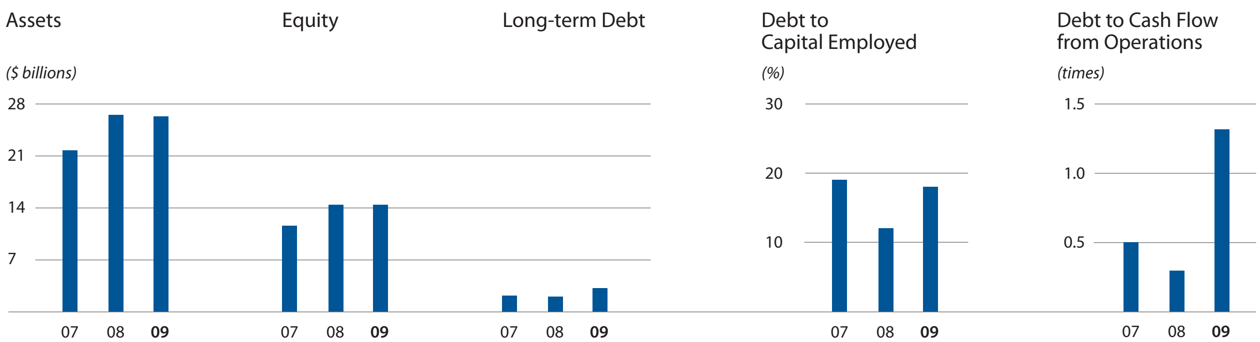
Husky Energy Inc.

Management's Discussion and Analysis

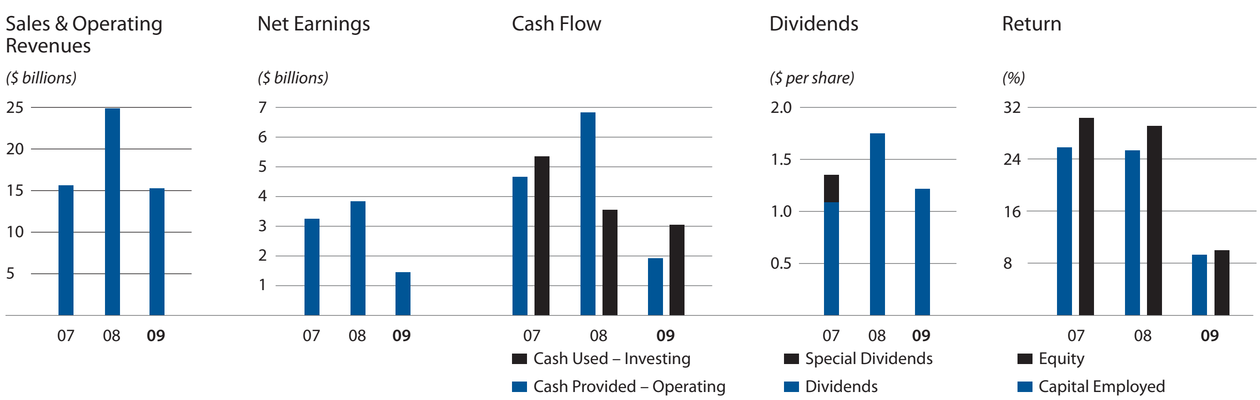
For the Year Ended December 31, 2009
February 24, 2010

1.0 Financial Summary

1.1 FINANCIAL POSITION



1.2 FINANCIAL PERFORMANCE



1.3 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
2005	77%	61%	22%
2006	37%	3%	15%
2007	18%	5%	7%
2008	(28)%	(36)%	(35)%
2009	2%	35%	31%
Five year average	20%	14%	8%
Five year cumulative return	102%	50%	27%

1.4 SELECTED ANNUAL INFORMATION

($ millions, except where indicated)		2009		2008 [1]		2007 [1]
Sales and operating revenues, net of royalties	**$**	**15,074**	$	24,701	$	15,518
Net earnings by sector						
Upstream	**$**	**1,113**	$	3,377	$	2,596
Midstream		**254**		470		521
Downstream		**265**		(299)		298
Corporate and eliminations		**(216)**		203		(214)
Net earnings	**$**	**1,416**	$	3,751	$	3,201
Net earnings per share - basic/diluted	**$**	**1.67**	$	4.42	$	3.77
Ordinary dividends per common share	**$**	**1.20**	$	1.70	$	1.16
Cash flow from operations	**$**	**2,507**	$	5,946	$	5,388
Total assets	**$**	**26,295**	$	26,486	$	21,666
Long-term debt including current portion	**$**	**3,229**	$	1,957	$	2,814
Cash and cash equivalents	**$**	**392**	$	913	$	208
Return on equity *(percent)*		**9.8**		28.9		30.1
Return on average capital employed *(percent)*		**9.1**		25.1		25.6

(1) 2008 and 2007 amounts as restated for the adoption of a new accounting policy. Refer to Note 4 of the Consolidated Financial Statements.

2.0 Husky Business Overview

Husky is a Canadian-based international energy and energy-related company with total assets greater than $26 billion and approximately 4,900 staff. Husky is integrated through the three industry sectors: upstream, midstream and downstream.

- In the upstream sector, the Company explores for, develops and produces crude oil and natural gas *(upstream business segment)*.
- In the midstream sector, Husky upgrades heavy crude oil *(upgrading business segment)*, processes and transports via pipeline heavy crude oil, maintains interests in two cogeneration plants as well as markets and operates storage facilities for crude oil and natural gas *(infrastructure and marketing business segment)*.
- In the downstream sector, the Company distributes motor fuel and ancillary and convenience products, manufactures and markets asphalt products, produces ethanol and operates two regional refineries in Canada *(Canadian refined products business segment)* and refines crude oil through interests in two refineries in Ohio and markets refined products in the U.S. Midwest *(U.S. refining and marketing business segment)*.

3.0 Capability to Deliver Results

Husky's results are dependent on a number of factors including commodity prices, foreign exchange rates, the Company's continued success in exploring for oil and natural gas, efficient and safe execution of capital projects and operations, effective marketing, retention of expertise and continued access to the financial markets.

3.1 UPSTREAM

- Large base of crude oil producing properties in Western Canada that have responded well to the application of increasingly sophisticated exploitation techniques. Enhanced oil recovery ("EOR") techniques including thermal in-situ recovery methods are extensively used in the mature Western Canada Sedimentary Basin to increase recovery rates and stabilize decline rates of heavy and light crude oil. Emerging EOR techniques are being field tested, while techniques that have been in practice for several decades continue to be optimized;
- Substantial position in the Alberta oil sands. The initial stages of the development of these assets include the Tucker oil sands project currently in production and the Sunrise project that is in the development phase. The Sunrise project will proceed as a joint 50/50 partnership with BP and is an integral part of a North American oil sands business that includes the BP-Husky Toledo Refinery;
- Harsh weather offshore exploration, development and production expertise, as demonstrated by the successful White Rose development and further development of the North Amethyst satellite field offshore Newfoundland. Husky also

holds an interest in the Terra Nova field and a large portfolio of significant discovery and exploration licences offshore Newfoundland and Labrador and offshore Greenland;

- Increased position in Western Canada gas resource plays with over 925,000 acres associated with several evaluation and development gas resource projects;
- Expertise and experience exploring and developing the high impact natural gas potential in the deep basin, foothills, and northwest plains of Alberta and British Columbia;
- Large acreage position offshore China that includes a production interest in the Wenchang oil field, natural gas discoveries at the Liwan field in Block 29/26 where development has commenced, significant gas discoveries at the Liuhua 29-1 and 34-2 fields within Block 29/26, and a portfolio of exploration blocks; and
- Offshore Indonesia Husky holds two exploration licences. The Madura BD natural gas and natural gas liquids discovery, in which the Company holds a 50% interest, 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 integrated heavy oil pipeline systems in the Lloydminster producing region;
- Participation in two cogeneration power facilities having a combined 295 MW of capacity, both of which are integrated with local plant operations;
- Natural gas storage in excess of 33 bcf, owned and leased;
- Petroleum marketer balancing the needs of both customers and suppliers; and
- Supplier of crude oil and natural gas feedstock for the Company's plants and facilities.

3.3 DOWNSTREAM

- Refinery at Lima, Ohio, and a 50% interest in the BP-Husky Refinery in Toledo, Ohio each with a crude oil throughput capacity of 160 mbbls/day;
- Refinery at Prince George, British Columbia with 12 mbbls/day capacity of low sulphur gasoline and ultra low sulphur diesel;
- Largest marketer of paving asphalt in Western Canada with a 28 mbbls/day capacity asphalt refinery located at Lloydminster, integrated with the local heavy oil production, transportation and upgrading infrastructure;
- 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; and
- Major regional motor fuel marketer with 473 retail marketing locations including bulk plants and travel centres with strategic land positions in Western Canada and Ontario. Retail outlets include in many cases convenience stores, restaurants, service bays and carwashes. An agreement to purchase 98 retail outlets in 2010 in the southern Ontario region will expand Husky's retail market.

3.4 CORPORATE

Husky's corporate capabilities are discussed in the following sections:

- Section 8 Liquidity and Capital Resources
- Section 11.5 Controls and Procedures

4.0 Strategic Plan

Husky's overall strategy is to create superior shareholder value through financial discipline and the development of a quality asset base, including the development of large scale sustainable oil and gas reserves with integration through the value chain.

Husky's upstream strategy is to exploit oil and gas assets in areas with large scale sustainable growth potential. The Company's upstream plans include projects in Canada (the Alberta oil sands and the basins offshore Canada's East Coast), Asia (the South China Sea, the Madura Strait and the East Java Sea), the U.S. Columbia River Basin and offshore Greenland. In addition, the Company will apply enhanced recovery technology to our heavy oil assets as well as continue to expand our exposure to gas resource plays in the Western Canada Sedimentary Basin. In the midstream and downstream sectors, Husky is enhancing performance and maximizing the value chain through integrating its businesses, optimizing plant operations and expanding plant and infrastructure.

Husky's strategic direction by business segment is as follows:

4.1 UPSTREAM

In Western Canada, Husky will optimize light and medium crude oil production with the application of selected enhanced recovery techniques and continue to focus on selected high impact natural gas plays in the foothills and deep basin portion of Western Canada. The Company is expanding its position in unconventional natural gas exploration and development including shale gas, tight gas, coal bed methane and gas resource plays.

The Company aims to increase heavy oil production through cold production, thermal recovery and other enhanced recovery techniques integrated with downstream processing.

Husky is well positioned in the oil sands with approximately 550,000 net acres of land in the Athabasca and Cold Lake deposits in Alberta, Canada. Husky will continue to optimize and develop the Tucker oil sands project to increase production. The Company, together with its partner BP, is continuing progress on the Sunrise oil sands project with production to be developed in stages; current maximum permitted production being 200 mbbls/day. Husky will continue to evaluate its other oil sands holdings including the Saleski and Caribou projects.

Husky continues to maximize the value of its assets offshore the East Coast of Canada through the development of the White Rose satellite tieback fields and the continuing development of Terra Nova. The Company is also pursuing exploration opportunities and evaluating options to develop natural gas discoveries in the region.

Husky is building a South East Asia business with the development of current resources and a focused exploration plan. The Company has completed a deep water appraisal drilling program at the Liwan natural gas discovery offshore China and is proceeding with its development, together with the Liuhua natural gas discoveries. In Indonesia, the Madura BD Indonesia natural gas and natural gas liquids project has completed front end engineering and is awaiting a Production Sharing Contract ("PSC") extension. Husky will continue exploration in the prospective basins in the South China Sea, the East China Sea and the North East Java Basin.

4.2 MIDSTREAM

Husky will continue to enhance and expand the infrastructure in the Lloydminster area and optimize the integration of the upgrader, pipeline, asphalt refinery, cogeneration and ethanol facilities. Husky will enhance and expand terminalling infrastructure and services to meet the requirements associated with growing bitumen and heavy oil development and will pursue greenhouse gas management strategies including participation in industry initiatives, carbon offset opportunities, sequestration and identification of carbon credit and trading opportunities.

4.3 DOWNSTREAM

Husky will continue to pursue projects to optimize, integrate and reconfigure the Lima, Ohio Refinery for heavy crude oil feedstock and is planning to reconfigure and expand the BP-Husky Toledo, Ohio Refinery to accommodate Sunrise production as its primary feedstock. The Company will also expand terminalling and product storage opportunities.

4.4 FINANCIAL

Husky is committed to maintain its strong financial position to support large capital growth projects and provide shareholders with an enhanced return on their investment. Over the business cycle, the Company intends to maintain a debt to capitalization ratio of less than 40% and maintain debt to cash flow from operations of less than three times. In view of the economic environment, action has been taken to maintain the Company's strong balance sheet including prudently reduced capital spending in 2009, implementation of cost containment and efficiency programs and managing access to capital markets to enhance liquidity.

5.0 Key Growth Highlights

The 2009 capital program focused mainly on optimizing upstream production, midstream and downstream development and progressing major projects offshore Canada's East Coast and South East Asia. The 2010 capital budget has been established with the view of maintaining the strength of Husky's balance sheet and taking advantage of opportunities as economic conditions begin to improve and financial uncertainty abates. Capital expenditures will be focused on those projects offering the highest potential for returns and mid to long-term growth.

5.1 UPSTREAM

East Coast Canada and Greenland

White Rose Development Projects

At the North Amethyst oil field, subsea installation and commissioning commenced on schedule in early June. Modifications to the *Sea Rose FPSO* to accommodate future production from the satellite field were carried out during the vessel's planned major maintenance turnaround which took place in July and August and development drilling resumed in November 2009. The initial production well and water injection well are expected to be completed and tested during the first quarter of 2010. Production from North Amethyst is targeted to come on stream in the second quarter of 2010.

Analysis of results from the North Amethyst E-17 exploration well that was drilled in 2008 to the deeper Hibernia formation revealed 55 metres of net oil-bearing reservoir. The resources of the Hibernia formation will be further assessed by reservoir studies and future drilling at both the North Amethyst and White Rose fields.

In November 2009, Husky filed an amended development plan with the Canada-Newfoundland and Labrador Offshore Petroleum Board ("C-NLOPB") for a two well pilot scheme at the West White Rose field. The proposed staged development plan for West White Rose would initially start with one production well and one water injection well drilled from the existing central drill centre at the main White Rose field. It is expected that this well pair would provide data pertinent to the next phase of the West White Rose development. Subject to receipt of the West White Rose development plan amendment approval, drilling could commence as early as the second quarter of 2010 with completion and first oil by late 2010/early 2011.

East Coast Exploration

Husky continues to evaluate the results of its recently acquired 2,150 square kilometre 3-D seismic program in the Jeanne d'Arc Basin with the objective of identifying additional exploratory well locations that can be drilled in the near-term. During 2009, the Company commenced public consultations on its Environmental Assessment ("EA") process for future seismic activity offshore Labrador and commenced the EA process for potential seismic acquisition in the Sydney Basin, located between Newfoundland and Cape Breton, Nova Scotia. The programs are planned for the summer/fall of 2010. In January 2010, the Company commenced drilling of the Glenwood exploration prospect (Husky 100%) on Exploration Licence ("EL") 1090.

Application was made in 2009 for a significant discovery licence based on the results of the December 2008 Mizzen exploration well. Husky has a 35% working interest in the Mizzen well located in the Flemish Pass Basin on EL 1049.

In November 2009, Husky was successful on a bid for the NL09-01 parcel in the Jeanne d'Arc Basin. This parcel consists of approximately 23,600 acres adjacent to the North Amethyst field. Husky is the operator and holds a 72.5% interest in this exploration prospect.

Offshore Greenland

Evaluation of a 7,000 kilometre 2-D seismic program acquired in the third quarter of 2008 on Blocks 5 and 7 is complete. Evaluation of an airborne gravity and magnetics survey that was acquired in the second quarter of 2009 is nearing completion. Husky is the operator and holds an 87.5% interest in these two blocks. Husky also holds a 43.75% working interest in Block 6 where 3,000 kilometres of 2-D seismic was acquired in the third quarter of 2008. In November 2009, Husky completed the acquisition of a 2,200 square kilometre 3-D seismic program over Block 7 and Block 5. This survey is the first 3-D seismic survey conducted offshore Greenland and utilizes a new "Geostreamer" technology.

South East Asia

Offshore China Block 29/26

In 2009, the *West Hercules* deep water drilling rig completed drilling and testing three appraisal wells on the Liwan 3-1 field, Block 29/26 in the South China Sea. In November 2009, the *West Hercules* drilling rig drilled a significant new natural gas discovery at Liuhua 34-2-1, approximately 20 kilometres to the northeast of the Liwan 3-1 field. The well tested natural gas with high liquids content at an equipment restricted rate of 55 mmcf/day, with indications that future well deliveries could exceed 140 mmcf/day. In February 2010, another significant new gas discovery was confirmed at Liuhua 29-1-1, approximately 43 kilometres to the northeast of the Liwan 3-1 field. The well tested natural gas at an equipment restricted rate of 57 mmcf/day, with indications that future well deliveries could exceed 90 mmcf/day. The *West Hercules* drilling rig is currently preparing to spud the first delineation well on the Liuhua 34-2 discovery. Both Liuhua fields will be tied into the proposed Liwan 3-1 shallow water infrastructure.

