 699

(1) 2003 and 2002 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.

Upstream earnings in 2004 were $354 million lower than in 2003 primarily due to the following factors:

- hedging losses which were related primarily to 85 mbbls/day of crude oil production hedged at a strike price of U.S. $27.46 compared with 27.6 mbbls/day hedged at a strike price of U.S. $29.50 in 2003
- higher royalties resulting from higher commodity prices
- lower sales volume of light and medium crude oil
- unit operating costs were $0.40/boe higher in 2004 compared with 2003 as a result of:
  - — higher field facilities maintenance costs
  - — higher fuel costs
  - — higher transportation costs

partially offset by:

  - — lower electrical power costs due to lower rates and initiatives that resulted in lower consumption
- unit depletion, depreciation and amortization expense (''DD&A'') increased by $1.01/boe to $9.06/boe in 2004 compared with 2003 as a result of:
  - — higher maintenance capital requirements for properties in the Western Canada Sedimentary Basin, particularly for mature properties under secondary or tertiary enhanced recovery schemes and shallow natural gas operations
  - — offshore operations requiring substantial capital investments
  - — purchased proved oil and gas reserves in-place, whether as individual properties or through a corporate acquisition, cost more per boe of reserves added than our current DD&A per boe of $9.06/boe
- higher income taxes

partially offset by:

- higher prices for crude oil and natural gas
- higher sales volume of heavy crude oil and natural gas

Income taxes with respect to our upstream business segment increased in 2004 to $363 million from $328 million in 2003 despite lower pre-tax earnings. In 2004 the indicative income tax rate was higher than in 2003 as a result of

amendments to the Federal and Alberta income tax acts, the benefits from which were recorded in 2003. The 2003 amendment to the Income Tax Act reduced the income tax rate on resource income by seven percent, provides for the deduction from income of crown royalties and eliminates the resource allowance deduction. The amendment is being phased in over a five-year period. The total benefit recorded in 2003 with respect to Bill C-48 was $141 million. In addition, a non-recurring upstream benefit totalling $18 million was recorded in 2003 pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. Both benefits recorded in 2003 reduced our future income taxes related to upstream operations. In 2004, an upstream benefit of $36 million was recorded for changes in the Alberta corporate tax rate.

Net Revenue Variance Analysis

	Crude Oil & NGL	Natural Gas	Other	Total
		($ millions)		
Year ended December 31, 2002				
Net revenues	$1,987	$ 637	$41	$2,665
Price changes	85	450	—	535
Volume changes	59	58	—	117
Royalties	16	(140)	—	(124)
Hedging	(50)	19	—	(31)
Processing and sulphur	—	—	24	24
Year ended December 31, 2003				
Net revenues	2,097	1,024	65	3,186
Price changes	359	98	—	457
Volume changes	(36)	172	—	136
Royalties	(67)	(60)	—	(127)
Hedging	(514)	(21)	—	(535)
Processing and sulphur	—	—	3	3
Year ended December 31, 2004				
Net revenues	$1,839	$1,213	$68	$3,120

Daily Production, before Royalties

	Year ended December 31		
	2004	2003	2002
Light crude oil & NGL *(mbbls/day)*	66.2	71.6	65.4
Medium crude oil *(mbbls/day)*	35.0	39.2	44.8
Heavy crude oil *(mbbls/day)*	108.9	99.9	95.1
Total crude oil & NGL *(mbbls/day)*	210.1	210.7	205.3
Natural gas *(mmcf/day)*	689.2	610.6	569.2
Barrels of oil equivalent (6:1) *(mboe/day)*	325.0	312.5	300.2

Average Sales Prices

	Year ended December 31		
	2004	2003	2002
Crude oil *($/bbl)*			
Light crude oil & NGL	$48.34	$39.53	$36.17
Medium crude oil	36.13	31.42	30.16
Heavy crude oil	28.66	25.87	26.60
Total average	36.07	31.54	30.43
Total average after hedging	28.43	30.93	30.50
Natural gas *($/mcf)*			
Average	$ 6.25	$ 5.86	$ 3.83
Average after hedging	6.24	5.94	3.83

Upstream Revenue Mix[1]

	Year ended December 31		
	2004	2003	2002
Percentage of upstream sales revenues, after royalties			
Light crude oil & NGL	27%	29%	24%
Medium crude oil	11%	12%	25%
Heavy crude oil	27%	26%	25%
Natural gas	35%	33%	26%
Total	100%	100%	100%

Effective Royalty Rates[1]

	Year ended December 31		
	2004	2003	2002
Percentage of upstream sales revenues			
Light crude oil & NGL	13%	12%	13%
Medium crude oil	18%	17%	17%
Heavy crude oil	12%	11%	11%
Natural gas	22%	22%	18%
Total	16%	16%	15%

(1) Before commodity hedging.

Operating Netbacks

Western Canada

Light Crude Oil Netbacks[1]

	Year ended December 31		
	2004	2003	2002
		(per boe)	
Sales revenues before hedging	$46.12	$39.91	$33.66
Royalties	7.76	7.28	4.55
Operating costs	8.94	9.27	10.46
Netback	$29.42	$23.36	$18.65

Medium Crude Oil Netbacks[1]

	Year ended December 31		
	2004	2003	2002
		(per boe)	
Sales revenues before hedging	$36.20	$31.57	$29.92
Royalties	6.10	5.28	5.59
Operating costs	10.07	9.53	7.19
Netback	$20.03	$16.76	$17.14

Heavy Crude Oil Netbacks[1]

	Year ended December 31		
	2004	2003	2002
		(per boe)	
Sales revenues before hedging	$28.73	$25.98	$26.48
Royalties	3.38	2.76	3.45
Operating costs	9.33	9.09	7.18
Netback	$16.02	$14.13	$15.85

Natural Gas Netbacks[2]

	Year ended December 31		
	2004	2003	2002
		(per mcfge)	
Sales revenues before hedging	$ 6.25	$ 5.79	$ 3.97
Royalties	1.44	1.29	0.81
Operating costs	0.89	0.79	0.70
Netback	$ 3.92	$ 3.71	$ 2.46

Total Western Canada Upstream Netbacks[1]

	Year ended December 31		
	2004	2003	2002
		(per boe)	
Sales revenues before hedging	$35.01	$31.58	$27.04
Royalties	6.22	5.48	4.46
Operating costs	7.85	7.56	6.54
Netback	$20.94	$18.54	$16.04

Terra Nova Crude Oil Netbacks

	Year ended December 31		
	2004	2003	2002
		(per boe)	
Sales revenues before hedging	$47.87	$38.91	$35.47
Royalties	1.80	0.81	0.36
Operating costs	3.28	3.16	3.62
Netback	$42.79	$34.94	$31.49

(1) Includes associated co-products converted to boe.

(2) Includes associated co-products converted to mcfge.

Wenchang Crude Oil Netbacks

	Year ended December 31		
	2004	2003	2002
		(per boe)	
Sales revenues before hedging	$47.66	$41.45	$44.36
Royalties	4.91	3.80	2.65
Operating costs	2.16	1.94	2.15
Netback	$40.59	$35.71	$39.56

Total Upstream Segment Netbacks[1]

	Year ended December 31		
	2004	2003	2002
		(per boe)	
Sales revenues before hedging	$36.34	$32.69	$28.12
Royalties	5.96	5.11	4.20
Operating costs	7.32	6.92	6.24
Netback	$23.06	$20.66	$17.68

(1) Includes associated co-products converted to boe.

Upstream Plans and Outlook

In 2004, 90 percent of our production of oil and gas was from the Western Canada Sedimentary Basin, up from 87 percent in 2003. Our total production in 2004 was up four percent over 2003 primarily due to higher production from our properties in Western Canada, in particular natural gas and heavy oil. Although the oil production from the White Rose oil field offshore Newfoundland and Labrador in 2006 will shift this balance significantly, Western Canada will remain our key production base and therefore our key exploration and development focus.

Western Canada Sedimentary Basin

Our exploration programs in the Western Canada Sedimentary Basin will remain focused in the foothills and Deep Basin area of Alberta and northeastern British Columbia. Recently we have directed some of our interest north of the 60th parallel to the central Mackenzie Valley in the Northwest Territories.

At our other oil and gas properties, we will continue our strategy of applying reservoir and production optimization through in-fill drilling, application of improved recovery schemes such as horizontal wells and chemical floods as well as traditional water flooding and emerging technologies, as they become available and commercially viable. We will also explore the limits of our reservoirs through step-out drilling programs and make use of opportunities such as property swaps, acquisitions and continue to expand the development potential of coal bed methane. Another common theme in our strategic plans involves utilizing new technology and implementation of improved practices to mitigate increasing costs.

