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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

Report of Foreign Private Issuer Pursuant to Rule 13a-16 or 15d-16
Under the Securities Exchange Act of 1934

SEC MAIL PROCESSING RECEIVED
MAR 29 2011
WASH. D.C. 193 SECTION

For the month of March 2011

Commission File Number: 001-04307

Husky Energy Inc.

(Translation of registrant's name into English)

707 8th Avenue S.W., Calgary, Alberta, Canada T2P 1H5
(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F ____ Form 40-F X

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1). X

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): ____

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ________ No X

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-_______.

On March 22, 2011, Husky Energy Inc. filed its annual report for the fiscal year ended December 31, 2010 with Canadian securities and regulatory authorities on the System for Electronic Document Analysis and Retrieval. The annual report is attached hereto as Exhibit A.

SIGNATURES

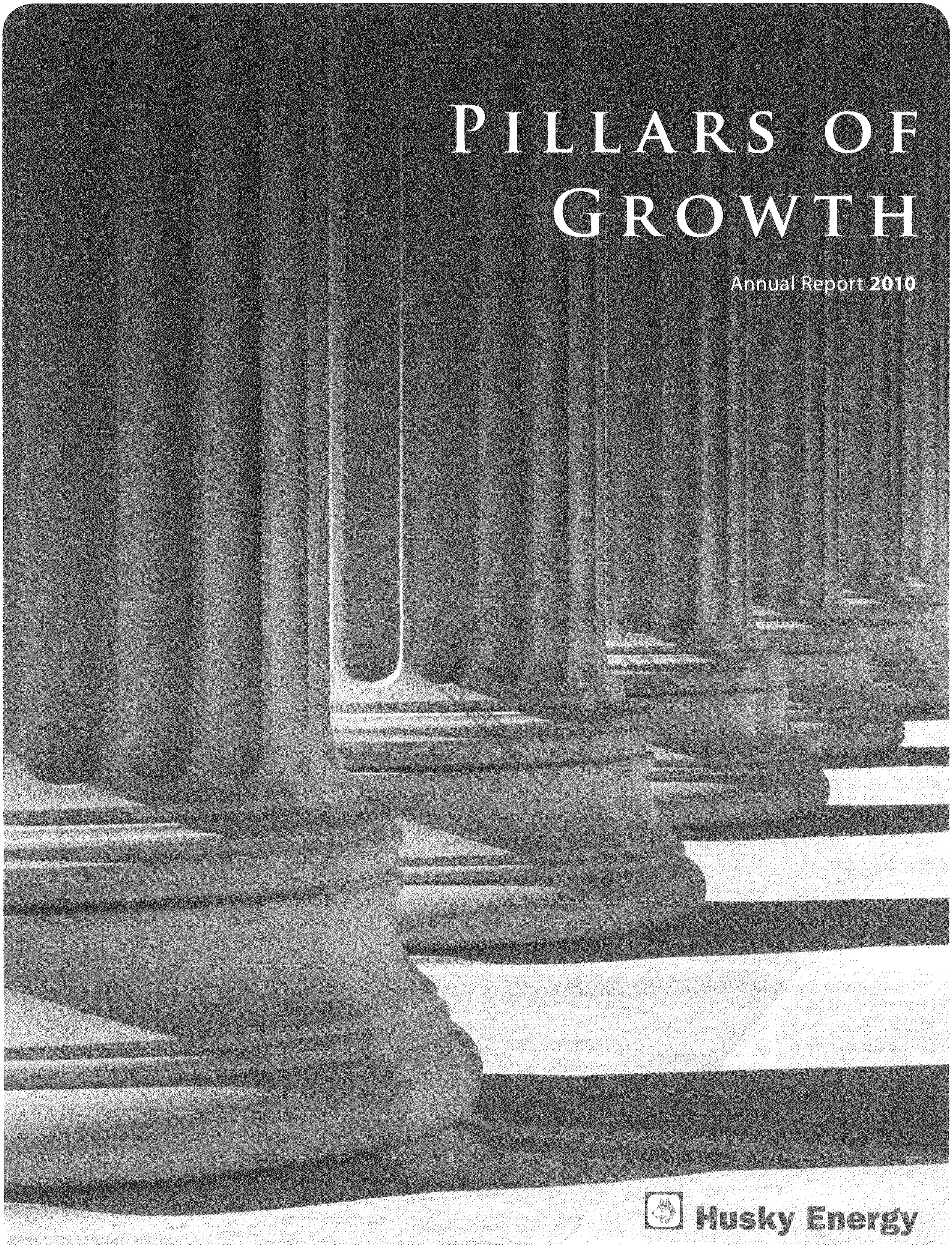
Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HUSKY ENERGY INC.