The Liwan 3-1 field is the first deep water development in offshore China. Following field delineation of the Liwan 3-1 natural gas field, Husky submitted the Original Gas In-Place ("OGIP") report to the Government of China in late December and expects to receive approval in early 2010. The Overall Development Plan ("ODP") is currently being prepared with the aim of submission to the Government of China in the first quarter of 2010. The field, which is located approximately 300 kilometres southeast of Hong Kong, will be developed using a subsea production system connected to a central shallow water platform. A subsea pipeline will transport gas to an onshore gas plant with access to the high demand energy markets of Hong Kong and Guangdong province on the China mainland. Front end engineering design ("FEED") commenced in the second quarter and was approximately 96% complete at the end of 2009 and is expected to be completed by mid 2010. First production is expected in 2013.

In 2009, the *West Hercules* drilling rig drilled three additional exploration wells on Block 29/26, the Liwan 4-1-1, Liwan 9-1-1 and Liwan 9-1-2, which were abandoned without testing.

Offshore China Exploration

Planning is underway for an exploration well on Block 04/35 in the East China Sea. A rig has been secured and the well is expected to be spud in early 2010. On Block 63/05 in the Qiongdongnan Basin, 50 kilometres south of Hainan Island, existing 2-D seismic has been interpreted and plans are in place to acquire 300 square kilometres of 3-D seismic in the March/April 2010 time frame.

During 2009, an application was made and regulatory approval was obtained to relinquish deepwater Block 29/06 in the Pearl River Mouth Basin, immediately to the east of Block 29/26 together with Blocks 35/18 and 50/14 in the Yinggehai Basin, due to higher than acceptable exploration risk.

Block 39/05 in the Pearl River Mouth Basin, immediately southwest of the Wenchang oil fields, was relinquished following the drilling of the QH-29-2-1 exploration well, which was abandoned without testing.

Indonesia Exploration and Development

The Madura BD field development plan has been approved by the Government of Indonesia and Husky, together with the operator CNOOC, continue to await approval of an extension to the PSC. FEED is 90% complete, and will be completed in the first quarter of 2010. Extension of the PSC is required to further progress development.

During 2009, contracts were awarded for the acquisition and processing of 1,020 kilometres of new 2-D seismic on the North Sumbawa II Block. This data was acquired in December 2009 and will be used to define exploration prospects that are planned for drilling in 2011. Husky holds a 100% interest in the North Sumbawa II Block, comprising 5,000 square kilometres in the East Java Sea.

In the East Bawean II PSC, an application was made to relinquish the block. The application was based on the drilling of two exploration wells, the Adiyasa 1 and Kukura 1, which were abandoned without testing in the third quarter of 2009, and a lack of any other attractive prospects on the block.

Heavy Oil and Oil Sands

Sunrise In-situ Oil Sands Integrated Project

Husky and BP continue to advance the development of the Sunrise project in multiple stages (Husky 50% interest). Bitumen production from phase one (planned at 60 mbbls/day) is expected to commence approximately four years after project sanction planned in 2010. Total gross production is currently planned to ramp up to 200 mbbls/day, subject to project sanction and market conditions. Work on optimization to simplify its scope was completed at the end of 2009. With FEED completed and regulatory approval for the amended design in place, Husky is preparing to issue requests for proposals for the central plant and field facilities.

Tucker In-situ Oil Sands Project

Husky continues to pursue operational strategies to achieve full implementation of the SAGD process in this reservoir. The majority of the wells in the project are in steady state SAGD operational mode and production rates were approximately 5 mbbls/day at the end of the year. During the first half of 2009, the full implementation of the steam chamber development plan was delayed due to low oil prices. With improving crude oil prices in the second half of 2009, drilling of three new well pairs commenced in December 2009 and are expected to be injecting steam by the third quarter of 2010. Regulatory applications are proceeding for additional drilling in 2010.

McMullen

Husky's development of the McMullen property, which is located in the west central region of the Athabasca oil sands of northern Alberta, involves a cold production project and plans for a thermal pilot project. In the fourth quarter of 2009, Husky completed and tied in a 13 well program previously drilled at the cold production project. An additional 13 wells were drilled in the fourth quarter and are being completed and equipped for start up in February 2010.

Pikes Peak South

Husky is progressing with an extension of its Pikes Peak South heavy oil thermal project. Pikes Peak South has a design capacity of 8,000 boe/day with first production planned for 2012.

Non-Thermal EOR

In the Lloydminster heavy oil producing area, Husky continues to test various non-thermal enhanced recovery techniques. Operations continue at the Company's first cold enhanced pilot project where six successful injection/production cycles have been completed. Husky's second pilot project, which utilizes CO_2, commenced during the second quarter of 2009 and continued to operate to the end of 2009 with promising initial results. Both pilots continue to provide insight into reservoir response and process economics.

Western Canada and USA (excluding Heavy Oil and Oil Sands)

Gas Resource Plays

Husky has increased its exposure to gas resource plays within the Western Canada Sedimentary Basin that have the potential to deliver significant volumes of low cost gas in the coming years. Husky currently has over 925,000 acres associated with several gas resource projects in various stages of evaluation and development. These include established assets at Bivouac (625,000 acres) and Ansell (115,000 acres), in addition to a number of emerging projects including the Montney formation and the Horn River Basin. In 2009, Husky added over 89,000 acres of new lands to its gas resource play portfolio.

In October 2009, Husky acquired a 50% working interest in 36 drilling spacing units with rights in the Doig and Montney formations. With this acquisition, Husky's combined holdings total approximately 25,000 acres in this resource play located in the Cypress area of Northeast British Columbia, which is largely characterized by shale gas reservoirs. Husky is currently participating in a horizontal exploration well on an adjacent section and further drilling is contingent on the results of this well.

During 2009, Husky tied in 55 gross (27.5 net) coal bed methane producing wells in the Elnora/Trochu area. Husky intends to continue with its coal bed methane program in 2010 with plans to tie in 8 gross (4 net) wells drilled in the fourth quarter, and recomplete 15 gross (7.5 net) shut-in conventional natural gas wells in the Horseshoe Canyon coal formation.

Northeastern British Columbia & Washington State Exploration

In the Bullmoose – Sukunka region of Northeastern British Columbia, Husky is participating in the Belcourt formation exploration well (42% Working Interest "WI") that will follow-up the Burnt River c-A61-A (55% WI) and the Sukunka a-27-F (20% WI) wells, which are capable of producing at gross rates in excess of 30 mmcf/day. Both the Burnt River and Sukunka wells were placed on production in early October at a combined rate of 15 to 25 mmcf/day net Husky raw gas rate depending on processing capacity availability.

The drilling of the Grey 31-23 well in the Columbia River Basin in Washington State was completed in 2009. The well yielded fresh water and only minor gas from the Oligocene aged sands. Husky is currently evaluating its Columbia River Basin holding in excess of 1.7 million gross acres of largely gas prone tight sandstone reservoirs to identify further drilling opportunities. The results from the Grey 31-23 well will be incorporated into this study. Husky holds up to a 50% working interest in this area.

Alkaline Surfactant Polymer Floods

Husky's Alkaline Surfactant Polymer ("ASP") enhanced oil recovery program continues to advance. Currently the program includes ASP developments at Fosterton and Bone Creek, Saskatchewan and operating ASP projects at Gull Lake, Saskatchewan and Warner and Crowsnest, Alberta. In addition, Husky holds a 20.3% non-operating working interest in the Instow, Saskatchewan ASP flood, in which oil response continues to increase in line with expectations. The Warner chemical injection has been increased following the successful drilling of two infill wells in 2009. The polymer injection is expected to continue through to 2012. Husky completed the Alkaline Surfactant portion of the injection scheme at the Crowsnest project in December 2009. Incremental recovery continues to increase according to plan at both floods. At Gull Lake, the ASP facility is fully operational and the project was completed on schedule. Surfactant was added to the injected fluids in December 2009 and the facility is pumping at full capacity. The Fosterton ASP reservoir and detailed facility design progressed throughout 2009 and is near completion. Upon project approval, the facility long lead equipment will be ordered in 2010. Facility construction will commence in early 2011 with an expected start up in late 2011. Husky is the operator and holds a 62.4% working interest in this project.

5.2 MIDSTREAM

Husky completed construction and commissioning of two 300,000 barrel tanks at Hardisty. Husky also completed connections from the Hardisty terminal to the new Keystone pipeline.

5.3 DOWNSTREAM

Lima, Ohio Refinery

An engineering evaluation has been completed on the reconfiguration of the Lima Refinery that is intended to increase processing capacity of heavier, less costly, crude oil feedstock to enhance margins and increase flexibility in product outputs. Implementation of this project on a phased basis is being evaluated to maximize capital spending efficiency and provide a hedge against uncertain market conditions. As proposed, the project would increase capacity to 170 mbbls/day crude charge, 105 mbbls/day of which would be heavy crude oil. The project is currently on hold pending an improvement in the light/heavy crude oil differential.

Toledo, Ohio Refinery

Husky and its partner, BP, have announced the sanction of the Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio refinery. The project will improve the efficiency and competitiveness of the refinery by reducing energy consumption and lowering operating costs with the replacement of two naphtha reformers and one hydrogen plant with one 42,000 bbls/day continuous catalyst regeneration reformer system plant.

An evaluation of the reposition of the refinery to process bitumen from the first two phases of the Sunrise oil sands integrated project is underway. Due to the integrated nature of this project, progress will coincide with the upstream development requirements. The refinery continues to advance a multi-year program to improve operational integrity and plant performance and reduce operating costs and environmental impacts.

Retail

In December 2009, Husky entered into an agreement to purchase 98 retail outlets in the southern Ontario region. The first site will be transferred to Husky in March 2010, with the remaining sites transferred between April and November 2010.

6.0 The 2009 Business Environment

6.1 BUSINESS RISK FACTORS

Husky's results of operations are significantly influenced by the global and domestic business environment. Some risk factors are entirely beyond the Company's influence and others can, to some extent, be strategically managed. Husky has implemented appropriate risk management processes to manage these risks. Salient risk factors include:

- the demand for the Company's products and the prices the Company receives for crude oil and natural gas production and refined petroleum products;
- the economic conditions of the markets in which Husky conducts business;
- the exchange rate between the Canadian and U.S. dollar;
- the ability to replace 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 that may impose operating costs or restrictions in the jurisdictions where the Company has operations;
- prevailing climatic conditions in the Company's operating locations;
- changes to royalty regimes;
- regulations to deal with climate change issues;
- changes to government fiscal, monetary and other financial policies;
- the competitive actions of other companies, including increased competition from other oil and gas companies;
- business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect Husky and that may or may not be financially recoverable;
- the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects;
- the inability to reach the Company's estimated production levels from existing and future oil and gas development projects as a result of technological or commercial difficulties or other risk factors;
- changes in workforce demographics;
- the cost and availability of capital, including access to capital markets at acceptable rates; and
- other financial risks as described in Section 8.6.

6.2 ECONOMIC SENSITIVITIES

Average Benchmarks

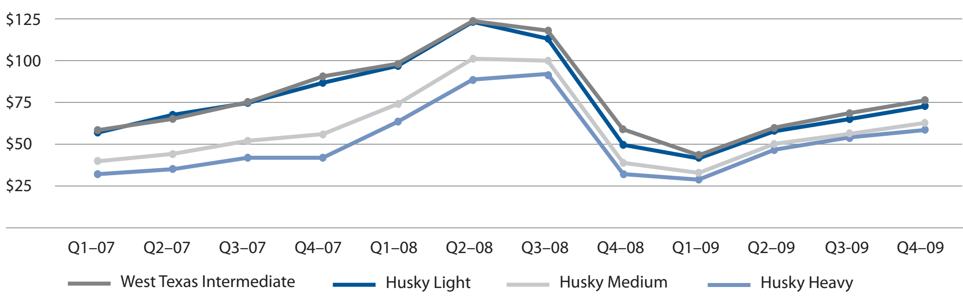
		2009	2008	2007
Upstream				
WTI crude oil	*(U.S. $/bbl)*	**61.80**	99.65	72.31
Brent crude oil	*(U.S. $/bbl)*	**61.54**	96.99	72.52
Canadian light crude 0.3% sulphur	*($/bbl)*	**66.19**	102.84	77.07
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**53.60**	72.44	40.75
NYMEX natural gas	*(U.S. $/mmbtu)*	**3.99**	9.04	6.86
NIT natural gas	*($/GJ)*	**3.92**	7.70	6.26
Midstream heavy crude oil upgrading				
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**9.93**	20.38	23.81
Downstream				
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**8.33**	9.96	14.15
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**8.43**	11.17	17.68
Cross segment				
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.880**	0.937	0.931

As an integrated producer, Husky's profitability is largely determined by realized prices for crude oil and natural gas and refinery processing margins including the effect of changes in the U.S./Canadian dollar exchange rate. All of Husky's crude oil production and the majority of its natural gas production receive the prevailing market price. The price for crude oil is determined largely by global factors and is beyond the Company's 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 also exert a dramatic effect on short-term supply and demand.

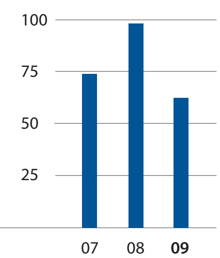
The midstream and downstream segments are also heavily impacted by the price of crude oil and natural gas. The largest cost factor in the midstream - upgrading business segment is the heavy crude oil feedstock, which is processed into light synthetic crude oil. The largest cost factors in the downstream sector are crude oil feedstock and processing costs. Husky's U.S. refining operations process a mix of different types of crude oil from various sources but are primarily light sweet crude oil at Lima and approximately 60% heavy crude oil feedstock at Toledo. The Company's refined products business in Canada relies primarily on purchased refined products for resale in the retail distribution network. Refined products are acquired from other Canadian refiners at rack prices or exchanged with production from the Husky Prince George refinery.

Crude Oil

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



Average WTI (US $/bbl)

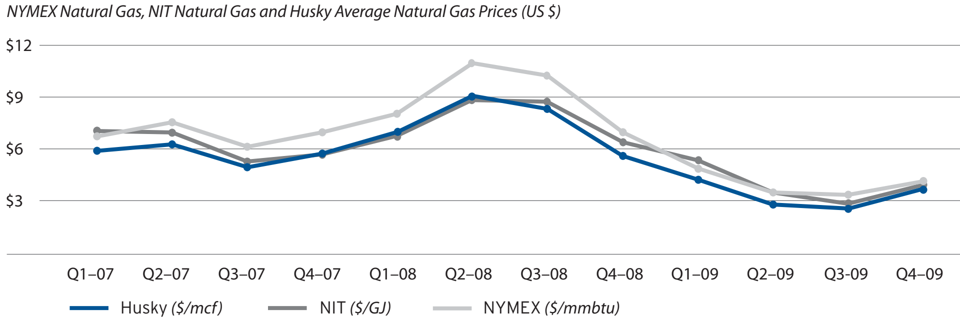


The price Husky receives for production from Western Canada is primarily driven by changes in the price of West Texas Intermediate ("WTI") while the majority of the Company's production offshore the East Coast of Canada is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2009 at U.S. $79.36/bbl recovering from U.S. $44.60/bbl on December 31, 2008, and averaged U.S. $61.80/bbl in 2009 compared with U.S. $99.65/bbl in 2008. In the last three years, WTI peaked to a high of U.S. $145.29/bbl in July 2008 and dropped to a low of U.S. $33.87/bbl in December 2008. The price of Brent ended 2009 at U.S. $77.67/bbl, recovering from U.S. $36.55/bbl on December 31, 2008, and averaged U.S. $61.54/bbl in 2009 compared with U.S. $96.99/bbl in 2008.

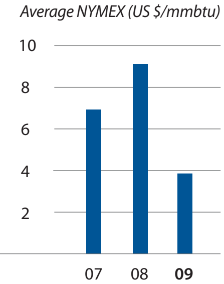
A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2009, 47% of Husky's crude oil production was heavy crude oil or bitumen compared with 42% in 2008. The light/heavy crude oil differential averaged U.S. $9.93 or 16% of WTI in 2009 compared with U.S. $20.38 or 20% of WTI in 2008.

Natural Gas

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



Average NYMEX (US $/mmbtu)



The near-month natural gas prices at NYMEX ended 2008 at U.S. $5.62/mmbtu and subsequently declined to less than U.S. $3.00/mmbtu by the end of August 2009 and then increased to U.S. $5.57/mmbtu at the end of 2009, averaging U.S. $3.99/mmbtu during 2009. In the last three years, natural gas prices peaked to a high of U.S. $13.58/mmbtu in July 2008 and dropped to a low of U.S. $2.51/mmbtu in September 2009. The average in 2008 was U.S. $9.04/mmbtu. During most of 2009, natural gas inventory in underground storage in the United States was higher than historical levels.

Foreign Exchange

The majority of the Company's revenues from the sale of oil and gas commodities receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the revenues received from the sale of oil and gas commodities. Correspondingly, 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.

The Canadian dollar ended 2008 at U.S. $0.817 and subsequently strengthened by 17% against the U.S. dollar during 2009, closing at U.S. $0.956 at December 31, 2009. In 2009, the Canadian dollar averaged U.S. $0.880 compared with U.S. $0.937 during 2008.

