Husky Energy Inc. Annual Report 2007

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Husky Energy Inc.

Headquartered in Calgary, Alberta, Canada, Husky Energy Inc. is one of Canada's largest integrated energy and energy-related companies with operations in upstream, midstream and downstream.

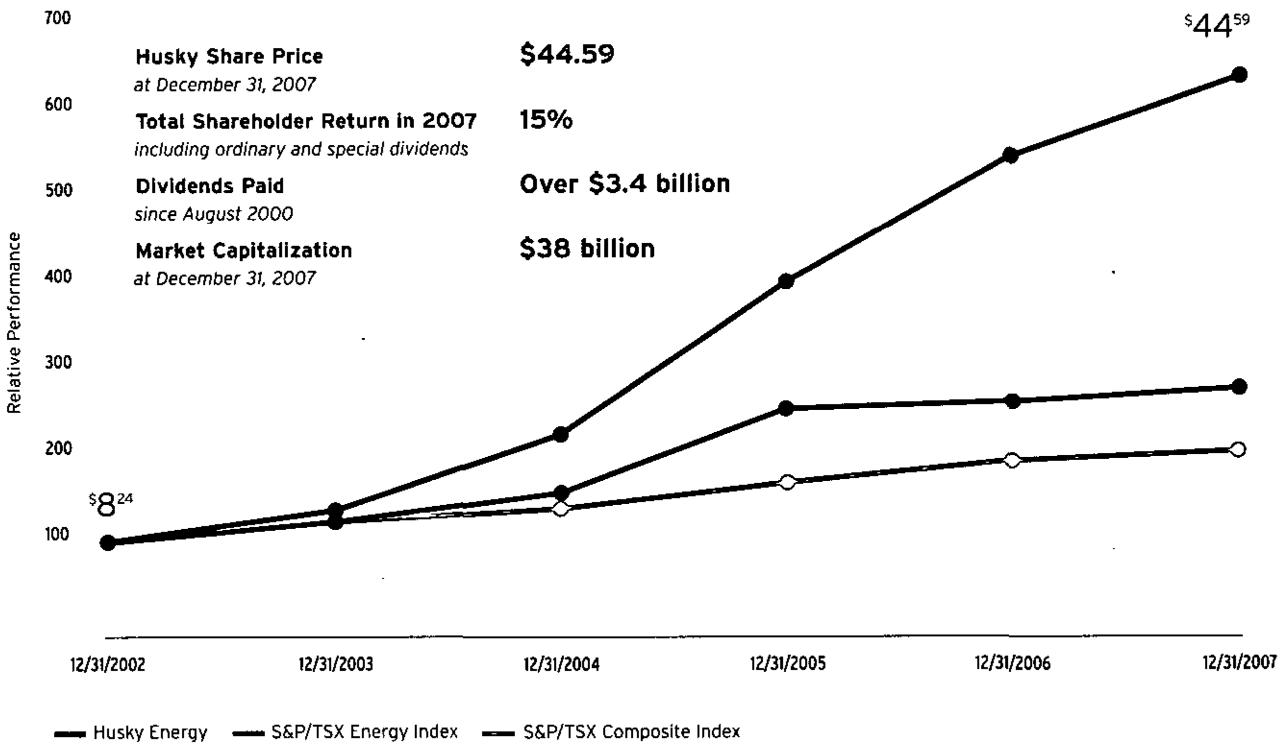
Husky's upstream operations include the exploration, development and production of crude oil, bitumen and natural gas from assets located in Western Canada, Northwest Territories and offshore Canada's East Coast, China, Indonesia and Greenland.

The Company's midstream operations include heavy oil upgrading, pipeline transportation, natural gas storage, processing, electricity cogeneration, and the marketing of crude oil, natural gas, natural gas liquids, sulphur, and petroleum coke.

Downstream operations include the refining, marketing and distribution of gasoline, aviation fuel, diesel, asphalt, ethanol and ancillary products and services across Canada and in the United States.

Husky Energy Inc. is listed on the Toronto Stock Exchange under the symbol HSE.

Husky Share Price Performance vs Indices



Share prices reflect a two-for-one stock split effective July 9, 2007.

2007 Annual Report

Husky had another outstanding year in 2007 with record production, revenue, cash flow and net earnings.

The Company's strategy of enhancing integration through the value chain and developing its oil sands holdings took a leap forward with the purchase of the Lima Refinery (Ohio, U.S.A.), followed by the agreement with BP, under which Husky will swap a 50 percent interest in the Sunrise Oil Sands Project for 50 percent of BP's Toledo, Ohio refinery. With these transactions, Husky will transform into a fully-integrated oil and gas producer, positioning it to move forward with the development of Sunrise and adding immediate revenue and cash flow.

In addition to its financial and operational successes, Husky was named "Producer of the Year" for 2007 by *Oilweek* magazine.

Husky Energy At a Glance

Western Canada

Business
- Crude oil and natural gas exploration and production

Strategy
- Natural gas exploration in the foothills and deep basin
- Tight gas and coal bed methane in the plains regions
- Application of enhanced recovery techniques

2007 Achievements
- More than 100% production replacement
- F&D costs reduced to $16.38/boe
- Quadrupled production to 1,200 bbls/day at Warner, AB ASP project
- Commissioned Crowsnest, AB ASP project

2008 Plans
- Achieve oil and gas production replacement above 100%
- Expand ASP projects
- Expand Ansell, AB and Bivouac, AB tight gas resource plays
- Evaluate two Mannville CBM plays
- Drill and evaluate two central Mackenzie, NWT exploration wells

Heavy Oil

Business
- Heavy oil and natural gas production in the Lloydminster area of Alberta and Saskatchewan

Strategy
- Optimize heavy oil production in Lloydminster
- Application of enhanced recovery techniques

2007 Achievements
- Thermal heavy oil production achieved 20,000 bbls/day by year end
- Progressed engineering design for new thermal projects
- Expanded operations for the successful cold EOR pilot
- Established trucking operation with 14 trailers

2008 Plans
- Maintain primary and thermal oil production volumes
- Progress engineering on new thermal projects, move into construction phases
- Follow up successful cold solvent EOR pilot operations with a second pilot

Oil Sands

Business
- Landholdings of 553,770 acres with discovered petroleum initially-in-place of more than 41 billion barrels at the end of 2007
- 100% interest in the Tucker Oil Sands development
- 50% interest in the Sunrise Oil Sands Partnership (following closing)

Strategy
- Develop in-situ bitumen resources integrated with downstream processing

2007 Achievements
- Signed agreement in principle with BP for 50/50 partnership to develop Sunrise and upgrade BP's Toledo, OH refinery
- Completed FEED and preliminary site work for the Sunrise Oil Sands Project

2008 Plans
- Sanction Sunrise Oil Sands Project and commence detailed engineering
- Complete final detailed agreements with BP
- Accelerate production ramp-up at Tucker
- Progress regulatory approvals for the Caribou Lake Oil Sands Project
- Assess potential recovery processes for the Saleski Oil Sands Project

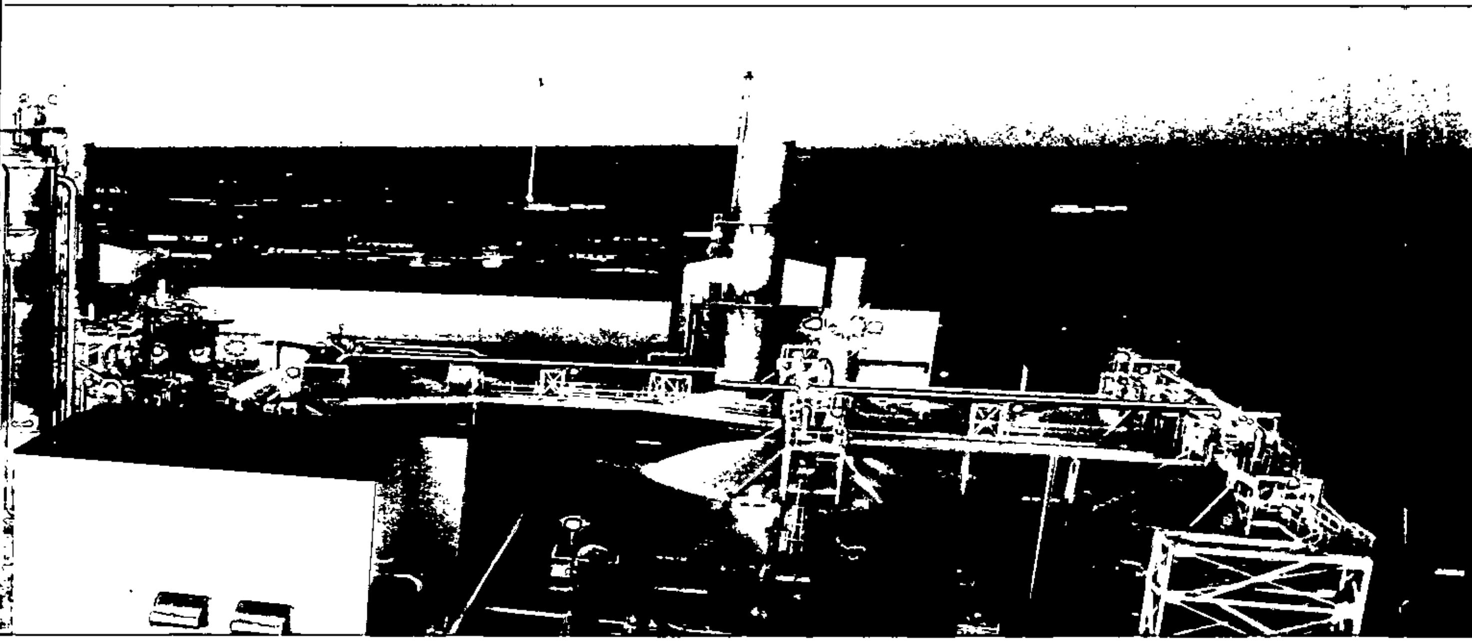
Canada's East Coast

Business
- 72.5% interest in, and operator of, the White Rose oil field
- 12.51% interest in the Terra Nova oil field

Strategy
- Maximize the value of the White Rose assets
- Develop White Rose satellite oil pools
- Continue development at Terra Nova
- Evaluate alternatives for natural gas development
- Pursue exploration and delineation opportunities

2007 Achievements
- Operated the *SeaRose FPSO* at 95% uptime
- Finalized fiscal terms for White Rose satellite developments
- Completed glory hole for North Amethyst
- Delineated West White Rose development area

2008 Plans
- Maximize *SeaRose FPSO* throughput
- Obtain development approvals for North Amethyst satellite development
- Progress North Amethyst satellite development
- Execute 2,500 square kilometres 3-D seismic program in Jeanne d'Arc Basin



International

Business
- 40% interest in the Wenchang oil field
- 100% interest in Liwan discovery
- Seven exploration blocks offshore China
- 100% interest in Madura BD and MDA fields and East Bawean II Block, offshore Indonesia
- Interests in three exploration blocks offshore Greenland

Strategy
- Pursue international exploration and development opportunities
- Create a material oil and gas business in Southeast Asia

2007 Achievements
- Completed 3-D seismic program over the Liwan 29/26 Block
- Signed sales agreements for Madura BD field natural gas
- Completed 3-D seismic over the East Bawean II Block
- Acquired interests in three exploration licences offshore Greenland

2008 Plans
- Drill two Liwan delineation wells and evaluate development options
- Acquire 3-D seismic data over Blocks 29/06 and 35/18, offshore China
- Commence development of the Madura BD field
- Complete a 2-D seismic program offshore Greenland

Midstream

Business
- 82,000 bbl/day Lloydminster Upgrader
- 2,087 kilometres crude oil pipeline system
- Crude oil and natural gas storage
- Electricity cogeneration
- Marketing of crude oil, natural gas, natural gas liquids, sulphur and coke

Strategy
- Increase heavy oil processing capacity to meet Upstream requirements
- Increase and optimize crude oil pipeline capacity
- Increase value of Husky's assets through the commodity marketing business

2007 Achievements
- Expanded Upgrader throughput to 82,000 bbls/day
- Commenced production of low-sulphur off-road diesel fuel from the Upgrader
- Managed in excess of 1 mmboe/day of commodities

2008 Plans
- Complete mainline pipeline expansion project between Lloydminster and Hardisty
- Increase Commodity Marketing volumes to 1.1 mmboe/day
- Assume supply of crude oil feedstock for the Lima Refinery

Canadian Refined Products

Business
- 28,000 bbls/day Lloydminster Asphalt Refinery
- 12,000 bbls/day Prince George Refinery
- 130 million litres per year production at each ethanol plant at Lloydminster, SK and Minnedosa, MB
- Retail network of more than 500 outlets

Strategy
- Expand asphalt sales in the U.S.A.
- Maintain ranking of Western Canada's largest producer and marketer of ethanol
- Upgrade retail facilities and expand ancillary sales

2007 Achievements
- Set throughput record of 28,930 bbls/day at the Lloydminster Asphalt Refinery
- Completed construction and commissioned the Minnedosa Ethanol Plant

2008 Plans
- Achieve design production rates at the Minnedosa Ethanol Plant
- Increase fuel volume throughput per retail location
- Increase ancillary income

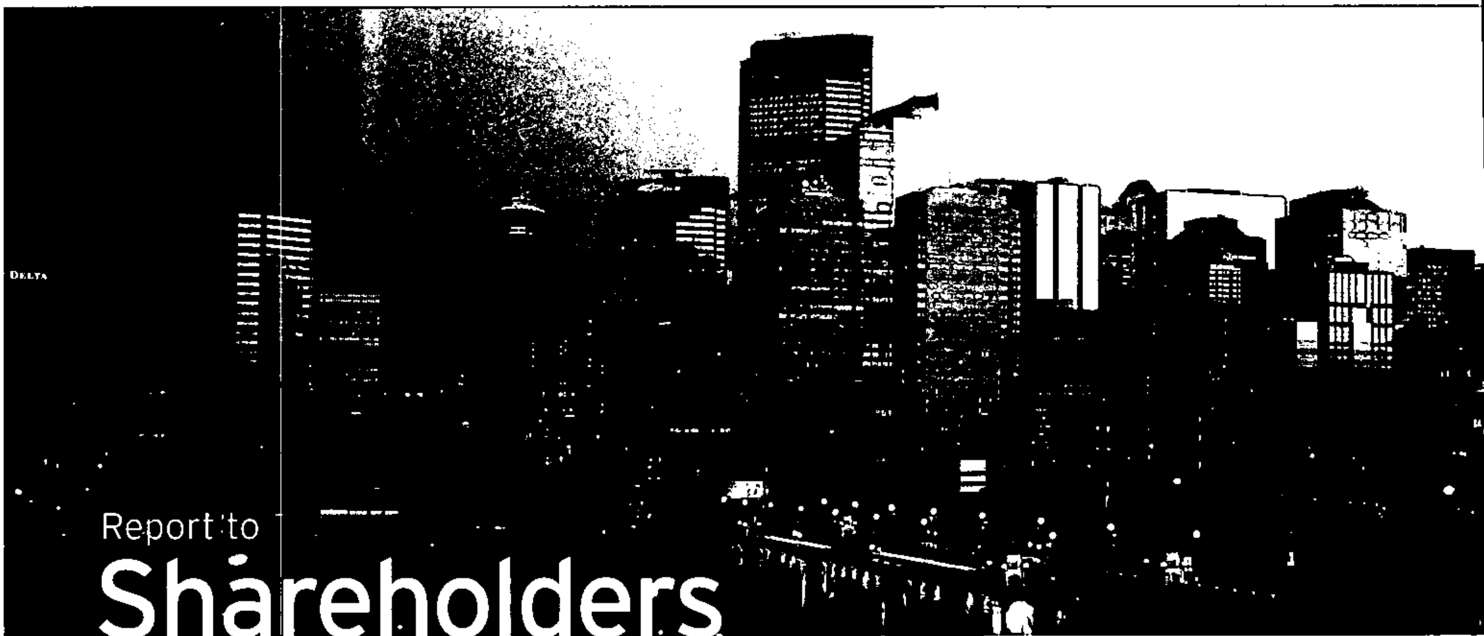
U.S. Refining & Marketing

Business
- 160,000 bbls/day Lima, OH refinery
- 50% interest in 135,000 bbls/day Toledo, OH refinery (following closing)

Strategy
- Reposition Lima for heavier feedstocks
- Optimize product sales in the U.S. Midwest

2007 Achievements
- Acquired the 160,000 bbls/day Lima refinery
- Increased production at Lima Refinery by 10%
- Signed agreement in principle with BP for 50/50 partnership to develop Sunrise and upgrade BP's Toledo, OH refinery

2008 Plans
- Complete arrangements for marketing products from the Lima Refinery
- Commence reconfiguring the Lima Refinery to take heavier feedstock
- Complete final detailed agreements with BP
- Establish a U.S. marketing office in Columbus, OH



Report to Shareholders

It is with great pleasure to report that 2007 was another record year for Husky Energy. The Company's total sales and operating revenues, net of royalties, increased 23 percent to $15.5 billion. Net earnings and cash flow from operations were $3.2 billion and $5.4 billion respectively.

For the year, Husky's return on equity again exceeded 30 percent to the shareholders. As of December 31, 2007, the value of the stock, including total special and quarterly dividends, had increased 715 percent since Husky became a public company in 2000. This continued strong growth has enabled the Company to increase its quarterly dividend by 32 percent in 2007 to $0.33 from $0.25. Husky made a two for one stock split in 2007.

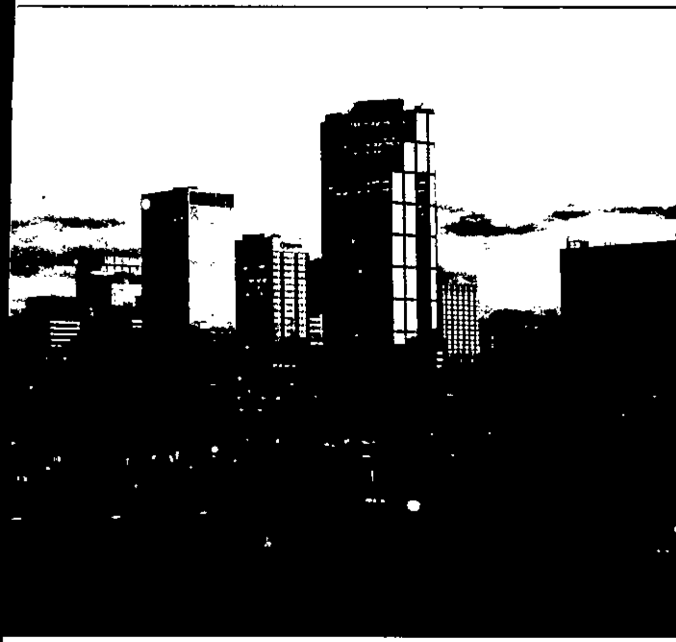
The Company's financial growth was mainly driven by stringent financial discipline and good project execution in this high commodity prices environment. The record results were due to oil production increases, contribution from the acquisition of the Lima Refinery, the strength of oil prices and midstream and refined product margins.

Capital expenditure in 2007, excluding the acquisition of the Lima Refinery, reduced to $2.9 billion from $3.2 billion in 2006, reflecting lower natural gas exploration spending in Western Canada. During the year total production volume averaged 376,600 barrels of oil equivalent per day, an increase of five percent over 2006.

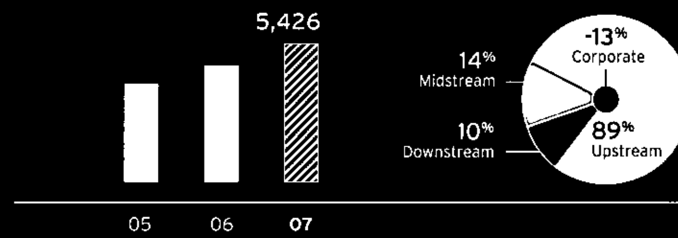
HIGHLIGHTS

2007 was a year of transformation and achievement for Husky.

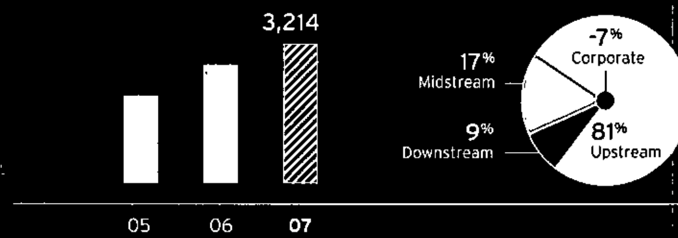
Husky's strategy to build integration through the hydrocarbon chain and grow value in its oil sands holdings advanced materially with the purchase of the 160,000 barrel per day Lima Refinery in July; followed by the agreement with BP in December, in which Husky agreed to swap a 50 percent interest in Sunrise for 50 percent of BP's Toledo Refinery in Ohio, U.S.A. The transaction with BP is subject to the execution of final agreements and regulatory approval and is expected to close in the first



Cash Flow from Operations *($ millions)*



Net Earnings *($ millions)*



quarter of 2008 with an effective date of January 1, 2008. These transactions will transform Husky into a fully integrated oil and gas company and position it to move forward with the development of its Sunrise Oil Sands Project.

The Toledo Refinery currently processes 135,000 barrels per day, including 60,000 barrels of heavy sour crude. Under the proposed joint venture, the partners are planning to expand the bitumen processing capacity to 120,000 barrels per day with a total throughput of approximately 170,000 barrels per day by 2015.

The integration of the Lima Refinery has been completed and its throughput capacity has increased from 135,000 barrels per day to 155,000 barrels per day in February 2008. The Lima Refinery will be repositioned to take heavier crude feedstock.

During the past year, Husky's Lloydminster Upgrader was successfully expanded to 82,000 barrels per day. As a result of the Lima and Toledo transactions, a decision has been made to defer further expansion of the Lloydminster Upgrader. It remains an option for future heavy oil expansion development.

Financial Highlights

Year ended December 31 *(millions of dollars except where indicated)*	**2007**	2006
Sales and operating revenues (1)	**15,518**	12,664
Cash flow from operations	**5,426**	4,501
Per share *(dollars)* – Basic/Diluted	**6.39**	5.30
Net earnings	**3,214**	2,726
Per share *(dollars)* – Basic/Diluted	**3.79**	3.21
Dividends		
Per share *(dollars)* – Ordinary	**1.08**	0.75
– Special	**0.25**	–
Capital expenditures (2)	**2,974**	3,201
Return on average		
capital employed *(percent)*	**25.7**	27.0
Return on equity *(percent)*	**30.2**	31.8
Debt to capital employed *(percent)*	**19.5**	14.3
Debt to cash flow from operations *(times)*	**0.5**	0.4

(1) Net of royalties.

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

The Sunrise Oil Sands Project's front-end engineering work and preliminary site clearing were completed on schedule in the fourth quarter of 2007. The first phase of the project will have a design capacity rate of 60,000 barrels per day of bitumen and is targeted for completion in 2012. Successive phases will increase production to 200,000 barrels of oil per day by 2015-20.

Husky has completed its acquisition of 110,000 contiguous acres of oil sands leases at McMullen, located in the west central region of the Athabasca oil sands deposit, for a purchase price of $105 million. This land lies adjacent to other oil sands leases currently held by Husky.

The White Rose oil field, offshore Newfoundland and Labrador, has had an excellent year, producing more than 43 million barrels of crude oil. Fiscal terms were finalized with the Government of Newfoundland and Labrador for the development of the West White Rose and the North Amethyst satellite fields. Under the agreement, the terms of the original White Rose development remain unchanged. Development of North Amethyst is progressing well towards a late 2009 or early 2010 start-up. The West White Rose development area has been delineated during the year and project work will commence in 2008.

In Greenland, Husky and Esso Exploration Greenland Limited were each awarded a joint interest of 43.75 percent in an exploration license in the Offshore Block 6 (2007/27). The block covers 13,213 square kilometres offshore the west coast of Disko Island. In addition, Husky has an 87.5 percent interest in two exploration licences, Blocks 5 and 7, covering an area of 21,067 square kilometres that border on License 2007/27.

Production at the Wenchang oil field offshore South China Sea continues to perform better than expected. Production averaged 13,000 barrels per day following a successful infill drilling program and the commissioning of a liquefied petroleum gas recovery facility.

For the Liwan discovery offshore China, 2,540 square kilometres of 3-D seismic was completed over Block 29/26 surrounding the original discovery. The deep water drilling rig, West Hercules, is expected to arrive at the field in the second half of 2008 to drill two further delineation wells.

Husky completed three gas sales contracts for the sale of 100 million cubic feet per day from the Madura BD development, offshore Indonesia. Each contract, which has a term of 20 years, commences with first production anticipated in 2011. The Company submitted a Plan of Development to regulatory authorities and is currently negotiating the extension of a production sharing contract. The Company also acquired 1,400 square kilometres of 3-D seismic over the East Bawean II Block.

Husky continued to increase its position in producing and marketing ethanol. Production reached design capacity at its 130 million litres per year ethanol plant in Lloydminster. The 130 million litres per year ethanol plant at Minnedosa, Manitoba was completed and commissioned in December 2007. With full production from the Lloydminster and Minnedosa plants, Husky will become Western Canada's largest producer and marketer of ethanol.

Husky's financial position remains strong. Including the acquisition of the Lima Refinery and a capital program of $2.9 billion, the Company's debt to cash flow ratio was only 0.5 to 1 and debt to capitalization ratio was 19 percent at December 31, 2007. During the year, Husky successfully completed a public offering in the United States of U.S. $300 million 10-year notes and U.S. $450 million 30-year notes at 6.20 percent and 6.80 percent, respectively.

OUTLOOK

The year 2007 highlights Husky's strength in financial performance and operational success in upstream, midstream and downstream. With cash flow in excess of $5.4 billion and proved and probable reserves exceeding 3.2 billion barrels of oil equivalent, Husky is well positioned to capitalize on future growth and expansion opportunities.

For 2008, the Company has a capital program of $3.0 billion for the ongoing exploration and development of its asset portfolio in Western Canada, offshore Canada's East Coast, Greenland, China and Indonesia. Husky's production in 2008 is forecast to be between 385,000 to 410,000 barrels of oil equivalent per day.

The Midstream and Downstream capital program of $600 million will fund ongoing investment in Husky's Canadian facilities as well as initial expenditures for expansion of the Lima and Toledo refineries. With the Lima Refinery's full integration and the Husky/BP Toledo Refinery partnership, Husky's crude upgrading and refining capacity is forecast to increase by more than 80 percent from 2007 levels to more than 300,000 barrels per day.

The notable achievements by Husky in 2007 were made possible by the dedication, commitment and hard work of our management team and employees, and the continued support of our shareholders. On behalf of the Board of Directors, we offer our sincere gratitude and appreciation.

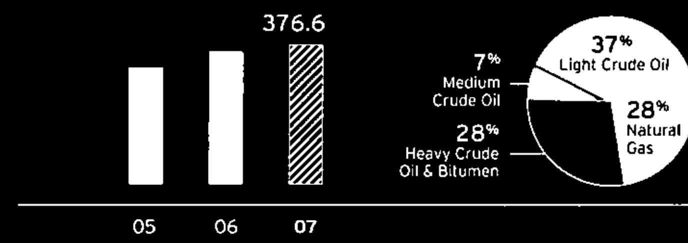
Victor T. K. Li
Co-Chairman

Canning K. N. Fok
Co-Chairman

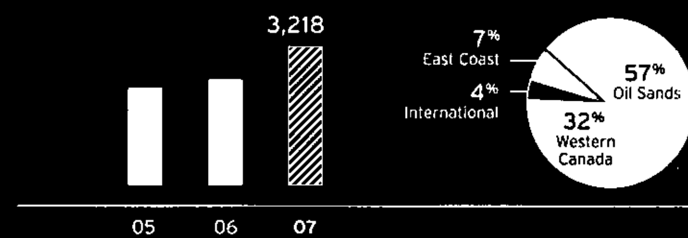
John C. S. Lau
President & Chief Executive Officer

February 4, 2008

Production *(mboe/day)*



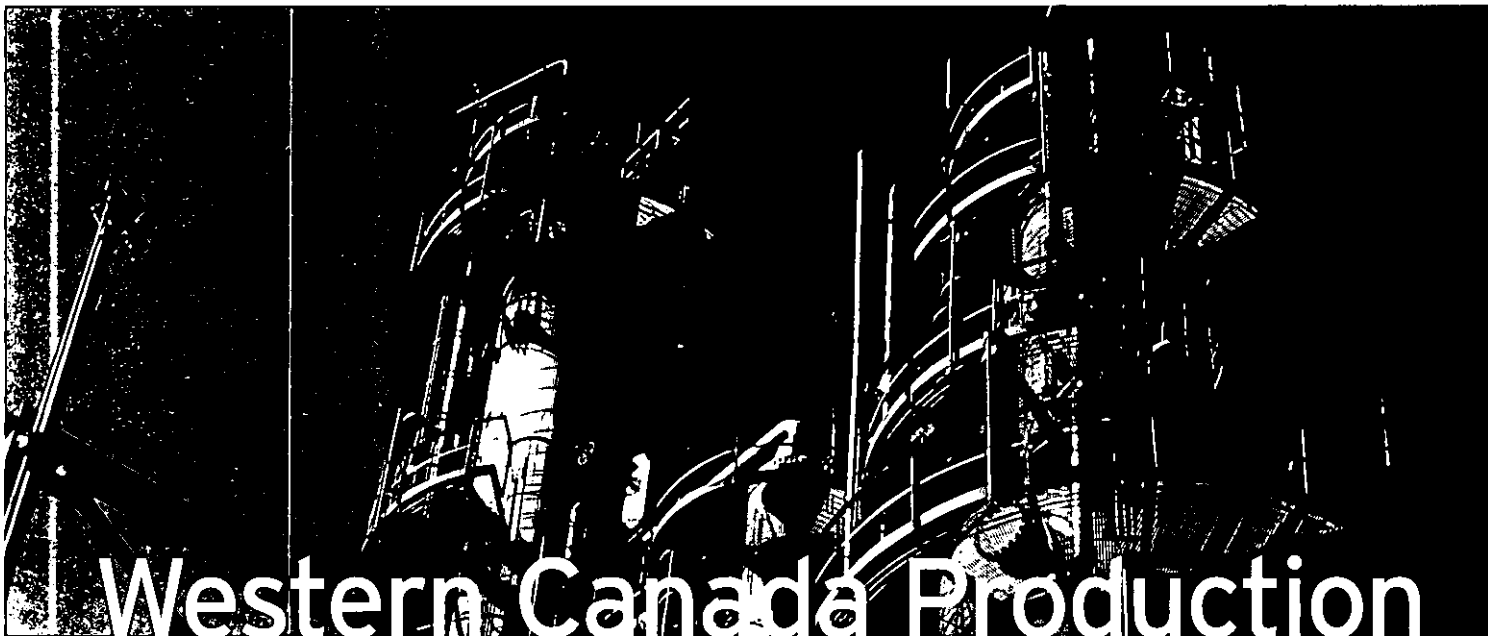
Proved + Probable Reserves *(mmboe)*



Operating Highlights

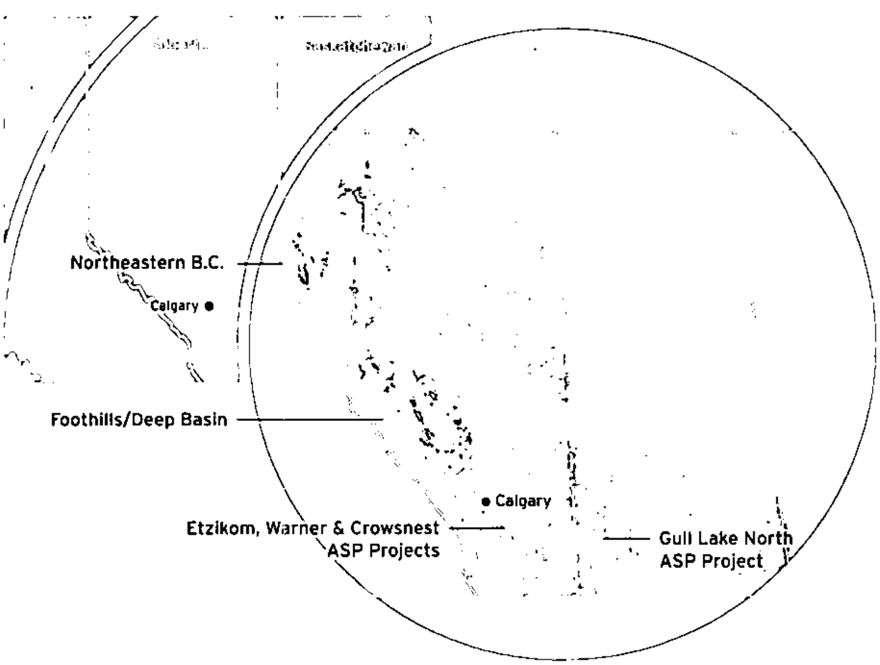
Year ended December 31	2007	2006
Daily production, before royalties		
Light crude oil & NGL *(mbbls/day)*	138.7	111.0
Medium crude oil *(mbbls/day)*	27.1	28.5
Heavy crude oil & bitumen *(mbbls/day)*	106.9	108.1
Total crude oil & NGL *(mbbls/day)*	272.7	247.6
Natural gas *(mmcf/day)*	623.3	672.3
Total *(mboe/day)*	376.6	359.7
Proved reserves, before royalties		
Light crude oil & NGL *(mmbbls)*	286	287
Medium crude oil *(mmbbls)*	88	87
Heavy crude oil & bitumen *(mmbbls)*	275	273
Natural gas *(bcf)*	2,191	2,143
Total *(mmboe)*	1,014	1,004
Upgrader throughput *(mbbls/day)*	61.4	71.0
Pipeline throughput *(mbbls/day)*	501	475
Light oil sales *(million litres/day)*	8.7	8.7
Lima Refinery throughput [(1)] *(mbbls/day)*	143.8	–
Asphalt Refinery throughput *(mbbls/day)*	25.3	27.1
Prince George Refinery throughput *(mbbls/day)*	10.5	9.0
Ethanol production *(thousand litres/day)*	324.6	59.7

(1) Husky purchased the Lima Refinery July 1, 2007.