By: ______________________________
James D. Girgulis
Vice President, Legal & Corporate Secretary

Date: March 22, 2011

Exhibit A



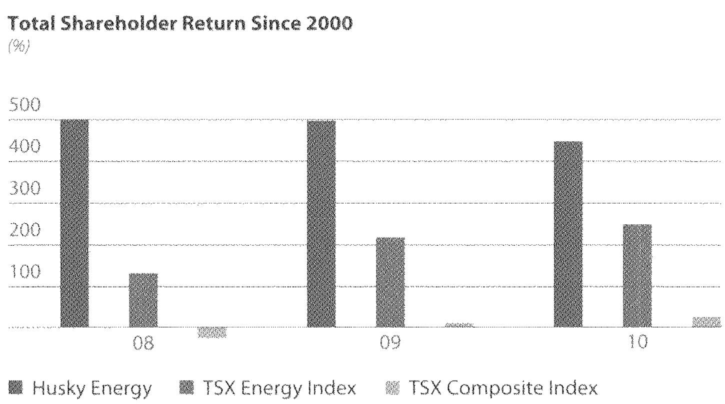
PILLARS OF GROWTH

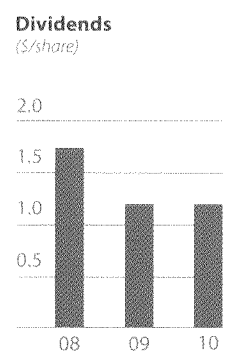
Annual Report **2010**

Husky Energy

Creating Shareholder Value

Husky Energy is one of Canada's largest integrated energy companies. It is headquartered in Calgary, Alberta, and is publicly traded on the Toronto Stock Exchange under the symbol HSE. The Company operates worldwide with Upstream, Midstream and Downstream business segments. Husky uses a combination of technological innovation, prudent investment, sound project management and responsible resource development to deliver a consistent return to shareholders.





Overview

Operations

Financial

2010 HIGHLIGHTS

Financial Highlights

Year ended December 31	2010	2009
(millions of dollars except where indicated)		
Sales and operating revenues	**18,178**	15,074
(Net of royalties)		
Cash flow from operations	**3,549**	2,507
Per share *(dollars)* – Basic/Diluted	**4.16**	2.95
Net earnings	**1,173**	1,416
Per share *(dollars)* – Basic/Diluted	**1.38**	1.67
Dividends		
Per share *(dollars)* – Ordinary	**1.20**	1.20
Capital expenditures [1]	**3,956**	2,797
Return on average capital employed *(%)*	**7.1**	9.1
Return on equity *(%)*	**7.8**	9.8
Debt to capital employed *(%)*	**21.3**	18.3
Debt to cash flow from operations *(times)*	**1.2**	1.3

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

Operational Highlights

Year ended December 31	2010	2009
Daily production, before royalties		
Light crude oil & NGL *(mbbls/day)*	**80.4**	89.1
Medium crude oil *(mbbls/day)*	**25.4**	25.4
Heavy crude oil & bitumen *(mbbls/day)*	**96.8**	101.7
Total crude oil & NGL *(mbbls/day)*	**202.6**	216.2
Natural gas *(mmcf/day)*	**506.8**	541.7
Total *(mboe/day)*	**287.1**	306.5
Proved reserves, before royalties [1] [2]		
Light crude oil & NGL *(mmbbls)*	**237**	243
Medium crude oil *(mmbbls)*	**88**	82
Heavy crude oil *(mmbbls)*	**110**	120
Bitumen *(mmbbls)*	**247**	200
Natural gas *(bcf)*	**2,395**	1,725
Total *(mmboe)*	**1,081**	933
Upgrader throughput *(mbbls/day)*	**65.4**	74.1
Commodity volumes marketed *(mmboe/day)*	**0.9**	0.9
Pipeline throughput *(mbbls/day)*	**512**	514
Light oil sales *(million litres/day)*	**8.2**	7.6
Lima Refinery throughput *(mbbls/day)*	**136.6**	114.6
Toledo Refinery throughput *(mbbls/day, 50% w.i.)*	**64.4**	64.9
Asphalt Refinery throughput *(mbbls/day)*	**27.8**	24.1
Prince George Refinery throughput *(mbbls/day)*	**10.0**	10.3
Ethanol production *(thousand litres/day)*	**619.3**	676.9

(1) 2009 proved reserves based on SEC constant prices.
(2) 2010 proved reserves based on forecasted prices in accordance to NI 51-101.

Key Achievements for 2010

Foundation

- **Production stabilized**
  - Announced $1.2 billion in acquisitions
  - Purchase of natural gas properties in West Central Alberta added 10,800 boe/day as of December 1, 2010
  - $860 million acquisition of natural gas and oil properties in Alberta and northeast British Columbia added 21,900 boe/day to production following closing in February 2011

Pillars of Growth

- **Oil Sands**
  - Sunrise Energy Project sanctioned
  - First oil production expected in 2014
- **Atlantic Region**
  - First production at North Amethyst satellite field
  - Total Husky production was 46,700 bbls/day
- **South East Asia**
  - Retention of assets
  - Advanced Liwan development; first gas expected in late 2013

Funding the Capital

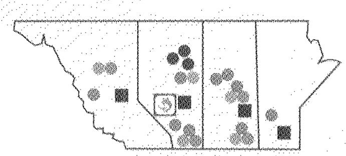
- $4.86 billion capital expenditure program for 2011
- Opportunity to receive dividend in stock or cash
- $1 billion equity issue completed