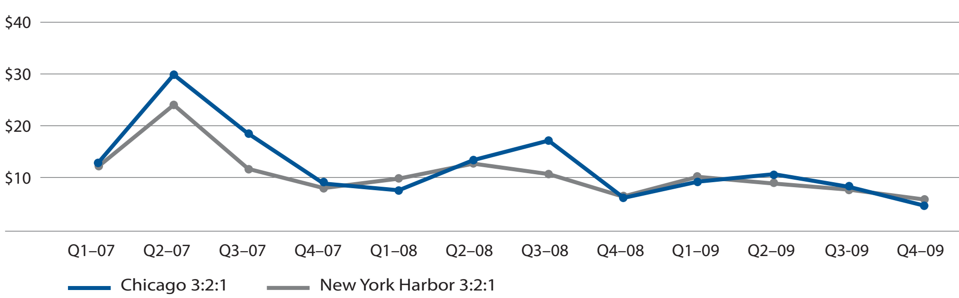
Refining Crack Spreads

The 3:2:1 refining crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is equal to the price of two-thirds of a barrel of gasoline plus one-third of a barrel of fuel oil (distillate) less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel, and do not necessarily reflect the actual crude purchase costs or product configuration of a specific refinery. Each refinery has a unique crack spread depending on several variables. Realized refining margins are affected by the product configuration of each refinery and by the time lag between the purchase and delivery of crude oil feedstock which is accounted for on a first in first out ("FIFO") basis in accordance with Canadian Generally Accepted Accounting Principles ("GAAP").

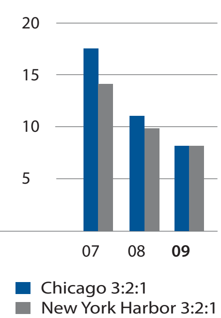
The New York Harbor 3:2:1 refining crack spread is a benchmark and is calculated as the difference between the price of a barrel of WTI crude oil and the sum of the price of two thirds of a barrel of reformulated gasoline and the price of one third of a barrel of heating oil. The Chicago 3:2:1 refining crack spread is calculated using WTI, regular unleaded gasoline and low sulphur diesel. During 2009, the New York Harbor 3:2:1 refining crack spread averaged U.S. $8.33/bbl compared with U.S. $9.96/bbl in 2008. During 2009, the Chicago crack spread averaged U.S. $8.43/bbl compared with U.S. $11.17/bbl in 2008.

Crack Spread

Chicago and New York Harbor Average Crack Spread (US $/bbl)



Average Crack Spread (US $/bbl)



During 2009, the 3:2:1 crack spreads were lower than 2008 reflecting the continuing weak U.S. economic environment which has resulted in reduced demand for transportation fuels and resulted in high inventory and weak margins.

Cost Environment

The oil and gas industry experienced an increase in costs in excess of the general rate of inflation during the recent years of increasing energy prices. These increases affect the cost of operating the Company's oil and gas properties, processing plants and refineries. They also affect capital projects which are susceptible to cost volatility. In the latter half of 2008, the oil and gas industry experienced significant decreases in commodity prices, while the cost environment continued to reflect the previous economic environment. In the third quarter of 2009, the cost environment began to partially reflect the decline in energy commodity prices and the effect of the current economic conditions.

Reserves

The Company's ability to generate cash flows is dependent, among other factors, on the ability to replace existing reserves. If Husky fails to find or acquire additional crude oil and natural gas reserves, its reserves and production will decline materially from their current levels and, therefore, its cash flows are highly dependent upon successfully exploiting current reserves and acquiring, discovering or developing additional reserves.

Global Economic and Financial Environment

In the wake of the economic downturn, world oil consumption declined and commercial inventories of crude oil are above average historical levels. The Energy Information Administration's ("EIA") February 10, 2010 Short-term Energy Outlook[(1)] indicates that world oil consumption declined by 1.7 mmbbls/day in 2009 compared with the previous year, reflecting 2.15 mmbbls/day in OECD countries partially offset by increased consumption in non-OECD countries, particularly China. The EIA has revised its projected global consumption due to higher than expected Asian consumption in December. The EIA now expects oil consumption to increase in 2010 by 1.2 mmbbls/day and 1.6 mmbbls/day in 2011 compared with 2009. Growth of oil consumption in 2010 is expected to result primarily from resurgence in the global economy. Non-OECD countries are expected to account for most of the increase in 2010. China continues to lead world consumption growth with projected increases of consumption of 0.44 mmbbls/day in 2010 and 0.47 mmbbls/day in 2011. The EIA estimated non-OPEC supply of crude oil averaged 50.2 mmbbls/day in 2009, up approximately 0.58 mmbbls/day compared with 2008. Most of the increase was from the United States, South America and the Former Soviet Union partially offset by lower production from the North Sea and Mexico. OPEC production was 29.1 mmbbls/day in 2009, down 2.2 mmbbls/day from the previous year. OPEC spare productive capacity is currently estimated at 5.0 mmbbls/day, primarily in Saudi Arabia. The EIA expects OPEC supply to trend upward in 2010 to average 29.5 mmbbls/day and 29.9 mmbbls/day in 2011, in line with increased demand.

Demand for natural gas in North American markets has also retracted in line with lower industrial and commercial consumption; as a result, working gas in storage has averaged above five year levels. In its February 12, 2010[(2)] release the EIA reported that natural gas stocks in 2009 were 2,215 bcf, 8.4% above the previous year and 5.4% above the five year average. The EIA estimates a 1.7% decline in natural gas consumption in 2009 and forecasts a consumption increase of 0.4% in 2010 and 0.4% in 2011 as the industrial sector increases activity. The EIA estimates that natural gas production in 2009 increased by 3.8% compared with the previous year and forecasts a decrease of 2.6% in 2010 followed by an increase of 1.3% in 2011. The EIA estimates pipeline imports declined by 1.1 bcf/day or 11.1% during 2009 due to declining production from Canada and expects this trend to continue with reduced natural gas imports of more than 0.7 bcf/day in 2010. The EIA estimates 2009 liquefied natural gas ("LNG") imports at 1.3 bcf/day compared with 1.0 bcf/day in 2008 and forecasts 1.8 bcf/day in 2010. The EIA expects U.S. LNG imports will increase as supply increases from Russia, Yemen, Qatar and Indonesia.

In its February 10th outlook the EIA estimates that fuel consumption in the United States in 2009 fell by 820 mbbls/day or 4.2% including 330 mbbls/day or 8.4% of diesel fuel and 130 mbbls/day or 8.6% of jet fuel. Consumption of motor gasoline is expected to increase marginally by 0.1% as lower gasoline prices have partially offset the effects of lower economic activity. The EIA's February 10th outlook expects a 180 mbbls/day or 0.9% increase in fuel consumption in 2010. According to the EIA data released on February 12, 2010, U.S. gasoline stocks were 230.4 mmbbls, 12.8 mmbbls higher than the previous year; U.S. distillate stocks were 156.2 mmbbls, 14.6 mmbbls higher than the previous year.

The current prospect that demand for energy will increase in 2010 depends on a number of assumptions about the timing and sustainability of a global economic recovery.

Companies with low operating costs and flexible capital expenditure plans, strong cash generation from operations, available cash, low debt with long maturities and unused committed credit facilities will be better positioned to manage through adverse economic conditions.

In view of the economic environment, Husky took action in the latter half of 2008 and prudently reduced capital spending in 2009 and continues to review and implement cost containment and efficiency opportunities throughout the organization. Husky's cash position, credit facilities and access to debt capital markets provide adequate liquidity to meet the Company's needs at present, and the Company continues to examine ways of enhancing its access to capital on an ongoing basis.

Note:

(1) Energy Information Administration, Short-Term Energy Outlook DOE/EIA – February 10, 2010 Release
(2) "This Week in Petroleum", February 12, 2010, Energy Information Administration U.S. Department of Energy

6.3 SENSITIVITIES BY SEGMENT FOR 2009 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 2009. The table below shows what the effect would have been on 2009 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2009. 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

	2009 Average	Increase	Effect on Pre-tax Cash Flow[5]		Effect on Net Earnings [5]	
			($ millions)	*($/share)* [6]	*($ millions)*	*($/share)* [6]
Upstream and Midstream						
WTI benchmark crude oil price [1]	$ 61.80	*U.S. $1.00/bbl*	75	0.09	53	0.06
NYMEX benchmark natural gas price [2]	$ 3.99	*U.S. $0.20/mmbtu*	25	0.03	18	0.02
WTI/Lloyd crude blend differential [3]	$ 9.93	*U.S. $1.00/bbl*	(13)	(0.02)	(10)	(0.01)
Downstream						
Canadian light oil margins	$ 0.040	*Cdn $0.005/litre*	14	0.02	10	0.01
Asphalt margins	$ 17.35	*Cdn $1.00/bbl*	8	0.01	6	0.01
New York Harbor 3:2:1 crack spread [4]	$ 8.33	*U.S. $1.00/bbl*	80	0.09	51	0.06
Consolidated						
Exchange rate (U.S. $ per Cdn $) [1]	$ 0.880	*U.S. $0.01*	(56)	(0.07)	(39)	(0.05)
Interest rate		*100 basis points*	(2)	-	(1)	-

(1) Does not include gains or losses on inventory.
(2) Includes decrease in earnings related to natural gas consumption.
(3) Excludes impact on asphalt operations.
(4) Relates to U.S. Refining & Marketing.
(5) Excludes mark to market accounting impacts.
(6) Based on 849.9 million common shares outstanding as of December 31, 2009.

7.0 Results of Operations

7.1 SEGMENT EARNINGS

Segment Earnings

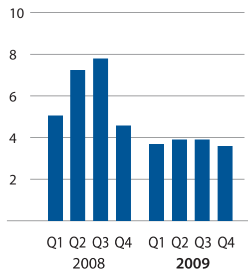
	Earnings (loss) before income taxes			Net Earnings (loss)			Capital Expenditures [2]		
($ millions)	**2009**	2008[1]	2007[1]	**2009**	2008[1]	2007[1]	**2009**	2008[1]	2007[1]
Upstream	**$ 1,560**	$ 4,757	$ 3,299	**$ 1,113**	$ 3,377	$ 2,596	**$ 2,326**	$ 3,580	$ 2,388
Midstream									
Upgrading	**77**	351	353	**54**	246	268	**69**	99	217
Infrastructure and Marketing	**279**	321	351	**200**	224	253	**25**	94	92
Downstream									
Canadian Refined Products	**198**	143	243	**141**	104	193	**81**	155	212
U.S. Refining and Marketing	**195**	(635)	168	**124**	(403)	105	**260**	133	21
Corporate and Eliminations	**(352)**	208	(305)	**(216)**	203	(214)	**36**	47	44
Total	**1,957**	5,145	4,109	**1,416**	3,751	3,201	**2,797**	4,108	2,974

(1) 2008 and 2007 amounts restated for adoption of new accounting policy. Refer to Note 4 to the Consolidated Financial Statements.
(2) Excludes capitalized costs related to asset retirement obligations incurred during the period and the Lima acquisition and the BP joint venture transaction.

7.2 SUMMARY OF QUARTERLY RESULTS

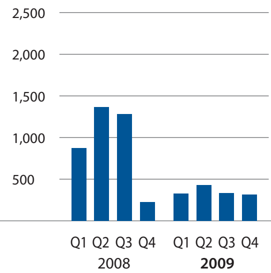
Sales & Operating Revenues

($ billions)



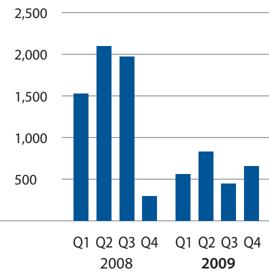
Net Earnings

($ millions)



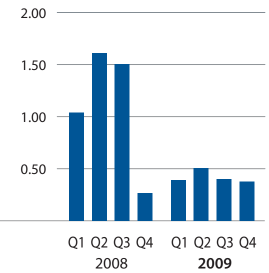
Cash Flow from Operations

($ millions)



Net Earnings Per Share

($ per share)



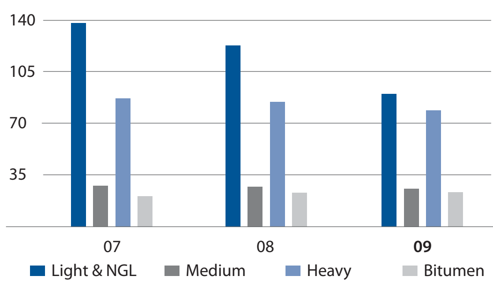
7.3 UPSTREAM

2009 Earnings $1,113 Million

Production

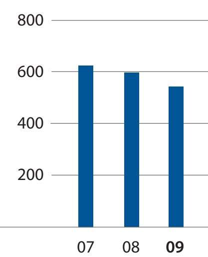
Oil

(mbbls/day)



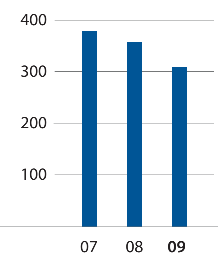
Gas

(mmcf/day)



Combined

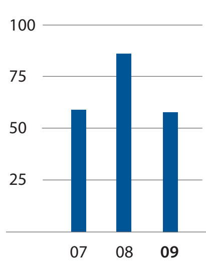
(mboe/day)



Average Price Realized

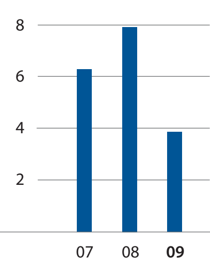
Crude Oil

($/bbl)



Natural Gas

($/mcf)



Average Sales Prices Realized	2009	2008	2007
Crude oil *($/bbl)*			
Light crude oil & NGL	$ 62.70	$ 97.28	$ 73.54
Medium crude oil	56.37	81.79	51.12
Heavy crude oil	52.54	71.98	40.43
Bitumen	51.90	70.24	38.96
Total average	57.11	84.96	58.24
Natural gas *($/mcf)*			
Average	$ 3.83	$ 7.94	$ 6.19

Upstream Earnings Summary

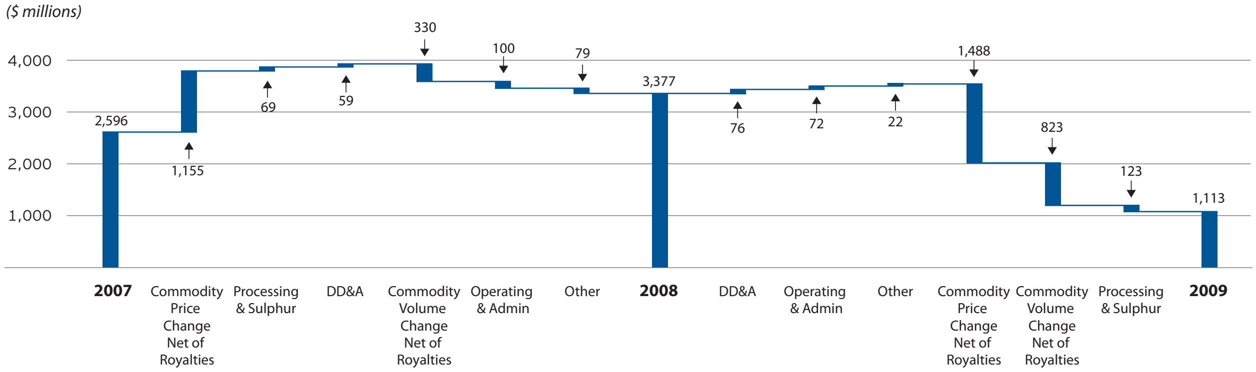
($ millions)	2009	2008	2007
Gross revenues	$ 5,313	$ 9,932	$ 7,287
Royalties	861	2,043	1,065
Net revenues	4,452	7,889	6,222
Operating and administration expenses	1,495	1,596	1,409
Depletion, depreciation and amortization	1,397	1,505	1,615
Other	-	31	(101)
Income taxes	447	1,380	703
Net earnings	$ 1,113	$ 3,377	$ 2,596

Upstream earnings were $2,264 million lower in 2009 compared with 2008 primarily as a result of lower production combined with lower average realized prices for commodities. Production declines were primarily due to lower light oil production offshore the East Coast of Canada and lower natural gas production in Western Canada. The decrease in royalties relative to 2008 is a result of lower upstream revenues combined with lower average rates due primarily to price sensitive royalties in both Canada and China.

During 2009, average realized prices declined 33% to $57.11/bbl for crude oil, NGL and bitumen combined compared with $84.96/bbl during 2008. The narrowing light to heavy crude oil differential in 2009 compared with 2008 partially offset the impact on earnings of declining light crude oil prices. Average realized natural gas prices declined 52% to $3.83/mcf in 2009 compared with $7.94/mcf in 2008.

After Tax Earnings Variance Analysis

($ millions)



Daily Gross Production		2009	2008	2007
Crude oil	*(mbbls/day)*			
Western Canada				
Light crude oil & NGL		**22.8**	24.6	26.5
Medium crude oil		**25.4**	26.9	27.1
Heavy crude oil (1)		**78.6**	84.3	86.5
Bitumen (1)		**23.1**	22.7	20.4
		149.9	158.5	160.5
East Coast Canada				
White Rose - light crude oil		**45.2**	73.2	85.0
Terra Nova - light crude oil		**10.0**	12.9	14.5
China				
Wenchang - light crude oil & NGL		**11.1**	12.2	12.7
		216.2	256.8	272.7
Natural gas	*(mmcf/day)*	**541.7**	594.4	623.3
Total	*(mboe/day)*	**306.5**	355.9	376.6

(1) Restated in accordance with the U.S. Securities and Exchange Commission definition of bitumen, as part of its new requirements for oil and gas reserves disclosure effective December 31, 2009. Under the new definition, a portion of crude oil previously reported as heavy crude oil has now been reclassified as bitumen. The presentation of heavy crude oil and bitumen reported in prior periods has been restated to reflect the new definition.