Also in the Western Canada Sedimentary Basin but relatively new to our portfolio of opportunities, the Tucker and Sunrise oil sands projects are on schedule. Tucker is expected to begin production in late 2006.

Western Canada Sedimentary Basin capital spending is projected to be $1.7 billion in 2005. Actual capital spending in 2004 was $1.5 billion.

Canada's East Coast

Our activities offshore Canada's East Coast began in the early 1980s and the results were first realized in 2002 with the development of the Terra Nova oil field (12.51 percent working interest). The White Rose oil field, in which we hold a 72.5 percent working interest, was sanctioned in 2002. White Rose is scheduled to produce first oil in late 2005 or early 2006.

We hold interests in 15 significant discovery license areas in the Jeanne d'Arc Basin and several exploration licenses, three of which were acquired in the fourth quarter of 2004. We will continue to pursue the potential of this area including its considerable natural gas potential.

East Coast capital spending is projected to be $556 million in 2005. Actual capital spending in 2004 was $519 million.

Offshore China

In the South China Sea we hold 40 percent of the Wenchang oil fields which commenced production in July 2002. We also hold production sharing contracts in five blocks in the South China Sea and one in the East China Sea. We expect to drill three exploration wells in 2005 in our exploration blocks in the South China Sea, contingent on rig availability.

Offshore China capital spending is projected to be $37 million in 2005. Actual capital spending in 2004 was $23 million.

Offshore Indonesia

In the fourth quarter of 2004 we acquired our partner's interest in a production sharing contract (''PSC'') in the Madura Strait providing us with a 100 percent interest. The PSC contains two natural gas and natural gas liquids discoveries. With only nine wells drilled in total on this 2,800 square kilometre block, we have identified several exploration opportunities.

Offshore Indonesia capital spending is projected to be $6 million in 2005.

Midstream

Upgrading Earnings Summary

	Year ended December 31		
	2004	**2003**	**2002**
	($ millions, except where indicated)		
Gross margin	$ 383	$ 313	$ 246
Operating costs	214	205	154
Other recoveries	(5)	(4)	(6)
Depreciation and amortization	19	20	18
Income taxes	43	21	26
Earnings	$ 112	$ 71	$ 54
Upgrader throughput (1) *(mbbls/day)*	64.6	72.5	65.4
Synthetic crude oil sales *(mbbls/day)*	53.7	63.6	59.3
Upgrading differential *($/bbl)*	$17.79	$12.88	$10.81
Unit margin *($/bbl)*	$19.48	$13.51	$11.05
Unit operating cost (2) *($/bbl)*	$ 9.07	$ 7.77	$ 6.48

(1) Throughput includes diluent returned to the field.

(2) Based on throughput.

Upgrading earnings increased by $41 million in 2004 primarily due to:

- wider upgrading differential, which averaged $17.79/bbl in 2004 compared with $12.88/bbl in 2003

partially offset by:

- lower throughput and sales volume
- higher operating costs
- higher income taxes

Upgrading Earnings Variance Analysis

	($ millions)
Year ended December 31, 2002	$ 54
Volume	18
Differential	49
Operating costs — energy related	(49)
Operating costs — non-energy related	(2)
Other	(2)
Depreciation and amortization	(2)
Income taxes	5
Year ended December 31, 2003	71
Volume	(48)
Differential	118
Operating costs — non-energy related	(9)
Other	1
Depreciation and amortization	1
Income taxes	(22)
Year ended December 31, 2004	$112

Infrastructure and Marketing Earnings Summary

	Year ended December 31		
	2004	2003	2002
	($ millions, except where indicated)		
Gross margin			
Pipeline	$ 84	$ 66	$ 55
Other infrastructure and marketing	136	141	147
	220	207	202
Other expenses	8	8	10
Depreciation and amortization	21	21	20
Income taxes	63	64	65
Earnings	$128	$114	$107
Aggregate pipeline throughput *(mbbls/day)*	492	484	457

Infrastructure and marketing earnings increased by $14 million in 2004 primarily due to:

- higher heavy crude oil pipeline throughput and tariffs
- higher Lloyd blend marketing margins
- higher crude oil and NGL trading

partially offset by:

- lower natural gas commodity marketing margins
- lower cogeneration income

Midstream Plans and Outlook

Upgrading

The Husky Lloydminster Upgrader is a heavy oil upgrading facility capable of a feedstock charge of 77 mbbls/day of blended heavy crude oil feedstock and production of approximately 65 mbbls/day of Husky Synthetic Blend after diluent is returned to the field. The facility is located in the midst of the Lloydminster heavy oil producing area and is integrated with our pipelines, storage and the Husky Lloydminster asphalt refinery. The upgrading facility is currently

undergoing a debottlenecking program, which when completed in 2006 will have increased processing capacity to 82 mbbls/day of blended feedstock and improved operating efficiency and reliability.

Upgrader capital spending is projected to be $87 million in 2005. Actual upgrader capital spending in 2004 was $62 million.

Pipelines

Our heavy oil pipeline systems total in excess of 2,050 kilometres throughout the Lloydminster heavy oil producing area from Cold Lake through Lloydminster to the Hardisty Alberta terminal. The pipeline systems are capable of transporting in excess of 575 mbbls/day of blended heavy crude oil. With the volume of heavy crudes and bitumen forecast to grow in the near term we will focus our pipeline investments where we hold a competitive advantage in preparation for increased throughput.

Pipeline capital spending is projected to be $44 million in 2005. Actual capital spending in 2004 was $31 million.

Refined Products

Refined Products Earnings Summary[1]

	Year ended December 31		
	2004	2003	2002
	($ millions, except where indicated)		
Gross margin			
Fuel sales	$ 93	$ 71	$ 81
Ancillary sales	30	28	26
Asphalt sales	51	51	45
	174	150	152
Operating and other expenses	71	74	66
Depreciation and amortization	38	26	31
Income taxes	24	18	22
Earnings	$ 41	$ 32	$ 33
Number of fuel outlets	531	552	571
Refined products sales volume			
Light oil products *(million litres/day)*	8.4	8.2	7.7
Light oil products per outlet *(thousand litres/day)*	11.7	10.8	10.0
Asphalt products *(mbbls/day)*	22.8	22.0	20.8
Refinery throughput			
Prince George refinery *(mbbls/day)*	9.8	10.3	10.1
Lloydminster refinery *(mbbls/day)*	25.3	25.7	22.0

(1) 2003 and 2002 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.

Refined products earnings increased by $9 million in 2004 primarily due to:

- higher light oil product margins
- higher restaurant and convenience store income

partially offset by:

- higher depreciation and amortization
- higher income taxes

Refined Products Plans and Outlook

Our refined products business is composed of a small full slate refinery at Prince George in north central British Columbia, an asphalt refinery in Lloydminster, Alberta, an ethanol plant at Minnedosa, Manitoba and, at December 31, 2004, 507 retail petroleum outlets and 24 wholesale outlets. Also, in association with our petroleum outlets we had 45 branded restaurants and 484 convenience stores. We will continue our retail outlet upgrade program to respond to

consumer expectations. In addition, we are beginning construction of a new ethanol plant located in Lloydminster, Saskatchewan to capture benefits from government mandated demand for ethanol blended motor fuels.

We are currently in the process of upgrading the Prince George refinery to meet new government specifications for sulphur content in fuel and to increase throughput capacity from 10,000 bbls/day to approximately 12,000 bbls/day.

In 2005, our asphalt products strategic focus will be directed toward refinery improvements including debottlenecking and various cost efficiency initiatives and terminal improvements.

Refined products capital spending is projected to be $240 million in 2005. Actual capital spending in 2004 was $106 million.

Corporate Earnings Summary[1]

	Year ended December 31		
	2004	2003	2002
	($ millions)		
Intersegment eliminations — net	$ 14	$ (14)	$ 19
Administration expenses	27	22	10
Stock-based compensation	67	—	—
Accretion	2	—	1
Other — net	8	3	5
Depreciation and amortization	24	36	17
Interest on debt	109	131	131
Interest capitalized	(75)	(52)	(26)
Interest income	(1)	(6)	(1)
Foreign exchange	(99)	(215)	13
Income taxes	(88)	45	(90)
Earnings (loss)	$ 12	$ 50	$ (79)

(1) 2003 and 2002 amounts as restated. Refer to Note 3 to The Consolidated Financial Statements.