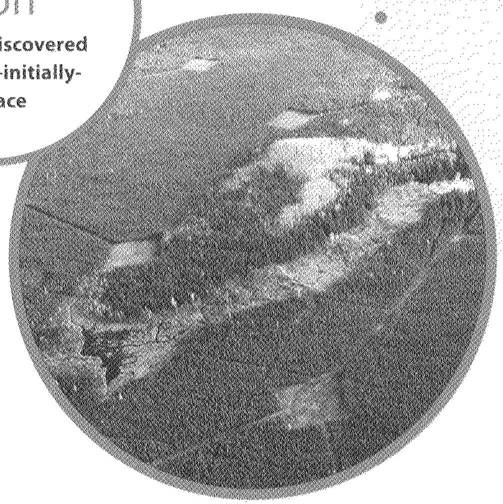
Global Portfolio

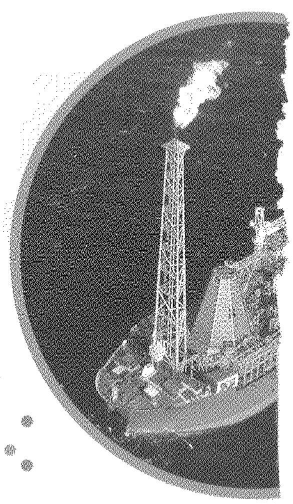
Husky's foundation is in Western Canada where the Company has extensive conventional oil and natural gas assets, significant heavy oil production, upgrading and transportation infrastructure. This base provides strong cash flow to develop the three pillars of growth: the Oil Sands, the Atlantic Region and South East Asia.

Sunrise
Phase 1
60,000 (1)
bbls/day

48
billion (1)
barrels of discovered petroleum-initially-in-place





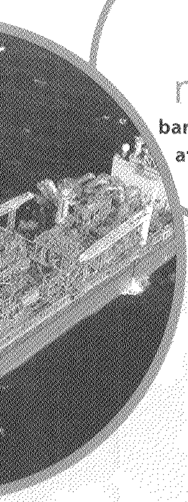


Oil Sands

Husky has an extensive portfolio of oil sands leases, encompassing 2,500 square kilometres. The Sunrise Energy Project is key to unlocking the potential of this vast resource base.

(1) Husky has 50 percent working interest.

- Exploration
- Production
- Development
- Infrastructure
- Husky Retail Outlets (by Province)



More than
150
million
barrels produced at White Rose

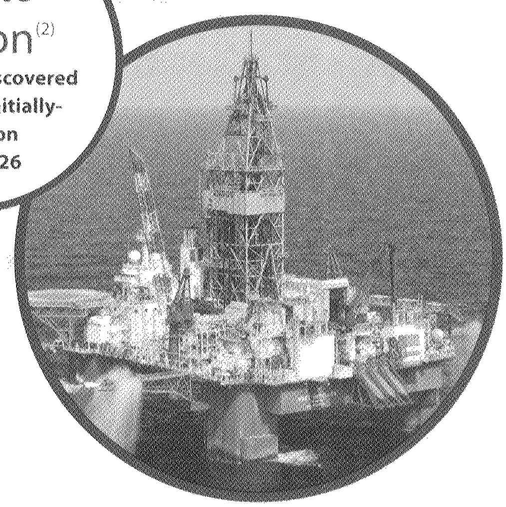
23
Significant Discovery Areas

Atlantic Region

This region offers significant growth potential. The Company holds interests in 20 Exploration Licences, six Production Licences and 23 Significant Discovery Areas.

2.6 to
3 trillion(2)
cubic feet of discovered natural gas-initially-in-place on Block 29/26

10,700
bbls/day
oil production
at Wenchang



South East Asia

Husky has a rich portfolio of assets in South East Asia, reflecting a dynamic, growth-oriented energy play. The Company has made significant progress on the Liwan 3-1 natural gas development, with first production anticipated in late 2013.

(2) Husky has 49 percent working interest.

2010 Report to Shareholders

This has been a year of significant progress for Husky. In 2010, the Company announced major acquisitions that will add flowing barrels and accelerate value for shareholders. We have a well-defined and growth-oriented business plan, a stable foundation, and have set course to realize value from our three mid to long-term growth pillars.

Husky undertook a rigorous review of its operations and business during the year to ensure its course is sound. The result is a clear strategy and five-year business plan that sets out milestones for the Company. The plan leverages our rich asset base of conventional and unconventional oil, natural gas interests and extensive heavy oil holdings, while providing the financial capacity to advance the Company's major growth opportunities in the Oil Sands, the Atlantic Region and South East Asia.

HIGHLIGHTS

While substantial progress was made during the year, 2010 proved to be a challenging business environment. The Company benefited from a strengthening in crude oil prices, but this was offset somewhat by a number of external factors including a slow economic recovery, low natural gas prices, the strengthening of the Canadian dollar and disruptions to third-party pipeline systems that serve the Company's U.S. Midwest refineries. Husky's overall production decreased primarily as a result of White Rose's natural decline.

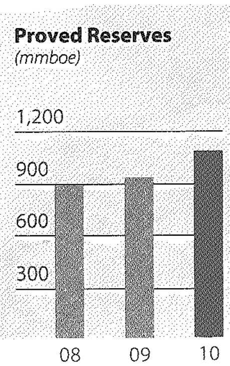
Husky took action to mitigate the impact of the external factors and set a course to return production to a path of steady growth.