Western Canada Production

Husky's Western Canadian strategy is focused on exploring, acquiring and developing properties in core areas that complement its infrastructure, on drilling low-risk shallow oil and gas properties, and on applying enhanced oil recovery technologies to increase production and generate good returns.



EXPLORATION

Husky is looking at new plays in areas where it already has infrastructure to create efficiencies and keep costs low, as well as in new core areas with material expected volumes and reserves.

One of the more attractive remaining areas for undiscovered natural gas potential is in the western portion of the Western Canada Sedimentary Basin.

Exploration is focusing on high-impact opportunities in British Columbia and deeper depth opportunities in Western Alberta.

FINANCING HUSKY'S GROWTH ON OUR WESTERN FRONT

- Average working interest: 90%
- 2007 average daily production:
  - Light oil and NGL: 27 mbbls/day
  - Medium oil: 27 mbbls/day
  - Natural gas: 623 mmcf/day
- Proved plus probable natural gas reserves: 2,664 bcf
- Proved plus probable oil and NGL reserves: 318 mmbbls
- Oil and gas landholdings: 6.75 million acres

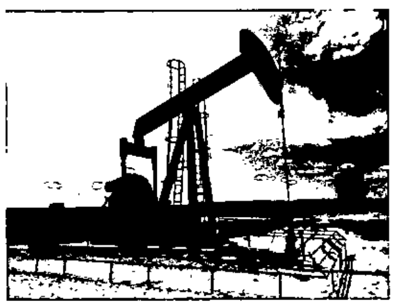
- Achieve production replacement over 100%
- Focus on high netback oil opportunity generation for new oil pools and enhanced oil recovery technologies
- Capture new resource gas plays for future development at higher prices
- Focus on controlling capital and operating costs

NORTHWEST TERRITORIES

In the Central Mackenzie Valley of the Northwest Territories, Husky holds two discoveries, Summit Creek B-44 and Stewart D-57. The Summit Creek B-44 well was drilled on Exploration License 397 in 2004 and tested at combined rates of approximately 20 million cubic feet per day of natural gas and in excess of 6,000 barrels per day of light oil and condensate. The Stewart D-57 well was drilled in 2006 and tested at a rate of five million cubic feet per day.

During 2007, the Company expanded its land holdings in the Northwest Territories by 27 percent to 277,000 acres. The Company plans to drill two exploration wells in the Central Mackenzie region in 2008.

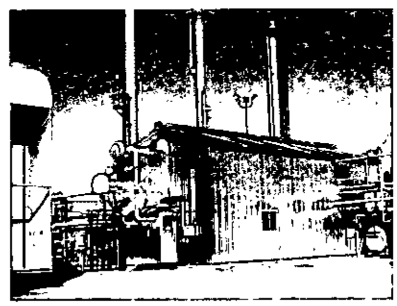
PRODUCTION



Husky's production activities are targeting high netback oil in Southern Saskatchewan and Eastern Alberta with 200 infill and stepout wells, and 30 new pool exploration drills planned for 2008.

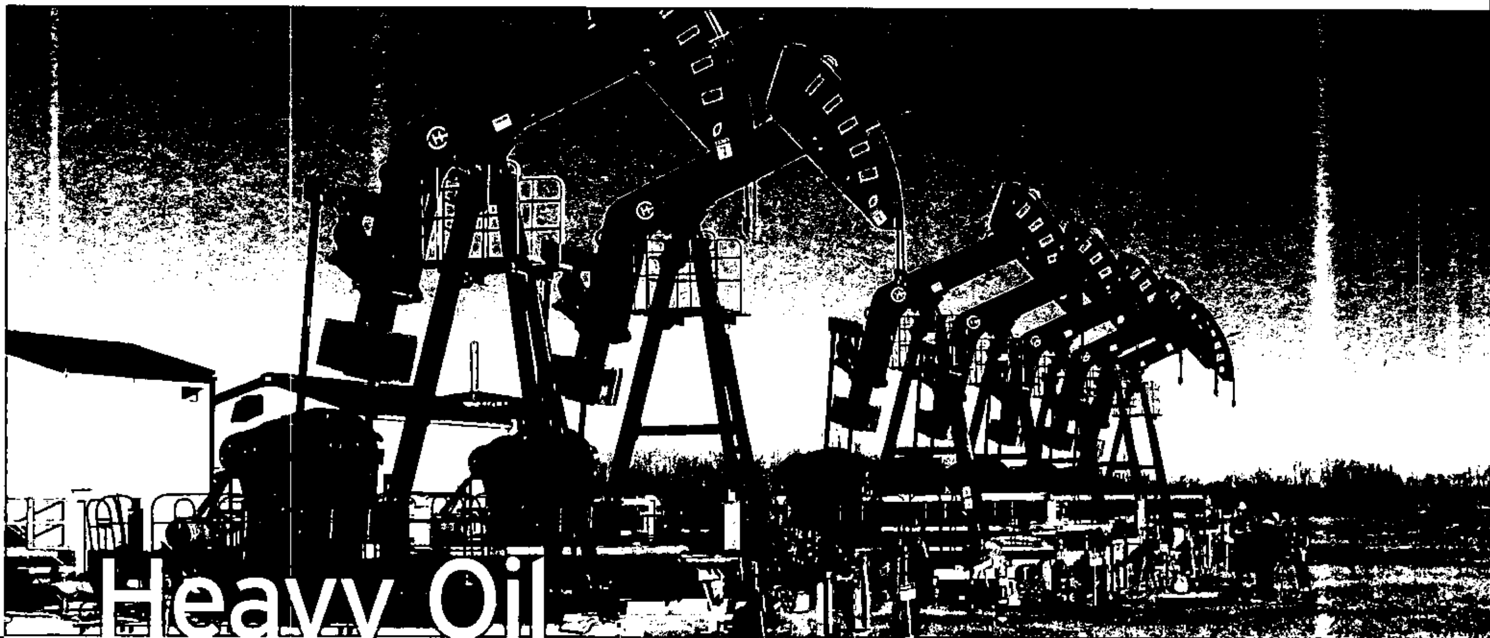
The Company sees potential in growing its Western Canadian natural gas production from unconventional gas sources such as tight gas and coal bed methane resource plays. It is pursuing tight gas opportunities in the Ansell/Galloway and greater Bivouac areas of Northwestern Alberta.

ENHANCED OIL RECOVERY



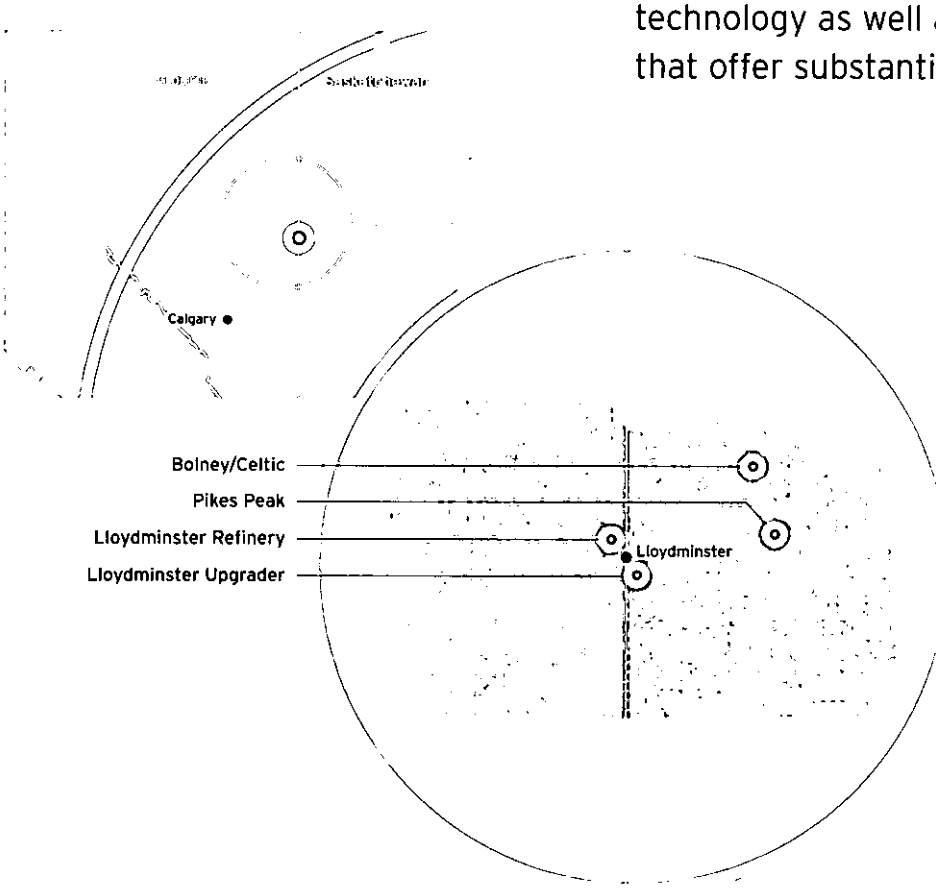
The Company sees great potential in applying enhanced oil recovery techniques and has had successful applications in its Etzikom and Warner fields. An Alkaline Surfactant Polymer (ASP) flood was initiated at the Warner field in 2006 and has quadrupled production to 1,200 barrels per day.

Husky initiated the Crowsnest ASP project in 2007 and is developing its Gull Lake North ASP for startup in the first quarter of 2009. The Company plans to proceed with two new projects scheduled for start-up in 2010.



Heavy Oil

To maintain its leadership position in heavy oil development, Husky is making increased use of existing enhanced oil recovery technology as well as piloting new methods that offer substantial potential.



CANADA'S LARGEST HEAVY OIL PRODUCER

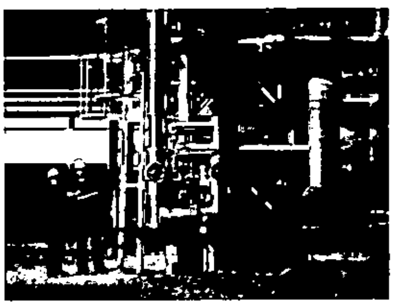
HEAVY OIL ASSETS

- Large resource base
- Average working interest: 95.8%
- 2007 average production: 105 mbbls/day
- Proved plus probable reserves: 282 mmbbls
- Landholdings: 1.6 million acres

OUTLOOK

- Maintain production through exploitation of primary and thermal properties
- Accelerate the pace of thermal project development
- Develop and further field test new enhanced oil recovery processes
- Focus on controlling operating and capital costs

DEVELOPMENT

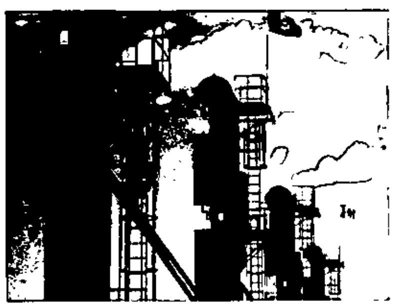


Husky has been a pioneer and leader in producing heavy oil in Western Canada. The Company's heavy oil strategy consists of utilizing primary "cold" production in an effort to optimize production to offset declines, applying enhanced oil recovery (EOR) technologies, and identifying new technologies for the long-term.

In 2007, Husky drilled 497 oil and gas wells including 34 wells in thermal project expansions.

In 2008, Husky plans to drill more than 560 oil and gas wells, advance the engineering on several thermal projects, initiate construction at the Pikes Peak South thermal expansion in Western Saskatchewan, and continue operations at its EOR pilot projects.

ENHANCED OIL RECOVERY

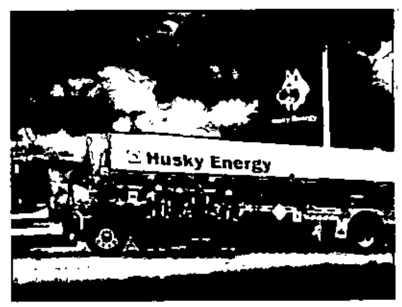


Husky is applying enhanced oil recovery (EOR) techniques to increase recovery from existing fields. In 2007, the Company was successful in increasing thermal production at its Pikes Peak operation. Total production from thermal developments reached 20,000 barrels per day by year end.

The Company is expanding operations at its Bolney/Celtic and Pikes Peak South thermal facilities, increasing expected oil recovery from 35 to 65 percent.

Husky has also successfully demonstrated increased oil recovery at its Edam cold EOR pilot project. Construction of its second solvent EOR pilot was completed in 2007.

OPERATING COST INITIATIVES

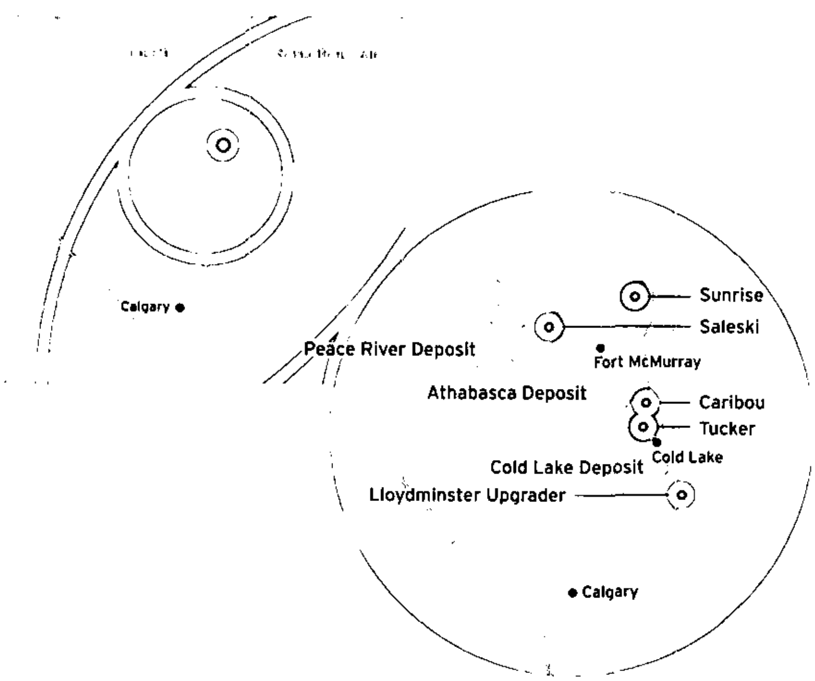


Husky continues to apply financial discipline to minimize operating costs. Cost reduction initiatives undertaken include the construction of pipelines to move more than 10 million barrels of liquids that were formerly trucked, and the installation of a large number of vent gas compressors to reduce greenhouse gas emissions and moderate operating costs.

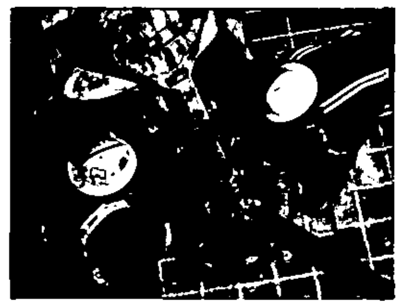
Husky has established a trucking business to transport heavy oil from its wells as a cost reduction initiative. The business commenced in 2007 with 14 trailers and will be expanded during 2008.

Oil Sands

Husky's oil sands play a major role in its future growth strategy. The Company has identified an integrated solution for the Sunrise Oil Sands Project. Husky will contribute and operate Sunrise and its partner, BP will contribute and operate its Toledo, Ohio refinery.



TUCKER



The Tucker Oil Sands development, located in the Cold Lake area of Northern Alberta, was completed on schedule and below its $500 million budget in 2006. Production has been slower than anticipated largely due to the positioning of certain wells relative to the water saturation in the reservoir.

In 2008, optimization strategies on the existing well pads will continue and new well pads are being planned to accelerate the ramp-up of production.

POSITIONED FOR INTEGRATED OIL SANDS DEVELOPMENT

- *Working interest: 100%*
- *Planned peak production: 30,000 bbls/day*

- *Working interest:*
  - *50% in the three primary leases (partnership with BP)*
  - *100% in four leases*
- *Gross planned peak production: 200,000 bbls/day*

- *Working interest: 100%*
- *Planned peak production: 30,000 bbls/day*

- *Working interest: 100%*

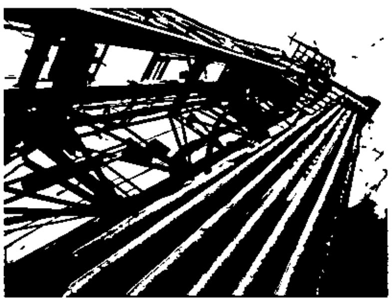
Tucker
- *Accelerate the production ramp-up*

Sunrise
- *Receive project sanction*

Caribou Lake
- *Complete front-end engineering and design and obtain regulatory approvals*

Saleski
- *Evaluate potential recovery processes for pilot project*

SUNRISE



Agreement in principle was reached with BP to create an integrated North American oil sands business consisting of two 50/50 partnerships; for Sunrise, contributed and operated by Husky, and for the Toledo Refinery, contributed and operated by BP.

The development will proceed in three phases with the first phase targeting 60,000 barrels per day by 2012 at an estimated joint investment of U.S. $3 billion. Peak production of 200,000 barrels per day is scheduled for 2015-20.

Front-end engineering and design was completed in 2007, and corporate sanction is anticipated in 2008. Site preparation, including clearing of the central plant site, is ongoing.

CARIBOU LAKE

The Caribou Lake Oil Sands Project is located near Tucker in the Cold Lake area of Northern Alberta. Husky is planning to develop this project in phases. The first phase is a demonstration project and has a production target of 10,000 barrels per day.

Production from this development will be integrated with Husky's heavy oil pipeline system and can be processed by the Lloydminster Upgrader.

Front-end engineering and design for the project was completed in 2007.

Plans for 2008 include finalizing additional technical work on the upstream facility and well design, and obtaining regulatory approvals.

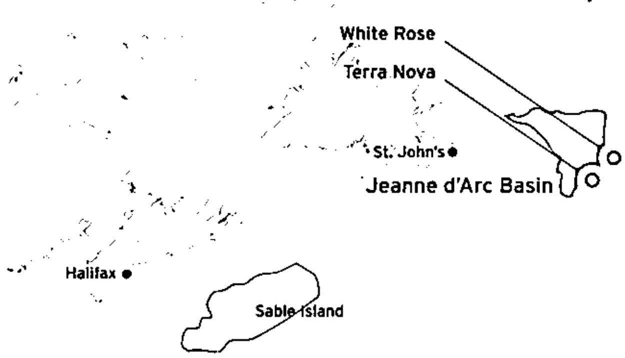
SALESKI

For more than 20 years, Husky has accumulated acreage in the Saleski area and now holds a 100 percent working interest in more than 241,760 acres. The Grosmont carbonate deposit constitutes the reservoir at the Saleski lease. It requires recovery technology different from those traditionally used for oil sands development. During the 1970s and 1980s, Husky carried out several pilot projects producing bitumen from carbonates.

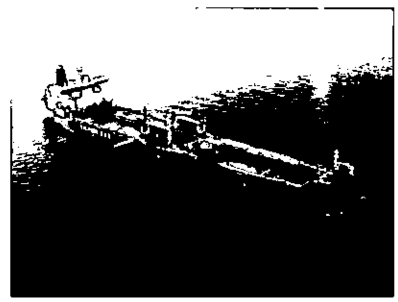
Reservoir characterization and process technology continue to be evaluated to select a recovery process for developing a future pilot project.

Canada's East Coast

Husky's East Coast strategy is focused on maximizing value from existing operations and new discoveries. The Company and its partners have embarked on a program to tie-in production from additional oil pools. First oil from the North Amethyst field, the first of these satellite developments, is expected in late 2009 or early 2010.



WHITE ROSE



Husky is the operator of, and holds a 72.5 percent interest in, the White Rose oil field. The development was completed on schedule and within the $2.35 billion budget in 2005. Initial production was achieved in November 2005, and the seventh and final production well of the initial development was completed in early 2007.

The White Rose oil field continued to provide strong performance throughout 2007 producing a total of 43 million barrels (Husky's working interest 31 million barrels). In the spring of 2007, Husky received government and regulatory approval to increase production throughput on the *SeaRose FPSO* to a maximum of 140,000 barrels per day.

- Working interest:
  - White Rose core development: 72.5%
  - Terra Nova: 12.51%
- 2007 average daily production: 99.5 mbbls/day
- Proved plus probable oil reserves: 216 mmbbls

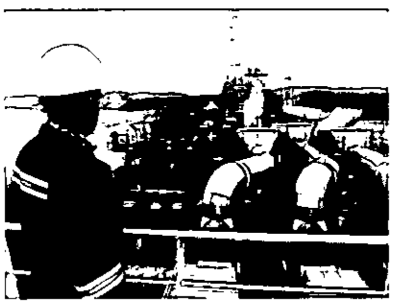
- Significant discovery areas: 22
- Exploration Licenses: 9
- Production Licenses: 6
- Exploration acreage: 4,944 square kilometres

White Rose
- Progress White Rose satellite developments
- Further delineate White Rose oil and gas reserves
- Undertake 3-D seismic to optimize field and satellite development

Terra Nova
- Continue to improve production performance
- Acquire 3-D seismic data to optimize field development

Exploration
- Acquire 3-D seismic data for five exploration licences
- Drill one exploration well

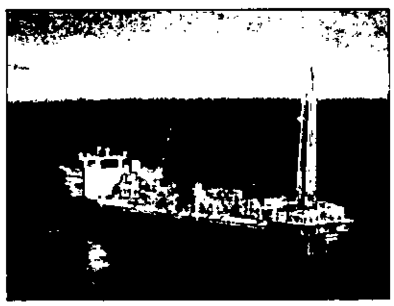
WHITE ROSE SATELLITES



During 2007, Husky agreed to fiscal terms with the Government of Newfoundland and Labrador for the White Rose satellite field developments. Under the agreement, the royalty terms for the original White Rose development remain unchanged. The timely completion of this agreement provides the stability and fiscal certainty required for Husky to proceed with the satellite developments.

Engineering for the first satellite development, the North Amethyst field, was essentially complete at the end of 2007. First production from this field is expected in late 2009 or early 2010.

TERRA NOVA



Husky holds a 12.51 percent working interest in the Terra Nova oil field. First production from the field was achieved in 2002.

The Terra Nova field resumed normal operations following a major turnaround in 2006. Terra Nova's 2007 production volume was 42 million barrels (Husky's working interest 5.3 million barrels).

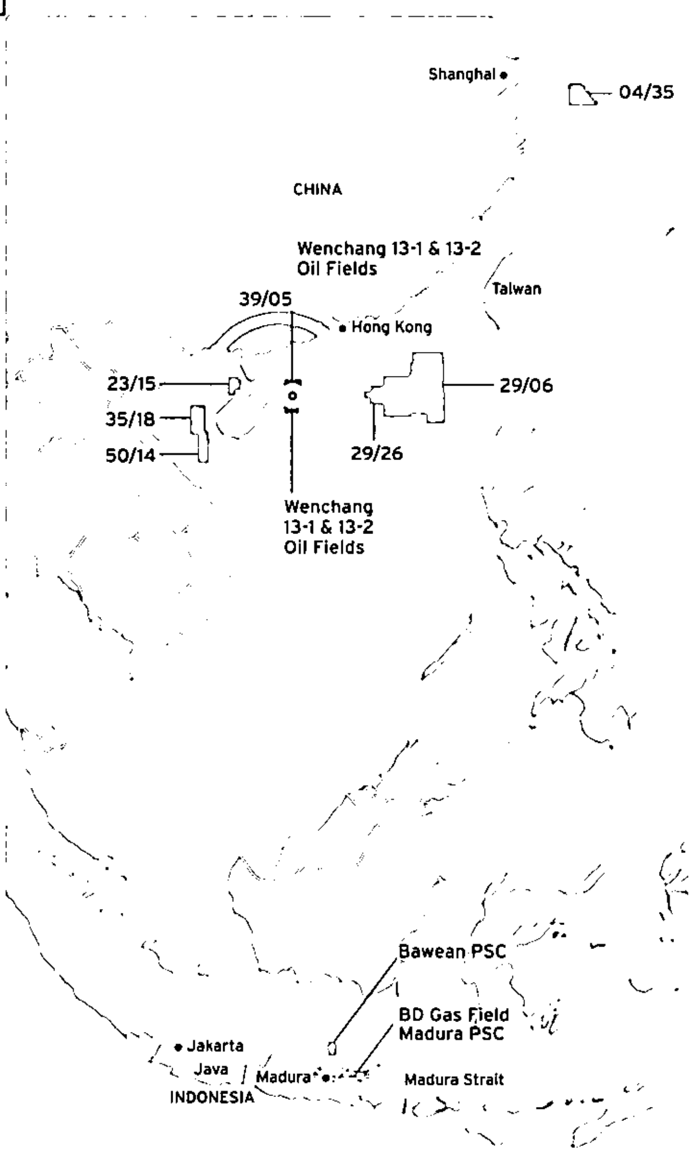
A delineation well was successfully drilled in the Far East South portion of the field in 2007.

EXPLORATION

Husky is one of the largest licence holders in the Jeanne d'Arc Basin. Currently, the Company holds exploration acreage of nearly 5,000 square kilometres in 16 Significant Discovery Licenses and nine Exploration Licenses. In addition, Husky holds interests in six Significant Discovery Licenses offshore Labrador.

In 2008, Husky plans to undertake a 2,500 square kilometres 3-D seismic program over five exploration blocks in the Jeanne d'Arc Basin, and over the White Rose field and potential satellite development areas. The Company also plans to drill one exploration well during the year.

International



Husky's international assets play a major role in its plans to increase oil and gas production. Production from Wenchang, combined with the production potential from the Madura gas development, the Liwan natural gas discovery, and extensive exploration holdings offshore China, Indonesia and Greenland, provide Husky with a solid foundation for future growth.

GROWING OUR PORTFOLIO INTERNATIONALLY

Wenchang: *W.I. 40%*
- *2007 average production: 12,700 bbls/day*

Liwan 3-1-1 Discovery: *W.I. 100%*
- *Contingent resource: 4 to 6 tcf of natural gas*

Exploration Blocks
- *Exploration blocks: 7*
- *Area: 32,767 square kilometres*

INDONESIA

Madura BD Field: *W.I. 100%*
- *Probable reserves:*
  - *Natural gas: 516 bcf*
  - *Liquids: 22 mmbbls*

East Bawean II – East Java Sea
- *Area: 4,255 square kilometres*

GREENLAND

Blocks 5 & 7: *W.I. 87.5%*
- *Area: 21,067 square kilometres*

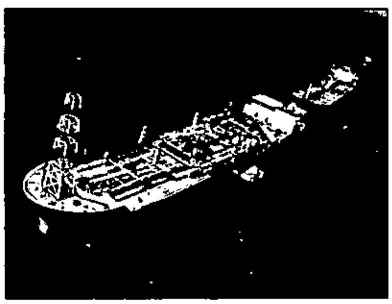
Block 6: *W.I. 43.75%*
- *Area: 13,213 square kilometres*

China
- *Maintain production levels at Wenchang*
- *Drill two Liwan delineation wells*
- *3-D seismic program over Blocks 29/06 and 35/18*
- *Drill two exploration wells*

Indonesia
- *Complete PSC extension negotiations for Madura*
- *Complete front end engineering for the Madura BD development*

Greenland
- *Acquire 2-D seismic over exploration blocks*

CHINA

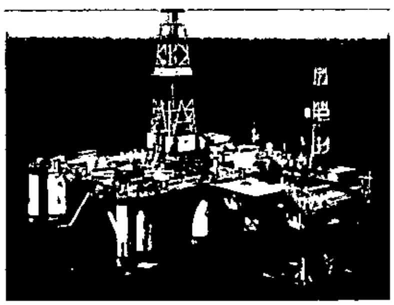


Husky and its partner continue to optimize production from the Wenchang field through infill drilling, tie-back opportunities and improving efficiencies.

The Company is progressing with plans to develop the Liwan discovery. A 3-D seismic program over Block 29/26 surrounding Liwan was completed in 2007. The *West Hercules* deep water drilling rig is expected to arrive at the field in the second half of 2008 and drill two delineation wells. Development planning including engineering concept design, pipeline routing and metocean studies will take place in 2008.

Preparation is also under way to drill exploration wells on two other offshore China blocks and conduct 3-D seismic surveys over Blocks 29/06 and 35/18.

INDONESIA

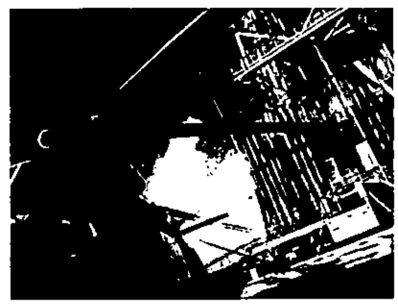


Husky signed three 20-year agreements for the sale of natural gas production from its Madura BD field. Each contract commences with first production which is anticipated in 2011. The total amount of natural gas contracted in the three agreements is 100 million cubic feet per day.

The Company has submitted a development plan to the Government of Indonesia for the field and is in the process of negotiating an extension to the Madura Strait Production Sharing Contract (PSC). Front-end engineering design of offshore facilities and pipelines will commence in 2008.

On the East Bawean II Block, Husky completed a 1,400 square kilometres 3-D seismic program.

GREENLAND

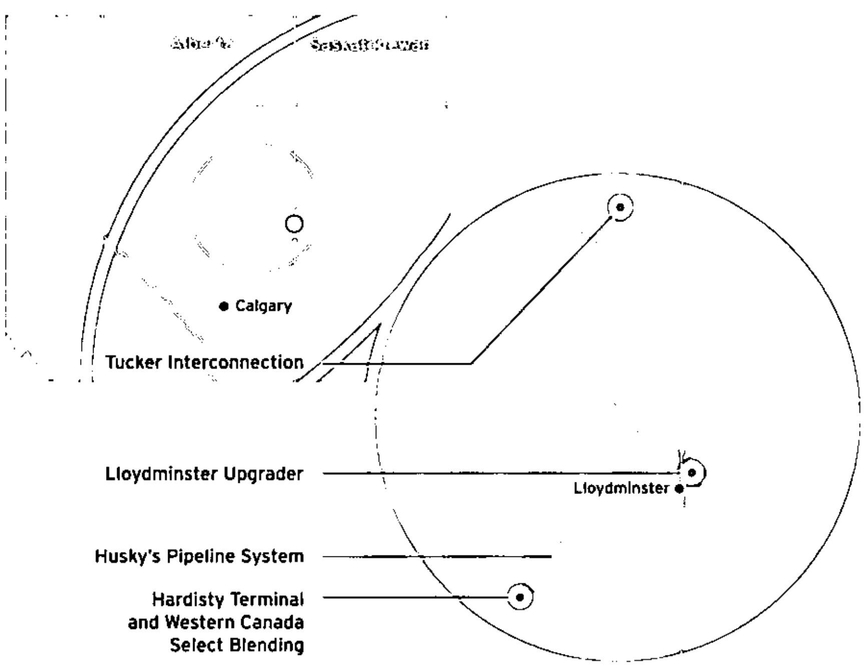


Husky added significantly to its international asset base in 2007 when it was awarded three exploration licences off the west coast of Disko Island, Greenland. It has an 87.5 percent interest in two blocks covering approximately 21,067 square kilometres, and a 43.75 percent interest in a third block covering 13,213 square kilometres. The geology and operating conditions are very similar to those of the East Coast of Canada.

Completion of a high resolution aero-gravity and magnetic survey and a 10,000 kilometre 2-D seismic program are planned for 2008 to evaluate prospects on these blocks.

Midstream

Husky's midstream assets, which include a heavy oil upgrader, pipeline operations, commodity marketing, electricity cogeneration, and crude oil and natural gas storage, contribute significant earnings while reducing overall financial volatility.



UPGRADER

Husky's Upgrader located in Lloydminster, Saskatchewan, near Husky's heavy oil production infrastructure, main pipeline and Tucker Oil Sands Project, processes heavy oil feedstock into premium quality synthetic crude oil for refiners. The Upgrader began operations in 1992 at a design throughput rate of 46,000 barrels per day. Since then, rates have increased through a number of expansion and reliability projects.

In 2007, Husky completed an expansion project which increased throughput capacity to 82,000 from 77,000 barrels per day. The Upgrader also commenced shipments of off-road low-sulphur diesel in July 2007 following the completion of enhancements to the facility.

- Crude oil: 690 mbbls/day
- Natural gas: 2.1 bcf/day
- Total: 1.0 mmboe/day

- Upgrader throughput: 82 mmbbls/day
- Pipeline system: 2,087 km
- Crude oil storage: 2.8 mmbbls
- Natural gas storage: 37.7 bcf
  - Hussar, AB: 100% interest: 17.2 bcf
  - East Cantuar, SK: 50% interest: 5.3 bcf
  - Contracted: 15.2 bcf

- Cogeneration:
  - Lloydminster, SK: 50% ownership interest: 215 MW
  - Rainbow Lake, AB: 50% ownership interest: 90 MW

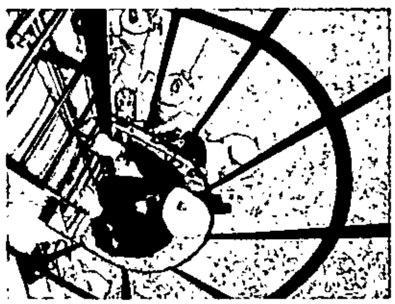
- Complete mainline pipeline expansion
- Construct two 300,000-barrel storage tanks at the Hardisty terminal
- Increase commodity sales from conventional production growth

PIPELINES AND TERMINALS

Husky's 2,087-kilometre pipeline system carries crude oil from Husky and third-party facilities in northeastern Alberta and northwestern Saskatchewan to its Lloydminster terminal for distribution to its nearby asphalt refinery and upgrader. Remaining crude and synthetic oil are shipped to Husky's terminal at Hardisty, Alberta.