Foreign Exchange Summary

	Year ended December 31		
	2004	2003	2002
		($ millions)	
(Gain) loss on translation of U.S. dollar denominated long-term debt			
Realized	$ (10)	$ 11	$ 11
Unrealized	(119)	(326)	(11)
	(129)	(315)	—
Cross currency swaps			
Realized	—	32	—
Unrealized	27	41	—
	27	73	—
Other losses	3	27	13
	$ (99)	$ (215)	$ 13
U.S./Canadian dollar exchange rates:			
At beginning of year	U.S.$0.774	U.S.$0.633	U.S.$0.628
At end of year	U.S.$0.831	U.S.$0.774	U.S.$0.633

Corporate earnings were lower in 2004 compared with 2003 primarily due to:

- lower foreign exchange gains
- stock-based compensation first recorded in June 2004 (refer to the section ''New Accounting Standards'')

- higher intersegment profit eliminated
- higher administration expenses

partially offset by:

- lower depreciation and amortization
- lower interest expense resulting from lower rates
- higher capitalized interest resulting from a higher capital base for the White Rose project

Consolidated Income Taxes

Consolidated income taxes decreased in 2004 to $405 million from $476 million in 2003 as a result of lower pre-tax earnings and non-recurring tax benefits. In 2004 the indicative income tax rate was higher than in the previous year as a result of the 2003 amendments to the Federal and Alberta income tax acts. On May 11, 2004, Bill 27-Alberta Corporate Tax Amendment Act, 2004 received royal assent in the Alberta Legislative Assembly. As a result, a non-recurring benefit of $40 million was recorded in 2004. During 2003, an amendment to the Income Tax Act reduced the income tax rate on resource income by seven percent, provides for the deduction from income of crown royalties and eliminates the resource allowance deduction. The amendment is being phased in over a five-year period. The total benefit recorded in 2003 was $141 million. In addition, in 2003 a non-recurring benefit totalling $20 million was recorded pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. All benefits reduced future income taxes.

In 2004 current income taxes totalled $302 million and comprised $85 million in respect of the Wenchang oil field operation, $20 million of capital taxes and $197 million of Canadian income tax.

The following table shows the effect of non-recurring tax benefits for the periods noted:

	2004	2003
	($ millions)	
Income taxes before tax amendments	$445	$637
Canadian federal and provincial tax amendments	40	161
Income taxes as reported	$405	$476

Husky's Canadian Tax Pools

	Year ended December 31	
	2004	2003
	($ millions)	
Canadian exploration expense	$ —	$ 42
Canadian development expense	1,616	1,103
Canadian oil and gas property expense	557	814
Foreign exploration and development expense	212	142
Undepreciated capital costs	3,269	2,909
Other	22	22
	$5,676	$5,032

CAPITAL RESOURCES

Operating Activities

In 2004 cash generated by operating activities was $2,352 million, a decrease of $186 million from the $2,538 million recorded in 2003. The lower cash from operating activities in 2004 was primarily due to the negative impact of the hedging program, partially offset by higher commodity prices.

Financing Activities

In 2004 cash provided by financing activities amounted to $149 million. The cash used was composed of the repayment of long-term debt of $1,937 million and a $22 million repayment of operating lines, payment of the return

on capital securities of $26 million, dividends of $424 million, including a $0.54 per share special dividend and debt issue costs of $5 million. Cash provided by financing activities in 2004 comprised $2,200 million issuance of long-term debt, $18 million of proceeds from the exercise of stock options, proceeds from monetization of financial instruments totalling $8 million and a change of $337 million in non-cash working capital.

Husky's long-term debt balances were also reduced by $129 million during 2004 primarily as a result of the narrowing of the exchange rate between Canadian and U.S. currencies.

Investing Activities

Cash used in investing activities amounted to $2,497 million in 2004, an increase of $456 million from the $2,041 million in 2003. Cash invested in 2004 was composed of capital expenditures of $2,349 million and the acquisition of Temple Exploration Inc. for $102 million, partially offset by $36 million of proceeds from asset sales. Change in non-cash working capital and other adjustments amounted to $82 million used in investing activities.

Capital Expenditures[1]

	Year ended December 31		
	2004	2003	2002
		($ millions)	
Upstream			
Exploration			
Western Canada	$ 322	$ 326	$ 304
East Coast Canada and Frontier	24	24	41
International	18	26	9
	364	376	354
Development			
Western Canada	1,211	869	739
East Coast Canada	515	533	417
International	67	—	66
	1,793	1,402	1,222
	2,157	1,778	1,576
Midstream			
Upgrader	62	25	41
Infrastructure and marketing	31	18	23
	93	43	64
Refined Products	106	58	44
Corporate	23	23	23
Capital expenditures	2,379	1,902	1,707
Settlement of asset retirement obligations	(30)	(34)	(16)
Capital expenditures per Consolidated Statements of Cash Flows	$2,349	$1,868	$1,691

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Upstream Capital Expenditures

Western Canada

During 2004, capital expenditures for exploration and development in Western Canada totalled $1,533 million compared with $1,195 million during 2003.

Total development capital spending in Western Canada during 2004 amounted to $1,211 million compared with $869 million during 2003. Development capital was directed to the following areas:

- In 2004, we increased exploitation spending in the Lloydminster heavy oil area to $362 million. We hold in excess of one million net undeveloped acres in the Lloydminster area and have established an integrated infrastructure throughout the area. Spending in 2004 continued to focus on primary production utilizing cold

production techniques and thermal production utilizing cyclic steam and steam assisted gravity drainage techniques. Production from thermal operations accounted for approximately 20 percent of heavy oil production from the Lloydminster area, up from 17 percent in 2003. In addition, considerable capital spending is devoted to optimization of existing operations employing updated technology and efficient practices. In 2003 and 2002, we spent $303 million and $273 million, respectively, in the Lloydminster area.

- In 2004, we increased development spending in the foothills and Deep Basin region of Alberta and northeastern British Columbia and in the plains of northern Alberta to $464 million. We hold interests in well established operations at Rainbow Lake, Ram River, Valhalla/Wapiti, Ansell/Galloway, Boyer/Haro, Martin Hills and Slave Lake. Spending in 2004 continued to focus primarily on natural gas potential, approximately 85 percent of this area's total development spending. In the plains area spending was primarily directed to step-out exploitation of shallow natural gas reservoirs and follow-up development of discoveries. The majority of our new field wildcat exploration drilling for natural gas is conducted in the foothills and Deep Basin of Alberta and northeastern British Columbia. In 2003 and 2002, we spent $305 million and $306 million, respectively, in this area on exploration and development activities.
- In 2004, we increased exploitation spending in the east central and southern areas of Alberta and southwestern Saskatchewan to $364 million, up from $259 million in 2003. Our operations consist of mature oil operations, including a number of waterfloods and extensive shallow natural gas primarily located at Sylvan Lake, Drumheller, Provost, Taber and Suffield in Alberta and Swift Current in Saskatchewan. Spending is focused on step-out exploitation and operational optimization. Over half of capital spending is directed toward natural gas assets including an emphasis in the new plays in the Shackleton, Lacadena and White Bear areas.
- In 2004, we spent $26 million on the development of the Tucker oil sands project.

Exploration expenditures on our prospects in the Western Canada Sedimentary Basin in 2004 amounted to $322 million compared with $326 million in 2003. The primary exploration targets were natural gas prospects in the Alberta foothills and Deep Basin as well as step-out drilling throughout Husky's properties in the Basin. In 2004 we commenced an exploration program to assess prospects in the central Mackenzie Valley, Northwest Territories. In addition, pre-development spending at the Sunrise oil sands project amounted to $27 million. Capital expenditures on the Tucker and Sunrise oil sands projects totalled $41 million and $20 million during 2003 and 2002, respectively.

Western Canada Drilling

	Year ended December 31					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
	(wells)					
Exploration						
Oil	45	39	12	11	21	20
Gas	234	180	147	124	139	131
Dry	34	33	22	21	15	14
	313	252	181	156	175	165
Development						
Oil	552	499	520	490	497	453
Gas	807	740	540	518	485	453
Dry	57	53	60	57	58	55
	1,416	1,292	1,120	1,065	1,040	961
Total	1,729	1,544	1,301	1,221	1,215	1,126

East Coast Canada

Capital spending at Husky's White Rose oil field development offshore Newfoundland and Labrador amounted to $489 million in 2004 compared with $505 million in 2003. Capital spending with respect to the Terra Nova oil field amounted to $26 million in 2004 compared with $28 million in 2003.

International

Exploration capital spending in the South China Sea amounted to $18 million in 2004 compared with $26 million in 2003. Spending in 2004 was primarily related to drilling one exploration well on the 40/30 block and preparation for an exploration program that is expected to include three exploration wells in 2005.