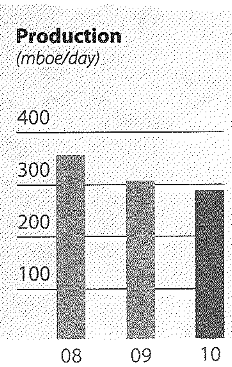
Efforts to accelerate near-term organic and inorganic growth resulted in a stabilization of production in the third and fourth quarters of 2010. Husky averaged a production rate of 287,100 barrels of oil equivalent (boe) per day for 2010 and exited the year at a production rate of 292,500 boe per day. At year end, the Company's total proved reserves stood at 1.08 billion boe.

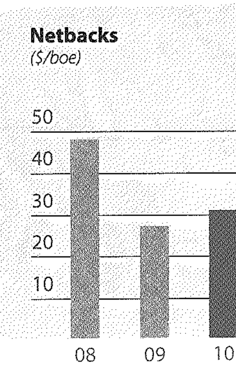
Total sales and operating revenues, net of royalties, for the year were $18.2 billion, compared to $15.1 billion in 2009. Net earnings were $1.17 billion, compared to $1.42 billion a year earlier and cash flow from operations increased 41 percent to $3.55 billion in 2010 compared to $2.51 billion in 2009. Our financial position remains strong with debt to cash flow ratio at 1.2 times, below the Company's target of 1.5 to 2.5, and debt to capital employed of 21.3 percent, also lower than the target of 25 to 35 percent.

Husky enhanced its financial flexibility by filing a $3 billion universal shelf prospectus in the fourth quarter. The Company issued $1 billion in equity and announced its intention to establish a mechanism that allows shareholders to receive dividends in cash or shares. Debt to cash and debt to capital metrics are below our peers, signalling a strong balance sheet.

During 2010, Husky continued to maintain a top-tier dividend, yielding more than four percent.







THE FOUNDATION

The Company undertook a number of initiatives in 2010 to create value and accelerate near-term production and add reserves in core operating areas. While Husky has an excellent portfolio of growth opportunities, the Company recognized that action was required to stabilize the production decline.

Husky announced two acquisitions at very attractive metrics, which will add a combined 32,700 boe per day to production. In September, Husky signed a purchase agreement to acquire natural gas properties in west central Alberta. The acquisition provides more than 65 million cubic feet per day of natural gas production, or approximately 10,800 boe per day, in a core producing area. It also optimizes the use of the Ram River gas plant and adds 650 square kilometres (160,000 acres) of prospective acreage. The acquisition closed on November 30, 2010.

The Ram River asset purchase was followed by another important acquisition in November. Husky signed a purchase agreement to acquire oil and natural gas properties in Alberta and north-east British Columbia, adding 21,900 boe per day to production for $860 million. The properties are located in core operating areas where existing infrastructure can be leveraged to create additional value. The acquisition closed in February 2011.

The Company took further action to strengthen its foundation with a decision to increase 2010 capital spending to $4.0 billion from a budgeted $3.1 billion. The majority of the investment targeted near-term, organic opportunities in heavy oil, conventional oil, liquids-rich gas resource plays and acquisitions.

The added investment in organic production, combined with the utilization of proven new technologies, is expected to have an increasingly positive impact over the next 12 to 18 months.

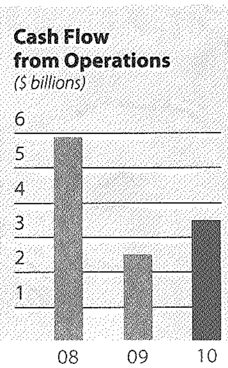
Husky has an extensive portfolio of assets in Western Canada and new technologies are making it possible to economically tap new pools and recover more production from existing reservoirs.

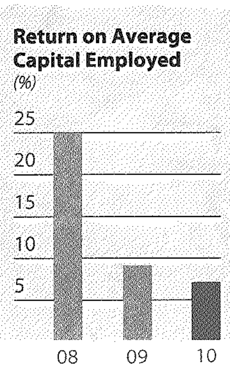
Enhanced development of our heavy oil portfolio is a prime example of how advancing technologies are producing tangible results. Through the use of proven new technologies such as horizontal drilling and thermal injection, Husky expects to substantially increase its recovery rate. In 2010, the Company more than tripled the number of horizontal wells drilled in heavy oil compared to 2009.

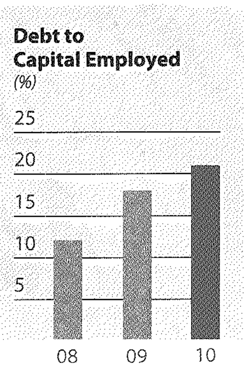
GROWTH PILLARS

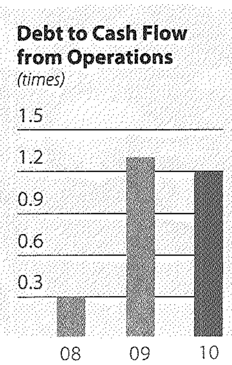
Oil Sands

Husky has an extensive portfolio of oil sands leases, encompassing 2,500 square kilometres in northern Alberta. The Company took a significant step toward unlocking the potential of this vast resource in 2010 with the sanctioning of Phase 1 of the Sunrise Energy Project.









Sunrise is a premier, in-situ oil sands development and represents a transformational opportunity for the Company. The first phase, representing an investment of $2.5 billion, is expected to produce about 60,000 barrels per day beginning in late 2014. Husky's working interest is 50 percent. Sunrise will use proven steam-assisted gravity drainage (SAGD) technology, keeping site disturbance to a minimum.