The Hardisty terminal blends various crude oil streams for Husky and third parties. The facility manages 25 percent of Canada's total oil exports to the United States via transcontinental pipelines. At the end of 2007, the mainline pipeline expansion project between Lloydminster and Hardisty was 85 percent completed. Husky will continue to expand its facilities at Hardisty during the next five years.

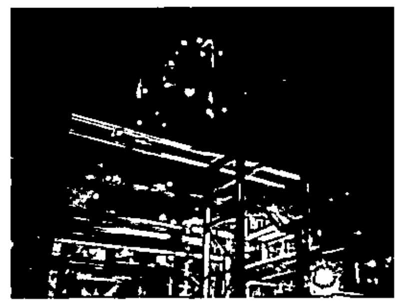
FACILITIES AND NEW VENTURES



The Facilities and New Ventures group consists of 37.7 billion cubic feet of owned and contracted natural gas storage and a 50 percent interest in two power cogeneration plants.

Facilities and New Ventures has the mandate to study the use of carbon dioxide from the recently completed Lloydminster and Minnedosa ethanol plants in enhanced oil recovery operations by Husky and third parties. The group represents Husky on the Integrated CO_2 Network (ICO_2N), an industry and government consortium piloting carbon dioxide sequestration.

COMMODITY MARKETING

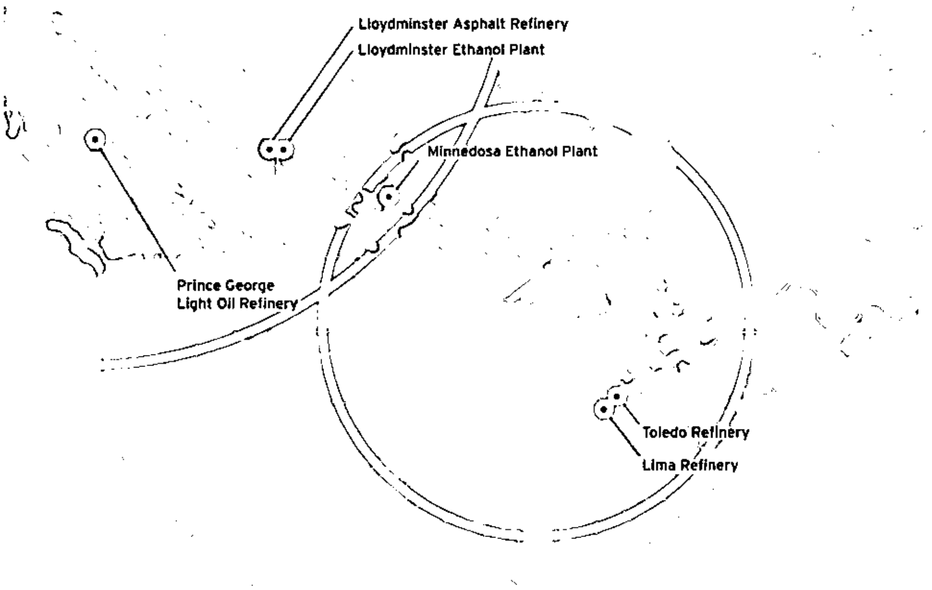


Commodity Marketing aggregates, supplies, transports, brands, stores, prices, sells and administers third-party crude oil, natural gas, natural gas liquids, sulphur and petroleum coke. The group continues to expand the marketing of Husky's and third party volumes. The group is also responsible for sourcing feedstock for the Lima Refinery.

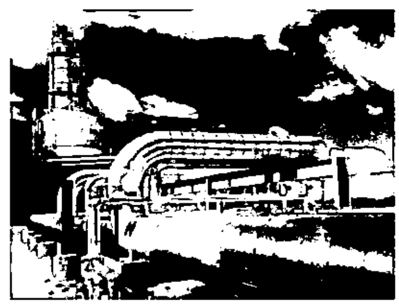
In 2007, the Commodity Marketing group handled more than one million barrels of oil equivalent per day, including nearly 700 thousand barrels per day of crude oil and more than two billion cubic feet per day of natural gas.

Downstream

The completion of two world-class ethanol plants, the acquisition of the 160,000 barrels per day Lima Refinery and the continued growth in sales from retail operations have made Husky's refined products operations a core business unit.



CANADIAN REFINED PRODUCTS



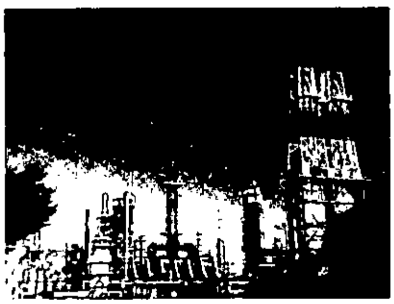
Located in the interior of British Columbia, the Prince George Light Oil Refinery celebrated its 40th anniversary of operation in 2007. The refinery, which produces low-sulphur gasoline and diesel fuels, butane and propane mix, and heavy fuel oil, set a production record of 3.8 million barrels in 2007.

The Lloydminster Asphalt Refinery produces asphalt products for road construction and maintenance, building materials, locomotive blendstock and specialized oil field products. The facility averaged throughputs of 25,300 barrels per day and shipped more than five million barrels of asphalt to customers across North America.

- Lima Refinery: 160 mbbls/day
- Prince George Light Oil Refinery: 12 mbbls/day
- Lloydminster Asphalt Refinery: 27 mbbls/day
- Lloydminster Ethanol Plant: 130 million litres/year
- Minnedosa Ethanol Plant: 130 million litres/year
- Emulsion Plants/Asphalt Terminals: 8

- Complete integration of the Lima Refinery into Husky's operations
- Develop a product marketing strategy for Lima Refinery
- Establish a U.S. marketing office
- Optimize production at the Minnedosa Ethanol Plant
- Increase sales volume per retail outlet by three percent
- Grow ancillary income by five percent over 2007

U.S. REFINED PRODUCTS



Lima Refinery
Husky acquired the Lima, Ohio, refinery in 2007 for U.S. $1.9 billion, plus net working capital. The refinery has a throughput capacity of 160,000 barrels per stream day of light crude oil, and produces gasoline, diesel and aviation fuels that meet U.S. clean fuel standards. During 2008, Husky will review its options for reconfiguring the facility to process heavy crude oil as a primary feedstock.

Toledo Refinery
Husky's strategy to provide a downstream solution for developing its oil sands assets was furthered by an agreement with BP in December 2007. Husky will swap a 50 percent interest in its Sunrise oil sands holdings for 50 percent of BP's 135,000 barrel per day refinery in Toledo, Ohio.

ETHANOL

Husky is a pioneer in the production and marketing of ethanol-blended fuels. The Company's first ethanol plant was built in 1981 in Minnedosa, Manitoba to produce ethanol for fuel and industrial use.

Husky commissioned a 130 million litres per year wheat-based ethanol plant at Lloydminster, Saskatchewan, in 2006 and a second 130 million litres per year plant in Minnedosa, Manitoba in late 2007.

When the Minnedosa facility reaches peak production in the first quarter of 2008, total production from it and the Lloydminster Ethanol Plant will total 260 million litres per year, making Husky Western Canada's largest producer and marketer of ethanol. Production from both plants is sold for blending into gasoline to reduce greenhouse gas emissions from vehicle exhausts.

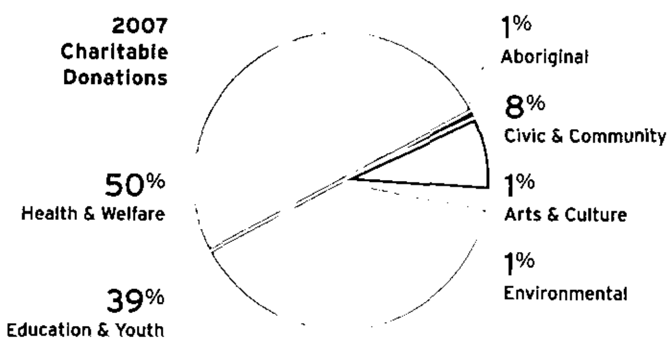
RETAIL MARKETING

Husky markets gasoline and diesel fuel and ancillary services through a network of more than 500 Husky and Mohawk retail outlets, travel centres and bulk distributors from Vancouver Island to eastern Ontario and the Yukon. Husky's travel centre network is strategically located along major highways and serves retail and commercial markets 24 hours-a-day, 365 days-a-year with quality products and services.

In 2007, Husky marketed more than 3.2 billion litres. Annual retail throughput per station has increased a total of 32 percent in the past five years. During the year, ancillary income from retail outlets grew by 18 percent. Growth in ancillary income from convenience store, restaurant, lubricants and carwash rent has increased an average of 12 percent per year from 2002 to 2007.

HSE & Social Responsibility

Husky approaches sustainable development by first seeking a balance among economic, operational integrity, health, safety, environmental and social issues, while maintaining growth. Secondly, it strives to find solutions to these issues that do not compromise the needs of future generations.



COMMUNITY INVESTMENT

Husky's community investment program focuses on initiatives which provide long-term benefits in the communities where its employees live and work. Education, health and community partnerships are the cornerstones of Husky's community investment program.

During 2007, Husky contributed $6.1 million to 450 charitable organizations. The Company's commitment extends directly from senior management to all employees. Husky supports the charitable activities of its employees through an annual matching charitable donations program. In 2007, Husky and its employees raised more than $1 million toward 48 regional and national charities.

HEALTH, SAFETY AND ENVIRONMENT IS OUR TOP PRIORITY

- *Oilweek named Husky as the Producer of the Year (2002 and 2007)*
- *The Saskatchewan Workers' Compensation Board awarded Husky's Lloydminster Upgrader with its 2007 Certificate of Achievement for exceptional performance in workplace safety and injury prevention without an employee lost-time incident*
- *President & Chief Executive Officer John C.S. Lau was honoured by the Calgary Exhibition & Stampede for Husky's longstanding support of the Stampede's Indian Village*

- *Exceed established health, safety and environmental standards*
- *Hire contractors who demonstrate best safety practices and environmental awareness*
- *Implement a new environmental data information management system*

- *Maximize the value of Husky's community investment contributions to provide long-term benefits*
- *Consult with Aboriginal communities in the planning of projects and assist them in benefiting from economic development*

INTEGRITY MANAGEMENT

Husky Operational Integrity Management System

Husky's already-strong commitment to workplace safety and environmental stewardship reached a new level with the development of the Husky Operational Integrity Management System, known as HOIMS.

The goal for HOIMS is to identify, control or eliminate all hazards and risks associated with operations, processes and related equipment. As the system is implemented, it will provide Husky with a systematic approach to operational excellence.

ENVIRONMENT

Husky's "life cycle" approach to environmental stewardship is integral within the Company. It starts with public consultation, stakeholder and regulator consultation, monitoring, addressing environmental issues before and during operations; and, at the end of the facility's life, remediation to ensure that impacts from its operations are addressed and managed.

The Company's environmental commitment extends outside operations as well. Husky supports environmental education and endangered species programs including the Husky Endangered Species Reintroduction Program at the Calgary Zoo.

ABORIGINAL RELATIONS

Husky continues to effectively consult with Aboriginal communities regarding development plans. By sponsoring initiatives that promote educational attainment, support community wellness, and foster economic development in Aboriginal communities, Husky continually demonstrates its commitment to reinforcing positive relationships.

Husky is proud to support the Aboriginal Pride Program at Calgary's Jack James High School. This educational program is designed to improve graduation rates among urban Aboriginal youths.

MD&A

Management's Discussion and Analysis February 21, 2008

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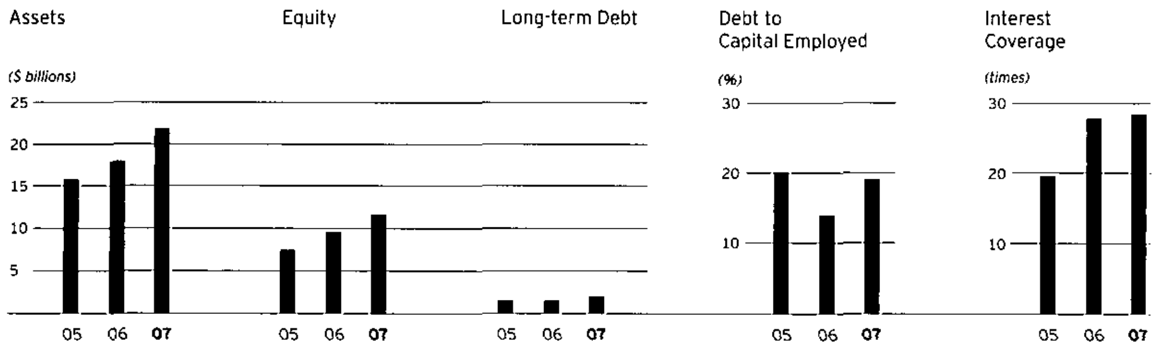
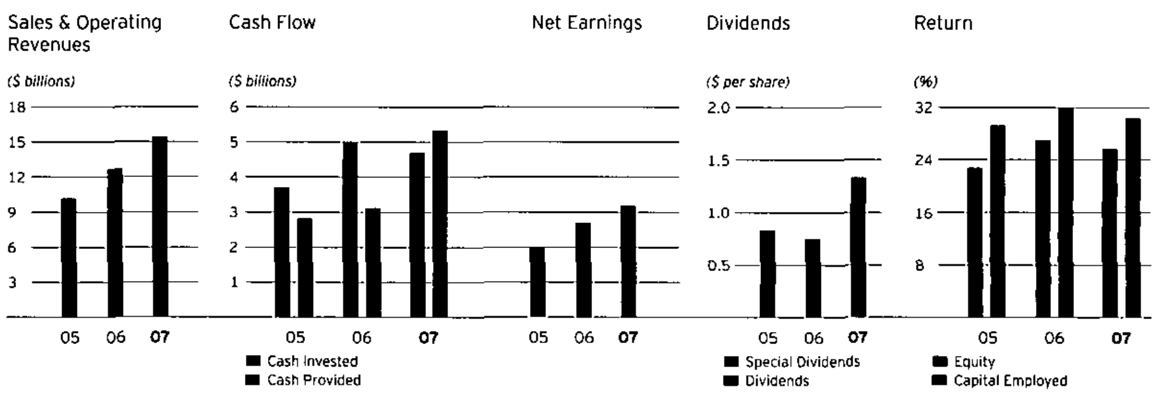
1.0 Financial Summary

1.1 FINANCIAL POSITION



1.2 FINANCIAL PERFORMANCE



Total Shareholder Returns

The following table shows the total shareholder returns compared with the Standard and Poor's and the Toronto Stock Exchange energy and composite indices.

	Husky common shares	S&P/TSX energy index	S&P/TSX composite index
2003	43%	24%	24%
2004	46%	29%	12%
2005	72%	61%	22%
2006	32%	3%	15%
2007	14%	5%	7%
Five year average	40%	23%	16%
Five year cumulative return	441%	178%	109%

1.3 SELECTED ANNUAL INFORMATION

($ millions, except where indicated)	**2007**	2006	2005
Sales and operating revenues, net of royalties	**$15,518**	$12,664	$10,245
Segmented earnings			
Upstream	**$ 2,596**	$ 2,295	$ 1,524
Midstream	**535**	482	495
Downstream	**297**	106	82
Corporate and eliminations	**(214)**	(157)	(98)
Net earnings	**$ 3,214**	$ 2,726	$ 2,003
Per share – basic/diluted	**$ 3.79**	$ 3.21	$ 2.36
Dividends per common share	**$ 1.08**	$ 0.75	$ 0.325
Special dividend per common share	**$ 0.25**	$ -	$ 0.50
Total assets	**$21,697**	$17,933	$15,716
Long-term debt excluding current portion	**$ 2,073**	$ 1,511	$ 1,612
Return on equity *(percent)*	**30.2**	31.8	29.2
Return on average capital employed *(percent)*	**25.7**	27.0	22.8

2.0 Husky's Businesses

Husky is a Canadian-based energy and energy-related company with revenues for the year of $15.5 billion and over 4,000 employees. Husky is integrated through the three industry sectors: upstream, midstream and downstream. In the upstream sector, we explore for, develop and produce crude oil and natural gas *(upstream business segment)*. In the midstream sector, we upgrade heavy crude oil *(upgrading business segment)*, process and pipeline heavy crude oil, maintain interests in two cogeneration plants as well as store and market crude oil and natural gas *(infrastructure and marketing business segment)*. In the downstream sector, we distribute motor fuel and ancillary and convenience products, manufacture and market asphalt products, produce ethanol and operate two regional refineries in Canada *(Canadian refined products business segment)* and refine crude oil and market refined products in the U.S. Midwest *(U.S. refining and marketing business segment)*.

3.0 Capability to Deliver Results

Husky's ability to deliver results is dependent on commodity prices, the Company's continued success in exploring for oil and gas, efficient and safe execution of capital projects, efficient and safe operations, effective marketing, retention of expertise and continued access to the financial markets.

3.1 UPSTREAM

- substantial position in the Alberta oil sands. The initial stages of the development of this asset include the Tucker oil sands project that is currently operating and the Sunrise project that is in the early development phase;
- leading position and extensive expertise in the exploration and production of heavy oil by both cold production and thermal recovery methods in Western Canada;
- large base of producing properties in Western Canada that have responded well to the application of increasingly sophisticated exploitation techniques;
- expertise and experience exploring and developing the significant natural gas potential in the deep basin, foothills, and northwest plains of Alberta and British Columbia;

- harsh weather offshore exploration, development and production expertise as demonstrated by the successful White Rose development offshore the East Coast of Canada. In addition to the White Rose oil field, we hold an interest in Terra Nova and a large portfolio of significant discovery and exploration licenses offshore Newfoundland and Labrador and offshore Greenland;
- large position offshore China that includes an interest in the Wenchang oil field and large portfolio of exploration blocks. By exploration, the Company discovered China's largest deep water natural gas field in 2006; and
- offshore Indonesia we hold significant discovery and exploration licenses. The Madura natural gas and natural gas liquids discovery is the current focus for development.

3.2 MIDSTREAM

- reliable heavy oil upgrading facility located in the Lloydminster heavy oil producing region with a throughput capacity of 82 mbbls/day;
- reliable and efficient heavy oil pipeline systems well integrated in the Lloydminster producing region;
- participation in two cogeneration power facilities having a combined 295 MW of capacity, both of which support local plant operations;
- natural gas storage in excess of 37 bcf, owned and leased;
- large scale petroleum marketer balancing the needs of both customers and suppliers; and
- large scale supplier of crude oil and natural gas feedstock for our plants and facilities.

3.3 DOWNSTREAM

- 160 mbbls/day full product spectrum refinery at Lima, Ohio, U.S.A.;
- major regional marketer with 505 retail marketing locations including bulk plants and travel centers with strategic land positions in Western Canada;
- refinery in Prince George, British Columbia with 12 mbbls/day capacity of low sulphur gasoline and ultra low sulphur diesel;
- largest producer of ethanol in Western Canada with a combined 260 million litre per year capacity at plants located in Lloydminster, Saskatchewan and Minnedosa, Manitoba;
- largest marketer of paving asphalt in Western Canada with a 28 mbbls/day capacity asphalt refinery located in Lloydminster, integrated with the local heavy oil production transportation and upgrading infrastructure;
- strong product niche in the areas of quality products such as our ethanol enhanced – Mother Nature's Fuel, Diesel Max, Chevron lubricants and our Black Max polymer modified asphalt;
- full retail network provides for substantial opportunities for ancillary non-fuel income streams, including convenience stores, restaurants, service bays and carwashes; and
- modern retail technology, with a proven new Husky Market design concept.

3.4 CORPORATE

Our corporate capabilities are discussed in the following sections:

- Section 8.0 Liquidity and Capital Resources
- Section 11.5 Controls and Procedures

4.0 Strategic Plan

Our upstream strategy is to continue exploiting our oil and gas asset base in the Western Canadian Sedimentary Basin while expanding into large scale sustainable areas including the Alberta oil sands, northern basins, Canada's East Coast, offshore Greenland and highly prospective basins offshore Southeast Asia.

Building on our proven track record of creating value through the integrated production to refined products value chain, we will grow our midstream and downstream throughput capacity to enhance our integration strategy. In the global energy business environment and volatile commodity prices, we must focus on our financial discipline in order to successfully maintain this strategy.

Our current strategic direction by business segments is as follows:

4.1 UPSTREAM

- continue the development of our large holdings in the Alberta oil sands through in-situ recovery methods such as SAGD and other thermal recovery schemes;
- in Western Canada focus on natural gas exploration in the foothills and deep basin, and tight gas and coalbed methane in the plains region. Increase recovery from mature fields through enhanced recovery techniques. Explore in the central Mackenzie region of the Northwest Territories;
- optimize heavy oil production through cold production, thermal recovery techniques and other enhanced recovery techniques;
- maximize the value of the White Rose asset through the development of satellite tieback oil pools. Participate in the continuing development of Terra Nova. Pursue exploration opportunities and evaluate options to develop natural gas discoveries in the region;
- optimize production from the Wenchang oil field offshore China by pursuing infill and optimization opportunities;
- delineate the Liwan discovery offshore China and continue exploration in the surrounding area to complete the evaluation of Block 29/26. Continue exploration of our extensive acreage position offshore China and advance development options for Liwan discovery;
- advance the development of the Madura field offshore Indonesia and continue exploration on the Madura and East Bawean II production sharing contracts; and
- explore offshore Greenland, leveraging the experience we have gained off the East Coast of Canada.

4.2 MIDSTREAM

- continue to enhance and expand our infrastructure in the Lloydminster area and optimize the integration of the upgrader, pipeline, asphalt refinery, cogeneration and ethanol facilities;
- further expand the Company's natural gas business;
- enhance and expand our terminalling infrastructure and services to meet the requirements associated with growing bitumen and heavy oil development;
- position the Company with greenhouse gas management strategies including participation in industry initiatives, carbon offset opportunities and identification of carbon credit and trading opportunities; and
- identify and pursue logistics opportunities to meet the requirements associated with the Sunrise development and downstream initiatives.

4.3 DOWNSTREAM

- look at opportunities to expand asphalt production in Lloydminster;
- optimize synergies by integrating Lloydminster asphalt refinery outputs with that of the upgrader creating new refined products;
- maximize revenues by producing ethanol efficiently and effectively and marketing it profitably;
- construction of strategically located new outlets, enhancement of nonfuel income streams, upgrading of existing petroleum outlets and the sale of nonperforming locations;
- modernize, automate and upgrade existing petroleum outlets and technology used in operations;
- pursue mergers, joint venture or form partnerships in the light oil business outside of Western Canada;
- reconfigure and expand the Lima, Ohio refinery to improve operations and profitability by processing heavier crudes and bitumen blends; and
- reconfigure and expand the Toledo, Ohio refinery to accommodate Sunrise production as its primary feedstock.

4.4 FINANCIAL OBJECTIVE

Our financial objective is to maintain a strong financial position providing us with the ability to undertake large capital growth projects and providing shareholders with a strong regular return on their investment.

Over the business cycle we intend to:

- maintain debt to capitalization ratio of less than 40%; and
- maintain debt to cash flow from operations of less than two times.

5.0 Key Performance Drivers

To achieve the corporate strategic objectives and provide our shareholders with a good return on investment, we need to capture opportunities that will drive corporate performance and increase our position to capture future opportunities. During 2007, key performance drivers that emerged or were advanced are noted below:

5.1 ACROSS SEGMENTS

Integrated Oil Sands Joint Development

On December 5, 2007, Husky announced a joint venture with BP to create an integrated oil sands business. The development consists of a 50/50 partnership to develop the Sunrise oil sands project in the Athabasca oil sands deposit, which Husky will operate and the formation of a 50/50 limited liability company for the existing Toledo, Ohio BP refinery, which BP will operate. These transactions are expected to be completed by the end of March 2008. The development of the Sunrise oil sands project is expected to proceed in three phases. The first phase will result in a productive capacity of 60 mbbls/day of bitumen by 2012 and the second and third phases are targeted to increase the productive capacity to approximately 200 mbbls/day of bitumen by 2015 to 2020. The Toledo refinery is expected to be modified by 2015 to process approximately 120 mbbls/day of bitumen feedstock (diluted as required for transportation purposes) matching the first two phases of the Sunrise oil sands development.

5.2 UPSTREAM

White Rose Development and Delineation

The White Rose oil field received approval on April 2, 2007 to increase annual production to 50 mmbbls from 36.5 mmbbls. The maximum daily production is increased to 140 mbbls/day, up from 100 mbbls/day. We completed the seventh production well in July 2007, which increased White Rose productive capacity to approximately 140 mbbls/day. With the completion of the second gas injection well in September 2007, the original development plan for the South Avalon portion of the White Rose oil field is complete.

At year-end, the North Amethyst front-end engineering design was complete, the glory hole to accommodate the subsea facilities was complete, a drilling rig had been secured and procurement of long lead equipment was underway. The development application has been submitted for approval by the Canada – Newfoundland and Labrador Offshore Petroleum Board ("CNLOPB") and the provincial government. West White Rose delineation results are being analyzed. The South White Rose extension development plan was approved by the federal and provincial governments.

East Coast Exploration

The acquisition of 3-D seismic covering 2,500 square kilometres is commencing in 2008.

Tucker Oil Sands Project

Tucker production ramp up has been slower than anticipated largely due to the position of some wells relative to the water saturation zone of the reservoir. While optimization strategies are continuing on the existing well pads, the drilling of eight new well pairs on Pad C is complete and a new D pad with well pairs placed in an optimized position in the reservoir has been planned.

Sunrise Oil Sands Project

The front-end engineering design for the Sunrise project was essentially completed. Discussions with regulatory authorities for the development application and the Sunrise project corporate sanction are expected to be in 2008.

Caribou

The front-end engineering design has been finalized for the 10 mbbls/day demonstration project and additional technical work is ongoing. Discussions with regulatory authorities are expected to continue in 2008.

Saleski

The winter drilling program has been reduced from 12 to 6 wells. We are continuing to work on reservoir characterization and various recovery processes.

McMullen Oil Sands Acquisition

In December 2007, an agreement was executed to purchase 110,000 contiguous acres of oil sands leases at McMullen, located in the west central Athabasca oil sands deposit, for $105 million. We have a 100% working interest in these oil sands leases. This land lies adjacent to oil sands leases that we currently hold.

Northwest Territories Exploration

Drilling on the Exploration License ("EL") 423 in the Central Mackenzie Valley is planned for the first half of 2008. EL 423 is located approximately 60 kilometres southeast of the Summit Creek B-44 and the Stewart Creek D-57 discovery wells. The Dahadinni B-20 well and the Keele River L-52 well commenced drilling in February 2008. We hold a 75% working interest in this play.

China Exploration

The acquisition of seismic over Block 29/26 in the South China Sea, including the Liwan natural gas discovery was completed. Delineation of the Liwan area is expected to commence in the second half of 2008 upon the arrival of the West Hercules deep water drilling rig, which is currently being constructed in South Korea.

Three exploration wells are planned to be drilled in the shallow waters of the South and East China seas. The first well is expected to spud in the first half of 2008 on Block 23/15 in the Beibu Wan Basin of the South China Sea north of Hainan Island. The second well is expected to spud on Block 39/05 southwest of the Wenchang oil field in the South China Sea before the end of 2008.

Indonesia Exploration and Development

In October 2007, we concluded natural gas sales agreements of 100 mmcf/day from our Madura BD field, offshore Indonesia. The contracts have a term of 20 years, which commences with first production anticipated in 2011. The development plan and production sharing licence extension were submitted to BPMIGAS and MIGAS, the Indonesian regulatory authorities, for approval. Front-end engineering design will commence once regulatory approvals have been received. On the East Bawean II block we completed the acquisition of 1,400 square kilometres of 3-D seismic data.

Land Acquisition Offshore Greenland

During June 2007, we were awarded two exploration licences, Block 5 and Block 7 that cover a combined 21,067 square kilometres. We have an 87.5% working interest in each block and will be the operator. During October 2007, we were awarded a joint working interest in a third exploration licence, Block 6 that covers 13,213 square kilometres. We have a 43.75% non-operated working interest in this licence.

Our work programs for 2008 have been finalized and consist of the acquisition of 3,000 kilometres of 2-D seismic over Block 6 and 7,000 kilometres over blocks 5 and 7. Acquisition of the remainder of the hi-resolution aero-gravity and magnetic survey is expected to be completed in the second quarter of 2008.

5.3 MIDSTREAM

Lloydminster Pipeline

The Lloydminster to Hardisty, Alberta pipeline expansion project phase one is complete and operational. With the exception of an 11 kilometre section in and around the City of Lloydminster, phase two is complete and operational.

Lloydminster Upgrader Expansion

The expansion of the Lloydminster upgrader from 82 to 150 mbbls/day has been deferred after a review of our options for processing heavy oil following the acquisition of the Lima refinery. The Lloydminster expansion remains an option for the future.

5.4 DOWNSTREAM

Acquisition of the Lima Refinery in Ohio

The acquisition of the Lima refinery was completed on July 3, 2007, for a purchase price of U.S. $1.9 billion plus U.S. $540 million for the cost of feedstock and product inventory. The acquisition was effective July 1, 2007. The Lima refinery has an atmospheric crude oil distillation capacity of 160 mbbls/day. The refinery currently processes a light sweet crude oil feedstock slate and produces gasoline and gasoline blendstocks, diesel, jet fuel, petrochemical feedstocks, petroleum coke and other byproducts. The refinery is serviced by both feedstock and product pipelines and production is primarily marketed in the Ohio, Illinois, Indiana and southern Michigan markets.

An engineering evaluation is underway to reconfigure the Lima refinery to increase its capacity to process heavy oil and bitumen blend feedstocks.

The acquisition of a 50% interest in the BP Toledo refinery was announced in December 2007 with an effective date of January 1, 2008. The refinery has the capacity to process 150 mbbls/day of crude oil including 60 mbbls/day of blended heavy sour crude.

Ethanol

In early December 2007, production commenced at the Minnedosa, Manitoba ethanol plant. With a design capacity rate of 130 million litres of ethanol per year, the plant will provide ethanol blending feedstock for the emerging market for ethanol blended gasoline.

5.5 CORPORATE

In September 2007, a public debt offering was completed in the United States that consisted of U.S. $300 million of 6.2% notes due on September 15, 2017 and U.S. $450 million of 6.8% notes due September 15, 2037. These notes rank on par with our other unsecured long-term debt. The net proceeds of the offering were used to repay part of the short-term bridge financing used to acquire the Lima refinery.

6.0 The 2007 Business Environment

6.1 RISK FACTORS

Results are significantly influenced by the global and domestic business environment. Some risk factors are entirely beyond our influence and others can, to some extent, be strategically managed. Salient risk factors include:

- crude oil and natural gas prices;
- the price differential between light and heavy crude oil and demand related to various crude oil qualities;
- the price differential between refined products and crude oil (Crack Spread);
- the availability of incremental reserves of oil and gas, whether sourced from exploration, improved recovery or acquisitions;
- the availability of prospective drilling rights;
- the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project development;
- the availability and cost of labour, material and equipment to efficiently, effectively and safely undertake capital projects;
- the costs to operate properties, plants and equipment in an efficient, reliable and safe manner;
- potential actions of governments, regulatory authorities and other stakeholders in the jurisdictions where we have operations;
- prevailing climatic conditions in our operating locations;
- the economic conditions of the markets in which we conduct business;
- regulations to deal with climate change issues;
- changes to government fiscal policies;
- the exchange rate between the Canadian and U.S. dollar;
- changes in workforce demographics; and
- the cost of capital.

6.2 COMMODITY PRICES AND MARGINS

Average Benchmarks

		2007	2006	2005
Upstream				
WTI crude oil	*(U.S. $/bbl)*	**72.31**	66.22	56.56
Brent crude oil	*(U.S. $/bbl)*	**72.52**	65.14	54.38
Canadian light crude 0.3% sulphur	*($/bbl)*	**77.07**	73.29	69.28
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**40.75**	39.92	31.07
NYMEX natural gas	*(U.S. $/mmbtu)*	**6.86**	7.23	8.62
NIT natural gas	*($/GJ)*	**6.26**	6.62	8.04
Midstream heavy crude oil upgrading				
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**23.81**	22.00	21.01
Downstream				
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**14.15**	9.80	9.50
Cross segment				
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.931**	0.882	0.826

As an integrated producer, profitability is largely determined by realized prices for crude oil and natural gas and refinery processing margins including the effect of change in the U.S./Canadian dollar exchange rate. All of our crude oil production and the majority of our natural gas production receive the prevailing market price. The price for crude oil is determined largely by global factors and is beyond our control. The price for natural gas is determined more by the North America fundamentals since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. Weather conditions will also exert a dramatic effect on short-term supply and demand.

The effect of a U.S. $1/bbl increase in the average price of WTI in 2007 would have resulted in an increase in upstream pre-tax cash flow of approximately $92 million and an increase in upstream earnings of $63 million. In contrast, if the Canadian dollar strengthened by U.S. $0.01, the reduction in 2007 cash flow and net earnings would have been approximately $72 million and $52 million, respectively.