In November 2004, we purchased our partner's share of a production sharing contract in the Madura Strait offshore Indonesia for $62 million. The contract includes two natural gas discoveries and additional prospective exploration acreage.

Midstream Capital Expenditures

Midstream capital expenditures in 2004 of $93 million were primarily for upgrader debottlenecking and pipeline upgrades.

Refined Products Capital Expenditures

Refined products capital expenditures in 2004 of $106 million were primarily for marketing outlet improvements, refinery upgrades and construction of an ethanol plant.

Corporate Capital Expenditures

Corporate capital expenditures amounted to $23 million in 2004 and were primarily for computer hardware and software and office furniture and equipment.

Oil and Gas Reserves

Husky applied for and was granted an exemption from Canada's National Instrument 51-101 ''Standards of Disclosure for Oil and Gas Activities'' to provide oil and gas reserves disclosures in accordance with the United States Securities and Exchange Commission (''SEC'') guidelines and the United States Financial Accounting Standards Board (''FASB'') disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101. Husky's internally generated oil and gas reserves data was audited by an independent firm of oil and gas reserves evaluation engineers.

For more detail on our oil and gas reserves and the disclosures with respect to the FASB's Statement No. 69, ''Disclosures about Oil and Gas Producing Activities'', refer to our Annual Information Form available at www.sedar.com or Form 40-F available at www.sec.gov or on our website at www.huskyenergy.ca.

At December 31, 2004, the present value of future net cash flows after tax from the Company's proved oil and gas reserves, based on prices and costs in effect at year-end and discounted at 10 percent, was $5.2 billion compared with $5.8 billion at the end of 2003.

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook (''COGEH'').

Reconciliation of Proved Reserves[1]

	Canada								
	Western Canada				East Coast	International	Total		
	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Light Crude Oil (mmbbls)	Light Crude Oil (mmbbls)	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	(mmboe)
	(constant price before royalties)								
Proved reserves at December 31, 2003	173	94	227	2,059	26	24	544	2,059	887
Revision of previous estimate	1	1	(114)	(23)	(1)	3	(110)	(23)	(114)
Purchase of reserves in place	1	—	—	23	—	—	1	23	5
Sale of reserves in place	—	—	(1)	(14)	—	—	(1)	(14)	(3)
Extensions and discoveries	7	2	32	372	24	—	65	372	127
Improved recovery	1	2	1	4	3	—	7	4	8
Production	(12)	(13)	(40)	(252)	(5)	(7)	(77)	(252)	(119)
Proved reserves at December 31, 2004	171	86	105	2,169	47	20	429	2,169	791

(1) Proved reserves are the estimated quantities of crude oil, natural gas and NGL which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Our oil and gas reserves are estimated in accordance with the regulations and guidance of the SEC and the FASB which, among other things, require reserves to be evaluated using prices in effect on the day the reserves are estimated. We have significant heavy oil reserves with an API gravity of 12 to 14 degrees. Heavy crude oil sells at a discount to light crude oils such as West Texas Intermediate, which has an API gravity of approximately 40 degrees, because it requires upgrading before it can be processed by conventional refineries. There is a finite capacity for upgrading in North America, which is often reached when heavy crude oil from other countries enters the North American market. Heavy crude oil requires blending with condensate or light synthetic crude oil (''diluent'') in order for it to be transported in a pipeline. During the winter, heavy crude oil requires a higher proportion of diluent because of the cold temperatures and diluent prices are similar to light crude oil prices. Heavy crude oil is also processed into asphalt, which is typically in demand during the spring to fall paving months.

As a result of these factors, prices for heavy crude oil are historically low in December. During 2004 the price of heavy crude oil at Lloydminster averaged $28.75/bbl but on December 31, 2004, the date our oil and gas reserves were evaluated, the calculated price of Lloydminster heavy crude oil was $12.27/bbl while the price for Husky Synthetic Blend was just under $50.00/bbl. Husky Synthetic Blend is produced in our upgrading facility in Lloydminster, which was constructed to capture the difference in value between heavy crude oil and high quality synthetic crude oil. At $12.27/bbl, 86 percent of our proved undeveloped heavy crude oil reserves in the Lloydminster area did not produce positive value after the required capital investment and, in accordance with SEC and FASB regulations, were required to be subtracted as a negative revision from proved reserves until prices increase sufficiently to return those reserves to economic status. In addition, 39 percent of our proved developed heavy crude oil reserves were uneconomic on December 31, 2004, and were included in the negative revision. The SEC requires oil and gas reserves to be economic at the well head and does not permit consideration of other economic factors such as our upgrading facility, which at December 31, 2004, produced cash netback of approximately $30.00/bbl after royalties, lease operating costs, transportation and upgrading operating costs. When considering our upgrading, asphalt refining and other heavy oil infrastructure, our heavy oil production was economic to Husky at December 31, 2004. Notwithstanding the economics at December 31, 2004, on January 10, 2005, the price of Lloydminster heavy crude oil had returned to $21.56/bbl, a price that would be sufficient to return 98 percent of the reserves subtracted by negative revision to the proved reserve category.

The following table shows our reserves after considering our upgrading capacity:

	Canada					International	Total		
	Western Canada				East Coast				
	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Light Crude Oil (mmbbls)	Light Crude Oil (mmbbls)	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	(mmboe)
Proved reserves at December 31, 2004	171	86	105	2,169	47	20	429	2,169	791
Heavy oil price revision at $12.27	—	—	120	3	—	—	120	3	120
Proved reserves excluding heavy oil revision at December 31, 2004	171	86	225	2,172	47	20	549	2,172	911

Before the effect of the negative revisions from low heavy oil prices at December 31, 2004, during 2004 we added 146 million barrels of oil equivalent from discoveries, extensions, improved recovery, acquisitions and technical revisions. Reserves were added at White Rose, Lloydminster and in the foothills and Deep Basin of Alberta and northeastern British Columbia.

The additions to crude oil proved reserves amounted to 83 million barrels and were primarily from the Lloydminster reservoir extensions from step-out drilling and improved recovery. At White Rose, offshore Newfoundland and Labrador, 23 million barrels qualified as proved reserves.

The additions to natural gas proved reserves amounted to 379 billion cubic feet and were primarily related to our drilling program in the foothills and Deep Basin areas of Alberta and northeastern British Columbia. Natural gas reserve additions also resulted from field extensions at Ekwan Sierra, Rainbow, Abbey in southwestern Saskatchewan and areas throughout the Alberta foothills and Deep Basin. Negative technical revisions of previously estimated natural gas reserves were primarily related to reservoir performance.

Reconciliation of Proved Developed Reserves[1]

	Canada					International	Total		
	Western Canada				East Coast				
	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Light Crude Oil (mmbbls)	Light Crude Oil (mmbbls)	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	(mmboe)
				(constant price before royalties)					
Proved developed reserves at December 31, 2003	159	86	156	1,712	17	24	442	1,712	727
Revision of previous estimate	4	3	(43)	114	1	3	(32)	114	(14)
Purchase of reserves in place	1	—	—	22	—	—	1	22	5
Sale of reserves in place	—	—	(1)	(14)	—	—	(1)	(14)	(3)
Extensions and discoveries	3	2	19	159	—	—	24	159	51
Improved recovery	—	2	—	4	3	—	5	4	6
Production	(12)	(13)	(40)	(252)	(5)	(7)	(77)	(252)	(119)
Proved developed reserves at December 31, 2004	155	80	91	1,745	16	20	362	1,745	653

(1) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

The following table shows our proved developed reserves after considering our upgrading capacity:

	Canada								
	Western Canada				East Coast	International	Total		
	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Light Crude Oil (mmbbls)	Light Crude Oil (mmbbls)	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	(mmboe)
Proved developed reserves at December 31, 2004	155	80	91	1,745	16	20	362	1,745	653
Heavy oil price revision at $12.27	—	—	60	3	—	—	60	3	61
Proved developed reserves excluding heavy oil revision at December 31, 2004	155	80	151	1,748	16	20	422	1,748	714

Crude Oil and Natural Gas Reserves Summary

	Proved Developed			Proved Undeveloped			Total Proved			Proved and Probable		
	2004	2003	2002	2004	2003	2002	2004	2003	2002	2004	2003	2002
	(constant price before royalties)											
Crude oil *(mmbbls)*												
Light & NGL	191	200	193	47	23	42	238	223	235	465	474	511
Medium	80	86	94	6	8	13	86	94	107	96	108	131
Heavy	91	156	152	14	71	75	105	227	227	150	319	379
Bitumen	—	—	—	—	—	—	—	—	—	79	79	—
	362	442	439	67	102	130	429	544	569	790	980	1,021
Natural gas *(bcf)*	1,745	1,712	1,547	424	347	548	2,169	2,059	2,095	2,724	2,507	2,497
Total *(mmboe)*	653	727	697	138	160	221	791	887	918	1,244	1,397	1,437

LIQUIDITY

Sources of Capital

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and proved developed reserves, to acquire strategic oil and gas assets, repay maturing debt and pay dividends. Husky's upstream capital programs are funded principally by cash provided from operating activities. During times of low oil and gas prices part of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining our production, it may be necessary to utilize alternative sources of capital to continue our strategic investment plan during periods of low commodity prices. As a result we continually examine our options with respect to sources of long and short-term capital resources. In addition, from time to time we engage in hedging a portion of our production to protect cash flow in the event of commodity price declines.