Upstream Revenue Mix

Percentage of Upstream Net Revenues	2009	2008	2007
Crude oil			
Light crude oil & NGL	**35%**	41%	51%
Medium crude oil	**10%**	8%	7%
Heavy crude oil	**29%**	24%	18%
Bitumen	**9%**	6%	4%
Natural gas	**17%**	21%	20%
	100%	100%	100%

In 2009, crude oil and NGL production decreased by 16% compared with the previous year. Production from the White Rose field decreased 28 mbbls/day or 38% due to subsea operational issues during the first half of 2009, and facility throughput restrictions on the *SeaRose FPSO* in the second quarter of 2009 as a result of heavy iceberg conditions, and in the second half of 2009 by a planned extended shutdown for tie-in work associated with the North Amethyst satellite development and scheduled maintenance combined with general declines in daily production rates post start up. At Terra Nova, scheduled maintenance and facility operational and maintenance issues resulted in reduced production in 2009 relative to the prior year.

During 2009, crude oil and NGL production from Western Canada was down 5% compared with 2008 primarily due to lower capital expenditures, reservoir decline, and shut-in of higher cost facilities as a result of lower commodity prices. Heavy crude oil average production, which excluded production from Lloydminster area thermal projects, was down 7% with normal reservoir decline only partially offset by new drilling. In November, Husky acquired approximately 6,000 boe/day of additional heavy oil production. Bitumen production increased by 2% compared to 2008. Tucker production averaged 5,000 boe/day in December 2009.

Production from natural gas decreased by 52.7 mmcf/day or 9% in 2009 compared with 2008 due to lower capital expenditures on drilling and tie-ins, and the shut-in of higher cost facilities as a result of lower commodity prices, flowline restrictions and general reservoir decline. Husky drilled 22 net natural gas exploration wells and 61 net gas development wells in 2009 compared with 79 net gas exploration and 270 net gas development wells in 2008 which resulted in fewer additions to producing wells.

2010 Production Guidance and 2009 Actual

Gross Production

		Guidance	Year ended December 31	Guidance
		2010	**2009**	2009
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		90 - 98	**89**	92 – 109
Medium crude oil		27 - 30	**25**	25 – 28
Heavy crude oil & bitumen		104 - 114	**102**	95 – 105
		221 - 242	**216**	212 – 242
Natural gas	*(mmcf/day)*	510 - 530	**542**	585 – 620
Total barrels of oil equivalent	*(mboe/day)*	306 - 330	**307**	310 - 345

Husky's 2010 guidance reflects new production from the North Amethyst satellite tie-back and lower gas production resulting from the strategic decision to reduce natural gas drilling activity in 2009.

Royalties

Royalty rates averaged 16% of gross revenue in 2009 compared with 21% in 2008. Royalty rates in Western Canada averaged 13% compared with 16% in 2008 primarily due to lower average commodity prices in 2009 compared with 2008 which resulted in lower price sensitive rates. Offshore the East Coast of Canada, the average rate was 25% in 2009 compared with 28% in 2008, primarily as a result of the impact of lower production and revenues on the overall royalty rate, which is a combination of royalties based on gross revenues and net cash flow. East Coast royalties were also impacted by positive adjustments to 2008 royalties recorded in 2009 as a result of annual reconciliations filed in accordance with East Coast royalty regulations. The royalty rate for Wenchang has decreased due to the sliding scale royalty clause in the PSC that results in lower rates in lower commodity price environments.

Operating Costs

Total upstream operating costs in 2009 decreased to $1,324 million from $1,428 million. Total upstream unit operating costs in 2009 averaged $11.82/boe compared with $10.93/boe in 2008 as lower costs were offset by lower production. Operating costs in Western Canada decreased to $1,124 million from $1,249 million and averaged $12.83/boe in 2009 compared with $13.16/boe in 2008 primarily as a result of lower energy, servicing, processing, handling and treating costs, slightly offset by higher maintenance, land and labour costs.

Operating costs at the East Coast offshore operations averaged $177 million or $8.73/boe in 2009 compared with $157 million or $4.99/boe in 2008 primarily as a result of lower production and higher maintenance costs.

Operating costs at the South China Sea offshore operations averaged $23 million or $5.35/boe in 2009 compared with $22 million or $4.78/boe in 2008 primarily as a result of lower production.

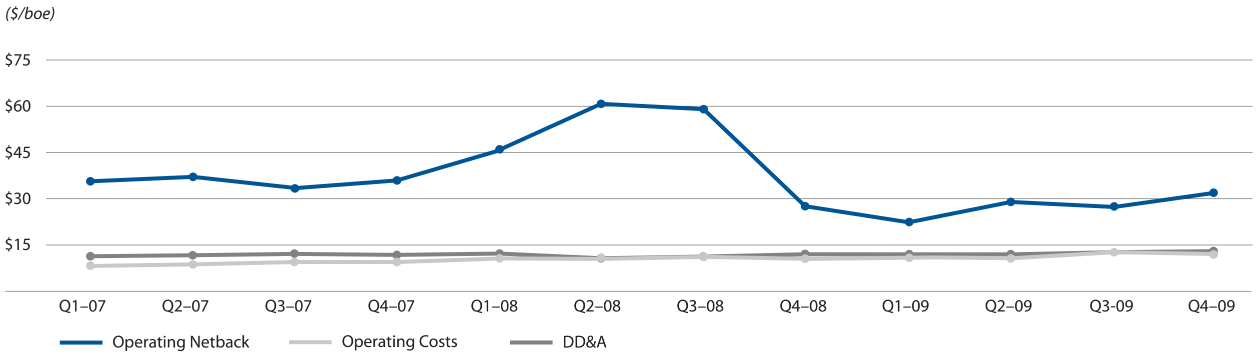
Depletion, Depreciation and Amortization ("DD&A")

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.

During 2009, total unit DD&A averaged $12.49/boe compared with $11.56/boe during 2008. The higher DD&A rate in 2009 was primarily due to lower oil and gas reserves as a result of commodity price adjustments at December 31, 2008 and a higher full cost base in 2009, partially offset by the effect of the disposition of 50% of the Sunrise oil sands asset on March 31, 2008.

At December 31, 2009, capital costs in respect of unproved properties and major development projects were $4.0 billion compared with $3.2 billion at the end of 2008. These costs are excluded from the Company's 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.

Operating Netback[(1)], Unit Operating Costs and DD&A



(1) Operating netbacks are Husky's average price less royalties and operating costs on a per unit basis.

Other Items

In 2008, a drilling contract previously treated as an embedded derivative no longer met the criteria and the related accounting treatment was discontinued. A loss of $101 million ($71 million after tax) was recorded in 2008. This was partially offset by a gain of $69 million on the sale of 50% of the shares of Husky Oil (Madura) Limited to CNOOC Southeast Asia Limited.

Upstream Capital Expenditures

In 2009, upstream capital expenditures were $2,326 million, $1,189 million (51%) in Western Canada, $574 million (25%) offshore the East Coast of Canada, $507 million (22%) in South East Asia, $25 million (1%) in the Northwest United States and $31 million (1%) offshore Greenland.

Upstream Capital Expenditures *(1)*

($ millions)	**2009**	2008	2007
Exploration			
Western Canada	**$ 266**	$ 680	$ 456
East Coast Canada and Frontier	**64**	160	84
Northwest United States	**25**	60	-
International	**526**	225	70
	881	1,125	610
Development			
Western Canada	**923**	1,881	1,575
East Coast Canada	**510**	569	197
International	**12**	5	6
	1,445	2,455	1,778
	$ 2,326	$ 3,580	$ 2,388

(1) Excludes capitalized costs related to asset retirement obligations incurred during the period and the Lima acquisition and the BP joint venture transaction.

Western Canada Drilling

(wells)		2009 Gross	2009 Net	2008 Gross	2008 Net	2007 Gross	2007 Net
Exploration	Oil	**18**	**9**	80	70	79	79
	Gas	**37**	**22**	102	79	114	92
	Dry	**7**	**6**	27	23	14	12
		62	**37**	209	172	207	183
Development	Oil	**315**	**278**	685	578	571	530
	Gas	**122**	**61**	435	270	343	251
	Dry	**7**	**7**	36	36	31	29
		444	**346**	1,156	884	945	810
Total		**506**	**383**	1,365	1,056	1,152	993

Western Canada

During 2009, Husky invested $1,189 million on exploration and development throughout the Western Canada Sedimentary Basin compared with $2,561 million in 2008. Of this, $379 million was invested on oil development and $143 million was invested on natural gas development compared with $678 million for oil development and $360 million for natural gas development in 2008. The Company drilled 383 net wells in the basin resulting in 287 net oil wells and 83 net natural gas wells compared with 648 net oil wells and 349 net natural gas wells in 2008. The reduction in capital expenditures, in particular natural gas drilling, reflects the Company's decision to reduce activity in this area in 2009 due to the low commodity price environment. In addition, $80 million was spent on production optimization and operating cost reduction initiatives. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $112 million.

During 2009, $214 million was spent on property acquisitions. Capital expenditures on oil sands projects were $29 million compared with $302 million in the same period of 2008. The decrease in spending at Sunrise was reflective of the Company's decision to simplify the project scope and delay capital spending until the oil and gas cost environment reflects the decline of the current economic environment.

Husky's exploration program is conducted along the foothills of Alberta and British Columbia and in the deep basin region of Alberta. In 2009, $169 million was invested in land, seismic and drilling in these regions of which $128 million was spent on gas resource play exploration, including $83 million spent on resource play acquisitions. $63 million was also spent on follow-up development including tie-ins, facility installation and development drilling.

The following table discloses Husky's offshore and international drilling activity during 2009:

Offshore and International Drilling Activity

Canada - East Coast			
Mizzen O-16 Flemish Pass	WI 35%	Stratigraphic test	Exploratory
White Rose J-22-3	WI 72.5%	Gas injection well	Development
United States – Columbia River Basin			
Grey 31-23	WI 50%	Exploration well	Exploratory
South East Asia - China			
QH 29-2-1 Block 39/05	WI 100% [(1)]	Stratigraphic test	Exploratory
Liwan 3-1-2 Block 29/26	WI 100% [(1)]	Stratigraphic test	Delineation
Liwan 3-1-3 Block 29/26	WI 100% [(1)]	Stratigraphic test	Delineation
Liwan 3-1-4 Block 29/26	WI 100% [(1)]	Stratigraphic test	Delineation
Liwan 4-1-1 Block 29/26	WI 100% [(1)]	Stratigraphic test	Exploratory
Liwan 9-1-1 Block 29/26	WI 100% [(1)]	Stratigraphic test	Exploratory
Liwan 9-1-2 Block 29/26	WI 100% [(1)]	Stratigraphic test	Exploratory
Liuhua 29-1-1 Block 29/26	WI 100% [(1)]	Stratigraphic test	Exploratory
Liuhua 34-2-1 Block 29/26	WI 100% [(1)]	Stratigraphic test	Exploratory
South East Asia - Indonesia			
Adiyasa 1	WI 100%	Stratigraphic test	Exploratory
Kukura 1	WI 100%	Stratigraphic test	Exploratory

[(1)] CNOOC has the right to participate in development of discoveries up to 51%.

East Coast Development

During 2009, $510 million was invested for East Coast development projects primarily for the North Amethyst and West White Rose satellite tie-back development projects, including drilling operations at North Amethyst and completion of facilities construction and installation. At West White Rose capital expenditures focused on advancing engineering design and planning.

East Coast Exploration

During 2009, Husky spent $64 million primarily on the Mizzen exploration well in the Flemish Pass off the coast of Newfoundland and geological and geophysical data and studies.

Northwest United States

During 2009, Husky spent $25 million on the Gray 31-23 exploration well in the Columbia River Basin in south Washington State that was abandoned after testing non-commercial quantities of natural gas. Husky has a 50% working interest in this exploration well.

Offshore China and Indonesia

During 2009, $472 million was spent on offshore China projects including the Liwan natural gas discovery delineation program, four exploration wells on the deepwater Block 29/26 and drilling one exploration well on Block 39/05. In Indonesia, capital expenditures during 2009 were $35 million, primarily related to drilling two exploration wells on the East Bawean II PSC.

Offshore Greenland

During 2009, Husky spent $31 million completing a 2,200 square kilometre 3-D seismic program.

2010 Upstream Capital Program

($ millions)

Western Canada	- oil and gas	$	1,200
	- oil sands		85
East Coast Canada			485
International			660
		$	2,430

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

The 2010 capital budget has been established with a view to enable Husky to maintain production levels and support its medium and long-term growth strategies. Capital expenditures are focused on those projects offering the highest potential for returns.

Capital expenditures for Western Canada upstream development and exploration will focus on heavy oil properties, EOR projects and unconventional gas holdings. Capital spending on oil sands is primarily focused on development at Sunrise.

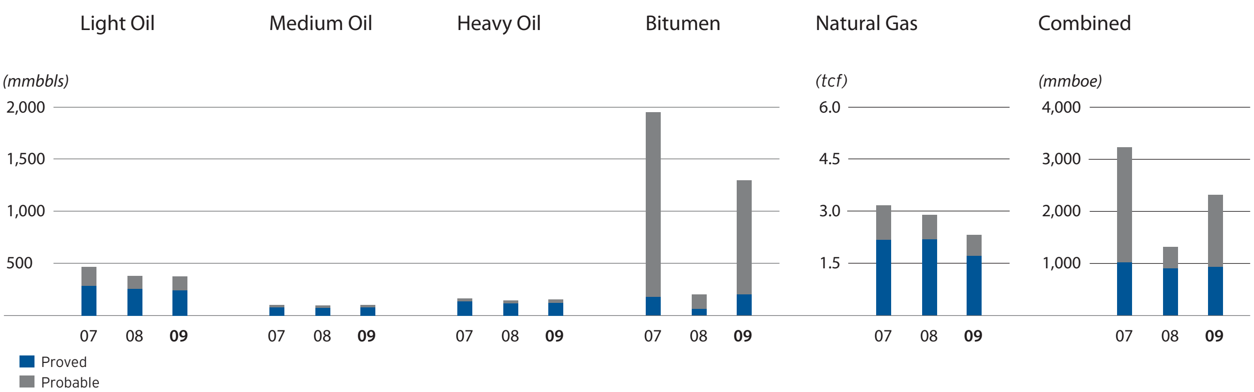
Offshore the East Coast of Canada, spending is concentrated on the drilling of development wells at North Amethyst.

In China and Indonesia, capital spending is focused on continuing the development of the Liwan Gas Project and the recently discovered Liuhua gas field, and offshore exploration and development programs.

Oil and Gas Reserves

Husky applied for and was granted an exemption from certain of the provisions of 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



Note: As at December 31 based on prices as per SEC regulations.

For more detail on the Company's oil and gas reserves and the disclosures with respect to the FASB Accounting Standards Codification 932, "Extractive Activities – Oil and Gas" and the differences between Husky's disclosures and those prescribed by National Instrument 51-101, refer to Husky's Annual Information Form available at www.sedar.com or Husky's Form 40-F available at www.sec.gov or on the Company's website at www.huskyenergy.com.

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.

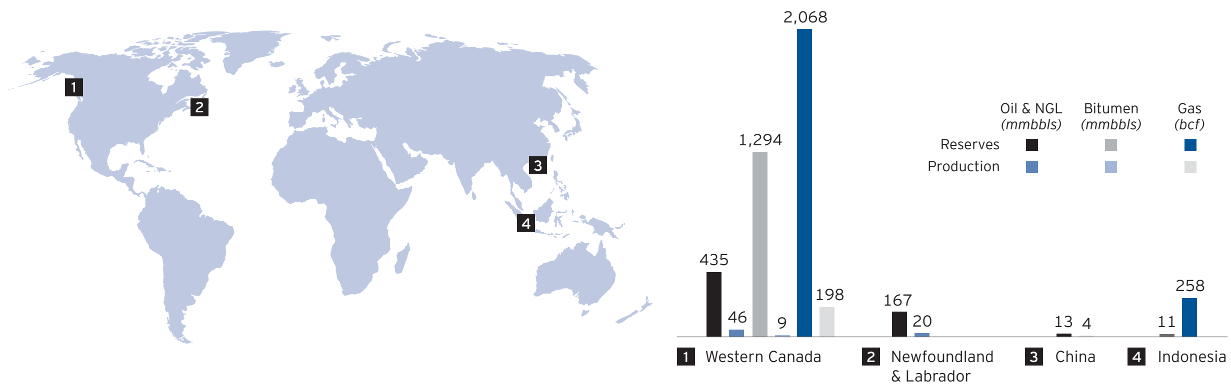
At December 31, 2009, Husky's proved oil and gas reserves were 933 mmboe, up from 896 mmboe at the end of 2008. The increase in proved reserves represents 133% of 2009 production. A major addition to proved reserves in 2009 was the inclusion of 64 mmboe of proved undeveloped reserves related to the first phase of the Sunrise oil sands project. This addition represents 59% of total additions from discoveries, extensions and improved recovery. Reserves added due to crude oil price recovery totalled 78 mmboe or 92% of the total revision of previous estimate of 85 mmboe.