In midstream and downstream, the price of crude oil represents the largest cost and the price of natural gas is one of the most significant operating costs. The largest cost factor in the midstream – upgrading business segment is the price of heavy crude oil feedstock, which is processed into light synthetic crude oil. The largest cost factors in the downstream sector are the crude feedstock and processing costs. Our Lima refining operations process a mix of different types of crude oil from various sources but are primarily light sweet crude oil. Our refined products business in Canada relies primarily on the cost of purchasing refined products for resale in our retail distribution network. The refined products are acquired from other Canadian refiners at rack prices or exchanged with production from our Prince George refinery.

Refining margins (Crack Spread) are calculated as the price difference between crude oil feedstock and two or more refined products in different proportions. The New York Harbor 3:2:1 Crack Spread is a benchmark and is calculated as the difference between the price of a barrel of WTI crude oil and the sum of the price of two thirds of a barrel of reformulated gasoline and the price of one third of a barrel of heating oil. Each refinery has a unique crack spread depending on several variables. The mix of different grades of crude oil feedstock and the mix of refined products produced result in different refinery crack spread calculations.

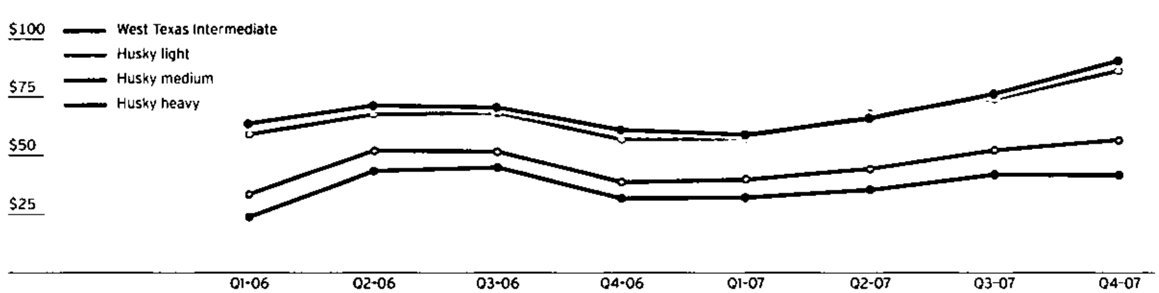
During the last few years, the world supply and demand balance for hydrocarbons has been edging toward higher demand and as a result prices have increased. Global economic growth is expected to continue with China and India leading the way. Higher prices have stimulated international efforts to increase production. Any reduction in global demand could set the stage for price declines.

Heavier grades of crude oil trade at a discount to light crude oil refinery feedstock since they are more costly to process into motor fuels.

The majority of our crude oil and natural gas production is marketed in North America.

Crude Oil

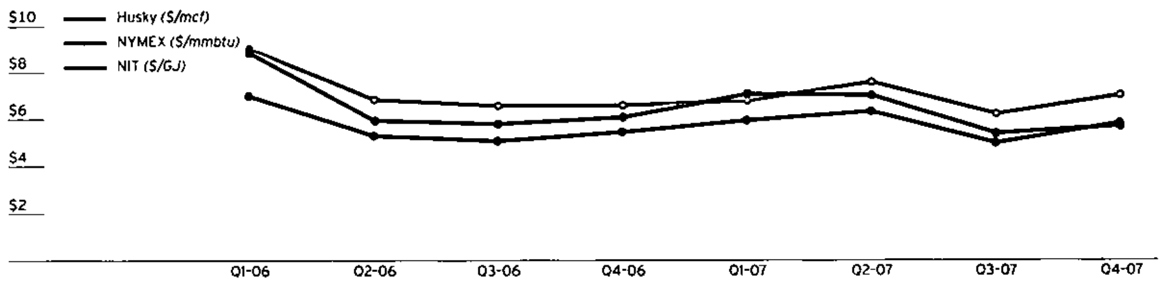
WTI and Husky Average Crude Oil Prices (US$/bbl)



In 2007, the price of the main benchmark crude oil, West Texas Intermediate ("WTI"), initially declined in the first quarter of 2007, recovered by the end of the first quarter and increased steadily through to the end of July 2007. Except for slight volatility the price of both WTI and Brent increased through the remainder of the third quarter and fourth quarter of 2007, with WTI reaching spot prices just short of U.S. $100/bbl in November. The supply/demand fundamentals supporting crude oil prices did not weaken in 2007. High prices did not result in demand abatement in the United States, the largest crude oil consumer, nor in the high growth emerging economies in Southeast Asia and India. Supply has been affected by OPEC adhering to their production quotas, lower OPEC spare productive capacity, limited refining capacity for heavy crude oil and ongoing geopolitical risk.

Natural Gas

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices (US$)



Natural gas inventories were above five year averages and climatic conditions in North America were generally moderate during both the 2007 heating and cooling seasons. These soft market conditions led Husky and other natural gas producers to reallocate capital from natural gas to other areas.

6.3 SENSITIVITIES BY SEGMENT FOR 2007 RESULTS

The following table is indicative of the relative annualized effect on pre-tax cash flow and net earnings from changes in certain key variables in 2007. In essence, the disclosure shows what the effect would have been on 2007 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2007. 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

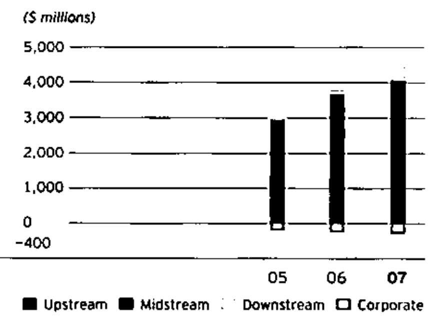
	2007 Average	Increase	Effect on Pre-tax Cash Flow (6)		Effect on Net Earnings (6)	
			($ millions)	*($/share)* (7)	*($ millions)*	*($/share)* (7)
Upstream and Midstream						
WTI benchmark crude oil price	$ 72.31	*U.S. $1.00/bbl*	92	0.11	63	0.07
NYMEX benchmark natural gas price (1)	$ 6.86	*U.S. $0.20/mmbtu*	33	0.04	23	0.03
WTI/Lloyd crude blend differential (2)	$ 23.81	*U.S. $1.00/bbl*	(30)	(0.04)	(21)	(0.02)
Exchange rate *(U.S. $ per Cdn $)* (3)	$ 0.931	*U.S. $0.01*	(72)	(0.08)	(52)	(0.06)
Downstream						
Light oil margins	$ 0.05	*Cdn $0.005/litre*	16	0.02	10	0.01
Asphalt margins	$ 18.24	*Cdn $1.00/bbl*	8	0.01	5	0.01
New York Harbor 3:2:1 crack spread (4)	$ 14.15	*U.S. $1.00/bbl*	24	0.03	15	0.02
Consolidated						
Year-end translation of U.S. $ debt *(U.S. $ per Cdn $)*	$1.012 (5)	*U.S. $0.01*			18	0.02

(1) Includes decrease in earnings related to natural gas consumption.
(2) Includes impact of upstream and midstream upgrading operations only.
(3) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items.
(4) The stated effect has been limited to the 6 month period from July 1, 2007, the effective acquisition date of the Lima refinery.
(5) U.S./Canadian dollar exchange rate at December 31, 2007.
(6) Excludes derivatives.
(7) Based on 849.0 million common shares outstanding as of December 31, 2007.

7.0 Results of Operations

The earnings of our upstream businesses correlate largely with the prevailing prices for the various grades of crude oil produced and the prices prevailing in the various North American markets for natural gas and natural gas liquids followed by the volume of those commodities that we produce and sell. The earnings of our midstream segment continues the economic value chain through logistics, upgrading, storage, pipeline, processing and marketing. The downstream businesses include refining crude oil into useable products such as transportation fuels, petrochemical feedstocks and road construction materials and marketing them to the end user.

Contribution to Earnings before Taxes by Industry Sector



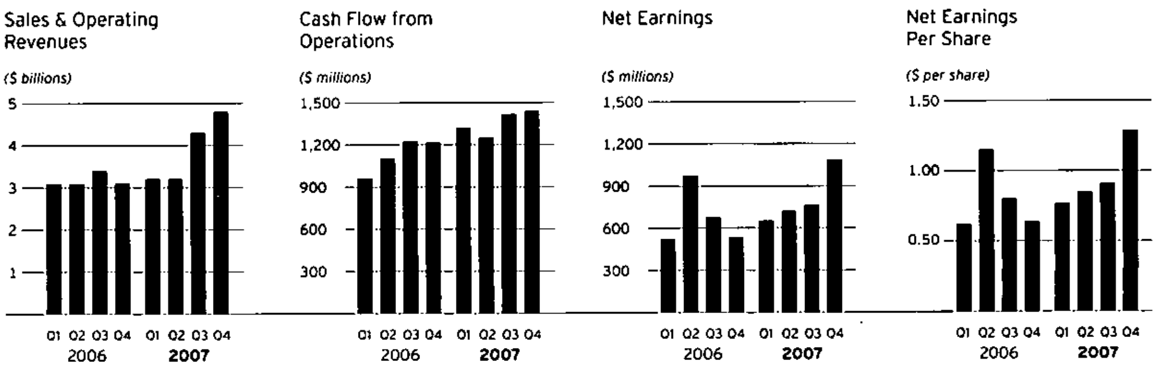
7.1 SEGMENT EARNINGS

Segment Earnings

($ millions)	Upstream	Midstream: Upgrading	Midstream: Infrastructure and Marketing	Downstream: Canadian Refined Products	Downstream: U.S. Refining and Marketing	Corporate and Eliminations	Total
2007							
Earnings (loss) before income taxes	$ 3,299	$ 372	$ 351	$ 242	$ 168	$ (305)	$ 4,127
Net earnings (loss)	2,596	282	253	192	105	(214)	3,214
Capital expenditures [1]	2,388	217	92	212	21	44	2,974
2006							
Earnings (loss) before income taxes	2,975	382	277	146	-	(274)	3,506
Net earnings (loss)	2,295	285	197	106	-	(157)	2,726
Capital expenditures [1]	2,627	184	68	285	-	37	3,201
2005							
Earnings (loss) before income taxes	2,173	449	278	129	-	(217)	2,812
Net earnings (loss)	1,524	313	182	82	-	(98)	2,003
Capital expenditures [1]	2,730	120	37	191	-	21	3,099

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

7.2 SUMMARY OF QUARTERLY RESULTS



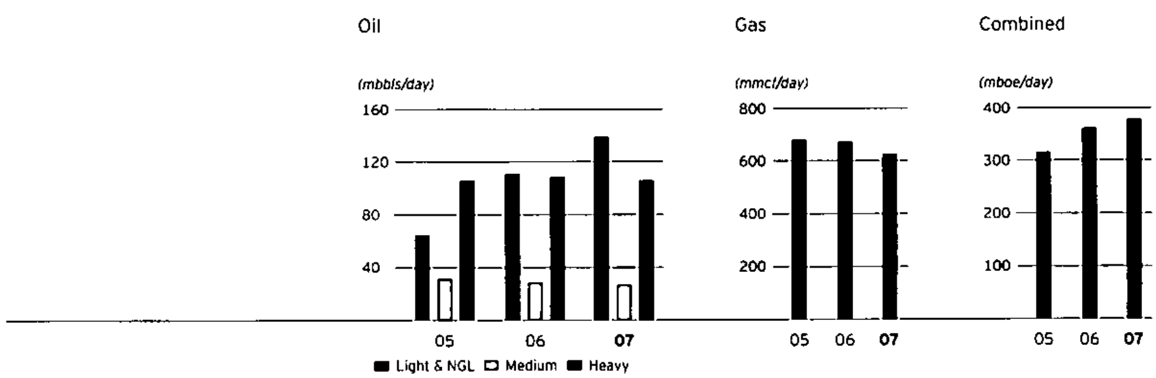
7.3 FOURTH QUARTER

Consolidated net earnings during the fourth quarter of 2007, were $1,074 million, an increase of $532 million or 98% compared with the fourth quarter of 2006. During the fourth quarter of 2007, we recorded a tax benefit of $365 million that resulted from the substantive enactment of Bill C-28 on December 13, 2007. Bill C-28 contains various measures including corporate tax rate reductions. Aside from the non-recurring tax benefit, pre-tax earnings increased by $295 million or 38% in the fourth quarter of 2007 compared with the same period in 2006. Stronger upstream earnings in the fourth quarter of 2007 were due largely to higher crude oil prices, which averaged the highest levels of all eight quarters. Higher pre-tax earnings from the upgrading operations were due to wider average upgrading differentials and higher sales volume. The upgrader operated closer to its capacity during the fourth quarter of 2007 after a second quarter turnaround of 49 days and some additional outages during the third quarter. Downstream pre-tax earnings were higher in the fourth quarter of 2007 because of the 2007 acquisition of the Lima, Ohio refinery. The refinery's results of operations have been included from the effective date of the acquisition, July 1, 2007.

7.4 UPSTREAM

2007 Earnings $2,596 Million, up $301 Million from 2006

Production



Upstream Results of Operations

Upstream Earnings Summary

($ millions)	**2007**	2006	2005
Gross revenues	**$ 7,287**	$ 6,586	$ 5,207
Royalties	**1,065**	814	840
Net revenues	**6,222**	5,772	4,367
Operating and administration expenses	**1,409**	1,321	1,050
Depletion, depreciation and amortization	**1,615**	1,476	1,144
Other [1]	**(101)**	-	-
Income taxes	**703**	680	649
Earnings	**$ 2,596**	$ 2,295	$ 1,524

(1) Embedded derivative described below.

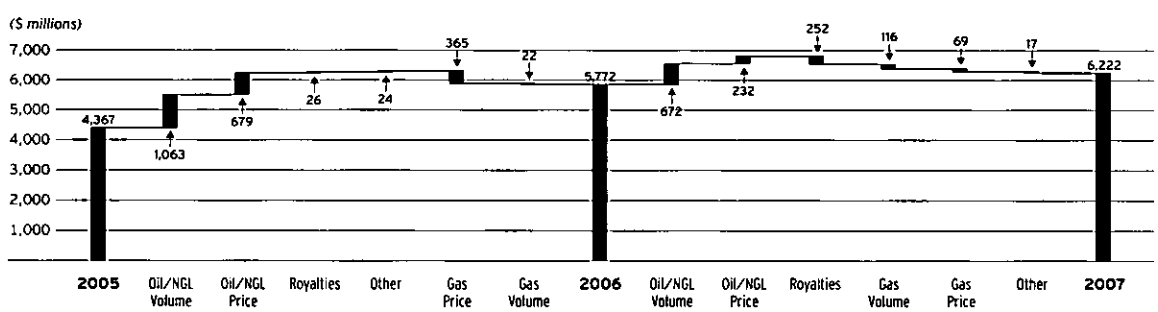
Revenue

Upstream earnings were $301 million higher in 2007 than in 2006 primarily as a result of increased production of light crude oil from the White Rose and Terra Nova oil fields off the East Coast of Canada. Upstream earnings during 2007 were also increased by higher crude oil prices. Upstream earnings were negatively affected by higher royalties on the East Coast production, lower natural gas prices and natural gas production.

Overall crude oil and NGL production increased by 10% in 2007 compared with 2006, White Rose and Terra Nova increased by 45%, Wenchang by 5% partly offset by a 4% decline of crude oil and NGL production from our Western Canada properties. During 2007, White Rose ramped up to a field capacity of 140 mbbls/stream day (102 mbbls/day Husky's interest) after the completion of the seventh and final production well of the development plan for the South Avalon portion of the White Rose field. Terra Nova returned to full operation in 2007 after a protracted turnaround and major modification of the FPSO in 2006. In Western Canada the ramping up of the Tucker oil sands production lagged as previously described in Section 5.0. Conventional heavy oil was marginally lower compared with 2006 due to facility issues and some underperforming wells drilled in 2006, partially offset by good results from the well recompletion and optimization program. Conventional light and medium crude oil production was affected by net divestitures and normal production declines.

Natural gas production decreased in 2007 by 7% compared with 2006 primarily as a result of the reallocation of capital spending for natural gas drilling and tie-ins to other portfolio uses in the low natural gas price and higher cost environment. Other contributing factors included land access and well tie-in delays, divestitures of non-core properties and reservoir depletion.

Net Revenue Variance Analysis



Operating Costs

Total upstream operating costs averaged $9.09/boe in 2007 compared with $8.77/boe in 2006.

Operating costs in Western Canada conventional averaged $10.93/boe in 2007 compared with $9.79/boe in 2006. Increasing operating costs in Western Canada are related to the nature of exploitation necessary to manage production from maturing fields and new more extensive but less prolific reservoirs. Western Canada operations require increasing amounts of infrastructure including more wells, more extensive pipeline systems, increased water handling and increased use of larger and more extensive natural gas compression systems. In addition, higher levels of industry activity lead to competition for resources and higher service rates and unit costs.

Operating costs at the East Coast offshore operations averaged $4.07/bbl in 2007 compared with $5.48/bbl in 2006. Unit operating costs decreased as a result of lower unit operating costs at White Rose, which benefited by higher production and reliable performance, and Terra Nova which returned to normal production levels following an extended turnaround in 2006.

Operating costs at the South China Sea offshore operations averaged $3.68/bbl compared with $3.61/bbl in 2006.

Depletion, Depreciation and Amortization ("DD&A")

DD&A under the full cost method of accounting for oil and gas activities is calculated on a country-by-country basis. The DD&A rate is calculated by dividing the capital costs subject to DD&A by the proved oil and gas reserves expressed as equivalent barrels ("boe"). The resultant dollar per boe is assigned to each boe of production to determine the DD&A expense for the period.

Total DD&A averaged $11.75/boe in 2007 compared with $11.24/boe in 2006.

DD&A in Canada averaged $11.77/boe in 2007 compared with $11.24/boe in 2006. The increase in DD&A results primarily from a higher capital base. The higher capital base is due to added infrastructure in Western Canada and large capital investments required to develop reserves off the East Coast of Canada.

At December 31, 2007, capital costs in respect of unproved properties and major development projects were $2.2 billion compared with $2.1 billion at the end of 2006. These costs are excluded from our DD&A calculation until the unproved properties are evaluated and proved reserves are attributed to the project or the project is deemed to be impaired.

Embedded Derivative

During 2007, a $101 million gain was recorded on an embedded derivative related to a contract requiring payment in U.S. currency. The payments are expected to occur over the three-year period from mid-2008. This amount will fluctuate with the U.S./Cdn forward exchange rate until the actual contract settlement.

Average Sales Prices

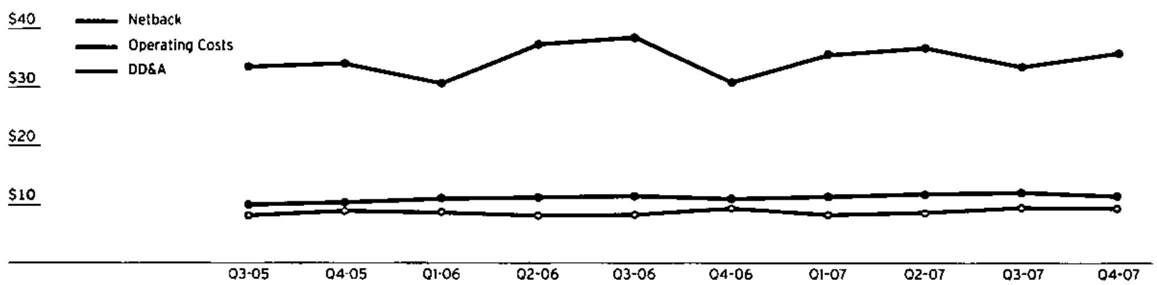
	2007	2006	2005
Crude oil *($/bbl)*			
Light crude oil & NGL	**$ 73.54**	$ 69.06	$ 61.56
Medium crude oil	**51.12**	49.48	43.44
Heavy crude oil & bitumen	**40.19**	39.92	31.09
Total average	**58.24**	54.08	42.75
Natural gas *($/mcf)*			
Average	**$ 6.19**	$ 6.47	$ 7.96

Upstream Revenue Mix

Percentage of upstream net revenues	**2007**	2006	2005
Crude oil			
Light crude oil & NGL	**51%**	45%	29%
Medium crude oil	**7%**	7%	9%
Heavy crude oil & bitumen	**22%**	24%	24%
Natural gas	**20%**	24%	38%
	100%	100%	100%

Netback, Unit Operating Costs and DD&A

($/boe)



Netbacks

	2007		2006		2005	
	$	% (1)	$	% (1)	$	% (1)
Total						
Crude oil equivalent *(per boe)* (2)						
Gross price	**52.41**		49.34		44.69	
Royalties	**7.74**	**15**	6.19	12	7.29	17
Net sales price	**44.67**		43.15		37.40	
Operating costs (3)	**9.09**	**17**	8.77	18	8.12	18
	35.58		34.38		29.28	
DD&A	**11.75**	**22**	11.24	23	9.95	22
Administration expenses & other (3)	**(0.17)**	**-**	0.48	1	0.20	-
Earnings before income taxes	**24.00**	**46**	22.66	46	19.13	43
Canada						
Crude oil equivalent *(per boe)* (2)						
Gross price	**51.54**		48.48		43.69	
Royalties	**7.46**	**14**	6.00	12	7.36	17
Net sales price	**44.08**		42.48		36.33	
Operating costs (3)	**9.28**	**18**	9.01	19	8.39	19
Operating netback	**34.80**		33.47		27.94	
Western Canada						
Crude oil *(per boe)* (2)						
Light crude oil						
Gross price	**61.02**		59.84		60.64	
Royalties	**7.87**	**13**	7.34	12	8.66	14
Net sales price	**53.15**		52.50		51.98	
Operating costs (3)	**13.24**	**22**	11.89	20	9.86	16
Operating netback	**39.91**		40.61		42.12	
Medium crude oil						
Gross price	**50.42**		48.97		43.67	
Royalties	**8.89**	**18**	8.61	18	7.77	18
Net sales price	**41.53**		40.36		35.90	
Operating costs (3)	**13.92**	**28**	13.09	27	10.97	25
Operating netback	**27.61**		27.27		24.93	
Heavy crude oil & bitumen						
Gross price	**40.14**		39.91		31.22	
Royalties	**5.26**	**13**	5.16	13	3.75	12
Net sales price	**34.88**		34.75		27.47	
Operating costs (3)	**12.81**	**32**	11.10	28	9.90	32
Operating netback	**22.07**		23.65		17.57	
Natural gas *(per mcfge)* (4)						
Gross price	**6.42**		6.65		8.02	
Royalties	**1.23**	**19**	1.37	21	1.76	22
Net sales price	**5.19**		5.28		6.26	
Operating costs (3)	**1.39**	**22**	1.18	18	1.04	13
Operating netback	**3.80**		4.10		5.22	
East Coast						
Light crude oil *(per boe)* (2)						
Gross price	**75.37**		71.18		62.61	
Royalties (5)	**9.43**	**13**	1.95	3	5.91	9
Net sales price	**65.94**		69.23		56.70	
Operating costs (3)	**4.07**	**5**	5.48	8	5.14	8
Operating netback	**61.87**		63.75		51.56	
International						
Light crude oil *(per boe)* (2)						
Gross price	**77.07**		73.60		63.15	
Royalties	**15.50**	**20**	12.17	17	5.93	9
Net sales price	**61.57**		61.43		57.22	
Operating costs (3)	**3.84**	**5**	3.81	5	2.92	5
Operating netback	**57.73**		57.62		54.30	

(1) Percent of gross price.
(2) Includes associated co-products converted to boe.
(3) Operating costs exclude accretion, which is included in administration expenses & other.
(4) Includes associated co-products converted to mcfge.
(5) During the third quarter of 2007, White Rose royalties increased to 16% because the project, off the East Coast, achieved payout status for Tier 1 royalties.

Daily Gross Production

		2007	2006	2005
Crude oil	*(mbbls/day)*			
Western Canada				
Light crude oil & NGL		**26.5**	30.4	31.4
Medium crude oil		**27.1**	28.5	31.1
Heavy crude oil & bitumen		**106.9**	108.1	106.0
		160.5	167.0	168.5
East Coast Canada				
White Rose – light crude oil		**85.0**	63.8	4.8
Terra Nova – light crude oil		**14.5**	4.7	12.4
China				
Wenchang – light crude oil & NGL		**12.7**	12.1	16.0
		272.7	247.6	201.7
Natural gas	*(mmcf/day)*	**623.3**	672.3	680.0
Total	*(mboe/day)*	**376.6**	359.7	315.0

2008 Production Guidance

Gross Production

		Guidance 2008	Year ended December 31 2007	Original Guidance 2007
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		139 – 148	**139**	128 – 135
Medium crude oil		28 – 29	**27**	28 – 30
Heavy crude oil & bitumen		114 – 124	**107**	122 – 130
		281 – 301	**273**	278 – 295
Natural gas	*(mmcf/day)*	625 – 655	**623**	670 – 690
Total barrels of oil equivalent	*(mboe/day)*	385 – 410	**377**	390 – 410

Upstream Capital Expenditure (1)

($ millions)	2007	2006	2005
Exploration			
Western Canada	**$ 456**	$ 497	$ 389
East Coast Canada and Frontier	**84**	79	66
International	**70**	77	55
	610	653	510
Development			
Western Canada	**1,575**	1,675	1,618
East Coast Canada	**197**	279	579
International	**6**	20	23
	1,778	1,974	2,220
	$ 2,388	$ 2,627	$ 2,730

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

Western Canada Drilling

(wells)		2007 Gross	2007 Net	2006 Gross	2006 Net	2005 Gross	2005 Net
Exploration	Oil	**79**	**79**	101	99	89	85
	Gas	**114**	**92**	330	192	392	196
	Dry	**14**	**12**	26	24	36	36
		207	**183**	457	315	517	317
Development	Oil	**571**	**530**	590	543	466	433
	Gas	**343**	**251**	565	490	610	551
	Dry	**31**	**29**	25	22	42	39
		945	**810**	1,180	1,055	1,118	1,023
Total		**1,152**	**993**	1,637	1,370	1,635	1,340

Upstream Capital Expenditure – Canada

In 2007, upstream capital spending in Canada amounted to $2,312 million, down from $2,530 million in 2006. Capital spending in 2007 comprised $1,236 million on Western Canada conventional areas ($1,443 million in 2006), $549 million in the Lloydminster heavy oil region ($453 million in 2006), $246 million in the Alberta oil sands regions ($276 million in 2006), $267 million for East Coast development ($313 million in 2006) and $14 million for East Coast and Northwest Territories exploration ($45 million in 2006).

In 2007, spending on exploration activities comprised $158 million in the foothills and deep basin regions of Alberta and north east British Columbia, down $78 million from 2006. Our targets in these regions are predominantly deep natural gas reservoirs that tend to be higher risk but more prolific than elsewhere in the Western Canada Sedimentary Basin. Exploration in this region, which extends along the eastern slopes of the Rocky Mountains in Alberta and into northeastern British Columbia, involves drilling deep wells into higher pressure gas formations. In 2007, the number of natural gas wells drilled was reduced due to low natural gas prices and high costs.

In the Lloydminster heavy oil production region, capital spending was primarily for drilling, well and facility optimization and expansion of thermal operations. The 10 to 14 degree API heavy crude oil is produced by several methods including SAGD, cyclic steam and cold production techniques. Producing technology is constantly being developed and evolving once applied in the field.

Capital spending in the oil sands region was on the Tucker, Sunrise, Caribou and Saleski projects. Our Tucker SAGD oil sands project was commissioned in late 2006. We spent $99 million on the Tucker project in 2007 and expect to spend approximately $100 million in 2008 to increase production. At the Sunrise oil sands project we spent $87 million for front-end engineering design, the regulatory approval process and preliminary field work. Sunrise is expected to be developed in three phases as described in Section 5.0. At Caribou and Saleski approximately $60 million was spent on early stage drilling, facility studies, seismic and technical studies.

At White Rose, production continued to ramp up through 2007 with the drilling of the seventh production well and a second gas injection well. Delineation of several satellite reservoirs to the south, west and north of the South Avalon portion of the field progressed during 2007. Front-end engineering design for the North Amethyst satellite was completed.

Upstream Capital Expenditure – International

Exploration spending totalled $70 million in China and largely involved a seismic program over Block 29/26 covering a total of 3,300 square kilometres. The seismic program was 92% complete prior to being delayed by weather and will be completed in 2008. We also completed the interpretation of seismic data previously acquired over the Liwan natural gas discovery on Block 29/26. In addition, we acquired 1,400 square kilometres of seismic over the East Bawean II Block in the north east Java Basin.

2008 Upstream Capital Program

($ millions)

Western Canada – oil and gas	$ 1,670
– oil sands	300
East Coast Canada and Frontier	650
International	430
	$ 3,050

Note: Capital program excludes capitalized administration costs, capitalized interest and asset retirement obligations incurred.

Our 2008 capital program concentrates on medium and long-term project development and is 31% above our upstream 2007 capital program spending. Our strategy is to focus on growth and high return projects offshore the East Coast of Canada, China and Indonesia as well as advance the integrated bitumen development at Sunrise.

Given the current low gas price environment, capital expenditure for natural gas development will be allocated to higher return areas, particularly in enhanced oil recovery and in conventional and heavy oil development. Exploration programs in 2008 will include $170 million directed toward opportunities in British Columbia and shallow depth opportunities in Alberta.

We plan to spend $300 million, including $100 million at the Tucker oil sands development, and $160 million on the first phase of the Sunrise project.

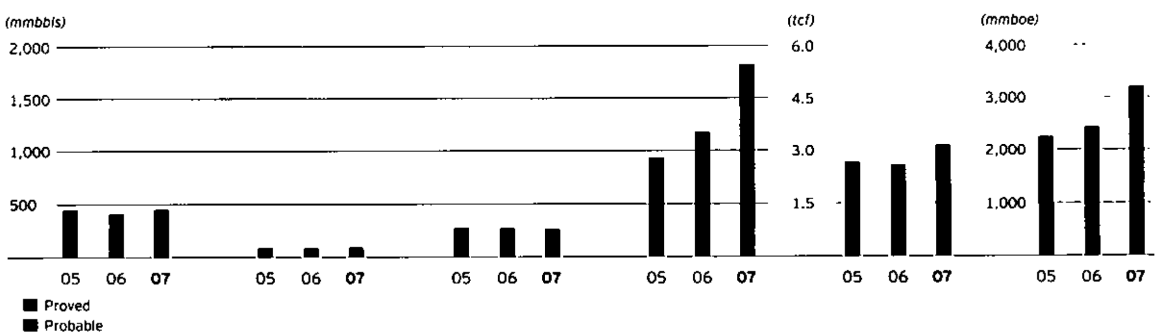
Off Canada's East Coast we plan to spend $425 million on the White Rose satellite tie-back project at North Amethyst and $120 million on the existing White Rose development. In the Central Mackenzie Valley of the Northwest Territories, Husky plans to drill two exploration wells.

Offshore China and Indonesia we plan to spend $430 million in 2008. Approximately $250 million will be spent on drilling, delineation and exploration of the Liwan discovery on Block 29/26 in the South China Sea commencing with delivery of the West Hercules drilling rig in mid-2008. The remainder of the capital program will be used for exploration in the South and East China Seas and development at the Madura BD field, offshore Indonesia. In addition, we plan to spend $40 million on seismic acquisition offshore Greenland.

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" and provides 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.

Oil and Gas Reserves

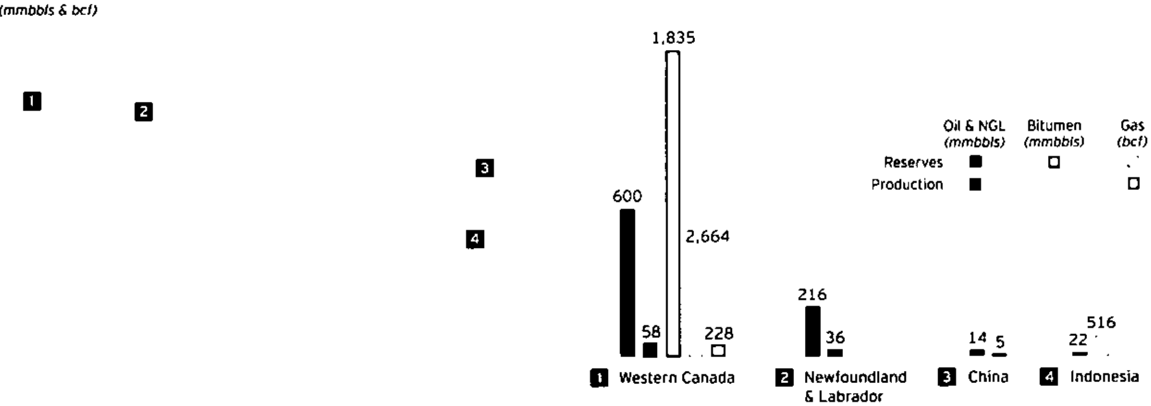


For more detail on our oil and gas reserves and the disclosures with respect to the FASB's Statement No. 69, "Disclosures about Oil and Gas Producing Activities" and the differences between our disclosures and those prescribed by National Instrument 51-101, refer to our Annual Information Form available at www.sedar.com or our Form 40-F available at www.sec.gov or on our website at www.huskyenergy.ca.

At December 31, 2007, the present value of future net cash flows after tax from Husky's proved oil and gas reserves, based on prices and costs in effect at year-end and discounted at 10%, was $14.8 billion compared with $10.1 billion at December 31, 2006.

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.