The following illustrates the Company's sources and uses of cash during the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
		($ millions)	
Cash sourced			
Cash flow from operations (1)	$2,223	$2,459	$2,096
Debt issue	2,200	669	972
Asset sales	36	511	93
Proceeds from exercise of stock options	18	51	9
Proceeds from monetization of financial instruments	8	44	—
Other	—	5	—
	4,485	3,739	3,170
Cash used			
Capital expenditures	2,349	1,868	1,691
Corporate acquisitions	102	809	3
Debt repayment	1,959	971	778
Special dividend on common shares	229	420	—
Ordinary dividends on common shares	195	160	151
Return on capital securities payment	26	29	31
Settlement of asset retirement obligations	40	34	16
Settlement of cross currency swap	—	32	—
Other	24	—	29
	4,924	4,323	2,699
Net cash (deficiency)	(439)	(584)	471
Increase (decrease) in non-cash working capital	443	281	(165)
Increase (decrease) in cash and cash equivalents	4	(303)	306
Cash and cash equivalents — beginning of year	3	306	—
Cash and cash equivalents — end of year	$ 7	$ 3	$ 306
Increase (decrease) in non-cash working capital			
Cash positive working capital change			
Accounts receivable decrease	$ 209	$ —	$ —
Inventory decrease	—	28	—
Prepaid expense decrease	—	—	1
Accounts payable and accrued liabilities increase	323	270	—
	532	298	1
Cash negative working capital change			
Accounts receivable increase	—	7	153
Inventory increase	77	—	2
Prepaid expense increase	12	10	—
Accounts payable and accrued liabilities decrease	—	—	11
	89	17	166
Increase (decrease) in non-cash working capital	$ 443	$ 281	$ (165)

(1) Cash flow from operations represents net earnings plus items not affecting cash, which include accretion, depletion, depreciation and amortization, future income taxes and foreign exchange.

Capital Structure

	December 31, 2004		
	Outstanding		Available
	(U.S. $)	(Cdn. $) ($ millions)	(Cdn. $)
Short-term bank debt	$ 5	$ 49	$ 123
Long-term bank debt			
Syndicated credit facility	—	70	880
Bilateral credit facility	—	40	110
Medium-term notes	—	300	
U.S. public notes	1,050	1,264	
U.S. senior secured bonds	117	140	
U.S. private placement notes	15	18	
Total short-term and long-term debt	$1,187	$1,881	$1,113
Capital securities	$ 225	$ 271	
Common shares and retained earnings		$6,200	

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2004, our working capital deficiency was $815 million compared with $604 million at December 31, 2003. The increase in the deficiency is primarily due to the $0.54 per share special dividend declared on November 8, 2004 and the increase in the sale of net trade receivables. It is not unusual for Husky to have working capital deficits at the end of a reporting period. These working capital deficits are primarily the result of accounts payable related to capital expenditures for exploration and development. Settlement of these current liabilities is funded by cash provided by operating activities and to the extent necessary by bank borrowings. This position is a common characteristic of the oil and gas industry which, by the nature of its business, spends large amounts of capital.

As at December 31, 2004, our outstanding long-term debt totalled $1,832 million, including amounts due within one year, compared with $1,698 million at December 31, 2003.

At December 31, 2004, we had $70 million drawn under our $950 million revolving syndicated credit facility. Interest rates under this facility vary and are based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected, credit ratings assigned by certain rating agencies to our senior unsecured debt and whether the facility is revolving or non-revolving. The syndicated credit facility requires Husky to maintain a debt to cash flow ratio of less than three times and a consolidated tangible net worth, as of December 31, 2004, of at least $3.9 billion.

At December 31, 2004, we had $40 million drawn under our $150 million bilateral credit facilities. The terms of these facilities are substantially the same as the syndicated credit facility.

At December 31, 2004, we had borrowed $49 million and utilized $23 million in support of letters of credit under our $195 million in short-term borrowing facilities. The interest rates applicable to these facilities vary and are based on Canadian prime, Bankers' Acceptance, money market rates or U.S. dollar equivalents. In addition, we utilized $84 million under our dedicated letter of credit facilities.

Husky has an agreement to sell up to $350 million of net trade receivables on a revolving basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, plus a program fee to be paid on an ongoing basis. As at December 31, 2004, $350 million in outstanding accounts receivable had been sold under this agreement. The arrangement matures on January 31, 2009.

We believe that, based on our current forecast for commodity prices for 2005, our non-cancellable contractual obligations and commercial commitments and our 2005 capital program will be funded by operating activities and, to the extent required, available credit facilities. In the event of significantly lower cash flow, we would be able to defer certain of our projected capital expenditures without penalty.

We declared dividends that aggregated $1.00 per share totalling $424 million in 2004, including a special dividend of $0.54 per share. The Board of Directors of Husky has established a dividend policy that pays quarterly dividends of

$0.12 ($0.48 annually) per common share. The declaration of dividends will be at the discretion of the Board of Directors, which will consider earnings, capital requirements, our financial condition and other relevant factors.

Financial Ratios

	Year ended December 31		
	2004	2003	2002
		($ millions)	
Cash flow — operating activities	$ 2,352	$ 2,538	$ 1,882
— financing activities	$ 149	$ (800)	$ 3
— investing activities	$(2,497)	$(2,041)	$(1,579)
Debt to capital employed *(percent)*	22.5	23.0	31.7
Corporate reinvestment ratio (1)	1.1	0.9	0.8

(1) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

Credit Ratings

Husky's senior debt and capital securities have been rated investment grade by several rating agencies. These ratings are disclosed and explained in detail in our Annual Information Form.

Capital Requirements

Husky plans to invest capital in the following segments in 2005:

	Year ended December 31 2005 Estimate (1)
	($ millions)
Upstream	
Western Canada	$1,688
East Coast Canada	556
International	44
	2,288
Midstream	140
Refined Products	240
Corporate	25
	$2,693

(1) Includes capitalized interest of $112 million and capitalized administration expenses of $36 million.

Contractual Obligations and Commercial Commitments

In the normal course of business Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

Contractual Obligations[(1)(2)]

	Payments due by period				
	Total	**2005**	**2006-2007**	**2008-2009**	**Thereafter**
			($ millions)		
Long-term debt (3)	$1,832	$ 56	$ 445	$ 233	$1,098
Capital securities (3)	271	—	—	271	—
Operating leases	554	68	152	151	183
Firm transportation agreements	1,061	213	375	262	211
Unconditional purchase obligations	1,481	593	684	87	117
Lease rentals	330	44	88	88	110
Exploration work agreements	50	27	15	—	8
Engineering and construction commitments	967	572	383	12	—
	$6,546	$1,573	$2,142	$1,104	$1,727

(1) The above table does not include asset retirement obligations. The Company currently includes such obligations in the amortizing base of its oil and gas properties. Effective January 1, 2004 with the adoption of the Canadian Institute of Chartered Accountants section 3110, ''Asset Retirement Obligations'', the Company records a separate liability for the fair value of its asset retirement obligations. See Note 12 to the Consolidated Financial Statements.

(2) The above table does not include post-retirement obligations. Husky has a defined contribution pension plan and a post-retirement health and dental care plan for its employees. In addition Husky has a defined benefit pension plan for approximately 200 employees. In 1991 admittance to the defined benefit pension plan ended after the majority of members transferred to the newly created defined contribution pension plan. See Note 17 to the Consolidated Financial Statements.

(3) Obligation related to long-term debt includes principal repayments only. If interest payable on our fixed interest rate debt was included, the total amount of the obligation would increase by $897 million. If the return on capital securities was included, assuming the capital securities were redeemed in 2008, the obligation would increase by $84 million.