Husky's oil and gas reserves are estimated in accordance with the regulations and guidelines of the SEC, which amended its oil and gas reserves estimation and disclosure requirements effective for annual reporting periods ending on or after December 31, 2009. Compared with the previous rules, only one of the amendments had a significant effect on Husky's reserves at December 31, 2009. The new requirement to determine reserve quantities based on a 12 month average price resulted in lower prices compared with the prices in effect at December 31, 2009, particularly for natural gas. The lower commodity prices resulted in a reduction of proved oil and gas reserves amounting to 59 mmboe; 53 mmboe or 90% related to lower natural gas prices.

The calculated average price of WTI in 2009 based on the new SEC rules was U.S. $61.18/bbl compared with U.S. $79.36/bbl at December 31, 2009 and U.S. $44.60/bbl at December 31, 2008. Lloydminster heavy crude oil, which trades at a discount to light crude oil, averaged $53.67/bbl in 2009 compared with $65.39/bbl at December 31, 2009 and $34.56/bbl at December 31, 2008. Natural gas averaged $3.57/mcf in 2009 compared with $5.60/mcf at December 31, 2009 and $6.10/mcf at December 31, 2008.

Husky's probable oil and gas reserves based on the new pricing rules increased by 951 mmboe in 2009 to 1,374 mmboe as at December 31, 2009 compared with 423 mmboe at the end of 2008. The increase in probable reserves in 2009 was primarily due to a positive revision of previously estimated reserves of 1,041 mmboe; 1,012 mmboe or 97% was related to higher average bitumen prices in 2009 compared with bitumen prices at December 31, 2008. Positive revisions to probable reserves were partially offset by transfers to the proved category. The effect of the new SEC pricing rule resulted in a reduction of probable natural gas and natural gas liquids reserves amounting to 34 mmboe.

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



Note: Based on prices as per SEC regulations.

Reconciliation of Proved Reserves

(constant prices and costs before royalties)	Canada – Western Canada – Light Crude Oil & NGL (mmbbls)	Canada – Western Canada – Medium Crude Oil (mmbbls)	Canada – Western Canada – Heavy Crude Oil (mmbbls)	Canada – Western Canada – Bitumen (mmbbls)	Canada – Western Canada – Natural Gas (bcf)	Canada – East Coast – Light Crude Oil (mmbbls)	International – Light Crude Oil (mmbbls)	International – Natural Gas (bcf)	Total – Crude Oil & NGL (mmbbls)	Total – Natural Gas (bcf)	Total – Equivalent Units (mmboe)
Proved reserves at December 31, 2008	148	85	122	65	2,190	104	7	-	531	2,190	896
Revision of previous estimate	2	6	5	75	(52)	-	6	-	94	(52)	85
Purchase of reserves in place	-	-	11	-	18	-	-	-	11	18	14
Sale of reserves in place	-	-	-	-	-	-	-	-	-	-	-
Discoveries, extensions and improved recovery	3	2	12	69	82	9	-	-	95	82	109
Production	(8)	(9)	(29)	(9)	(198)	(20)	(4)	-	(79)	(198)	(112)
Proved reserves at December 31, 2009 (previous pricing rules)	**145**	**84**	**121**	**200**	**2,040**	**93**	**9**	**-**	**652**	**2,040**	**992**
Effect of new SEC pricing rules	(4)	(2)	(1)	-	(315)	-	-	-	(7)	(315)	(59)
Proved reserves at December 31, 2009	**141**	**82**	**120**	**200**	**1,725**	**93**	**9**	**-**	**645**	**1,725**	**933**
Proved and probable reserves at December 31, 2009	**185**	**99**	**151**	**1,294**	**2,068**	**167**	**24**	**258**	**1,920**	**2,326**	**2,307**
At December 31, 2008	195	99	147	204	2,648	168	21	258	834	2,906	1,319

Reconciliation of Proved Developed Reserves

(constant prices and costs before royalties)	Canada – Western Canada – Light Crude Oil & NGL (mmbbls)	Canada – Western Canada – Medium Crude Oil (mmbbls)	Canada – Western Canada – Heavy Crude Oil (mmbbls)	Canada – Western Canada – Bitumen (mmbbls)	Canada – Western Canada – Natural Gas (bcf)	Canada – East Coast – Light Crude Oil (mmbbls)	International – Light Crude Oil (mmbbls)	International – Natural Gas (bcf)	Total – Crude Oil & NGL (mmbbls)	Total – Natural Gas (bcf)	Total – Equivalent Units (mmboe)
Proved developed reserves at December 31, 2008	128	79	93	25	1,760	83	7	-	415	1,760	708
Revision of previous estimate	1	8	10	51	(5)	-	6	-	76	(5)	76
Purchase of reserves in place	-	-	9	-	18	-	-	-	9	18	12
Sale of reserves in place	-	-	-	-	-	-	-	-	-	-	-
Discoveries, extensions and improved recovery	1	1	4	-	46	1	-	-	7	46	15
Production	(8)	(9)	(29)	(9)	(198)	(20)	(4)	-	(79)	(198)	(112)
Proved developed reserves at December 31, 2009 (previous pricing rules)	**122**	**79**	**87**	**67**	**1,621**	**64**	**9**	**-**	**428**	**1,621**	**699**
Effect of new SEC pricing rules	(1)	(1)	(1)	-	(169)	-	-	-	(3)	(169)	(32)
Proved developed reserves at December 31, 2009	**121**	**78**	**86**	**67**	**1,452**	**64**	**9**	**-**	**425**	**1,452**	**667**

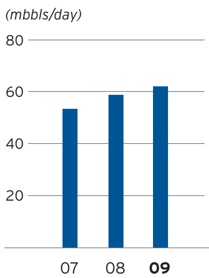
7.4 MIDSTREAM

2009 Earnings $254 Million

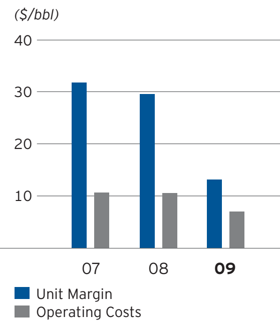
Total midstream earnings in 2009 were $254 million, down from $470 million in 2008. The decrease is primarily due to the lower upgrading differential in 2009 compared to 2008 as well as lower margins realized on crude oil and natural gas trading contracts as a result of lower commodity prices.

Upgrader

Synthetic Crude Sales

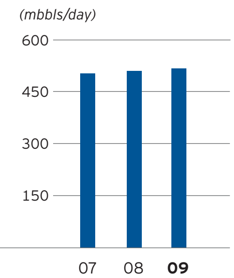


Unit Margin & Operating Costs



Pipelines

Daily Throughput



Upgrading Earnings Summary

($ millions, except where indicated)		2009	2008 [1]	2007 [1]
Gross revenues		$ 1,572	$ 2,435	$ 1,524
Gross margin		$ 296	$ 633	$ 614
Operating and administration expenses		188	255	240
Other recoveries		(3)	(4)	(4)
Depreciation and amortization		34	31	25
Income taxes		23	105	85
Net earnings		$ 54	$ 246	$ 268
Upgrader throughput [2]	*(mbbls/day)*	74.1	71.1	61.4
Synthetic crude oil sales	*(mbbls/day)*	61.8	58.7	53.1
Upgrading differential	*($/bbl)*	$ 11.89	$ 28.77	$ 30.73
Unit margin	*($/bbl)*	$ 13.11	$ 29.48	$ 31.67
Unit operating cost [3]	*($/bbl)*	$ 6.92	$ 10.54	$ 10.68

(1) 2008 and 2007 amounts as restated for adoption of a new accounting policy. Refer to Note 4 to the Consolidated Financial Statements.
(2) Throughput includes diluent returned to the field.
(3) Based on throughput.

In 2009, upgrading earnings were 78% lower than 2008. The large decline is due to the significant reduction in the upgrading differential realized which is the result of low heavy oil differentials in 2009 compared with 2008 partially offset by higher throughput. In 2008, the upgrader was shutdown for 34 days for scheduled maintenance and a temporary shutdown to replace the hydrogen plant catalyst.

Unlike heavy crude oil, synthetic crude oil is a higher value feedstock for many refineries in Canada and the United States. During 2009, the price of Husky's synthetic crude oil averaged $68.92/bbl (2008, $108.73/bbl) compared with the average cost of blended heavy crude oil from the Lloydminster area of $57.03/bbl (2008, $79.96/bbl). This resulted in an average synthetic/heavy crude differential of $11.89/bbl (2008, $28.77/bbl) and a gross unit margin of $13.11/bbl (2008, $29.48/bbl). Gross unit margin includes secondary products. The cost of upgrading averaged $6.92/bbl compared with $10.54/bbl in

2008, which results in a net margin for upgrading Lloydminster heavy crude of $6.19/bbl, down 67% compared with $18.94/bbl in 2008.

Operating costs have decreased in 2009 primarily due to lower energy costs. Depreciation is recorded at the upgrader on a unit of production basis which is the primary driver behind the increase in 2009 compared with 2008 as throughput volumes have increased.

Infrastructure and Marketing Earnings Summary

($ millions, except where indicated)		**2009**	2008	2007
Gross revenues		**$ 6,984**	$ 13,544	$ 10,217
Gross margin				
Pipeline		**$ 106**	$ 120	$ 115
Other infrastructure and marketing		**195**	249	278
		301	369	393
Operating and administration expenses		**19**	17	14
Depreciation and amortization		**36**	31	28
Other income		**(33)**	-	-
Income taxes		**79**	97	98
Net earnings		**$ 200**	$ 224	$ 253
Commodity volumes marketed	*(mboe/day)*	**912**	1,103	1,042
Aggregate pipeline throughput	*(mbbls/day)*	**514**	507	501

Infrastructure and marketing earnings in 2009 decreased by $24 million compared with 2008 due primarily to lower margins on crude and natural gas trading contracts as a result of lower commodity prices. 2009 earnings include unrealized gains of $32 million ($25 million in 2008) on natural gas storage contracts. Pipeline earnings in 2009 decreased relative to 2008 due to lower blending differentials and brokering margins.

Midstream Capital Expenditures

Midstream capital expenditures totalled $94 million in 2009. At the Lloydminster upgrader, Husky spent $62 million, primarily for contingent consideration and facility reliability projects. The remaining $32 million was spent on the construction and commissioning of two new tanks at Hardisty, Alberta; the pipeline extension between Lloydminster and Hardisty, Alberta; tankage upgrades at Hardisty and capital enhancements of the cogeneration plants.

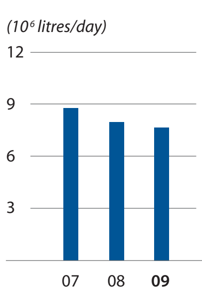
7.5 DOWNSTREAM

2009 Earnings $265 Million

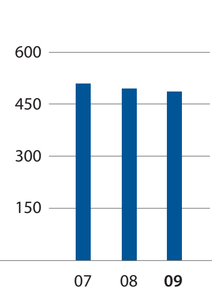
In 2009, the downstream segment earnings include twelve months (2008 – twelve months) from the Lima, Ohio Refinery, which was acquired on July 1, 2007 and twelve months (2008 – nine months) from the BP-Husky Toledo, Ohio Refinery, 50% of which was acquired on March 31, 2008.

Light Oil Product Marketing

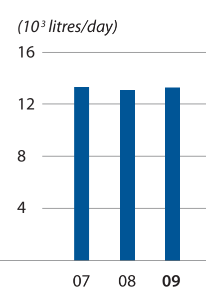
Volume



Outlets

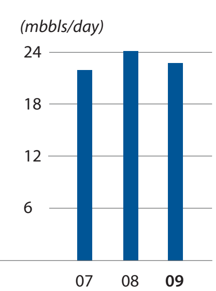


Volume per Outlet



Asphalt Products

Volume



Canadian Refined Products

Canadian Refined Products Earnings Summary

($ millions, except where indicated)		2009	2008 (1)	2007 (1)
Gross revenues		$ 2,495	$ 3,564	$ 2,916
Gross margin				
Fuel		$ 111	$ 96	$ 156
Ethanol		62	26	32
Ancillary		53	42	42
Asphalt		166	130	160
		392	294	390
Operating and administration expenses		101	70	81
Depreciation and amortization		93	81	66
Income taxes		57	39	50
Net earnings		$ 141	$ 104	$ 193
Number of fuel outlets (2)		482	492	505
Refined products sales volume				
Light oil products	*(million litres/day)*	7.6	7.9	8.7
Light oil products per outlet	*(thousand litres/day)*	13.2	13.0	13.2
Asphalt products	*(mbbls/day)*	22.6	24.0	21.8
Refinery throughput				
Prince George refinery	*(mbbls/day)*	10.3	10.1	10.5
Lloydminster refinery	*(mbbls/day)*	24.1	26.1	25.3
Ethanol production	*(thousand litres/day)*	676.9	627.2	324.6

(1) 2008 and 2007 amounts as restated for adoption of a new accounting policy. Refer to Note 4 to the Consolidated Financial Statements.
(2) Average number of fuel outlets for period indicated.

Gross margins on fuel sales were higher in 2009 compared with 2008 due to improved unit margins. Light oil retail sales per outlet were higher due to increased demand as the economy in Western Canada showed signs of recovery in the latter half of 2009 compared with a significant drop in demand in the fourth quarter of 2008.

Asphalt gross margins increased in 2009 compared with 2008 primarily due to the positive impact in early 2009 of consuming low cost feedstock due to the significant drop in crude oil prices at the end of 2008 which continued into the first quarter of 2009.

The higher ethanol gross margin in 2009 was due to higher sales volumes partially offset by lower sales prices resulting primarily from competition with low priced U.S. imported ethanol. Ethanol production in 2009 was higher than in 2008 due to improved operational performance at the Lloydminster plant. Included in ethanol gross margin in 2009 is $53 million related to government assistance grants received compared with $18 million received in 2008.

Operating and administration expenses in 2008 included a $15 million credit resulting from an insurance settlement. The remaining increases are primarily due to higher repair and maintenance costs and property taxes.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary

($ millions, except where indicated)		2009	2008 [1]	2007 [1]
Gross revenues		$ 5,349	$ 7,802	$ 2,383
Gross refining margin		$ 852	$ (58)	$ 310
Processing costs		423	417	93
Operating and administration expenses		7	3	1
Interest - net		3	3	1
Depreciation and amortization		194	154	47
Other expense		30	-	-
Income taxes		71	(232)	63
Net earnings (loss)		$ 124	$ (403)	$ 105
Selected operating data:				
Lima Refinery throughput [2]	*(mbbls/day)*	114.6	136.6	143.8
Toledo Refinery throughput [3]	*(mbbls/day)*	64.9	60.6	-
Refining margin	*($/bbl crude throughput)*	$ 13.12	$ (0.88)	$ 12.42
Refinery inventory *(feedstocks and refined products)*	*(mmbbls)*	12.3	11.9	7.4

(1) 2008 and 2007 amounts restated for adoption of a new accounting policy. Refer to Note 4 of the Consolidated Financial Statements.

(2) The Lima Refinery operating results are included from July 1, 2007, the date the acquisition was completed. Throughput in 2007 represents six months of operations.

(3) The BP-Husky Toledo Refinery operating results are included from March 31, 2008, the date the acquisition was completed. Throughput in 2008 represents Husky's share of nine months of operations.

The U.S. refining and marketing segment commenced operations on July 1, 2007 with the acquisition of the Lima, Ohio Refinery, as a first step in pursuing integration and enhancing the value of heavy oil and bitumen production.

On March 31, 2008, Husky completed a transaction that resulted in the formation of two joint venture entities forming an integrated oil sands business and a refining joint venture. Husky holds a 50% interest in the BP-Husky Toledo Refinery. Net earnings for 2009 include both the Lima and Toledo refineries whereas the comparative period in 2008 includes the results from the Toledo Refinery for nine months.

U.S. refining and marketing earnings have increased in 2009 compared with 2008 as a result of improved product margins offsetting reduced sales volumes. Margins in 2008 were dramatically impacted by rapidly falling crude oil prices which resulted in significant inventory write downs. Refining margins realized in 2009 reflect the positive benefit of consuming feedstock purchased one to two months prior to production in a rising crude oil price environment compared to the negative impact of falling crude oil prices in late 2008. The Lima Refinery was shutdown on October 2, 2009 for scheduled major turnaround and maintenance work and resumed production on November 20, 2009. Higher refinery throughput at Toledo in 2009 compared with 2008 is the result of improved turnaround efficiency and generally stable operations throughout the year.

Other expenses in 2009 include $30 million of losses on forward contracts for feedstock purchases.

Downstream Capital Expenditures

Downstream capital expenditures totalled $341 million during 2009.

In Canada, capital expenditures totalled $81 million primarily for facility and environmental upgrades at the retail outlets, refineries and ethanol plants.

In the United States, capital expenditures totalled $260 million. At the Lima Refinery, $136 million was spent on various debottleneck projects, optimizations and environmental initiatives and $69 million was spent on the scheduled major turnaround. At the BP-Husky Toledo Refinery, capital expenditures totalled $55 million (Husky's 50% share) primarily for engineering work on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection.