Sunrise marks the beginning of a new era for our Company in developing this increasingly important source of energy. Over time, Sunrise alone has the potential to deliver 200,000 barrels per day net, more than half of Husky's current production.

Atlantic Region

It was a year of milestones and major achievements for our Atlantic Region business. In May, first oil was produced at North Amethyst, the Company's first subsea satellite tie-back field in the White Rose project. North Amethyst was brought on production less than four years after discovery and is expected to reach its peak production rate in 2011 as more wells are drilled and brought on line.

In the third quarter, Husky received approval for a two-well pilot project at its next satellite development, West White Rose. Production is expected to come on stream in mid-2011.

The White Rose project celebrated its 150-millionth barrel of oil and marked five years of production with significant potential remaining in the core White Rose area. The Atlantic Region continues to represent a growth opportunity, with the Company holding 20 Exploration Licences and interests in six Production Licences and 23 Significant Discovery Areas. Work is well under way to identify new and innovative ways to further develop the significant resources in the basin.

South East Asia

Husky made an important decision in 2010 with respect to its assets in South East Asia. After carefully weighing its options, including a potential spinoff, the Company decided the assets would remain a core component of the growth strategy. At this stage of development, the Board has determined it is in the best interest of shareholders to continue to build a material oil and natural gas business in this resource-rich region.

In conjunction with that decision, we are moving forward with plans to develop the Liwan 3-1 natural gas project on Block 29/26 in the South China Sea. The Liwan 3-1 field, located about 300 kilometres southeast of Hong Kong, is an important component of our mid-term production growth strategy and a key step in accessing the burgeoning energy markets in Hong Kong and Mainland China. Husky has partnered with China National Offshore Oil Corporation (CNOOC) on the development and first gas production is anticipated in late 2013.

Combined with the producing Wenchang oil field, further natural gas discoveries on Block 29/26, and growth opportunities in Indonesia including the extension of the Madura Strait Production Sharing Contract, South East Asia represents a strong growth engine for Husky.

STRATEGIC FOCUS

Husky is a company with strong core values, founded on an unwavering commitment to process and occupational safety, strict financial discipline and creating value for shareholders through responsible and sustainable growth. Our strategic plan ensures the Company remains committed to these values, while setting a sound course toward accelerating value for shareholders.

The capital expenditure program approved for 2011 builds on the momentum achieved in 2010 to increase near-term production, while at the same time providing the investment required to advance our mid to long-term pillars of growth.

The achievements of the past year represent the culmination of significant effort and focus by employees and management. On behalf of Husky's Board of Directors, we would like to offer our sincere gratitude to them and extend our appreciation to the shareholders for their continued support.

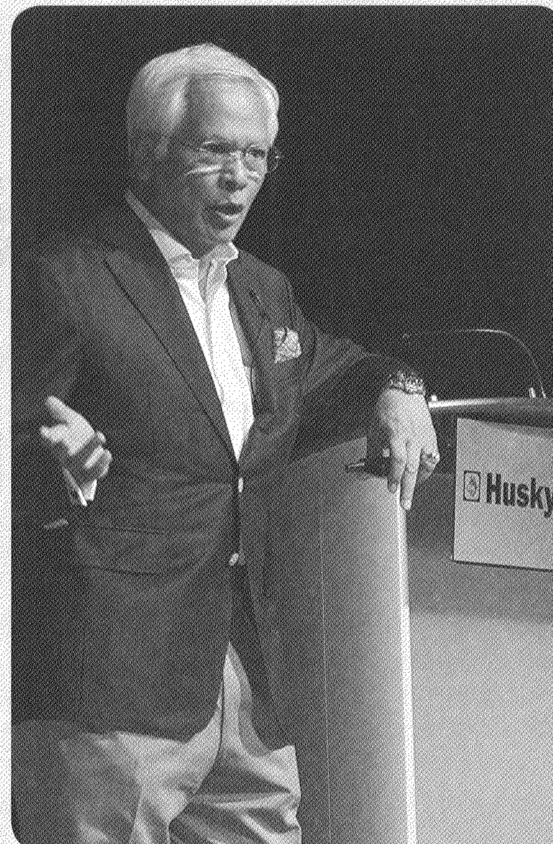
Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman

Asim Ghosh
President & Chief Executive Officer

March 8, 2011

Letter from the CEO



Since being appointed as CEO of Husky Energy in June of 2010, I have visited most of our operations and gained a deeper understanding of the business. I have been struck by many things: our commitment to process and occupational safety, financial discipline, sustainability, the talent and dedication of Husky employees and the depth of our resource portfolio. We have an enviable asset base in Western Canada and growth opportunities in the Oil Sands, the Atlantic Region and South East Asia.

Unlike many of our industry peers, the challenge for Husky is not acquiring new opportunities, but in determining how to best commercialize the valuable assets in our portfolio. This requires a plan, it requires capital, and it requires definitive execution.

We undertook a comprehensive portfolio review to prioritize our most attractive opportunities. This process resulted in a five-year plan which sets out a sound course to increase near-term production and a disciplined approach to developing the pillars that will fuel our growth in the mid to long term. This strategy is underpinned by a funding plan that supports organic and inorganic growth opportunities while advancing our major growth projects toward production.