Investment Canada Undertakings

In respect to the acquisition of Marathon Canada Limited, Husky confirmed certain undertakings to the Minister Responsible for the Investment Canada Act. The undertakings, which have been satisfied, included capital expenditures on the purchased and retained Marathon Canada Limited lands amounting to $65 million, spending on community activities amounting to $1.4 million and environmental expenditures of $40 million, all to occur in 2004.

Other Obligations

Husky is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

OFF BALANCE SHEET ARRANGEMENTS

We do not utilize off-balance sheet arrangements with unconsolidated entities to enhance perceived liquidity.

We engage in the ordinary course of business in the securitization of accounts receivable. In December 2004 our receivable securitization program was increased from $250 million to $350 million. The securitization agreement terminates on January 31, 2009. The accounts receivable are sold to an unrelated third party on a revolving basis. In accordance with the agreement we must provide a loss reserve to replace defaulted receivables.

The securitization program provides us with cost effective short-term funding for general corporate use. We account for these securitizations as asset sales. In the event the program is terminated our liquidity would not be substantially reduced.

TRANSACTIONS WITH RELATED PARTIES AND MAJOR CUSTOMERS

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, we paid approximately $10 million for office space in Western Canadian Place during 2004.

We did not have any customers that constituted more than five percent of total sales and operating revenues during 2004.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Refer to the section ''Business Environment''. From time to time, we use derivative instruments to manage our exposure to these risks.

Commodity Price Risk Management

Husky uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

We implemented a corporate hedging program for 2004 to manage the volatility of natural gas and crude oil prices.

Natural Gas

Husky's natural gas price risk management program for 2004 expired in April 2004. During 2004, Husky received net payments totalling $8 million on those contracts. As a result of a corporate acquisition, we assumed a natural gas derivative contract for a notional 7.5 mmcf/day that matures at the end of 2005. During 2004, we recorded payments totalling $9 million on this contract.

Crude Oil

Crude oil hedges on 85 mbbls/day were in effect from January to December 2004. During that period we recorded net payments totalling $560 million on these contracts.

Power Consumption

At December 31, 2004 Husky had hedged power consumption as follows:

	Notional Volumes	Term	Price	Unrecognized Gain (Loss)
	(MW)			($ millions)
Fixed price purchase	10.0	Jan. to Dec. 2005	$49.25/MWh	$(0.1)
	12.5	Jan. to Dec. 2005	$50.50/MWh	(0.3)
	15.0	Jan. to Jun. 2005	$48.00/MWh	(0.2)
				$(0.6)

Foreign Currency Risk Management

At December 31, 2004, Husky had the following cross currency debt swaps in place:

- U.S. $150 million at 7.125 percent swapped at $1.45 to $218 million at 8.74 percent until November 15, 2006.
- U.S. $150 million at 6.250 percent swapped at $1.41 to $212 million at 7.41 percent until June 15, 2012.

At December 31, 2004 the cost of a U.S. dollar in Canadian currency was $1.2036.

In 2004 the cross currency swaps resulted in an offset to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $27 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized gains totalling approximately $14 million in 2004. In 2004, Husky unwound its long-dated forwards totalling U.S. $36 million, resulting in a gain of $8 million, which will be recognized into income on the dates the underlying hedged transactions are to take place.

Interest Rate Risk Management

In 2004 the interest rate risk management activities resulted in a decrease to interest expense of $22 million.

The cross currency swaps resulted in an addition to interest expense of $8 million in 2004.

We have interest rate swaps on $200 million of long-term debt, effective February 8, 2002, whereby 6.95 percent was swapped for CDOR + 175 bps until July 14, 2009. During 2004, these swaps resulted in an offset to interest expense amounting to $5 million.

We have interest rate swaps on U.S. $200 million of long-term debt, effective February 12, 2002, whereby 7.55 percent was swapped for an average U.S. LIBOR + 194 bps until November 15, 2011. During 2004, these swaps resulted in an offset to interest expense amounting to $11 million.

We have interest rate swaps on U.S. $300 million of long-term debt, effective June 18, 2004, whereby 6.15 percent was swapped for an average U.S. LIBOR + 63 bps until June 15, 2019. During 2004, these swaps resulted in an offset to interest expense amounting to $7 million.

The amortization of previous interest rate swap terminations resulted in an additional $7 million offset to interest expense in 2004.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Husky's financial statements have been prepared in accordance with Canadian generally accepted accounting principles. The significant accounting policies we use are disclosed in Note 3 to the Consolidated Financial Statements. Certain accounting policies require that we make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such accounting policies and is included in Management's Discussion and Analysis to aid you in assessing the critical accounting policies and practices of Husky and the likelihood of materially different results being reported. We review our estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. Husky might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

Full Cost Accounting for Oil and Gas Activities

The indicated change in the following estimates will result in a corresponding increase in the amount of DD&A expense charged to income in a given period:

An increase in:

- estimated costs to develop the proved undeveloped reserves
- estimated fair value of the asset retirement obligation related to the oil and gas properties
- estimated impairment of costs excluded from the DD&A calculation

A decrease in:

- previously estimated proved oil and gas reserves
- estimated proved reserves added compared to capital invested

Depletion Expense

Husky uses the full cost method of accounting for exploration and development activities as recommended by the Canadian Institute of Chartered Accountants (''CICA''). In accordance with this method of accounting, all costs associated with exploration and development are capitalized on a country by country basis. The aggregate of capitalized costs, net of accumulated DD&A, plus the estimated future costs required to develop the proved undeveloped oil and gas reserves less estimated equipment salvage values is charged to income using the unit of production method based on estimated proved oil and gas reserves.

Withheld Costs

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Full Cost Accounting

Effective January 1, 2004, we adopted Accounting Guideline 16, ''Oil and Gas Accounting — Full Cost''. The new guideline modified the ceiling test, which requires, for each cost centre, capitalized costs be tested for recoverability. The test uses the estimated undiscounted future net cash flows from proved oil and gas reserves based on forecast prices and costs. When the carrying amount of a cost centre is not recoverable, the cost centre is written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties as well as the future value of reserves when determining estimated cash flows.

Impairment of Long-lived Assets

We are required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

Fair Value of Derivative Instruments

Periodically we utilize financial derivatives to manage market risk. The purpose of the derivative is to provide an element of stability to our cash flow in a volatile environment. We disclose the estimated fair value of open hedging contracts as at the end of a reporting period. Effective January 1, 2004 Husky adopted CICA Accounting Guideline 13, ''Hedging Relationships'' (''AcG-13''). AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the FASB Statement No. 133, ''Accounting for Derivative Instruments and Hedging Activities'' (''FAS 133''). Refer to the description of FAS 133 in Note 20 to the Consolidated Financial Statements.

The estimation of the fair value of certain hedging derivatives requires considerable judgement. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and, which when compared with Husky's open hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions.

Accounting rules for transactions involving derivative instruments are complex and subject to a range of interpretation. The FASB has established the Derivative Implementation Group task force, which, on an ongoing basis, considers issues arising from interpretation of these accounting rules. The potential exists that the task force may promulgate interpretations that differ from those of Husky. In this event our policy would be modified.

Asset Retirement Obligations

Effective January 1, 2004, we adopted the recommendations of CICA section 3110, ''Asset Retirement Obligations'' (''ARO''), which is essentially identical to the United States accounting requirements of FAS 143.

We have significant obligations to remove tangible assets and restore land after operations cease and we retire or relinquish the asset. The ARO relates to all of our business operations, however approximately 90 percent of the liability relates to the upstream business. The retirement of upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and sub-sea equipment and facilities and restoration of land to a state required by regulation or contract. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgements because most of the removal obligations are many years in the future and contracts and regulations often require interpretation. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

The new ARO rules require that an asset retirement obligation associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying cost of the associated asset. The cost of the tangible asset, including the

initially recognized ARO, is depleted such that the initial fair value of the ARO is recognized over the useful life of the asset. The initial fair value of the ARO is accreted to its expected settlement date. The accretion amount is expensed as a cost of operating and is added to the ARO liability. The fair value of the ARO is measured using expected future cash outflows discounted at our credit adjusted risk free interest rate.

Inherent in the present value calculation are numerous assumptions and judgements including the ultimate settlement amounts, future third party pricing, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the tangible asset balance.

Refer to Note 12 to the Consolidated Financial Statements, Other Long-term Liabilities, for a description of the effect of adopting the new ARO accounting policy.