7.6 CORPORATE

2009 Expense $216 Million

Corporate Earnings Summary

($ millions) income (expense)	**2009**	2008	2007
Intersegment eliminations – net	**$ (44)**	$ 61	$ (51)
Administration expenses	**(69)**	(95)	(54)
Other income (expense)	**(1)**	48	(9)
Stock-based compensation	**(1)**	33	(88)
Depreciation and amortization	**(51)**	(30)	(25)
Interest – net	**(191)**	(144)	(129)
Foreign exchange	**5**	335	51
Income taxes	**136**	(5)	91
Net earnings (loss)	**$ (216)**	$ 203	$ (214)

The corporate segment reported a loss in 2009 of $216 million compared with earnings of $203 million in 2008. Foreign exchange gains decreased by $330 million in 2009 compared with 2008. In late 2008, the U.S./Canadian exchange rate dropped significantly and Husky's net U.S. dollar position resulted in a large unrealized gain. In 2009, Husky took steps to manage the impact of the strengthening Canadian dollar compared with the Company's net U.S. dollar position. The decrease in stock-based compensation recoveries in 2009 is due to the relatively flat share price in 2009 compared with 2008. Administration expense has decreased from the prior year due to cost reduction initiatives. The increase in depreciation and amortization is due to adjustments to the book value of legacy sites that have been deemed inactive. The increase in net interest in 2009 is due to higher debt levels compared to 2008. The reduction of other income was a result of lower unrealized gains on forward purchase contracts in 2009 compared to 2008. Intersegment eliminations are profit included in inventory that has not been sold to third parties at the end of the period.

Foreign Exchange Summary

($ millions)	**2009**	2008	2007
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ (327)**	$ 217	$ (197)
(Gain) loss on cross currency swaps	**62**	(83)	62
(Gain) loss on contribution receivable	**216**	(228)	-
Other (gains) losses	**44**	(241)	84
	$ (5)	$ (335)	$ (51)
U.S./Canadian dollar exchange rates:			
At beginning of year	**U.S. $0.817**	U.S. $1.012	U.S. $0.858
At end of year	**U.S. $0.956**	U.S. $0.817	U.S. $1.012

Consolidated Income Taxes

Consolidated income taxes decreased in 2009 to $541 million from $1,394 million in 2008, an effective tax rate of 27.6% for 2009 and 27.1% for 2008.

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

($ millions)	**2009**	2008	2007
Income taxes before tax amendments	**$ 541**	$ 1,394	$ 1,303
Canadian federal and provincial tax amendments	**-**	-	395
Income taxes as reported	**$ 541**	$ 1,394	$ 908
Cash taxes paid	**$ 1,323**	$ 615	$ 926

Taxable income from Canadian operations is primarily generated through partnerships, with the related income taxes payable in a future period. Accrued liabilities include $530 million of cash tax payable in 2010. In addition, during 2010, cash tax instalments of $310 million are payable in respect of the 2009 reported earnings but which are not taxable until 2010.

Corporate Capital Expenditures

Corporate capital expenditures of $36 million in 2009 were primarily for computer hardware, software, office furniture and renovations and equipment and system upgrades. In 2008, corporate capital expenditures were $47 million.

7.7 FOURTH QUARTER

Consolidated net earnings during the fourth quarter of 2009 were $320 million, an increase of $89 million or 39% compared with the fourth quarter of 2008 as a result of higher crude oil prices, improved U.S. Downstream results and a decline in operating costs, partially offset by lower production and lower natural gas prices.

After-tax earnings from the upstream sector were $334 million in the fourth quarter of 2009, a decrease of $8 million from the same period in 2008. Lower upstream earnings in the fourth quarter of 2009 were due largely to higher crude oil prices realized offset by a decrease in production and lower natural gas prices relative to the same period in 2008. Production for the fourth quarter of 2009 was 291,500 boe/day compared with 358,400 boe/day in the fourth quarter of 2008 primarily due to lower light oil production off the East Coast of Canada and lower natural gas production in Western Canada. Crude oil prices in the fourth quarter of 2009 averaged $66.65/bbl compared with $49.02/bbl in the fourth quarter of 2008. Natural gas prices in the fourth quarter of 2009 averaged $3.94/mcf compared with $6.84/mcf during the same period in 2008.

Upgrading after-tax earnings were $14 million in the fourth quarter of 2009, a decrease of $33 million compared with the same period in 2008. Lower after-tax earnings from upgrading operations were due to lower average upgrading differentials which resulted from narrowing heavy to light oil differentials. After-tax earnings from infrastructure and marketing were $49 million in the fourth quarter of 2009, an increase of $21 million due to inventory holding gains as a result of rising crude oil prices compared with inventory holding losses as a result of falling prices in the fourth quarter of 2008. Pipeline margins increased primarily due to increases in net broker margins.

Canadian refined products after-tax earnings in the fourth quarter of 2009 were $10 million compared to $15 million in the same period in 2008. The decrease was due to lower margins for asphalt more than offsetting higher sales volume at retail outlets combined with increased demand for the product. In the fourth quarter of 2009, ethanol gross margin increased due to higher sales volumes combined with the receipt of funds earned under government incentive programs designed to offset low market prices resulting primarily from competition from low priced U.S. imported ethanol.

U.S. Refining and Marketing operations recorded a loss of $43 million after-tax in the fourth quarter of 2009 compared to a loss of $535 million after-tax in the same period of 2008. The recovery in the fourth quarter of 2009 was due to improved product margins offset by reduced sales volumes as a result of a 49 day scheduled major turnaround at the Lima Refinery. Margins in the fourth quarter of 2008 were dramatically impacted by rapidly falling crude oil prices.

7.8 RESULTS OF OPERATIONS FOR 2008 COMPARED WITH 2007

Net earnings in 2008 were $3,751 million compared with $3,201 million in 2007. The increase of $550 million was attributable to the following:

Upstream earnings increased by $781 million due to higher crude oil and natural gas prices and lower DD&A, offset by lower crude oil and natural gas production and higher operating costs.

Midstream earnings decreased by $51 million due to lower upgrading differentials, lower marketing earnings due to rapidly declining prices in 2008, and increased operating costs, partially offset by higher upgrading throughput.

Downstream earnings decreased by $597 million due to significantly reduced refining margin and higher processing costs.

Corporate earnings increased by $417 million due to higher intersegment profit eliminations, higher foreign exchange gains, lower administration expenses and an increase in stock-based compensation recovery, partially offset by an increase in interest expense.

8.0 Liquidity and Capital Resources

8.1 SUMMARY OF CASH FLOW

In 2009, the Company funded its capital programs and dividend payments by cash generated from operating activities, cash on hand and long-term debt issuance. Husky maintained its strong financial position at December 31, 2009, with debt of $3,229 million partially offset by cash on hand of $392 million for $2,837 million of net debt at December 31, 2009. Husky has no long-term debt maturing until 2012. At December 31, 2009 Husky had $1.7 billion in unused short and long-term credit facilities and unused capacity under the new debt shelf prospectuses filed in Canada and the U.S. of $1.0 billion and U.S. $1.5 billion, respectively (refer to Section 8.2).

	2009	2008 (1)	2007 (1)
Cash flow - operating activities *($ millions)*	**$ 1,918**	$ 6,778	$ 4,619
- financing activities *($ millions)*	**$ 594**	$ (2,559)	$ 433
- investing activities *($ millions)*	**$ (3,033)**	$ (3,514)	$ (5,286)
Debt to capital employed *(percent)*	**18.3**	12.0	19.5
Debt to cash flow from operations *(times)*	**1.3**	0.3	0.5
Corporate reinvestment ratio *(percent)* (2)	**111**	66	86
Interest coverage ratios on long-term debt only (3)			
Earnings	**11.1**	34.4	28.1
Cash Flow	**17.4**	50.9	33.8
Interest coverage on ratios of total debt (4)			
Earnings	**10.7**	33.4	27.1
Cash flow	**16.7**	49.3	32.5

(1) 2008 and 2007 amounts as restated for the adoption of a new accounting policy. Refer to Note 4 of the Consolidated Financial Statements.

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

(3) Interest coverage on long-term debt on an earnings basis is equal to earnings before interest expense on long-term debt and income taxes divided by interest expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow from operating activities before interest expense on long-term debt and current income taxes divided by interest expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.

(4) Interest coverage on total debt on an earnings basis is equal to earnings before interest expense on total debt and income taxes divided by interest expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow from operating activities before interest expense on total debt and current incomes taxes divided by interest expense on total debt and capitalized interest. Total debt includes short and long-term debt.

Cash Flow from Operating Activities

Cash generated from operating activities totalled $1,918 million in 2009 compared with $6,778 million in 2008. Lower cash flow from operating activities was primarily due to lower commodity prices, lower refining margins, lower crude oil and natural gas production and the payment of current income taxes in 2009 related to 2008 and 2007 earnings, partially offset by a weaker Canadian dollar relative to the U.S. dollar.

Cash Flow from (used for) Financing Activities

Cash provided by financing activities was $594 million in 2009 compared with cash used in financing activities of $2,559 million in 2008. In May 2009, the Company issued U.S. $1.5 billion in long-term bonds, and in 2008, bridge financing related to the Lima acquisition was repaid.

Cash Flow used for Investing Activities

Cash used in investing activities was $3,033 million for 2009 compared with $3,514 million in 2008. Cash invested in both periods was used primarily for capital expenditures and acquisitions.

8.2 WORKING CAPITAL COMPONENTS

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2009, Husky's working capital was $726 million compared with $404 million at December 31, 2008. Working capital increased as a result of an increase in inventories of $488 million due to build up of inventory from the turnaround at Lima at the end of 2009; a decrease in accounts payable of $150 million due to lower capital accruals as a result of decreased capital spending; a decrease in other accrued liabilities of $412 million as a result of lower dividends declared and a decrease of income taxes payable of $149 million due to lower taxable income and payments on prior year taxes offset by a decrease in accounts receivable of $357 million due to lower natural gas production and lower joint venture receivables reflecting lower levels of drilling in 2009.

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 and committed credit facilities. 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 production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic long-term investment plan during periods of low commodity prices. As a result, Husky frequently evaluates its options with respect to sources of long and short-term capital resources. In addition, from time to time the Company engages in hedging a portion of production to protect cash flow in the event of commodity price declines. Corporate acquisitions, such as the Lima Refinery, are financed by issuing investment grade long-term debt.

At December 31, 2009 Husky had the following available credit facilities:

Credit Facilities	Available	Unused
Operating facilities	$ 395	$ 262
Syndicated bank facility	1,250	1,250
Bilateral credit facilities	150	150
Total	$ 1,795	$ 1,662

Cash and cash equivalents at December 31, 2009 totalled $392 million compared with $913 million at the beginning of the year.

At December 31, 2009, Husky had unused committed long and short-term borrowing credit facilities totalling $1.5 billion. In addition, a further $195 million of uncommitted short-term borrowing facilities were available of which a total of $41 million were used in support of outstanding letters of credit.

Husky filed a debt shelf prospectus with the Alberta Securities Commission on February 26, 2009 and the U.S. Securities and Exchange Commission on February 27, 2009. The shelf prospectus enables Husky to offer up to U.S. $3 billion of debt securities in the United States until March 26, 2011. During the 25-month period that the shelf prospectus is 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. As of December 31, 2009, U.S. $1.5 billion of long-term debt securities had been issued under this shelf prospectus. On December 21, 2009, Husky filed an additional debt shelf prospectus with the Alberta Securities Commission that enables Husky to offer up to $1 billion of medium term notes in Canada until January 21, 2012. During the 25-month period that the shelf prospectus is effective, medium term notes may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of December 31, 2009, no medium term notes had been issued under this shelf prospectus (refer to Note 16 to the Consolidated Financial Statements).

The Sunrise Oil Sands Partnership has an unsecured demand credit facility available of $10 million for general purposes. Husky's proportionate share is $5 million.

In 2008, Husky initiated a cash tender offer to purchase any and all of the U.S. $225 million 8.90% capital securities outstanding. At the time of expiration of the tender offer, U.S. $214 million or 95% of the capital securities had been tendered. The remaining capital securities were redeemed in 2008.

In 2008, Husky redeemed the 6.95% medium-term notes - Series E due July 14, 2009. The principal amount was $200 million and the redemption price, including accrued interest, totalled $208 million.

During 2008, Husky repurchased U.S. $63 million of the outstanding U.S. $450 million 6.80% notes due September 2037.

Quarterly dividends of $0.30 ($1.20 annually) per common share were declared totalling $1.0 billion in 2009. The declaration of dividends will be at the discretion of the Board of Directors, which will consider earnings, capital requirements, the Company's financial condition and other relevant factors.

Capital Structure

	December 31, 2009	
($ millions)	Outstanding	Available
Total short-term and long-term debt	$ 3,229	$ 1,662
Common shares, retained earnings and accumulated other comprehensive income	$ 14,413	

Credit Ratings

Husky's senior debt has been rated investment grade by several rating agencies. These ratings are disclosed and explained in detail in Husky's 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)	2010	2011-2012	2013-2014	Thereafter	Total
Long-term debt and interest on fixed rate debt	$ 211	$ 827	$ 1,130	$ 3,093	$ 5,261
Operating leases	102	170	123	162	557
Firm transportation agreements	188	290	254	1,413	2,145
Unconditional purchase obligations (1)	2,701	2,317	54	106	5,178
Lease rentals and exploration work agreements	98	242	285	462	1,087
Asset retirement obligations (2)	29	66	60	5,725	5,880
	$ 3,329	$ 3,912	$ 1,906	$ 10,961	$ 20,108

(1) Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling rig services, natural gas purchases and the retail outlets acquisition.

(2) Asset retirement obligations - amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.

Based on Husky's 2010 commodity price forecast, the Company believes that its non-cancellable contractual obligations, other commercial commitments and 2010 capital program will be funded by cash flow from operating activities and, to the extent required, by available committed credit facilities and the issuance of long-term debt. In the event of significantly lower cash flow, Husky would be able to defer certain projected capital expenditures without penalty.

The Terra Nova oil field is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Husky currently holds a combined 12.51% working interest in the field, subject to redetermination. The process of working interest redetermination is before an arbitrator who is expected to make a decision by the third quarter of 2010. The outcome and impact of the arbitration process is not reasonably determinable at this time.

Estimated Obligations Not Included in the Table

Husky provides a defined contribution plan and a post-retirement health and dental plan for all qualified employees in Canada. The Company also provides a defined benefit pension plan for approximately 119 active employees and 506 retirees and their beneficiaries in Canada. This plan was closed to new entrants in 1991 after the majority of employees transferred to the defined contribution pension plan. Husky provides a defined benefit pension plan for approximately 400 active employees in the United States. This pension plan was established effective July 1, 2007 in conjunction with the acquisition of the Lima Refinery. Husky also assumed a post-retirement welfare plan covering the employees at the Lima Refinery. See Note 21 to the Consolidated Financial Statements.

Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery LLC (refer to Note 11 to the Consolidated Financial Statements) which is payable between December 31, 2009 and December 31, 2015 with the final balance due and payable by December 31, 2015. The timing of payments during this period will be determined by the capital expenditures made at the refinery during this same period. At December 31, 2009, Husky's share of this obligation was U.S. $1.4 billion including accrued interest.

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.

The Company has a number of contingent environmental liabilities, which individually have been estimated to be immaterial and have not been reflected in the Company's financial statements beyond the associated asset retirement obligations. These contingent environmental liabilities are primarily related to the migration of contamination at fuel outlets and certain legacy sites where Husky had previously conducted operations. The contingent environmental liabilities involved have been considered in aggregate and based on reasonable estimates the Company does not believe they will result, in aggregate, in a material adverse effect on its financial position, results of operations or liquidity.

8.4 OFF-BALANCE SHEET ARRANGEMENTS

Accounts Receivable Securitization Program

In the ordinary course of business, Husky engaged in the securitization of accounts receivable. The securitization program permitted the sale of a maximum of $350 million of accounts receivable on a revolving basis. The securitization agreement expired on March 31, 2009 and Husky chose not to renew.

Standby Letters of Credit

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

Derivative Instruments

Husky utilizes 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

On May 11, 2009, the Company issued 5 and 10-year senior notes of U.S. $251 million and U.S. $107 million respectively to certain management, shareholders, affiliates and directors as part of the U.S. $1.5 billion 5 and 10-year senior notes issued through the existing base shelf prospectus, which was filed in February 2009 (refer to Note 16 to the Consolidated Financial Statements). Subsequent to this offering, U.S. $22 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. The coupon rates offered were 5.90% and 7.25% for the 5 and 10-year tranches respectively. These transactions were measured at the exchange amount, which was equivalent to the fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties. At December 31, 2009, the senior notes were included in long-term debt on the Company's balance sheet.

TransAlta Power, L.P. ("TAPLP") is under the indirect control of one 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 2009, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $90 million (2008 - $125 million). At December 31, 2009, the total value of accounts receivables related to these transactions was nil (2008 - nil).

Husky did not have any customers that constituted more than 10% of total sales and operating revenues during 2009.

8.6 FINANCIAL RISK AND RISK MANAGEMENT

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates, interest rates, credit risk and changes in fiscal, monetary and other financial policies related to royalties, taxes and others (refer to Section 6, The 2009 Business Environment). From time to time, the Company will use derivative instruments to manage its exposure to these risks.

Husky is exposed to risk factors associated with operating in developing countries, as well as political and regulatory instability. The Company maintains close contact with governments in the areas within which it operates.

In June 2009, the United States House of Representatives passed the Waxman-Markey American Clean Energy and Security Act, which requires a 17% reduction of greenhouse gas emissions from 2005 levels by 2020 and an 80% reduction by 2050. The bill also sets a system of permitting under which regulated industries would need to acquire sufficient allowances for their emissions. In September 2009, the Kerry-Boxer Clean Energy Jobs and American Power Act, which increases the required reduction of greenhouse gases to 20% by 2020, was introduced in the United States Senate. Each bill requires further legislative approvals before becoming law and their respective scope and requirements could be changed through this process before receiving final approval. Husky's operations may be impacted by whatever legislation emerges as law. Such legislation could require U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

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.