The plan includes well-defined milestones. Our target is to grow production at an average annual compound growth rate of three to five percent, to achieve an annual reserve replacement rate of greater than 140 percent and to increase the return on capital employed by five percentage points over the term of the plan, while maintaining an attractive dividend yield.

Husky remains an integrated company, but in a specialized sense. We are not integrated on a barrel-for-barrel basis, but we do see value in maintaining Midstream and Downstream operations to provide specialized support to developing Upstream assets. We are a major player in heavy oil, for example, and our Lloydminster Upgrader and pipeline network are key components in deriving the greatest value from our production.

Much has been achieved in the past year, but the work is only beginning. For 2011, Husky has approved a capital expenditure program of $4 billion, in addition to an $860 million acquisition, which represents a 20 percent increase over 2010. This will allow us to build on the momentum achieved in the past year and carry out our growth strategy.

The course has been set and the work is underway as we embark on a new era of creating value for shareholders.

Sincerely,

Asim Ghosh

A Solid Foundation

Western Canada – Conventional, Unconventional and Heavy Oil

Western Canada is Husky's historic foundation. The Company is pursuing new oil and gas resource plays and using technological innovation to realize value.

Working from a land base of 35,612 square kilometres (8.8 million net acres) and proven reserves of 761 million barrels of oil equivalent (mmboe), Husky is active in the exploration and production of heavy oil, light crude oil, natural gas and natural gas liquids. The Company has more than 15,000 producing wells, and drilled 835 additional exploration and development wells in 2010.

Husky's strategy is to grow its most promising oil resource plays, focus capital into liquids-rich gas plays and maintain its heavy oil production.

Conventional

Conventional production accounted for approximately 135,000 boe/day. However, the Western Canadian Sedimentary Basin, while providing a strong land position and cash flow, is maturing. The application of new technologies and recent acquisitions are presenting new production opportunities. To offset the declines in the mature fields, Husky is ensuring that capital is spent efficiently, while emphasizing oil and liquids-rich gas resource plays to maintain top-quartile metrics and cash flow generation for investment in other parts of the business.

Pikes Peak EOR project expects first oil in 2012 (approximately 8,000 bbls/day).

Unconventional

Husky currently has approximately 5,000 bbls/day of unconventional oil production with contributions from the Viking, Lower Shaunavon and Bakken plays in south Saskatchewan and Central Alberta. Husky drilled 112 wells associated with oil resource plays in 2010 and plans to drill 185 wells over the next two years. These plays are currently in various stages of development and further drilling will be required to book additional reserves and advance development.

The Company's unconventional gas resource plays have 1.2 trillion cubic feet equivalent (tcfe) of contingent resource and 4.2 tcfe of prospective resource. Additional drilling will be required to delineate the resources and advance development plans to allow booking of additional reserves in the future. Volumes associated with gas resource plays ended the year at 53 mmcf/day. The portfolio in which Husky holds an average 84 percent working interest consists of established liquids-rich plays at Ansell and Kakwa, and a position in the emerging Wild River Duvernay play, all in west central Alberta. Husky has a large position in the Jean-Marie play in Bivouac as well as a position in Montney and Horn River, all in northeastern British Columbia.

Heavy Oil

In heavy oil, Husky has extracted approximately seven percent, or 775 million barrels of the estimated 10 billion barrels of petroleum-initially-in-place on its leases in Central Alberta and Saskatchewan. By using enhanced oil recovery (EOR) techniques, including thermal recovery, horizontal wells and high-volume lift, the Company expects to substantially increase the recovery from existing reservoirs to potentially 12 percent. With the application of new technology such as cold solvent CO_2 injection, the overall recovery of heavy oil could increase further.

The Company's Midstream and Downstream operations provide strategic support for the Upstream business. The Company pursues integration where it adds value in support of Upstream business segments.

2010 Highlights for Western Canada

- Husky agreed to purchase oil and natural gas properties in Alberta and northeast British Columbia. The acquisition adds 21,900 boe/day of production, 104 million barrels of proven oil equivalent and nine mmboe of probable reserves, as of December 1, 2010. This acquisition closed in February 2011.
- The Company acquired 650 square kilometres (160,000 net acres) of producing assets and land near its Ram River gas plant. The acquisition will provide 10,800 boe/day from 33 mmboe of proved reserves and 11 mmboe probable reserves.
- Commercial construction of the heavy oil Pikes Peak South project progressed. The facility will start up in 2012 with an estimated production of 8,000 bbls/day.
- Husky advanced development of the liquids-rich Ansell gas resource play with production of 26 mmcf/day.
- The Company drilled 835 exploration and development wells, more than double the 2009 total.

Daily Production (includes heavy oil)
229.7
mboe

Land Position
8.8 million
net acres, undeveloped and developed

Proved Reserves
761
mmboe

New Technology and Mature Fields

In the mature oil fields of Western Canada, Husky is turning to innovative enhanced oil recovery (EOR) technology to extract more production from tight reservoirs.

In the past 64 years, Husky has produced approximately 775 million barrels of heavy oil in the Lloydminster area. This represents only about seven percent of the oil under Husky leases in the area.