Oil & Gas Proved + Probable Reserves and Production
(mmbbls & bcf)



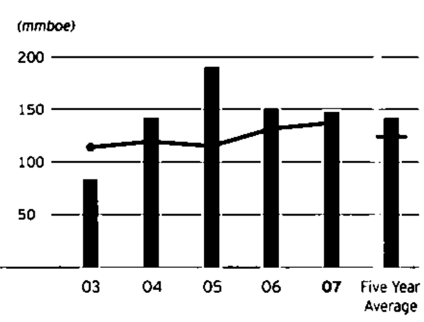
Reconciliation of Proved Reserves

	Canada						International		Total		
	Western Canada					East Coast					
(constant prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved reserves at											
December 31, 2006	166	87	213	60	2,143	107	14	–	647	2,143	1,004
Technical revisions	1	4	(8)	–	64	26	2	–	25	64	36
Purchase of reserves in place	1	–	–	–	36	–	–	–	1	36	7
Sale of reserves in place	(10)	–	–	–	(23)	–	–	–	(10)	(23)	(14)
Discoveries, extensions and improved recovery	10	7	38	11	199	19	–	–	85	199	118
Production	(9)	(10)	(38)	(1)	(228)	(36)	(5)	–	(99)	(228)	(137)
Proved reserves at December 31, 2007	**159**	**88**	**205**	**70**	**2,191**	**116**	**11**	**–**	**649**	**2,191**	**1,014**
Proved and probable reserves											
At December 31, 2007	**213**	**105**	**282**	**1,835**	**2,664**	**216**	**37**	**516**	**2,688**	**3,180**	**3,218**
At December 31, 2006	219	102	289	1,187	2,533	186	23	93	2,006	2,626	2,444

Reconciliation of Proved Developed Reserves

	Canada						Intn'l	Total		
	Western Canada					East Coast				
(constant prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil *(mmbbls)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves at										
December 31, 2006	147	79	135	47	1,703	97	13	518	1,703	802
Revision of previous estimate	3	9	16	1	180	33	3	65	180	95
Purchase of reserves in place	–	–	–	–	30	–	–	–	30	5
Sale of reserves in place	(9)	–	–	–	(22)	–	–	(9)	(22)	(13)
Improved recovery	4	2	11	–	117	–	–	17	117	36
Production	(9)	(10)	(38)	(1)	(228)	(36)	(5)	(99)	(228)	(137)
Proved developed reserves at December 31, 2007	**136**	**80**	**124**	**47**	**1,780**	**94**	**11**	**492**	**1,780**	**788**

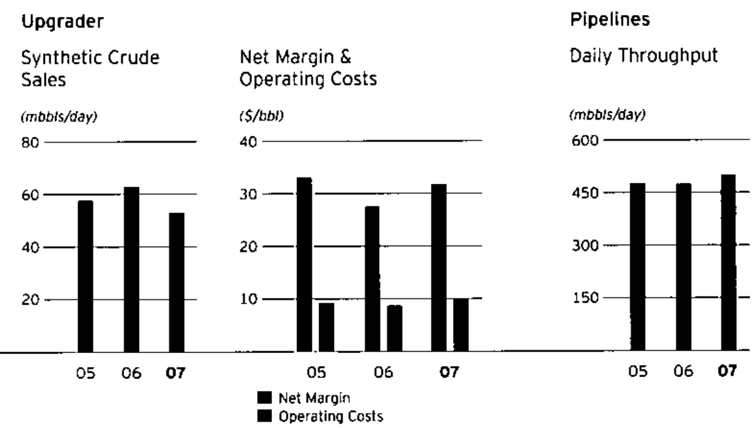
Reserves Replacement



7.5 MIDSTREAM

2007 Earnings $535 Million, up $53 Million from 2006

The midstream business is centered around the upgrading operations, which is a business that adds value to heavy crude oil by converting it to synthetic light crude oil. Unlike heavy crude oil, synthetic crude oil is a higher value feedstock for many refineries in Canada and the United States. During 2007 the price of our synthetic crude oil averaged $79.11/bbl compared with $48.38/bbl, the average price of blended heavy crude oil from the Lloydminster area. This resulted in an average synthetic/heavy crude differential of $30.73/bbl. After the cost of upgrading, which averaged $9.83/bbl, the margin of upgrading Lloydminster heavy crude was $20.90/bbl, up 19% over 2006. Profitability also depends on the level of production or throughput.



Upgrading Earnings Summary

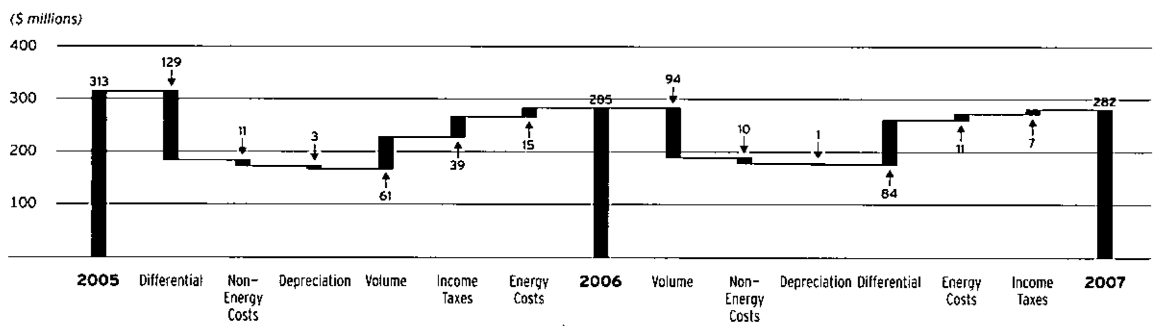
Upgrader throughput had lower capacity in 2007 due to a 49 day turnaround in the second quarter of 2007 and other minor outages during the year. In September 2007, a debottleneck project was completed that increased throughput capacity to 82 mbbls/stream day. The second phase of an on-stream reliability project is currently underway and is expected to be complete by the second quarter of 2008.

Upgrading Earnings Summary

($ millions, except where indicated)		**2007**	2006	2005
Gross margin		**$ 614**	$ 624	$ 692
Operating costs		**221**	224	228
Other recoveries		**(4)**	(6)	(6)
Depreciation and amortization		**25**	24	21
Income taxes		**90**	97	136
Earnings		**$ 282**	$ 285	$ 313
Upgrader throughput (1)	*(mbbls/day)*	**61.4**	71.0	66.6
Synthetic crude oil sales	*(mbbls/day)*	**53.1**	62.5	57.5
Upgrading differential	*($/bbl)*	**$ 30.73**	$ 26.16	$ 30.70
Unit margin	*($/bbl)*	**$ 31.67**	$ 27.35	$ 33.01
Unit operating cost (2)	*($/bbl)*	**$ 9.83**	$ 8.65	$ 9.38

(1) Throughput includes diluent returned to the field.
(2) Based on throughput.

Upgrading Earnings Variance Analysis



Infrastructure and Marketing Earnings Summary

Infrastructure and marketing earnings in 2007 increased by $56 million compared with 2006. Higher earnings from oil and gas commodity marketing were realized entirely during the second half of 2007 as crude oil premiums, gas storage profits and NGL extraction margins rose to unprecedented levels. Pipeline earnings in 2007 increased over 2006 supported by higher throughput volume.

Infrastructure and Marketing Earnings Summary

($ millions, except where indicated)		**2007**	2006	2005
Gross margin				
Pipeline		**$ 115**	$ 104	$ 92
Other infrastructure and marketing		**278**	208	217
		393	312	309
Other expenses		**14**	11	10
Depreciation and amortization		**28**	24	21
Income taxes		**98**	80	96
Earnings		**$ 253**	$ 197	$ 182
Aggregate pipeline throughput	*(mbbls/day)*	**501**	475	474

Midstream Capital Expenditure

Midstream capital expenditure of $309 million in 2007 was primarily for front-end engineering design for the upgrader expansion, debottleneck projects, contingent consideration, equipment and pipeline upgrades and expansion compared with $252 million in 2006.

In midstream, Husky plans to spend $300 million in 2008 of which $75 million will be spent on plant maintenance at the Lloydminster upgrader and $225 million in the pipeline, infrastructure, contingent consideration and other businesses.

7.6 DOWNSTREAM

2007 Earnings $297 Million, up $191 Million from 2006

The downstream business is comprised of a Canadian based light oil product (motor fuel) retail and wholesale marketing business, a heavy oil products (asphalt) manufacturing and marketing business and a U.S. based refining and wholesale marketing business. The light oil products business relies primarily on acquiring refined product from other Canadian refiners and to a lesser extent, from our own regional refinery located at Prince George, British Columbia. Asphalt products are sourced from our asphalt plant in Lloydminster, Alberta.

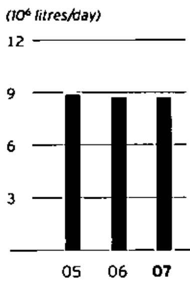
The downstream segment is a margin business, which, in order to provide a return, depends on the unit output prices being sufficiently higher than the unit input costs in order to cover process/operating costs and leave a profit.

In 2007, the downstream segment earnings increased due to the acquisition of the Lima, Ohio refinery, for which results have been included since July 1, 2007, and increased Canadian downstream earnings from higher retail light oil product and asphalt product margins.

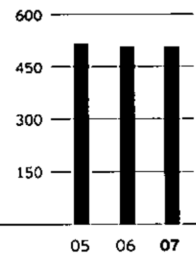
Canadian Refined Products

Light Oil Product Marketing

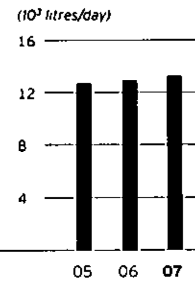
Volume



Outlets

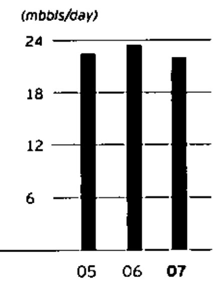


Volume per Outlet



Asphalt Products

Volume



Downstream Earnings Summaries

Canadian Refined Products Earnings Summary

($ millions, except where indicated)		**2007**	2006	2005
Gross margin				
Fuel sales		**$ 188**	$ 138	$ 126
Ancillary sales		**42**	36	34
Asphalt sales		**160**	94	91
		390	268	251
Operating and other expenses		**82**	74	75
Depreciation and amortization		**66**	48	47
Income taxes		**50**	40	47
Earnings		**$ 192**	$ 106	$ 82
Number of fuel outlets		**505**	505	515
Refined products sales volume				
Light oil products	*(million litres/day)*	**8.7**	8.7	8.9
Light oil products per outlet	*(thousand litres/day)*	**13.2**	12.9	12.7
Asphalt products	*(mbbls/day)*	**21.8**	23.4	22.5
Refinery throughput				
Prince George refinery	*(mbbls/day)*	**10.5**	9.0	9.7
Lloydminster refinery	*(mbbls/day)*	**25.3**	27.1	25.5
Ethanol production	*(thousand litres/day)*	**324.6**	59.7	25.6

U.S. Refining and Marketing Earnings Summary

($ millions, except where indicated)	**2007**
Gross refining margin	**$ 310**
Processing costs	**93**
Operating and other expenses	**1**
Interest – net	**1**
Depreciation and amortization	**47**
Income taxes	**63**
Earnings	**$ 105**

U.S. Refining and Marketing Earnings Summary (continued)

		2007
Selected operating data:		
Refinery throughput	*(mbbls/day)*	
Crude oil		**135**
Other feedstock		**9**
Yield	*(mbbls/day)*	
Gasoline		**82**
Middle distillates		**47**
Other fuel and feedstock		**16**
Margins	*($/bbl crude throughput)*	
Gross refining margin		**12.42**
Unit operating costs	*($/bbl of yield)*	**3.48**
Refined product sales	*(mbbls/day)*	
Gasoline		**81**
Middle distillates		**46**
Other fuel and feedstock		**13**

Downstream Capital Expenditure

In 2007, downstream capital expenditure of $233 million was primarily for the construction of the Minnedosa ethanol plant, various capital programs related to environmental protection and reliability upgrades at our refineries and plants and for marketing outlet construction and upgrades. In 2006, total downstream capital expenditures were $285 million largely for similar capital programs but also the construction of the Lloydminster ethanol plant, which was commissioned in September 2006.

Downstream plans to spend approximately $300 million in 2008, with $160 million allocated to the Lima refinery for maintenance and for front-end engineering to reconfigure the plant to process heavy oil. The remainder of the capital will be for maintenance of our refining and ethanol assets and remodeling of our retail stations.

7.7 CORPORATE

2007 Expense $214 Million, up $57 Million from 2006

In 2007, intersegment eliminations were $71 million higher than in 2006 as inventory value increased with commodity prices. Corporate expenses decreased in 2007 by $14 million compared with 2006 as a result of several offsetting items. Lower administrative costs were largely due to the result of lower measured stock-based compensation offset partially by higher staffing costs. Interest expense increased due to higher borrowing and lower capitalized interest. In 2007, foreign exchange gains were higher than 2006 due to a further decrease in the Canadian dollar equivalent of our U.S. dollar denominated debt commensurate with the U.S./Canadian dollar exchange rate.

Corporate Earnings Summary

($ millions) income (expense)	2007	2006	2005
Intersegment eliminations – net	**$ (51)**	$ 20	$ (50)
Administration expenses	**(151)**	(199)	(143)
Depreciation and amortization	**(25)**	(27)	(23)
Interest – net	**(129)**	(92)	(32)
Foreign exchange	**51**	24	31
Income taxes	**91**	117	119
Earnings (expense)	**$ (214)**	$ (157)	$ (98)

Foreign Exchange Summary

($ millions)	2007	2006	2005
(Gain) loss on translation of U.S. dollar denominated long-term debt			
Realized	**$ -**	$ (42)	$ (13)
Unrealized	**(197)**	35	(38)
	(197)	(7)	(51)
Cross currency swaps			
Realized	**-**	47	-
Unrealized	**62**	(43)	14
	62	4	14
Other (gains) losses	**84**	(21)	6
	$ (51)	$ (24)	$ (31)
U.S./Canadian dollar exchange rates:			
At beginning of year	**U.S. $0.858**	U.S. $0.858	U.S. $0.831
At end of year	**U.S. $1.012**	U.S. $0.858	U.S. $0.858

Foreign Exchange Risk

Our results are affected by the exchange rate between the Canadian and U.S. dollar. 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 our 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. 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, 2007, 93% or $2.6 billion of our long-term debt was denominated in U.S. dollars. The U.S./Cdn exchange rate at the end of 2007 was U.S. $1.012. The percentage of our long-term debt exposed to the U.S./Cdn exchange rate decreases to 80% when the cross currency swaps are included. Additionally, U.S. $1.5 billion of our U.S. dollar denominated debt has been designated as a hedge of a net investment and the unrealized foreign exchange gain is recorded in Other Comprehensive Income, further reducing the long-term debt exposed to the U.S./Cdn exchange rate to 27%. Refer to Section 8.6, "Financial Risk and Risk Management."

Consolidated Income Taxes

Consolidated income taxes increased in 2007 to $913 million from $780 million in 2006, an effective tax rate of 22% for both 2007 and 2006.

In 2007, a recovery of future income taxes resulted from recording non-recurring tax benefits of $395 million, $365 million due to changes in the tax rate levied by the Federal Government by Bill C-28 and $30 million due to changes from Bill C-52. In 2006, a recovery of future taxes resulted from recording non-recurring tax benefits of $328 million that arose due to changes in the tax rates for the governments of Canada ($198 million), Alberta ($90 million) and Saskatchewan ($40 million).

The following table shows the effect of non-recurring tax benefits for the periods noted:

($ millions)	2007	2006	2005
Income taxes before tax amendments	**$ 1,308**	$ 1,108	$ 813
Canadian federal and provincial tax amendments	**395**	328	4
Income taxes as reported	**$ 913**	$ 780	$ 809

Corporate Capital Expenditure

Corporate capital expenditure of $44 million in 2007 was primarily for computer hardware, software, office furniture and equipment and system upgrades compared with $37 million in 2006.

7.8 RESULTS OF OPERATIONS FOR 2006 COMPARED WITH 2005

Net earnings in 2006 were $2,726 million compared with $2,003 million in 2005. The increase of $723 million was attributable to the following:

Upstream – increase of $771 million due to higher crude oil prices and higher light crude oil production partially offset by lower natural gas sales volume and prices, higher operating costs and DD&A.

Midstream – decrease of $13 million due to narrower upgrading differentials and lower commodity marketing income partially offset by higher crude oil pipeline income.

Downstream – increase of $24 million due to higher margins for motor fuels, higher asphalt product sales volume partially offset by higher depreciation and lower sales volume of motor fuels.

Corporate – expense increased by $59 million due to lower capitalized interest, 2005 litigation settlement, higher staffing costs partially offset by lower intersegment profit eliminations, stock-based compensation and interest expense.

8.0 Liquidity and Capital Resources

8.1 SUMMARY OF CASH FLOW

	2007	2006	2005
Cash flow – operating activities *($ millions)*	**$ 4,657**	$ 5,009	$ 3,650
– financing activities *($ millions)*	**$ 433**	$ (1,626)	$ (668)
– investing activities *($ millions)*	**$ (5,324)**	$ (3,109)	$ (2,814)
Debt to capital employed *(percent)*	**19.5**	14.3	20.1
Corporate reinvestment ratio [(1)]	**0.9**	0.7	0.8

(1) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

Cash Flow from Operating Activities

In 2007, cash generated by operating activities was $4,657 million, a decrease of $352 million from 2006. The decrease was largely due to an increase in accounts receivable partially offset by higher payables attributable to the U.S. refining and marketing operation acquired in July 2007.

Cash Flow from (used for) Financing Activities

In 2007, cash provided by financing activities amounted to $433 million. The cash provided was largely from the issuance of long-term debt of $7,222 million offset by the repayment of $5,722 million of long-term debt and the payment of dividends of $1,129 million, which resulted in a net amount of $371 million provided. The remaining $62 million of cash provided was from stock option exercises and change in non-cash working capital less debt issue costs.

Cash Flow used for Investing Activities

Cash used in investing activities amounted to $5,324 million in 2007, an increase of $2,215 million over 2006. Cash invested in 2007 was composed of capital expenditures of $2,931 million, corporate acquisition of $2,589 million and $137 million related to change in non-cash working capital and miscellaneous items partially offset by $333 million of proceeds from asset sales.

8.2 WORKING CAPITAL COMPONENTS

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2007, our working capital deficiency was $51 million compared with $495 million at December 31, 2006. It is not unusual for us 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.

($ millions)	2007	2006	Change	
Current assets				
Cash and cash equivalents	**$ 208**	$ 442	$ (234)	Tax payment
Accounts receivable	**1,622**	1,284	338	Inclusion of Lima receivables
Inventories	**1,190**	428	762	Inclusion of Lima inventory
Prepaid expenses	**28**	25	3	
	3,048	2,179	869	
Current liabilities				
Accounts payable	**1,460**	1,268	(192)	Inclusion of Lima payables offset by lower capital accruals
Accrued interest payable	**20**	27	7	
Income taxes payable	**36**	615	579	Tax payment and deferred earnings
Other accrued liabilities	**842**	664	(178)	Higher accruals due to Lima and increase in dividend offset by lower stock-based compensation in 2007
Long-term debt due within one year	**741**	100	(641)	Bridge financing for Lima acquisition
	3,099	2,674	(425)	
Working capital	**$ (51)**	$ (495)	$ 444	

Sources and Uses of Cash

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 develop 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 frequently evaluate 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. Corporate acquisitions, such as the Lima refinery are financed by issuing investment quality funded debt.

As at December 31, 2007, our outstanding long-term debt totalled $2.8 billion, including amounts due within one year, compared with $1.6 billion at December 31, 2006.

During the second quarter of 2007, we arranged short-term bridge financing from several banks to facilitate closing the acquisition of the Lima refinery on July 3, 2007. The bridge financing provided U.S. $1.5 billion while the remaining funds required were drawn under existing credit facilities.

In September 2007, we issued U.S. $300 million of 6.20% 10-year notes due September 15, 2017 and U.S. $450 million of 6.80% 30-year notes due September 15, 2037 under a shelf prospectus dated September 21, 2006. The net proceeds of these notes were used to repay part of the U.S. $1.5 billion short-term bridge financing for the acquisition of the Lima refinery. Total net proceeds from these issues were U.S. $743 million or $775 million at the then effective exchange rate. The remaining amount that is eligible for issue under our shelf prospectus is U.S. $250 million until October 21, 2008. During the remaining period that the prospectus remains effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale.

At December 31, 2007, we had no drawings under our $1.25 billion 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 and credit ratings assigned by certain rating agencies to our senior unsecured debt. The syndicated credit facility requires Husky to maintain a debt to cash flow ratio of less than 3.5 times.

At December 31, 2007, we had no draw-down under our $150 million bilateral credit facilities. The terms of these facilities are substantially the same as the syndicated credit facility.

At December 31, 2007, we had utilized $73 million in support of letters of credit under our $270 million in short-term borrowing facilities. The interest rates applicable to these facilities vary and are based on Bankers' Acceptance, U.S. LIBOR or prime rates. In addition, we utilized $13 million under a $50 million dedicated letter of credit facility.

At a special meeting of the shareholders on June 27, 2007, the shareholders approved a two-for-one share split of our issued and outstanding common shares. On June 27, 2007, the Company filed Articles of Amendment to effect the share split. All references to common share amounts, including common shares issued and outstanding, basic and diluted earnings per share, dividend per share, weighted average number of common shares outstanding and stock options granted, exercised, surrendered and forfeited have been retroactively restated to reflect the impact of the two-for-one share split. The common shares commenced trading on the Toronto Stock Exchange reflecting this split on July 9, 2007.

We declared dividends that aggregated $1.33 per share totalling $1.1 billion in 2007. This included a special dividend of $0.25 per share. The Board of Directors of Husky has established a dividend policy that pays quarterly dividends of $0.33 ($1.32 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.

Cash and cash equivalents at December 31, 2007 totalled $208 million compared with $442 million at the beginning of the year.

Capital Structure

	December 31, 2007		
	Outstanding		Available
($ millions)	*(U.S. $)*	*(Cdn $)*	*(Cdn $)*
Short-term bank debt	$ –	$ –	$ 197
Long-term bank debt			
Syndicated credit facility	–	–	1,250
Bilateral credit facilities	–	–	150
Bridge facility	750	741	
Medium-term notes (1)	–	200	
Capital securities	225	223	
U.S. public notes	1,650	1,630	
	2,625	2,794	1,597
Fair value adjustment (1)		3	
Debt issue costs (2)		(20)	
Unwound interest rate swaps (3)		37	
Total short-term and long-term debt	$ 2,625	$ 2,814	$ 1,597
Common shares, retained earnings and accumulated other comprehensive income		$11,650	

(1) *The carrying value of the medium-term notes has been adjusted to fair value to meet the accounting requirements for a fair value hedge. Refer to Note 19 to the Consolidated Financial Statements.*

(2) *Debt issue costs have been reclassified to long-term debt with the adoption of financial instruments. Previously these deferred costs were included in other assets. Refer to Note 12 to the Consolidated Financial Statements.*

(3) *The unamortized portion of the gain on previously unwound interest rate swaps that would be designated as fair value hedges is required to be included in the carrying value of long-term debt with the adoption of financial instruments. Refer to Note 12 to the Consolidated Financial Statements.*

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.

8.3 CASH REQUIREMENTS

Contractual Obligations and Other 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

Payments due by period (*$ millions*)	Total	2008	2009–2010	2011–2012	Thereafter
Long-term debt and interest on fixed rate debt	$ 4,382	$ 1,104	$ 429	$ 595	$ 2,254
Operating leases	1,024	218	553	225	28
Firm transportation agreements	549	165	168	69	147
Unconditional purchase obligations (1)	4,236	2,564	1,472	161	39
Lease rentals and exploration work agreements	848	175	226	232	215
Engineering and construction commitments	71	71	–	–	–
	$11,110	$ 4,297	$ 2,848	$ 1,282	$ 2,683

(1) Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums and natural gas purchases.

Based on our 2008 commodity price forecast, we believe that our non-cancellable contractual obligations and other commercial commitments and our 2008 capital program will be funded by cash flow from operating activities and, to the extent required, by 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.

Estimated Obligations Not Included in the Table

- Asset retirement obligations ("ARO")

  Husky 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 ("CICA") section 3110, "Asset Retirement Obligations," Husky records a separate liability for the fair value of its ARO. See Note 13 to the Consolidated Financial Statements.

- Employee future benefits

  Husky provides a defined contribution plan and a post-retirement health and dental plan for all qualified employees in Canada. We also provide a defined benefit pension plan for approximately 180 active employees and 480 retirees and their beneficiaries in Canada. This plan was closed to new entrants in 1991 after the majority of our employees transferred to the defined contribution pension plan. We provide a defined benefit pension plan for approximately 385 active employees in the United States. This pension plan was established effective July 1, 2007 in conjunction with the acquisition of the Lima refinery. We also assumed a post-retirement welfare plan covering the employees at the Lima refinery. See Note 17 to the Consolidated Financial Statements.

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.

8.4 OFF–BALANCE SHEET ARRANGEMENTS

Accounts Receivable Securitization Program

In the ordinary course of business, we engage in the securitization of accounts receivable. The securitization program permits the sale of a maximum of $350 million of accounts receivable on a revolving basis. At December 31, 2007, there were no accounts receivable sold under the program. The securitization agreement terminates on January 31, 2009. The accounts receivable are sold to an unrelated third party and 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.

Standby Letters of Credit

In addition, from time to time, we issue letters of credit in connection with transactions in which the counterparty requires such security.

Derivative Instruments

We utilize derivative financial instruments in order to manage unacceptable risk. The derivative financial instruments currently outstanding are listed and discussed in Section 8.6, "Financial Risk and Risk Management."

8.5 TRANSACTIONS WITH RELATED PARTIES AND MAJOR CUSTOMERS

In late 2007, TransAlta Power, L.P. was acquired by an indirect subsidiary of Cheung Kong Infrastructure Holdings Limited, which is majority owned by Hutchison Whampoa Limited, which owns 100% of U.F. Investments (Barbados) Ltd. a 34.58% shareholder in Husky. TransAlta Power L.P. is a 49.99% owner of TransAlta Cogeneration, L.P. our partner in the Meridian Cogeneration plant in Lloydminster, Saskatchewan. We sell natural gas to the Meridian Cogeneration plant and other cogeneration plants owned by TransAlta Power L.P. In 2007, we sold $104 million of natural gas to TransAlta Power L.P.

We did not have any customers that constituted more than 10% of total sales and operating revenues during 2007.

8.6 FINANCIAL RISK AND RISK MANAGEMENT

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Refer to Section 6.0 under "The 2007 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 from time to time 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.

Power Consumption

During 2007, we made payments totalling less than $1 million on our power consumption hedges.

Foreign Currency Risk Management

At December 31, 2007, Husky had the following cross currency debt swaps in place:

- U.S. $150 million at 6.250% swapped at $1.41 to $212 million at 7.41% until June 15, 2012.
- U.S. $75 million at 6.250% swapped at $1.19 to $90 million at 5.65% until June 15, 2012.
- U.S. $50 million at 6.250% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.
- U.S. $75 million at 6.250% swapped at $1.17 to $88 million at 5.61% until June 15, 2012.

At December 31, 2007 the cost of a U.S. dollar in Canadian currency was $0.9881.

In 2007, the cross currency swaps resulted in an offset to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $62 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized losses totalling approximately $18 million in 2007. In 2004, Husky unwound its long-dated forwards resulting in a gain of $8 million, which was recognized into income during 2005 on the dates the underlying hedged transactions took place.

In 2007, we recorded a $101 million gain on an embedded derivative related to a contract requiring payment in U.S. currency. The payments are expected over a three-year period, commencing in 2008. This amount will fluctuate with the U.S./Cdn forward exchange rate until the actual contract settlement.

During the year, the Company entered into forward purchases of U.S. dollars to partially offset the fluctuations in foreign exchange related to the embedded derivative. In 2007, the impact of these transactions was a gain of $8 million.

Effective July 1, 2007, the Company's U.S. $1.5 billion of debt financing related to the Lima acquisition has been designated as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. The unrealized foreign exchange gain arising from the translation of the debt was $102 million, net of tax of $19 million, which was recorded in "Other Comprehensive Income."

Interest Rate Risk Management

In 2007, interest rate risk management activities resulted in a decrease to interest expense of less than $1 million.

The cross currency swaps resulted in an addition to interest expense of $6 million in 2007.

We have interest rate swaps on $200 million of long-term debt, effective February 8, 2002, whereby 6.95% was swapped for CDOR + 175 bps until July 14, 2009. During 2007, these swaps resulted in an offset to interest expense amounting to $1 million.

The amortization of previous interest rate swap terminations resulted in an additional $5 million offset to interest expense in 2007.

8.7 OUTSTANDING SHARE DATA

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 15, 2008

■ common shares	849,018,162
■ preferred shares	none
■ stock options	30,195,824
■ stock options exercisable	4,021,714

At February 15, 2008, 54,563,199 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.

9.0 Application of Critical Accounting Estimates

Husky's Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Significant accounting policies are disclosed in Note 3 to the Consolidated Financial Statements. Certain of our accounting policies require subjective judgment about uncertain circumstances. The following discussion highlights the nature and potential effect of these estimates. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

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 ARO related to the oil and gas properties; and
- estimated impairment of costs excluded from the DD&A calculation.

A decrease in:

- previously estimated proved oil and gas reserves; and
- estimated proved reserves added compared to capital invested.

DEPLETION EXPENSE

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 costs required to develop the proved undeveloped reserves, less estimated salvage values, is charged to income over the life of the proved reserves using the unit of production method.

WITHHELD COSTS

Costs related to unproved properties and major development projects are excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. Impairment is transferred to 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.

CEILING TEST

Each cost centre's capitalized costs are tested for recoverability at least yearly. The test compares the estimated undiscounted future net cash flows from proved oil and gas reserves based on forecast prices and costs to the carrying amount of a cost centre. If the future cash flows are lower than the carrying costs, the cost centre is written down to its fair value. Fair value is estimated using 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

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. Effective January 1, 2007, Husky adopted CICA section 3855, "Financial Instruments – Recognition and Measurement," section 3865, "Hedges," section 1530, "Comprehensive Income" and section 3861, "Financial Instruments – Disclosure and Presentation." These standards provide the recognition, measurement and disclosure requirements for financial instruments and hedge accounting. Refer to Note 19 in the Consolidated Financial Statements.

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through forward market prices and compared with quotes from financial institutions. The estimation of fair value for the Company's embedded derivative and the forward purchases of U.S. dollars to partially offset the fluctuations in foreign exchange related to the embedded derivative is determined using forward market prices.

ASSET RETIREMENT OBLIGATION

We have significant obligations to remove tangible assets and restore land after operations cease and we retire or relinquish the asset. Our ARO primarily 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 ARO requires us to estimate costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the calculation of the ARO are numerous assumptions and judgments 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. Future revisions to these assumptions result in changes to the ARO.

LEGAL, ENVIRONMENTAL REMEDIATION AND OTHER CONTINGENT MATTERS

We are required to both determine whether a loss is probable based on judgment 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. We 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

Under the purchase method, the acquiring company includes the fair value of the various assets and liabilities of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. In some circumstances the fair value of an asset is determined by estimating the amount and timing of future cash flow associated with that asset. The actual amounts and timing of cash flow may differ materially and may possibly lead to an impairment charged to earnings.

GOODWILL

In combination with purchase accounting, any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of purchase accounting, described above, it too is inherently imprecise. Goodwill must routinely be assessed for impairment and necessarily requires the judgmental determination of the fair value of assets and liabilities.

10.0 New and Pending Accounting Standards

NEW

Financial Instruments

The new standards for accounting for financial instruments were adopted January 1, 2007. The effect of these standards is disclosed in Note 19 of the Consolidated Financial Statements.

Accounting Changes

In July 2006, the Canadian Accounting Standards Board ("AcSB") issued a revised CICA section 1506, "Accounting Changes." Under CICA section 1506, voluntary changes in accounting policy are only permitted if they result in financial statements that provide more reliable and relevant information. Accounting changes are to be applied retrospectively unless impractical. Material prior period errors are applied retrospectively. The revised standard was adopted January 1, 2007 and did not have a material effect on our Consolidated Financial Statements.

PENDING

Financial Instruments – Disclosures and Presentation

In December 2006, the AcSB issued CICA section 3862, "Financial Instruments – Disclosures" and CICA section 3863, "Financial Instruments – Presentation" to replace CICA section 3861, "Financial Instruments – Disclosure and Presentation." These standards were issued to converge with recently issued International Financial Reporting Standard ("IFRS") 7. The presentation requirements under section 3863 are unchanged from section 3861. The disclosure requirements under section 3862 have been revised and enhanced. Upon application of section 3862, a reader of our financial statements will be afforded information to evaluate the effect of financial instruments on our financial position and the amount, timing and uncertainty of cash flows associated with financial instruments. Specifically, an increased emphasis has been placed on disclosures regarding the risks associated with recognized and unrecognized financial instruments and how these risks are managed. The disclosures will include both qualitative information about our objectives, policies and processes for risk management and quantitative information that will provide information about the extent to which we are exposed to risk. CICA section 3862 and section 3863 are effective for fiscal years beginning on or after October 1, 2007.

Capital Disclosures

In December 2006, the AcSB issued CICA section 1535, "Capital Disclosures." This standard was issued to converge with amendments to International Accounting Standard 1. Upon application of these recommendations, readers of financial statements will be provided information pertinent to our objectives, policies and processes for managing capital. We will also disclose quantitative data regarding what we consider capital and whether we are in compliance with all externally imposed capital requirements and the consequences of non-compliance. CICA section 1535 is effective for fiscal years beginning on or after October 1, 2007.