At December 31, 2009, the Company had third party physical purchase and sale natural gas contracts and natural gas storage contracts. These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized loss of $37 million has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income. The natural gas inventory held in storage relating to the natural gas storage contracts is recorded at fair value. At December 31, 2009, the fair value of the inventory was $173 million, resulting in a $69 million unrealized gain recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

On July 1, 2009, the Company designated certain crude oil purchase and sale contracts as fair value hedges against the changes in the fair value of the inventory held in storage. The assessment of effectiveness for the fair value hedges excludes changes between current market prices and market prices on the settlement date in the future.

These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of $4 million has been recorded in earnings in the Consolidated Statements of Earnings and Comprehensive Income. The crude oil inventory held in storage is recorded at fair value. At December 31, 2009, the fair value of the inventory was $124 million, resulting in a $1 million unrealized loss recorded in earnings in the Consolidated Statements of Earnings and Comprehensive Income.

Prior to July 1, 2009, the Company had entered into contracts for future crude oil purchases, whereby there is a requirement to pay the market difference of the inventory price paid at delivery and the current market price at the settlement date in the future. These contracts have settled and the resulting loss of $30 million has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Foreign Currency Risk Management

At December 31, 2009, Husky had the following cross currency debt swaps in place:

- U.S. $150 million at 6.25% swapped at $1.41 to $211 million at 7.41% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.19 to $89 million at 5.65% until June 15, 2012.
- U.S. $50 million at 6.25% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.17 to $88 million at 5.61% until June 15, 2012.

At December 31, 2009, the cost of a U.S. dollar in Canadian currency was $1.0466.

During 2009, the Company settled its two remaining forward purchases of U.S. dollars realizing a loss of $9 million recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Husky’s results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of Husky’s expenditures are in Canadian dollars. The majority of the Company’s 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. 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, 2009, 100% or $3.2 billion of Husky's outstanding debt was denominated in U.S. dollars (100% or $2.0 billion at December 31, 2008). The percentage of the Company's debt exposed to the Cdn/ U.S. exchange rate decreases to 88% when cross currency swaps are considered (2008 – 78%).

Effective July 1, 2007, Husky'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 operations. During 2008, the Company repaid U.S. $750 million of bridge financing and repurchased U.S. $63 million of bonds that were classified as a net investment hedge. As a result, the Company's net investment hedge is limited to the remaining U.S. $687 million. For 2009, the unrealized foreign exchange gain arising from the translation of the debt was $104 million, net of tax expense of $18 million, which was recorded in Other Comprehensive Income.

Effective December 3, 2009, Husky designated U.S. $300 million of the U.S. $750 million senior notes due December 15, 2019 as a hedge of the Company's net investment in the U.S. refining operations. For 2009, unrealized foreign exchange losses arising from the translation of the debt were less than $1 million, net of tax, which was recorded in Other Comprehensive Income.

Including cross-currency swaps and the debt that has been designated as a hedge of a net investment, 57% of long-term debt is exposed to changes in the U.S. / Canadian exchange rate (2008 - 35%).

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and a major portion of this receivable is denominated in U.S. dollars. Related gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in foreign exchange in current period earnings. At December 31, 2009, Husky's share of this receivable was U.S. $1.2 billion including accrued interest. Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in Other Comprehensive Income as this item relates to a self-sustaining foreign operation. At December 31, 2009 Husky's share of this obligation was U.S. $1.4 billion including accrued interest.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meets its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meets its liabilities when they become due. The Company prepares annual capital expenditure budgets, which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

The following are the contractual maturities of financial liabilities as at December 31, 2009:

Financial Liability	Less than 1 Year	1 to less than 2 Years	2 to less than 5 Years	Thereafter
Accounts payable and accrued liabilities	$ 2,185	$ -	$ -	$ -
Cross currency swaps	-	-	447	-
Long-term debt and interest on fixed rate debt	212	212	1,750	3,122
Total	$ 2,397	$ 212	$ 2,197	$ 3,122

The Company's objectives, processes and policies for managing liquidity risk have not changed from the previous year.

Interest Rate Risk Management

In 2009, interest rate risk management activities resulted in a decrease to interest expense of less than $1 million.

At December 31, 2009, Husky had the following interest rate swaps in place:

- U.S. $100 million of long-term debt whereby a fixed interest rate of 7.55% was swapped for LIBOR + 420 bps until November 15, 2016.

- U.S. $275 million of long-term debt whereby a fixed interest rate of 6.20% was swapped for LIBOR + 265 bps blended until September 15, 2017.

During 2009, these swaps resulted in an offset to interest expense amounting to less than $1 million.

In 2008, interest rate swaps on $200 million of long-term debt were discontinued as a fair value hedge as the $200 million medium-term notes were redeemed. During 2009, a loss of less than $1 million was recognized in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

The amortization of previous interest rate swap terminations resulted in an additional $3 million offset to interest expense in 2009.

Cross currency swaps resulted in an addition to interest expense of $4 million in 2009.

Credit and Contract Risk

Husky actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective.

Fair Value of Financial Instruments

The derivative portion of cashflow hedges, fair value hedges, and free standing derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon fair value hierarchy in accordance with the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3862. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. All of Husky's assets and liabilities that are recorded at fair value on a recurring basis are included in Level 2.

8.7 OUTSTANDING SHARE DATA

Authorized:

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

Issued and outstanding: February 23, 2010

• common shares	849,860,935
• preferred shares	none
• stock options	28,281,307
• stock options exercisable	14,915,410

At February 23, 2010, 49.2 million common shares were reserved for issuance under the stock option plan. Other than in respect of the performance based upon, options awarded under the stock option plan have a maximum term of five years and vest evenly over the first three years (refer to Note 20 to the Consolidated Financial Statements).

9.0 Application of Critical Accounting Estimates

Husky's Consolidated Financial Statements have been prepared in accordance with GAAP. Significant accounting policies are disclosed in Note 3 to the Consolidated Financial Statements. Certain of the Company's 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 Asset Retirement Obligation ("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 Husky utilizes financial derivatives to manage market risk. Effective January 1, 2007, Husky adopted CICA Handbook Section 3855, "Financial Instruments - Recognition and Measurement," Section 3865, "Hedges," Section 1530, "Comprehensive Income" and Section 3862, "Financial Instruments - Disclosure and Presentation." These standards provide the recognition, measurement and disclosure requirements for financial instruments and hedge accounting. Refer to Note 23 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 of forward purchases of U.S. dollars is determined using forward market prices.

Asset Retirement Obligation

Husky has significant obligations to remove tangible assets and restore land after operations cease and Husky retires or relinquishes the asset. The Company's 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 subsea equipment and facilities and restoration of land to a state required by regulation or contract. Estimating the ARO requires that Husky 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.

Employee Future Benefits

The determination of 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 fair value of the plan assets are used for the purposes of calculating the expected return on plan assets.

Legal, Environmental Remediation and Other Contingent Matters

Husky is 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. Husky 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 the Company's 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 be assessed annually for impairment and requires judgment in the determination of the fair value of assets and liabilities.

10.0 New and Pending Accounting Standards

10.1 NEW ACCOUNTING STANDARDS

Goodwill and Intangible Assets

Effective January 1, 2009, the Company retroactively adopted CICA Handbook Section 3064, "Goodwill and Intangible Assets," which replaced Section 3062 of the same name. As a result of issuing this guidance, Section 3450, "Research and Development Costs," and Emerging Issues Committee ("EIC") Abstract No. 27, "Revenues and Expenditures during the Pre-operating Period," have been withdrawn. This new guidance requires recognizing all goodwill and intangible assets in accordance with Section 1000, "Financial Statement Concepts." Section 3064 has eliminated the practice of recognizing items as assets that do not meet the Section 1000 definition and recognition criteria. Under this new guidance, fewer items meet the criteria for capitalization.

This adoption has resulted in a reduction of retained earnings at January 1, 2007 of $9 million, a reduction of earnings after tax of $3 million and $13 million for the years ended December 31, 2008 and 2007, respectively, and a reduction to assets of $36 million and $31 million as at December 31, 2008 and 2007, respectively (refer to Note 4 to the Consolidated Financial Statements).

Financial Instruments

Effective July 1, 2009, the Company prospectively adopted the amendments to CICA Handbook Section 3855, "Financial Instruments – Recognition and Measurement." Amendments to this section have prohibited the reclassification of a financial asset out of the held-for-trading category when the fair value of the embedded derivative in a combined contract cannot be reasonably measured. The adoption of the amendments to this standard did not have an impact on the Company's financial statements.

Effective September 30, 2009, the Company adopted the amendments to CICA Handbook Section 3855, "Financial Instruments – Recognition and Measurement," in relation to the impairment of financial assets. Amendments to this section have revised the definition of "loans and receivables" and provided that certain conditions have been met, permits reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. These amendments are effective for the Company's annual financial statements relating to its fiscal year beginning on January 1, 2009. The adoption of the amendments to this standard did not have an impact on the Company's financial statements.

Effective December 31, 2009, the Company adopted the amendments to CICA Handbook Section 3862, "Financial Instruments – Disclosures," to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. Amendments to this standard are reflected in note disclosures for financial instruments.

10.2 PENDING ACCOUNTING PRONOUNCEMENTS

Business Combinations

In December 2008, the CICA issued Section 1582 "Business Combinations," which will replace CICA Handbook Section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and remeasured at fair value through earnings each period until settled. Currently only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation. Section 1582 will be effective for Husky on January 1, 2011 with prospective application.

Consolidated Financial Statements

In January 2009, the CICA issued Section 1601, "Consolidated Financial Statements," which will replace CICA Handbook Section 1600 of the same name. This guidance requires uniform accounting policies to be consistent throughout all consolidated entities and the difference between reporting dates of a parent and a subsidiary to be no longer than three months. These are not explicitly required under the current standard. Section 1601 is effective for Husky on January 1, 2011 with early adoption permitted. This standard will have no impact to the Company.

Non-Controlling Interests

In January 2009, the CICA issued Section 1602, "Non-controlling Interests," which will replace CICA Handbook Section 1600, "Consolidated Financial Statements." Minority interest is now referred to as non-controlling interest, ("NCI"), and is presented within equity. Under this new guidance, when there is a loss or gain of control the Company's previously held interest is revalued at fair value. Currently an increase in an investment is accounted for using the purchase method and a decrease in an investment is accounted for as a sale resulting in a gain or loss in earnings. In addition, NCI may be reported at fair value or at the proportionate share of the fair value of the acquired net assets and allocation of the net income to the NCI will be on this basis. Currently, NCI is recorded at the carrying amount and can only be in a deficit position if the NCI has an obligation to fund the losses. Section 1602 is effective for Husky on January 1, 2011 with early adoption permitted.

International Financial Reporting Standards

In January 2006, the Canadian Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. In February 2008, as part of its strategic plan, the AcSB confirmed that Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian GAAP for years beginning on or after January 1, 2011. An omnibus exposure draft was issued by the AcSB in the second quarter of 2008, which incorporates IFRS into the CICA Handbook and prescribes the transitional provisions for adopting IFRS. In March 2009, the AcSB issued a second omnibus exposure draft on the adoption of IFRS. This exposure draft confirms the IFRS transition date as January 1, 2011 for all Canadian publicly accountable enterprises, incorporates any changes to IFRS since the previous exposure draft was issued and discusses additional key transitional issues. In October 2009, the AcSB issued a third omnibus exposure draft on the adoption of IFRS. This exposure draft incorporates changes to IFRS since the previous exposure draft that will be applicable to Canadian entities.

The Company commenced its IFRS transition project in 2008, which includes four key phases:

- Project awareness and engagement – This phase includes identifying and engaging the appropriate members for the core IFRS transition team, steering committee and other representatives as required. In addition, this phase includes communicating the key project requirements and objectives to the areas of the organization that will be impacted by IFRS conversion, including the Company's senior executive management team, Board of Directors and Audit Committee.
- Diagnostic – This phase includes an assessment of the differences between current Canadian GAAP and IFRS, focusing on the areas which will have the most significant impact to Husky. A preliminary conversion roadmap has been prepared as part of this phase.
- Design, planning and solution development – This phase focuses on determining the specific impacts to the Company based on the application of the IFRS requirements. This includes the design and development of detailed solutions and work plans by each key area to address implementation requirements. In addition, impact analysis will be performed on all areas of the business, including tax and information technology systems. Accounting policies will be finalized, first-time adoption exemptions will be considered, draft financial statements and disclosures will be prepared and a detailed implementation plan and timeline will be developed. This phase also includes the development of a training plan.
- Implementation – This phase includes implementing the required changes necessary for IFRS compliance. The focus of this phase is the finalization of IFRS conversion impacts, approval and implementation of accounting and tax policies, implementation and testing of new processes, systems and controls, execution of customized training programs and preparation of opening IFRS balances.

Corporate governance over the project has been established and a steering committee and project team have been formed. This committee is comprised of members of senior executive management and is responsible for final approval of project recommendations and deliverables to the Audit Committee and Board. Due to the scope of the IFRS project, the Company ensured that the appropriate stakeholders have been engaged by establishing a project advisory committee, which includes representatives from each area of the organization that will be significantly impacted. Husky has also engaged an external advisor to assist with the IFRS conversion process.

The Company completed the diagnostic assessment phase by performing comparisons of the differences between Canadian GAAP and IFRS. The Company has determined that the most significant impact of IFRS conversion is to property, plant and equipment. IFRS does not prescribe specific oil and gas accounting guidance other than for costs associated with the exploration and evaluation phase. The Company currently follows full cost accounting as prescribed in Accounting Guideline ("AcG") 16, "Oil and Gas Accounting – Full Cost." Conversion to IFRS will significantly impact how the Company accounts for costs pertaining to oil and gas activities, in particular those related to the pre-exploration and development phases. In addition, the level at which impairment tests are performed and the impairment testing methodology will differ under IFRS.

In July 2009, the International Accounting Standards Board ("IASB") approved additional IFRS transitional exemptions that will allow entities to allocate their oil and gas asset balances as determined under full cost accounting to the IFRS categories of exploration and evaluation assets and development and producing properties. This exemption will relieve entities from significant adjustments resulting from retrospective adoption of IFRS. The Company intends to utilize this exemption. Husky is also evaluating other first-time adoption exemptions available upon transition which give relief from retrospective application of IFRS. In 2009, the Company progressed significantly into the implementation phase for key areas including property, plant, and equipment.

The Company completed its most significant IT systems conversion for property, plant, and equipment in the first month of 2010. This IT initiative requires the Company complete its full cost exemption allocation and track assets at the level required for compliance with IFRS while maintaining appropriate asset data for Canadian GAAP reporting. System initiatives for other areas of convergence including asset retirement obligation and foreign exchange are scheduled to be completed in the first half of 2010. The Company intends to quantify the impacts of the IFRS conversion on key areas in 2010 and to focus on creation of 2010 quarterly data in compliance with IFRS.

The Company continues to focus on analyzing and developing implementation strategies and processes for other key IFRS transition issues identified. Assessments of other impacts completed to date include foreign exchange, revenue recognition, provisions and asset retirement obligations. Where applicable, key IFRS transition alternatives have been evaluated and implementation has commenced. The Company continues to perform preliminary accounting assessments on less critical IFRS transition issues and has commenced analysis of IFRS financial statement presentation and disclosure requirements. These assessments will need to be further analyzed and evaluated throughout the implementation phase of the Company's project and these impacts continue to be assessed by the Company. At this time, the impact on the Company's financial position and results of operations is not reasonably determinable or estimable for any of the IFRS conversion impacts identified.

As accounting policies are finalized by the Company, initiatives will commence to incorporate conversion impacts into existing internal controls over financial reporting and disclosure controls and procedures. In the first quarter of 2010, the Company will complete its risk assessment of key processes that will be impacted by IFRS. Internal control process documents are expected to be updated and implemented in the second half of 2010.

The Company's response to the global economic and financial crisis has had no significant impact to its IFRS conversion project plan.

In addition, the Company continues to monitor the IASB's active projects and all changes to IFRS prior to January 1, 2011 will be incorporated as required.

11.0 Reader Advisories

11.1 FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A are forward-looking statements within the meaning of 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 and forward-looking information within the meaning of applicable Canadian securities legislation (collectively "forward-looking statements"). The Company hereby provides cautionary statements identifying important factors that could cause 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," "target," "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks, uncertainties and other factors some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

In particular, forward-looking statements in this MD&A include, but are not limited to: the Company's general strategic plans; strategic plans for the upstream, midstream and downstream business segments; reserve estimates; development and production plans for the White Rose development projects; exploration plans for Canada's East Coast; offshore Greenland exploration plans; offshore China exploration plans; exploration and development plans for the Liuhua 34-2 discovery and development and production plans for the Liwan 3-1 discovery; exploration and drilling plans for the North Sumbawa II Block; receipt of an extension of the PSC for the Madura BD field; development plans, anticipated project sanctions, production plans and production capacity for the Sunrise Project; production optimization and drilling plans for the Tucker Oil Sands Project; testing and implementation of various enhanced recovery techniques in Western Canada; production plans for the McMullen property; production plans for the Pikes Peak South project; conventional and shale gas exploration plans for Western Canada; the Company's coal bed methane program; reconfiguration plans for the Lima Refinery; Continuous Catalyst Regeneration Reformer Project plans; planned execution of the agreement to purchase southern Ontario retail outlets; plans to reposition and upgrade the Toledo Refinery; expectations in respect of the timing of the Terra Nova redetermination; 2010 production guidance; 2010 capital expenditure guidance; and 2010 payments to be made pursuant to existing contractual obligations.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. In addition, information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.