The Company can recover heavy oil in the region using known technologies such as thermal, CHOPS (cold heavy oil production with sand), horizontal drilling and high-volume lifts to improve recovery factors an additional five percentage points. Husky is evaluating additional technologies to further increase the recovery factor.

One of the most significant innovations in heavy oil is the extensive use of horizontal wells as a means of targeting pockets of existing oil in known regions. Drilling crews can pinpoint a location within a metre, making it easier to find pockets of thinner beds of oil.

The total number of horizontal wells drilled in the region increased in 2010 to 101, with up to 140 planned for 2011.

In other parts of Western Canada, Husky plans to maximize EOR from existing mature pools by using ASP (alkali surfactant polymer) and CO_2 floods, which are the next phase of recovery beyond water floods. This technology is expected to unlock an incremental 10 to 15 percent of production. At the end of 2010, EOR projects were producing approximately 3,500 barrels per day, with plans to grow these volumes to 5,000 barrels per day over the next two years. Crowsnest and Warner in southern Alberta are the two most advanced fields undergoing ASP floods.

PILLARS OF GROWTH

Oil Sands – Delivering energy for future generations

Husky has a significant oil sands position which will deliver medium and long-term production. This growth-intensive portfolio, which includes the Sunrise Energy Project, is being advanced with proven technologies and responsible environmental stewardship.

The Sunrise Energy Project is a key component of Husky's oil sands growth platform. Sanctioned in 2010, Sunrise is a world-class reservoir with 1.85 billion barrels of reserves (0.12 billion proved, 0.89 billion probable and 0.84 billion possible). Husky's working interest is 50 percent.

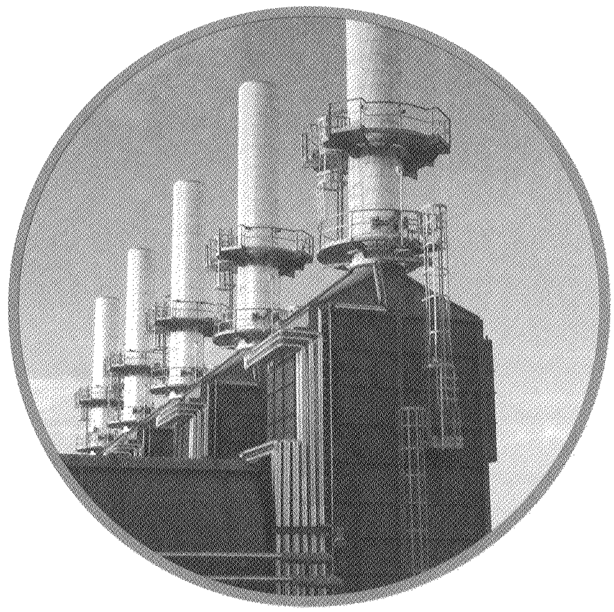
Sunrise is expected to produce approximately 60,000 bbls/day in Phase 1 with first oil in 2014. Current plans call for total gross production of 200,000 bbls/day by 2020 with further growth potential identified.

Sunrise will use an in-situ recovery technology called steam-assisted gravity drainage (SAGD) development, which is similar to conventional drilling with minimal surface land disturbance. Steam injection heats and mobilizes the bitumen, allowing it to be pumped to the surface more easily.

Regulatory approvals are in place for all currently planned phases. Sunrise will be developed sequentially and reclamation of disturbed land will be undertaken as drilling and production moves onto the next phase. Under the current plan, the development of Sunrise will affect less than five percent of the lease area, and only three percent will be under development at any given time. When work is completed at a site, the land will be restored to an equivalent pre-disturbed condition.

The water required to process bitumen at Sunrise will not be sourced from surface lakes, rivers or streams. More than 90 percent of the water will be from recycled sources and the additional water required will come from non-potable aquifers located in the same geological formation from which Husky is producing.

Husky operates the oil sands facilities and its partner operates the jointly-owned 160,000 barrels-per-day refinery near Toledo, Ohio, where bitumen will be processed into various transportation fuels. Minimal expenditure is required for the Toledo refinery to process initial Sunrise production, and a decision on the repositioning required to process subsequent phases is being studied.



At the Sunrise Energy Project, generators will convert non-potable water from deep aquifers to steam for the in-situ bitumen extraction. Ninety percent of the water will be recycled.

Major construction contracts for the Sunrise Central Plant Facility and Field Facilities, along with transportation agreements, are in place. Early site preparation was completed in 2010 with SAGD drilling underway in early 2011 and construction to begin in mid-2011. Sunrise Phase 2 pre-engineering is underway.

Husky's additional oil sands activities include continual improvements in steam-to-oil ratios and production at Tucker, pilot project development at McMullen, and studying the recovery process for the Saleski project.

Husky has a significant portfolio of oil sands leases, representing a combined 48 billion barrels of discovered petroleum-initially-in-place. This includes 183 million barrels proved reserves, 995 million barrels probable reserves, 964 million barrels of possible reserves and 2.02 billion barrels of contingent resources.

2010 Highlights for Oil Sands

- Husky sanctioned the in-situ Sunrise Energy Project.
- Regulatory approvals are in place and first oil is expected by 2014.
- Key contracts for Sunrise were awarded.
- Early site preparation at Sunrise is complete.
- First Nations and other key stakeholders are actively engaged in consultations around the development and operation of Sunrise to ensure best practices in all aspects of resource recovery.
- At year end, Tucker production exceeded 6,000 bbls/day with a steam-to-oil ratio below 5.0.
- McMullen production exceeded 2,400 bbls/day, a 14.3% increase over December 2009.
- Regulatory approval was granted for a 2011 air injection pilot test at McMullen that will burn residual oil to conduct heat to underlying bitumen.