Legal, Environmental Remediation and Other Contingent Matters

We are required to both determine whether a loss is probable based on judgement and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

Income Tax Accounting

The determination of our income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Business Combinations

Over recent years Husky has grown considerably through combining with other businesses. Husky acquired Temple Exploration Inc. in 2004 and Marathon Canada Limited in 2003. These transactions were accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and gas properties primarily relies on placing a value on the oil and gas reserves. The valuation of oil and gas reserves entails the process described in the ''Capital Resources'' section under the caption ''Oil and Gas Reserves'' but in contrast incorporates the use of economic forecasts that estimate future changes in prices and costs. In addition, this methodology is used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

Goodwill

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise the determination of goodwill is also imprecise. In accordance with the issuance of FASB Statement No. 142 and CICA section 3062, ''Goodwill and Other Intangible Assets'', goodwill is no longer amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires Husky to determine the fair value of its assets and liabilities. Such a process involves considerable judgement.

NEW ACCOUNTING STANDARDS

Asset Retirement Obligations

Effective January 1, 2004, we retroactively adopted CICA section 3110, ''Asset Retirement Obligations''. This standard harmonizes Canadian GAAP with FASB Statement No. 143. ''Accounting for Asset Retirement Obligations'', which became effective January 1, 2003.

The new standard changes the method for recognition of legal obligations, or liabilities, associated with the retirement of tangible long-lived assets. When incurred, the liabilities are recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid when the assets are retired. The amount is added to the

carrying values of the assets and depreciated over the estimated remaining lives of the assets. The liability increases each period as the amount of the discount decreases over time. The resulting expense is referred to as accretion expense and is included in operating expenses. The liability and associated capital assets are also adjusted for any changes in the estimated amount or timing of the underlying future cash flows. Previously, asset retirement obligations were accrued over the estimated remaining useful lives of the assets. See Note 12 to the Consolidated Financial Statements for further information.

Accounting for Stock-based Compensation

In October 1995, the FASB issued Statement No. 123, ''Accounting for Stock-based Compensation Plans'' (''FAS 123''), which established a fair value method of accounting for stock-based compensation and required companies that continued to account for stock-based compensation in accordance with the ''intrinsic method'' to provide a pro forma disclosure that reflects the difference between the two methods. This statement also includes transactions that involve the issuance of equity instruments in exchange for goods and services.

In December 2004, the FASB issued FAS 123(R), ''Share-Based Payment'', which replaces FAS 123 and supersedes Accounting Principles Board (''APB'') Opinion 25. FAS 123(R) requires compensation costs related to share-based payments be recognized in the financial statements and the cost be measured based on the fair value of the equity or liability instrument issued. Under FAS 123(R), all share-based payment plans must be valued using an option-pricing model. For U.S. GAAP, the liability related to the options issued under our tandem plan will be measured using an option-pricing model. Under Canadian GAAP, the liability will be measured using the intrinsic method. Over the life of the option the amount of compensation expense will differ between U.S. and Canadian GAAP. Upon exercise or surrender of the option, the compensation expense recorded is based on the cash payment, which will be the same under both U.S. and Canadian GAAP, and there will no longer be a difference between U.S. and Canadian GAAP. FAS 123(R) is effective July 1, 2005.

Employer's Disclosures about Pension and Other Post-retirement Benefits

In December 2003, the FASB issued Statement 132(R) that was developed in response to the need for additional information about pension plan assets, obligations, benefit payments, contributions and net benefit costs. The effective dates of FAS 132(R) have been phased in since December 2003 and the final aspects of FAS 132(R)became effective for fiscal years ending after June 15, 2004. The pertinent revision included in our 2004 financial statements required the disclosure of estimated future benefit payments for the next five years and for years six to ten in aggregate.

Inventory Costs

In November 2004, the FASB issued FAS 151, ''Inventory Costs'' that clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material as they relate to inventory costing. FAS 151 requires these items to be recognized as current expenses. Additionally, the allocation of fixed production overheads to the cost of inventory should be based on the normal capacity of the production facilities.

SAB 106

In September 2004, the SEC issued Staff Accounting Bulletin 106 (''SAB 106'') regarding the application of FAS 143 by oil and gas producing entities that follow the full cost accounting method under Rule 4-10(c) of Regulation S-X. SAB 106 states that after the adoption of FAS 143 the future cash outflows associated with the settlement of asset retirement obligations that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues from the development and production of proved oil and gas reserves for purposes of the full cost ceiling test calculation. Husky excludes the future cash outflows associated with settling asset retirement obligations from the present value of estimated future net revenues because the fair value of the asset retirement cash outflows were capitalized by increasing long-lived oil and gas assets and those costs must be recovered by the estimated future net revenues from the development and production of proved oil and gas reserves. The estimated future net revenues from proved oil and gas reserves should, however, be reduced by the estimated dismantlement and abandonment costs, net of estimated salvage values, that are estimated to result from future development activities. Costs subject to depletion and depreciation include the estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations.

Accounting for Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation 46, ''Accounting for Variable Interest Entities'' (''FIN 46'') that requires the consolidation of Variable Interest Entities (''VIEs''). VIEs are entities that have insufficient equity or their equity investors lack one or more of the specified elements that a controlling entity would have. The VIEs are controlled through financial interests that indicate control (referred to as ''variable interests''). Variable interests are the rights or obligations that expose the holder of the variable interest to expected losses or expected residual gains of the entity. The holder of the majority of an entity's variable interests is considered the primary beneficiary of the VIE and is required to consolidate the VIE. In December 2003, the FASB issued FIN 46(R) which superseded FIN 46 and restricts the scope of the definition of entities that would be considered VIEs that require consolidation. We do not believe FIN 46(R) results in the consolidation of any additional entities.

Accounting for Exchanges of Nonmonetary Assets

In December 2004, the FASB issued FAS 153 which deals with the accounting for the exchanges of nonmonetary assets. FAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. FAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for nonmonetary exchanges of similar productive assets and introduces a broader exception for exchanges of nonmonetary assets that do not have commercial substance. FAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We do not believe that the application of FAS 153 will have an impact on the financial statements.

QUARTERLY FINANCIAL SUMMARY

	2004				2003			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
	($ millions, except where indicated)							
Sales and operating revenues, net of royalties	$ 2,018	$ 2,191	$ 2,210	$ 2,021	$ 1,800	$ 1,871	$ 1,769	$ 2,218
Net earnings	$ 218	$ 286	$ 239	$ 263	$ 236	$ 249	$ 441	$ 408
Per share								
— Basic	$ 0.53	$ 0.70	$ 0.54	$ 0.60	$ 0.60	$ 0.56	$ 1.09	$ 1.01
— Diluted	$ 0.52	$ 0.70	$ 0.54	$ 0.60	$ 0.59	$ 0.56	$ 1.09	$ 1.01
Share price								
— High	$ 35.65	$ 31.15	$ 28.30	$ 28.04	$ 23.95	$ 20.95	$ 18.14	$ 17.49
— Low	$ 30.05	$ 25.42	$ 23.74	$ 22.73	$ 20.40	$ 17.35	$ 16.15	$ 16.03
— Close (end of period)	$ 34.25	$ 30.79	$ 25.65	$ 26.20	$ 23.47	$ 20.50	$ 17.50	$ 16.93
Shares traded *(thousands)*	37,417	35,074	26,654	22,824	22,171	35,453	24,858	18,371
Dividends declared per common share	$ 0.12	$ 0.12	$ 0.12	$ 0.10	$ 0.10	$ 0.10	$ 0.09	$ 0.09
Special dividend per common share	$ 0.54	$ —	$ —	$ —	$ —	$ 1.00	$ —	$ —
Number of weighted average common shares outstanding *(thousands)*								
— Basic	423,708	423,610	423,413	422,711	421,702	419,729	418,539	418,163
— Diluted	426,825	426,043	425,169	424,720	423,830	422,010	420,331	419,985

RESULTS OF OPERATIONS FOR 2003 COMPARED WITH 2002

The consolidated revenue during 2003 was 20 percent higher than in 2002 primarily as a result of higher realized prices for crude oil and natural gas in the upstream segment.