The Company's Annual Information Form filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describes the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

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 Oil and Gas Reserves and Other Oil and Gas Information

The Company's disclosure of proved and probable oil and gas reserves and other information about its oil and gas activities has been made based in reliance on an exemption granted by Canadian Securities Administrators. The exemption permits the Company to make these disclosures in accordance with U.S. requirements relating to the disclosure of oil and gas reserves and other information. 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 reserves estimates and related disclosures presented in this document have been prepared in accordance with the definitions in Regulation S-X and the disclosure requirements in Regulation S-K prescribed by the United States Securities and Exchange Commission. Please refer to "Disclosure of Exemption under National Instrument 51-101" in the Annual Information Form for the year ended December 31, 2009 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.

11.3 NON-GAAP MEASURES

Disclosure of non-GAAP Measurements

Husky uses 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, operating netback, return on equity, return on capital employed, debt to capitalization and corporate reinvestment ratio. None of these measurements are used to enhance the Company's reported financial performance or position. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. They are common in the reports of other companies but may differ by definition and application. Except as described below, the definitions of these measurements are found in Section 11.4, "Additional Reader Advisories."

Disclosure of Cash Flow from Operations

Husky uses the term "cash flow from operations," which should not be considered an alternative to, or more meaningful than "cash flow - operating activities" as determined in accordance with GAAP, as an indicator of financial performance. Cash flow from operations or earnings is presented in the Company's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items.

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

($ millions)		**2009**	2008	2007
Non-GAAP	Cash flow from operations	**$ 2,507**	$ 5,946	$ 5,388
	Settlement of asset retirement obligations	**(41)**	(56)	(51)
	Change in non-cash working capital	**(548)**	888	(718)
GAAP	Cash flow – operating activities	**$ 1,918**	$ 6,778	$ 4,619

Disclosure of Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. This measurement helps management and investors to evaluate the specific operating performance by product at the oil and gas lease level. It is equal to product revenue less transportation costs, royalties and lease operating costs divided by either a barrel of oil equivalent or a mcf of gas equivalent.

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 the Company's prospects and plans. It provides additional information that is not contained in the Company's 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 24, 2010. 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 2009, 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.com.

Use of Pronouns and Other Terms

"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, 2009 and 2008 and Husky's financial position as at December 31, 2009 and at December 31, 2008.

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.sec.gov.
- Currency is presented in millions of Canadian dollars ("$").
- 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 solid or semi-solid with a viscosity greater than 10,000 centipoise at original temperature in the deposit and atmospheric pressure.

TERMS

Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
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*
Coal Bed 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 Capitalization	*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 a working 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 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 oil and gas reserves" are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

"Proved developed oil and gas reserves" are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"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. Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years. 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, but which taken together with proved reserves, are as likely as not to be recovered.

ABBREVIATIONS

bbls	*barrels*	*mmbtu*	*million British Thermal Units*
bps	*basis points*	*mmlt*	*million long tons*
mbbls	*thousand barrels*	*MW*	*megawatt*
mbbls/day	*thousand barrels per day*	*NGL*	*natural gas liquids*
mmbbls	*million barrels*	*WTI*	*West Texas Intermediate*
mcf	*thousand cubic feet*	*NYMEX*	*New York Mercantile Exchange*
mmcf	*million cubic fee*	*NIT*	*NOVA Inventory Transfer*
mmcf/day	*million cubic feet per day*	*LIBOR*	*London Interbank Offered Rate*
bcf	*billion cubic feet*	*CDOR*	*Certificate of Deposit Offered Rate*
tcf	*trillion cubic feet*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
boe	*barrels of oil equivalent*	*FPSO*	*Floating production, storage and offloading vessel*
mboe	*thousand barrels of oil equivalent*	*FEED*	*Front end engineering design*
mboe/day	*thousand barrels of oil equivalent per day*	*OPEC*	*Organization of Petroleum Exporting Countries*
mmboe	*million barrels of oil equivalent*	*PIIP*	*Petroleum initially-in-place*
mcfge	*thousand cubic feet of gas equivalent*	*SAGD*	*Steam assisted gravity drainage*
GAAP	*Generally Accepted Accounting Principles*	*MD&A*	*Management's Discussion and Analysis*
GJ	*gigajoule*	*C-NLOPB*	*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 the Chief Financial Officer, have 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, 2009, and have 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 and Canadian securities laws is (i) recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and Canadian securities laws 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, 2009, 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.
4) KPMG LLP, who has audited the Consolidated Financial Statements of Husky for the year ended December 31, 2009, has also issued a report on internal controls over financial reporting 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, 2009, 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

	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	2008 Q2	2008 Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	76.7	62.5	99.3	119.0	125.9	121.7	123.6	120.5
Medium crude oil *(mbbls/day)*	24.8	24.8	25.6	26.3	26.6	26.9	27.0	26.9
Heavy crude oil *(mbbls/day)*	78.6	75.7	78.1	82.1	86.8	84.4	83.8	82.6
Bitumen *(mbbls/day)*	23.3	24.0	22.2	22.7	23.9	23.2	21.7	21.7
	203.4	187.0	225.2	250.1	263.2	256.2	256.1	251.7
Natural gas *(mmcf/day)*	528.7	535.0	552.3	551.2	571.1	598.3	618.0	590.4
Total production *(mboe/day)*	291.5	276.2	317.2	342.0	358.4	355.9	359.1	350.1
Average sales prices								
Light crude oil & NGL *($/bbl)*	$ 73.98	$ 67.56	$ 65.32	$ 50.42	$ 58.43	$ 114.85	$ 121.71	$ 95.20
Medium crude oil *($/bbl)*	$ 65.78	$ 61.28	$ 58.32	$ 40.68	$ 47.02	$ 103.60	$ 101.87	$ 74.30
Heavy crude oil *($/bbl)*	$ 61.55	$ 59.21	$ 54.22	$ 35.80	$ 39.08	$ 95.66	$ 89.92	$ 64.30
Bitumen *($/bbl)*	$ 60.70	$ 58.44	$ 53.32	$ 34.23	$ 37.93	$ 95.12	$ 87.15	$ 62.44
Natural gas *($/mcf)*	$ 3.94	$ 2.84	$ 3.26	$ 5.31	$ 6.84	$ 8.66	$ 9.14	$ 7.04
Operating costs *($/boe)*	$ 12.24	$ 13.14	$ 11.05	$ 11.10	$ 10.84	$ 11.20	$ 10.91	$ 10.75
Operating netbacks (1)								
Light crude oil *($/boe)* (2)	$ 46.94	$ 38.37	$ 40.58	$ 32.95	$ 39.42	$ 76.03	$ 79.73	$ 65.39
Medium crude oil *($/boe)* (2)	$ 39.87	$ 32.47	$ 33.55	$ 17.64	$ 23.95	$ 67.32	$ 65.34	$ 44.88
Heavy crude oil *($/boe)* (2)	$ 37.16	$ 37.21	$ 33.85	$ 18.16	$ 19.55	$ 66.12	$ 62.23	$ 41.79
Bitumen *($/boe)* (2)	$ 26.59	$ 38.10	$ 33.75	$ 14.54	$ 12.66	$ 47.67	$ 54.48	$ 34.64
Natural gas *($/mcfge)* (3)	$ 2.29	$ 1.16	$ 1.73	$ 2.72	$ 3.94	$ 5.33	$ 6.23	$ 4.50
Total *($/boe)* (2)	$ 32.02	$ 27.30	$ 29.03	$ 22.44	$ 27.31	$ 58.99	$ 60.85	$ 45.43
Net wells drilled (4)								
Exploration Oil	5	1	1	2	34	10	3	23
Gas	-	1	3	18	15	11	4	49
Dry	1	-	-	5	2	2	-	19
	6	2	4	25	51	23	7	91
Development Oil	116	72	19	71	190	211	73	104
Gas	8	2	2	49	78	88	17	87
Dry	2	1	-	4	20	13	-	3
	126	75	21	124	288	312	90	194
	132	77	25	149	339	335	97	285
Success ratio *(percent)*	98	99	100	94	94	96	100	92
Midstream								
Synthetic crude oil sales *(mbbls/day)*	64.5	58.6	63.1	61.0	58.2	69.1	51.6	55.6
Upgrading differential *($/bbl)*	$ 13.06	$ 10.16	$ 8.31	$ 16.74	$ 27.48	$ 26.09	$ 30.12	$ 28.53
Pipeline throughput *(mbbls/day)*	498	498	534	529	493	494	539	504
Canadian Refined Products								
Refined products sales volumes								
Light oil products *(million litres/day)*	7.7	7.8	7.4	7.6	7.5	8.3	7.9	7.9
Asphalt products *(mbbls/day)*	18.9	32.4	17.5	21.7	21.4	33.9	23.0	17.8
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	22.2	27.5	17.8	28.8	28.8	27.3	26.4	22.0
Prince George refinery *(mbbls/day)*	10.4	10.2	10.0	10.6	10.7	7.9	10.5	11.4
Refinery utilization *(percent)*	82	94	70	99	99	88	92	84

(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

($ millions)	Upstream				Midstream							
					Upgrading				Infrastructure and Marketing			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
2009												
Sales and operating revenues, net of royalties	$ 1,200	$ 1,040	$ 1,167	$ 1,045	$ 445	$ 415	$ 399	$ 313	$ 1,692	$ 1,497	$ 1,760	$ 2,035
Costs and expenses												
Operating, cost of sales, selling and general	372	382	364	377	415	403	389	254	1,615	1,428	1,678	1,948
Depletion, depreciation and amortization	351	327	348	371	9	9	8	8	9	9	9	9
Interest - net	-	-	-	-	-	-	-	-	-	-	-	-
Foreign exchange	-	-	-	-	-	-	-	-	-	-	-	-
	723	709	712	748	424	412	397	262	1,624	1,437	1,687	1,957
Earnings (loss) before income taxes	477	331	455	297	21	3	2	51	68	60	73	78
Current income taxes	96	252	270	291	57	18	17	19	26	25	25	25
Future income taxes	47	(166)	(138)	(205)	(50)	(17)	(17)	(4)	(7)	(7)	(5)	(3)
Net earnings (loss)	$ 334	$ 245	$ 323	$ 211	$ 14	$ 2	$ 2	$ 36	$ 49	$ 42	$ 53	$ 56
Capital expenditures (2)	$ 841	$ 412	$ 405	$ 668	$ 20	$ 17	$ 12	$ 19	$ -	$ 7	$ 5	$ 14
Total assets	$ 16,338	$ 15,853	$ 15,877	$ 16,025	$ 1,427	$ 1,395	$ 1,429	$ 1,387	$ 1,712	$ 1,193	$ 1,364	$ 1,336
2008 (3)												
Sales and operating revenues, net of royalties	$ 1,295	$ 2,341	$ 2,424	$ 1,829	$ 445	$ 859	$ 648	$ 483	$ 2,456	$ 4,077	$ 3,909	$ 3,102
Costs and expenses												
Operating, cost of sales, selling and general	455	431	328	413	369	757	554	373	2,408	4,014	3,779	2,991
Depletion, depreciation and amortization	394	369	352	390	9	9	7	6	8	8	7	8
Interest - net	-	-	-	-	-	-	-	-	-	-	-	-
Foreign exchange	-	-	-	-	-	-	-	-	-	-	-	-
	849	800	680	803	378	766	561	379	2,416	4,022	3,786	2,999
Earnings (loss) before income taxes	446	1,541	1,744	1,026	67	93	87	104	40	55	123	103
Current income taxes	123	197	99	166	21	27	14	22	37	31	28	30
Future income taxes	(19)	265	406	143	(1)	1	11	10	(25)	(14)	9	1
Net earnings (loss)	$ 342	$ 1,079	$ 1,239	$ 717	$ 47	$ 65	$ 62	$ 72	$ 28	$ 38	$ 86	$ 72
Capital expenditures (2)	$ 1,174	$ 983	$ 625	$ 798	$ 23	$ 26	$ 28	$ 22	$ 58	$ 21	$ 5	$ 10
Total assets	$ 15,653	$ 14,724	$ 14,708	$ 13,114	$ 1,322	$ 1,450	$ 1,462	$ 1,406	$ 1,486	$ 1,802	$ 1,300	$ 1,322

(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 the Lima acquisition and the BP joint venture transaction.

(3) 2008 amounts as restated for adoption of a new accounting policy. Refer to Note 4 to the Consolidated Financial Statements.

	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
	$ 634	$ 786	$ 587	$ 488	$ 1,169	$ 1,555	$ 1,497	$ 1,128	$ (1,535)	$ (1,390)	$ (1,494)	$ (1,359)	$ 3,605	$ 3,903	$ 3,916	$ 3,650
	596	680	506	422	1,189	1,490	1,237	1,041	(1,520)	(1,405)	(1,438)	(1,300)	2,667	2,978	2,736	2,742
	24	23	23	23	47	48	49	50	15	14	13	9	455	430	450	470
	-	-	-	-	1	1	-	1	52	52	50	37	53	53	50	38
	-	-	-	-	-	-	-	-	(6)	-	34	(33)	(6)	-	34	(33)
	620	703	529	445	1,237	1,539	1,286	1,092	(1,459)	(1,339)	(1,341)	(1,287)	3,169	3,461	3,270	3,217
	14	83	58	43	(68)	16	211	36	(76)	(51)	(153)	(72)	436	442	646	433
	9	13	8	8	3	-	-	-	25	26	25	24	216	334	345	367
	(5)	11	8	5	(28)	6	77	13	(57)	(57)	(54)	(68)	(100)	(230)	(129)	(262)
	$ 10	$ 59	$ 42	$ 30	$ (43)	$ 10	$ 134	$ 23	$ (44)	$ (20)	$ (124)	$ (28)	$ 320	$ 338	$ 430	$ 328
	$ 38	$ 18	$ 20	$ 5	$ 137	$ 54	$ 43	$ 26	$ 14	$ 9	$ 7	$ 6	$ 1,050	$ 517	$ 492	$ 738
	$ 1,430	$ 1,587	$ 1,624	$ 4,504	$ 4,771	$ 4,647	$ 5,081	$ 2,259	$ 617	$ 1,478	$ 1,486	$ 453	$26,295	$26,153	$26,861	$25,964
	$ 673	$ 1,187	$ 982	$ 722	$ 1,474	$ 2,446	$ 2,553	$ 1,329	$ (1,642)	$ (3,195)	$ (3,317)	$ (2,379)	$ 4,701	$ 7,715	$ 7,199	$ 5,086
	640	1,131	911	658	2,265	2,456	2,263	1,296	(1,788)	(3,323)	(3,050)	(2,419)	4,349	5,466	4,785	3,312
	20	21	20	20	50	42	43	19	8	8	7	7	489	457	436	450
	-	-	-	-	1	1	-	1	30	28	41	45	31	29	41	46
	-	-	-	-	-	-	-	-	(275)	(76)	6	10	(275)	(76)	6	10
	660	1,152	931	678	2,316	2,499	2,306	1,316	(2,025)	(3,363)	(2,996)	(2,357)	4,594	5,876	5,268	3,818
	13	35	51	44	(842)	(53)	247	13	383	168	(321)	(22)	107	1,839	1,931	1,268
	8	7	7	6	(33)	(28)	59	(22)	20	32	27	23	176	266	234	225
	(8)	3	9	7	(274)	10	29	27	27	34	(125)	(33)	(300)	299	339	155
	$ 13	$ 25	$ 35	$ 31	$ (535)	$ (35)	$ 159	$ 8	$ 336	$ 102	$ (223)	$ (12)	$ 231	$ 1,274	$ 1,358	$ 888
	$ 63	$ 45	$ 28	$ 19	$ 70	$ 22	$ 34	$ 7	$ 14	$ 7	$ 14	$ 12	$ 1,402	$ 1,104	$ 734	$ 868
	$ 1,375	$ 1,560	$ 1,629	$ 1,395	$ 5,380	$ 5,506	$ 5,403	$ 6,574	$ 1,270	$ 1,216	$ 757	$ 551	$26,486	$26,258	$25,259	$24,362

Segmented Capital Expenditures

($ millions)	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	2008 Q2	2008 Q1
Upstream								
Western Canada	$ 579	$ 152	$ 109	$ 349	$ 815	$ 574	$ 497	$ 675
East Coast Canada	95	111	160	208	237	306	93	93
Northwest United States	10	3	7	5	10	50	-	-
International	157	146	129	106	112	53	35	30
	841	412	405	668	1,174	983	625	798
Midstream								
Upgrader	20	17	12	19	23	26	28	22
Infrastructure and Marketing	-	7	5	14	58	21	5	10
	20	24	17	33	81	47	33	32
Downstream								
Canadian Refined Products	38	18	20	5	63	45	28	19
U.S. Refining and Marketing	137	54	43	26	70	22	34	7
	175	72	63	31	133	67	62	26
Corporate	14	9	7	6	14	7	14	12
	$ 1,050	$ 517	$ 492	$ 738	$ 1,402	$ 1,104	$ 734	$ 868

Note: Excludes capitalized costs related to asset retirement obligations incurred during the period and the Lima acquisition and the BP joint venture transaction.