11.0 Reader Advisories

11.1 FORWARD–LOOKING STATEMENTS

Certain statements in this document are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, 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 these forward-looking statements. 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," "intend," "plan," "projection," "could," "vision," "goals," "objective" 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. In particular, forward-looking statements include: our general strategic plans, our production expectation for the Tucker in-situ oil sands project, the completion of the transactions with BP in respect of the 50/50 partnership to develop the Sunrise oil sands project and the 50/50 limited liability company for the Toledo refinery, our integrated oil sands joint development including the Sunrise oil sands project phased development and Toledo refinery modifications, our conceptual development planning for Saleski and Caribou, our White Rose oil field drilling, development and production plans, our East Coast and Northwest Territories exploration programs, our seismic acquisition programs offshore Greenland, the schedule and expected results of our offshore China geophysical and drilling programs, our development plans for the Madura BD field in Indonesia, our plans for expanding our heavy crude oil mainline and the results of the Lima refinery engineering evaluation to increase its heavy oil and bitumen capacity. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this MD&A. Among the key factors that have a direct bearing on our results of operations are the nature of our involvement in the business of exploration for, and development and production of crude oil and natural gas reserves and the fluctuation of the exchange rates between the Canadian and United States dollar.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to:

- adequacy of and fluctuations in oil and natural gas prices;
- demand for our products and services and the cost of required inputs;
- our ability to replace our reserves;
- competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy;
- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures, natural disasters and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us and that may or may not be financially recoverable;
- actions by governmental authorities, including changes in environmental and other regulations that may impose restrictions in areas where we operate; and
- the accuracy of our oil and gas reserve estimates and estimated production levels as they are affected by our success at exploration and development drilling and related activities and estimated decline rates.

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable law, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. 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 statement.

11.2 OIL AND GAS RESERVE REPORTING

Disclosure of Proved Oil and Gas Reserves and Other Oil and Gas Information

Husky'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 Canadian Securities Administrators. The exemption permits Husky 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 document have been evaluated using the United States standards contained in Rule 4-10 of Regulation S-X of the Securities Exchange Act of 1934 and Guide 2 of the Securities Act Industry Guides. The probable oil and gas reserves disclosed in this document have been evaluated in accordance with the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101. Please refer to "Disclosure of Exemption under National Instrument 51-101" in the Annual Information Form for the year ended December 31, 2007 filed with securities regulatory authorities for further information.

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 ("SEC") permits U.S. oil and gas companies, in their filings with the SEC, to disclose only proved reserves, that is reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. We use certain terms in this document, such as "probable reserves", that the SEC's guidelines strictly prohibit in filings with the SEC by U.S. oil and gas companies. U.S. investors should refer to our Annual Report on Form 40-F available from us or the SEC for further reserve disclosure.

11.3 NON-GAAP MEASURES

We use measurements primarily based on GAAP and also on secondary non-GAAP measurements. The non-GAAP measurements included in this report are: Cash flow from operations, Return on equity, Return on capital employed, Debt to capital employed and Corporate reinvestment ratio. None of these measurements is used to enhance our reported financial performance or position. These are useful complementary measurements in assessing our financial performance, efficiency and liquidity. They are common in the reports of other companies but may differ by definition and application. The definitions of these measurements are found in Section 11.4, "Additional Reader Advisories."

The following table shows the reconciliation of cash flow from operations to cash flow – operating activities for the years ended December 31:

($ millions)		**2007**	2006	2005
Non-GAAP	Cash flow from operations	**$ 5,426**	$ 4,501	$ 3,785
	Settlement of asset retirement obligations	**(51)**	(36)	(41)
	Change in non-cash working capital	**(718)**	544	(72)
GAAP	Cash flow – operating activities	**$ 4,657**	$ 5,009	$ 3,672

Cash flow from operations is presented in our financial reports because investors use it to analyze operating performance.

11.4 ADDITIONAL READER ADVISORIES

Intention of Management's Discussion and Analysis

This MD&A is intended to provide an explanation of financial and operational performance compared with prior periods and our prospects and plans. It provides additional information that is not contained in our financial statements.

Review by the Audit Committee

This MD&A was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 21, 2008. Any events subsequent to that date could conceivably materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes. The readers are also encouraged to refer to Husky's interim reports filed in 2006, which contain MD&A and Consolidated Financial Statements, and Husky's Annual Information Form filed separately with Canadian regulatory agencies and Form 40-F filed with the SEC, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.ca.

Use of Pronouns and Other Terms

"We", "our", "us", "Husky" and "the Company" refer to Husky Energy Inc. on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2007 and 2006 and Husky's financial position as at December 31, 2007 and at December 31, 2006.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform to current year presentation. Materiality for disclosures is determined on the basis of whether the information omitted or misstated would cause a reasonable investor to change their decision to buy, sell or hold the securities of Husky.

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with GAAP in Canada. Significant differences between Canadian and United States GAAP are disclosed in the U.S. GAAP reconciliation contained in Form 40-F and available at www.sedar.com.
- Currency is presented in millions of Canadian dollars ("C$").
- Gross production and reserves are Husky's working interest prior to deduction of royalty volume.
- Prices are presented before the effect of hedging.
- Light crude oil is 30° API and above.
- Medium crude oil is 21° API and above but below 30° API.
- Heavy crude oil is above 10° API but below 21° API.
- Bitumen is 10° API and below.

TERMS

Bitumen	*A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. It is more viscous than 10 degrees API*
Brent Crude Oil	*Prices which are dated less than 15 days prior to loading for delivery*
Capital Employed	*Short- and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital*
Coalbed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Corporate Reinvestment Ratio	*Net capital expenditures (capital expenditures net of proceeds from asset sales) plus corporate acquisitions (net assets acquired) divided by cash flow from operations*
Debt to Capital Employed	*Total debt divided by total debt and shareholders' equity*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
Embedded Derivative	*Implicit or explicit term(s) in a contract that affects some or all of the cash flows or the value of other exchanges required by the contract*
Feedstock	*Raw materials which are processed into petroleum products*
Front-end Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Glory Hole	*An excavation in the seabed where the wellheads and other equipment are situated to protect them from scouring icebergs*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which an interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Interest Coverage Ratio	*A calculation of a company's ability to pay to meet its interest payment obligation. It is equal to earnings before income taxes and interest divided by interest paid before deduction of capitalized interest*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
Return on Capital Employed	*Net earnings plus after tax interest expense divided by average capital employed*
Return on Shareholders' Equity	*Net earnings divided by average shareholders' equity*
Seismic	*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*
Shareholders' Equity	*Shares, retained earnings and accumulated other comprehensive income*
Total Debt	*Long-term debt including current portion and bank operating loans*

"Proved" reserves have been estimated in accordance with the SEC definition set out in Rule 4-10(a) of Regulation S-X under the Securities Exchange Act of 1934 as follows: 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. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

"Proved Developed" reserves are those reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"Proved Undeveloped" reserves are those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which a relatively major expenditure is required for recompletion. Inclusion of reserves on undrilled acreage is limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are included only if it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

"Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.

ABBREVIATIONS

bbls	*barrels*
bps	*basis points*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
bcf	*billion cubic feet*
tcf	*trillion cubic feet*
boe	*barrels of oil equivalent*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mmboe	*million barrels of oil equivalent*
mcfge	*thousand cubic feet of gas equivalent*
GAAP	*Generally Accepted Accounting Principles*
GJ	*gigajoule*
mmbtu	*million British Thermal Units*
mmlt	*million long tons*
MW	*megawatt*
NGL	*natural gas liquids*
WTI	*West Texas Intermediate*
NYMEX	*New York Mercantile Exchange*
NIT	*NOVA Inventory Transfer*
LIBOR	*London Interbank Offered Rate*
CDOR	*Certificate of Deposit Offered Rate*
SEDAR	*System for Electronic Document Analysis and Retrieval*
FPSO	*Floating production, storage and offloading vessel*
FEED	*Front-end engineering design*
OPEC	*Organization of Petroleum Exporting Countries*
SAGD	*Steam-assisted gravity drainage*
MD&A	*Management's Discussion and Analysis*
CNLOPB	*Canada-Newfoundland and Labrador Offshore Petroleum Board*

11.5 CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Husky's management, with the participation of the Chief Executive Officer and in his capacity as Acting Chief Financial Officer, has evaluated the effectiveness of Husky's disclosure controls and procedures (as defined in the rules of the SEC and the Canadian Securities Administrators ("CSA")) as at December 31, 2007, and has concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by Husky in reports that it files or submits under the Securities Exchange Act of 1934 is (i) recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and (ii) accumulated and communicated to Husky's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting

The following report is provided by management in respect of Husky's internal controls over financial reporting (as defined in the rules of the SEC and the CSA):

1) Husky's management is responsible for establishing and maintaining adequate internal control over financial reporting for Husky. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.
2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework to evaluate the effectiveness of Husky's internal control over financial reporting.
3) As at December 31, 2007, management assessed the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective and that there are no material weaknesses in Husky's internal control over financial reporting that have been identified by management.

   The Company excluded from its assessment the internal control over financial reporting at our Lima refinery, which was acquired effective July 1, 2007. The operations of the Lima refinery are currently being integrated into our operations, including assessing and designing internal controls over financial reporting and disclosure controls and procedures for the Lima refinery operations. At December 31, 2007, total assets of the Lima, Ohio refinery accounted for 14% of the Company's total consolidated assets and total revenues from the Lima refinery accounted for 15% of the Company's total consolidated revenues and are included in the December 31, 2007 Consolidated Financial Statements.
4) KPMG LLP, who has audited the Consolidated Financial Statements of Husky for the year ended December 31, 2007, has also issued a report on internal controls under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States).

Changes in Internal Control over Financial Reporting

There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect its internal control over financial reporting.

12.0 Selected Quarterly Financial & Operating Information

SEGMENTED OPERATIONAL INFORMATION

	2007				2006			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	129.7	133.3	144.3	147.8	128.2	117.2	97.7	100.5
Medium crude oil *(mbbls/day)*	27.0	26.7	26.8	27.5	28.0	28.1	28.5	29.4
Heavy crude oil & bitumen *(mbbls/day)*	107.8	106.5	105.4	108.0	109.5	107.9	105.6	109.5
	264.5	266.5	276.5	283.3	265.7	253.2	231.8	239.4
Natural gas *(mmcf/day)*	617.8	620.1	615.7	640.0	662.2	669.1	672.8	685.4
Total production *(mboe/day)*	367.5	369.9	379.1	390.0	376.1	364.7	344.0	353.6
Average sales prices								
Light crude oil & NGL *($/bbl)*	$ 83.43	$ 76.00	$ 72.28	$ 64.88	$ 62.55	$ 74.05	$ 73.74	$ 67.04
Medium crude oil *($/bbl)*	$ 55.37	$ 54.55	$ 48.15	$ 46.40	$ 43.99	$ 57.35	$ 58.42	$ 38.39
Heavy crude oil & bitumen *($/bbl)*	$ 41.13	$ 43.64	$ 38.31	$ 37.62	$ 35.46	$ 49.62	$ 48.12	$ 26.73
Natural gas *($/mcf)*	$ 5.72	$ 5.18	$ 6.91	$ 6.94	$ 6.19	$ 5.69	$ 5.95	$ 8.06
Operating costs *($/boe)*	$ 9.61	$ 9.60	$ 8.84	$ 8.34	$ 9.51	$ 8.45	$ 8.24	$ 8.78
Operating netbacks (1)								
Light crude oil *($/boe)* (2)	$ 61.39	$ 53.66	$ 59.13	$ 56.14	$ 51.66	$ 61.86	$ 60.40	$ 54.86
Medium crude oil *($/boe)* (2)	$ 29.99	$ 28.81	$ 26.95	$ 24.67	$ 21.02	$ 33.34	$ 35.06	$ 19.72
Heavy crude oil & bitumen *($/boe)* (2)	$ 21.56	$ 25.11	$ 20.37	$ 21.11	$ 18.94	$ 32.01	$ 31.30	$ 12.65
Natural gas *($/mcfge)* (3)	$ 3.60	$ 3.05	$ 4.32	$ 4.24	$ 3.73	$ 3.55	$ 3.98	$ 5.16
Total *($/boe)* (2)	$ 36.01	$ 33.68	$ 36.91	$ 35.70	$ 31.00	$ 38.46	$ 37.34	$ 30.89
Net wells drilled (4)								
Exploration Oil	23	23	13	20	29	41	7	22
Gas	20	13	3	56	42	46	18	86
Dry	-	2	1	9	2	5	3	14
	43	38	17	85	73	92	28	122
Development Oil	143	203	54	130	209	174	57	103
Gas	56	54	4	137	159	115	23	193
Dry	10	7	2	10	5	6	2	9
	209	264	60	277	373	295	82	305
	252	302	77	362	446	387	110	427
Success ratio *(percent)*	96	97	96	95	98	97	95	95
Midstream								
Synthetic crude oil sales *(mbbls/day)*	66.5	55.1	32.9	57.8	64.1	65.7	56.9	63.4
Upgrading differential *($/bbl)*	$ 36.74	$ 30.41	$ 30.41	$ 24.11	$ 23.81	$ 23.75	$ 22.73	$ 34.82
Pipeline throughput *(mbbls/day)*	497	506	506	493	465	457	480	500
Canadian Refined Products								
Refined products sales volumes								
Light oil products *(million litres/day)*	8.5	9.0	8.6	8.9	8.6	9.1	8.6	8.6
Asphalt products *(mbbls/day)*	24.5	25.9	19.5	17.3	21.0	30.0	24.9	17.7
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	28.8	29.0	18.5	24.7	28.1	27.9	25.4	27.1
Prince George refinery *(mbbls/day)*	11.6	10.8	8.4	11.1	11.2	11.6	3.7	9.3
Refinery utilization *(percent)*	101	100	67	90	98	99	73	91

(1) Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.
(2) Includes associated co-products converted to boe.
(3) Includes associated co-products converted to mcfge.
(4) Western Canada.

SEGMENTED FINANCIAL INFORMATION

	Upstream				Midstream							
					Upgrading				Infrastructure and Marketing			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
2007												
Sales and operating revenues, net of royalties	$ 1,568	$ 1,496	$ 1,593	$ 1,565	$ 530	$ 406	$ 229	$ 359	$ 2,617	$ 2,524	$ 2,521	$ 2,555
Costs and expenses												
Operating, cost of sales, selling and general	358	332	295	323	358	305	186	278	2,509	2,423	2,445	2,461
Depletion, depreciation and amortization	396	413	407	399	8	7	4	6	7	7	7	7
Interest - net	-	-	-	-	-	-	-	-	-	-	-	-
Foreign exchange	-	-	-	-	-	-	-	-	-	-	-	-
	754	745	702	722	366	312	190	284	2,516	2,430	2,452	2,468
Earnings (loss) before income taxes	814	751	891	843	164	94	39	75	101	94	69	87
Current income taxes	41	56	3	22	5	4	-	1	18	5	29	16
Future income taxes	(91)	179	252	241	22	25	10	23	2	25	(8)	11
Net earnings (loss)	$ 864	$ 516	$ 636	$ 580	$ 137	$ 65	$ 29	$ 51	$ 81	$ 64	$ 48	$ 60
Capital expenditures (2)	$ 706	$ 545	$ 520	$ 617	$ 44	$ 51	$ 74	$ 48	$ 15	$ 36	$ 5	$ 36
Goodwill additions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total assets	$ 14,395	$ 14,085	$ 13,974	$ 14,168	$ 1,405	$ 1,354	$ 1,193	$ 1,177	$ 1,134	$ 1,016	$ 1,147	$ 1,057
2006												
Sales and operating revenues, net of royalties	$ 1,434	$ 1,600	$ 1,451	$ 1,287	$ 385	$ 485	$ 404	$ 405	$ 2,377	$ 2,451	$ 2,267	$ 2,464
Costs and expenses												
Operating, cost of sales, selling and general	373	329	308	311	293	399	319	262	2,300	2,396	2,190	2,372
Depletion, depreciation and amortization	389	382	354	351	6	6	6	6	7	6	5	6
Interest - net	-	-	-	-	-	-	-	-	-	-	-	-
Foreign exchange	-	-	-	-	-	-	-	-	-	-	-	-
	762	711	662	662	299	405	325	268	2,307	2,402	2,195	2,378
Earnings (loss) before income taxes	672	889	789	625	86	80	79	137	70	49	72	86
Current income taxes	62	158	156	143	(31)	31	29	24	22	18	20	19
Future income taxes	157	123	(189)	70	58	(5)	(29)	20	2	(2)	(9)	10
Net earnings (loss)	$ 453	$ 608	$ 822	$ 412	$ 59	$ 54	$ 79	$ 93	$ 46	$ 33	$ 61	$ 57
Capital expenditures (2)	$ 704	$ 612	$ 554	$ 757	$ 65	$ 44	$ 38	$ 37	$ 27	$ 29	$ 11	$ 1
Goodwill additions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total assets	$ 13,920	$ 13,531	$ 13,443	$ 13,237	$ 992	$ 943	$ 912	$ 858	$ 1,329	$ 1,093	$ 718	$ 763

(1) 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.

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

Downstream								Corporate and Eliminations [1]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
$ 758	$ 831	$ 709	$ 618	$ 1,340	$ 1,043	$ –	$ –	$ (2,053)	$ (1,949)	$ (1,889)	$ (1,853)	$ 4,760	$ 4,351	$ 3,163	$ 3,244
699	717	620	572	1,234	933	–	–	(1,982)	(1,969)	(1,801)	(1,790)	3,176	2,741	1,745	1,844
19	16	15	16	25	22	–	–	7	6	7	5	462	471	440	433
–	–	–	–	–	1	–	–	40	46	22	21	40	47	22	21
–	–	–	–	–	–	–	–	6	(20)	(36)	(1)	6	(20)	(36)	(1)
718	733	635	588	1,259	956			(1,929)	(1,937)	(1,808)	(1,765)	3,684	3,239	2,171	2,297
40	98	74	30	81	87	–	–	(124)	(12)	(81)	(88)	1,076	1,112	992	947
4	(2)	7	8	14	14	–	–	28	22	27	25	110	99	66	72
(16)	33	14	2	16	19	–	–	(41)	(37)	(63)	(52)	(108)	244	205	225
$ 52	$ 67	$ 53	$ 20	$ 51	$ 54	$ –	$ –	$ (111)	$ 3	$ (45)	$ (61)	$ 1,074	$ 769	$ 721	$ 650
$ 52	$ 77	$ 43	$ 40	$ 16	$ 5	$ –	$ –	$ 20	$ 8	$ 11	$ 5	$ 853	$ 722	$ 653	$ 746
$ –	$ –	$ –	$ –	$ –	$ 500	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 500	$ –	$ –
$ 1,335	$ 1,212	$ 1,304	$ 1,180	$ 3,058	$ 2,915	$ –	$ –	$ 370	$ 136	$ 351	$ 199	$ 21,697	$ 20,718	$ 17,969	$ 17,781
$ 579	$ 776	$ 674	$ 546	$ –	$ –	$ –	$ –	$ (1,691)	$ (1,876)	$ (1,756)	$ (1,598)	$ 3,084	$ 3,436	$ 3,040	$ 3,104
550	724	596	511	–	–	–	–	(1,671)	(1,837)	(1,705)	(1,529)	1,845	2,011	1,708	1,927
14	11	13	10	–	–	–	–	10	6	5	6	426	411	383	379
–	–	–	–	–	–	–	–	24	19	22	27	24	19	22	27
–	–	–	–	–	–	–	–	8	5	(32)	(5)	8	5	(32)	(5)
564	735	609	521	–	–	–	–	(1,629)	(1,807)	(1,710)	(1,501)	2,303	2,446	2,081	2,328
15	41	65	25	–	–	–	–	(62)	(69)	(46)	(97)	781	990	959	776
2	5	3	9	–	–	–	–	(1)	(2)	2	9	54	210	210	204
3	8	10	–	–	–	–	–	(35)	(26)	(12)	(52)	185	98	(229)	48
$ 10	$ 28	$ 52	$ 16	$ –	$ –	$ –	$ –	$ (26)	$ (41)	$ (36)	$ (54)	$ 542	$ 682	$ 978	$ 524
$ 83	$ 59	$ 79	$ 64	$ –	$ –	$ –	$ –	$ 14	$ 10	$ 7	$ 6	$ 893	$ 754	$ 689	$ 865
$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –
$ 1,114	$ 1,070	$ 998	$ 883	$ –	$ –	$ –	$ –	$ 578	$ 687	$ 257	$ 114	$ 17,933	$ 17,324	$ 16,328	$ 15,855

SEGMENTED CAPITAL EXPENDITURES

	2007				2006			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream								
Western Canada	$ 594	$ 451	$ 433	$ 553	$ 630	$ 465	$ 397	$ 680
East Coast Canada and Frontier	87	73	62	59	66	104	115	73
International	25	21	25	5	8	43	42	4
	706	545	520	617	704	612	554	757
Midstream								
Upgrader	44	51	74	48	65	44	38	37
Infrastructure and Marketing	15	36	5	36	27	29	11	1
	59	87	79	84	92	73	49	38
Downstream								
Canadian Refined Products	52	77	43	40	83	59	79	64
U.S. Refining and Marketing	16	5	-	-	-	-	-	-
	68	82	43	40	83	59	79	64
Corporate	20	8	11	5	14	10	7	6
	$ 853	$ 722	$ 653	$ 746	$ 893	$ 754	$ 689	$ 865

Note: Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Management's Report

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

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 judgments. 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 financial document 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. Management evaluation concluded that our internal control over financial reporting was effective as of December 31, 2007. The system of internal controls is further supported by an internal audit function.

The Company excluded from its assessment the internal control over financial reporting at our Lima, Ohio refinery, which was acquired effective July 1, 2007. The operations of the Lima refinery are currently being integrated into our operations, including assessing and designing internal controls over financial reporting and disclosure controls and procedures for the Lima refinery operations. At December 31, 2007, total assets of the Lima, Ohio refinery accounted for 14% of the Company's total consolidated assets and total revenues from the Lima refinery accounted for 15% of the Company's total consolidated revenues and are included in the December 31, 2007 consolidated financial statements.

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 Committee is also responsible for the appointment of the external auditors for the Company.

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 has full and free access to the Audit Committee.

John C. S. Lau
President & Chief Executive Officer

Calgary, Alberta, Canada
February 4, 2008

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Husky Energy Inc. ("the Company") as at December 31, 2007, 2006 and 2005 and the consolidated statements of earnings and comprehensive income, changes in shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. With respect to the consolidated financial statements for the years ended December 31, 2007 and 2006, we also conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 4, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Chartered Accountants
Calgary, Alberta, Canada
February 4, 2008

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Husky Energy Inc.

We have audited Husky Energy Inc. ("the Company")'s internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management of Husky Energy Inc. excluded from its assessment the internal control over financial reporting at the Lima, Ohio refinery, which was acquired effective July 1, 2007. Our audit of internal control over financial reporting of Husky Energy Inc. also excluded an evaluation of the internal control over financial reporting of the Lima refinery.

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards. With respect to the years ended December 31, 2007 and 2006, we also have conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our report dated February 4, 2008 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Chartered Accountants
Calgary, Alberta, Canada
February 4, 2008

Consolidated Balance Sheets

As at December 31 *(millions of dollars)*	**2007**	2006	2005
ASSETS			
Current assets			
Cash and cash equivalents	**$ 208**	$ 442	$ 168
Accounts receivable *(notes 5, 19)*	**1,622**	1,284	856
Inventories *(note 6)*	**1,190**	428	471
Prepaid expenses	**28**	25	40
	3,048	2,179	1,535
Property, plant and equipment, net *(notes 1, 7)*	**17,805**	15,550	13,959
Goodwill *(notes 1, 8)*	**660**	160	160
Other assets *(notes 12, 19)*	**184**	44	62
	$ 21,697	$ 17,933	$ 15,716
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities *(note 11)*	**$ 2,358**	$ 2,574	$ 2,310
Long-term debt due within one year *(notes 12, 19)*	**741**	100	274
	3,099	2,674	2,584
Long-term debt *(notes 12, 19)*	**2,073**	1,511	1,612
Other long-term liabilities *(note 13)*	**918**	756	730
Future income taxes *(note 14)*	**3,957**	3,372	3,270
Commitments and contingencies *(note 15)*			
Shareholders' equity			
Common shares *(note 16)*	**3,551**	3,533	3,523
Retained earnings	**8,176**	6,087	3,997
Accumulated other comprehensive income	**(77)**	–	–
	11,650	9,620	7,520
	$ 21,697	$ 17,933	$ 15,716

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

John C. S. Lau
Director

R.D. Fullerton
Director

Consolidated Statements of Earnings and Comprehensive Income

Year ended December 31 *(millions of dollars, except per share amounts)*	**2007**	2006	2005
Sales and operating revenues, net of royalties	**$ 15,518**	$ 12,664	$ 10,245
Costs and expenses			
Cost of sales and operating expenses *(note 13)*	**9,296**	7,169	5,917
Selling and administration expenses	**219**	162	138
Stock-based compensation *(note 16)*	**88**	138	171
Depletion, depreciation and amortization *(notes 1, 7)*	**1,806**	1,599	1,256
Interest – net *(note 12)*	**130**	92	32
Foreign exchange *(note 12)*	**(51)**	(24)	(31)
Other – net *(notes 15, 19)*	**(97)**	22	(50)
	11,391	9,158	7,433
Earnings before income taxes	**4,127**	3,506	2,812
Income taxes *(note 14)*			
Current	**347**	678	297
Future	**566**	102	512
	913	780	809
Net earnings	**3,214**	2,726	2,003
Other comprehensive income			
Derivatives designated as cash flow hedges, net of tax *(note 19)*	**14**	–	–
Cumulative foreign currency translation adjustment	**(175)**	–	–
Hedge of net investment, net of tax *(note 19)*	**102**	–	–
	(59)	–	–
Comprehensive income	**$ 3,155**	$ 2,726	$ 2,003
Earnings per share			
Basic and diluted *(note 16)*	**$ 3.79**	$ 3.21	$ 2.36
Weighted average number of common shares outstanding *(millions)*			
Basic and diluted *(note 16)*	**848.8**	848.4	847.9

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Changes in Shareholders' Equity

Year ended December 31 *(millions of dollars)*	2007	2006	2005
Common shares			
Beginning of year	**$ 3,533**	$ 3,523	$ 3,506
Options and warrants exercised	**18**	10	17
End of year	**3,551**	3,533	3,523
Retained earnings			
Beginning of year	**6,087**	3,997	2,694
Net earnings	**3,214**	2,726	2,003
Dividends on common shares *(note 16)*			
Ordinary	**(917)**	(636)	(276)
Special	**(212)**	-	(424)
Adoption of financial instruments *(note 19)*	**4**	-	-
End of year	**8,176**	6,087	3,997
Accumulated other comprehensive income			
Beginning of year	**-**	-	-
Adoption of financial instruments *(note 19)*	**(18)**	-	-
Other comprehensive income			
Derivatives designated as cash flow hedges, net of tax *(note 19)*	**14**	-	-
Cumulative foreign currency translation adjustment	**(175)**	-	-
Hedge of net investment, net of tax *(note 19)*	**102**	-	-
	(59)	-	-
End of year	**(77)**	-	-
Shareholders' equity	**$ 11,650**	$ 9,620	$ 7,520

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

Year ended December 31 *(millions of dollars)*	2007	2006	2005
Operating activities			
Net earnings	**$ 3,214**	$ 2,726	$ 2,003
Items not affecting cash			
Accretion *(note 13)*	**47**	45	33
Depletion, depreciation and amortization	**1,806**	1,599	1,256
Future income taxes	**566**	102	512
Foreign exchange	**(135)**	(3)	(37)
Other	**(72)**	32	18
Settlement of asset retirement obligations *(note 13)*	**(51)**	(36)	(41)
Change in non-cash working capital *(note 9)*	**(718)**	544	(94)
Cash flow – operating activities	**4,657**	5,009	3,650
Financing activities			
Bank operating loans financing – net	**-**	-	(101)
Long-term debt issue	**7,222**	1,226	3,235
Long-term debt repayment	**(5,722)**	(1,493)	(3,401)
Settlement of cross currency swap	**-**	(47)	-
Debt issue costs	**(8)**	-	-
Proceeds from exercise of stock options	**5**	3	6
Proceeds from monetization of financial instruments	**-**	-	39
Dividends on common shares	**(1,129)**	(636)	(700)
Other	**-**	(1)	(1)
Change in non-cash working capital *(note 9)*	**65**	(678)	255
Cash flow – financing activities	**433**	(1,626)	(668)
Available for investing	**5,090**	3,383	2,982
Investing activities			
Capital expenditures	**(2,931)**	(3,171)	(3,068)
Corporate acquisition *(note 8)*	**(2,589)**	-	-
Asset sales	**333**	34	74
Other	**(44)**	(12)	(31)
Change in non-cash working capital *(note 9)*	**(93)**	40	211
Cash flow – investing activities	**(5,324)**	(3,109)	(2,814)
Increase (decrease) in cash and cash equivalents	**(234)**	274	168
Cash and cash equivalents at beginning of year	**442**	168	-
Cash and cash equivalents at end of year	**$ 208**	$ 442	$ 168

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to the Consolidated Financial Statements

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

Note 1. Segmented Financial Information

	Upstream			Midstream					
				Upgrading			Infrastructure and Marketing		
Year ended December 31	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Sales and operating revenues, net of royalties	**$ 6,222**	$ 5,772	$ 4,367	**$ 1,524**	$ 1,679	$ 1,488	**$ 10,217**	$ 9,559	$ 7,383
Costs and expenses									
Operating, cost of sales, selling and general	**1,308**	1,321	1,050	**1,127**	1,273	1,018	**9,838**	9,258	7,084
Depletion, depreciation and amortization	**1,615**	1,476	1,144	**25**	24	21	**28**	24	21
Interest – net	**-**	-	-	**-**	-	-	**-**	-	-
Foreign exchange	**-**	-	-	**-**	-	-	**-**	-	-
	2,923	2,797	2,194	**1,152**	1,297	1,039	**9,866**	9,282	7,105
Earnings (loss) before income taxes	**3,299**	2,975	2,173	**372**	382	449	**351**	277	278
Current income taxes	**122**	519	215	**10**	53	16	**68**	79	(14)
Future income taxes	**581**	161	434	**80**	44	120	**30**	1	110
Net earnings (loss)	**$ 2,596**	$ 2,295	$ 1,524	**$ 282**	$ 285	$ 313	**$ 253**	$ 197	$ 182
Property, plant and equipment – As at December 31									
Cost	**$ 23,611**	$ 21,770	$ 19,167	**$ 1,607**	$ 1,390	$ 1,205	**$ 842**	$ 750	$ 683
Accumulated depletion, depreciation and amortization	**9,956**	8,545	7,083	**480**	455	430	**298**	270	247
Net	**$ 13,655**	$ 13,225	$ 12,084	**$ 1,127**	$ 935	$ 775	**$ 544**	$ 480	$ 436
Capital expenditures – Year ended December 31 (2)	**$ 2,388**	$ 2,627	$ 2,730	**$ 217**	$ 184	$ 120	**$ 92**	$ 68	$ 37
Goodwill additions – Year ended December 31	**$ -**	$ -	$ -	**$ -**	$ -	$ -	**$ -**	$ -	$ -
Total assets – As at December 31	**$ 14,395**	$ 13,920	$ 12,887	**$ 1,405**	$ 992	$ 844	**$ 1,134**	$ 1,329	$ 866

(1) 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.

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

Geographical Financial Information

	Canada			United States			Other International		
	2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005
Year ended December 31									
Sales and operating revenues, net of royalties	**$ 11,736**	$ 11,050	$ 8,500	**$ 3,494**	$ 1,340	$ 1,407	**$ 288**	$ 274	$ 338
Capital expenditures (1)	**2,877**	3,104	3,021	**21**	-	-	**76**	97	78
As at December 31									
Property, plant and equipment, net	**$ 16,017**	$ 15,200	$ 13,655	**$ 1,417**	$ 3	$ 3	**$ 371**	$ 347	$ 301
Goodwill (2)	**160**	160	160	**500**	-	-	**-**	-	-
Total assets	**17,983**	17,443	15,157	**3,240**	115	231	**474**	375	328

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

(2) Changes in goodwill for the U.S. arise from translation of goodwill in our self-sustaining U.S. operations. Refer to note 8, Corporate Acquisition.