Net earnings in 2003 were $1,334 million compared with $814 million in 2002. The increase of $520 million was attributable to the following:

Upstream — increase of $368 million

- higher realized crude oil and natural gas prices and production
- lower income taxes

partially offset by:

- higher operating costs and DD&A
- higher royalties

Midstream — increase of $24 million

- wider upgrading differential
- higher upgrader throughput and sales volume
- higher heavy crude oil pipeline throughput
- higher cogeneration income

partially offset by:

- higher unit operating costs, which were primarily energy related
- lower crude oil and natural gas commodity marketing margins

Refined Products — decrease of $1 million

- lower fuel margins

partially offset by:

- higher asphalt margins and sales volumes
- lower income taxes

Corporate — increase of $129 million

- foreign exchange gains on translation of U.S. dollar denominated long-term debt
- lower intersegment profit eliminations
- lower net interest expense due to higher capitalization

partially offset by:

- higher income taxes

DISCLOSURE OF OUTSTANDING SHARE DATA

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 10, 2005

• common shares	423,794,385
• preferred shares	none
• stock options	9,783,958
• stock options exercisable	1,291,552
• warrants	24,500

At February 10, 2005, 23,049,479 common shares were reserved for issuance under the stock option plan. Options awarded under the stock option plan have a maximum term of five years and vest evenly over the first three years.

In 2000, Husky issued Renaissance Energy Limited (''Renaissance'') replacement options, which replaced options held to acquire Renaissance common shares. The former shareholders of Husky were issued warrants to acquire 1.86 common shares of Husky for each common share issued under the Renaissance replacement option plan. Warrants are only exercisable if Renaissance replacement options are exercised. At February 10, 2005, the maximum number of common shares that could be issued for warrants was 45,497 common shares. At February 10, 2005, the Renaissance replacement options had a term of one month.

FORWARD-LOOKING STATEMENTS

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Annual Report contains certain forward-looking statements relating, but not limited, to Husky's operations, anticipated financial performance, business prospects and strategies and which are based on Husky's current expectations, estimates, projections and assumptions and were made by Husky in light of experience and perception of historical trends. Some of Husky's forward-looking statements may be identified by words like ''expects'', ''anticipates'', ''plans'', ''intends'', ''believes'', ''projects'', ''could'', ''vision'', ''goal'', ''objective'' and similar expressions. Husky's business is subject to risks and uncertainties, some of which are similar to other energy companies and some of which are unique to Husky. All statements that address expectations or projections about the future, including statements about strategy for growth, expected expenditures, commodity prices, costs, schedules and production volumes, operating or financial results, are forward-looking statements.

The reader is cautioned not to place undue reliance on Husky's forward-looking statements. Husky's actual results may differ materially from those expressed or implied by Husky's forward-looking statements as a result of known and unknown risks, uncertainties and other factors. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, that contribute to the possibility that the predicted outcomes will not occur. The risks, uncertainties and other factors, many of which are beyond Husky's control, that could influence actual results include, but are not limited to:

- fluctuations in commodity prices
- changes in general economic, market and business conditions
- fluctuations in supply and demand for Husky's products
- fluctuations in the cost of borrowing
- Husky's use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and foreign currency exchange rates
- political and economic developments, expropriations, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which Husky operates
- Husky's ability to receive timely regulatory approvals
- the integrity and reliability of Husky's capital assets
- the cumulative impact of other resource development projects
- estimated production levels and Husky's success at exploration and development drilling and related activities
- the maintenance of satisfactory relationships with unions, employee associations and joint venturers
- competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy
- the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures
- actions by governmental authorities, including changes in environmental and other regulations
- the ability and willingness of parties with whom Husky has material relationships to fulfil their obligations
- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect Husky

OIL AND GAS RESERVE REPORTING

Disclosure of Proved Oil and Gas Reserves and Other Oil and Gas Information

The Company's disclosure of proved oil and gas reserves and other information about its oil and gas activities has been made based on reliance of an exemption granted by the Canadian Securities Administrators. The exemption permits the Company to make these disclosures in accordance with requirements in the United States. These requirements and, consequently, the information presented may differ from Canadian requirements under National

Instrument 51-101, ''Standards of Disclosure for Oil and Gas Activities''. The proved oil and gas reserves disclosed in this Annual Report have been evaluated using the United States standards contained in Rule 4-10 of Regulation S-X of the Securities Exchange Act of 1934. The probable oil and gas reserves disclosed in this Annual Report have been evaluated in accordance with the COGEH and NI 51-101.

The Company uses the terms barrels of oil equivalent (''boe'') and thousand cubic feet of gas equivalent (''mcfge''), which are calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the terms boe and mcfge may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the well head.

Cautionary note to U.S. Investors — The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The Company uses certain terms in this Annual Report, such as probable (possible, recoverable, established, etc.) that the SEC's guidelines strictly prohibit from inclusion in filings with the SEC.

NON-GAAP MEASURES

Disclosure of Cash Flow from Operations

This Annual Report contains the term ''cash flow from operations'', which should not be considered an alternative to, or more meaningful than ''cash flow — operating activities'', as determined in accordance with generally accepted accounting principles as an indicator of the Company's financial performance. The Company's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items.

The following table shows the reconciliation of cash flow from operations to cash flow — operating activities for the years ended December 31:

		2004	2003	2002
			($ millions)	
Non-GAAP	Cash flow from operations	$2,223	$2,459	$2,096
	Settlement of asset retirement obligations	(40)	(34)	(16)
	Change in non-cash working capital	169	113	(198)
GAAP	Cash flow — operating activities	$2,352	$2,538	$1,882

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Company's chief executive officer and chief financial officer (its principal executive officer and principal financial officer, respectively) have concluded, based on their evaluation as of a date within 90 days prior to the filing of this Annual Report (the ''evaluation date''), that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by it in reports filed or submitted by it under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by it in such reports is accumulated and communicated to the Company's management, including its chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

There have been no significant changes to Husky's internal controls or in other factors that could significantly affect these controls subsequent to the evaluation date and the filing date of this Annual Report.

PUBLIC SECURITIES FILINGS

You may access additional information about our Company, including our Annual Information Form, which is filed with the Canadian Securities Administrators at www.sedar.com and the Form 40-F, which is filed with the United States Securities and Exchange Commission at www.sec.gov.

EXHIBITS

Exhibit	Description
23.1	Consent of KPMG LLP, independent accountants.
23.2	Consent of McDaniel and Associates Consultants Ltd., independent engineers.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
32.1	Certifications of Chief Executive Officer pursuant to Rule 13(a)-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
32.2	Certifications of Chief Financial Officer pursuant to Rule 13(a)-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).

Exhibit 23.1

CONSENT OF INDEPENDENT CHARTERED ACCOUNTANTS

The Board of Directors
Husky Energy Inc.

We consent to the use of our report dated January 17, 2005 included in this annual report on Form 40-F to be filed with United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

We also consent to the incorporation by reference of our report in the Registration Statement of Husky Energy Inc. on Form F-9 (No. 333-117972).

/s/ KPMG LLP
Chartered Accountants

Calgary, Canada

January 17, 2005

Exhibit 23.2

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report auditing estimates of the natural gas, natural gas liquids and conventional oil reserves attributable to Husky Energy Inc. (the ''Company'') as of December 31, 2004 (the ''Report'').

We hereby consent to references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, and the Company's registration statement on Form F-9 (File No. 333-117972). We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2004 dated March 16, 2005 and that we have no reason to believe that there are any misrepresentations in the information contained in it that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

Sincerely,

McDaniel & Associates Consultants Ltd.

/s/ B. H. Emslie

B. H. Emslie, P. Eng.
Senior Vice President

Calgary, Alberta, Canada

March 16, 2005

Exhibit 31.1

Certification required by Rule 13a-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code

Certification

In connection with the annual report of Husky Energy Inc. (the ''Company'') on Form 40-F for the fiscal year ending December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the ''Report''), I, John C. S. Lau, President & Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JOHN C. S. LAU

John C. S. Lau
President & Chief Executive Officer

Date: March 16, 2005

Exhibit 31.2

Certification required by Rule 13a-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code

Certification

In connection with the annual report of Husky Energy Inc. (the ''Company'') on Form 40-F for the fiscal year ending December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the ''Report''), I, Neil D. McGee, Vice-President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ NEIL D. MCGEE

Neil D. McGee
Vice-President & Chief Financial Officer

Date: March 16, 2005

Exhibit 32.1

Certification required by Rule 13a-14(a) or 15d-14
of the Securities Exchange Act of 1934

Certifications

I, John C.S. Lau, certify that:

1. I have reviewed this annual report on Form 40-F of Husky Energy Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ John C. S. Lau
John C. S. Lau
President & Chief Executive Officer

Date: March 16, 2005

Exhibit 32.2

Certification required by Rule 13a-14(a) or 15d-14
of the Securities Exchange Act of 1934

Certifications

I, Neil D. McGee, certify that:

1. I have reviewed this annual report on Form 40-F of Husky Energy Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ NEIL D. MCGEE
Neil D. McGee
Vice President & Chief Financial Officer

Date: March 16, 2005