Downstream						Corporate and Eliminations [1]			Total		
Canadian Refined Products			U.S. Refining and Marketing								
2007	2006	2005	**2007**	2006	2005	**2007**	2006	2005	**2007**	2006	2005
$ 2,916	$ 2,575	$ 2,345	**$ 2,383**	$ -	$ -	**$ (7,744)**	$ (6,921)	$ (5,338)	**$ 15,518**	$ 12,664	$ 10,245
2,608	2,381	2,169	**2,167**	-	-	**(7,542)**	(6,742)	(5,145)	**9,506**	7,491	6,176
66	48	47	**47**	-	-	**25**	27	23	**1,806**	1,599	1,256
-	-	-	**1**	-	-	**129**	92	32	**130**	92	32
-	-	-	**-**	-	-	**(51)**	(24)	(31)	**(51)**	(24)	(31)
2,674	2,429	2,216	**2,215**	-	-	**(7,439)**	(6,647)	(5,121)	**11,391**	9,158	7,433
242	146	129	**168**	-	-	**(305)**	(274)	(217)	**4,127**	3,506	2,812
17	19	(3)	**28**	-	-	**102**	8	83	**347**	678	297
33	21	50	**35**	-	-	**(193)**	(125)	(202)	**566**	102	512
$ 192	$ 106	$ 82	**$ 105**	$ -	$ -	**$ (214)**	$ (157)	$ (98)	**$ 3,214**	$ 2,726	$ 2,003
$ 1,550	$ 1,344	$ 1,063	**$ 1,459**	$ -	$ -	**$ 338**	$ 298	$ 257	**$ 29,407**	$ 25,552	$ 22,375
590	525	476	**46**	-	-	**232**	207	180	**11,602**	10,002	8,416
$ 960	$ 819	$ 587	**$ 1,413**	$ -	$ -	**$ 106**	$ 91	$ 77	**$ 17,805**	$ 15,550	$ 13,959
$ 212	$ 285	$ 191	**$ 21**	$ -	$ -	**$ 44**	$ 37	$ 21	**$ 2,974**	$ 3,201	$ 3,099
$ -	$ -	$ -	**$ 500**	$ -	$ -	**$ -**	$ -	$ -	**$ 500**	$ -	$ -
$ 1,335	$ 1,114	$ 834	**$ 3,058**	$ -	$ -	**$ 370**	$ 578	$ 285	**$ 21,697**	$ 17,933	$ 15,716

Total		
2007	2006	2005
$ 15,518	$ 12,664	$ 10,245
2,974	3,201	3,099
$ 17,805	$ 15,550	$ 13,959
660	160	160
21,697	17,933	15,716

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 responsibility. The Company's business is conducted predominantly through three major business segments – upstream, midstream and downstream.

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 Greenland, 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).

Downstream includes refining in Canada of crude oil and marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products (Canadian refined products) and refining in the U.S. of primarily light sweet crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (U.S. refining and marketing).

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 the section, Reconciliation to Accounting Principles Generally Accepted in the United States, contained in Form 40-F filed with the United States Securities and Exchange Commission and available at www.sedar.com.

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.

Accounting policy changes are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively by including these changes in the opening balance of each affected component of equity for the earliest period presented. Changes in accounting estimates are applied prospectively.

The consolidated financial statements include the accounts of Husky Energy Inc. and its subsidiaries after the elimination of intercompany balances and transactions. The Company consolidates all investments in which it has either direct or indirect voting ownership in excess of 50%. In addition, the Company consolidates variable interest entities when it is deemed to be the primary beneficiary.

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 less outstanding cheques and deposits with a maturity of less than three months at the time of purchase. When outstanding cheques are in excess of cash on hand, the excess is reported in bank operating loans.

c) Inventory Valuation

Crude oil, natural gas, refined petroleum products and purchased sulphur inventories are valued at the lower of cost or net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. 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) Precious Metals

The Company uses precious metals in conjunction with catalyst as part of the downstream U.S. refining process. These precious metals remain intact; however, there is a loss during the reclamation process. The estimated loss is amortized to operating expenses over the period that the precious metal is in use, which is approximately two to five years. After the reclamation process, the actual loss is compared to the estimated loss and any difference is recognized in earnings.

e) 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.

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% 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 based on forecast oil and gas prices and costs;
- 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 and major development projects 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 35 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. Certain 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

The recognition of the fair value of obligations associated with the retirement of tangible long-lived assets is 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.

iv) Capitalized Interest

Interest is capitalized on significant major capital projects based on the Company's long-term cost of borrowing. Capitalization of interest ceases when the capital project is substantially complete and ready for its intended use.

f) 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.

g) 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 at least an annual basis or sooner if there are indicators of impairment. 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, determined based on the fair value of the assets and liabilities of the reporting unit. Impairment losses would be recognized in current period earnings.

h) Derivative Financial Instruments and Hedging Activities

i) Financial Instruments

All financial instruments must initially be recognized at fair value on the balance sheet. The Company has classified each financial instrument into the following categories: held for trading financial assets and financial liabilities, loans or receivables, held to maturity investments, available for sale financial assets, and other financial liabilities. Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held for trading financial instruments are recognized in earnings. Gains and losses on available for sale financial assets are recognized in other comprehensive income ("OCI") and are transferred to earnings when the asset is derecognized. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method.

A held for trading financial instrument is not a loan or receivable and includes one of the following criteria:

- is a derivative, except for those derivatives that have been designated as effective hedging instruments;
- has been acquired or incurred principally for the purpose of selling or repurchasing in the near future; or
- is part of a portfolio of financial instruments that are managed together and for which there is evidence of a recent actual pattern of short-term profit taking.

For financial assets and financial liabilities that are not classified as held for trading, the transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are added to the fair value initially recognized for that financial instrument. These costs are expensed to earnings using the effective interest rate method.

ii) Derivative Instruments and Hedging Activities

Derivative 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 instruments for speculative purposes. The Company may choose to designate derivative instruments as hedges. Hedge accounting continues to be optional.

At the inception of a hedge, if the Company elects to use hedge accounting, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between the 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.

All derivative instruments are recorded on the balance sheet at fair value in either accounts receivable, other assets, accounts payable and accrued liabilities, or other long-term liabilities. Freestanding derivative instruments are classified as held for trading financial instruments. Gains and losses on these instruments are recorded in other expenses in the consolidated statement of earnings in the period they occur. Derivative instruments that have been designated and qualify for hedge accounting have been classified as either fair value or cash flow hedges. For fair value hedges, the gains or losses arising from adjusting the derivative to its fair value are recognized immediately in earnings along with the gain or loss on the hedged item. For cash flow hedges, the effective portion of the gains and losses is recorded in OCI until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the consolidated statement of earnings, the fair value of the associated cash flow hedge is reclassified from OCI into earnings. Any hedge ineffectiveness is immediately recognized in earnings. Hedge accounting is discontinued on a prospective basis when the hedging relationship no longer qualifies for hedge accounting.

The Company may enter into commodity price contracts to hedge anticipated sales of crude 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 to retain market prices while meeting customer or supplier pricing requirements. Gains and losses from these contracts are recognized in midstream revenues or costs of sales.

The Company may enter into power price contracts to hedge anticipated purchases of electricity to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream operating expenses as the related purchases occur.

The Company may enter into interest rate swap agreements to hedge its fixed and floating interest rate mix on long-term debt. Gains and losses from these contracts are recognized as an adjustment to the interest expense on the hedged debt instrument.

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 related to foreign exchange are recorded in the foreign exchange expense 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 remaining portion of the gain or loss is recorded in accumulated other comprehensive income and is adjusted for changes in the fair value of the instrument over the life of the debt.

The Company may designate certain U.S. dollar denominated debt as a hedge of its net investment in self-sustaining foreign operations. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in OCI, net of tax and are limited to the translation gain or loss on the net investment.

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

For cash flow hedges that have been terminated or cease to be effective, prospective gains or losses on the derivative are recognized in earnings. Any gain or loss that has been included in accumulated other comprehensive income at the time the hedge is discontinued continues to be deferred in accumulated other comprehensive income until the original hedged transaction is recognized in earnings. However, if the likelihood of the original hedged transaction occurring is no longer probable, the entire gain or loss in accumulated other comprehensive income related to this transaction is immediately reclassified to earnings.

Fair values of the derivatives are based on quoted market prices where available. The fair values of swaps and forwards are based on forward market prices. If a forward price is not available for a commodity based forward, a forward price is estimated using an existing forward price adjusted for quality or location.

iii) Embedded Derivatives

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract when their economic characteristics and risks are not clearly and closely related to those of the host contract, the terms of the embedded derivatives are the same as those of a freestanding derivative and the combined contract is not classified as held for trading or designated at fair value. The Company selected January 1, 2003 as its transition date for accounting for any potential embedded derivatives.

The Company may enter into foreign exchange contracts to offset its foreign exchange exposure. Gains and losses on these instruments are recorded at fair value and are recognized in other expense in the consolidated statement of earnings.

iv) Comprehensive Income

Comprehensive income consists of net earnings and OCI. OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge or net investment hedge and exchange gains and losses arising from the translation of the financial statements of a self-sustaining foreign operation. Amounts included in OCI are shown net of tax. Accumulated other comprehensive income is an equity category comprised of the cumulative amounts of OCI.

i) Employee Future Benefits

In Canada, 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.

Effective July 1, 2007, the Company established a defined benefit pension plan for the employees at the Lima, Ohio refinery. The Company also assumed an unfunded post-retirement welfare plan effective July 1, 2007 that provides life insurance and partially subsidizes the cost of medical benefit premiums. The accounting for the cost of benefits earned by employees covered by these plans is the same as for the Canadian defined benefit pension plan and post-retirement health and dental care plan.

j) 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.

k) Non-monetary Transactions

Non-monetary transactions are measured based on fair value when there is evidence to support the fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business.

l) 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 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.

m) Foreign Currency Translation

Results of foreign operations, 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 non-monetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in earnings.

The accounts of self-sustaining foreign operations are translated to Canadian dollars using the current rate method. Assets and liabilities are translated at the period-end exchange rate and revenues and expenses are translated at the average exchange rates for the period. Gains and losses on the translation of self-sustaining foreign operations are included in OCI.

n) Stock-based Compensation

In accordance with the Company's stock option plan, common share options may be granted to officers and certain other employees. The Company records compensation expense over the vesting period based on the fair value of options granted.

The Company's stock option plan is 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.

o) 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 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. However, since the Company has a tandem stock option plan and accrues a liability for expected cash settlements, the potential common shares issuable upon exercise associated with the stock options are not included in diluted common shares outstanding. 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.

p) Reclassification

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

Note 4. Pending Accounting Pronouncements

a) Financial Instruments – Disclosures and Presentation

In December 2006, the Accounting Standards Board ("AcSB") issued the Canadian Institute of Chartered Accountants ("CICA") section 3862, "Financial Instruments – Disclosures" and CICA section 3863, "Financial Instruments – Presentation," which replaces the current CICA section 3861, "Financial Instruments – Disclosure and Presentation." Section 3862 outlines the disclosure requirements for financial instruments and non-financial derivatives. This guidance prescribes an increased importance on risk disclosures associated with recognized and unrecognized financial instruments and how such risks are managed. Specifically, section 3862 requires disclosure of the significance of financial instruments for a company's financial position. In addition, the guidance outlines revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments.

The presentation requirements under section 3863 are relatively unchanged from section 3861. Sections 3862 and 3863 are effective for the Company on January 1, 2008. The Company is currently determining the impact of these additional disclosure requirements.

b) Capital Disclosures

In December 2006, the AcSB issued new CICA section 1535, "Capital Disclosures" requiring disclosures regarding an entity's objectives, policies and processes for managing capital. These disclosures include a description of what the Company manages as capital, the nature of externally imposed capital requirements, how the requirements are incorporated into the Company's management of capital, whether the requirements have been complied with, or consequences of non-compliance and an explanation of how the Company is meeting its objectives for managing capital. In addition, quantitative data about capital and whether the Company has complied with all capital requirements are also required. Section 1535 is effective for the Company on January 1, 2008. The Company is currently determining the impact of these additional disclosure requirements.

c) Inventories

In June 2007, the AcSB issued new CICA section 3031, "Inventories," which replaces the current CICA section 3030 of the same name. The new guidance provides additional measurement and disclosure requirements. Under the new guidance, the last-in, first-out (LIFO) basis for determining cost will no longer be permitted and reversals of impairment write-downs, which are not currently allowable, will be required. Section 3031 is effective for the Company on January 1, 2008. The transitional provisions of section 3031 provide entities the option of either applying this guidance retrospectively and restating prior periods in accordance with section 1506, "Accounting Changes" or adjusting opening retained earnings and not restating prior periods. The Company has assessed section 3031 and has determined that the adoption of this standard will not have an impact on the financial statements.

Note 5. Accounts Receivable

	2007	2006	2005
Trade receivables	**$ 1,599**	$ 1,286	$ 854
Allowance for doubtful accounts	**(10)**	(10)	(10)
Derivatives due within one year	**22**	-	-
Other	**11**	8	12
	$ 1,622	$ 1,284	$ 856

Sale of Accounts Receivable

As at December 31, 2007, the Company's ceiling on its securitization program to sell, on a revolving basis, accounts receivable to a third party was $350 million. As at December 31, 2007, no accounts receivable had been sold under the program (2006 – nil; 2005 – $350 million). The agreement includes a program fee. The average effective rate for 2007 was approximately 5.3% (2006 – 4.1%; 2005 – 3.0%).

Proceeds from revolving sales between the third party and the Company in 2007 totalled approximately $3.5 billion (2006 – $3.1 billion; 2005 – $3.4 billion).

Note 6. Inventories

	2007	2006	2005
Crude oil	**$ 539**	$ 119	$ 167
Natural gas	**192**	193	207
Refined petroleum products	**409**	89	74
Materials, supplies and other	**50**	27	23
	$ 1,190	$ 428	$ 471

Note 7. Property, Plant and Equipment

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

Administrative costs related to exploration and development activities capitalized in 2007 were $48 million (2006 – $68 million; 2005 – $61 million).

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

	2007	2006	2005
Canada	**$ 1,954**	$ 1,932	$ 2,317
International	**243**	165	127
	$ 2,197	$ 2,097	$ 2,444

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2007 were:

Canada	2008	2009	2010	2011	2012	Price increase 2012 to 2027 *(percent)*
Crude oil *($/bbl)*	$ 61.56	$ 55.73	$ 51.07	$ 48.13	$ 46.99	3
Natural gas *($/mcf)*	6.59	6.72	6.63	6.73	6.86	2

Note 8. Corporate Acquisition

In July 2007, the Company acquired a refinery in Lima, Ohio from The Premcor Refining Group Inc., an indirect wholly owned subsidiary of Valero Energy Corporation through the purchase of all of the issued and outstanding shares of Lima Refining Company ("Lima"). The total cash consideration was U.S. $1.9 billion plus U.S. $540 million for the cost of feedstock and product inventory. The results of Lima are included in the consolidated financial statements of the Company from its acquisition date. The Lima operations have been included in the Downstream – U.S. Refining and Marketing segment in note 1, Segmented Financial Information. The operations of Lima are a self-sustaining foreign operation for foreign currency translation purposes.

The allocation of the aggregate purchase price based on the estimated fair values of the net assets of Lima on its acquisition date was as follows:

	U.S. $	Cdn $
Net assets acquired		
Working capital	$ 4	$ 4
Property, plant and equipment	1,455	1,542
Goodwill [(1)]	506	536
Other assets	25	26
Other long-term liabilities	(86)	(91)
	1,904	2,017
Feedstock and product inventory acquired	540	572
Total	$ 2,444	$ 2,589

(1) Allocated to U.S. Refining and Marketing in the Company's downstream segment. For U.S. income tax purposes, goodwill is deductible and amortized over a 15-year period. Refer to note 1, Segmented Financial Information.

Note 9. Cash Flows – Change in Non-cash Working Capital

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

	2007	2006	2005
Decrease (increase) in non-cash working capital			
Accounts receivable	**$ (345)**	$ (428)	$ (410)
Inventories	**(212)**	43	(197)
Prepaid expenses	**1**	14	17
Accounts payable and accrued liabilities	**(190)**	277	962
Change in non-cash working capital	**$ (746)**	$ (94)	$ 372
Relating to:			
Operating activities	**$ (718)**	$ 544	$ (94)
Financing activities	**65**	(678)	255
Investing activities	**(93)**	40	211

b) Other cash flow information:

	2007	2006	2005
Cash taxes paid	**$ 926**	$ 215	$ 154
Cash interest paid	**162**	147	147

Note 10. Bank Operating Loans

At December 31, 2007, the Company had unsecured short-term borrowing lines of credit with banks totalling $270 million (2006 – $220 million; 2005 – $195 million). As at December 31, 2007, bank operating loans (excluding reclassified outstanding cheques) were nil (2006 – nil; 2005 – $0.4 million) and letters of credit under these lines of credit totalled $73 million (2006 – $19 million; 2005 – $18 million). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. During 2007, the weighted average interest rate on short-term borrowings was approximately 5.8% (2006 – 5.8%; 2005 – 3.9%).

Note 11. Accounts Payable and Accrued Liabilities

	2007	2006	2005
Trade payables	**$ 23**	$ 74	$ 7
Accrued liabilities	**1,743**	1,322	1,338
Dividend payable	**280**	212	530
Stock-based compensation	**159**	234	130
Current income taxes	**36**	615	164
Other	**117**	117	141
	$ 2,358	$ 2,574	$ 2,310

Note 12. Long-term Debt

		Cdn $ Amount			U.S. $ Denominated		
	Maturity	2007	2006	2005	2007	2006	2005
Long-term debt							
6.85% medium-term notes – Series B	2007	**$ -**	$ –	$ 100	**$ -**	$ –	$ –
6.95% medium-term notes – Series E	2009	**203**	200	200	**-**	–	–
6.25% notes	2012	**395**	466	467	**400**	400	400
7.55% debentures	2016	**198**	233	233	**200**	200	200
6.20% notes	2017	**296**	–	–	**300**	–	–
6.15% notes	2019	**296**	350	350	**300**	300	300
8.90% capital securities	2028	**223**	262	262	**225**	225	225
6.80% notes	2037	**445**	–	–	**450**	–	–
Debt issue costs		**(20)**	–	–	**-**	–	–
Unwound interest rate swaps		**37**	–	–	**-**	–	–
		$ 2,073	$ 1,511	$ 1,612	**$ 1,875**	$ 1,125	$ 1,125
Long-term debt due within one year							
Bridge financing	2008	**$ 741**	$ –	$ –	**$ 750**	$ –	$ –
6.85% medium-term notes – Series B	2007	**-**	100	–	**-**	–	–
7.125% notes	2006	**-**	–	175	**-**	–	150
8.45% senior secured bonds	2006	**-**	–	99	**-**	–	85
		$ 741	$ 100	$ 274	**$ 750**	$ –	$ 235

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

	2007	2006	2005
Long-term debt	**$ 151**	$ 130	$ 144
Short-term debt	**6**	5	4
	157	135	148
Amount capitalized	**(19)**	(33)	(114)
	138	102	34
Interest income	**(8)**	(10)	(2)
	$ 130	$ 92	$ 32

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

	2007	2006	2005
Gain on translation of U.S. dollar denominated long-term debt	**$ (197)**	$ (7)	$ (51)
Cross currency swaps	**62**	4	14
Other (gains) losses	**84**	(21)	6
	$ (51)	$ (24)	$ (31)

Credit Facilities

The revolving syndicated credit facility allows the Company to borrow up to $1.25 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a five-year committed revolving credit facility. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

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

In July 2007, the Company obtained U.S. $1.5 billion of short-term bridge financing at an interest rate based on U.S. LIBOR, maturing June 26, 2008, to facilitate closing the acquisition of the Lima, Ohio refinery. On September 11, 2007, the Company refinanced U.S. $750 million with long-term notes. The Company has the right to extend the remaining bridge financing of U.S. $750 million to June 26, 2009 by providing 30 days' notice.

As at December 31, 2007, there were no borrowings under the syndicated credit facility or the bilateral credit facilities.

Notes and Debentures

On September 21, 2006, Husky filed a shelf prospectus, which enables Husky to offer up to U.S. $1.0 billion of debt securities in the United States until October 21, 2008. During the 25-month period that the prospectus remains effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. In 2007, U.S. $750 million of debt securities were issued under this new shelf prospectus.

The medium-term notes Series E represent unsecured securities under a trust indenture dated May 4, 1999. Interest is payable semi-annually.

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

The 7.55% debentures represent unsecured securities under a trust indenture dated October 31, 1996. Interest is payable semi-annually.

The 6.20% and the 6.80% notes represent unsecured securities under a trust indenture dated September 11, 2007. Interest is payable semi-annually.

The 8.90% capital securities represent unsecured securities under an indenture dated August 10, 1998. Such securities rank junior to all senior debt and other financial debt of the Company. The 8.90% interest is payable semi-annually until August 15, 2008. The capital securities mature in 2028. They 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 interest rate changes to a floating rate equal to U.S. LIBOR plus 5.50% payable semi-annually. The Company has the right at any time prior to maturity, subject to certain conditions, to defer payment of interest for up to five years. The Company also has the unrestricted ability to settle its deferred interest, principal and redemption obligations through the issuance of common or preferred shares.

The medium-term notes Series B represented unsecured securities under a trust indenture dated February 3, 1997 and matured in 2007.

The 7.125% notes represented unsecured securities under a trust indenture dated October 31, 1996 and matured in 2006. Interest was payable semi-annually.

The 8.45% senior secured bonds represented securities under a trust indenture dated July 20, 1999 that were redeemed in full on February 1, 2006. Interest was payable semi-annually. Certain related financial obligations required collateral of letters of credit and/or cash equivalents. As at December 31, 2005, letters of credit totalling $41 million were outstanding.

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.

Commencing in 2007, debt issue costs have been reclassified to long-term debt with the adoption of CICA section 3855, "Financial Instruments – Recognition and Measurement" (refer to notes 3 and 19). Previously, these deferred costs were included in other assets. As at December 31, 2006 and 2005, other assets included $12 million and $21 million of deferred debt issue costs, respectively.

The unamortized portion of the gain on previously unwound interest rate swaps that would be designated as fair value hedges is included in the carrying value of long-term debt with the adoption of Financial Instruments.

Note 13. Other Long-term Liabilities

	2007	2006	2005
Asset retirement obligations	**$ 662**	$ 622	$ 557
Cross currency swaps (1)	**107**	40	40
Interest rate swaps	**–**	37	42
Employee future benefits	**69**	30	27
Capital lease	**36**	–	–
Stock-based compensation	**13**	4	46
Other	**31**	23	18
	$ 918	$ 756	$ 730

(1) Refer to note 19, Financial Instruments and Risk Management.

Asset Retirement Obligations

At December 31, 2007, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $4.7 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2% to 6.8%.

Changes to the asset retirement obligations were as follows:

	2007	2006	2005
Asset retirement obligations at beginning of year	**$ 622**	$ 557	$ 509
Liabilities incurred	**57**	35	63
Liabilities disposed	**(13)**	(1)	(7)
Liabilities settled	**(51)**	(36)	(41)
Revisions	**-**	22	-
Accretion [1]	**47**	45	33
Asset retirement obligations at end of year	**$ 662**	$ 622	$ 557

(1) Accretion is included in cost of sales and operating expenses.

Note 14. Income Taxes

The provision for income taxes in the Consolidated Statements of Earnings and Comprehensive Income 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:

	2007	2006	2005
Earnings (loss) before income taxes			
Canada	**$ 3,763**	$ 3,276	$ 2,553
United States	**95**	15	(6)
Other foreign jurisdictions	**269**	215	265
	4,127	3,506	2,812
Statutory income tax rate *(percent)*	**32.7**	35.7	38.4
Expected income tax	**1,350**	1,252	1,080
Effect on income tax of:			
Royalties, lease rentals and mineral taxes payable to the crown	**-**	10	105
Resource allowance on Canadian production income	**-**	(35)	(133)
Change in statutory tax rate	**(395)**	(328)	(4)
Rate benefit on partnership earnings	**(53)**	(97)	(69)
Capital gains and losses	**(24)**	(1)	(140)
Foreign jurisdictions	**8**	(6)	(14)
Non-deductible capital taxes	**-**	(17)	15
Other – net	**27**	2	(31)
Income tax expense	**$ 913**	$ 780	$ 809

During 2007, a tax benefit of $395 million was recognized as a result of reductions in the Canadian federal tax rate, compared with a benefit of $328 million in 2006 as a result of reductions in both federal and provincial tax rates.

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

	2007	2006	2005
Future tax liabilities			
Property, plant and equipment	**$ 4,081**	$ 3,607	$ 3,487
Foreign exchange gains taxable on realization	**131**	48	60
Other temporary differences	**1**	1	2
	4,213	3,656	3,549
Future tax assets			
Asset retirement obligations	**186**	194	195
Loss carry forwards	**-**	2	-
Provincial royalty rebates	**-**	2	7
Other temporary differences	**70**	86	77
	256	284	279
	$ 3,957	$ 3,372	$ 3,270

Note 15. 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 2007, the Company capitalized $84 million (2006 – $85 million; 2005 – $68 million) of payments under this arrangement.

At December 31, 2007, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

	2008	2009	2010	2011	2012	After 2012	Total
Long-term debt and interest	$ 1,104	$ 323	$ 106	$ 107	$ 488	$ 2,254	$ 4,382
Operating leases	218	285	268	161	64	28	1,024
Firm transportation agreements	165	100	68	36	33	147	549
Unconditional purchase obligations	2,564	1,189	283	115	46	39	4,236
Lease rentals and exploration work agreements	175	105	121	141	91	215	848
Engineering and construction commitments	71	-	-	-	-	-	71
	$ 4,297	$ 2,002	$ 846	$ 560	$ 722	$ 2,683	$11,110

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. In 2005 a lawsuit was settled with proceeds received and the resulting gain was recognized in earnings and recorded in other – net.

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 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

On June 27, 2007, the Company filed Articles of Amendment to implement a two-for-one share split of its issued and outstanding common shares. The share split was approved at a special meeting of the shareholders on June 27, 2007. All references to common share amounts, including common shares issued and outstanding, basic and diluted earnings per share, dividend per share, weighted average number of common shares outstanding, stock options granted, exercised, surrendered and forfeited, Renaissance Energy Ltd. ("Renaissance") replacement options and warrants granted and exercised have been retroactively restated to reflect the impact of the two-for-one share split. Changes to issued share capital were as follows:

	Number of Shares	Amount
December 31, 2004	847,472,828	$ 3,506
Options and warrants exercised	777,328	17
December 31, 2005	848,250,156	3,523
Options exercised	286,862	10
December 31, 2006	848,537,018	3,533
Options exercised	423,292	18
December 31, 2007	**848,960,310**	**$ 3,551**

Stock Options

At December 31, 2007, 55.0 million common shares were reserved for issuance under the Company stock option plan. The stock option plan is 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 weighted average trading 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 weighted average trading 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 terms of the original 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. Effective February 26, 2007, the Board of Directors approved amendments to the Company's stock option plan to also provide for performance vesting of stock options. Shareholder ratification was obtained at the Annual and Special Meeting of Shareholders on April 19, 2007. Performance options granted may vest in up to one-third increments if the Company's annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to its industry peer group. The ultimate number of performance options that vest will depend upon the Company's performance measured over three calendar years. If the Company's performance is below the specified level compared with its industry peer group, the performance options awarded will be forfeited. If the Company's performance is at or above the specified level compared with its industry peer group, the number of performance options exercisable shall be determined by the Company's relative ranking. Stock compensation expense related to the performance options is accrued based on the price of the common shares at the end of the period and the anticipated performance factor. This expense is recognized over the three-year vesting period of the performance options. During 2007, $12.2 million of expense was recognized related to the performance options.

As a result of the special $0.25 per share dividend that was declared in February 2007, a downward adjustment of $0.175 was made to the exercise price of all outstanding stock options effective February 28, 2007, in accordance with the terms of the stock option plan under which the options were issued. In 2005, a similar downward adjustment of $0.275 was made to the exercise price of all outstanding stock options as a result of a special $0.50 dividend declared in that year.

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

	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Options Exercisable *(thousands)*
December 31, 2004	19,929	$ 11.30	4	2,834
Granted	1,339	$ 24.07	5	
Exercised for common shares	(718)	$ 7.92	1	
Surrendered for cash	(4,886)	$ 9.52	2	
Forfeited	(1,094)	$ 12.05	3	
December 31, 2005	14,570	$ 12.91	3	3,066
Granted	1,804	$ 35.71	4	
Exercised for common shares	(287)	$ 11.15	2	
Surrendered for cash	(3,902)	$ 11.97	2	
Forfeited	(529)	$ 21.41	3	
December 31, 2006	11,656	$ 16.40	3	4,463
Granted	26,926	$ 41.65	4	
Exercised for common shares	(423)	$ 11.84	1	
Surrendered for cash	(5,147)	$ 13.40	2	
Forfeited	(2,881)	$ 40.41	4	
December 31, 2007	**30,131**	**$ 37.18**	**4**	**4,494**

As at December 31, 2007	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices
$7.23 – $9.99	44	$ 7.26	–	44	$ 7.26
$10.00 – $10.99	27	$ 10.32	1	27	$ 10.32
$11.00 – $12.99	3,832	$ 11.74	1	3,832	$ 11.74
$13.00 – $19.99	130	$ 15.92	2	84	$ 15.39
$20.00 – $29.99	455	$ 26.17	3	205	$ 26.43
$30.00 – $39.99	1,258	$ 35.89	3	302	$ 36.46
$40.00 – $42.57	24,385	$ 41.65	4	–	$ –
	30,131	**$ 37.18**	**4**	**4,494**	**$ 14.09**

Warrants

In 2000, the Company granted 2.7 million 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. As at December 31, 2007, 2006 and 2005, there were no Renaissance replacement options or warrants outstanding. During 2005, 32,000 warrants were exercised.

Dividends

During 2007, the Company declared dividends of $1.33 per common share (2006 – $0.75 per common share; 2005 – $0.825 per common share), including special dividends of $0.25 per common share in 2007 and $0.50 per common share in 2005.

Note 17. Employee Future Benefits

a) Canada

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.

Defined Benefit Pension Plan

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

	2007	2006	2005
Discount rate *(percent)*	**5.0**	5.0	5.8
Long-term rate of increase in compensation levels *(percent)*	**5.0**	5.0	5.0
Long-term rate of return on plan assets *(percent)*	**7.5**	7.5	7.5

The discount rate used at the end of 2007 to determine the accrued benefit obligation was 5%.

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 2007 was 7.5%.

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

Benefit Obligation	2007	2006	2005
Benefit obligation, beginning of year	**$ 149**	$ 138	$ 124
Current service cost	**2**	3	2
Interest cost	**7**	7	7
Benefits paid	**(8)**	(7)	(6)
Actuarial losses	**-**	8	11
Benefit obligation, end of year	**$ 150**	$ 149	$ 138

Fair Value of Plan Assets	2007	2006	2005
Fair value of plan assets, beginning of year	**$ 132**	$ 108	$ 96
Contributions	**10**	13	11
Benefits paid	**(8)**	(7)	(6)
Expected return on plan assets	**10**	8	7
Gain on plan assets	**(3)**	10	-
Fair value of plan assets, end of year	**$ 141**	$ 132	$ 108

Funded Status of Plan	2007	2006	2005
Fair value of plan assets	**$ 141**	$ 132	$ 108
Benefit obligation	**(150)**	(149)	(138)
Excess obligation	**(9)**	(17)	(30)
Unrecognized past service costs	**3**	3	1
Unrecognized losses	**32**	33	40
Accrued benefit asset	**$ 26**	$ 19	$ 11

Husky adheres to a Statement of Investment Policies and Procedures (the "Policy"). 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 Company's actuaries perform valuations as at December 31 for the defined benefit pension plan. The last actuarial valuation was conducted in 2007 and the next valuation will be conducted in 2008.

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

	2007	2006	2005
U.S. common equities	**1%**	1%	–%
Canadian common equities	**30**	30	29
International equity mutual funds	**27**	30	28
Canadian government bonds	**14**	16	18
Canadian corporate bonds	**4**	3	3
International fixed income	**2**	–	–
Canadian fixed income mutual funds	**20**	19	20
Cash and receivables	**2**	1	2
Total	**100%**	100%	100%

During 2007, 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 $6 million in 2008.

The Company amortizes the portion of the unrecognized actuarial gains or losses that exceed 10% 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% are amortized over the expected future years of service, which is currently seven years.

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

Post-retirement Health and Dental Care Plan

The discount rate used in the calculation of the benefit obligation was 5%. The average health care cost trend used was 9.5% which is reduced by 0.50% until 2015. The average dental care cost trend used was 4%, which remains constant.

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

Benefit Obligation	2007	2006	2005
Benefit obligation, beginning of year	**$ 49**	$ 33	$ 25
Current service cost	**4**	2	2
Interest cost	**2**	2	1
Benefits paid	**(1)**	–	–
Actuarial losses	**–**	12	5
Benefit obligation, end of year	**$ 54**	$ 49	$ 33

Funded Status of Plan	2007	2006	2005
Benefit obligation	**$ (54)**	$ (49)	$ (33)
Unrecognized losses	**17**	19	6
Accrued benefit liability	**$ (37)**	$ (30)	$ (27)

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	$ 2	$ (1)
Effect on post-retirement benefit obligation	$ 12	$ (9)

Pension Expense and Post-retirement Health and Dental Care Expense

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

Pension Expense	**2007**	2006	2005
Defined benefit pension plan			
Employer current service cost	**$ 2**	$ 3	$ 2
Interest cost	**7**	7	7
Expected return on plan assets	**(10)**	(8)	(7)
Amortization of net actuarial losses	**3**	3	3
	2	5	5
Defined contribution pension plan	**18**	16	14
Total expense	**$ 20**	$ 21	$ 19

Post-retirement Health and Dental Care Expense	**2007**	2006	2005
Employer current service cost	**$ 4**	$ 2	$ 2
Interest cost	**2**	2	1
Amortization of net actuarial losses	**1**	–	–
Total expense	**$ 7**	$ 4	$ 3

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
2008	$ 8	$ 1
2009	9	1
2010	9	1
2011	9	1
2012	10	2
2013 – 2017	52	10

b) United States

Defined Benefit Pension Plan

As at December 31, 2007, the benefit obligation was $1 million and the fair value of the plan assets was $1 million. The discount rate used at the end of 2007 to determine the accrued benefit obligation was 6.10%. During 2007, Husky contributed $1 million to the defined benefit pension plan assets and currently plans to contribute $2 million in 2008.

Pension expense for the six months ended December 31, 2007 was $1 million.

Post-retirement Welfare Plan

As at December 31, 2007, the benefit obligation was $33 million. The discount rate used at the end of 2007 to determine the accrued benefit obligation was 6.25%.

Post-retirement welfare expense for the six months ended December 31, 2007 was $1.5 million.

Note 18. Related Party Transactions

During the year, TransAlta Power, L.P. ("TAPLP") came under the indirect control of Husky's principal shareholders. TAPLP is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP") which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions and have been measured at the exchange amount. For 2007, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $104 million. At December 31, 2007, the total value of accounts receivables related to these transactions was $10 million.

Note 19. Financial Instruments and Risk Management

Effective January 1, 2007, the Company adopted CICA section 3855, "Financial Instruments – Recognition and Measurement," section 3865, "Hedges," section 1530, "Comprehensive Income" and section 3861, "Financial Instruments – Disclosure and Presentation." The Company has adopted these standards prospectively and the comparative consolidated financial statements have not been restated. Transition amounts have been recorded in retained earnings or accumulated other comprehensive income.

Upon adoption and with any new financial instrument, an irrevocable election was available to classify any financial asset or financial liability as held for trading, even if the financial instrument did not meet the criteria to designate it as held for trading. The Company did not elect to classify any financial assets or financial liabilities as held for trading unless they met the held for trading criteria.

The following table summarizes the prospective adoption adjustments that were required as at January 1, 2007:

	December 31, 2006 (As Reported)	Adoption Adjustment	January 1, 2007 (As Restated)
Consolidated Balance Sheets			
Assets			
Accounts receivable	$ 1,284	$ 6	$ 1,290
Prepaid expenses	25	(2)	23
Other assets	44	(7)	37
Liabilities and Shareholders' Equity			
Accounts payable and accrued liabilities	2,574	(5)	2,569
Long-term debt due within one year	100	(2)	98
Long-term debt	1,511	34	1,545
Other long-term liabilities	756	(10)	746
Future income taxes	3,372	(6)	3,366
Retained earnings	6,087	4	6,091
Accumulated other comprehensive income	–	(18)	(18)

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 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 long-term debt at December 31 was as follows:

	2007		2006		2005	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	**$ 2,814**	**$ 2,903**	$ 1,611	$ 1,671	$ 1,886	$ 1,995

Commodity Price Risk Management

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, 2007, the Company had the following third party offsetting physical purchase and sale natural gas contracts, which met the definition of a derivative instrument:

	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	32,930	$ 6
Physical sale contracts	(32,930)	$ (5)

These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain has been recorded in other expenses in the consolidated statement of earnings for the period.

Natural Gas Production

The Company did not have a natural gas hedge program in 2007 or 2006. In 2005, the Company realized a loss of $17 million related to these natural gas contracts.

Power Consumption

In 2007, the Company realized a loss of less than $1 million (2006 – gain of $6 million; 2005 – gain of $4 million) on hedged power consumption.

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, 2007, the Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the medium-term notes was swapped to floating rates with the following terms:

Debt	Amount	Swap Maturity	Swap Rate *(percent)*	Fair Value
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps	$ 3

This contract has been recorded at fair value in other assets. In 2007, the Company recognized a gain of less than $1 million (2006 – $1 million; 2005 – $13 million) on the interest rate swap arrangements.

In 2005 the Company unwound interest rate swaps for proceeds of $37 million. The proceeds have been deferred and are being amortized to income over the remaining term of the underlying debt.

Embedded Derivative

The Company entered into a contract with a Norwegian-based company for drilling services offshore China. The contract currency is U.S. dollars, which is not the functional currency of either transacting party. As a result, this contract has been identified as containing an embedded derivative requiring bifurcation and separate accounting treatment at fair value. This embedded derivative has been recorded at fair value in accounts receivable and other assets and the resulting unrealized gain has been recorded in other expenses in the consolidated statement of earnings for the period. In 2007, the impact was an unrealized gain on the embedded derivative of $101 million.

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, 2007, the Company had a cash flow hedge using the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate *(percent)*	Fair Value
6.25% notes	U.S. $150	$212	June 15, 2012	7.41	$ (75)
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65	$ (13)
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67	$ (8)
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61	$ (11)

These contracts have been recorded at fair value in other long-term liabilities. The portion of the fair value of the derivative related to foreign exchange losses has been recorded in earnings to offset the foreign exchange on the translation of the underlying debt. The remaining loss of $5 million, net of tax of $1 million, has been included in OCI. At December 31, 2007, the balance in accumulated other comprehensive income was $14 million, net of tax of $7 million. In 2007, the Company recognized a loss of $62 million (2006 – $4 million; 2005 – $14 million) on the cross currency debt swaps.

On November 10, 2004, the Company unwound its long-dated forwards, which resulted in a gain of $8 million that was deferred and was recognized into income during 2005 on the dates that the underlying hedged transactions took place.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. During 2007, the impact of these contracts was a loss of $18 million (2006 – gain of $2 million; 2005 – gain of $15 million).

The Company entered into forward purchases of U.S. dollars to partially offset the fluctuations in foreign exchange related to the contract for drilling services offshore China, which contains an embedded derivative. At December 31, 2007, the following foreign exchange transactions had been entered into:

Date	Forward Purchases	Canadian Equivalent	Fair Value
October 5, 2007	U.S. $119	$117	$2
October 11, 2007	U.S. $119	$116	$2
October 29, 2007	U.S. $119	$115	$4

These forward contracts have been recorded at fair value in accounts receivable and other assets and the resulting gain has been recorded in other expenses in the consolidated statement of earnings. In 2007, the impact was a gain of $8 million.

Effective July 1, 2007, the Company's U.S. $1.5 billion of debt financing related to the Lima acquisition was designated as a hedge of the Company's net investment in the U.S. refining and marketing operations, which are considered self-sustaining. The unrealized foreign exchange gain of $102 million, net of tax of $19 million, arising from the translation of the debt is recorded in OCI.

Unrecognized Gains (Losses) on Derivative Instruments

Prior to the adoption of the new Canadian GAAP financial instruments standards, certain gains and losses on derivative instruments were unrecognized. The following table summarizes these unrecognized gains and losses for comparative purposes.

	2006	2005
Interest rate risk management		
Interest rate swaps	$ 5	$ 7
Foreign currency risk management		
Foreign exchange contracts	(26)	(32)

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's policy is to primarily deal with major financial institutions and investment grade rated entities to mitigate these risks.

Husky did not have any customers that constituted more than 10% of total sales and operating revenues during 2007.

Note 20. Proposed Transaction with BP

In December 2007, the Company entered into an arrangement to create a 50/50 integrated oil sands joint venture with BP Corporation North America Inc. ("BP"), consisting of upstream and downstream assets. Under the terms of the arrangement, Husky will contribute its Sunrise assets located in the Athabasca oil sands in northeast Alberta to an oil sands partnership and BP will contribute its Toledo refinery located in Ohio, USA to a U.S. joint venture entity. In accordance with Canadian GAAP, these joint entities will be accounted for using the proportionate consolidation method. The transaction is scheduled to close in the first quarter of 2008.

Supplemental Financial and Operating Information

Segmented Financial Information

	Upstream					Midstream									
						Upgrading					Infrastructure and Marketing				
($ millions)	**2007**	2006	2005	2004	2003	**2007**	2006	2005	2004	2003	**2007**	2006	2005	2004	2003
Year ended December 31															
Sales and operating revenues, net of royalties	**$ 6,222**	$ 5,772	$ 4,367	$ 3,120	$3,186	**$1,524**	$1,679	$1,488	$1,058	$1,013	**$10,217**	$9,559	$7,383	$6,126	$4,946
Costs and expenses															
Operating, cost of sales, selling and general	**1,308**	1,321	1,050	967	873	**1,127**	1,273	1,018	884	901	**9,838**	9,258	7,084	5,914	4,747
Depletion, depreciation and amortization	**1,615**	1,476	1,144	1,077	918	**25**	24	21	19	20	**28**	24	21	21	21
Interest – net	**-**	-	-	-	-	**-**	-	-	-	-	**-**	-	-	-	-
Foreign exchange	**-**	-	-	-	-	**-**	-	-	-	-	**-**	-	-	-	-
	2,923	2,797	2,194	2,044	1,791	**1,152**	1,297	1,039	903	921	**9,866**	9,282	7,105	5,935	4,768
Earnings (loss) before income taxes	**3,299**	2,975	2,173	1,076	1,395	**372**	382	449	155	92	**351**	277	278	191	178
Current income taxes	**122**	519	215	211	95	**10**	53	16	-	1	**68**	79	(14)	31	27
Future income taxes	**581**	161	434	152	233	**80**	44	120	43	20	**30**	1	110	32	37
Net earnings (loss)	**$ 2,596**	$ 2,295	$ 1,524	$ 713	$1,067	**$ 282**	$ 285	$ 313	$ 112	$ 71	**$ 253**	$ 197	$ 182	$ 128	$ 114
Total assets – As at December 31	**$14,395**	$13,920	$12,887	$11,025	$9,847	**$1,405**	$ 992	$ 844	$ 708	$ 650	**$ 1,134**	$1,329	$ 866	$ 746	$ 804

(1) 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.

Segmented Capital Expenditures

($ millions)	**2007**	2006	2005	2004	2003
Upstream					
Western Canada	**$ 2,031**	$ 2,172	$ 2,007	$ 1,533	$ 1,195
East Coast Canada and Frontier	**281**	358	645	539	557
International	**76**	97	78	85	26
	2,388	2,627	2,730	2,157	1,778
Midstream					
Upgrader	**217**	184	120	62	25
Infrastructure and Marketing	**92**	68	37	31	18
	309	252	157	93	43
Downstream					
Canadian Refined Products	**212**	285	191	106	58
U.S. Refining and Marketing	**21**	-	-	-	-
	233	285	191	106	58
Corporate	**44**	37	21	23	23
	$ 2,974	$ 3,201	$ 3,099	$ 2,379	$ 1,902

Note: Excludes capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Downstream						Corporate and Eliminations (1)					Total				
Canadian Refined Products					U.S. Refining and Marketing										
2007	2006	2005	2004	2003	**2007**	**2007**	2006	2005	2004	2003	**2007**	2006	2005	2004	2003
$2,916	$ 2,575	$ 2,345	$ 1,797	$ 1,502	**$2,383**	**$(7,744)**	$(6,921)	$(5,338)	$(3,661)	$(2,989)	**$15,518**	$12,664	$10,245	$ 8,440	$ 7,658
2,608	2,381	2,169	1,694	1,426	**2,167**	**(7,542)**	(6,742)	(5,145)	(3,543)	(2,978)	**9,506**	7,491	6,176	5,916	4,969
66	48	47	38	26	**47**	**25**	27	23	24	36	**1,806**	1,599	1,256	1,179	1,021
-	-	-	-	-	**1**	**129**	92	32	60	102	**130**	92	32	60	102
-	-	-	-	-	**-**	**(51)**	(24)	(31)	(120)	(282)	**(51)**	(24)	(31)	(120)	(282)
2,674	2,429	2,216	1,732	1,452	**2,215**	**(7,439)**	(6,647)	(5,121)	(3,579)	(3,122)	**11,391**	9,158	7,433	7,035	5,810
242	146	129	65	50	**168**	**(305)**	(274)	(217)	(82)	133	**4,127**	3,506	2,812	1,405	1,848
17	19	(3)	11	9	**28**	**102**	8	83	49	15	**347**	678	297	302	147
33	21	50	13	9	**35**	**(193)**	(125)	(202)	(143)	32	**566**	102	512	97	331
$ 192	$ 106	$ 82	$ 41	$ 32	**$ 105**	**$ (214)**	$ (157)	$ (98)	$ 12	$ 86	**$ 3,214**	$ 2,726	$ 2,003	$ 1,006	$ 1,370
$1,335	$ 1,114	$ 834	$ 625	$ 540	**$3,058**	**$ 370**	$ 578	$ 285	$ 129	$ 105	**$21,697**	$17,933	$15,716	$13,233	$11,946

Upstream Operating Information

	2007	2006	2005	2004	2003
Daily production, before royalties					
Light crude oil & NGL *(mbbls/day)*	**138.7**	111.0	64.6	66.2	71.6
Medium crude oil *(mbbls/day)*	**27.1**	28.5	31.1	35.0	39.2
Heavy crude oil & bitumen *(mbbls/day)*	**106.9**	108.1	106.0	108.9	99.9
	272.7	247.6	201.7	210.1	210.7
Natural gas *(mmcf/day)*	**623.3**	672.3	680.0	689.2	610.6
Total production *(mboe/day)*	**376.6**	359.7	315.0	325.0	312.5
Average sales prices					
Light crude oil & NGL *($/bbl)*	**$ 73.54**	$ 69.06	$ 61.56	$ 48.34	$ 39.53
Medium crude oil *($/bbl)*	**$ 51.12**	$ 49.48	$ 43.44	$ 36.13	$ 31.42
Heavy crude oil & bitumen *($/bbl)*	**$ 40.19**	$ 39.92	$ 31.09	$ 28.66	$ 25.87
Natural gas *($/mcf)*	**$ 6.19**	$ 6.47	$ 7.96	$ 6.25	$ 5.86
Operating costs *($/boe)*	**$ 9.09**	$ 8.77	$ 8.12	$ 7.32	$ 6.92
Operating netbacks (1)					
Light crude oil *($/boe)* (2)	**$ 57.52**	$ 57.06	$ 47.76	$ 35.42	$ 30.21
Medium crude oil *($/boe)* (2)	**$ 27.61**	$ 27.27	$ 24.93	$ 20.03	$ 16.76
Heavy crude oil & bitumen *($/boe)* (2)	**$ 22.07**	$ 23.65	$ 17.57	$ 16.02	$ 14.13
Natural gas *($/mcfge)* (3)	**$ 3.80**	$ 4.10	$ 5.22	$ 3.92	$ 3.71

(1) Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.
(2) Includes associated co-products converted to boe.
(3) Includes associated co-products converted to mcfge.

Western Canada Wells Drilled

		2007		2006		2005		2004		2003	
		Gross	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	**79**	**79**	101	99	89	85	45	39	12	11
	Gas	**114**	**92**	330	192	392	196	234	180	147	124
	Dry	**14**	**12**	26	24	36	36	34	33	22	21
		207	**183**	457	315	517	317	313	252	181	156
Development	Oil	**571**	**530**	590	543	466	433	552	499	520	490
	Gas	**343**	**251**	565	490	610	551	807	740	540	518
	Dry	**31**	**29**	25	22	42	39	57	53	60	57
		945	**810**	1,180	1,055	1,118	1,023	1,416	1,292	1,120	1,065
		1,152	**993**	1,637	1,370	1,635	1,340	1,729	1,544	1,301	1,221
Success ratio *(percent)*		**96**	**96**	97	97	95	94	95	94	94	94

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Financial Highlights										
Sales and operating revenues,										
net of royalties	**$ 15,518**	$ 12,664	$ 10,245	$ 8,440	$ 7,658	$ 6,384	$ 6,596	$ 5,066	$ 2,787	$ 2,023
Net earnings (loss)	**$ 3,214**	$ 2,726	$ 2,003	$ 1,006	$ 1,370	$ 796	$ 629	$ 398	$ 91	$ (8)
Earnings per share										
Basic	**$ 3.79**	$ 3.21	$ 2.36	$ 1.19	$ 1.63	$ 0.95	$ 0.76	$ 0.62	$ 0.17	$ (0.01)
Diluted	**$ 3.79**	$ 3.21	$ 2.36	$ 1.19	$ 1.62	$ 0.95	$ 0.76	$ 0.62	$ 0.17	$ (0.01)
Capital expenditures (1)	**$ 2,974**	$ 3,201	$ 3,099	$ 2,379	$ 1,902	$ 1,707	$ 1,474	$ 803	$ 706	$ 829
Total debt	**$ 2,814**	$ 1,611	$ 1,886	$ 2,204	$ 2,094	$ 2,740	$ 2,572	$ 2,726	$ 1,725	$ 1,485
Debt to capital employed *(percent)*	**19**	14	20	26	27	36	38	43	51	51
Reinvestment ratio *(percent)* (2)	**86**	70	80	110	91	78	79	59	142	204
Return on average capital										
employed *(percent)* (3)	**25.7**	27.0	22.8	13.0	18.9	12.3	10.8	11.9	7.3	4.3
Return on equity *(percent)* (4)	**30.2**	31.8	29.2	17.0	26.4	17.9	16.3	20.5	13.7	7.2
Upstream										
Daily production, before royalties										
Light crude oil & NGL *(mbbls/day)*	**138.7**	111.0	64.6	66.2	71.6	65.4	46.4	42.8	22.3	23.7
Medium crude oil *(mbbls/day)*	**27.1**	28.5	31.1	35.0	39.2	44.8	47.2	20.8	4.2	3.9
Heavy crude oil &										
bitumen *(mbbls/day)*	**106.9**	108.1	106.0	108.9	99.9	95.1	83.8	53.5	42.1	42.0
	272.7	247.6	201.7	210.1	210.7	205.3	177.4	117.1	68.6	69.6
Natural gas *(mmcf/day)*	**623**	672	680	689	611	569	573	358	251	233
Total production *(mboe/day)*	**376.6**	359.7	315.0	325.0	312.5	300.2	272.8	176.8	110.4	108.4
Total proved reserves,										
before royalties *(mmboe)*	**1,014**	1,004	985	791	887	918	927	872	430	431
Midstream										
Synthetic crude oil sales *(mbbls/day)*	**53.1**	62.5	57.5	53.7	63.6	59.3	59.5	60.6	61.9	54.8
Upgrading differential *($/bbl)*	**$ 30.73**	$ 26.16	$ 30.70	$ 17.79	$ 12.88	$ 10.81	$ 17.91	$ 13.77	$ 6.49	$ 7.85
Pipeline throughput *(mbbls/day)*	**501**	475	474	492	484	457	537	528	394	412
Canadian Refined Products										
Light oil products										
sales *(million litres/day)*	**8.7**	8.7	8.9	8.4	8.2	7.7	7.6	7.4	7.6	6.0
Asphalt products sales *(mbbls/day)*	**21.8**	23.4	22.5	22.8	22.0	20.8	21.4	20.2	17.1	19.5
Refinery throughput										
Prince George refinery *(mbbls/day)*	**10.5**	9.0	9.7	9.8	10.3	10.1	10.2	9.2	10.2	9.9
Lloydminster refinery *(mbbls/day)*	**25.3**	27.1	25.5	25.3	25.7	22.0	23.7	23.4	17.9	21.9
Refinery utilization *(percent)*	**90**	90	101	100	103	92	97	93	80	91

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

(2) Reinvestment ratio is based on net capital expenditures including corporate acquisitions (other than Renaissance Energy Ltd.).

(3) Capital employed for purposes of this calculation has been weighted for 2000.

(4) Equity for purposes of this calculation has been weighted for 2000 and includes amounts due to shareholders prior to August 25, 2000.

Board of Directors

Victor T. K. Li

Canning K. N. Fok

Victor T.K. Li, Co-Chairman,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Li is Managing Director and Deputy Chairman of Cheung Kong (Holdings) Limited. He is Deputy Chairman and Executive Director of Hutchison Whampoa Limited, Executive Director and Chairman of CK Life Sciences Int'l., (Holdings) Inc, and of Cheung Kong Infrastructure Holdings Limited. Mr. Li is an Executive Director of Hongkong Electric Holdings Limited and a Director of The Hongkong and Shanghai Banking Corporation Limited.

Canning K. N. Fok (2), Co-Chairman,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Fok is Group Managing Director and Executive Director of Hutchison Whampoa Limited. He is Chairman and a Director of Hutchison Harbour Ring Limited, Hutchinson Telecommunication International Limited, Hutchison Telecommunications (Australia) Limited, Partner Communications Company Ltd. and Hongkong Electric Holdings Limited. Mr. Fok is the Deputy Chairman and a Director of Cheung Kong Infrastructure Holdings Limited and a Director of Cheung Kong (Holdings) Limited.

William Shurniak (1), Deputy Chairman,
a resident of Limerick, Saskatchewan has been a Director of Husky Energy Inc. since 2000. Mr. Shurniak is a Director of Hutchison Whampoa Limited and a Director and Chairman of Northern Gas Networks Limited.

R. Donald Fullerton (1), Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2003. Mr. Fullerton serves as a corporate director on a number of private companies and is a Director of the Li Ka Shing (Canada) Foundation.

Martin J. G. Glynn (1) (3), Director,
a resident of Scotland, has been a Director of Husky Energy Inc. since 2000. Mr. Glynn is a director of Hathor Exploration Limited.

Holger Kluge (2) (3) (4), Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2000. Mr. Kluge is a Director of Hongkong Electric Holdings Limited, Hutchison Whampoa Limited and Shoppers Drug Mart Corporation.


William Shurniak


R. Donald Fullerton


Martin J. G. Glynn


Holger Kluge


Poh Chan Koh


Eva L. Kwok


Stanley T. L. Kwok


John C. S. Lau


Colin S. Russel


Wayne E. Shaw


Frank J. Sixt

Poh Chan Koh, Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Miss Koh is the Finance Director of Harbour Plaza Hotel Management (International) Ltd.

Eva L. Kwok (2) (3), Director,
a resident of Vancouver, has been a Director of Husky Energy Inc. since 2000. Mrs. Kwok is a Director, Chairman and Chief Executive Officer of Amara International Investment Corp. She is a Director of the Bank of Montreal Group of Companies, CK Life Sciences Int'l., (Holdings) Inc., Cheung Kong Infrastructure Holdings Limited and the Li Ka Shing (Canada) Foundation.

Stanley T. L. Kwok (4), Director
a resident of Vancouver, has been a Director of Husky Energy Inc. since 2000. Mr. Kwok is the President and a Director of Stanley Kwok Consultants. He is President and a Director of Amara International Investment Corp. and a Director of Cheung Kong (Holdings) Limited.

John C.S. Lau, President & CEO, Director,
a resident of Calgary, has been a Director of Husky Energy Inc. since 2000. Prior to joining Husky in 1992, Mr. Lau served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies.

Colin S. Russel, Director
a resident of the United Kingdom, has been a Director of Husky Energy since 2008. Mr. Russel is the founder and Managing Director of Emerging Markets Advisory Services Ltd. Mr. Russel is a Director of Cheung Kong Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd.

Wayne E. Shaw (3) (4), Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2000. Mr. Shaw is a Senior Partner at Stikeman Elliott LLP, Barristers & Solicitors and a Director of the Li Ka Shing (Canada) Foundation.

Frank J. Sixt (2), Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Sixt is Group Finance Director and Executive Director of Hutchison Whampoa Limited. He is the Chairman and a Director of TOM Online Inc. and TOM Group Limited, and Executive Director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited, and a Director of Hutchison Telecommunications International Limited, Cheung Kong (Holdings) Limited, Hutchison Telecommunications (Australia) Limited, Partner Communications Company Ltd. and the Li Ka Shing (Canada) Foundation.

The Management Information Circular contains additional information regarding the Directors.

(1) Audit Committee
(2) Compensation Committee
(3) Corporate Governance Committee
(4) Health, Safety & Environment Committee

Officers/Executives

John C. S. Lau

Robert J. Peabody

Donald R. Ingram

James D. Girgulis

HUSKY ENERGY INC.

John C. S. Lau, President & Chief Executive Officer
Mr. Lau was appointed to his position in 1993 and is responsible for Husky's corporate direction, strategic planning and corporate policies, and a member of the Company's Board of Directors. Prior to his appointment he was Senior Vice President. Before joining Husky he served in a number of senior executive roles within the Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies.

Robert J. Peabody, Chief Operating Officer, Operations & Refining
Mr. Peabody is responsible for managing Husky Energy's upstream operations including Western Canada conventional, heavy oil, east coast operations, frontier and international exploration and development, and exploration and production services. He is also responsible for managing refining, upgrading and ethanol production activities. Prior to joining Husky in 2006, he led four major businesses for British Petroleum in Europe and the United States. Mr. Peabody is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Donald R. Ingram, Senior Vice President, Midstream & Refined Products
Mr. Ingram has been an officer of Husky since 1994. He joined the Company in 1982 and has more than 30 years' experience in the midstream and downstream business. Mr. Ingram is a Certified Management Accountant (CMA) and a fellow of the Society of Management Accountants of Canada (FCMA).

James D. Girgulis, Q.C., Vice President, Legal & Corporate Secretary
Mr. Girgulis was appointed Vice President, Legal & Corporate Secretary in 2000. Previously he was General Counsel & Corporate Secretary of Husky Oil Limited. Prior to joining Husky he held positions with Alberta and Southern Gas Co. and Alberta Natural Gas Company. Mr. Girgulis was called to the Alberta Bar in 1982 and was appointed Queen's Counsel in 2005.

HUSKY OIL OPERATIONS LIMITED

Ronald J. Butler, Vice President, Corporate Administration
Mr. Butler is responsible for human resources, health, safety and environment, risk management and records management. He is an experienced human resources practitioner and leader with extensive oil and gas experience. Prior to joining Husky he was Vice President, Human Resources with BP Canada and formerly Manager, Human Resources of Amoco (U.K.) Exploration Company. Mr. Butler is a Past-President and current member of the Human Resources Association of Calgary and a Past Director of the Human Resources Institute of Alberta.

Edward T. Connolly, Vice President, Heavy Oil
Mr. Connolly was appointed Vice President, Heavy Oil in 2006 and has responsibility for increasing both heavy oil reserves and production. Previously he was Manager, Drilling, Well Completions & Facilities Construction with Talisman Energy Canada, and Facilities Construction Project Manager with BP Canada.
Mr. Connolly is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.


Ronald J. Butler


Edward T. Connolly


Robert S. Coward


J. Michael D'Aguiar


Catherine J. Hughes


Bill Watson


Ruud B. Zoon


Roy C. Warnock

Robert S. Coward, Vice President, Western Canadian Conventional Production

Mr. Coward became a corporate officer in 1993 and has served with Husky since 1977. He was appointed Vice President, Western Canadian conventional production in 2005 and is responsible for optimizing the value of Husky's assets by increasing both reserves and production, and by controlling costs. Mr. Coward is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

J. Michael D'Aguiar, Vice President, Finance

Mr. D'Aguiar joined Husky Energy as Treasurer in 2002. He was appointed Vice President, Finance in 2007, and is responsible for the Treasury, Taxation and Controller's groups. Mr. D'Aguiar has extensive finance experience in the international upstream oil industry, and has fulfilled positions in financial management with major oil and gas companies. Prior to joining Husky he was Chief Financial Officer of Ranger Oil Limited. He is a CFA charter holder.

Catherine J. Hughes, Vice President, Oil Sands

Ms. Hughes was appointed Vice President, Oil Sands in 2007. She had previously served as Vice President, Exploration & Production Services. She joined Husky in 2005 and has extensive senior level experience in the oil and gas industry. Ms. Hughes served as President of Schlumberger Canada, and worked in a variety of operational, technical and management positions with Schlumberger in the United States, the United Kingdom, Europe and Nigeria.

Bill Watson, Vice President, Engineering & Project Management

Mr. Watson was appointed Vice President, Engineering & Project Management in 2004, and brings more than 30 years of experience in the energy business to Husky. Previously Mr. Watson was Vice President of Triton Equatorial Guinea Inc., a wholly owned subsidiary of Amerada Hess, and held many management and executive positions with Marathon Oil Company including President of Marathon Canada Ltd.

Ruud B. Zoon, Vice President, East Coast Operations

Mr. Zoon joined Husky Energy in 2004 as General Manager, East Coast Development, and was appointed Vice President, East Coast Operations in 2005. Based in St. John's, Newfoundland and Labrador, he is responsible for all aspects of Husky's East Coast operations including the White Rose development. Prior to joining Husky he worked in leadership roles in the Netherlands, the United Kingdom, South Africa, China and the United States. He has worked for Sonoil B.V., Bluewater Energy Services B.V. and Mobil Oil Corporation. Mr. Zoon has been a member of the Society of Petroleum Engineers since 1984.

Roy C. Warnock, Vice President & General Manager

Mr. Warnock was appointed Vice President & General Manager of the Lima Refining Company in 2007, and is responsible for all refining operations in the United States. Mr. Warnock is Vice President, Upgrading & Refining, Husky Oil Operations Limited. Mr. Warnock joined Husky in 1983, and served as the Manager of the Prince George Refinery and the Lloydminster Upgrader. Prior to Husky, he held a number of engineering and operations positions with Imperial Oil. Mr. Warnock is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and Association of Professional Engineers and Geoscientists of Saskatchewan.

Common Share Information

Year ended December 31		2007	2006	2005
Share price	High	**$ 46.65**	$ 41.50	$ 34.98
	Low	**$ 35.01**	$ 29.00	$ 16.15
	Close at December 31	**$ 44.59**	$ 39.02	$ 29.50
Average daily trading volumes *(thousands)*		**1,063**	1,210	1,328
Number of common shares outstanding, December 31 *(thousands)*		**848,960**	848,538	848,250
Weighted average number of common shares outstanding *(thousands)*				
	Basic	**848,777**	848,412	847,928
	Diluted	**848,777**	848,412	847,928

Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite, S&P/TSX Canadian Energy Sector and in the S&P/TSX 60 indices.

Share prices and volumes reflect a two-for-one stock split effective July 9, 2007.

Toronto Stock Exchange Listing: HSE

Outstanding Shares
The number of common shares outstanding (in thousands) at December 31, 2007 was 848,960.

Transfer Agent and Registrar
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. Share certificates may be transferred at Computershare's principal offices in Calgary, Toronto, Montreal and Vancouver, and at Computershare's principal office in Denver, Colorado, in the United States.

Queries regarding share certificates, dividends and estate transfers should be directed to Computershare Trust Company at 1-888-267-6555 (toll free in North America).

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KPMG LLP
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Calgary, Alberta T2P 4B9

Annual Meeting
The annual meeting of shareholders will be held at 10:30 a.m. on Tuesday, April 22, 2008 in the Palomino Room, at the Round Up Centre, Twelfth Avenue S.E. and Third Street S.E., Calgary, Alberta.

Additional Publications
The following publications are available on our website or from our Investor Relations department:

- Annual Information Form, filed with Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports

Dividends
Husky's Board of Directors has approved a dividend policy that pays quarterly dividends.

The following table is restated for the two-for-one split of the common shares that occurred in July 2007.

Declaration Date	Quarter Dividend	Special Dividend
February 2008	$ 0.330	
October 2007	0.330	
August 2007	0.250	
May 2007	0.250	
February 2007	0.250	$ 0.250
October 2006	0.250	
July 2006	0.250	
April 2006	0.125	
February 2006	0.125	
October 2005	0.125	0.500
July 2005	0.070	
April 2005	0.070	
February 2005	0.060	
November 2004	0.060	0.270
July 2004	0.060	
April 2004	0.060	
February 2004	0.050	
November 2003	0.050	
July 2003	0.050	0.500
April 2003	0.045	
February 2003	0.045	

ABBREVIATIONS AND ADVISORIES

bbls	barrels
bcf	billion cubic feet
boe	barrels of oil equivalent
bps	basis points
CDOR	Certificate of Deposit Offered Rate
GJ	gigajoule
hectare	1 hectare is equal to 2.47 acres
km	kilometre
LIBOR	London Interbank Offered Rate
mbbls	thousand barrels
mbbls/day	thousand barrels per day
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per day
mcf	thousand cubic feet
mcfge	thousand cubic feet of gas equivalent
mmbbls	million barrels
mmboe	million barrels of oil equivalent
mmbtu	million British Thermal Units
mmcf	million cubic feet
mmcf/day	million cubic feet per day
mmlt	million long tons
MW	megawatt
MWh	megawatt-hour
NGL	natural gas liquids
NIT	NOVA Inventory Transfer (1)
NYMEX	New York Mercantile Exchange
tcf	trillion cubic feet
WTI	West Texas Intermediate

(1) NOVA Inventory Transfer is an exchange or transfer of title of gas that has been received into the NOVA pipeline system but not delivered to a connecting pipeline.

The Company has disclosed contingent resources of natural gas in this Annual Report. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

The contingent resources disclosed refer to the Liwan natural gas discovery in the South China Sea on Block 29/26. These contingent resources were estimated following the drilling of the Liwan 3-1-1 discovery well in June 2006. Delineation of Liwan is planned for the second half of 2008. Completion of delineation drilling will provide data necessary to assign reserves and advance development plans. Other contingencies may include factors such as adequate economic and market considerations and commitment to develop these resources as well as other factors such as legal, environmental, political and regulatory issues. There is no certainty that it will be commercially viable to produce any portion of these resources. CNOOC has the right to participate in up to 51% in the development of any discoveries.

The Company has disclosed discovered petroleum initially-in-place in this Report in respect of bitumen. Discovered petroleum initially-in-place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and contingent resources; the remainder is unrecoverable. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Please refer to page 62 "Disclosure of Proved Oil and Gas Reserves and Other Oil and Gas Information" for further information regarding the Company's disclosure of reserve information in this Report, including proved and probable reserves, and of contingent resources and discovered petroleum initially-in-place, and cautions regarding the use of the terms "boe" and "mcfge". We also use certain terms in this Report, such as "contingent resources" and "discovered petroleum initially-in-place", that the guidelines of the United States Securities and Exchange Commission ("SEC") strictly prohibit in filings with the SEC by U.S. oil and gas companies; please also refer to "Cautionary Note to U.S. Investors" at page 62.

This Report contains forward looking statements or information. For a description of these forward looking statements or information and the risks and uncertainties related thereto, please refer to page 61 of this Report and also to Husky's March 10, 2008 Annual Information Form and Form 40-F.

In this report, the terms "Husky Energy Inc.," "Husky" or "the Company" mean Husky Energy Inc. and its subsidiaries and partnership interests on a consolidated basis.

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