Sunrise approvals are in place for
200,000
bbls/day

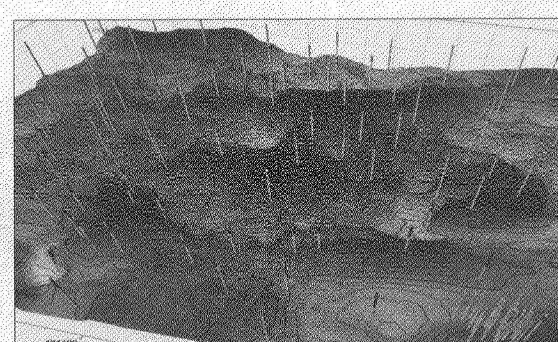
1.85 billion (1)
barrels of reserves at Sunrise

75%
of Phase 1 contracts for Sunrise have been awarded

(1) Husky has 50 percent working interest.

Technology Guides Well Optimization

Sunrise is a world-class oil sands resource. On average, bitumen pay thickness is 40 metres with 74 percent bitumen saturation.



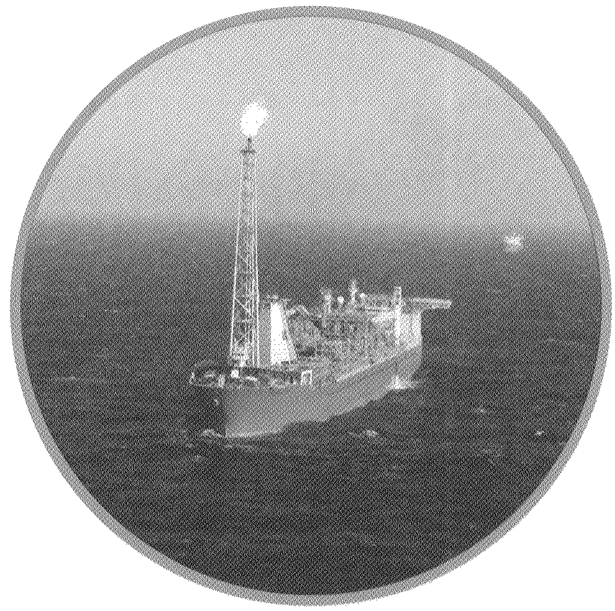
Subsurface research and exploration gives Sunrise one of the most comprehensive industry data sets and information regarding reservoir description. Substantial subsurface field work included delineation wells, 3-D seismic, core analysis, log analysis, geological modeling, reservoir modeling, production forecasting, and comparisons to industry analogues from the neighbouring Firebag and Mackay River leases.

This collection of information is critical to optimize the well placement for recovery of the resource, while enabling the most efficient use of the land. It will provide for maximum energy efficiency.

PILLARS OF GROWTH

Atlantic Region – Strong performance and compelling opportunities

The Company has a diverse portfolio of near, medium and long-term opportunities in the Atlantic Region, with many prospects near existing infrastructure.



Production from the North Amethyst satellite field will be piped to the SeaRose floating production, storage and offloading vessel (FPSO). The produced crude oil is offloaded to tenders for transport.

The Atlantic Region is a core development area for Husky and experienced several significant milestones in 2010, from safety to production. These successes provide a solid base for continued development.

Husky is the operator and majority owner in the White Rose oil field and satellite expansions, and has an ownership interest in the Terra Nova field as well as a number of other discoveries in the central part of the Jeanne d'Arc Basin.

November marked the fifth anniversary of first oil from the White Rose field, 350 kilometres offshore Newfoundland & Labrador. In its first five years of operation, the field has produced more than 150 million barrels of light sweet crude.

The North Amethyst satellite field expansion marks the first subsea tieback offshore Canada's East Coast. The field was developed in less than four years from the time of its discovery in 2006. By the end of 2010, North Amethyst had two production wells on line, with two supporting water injection wells nearing completion. A total of 11 wells are planned for the development.

Mid-term opportunities include the staged development of the West White Rose field. In August 2010, regulators approved the drilling of two wells into the reservoir from existing subsea infrastructure. First production is anticipated in the third quarter of 2011. Information from these wells will be used to formulate a full-field development plan for West White Rose, with a potential development application in 2012.

The Company is studying new and innovative ways to develop resources in the harsh North Atlantic environment. Husky is identifying strategies to optimize its existing resource base and to expand opportunities in the Jeanne d'Arc Basin. This includes a review of the economic and practical feasibility of a fixed drilling rig for production operations in the Basin.

For longer-term development, Husky has an extensive exploration portfolio in the Jeanne d'Arc Basin, the deepwater Mizzen discovery and exploration blocks off Greenland and Labrador with world-class hydrocarbon potential.

Husky holds exploration licences on 20 parcels of land and has 23 Significant Discovery Areas.

2010 Highlights for Atlantic Region

- Husky achieved first production at the North Amethyst satellite field on May 31, 2010.
- Husky and its partner were awarded a significant discovery licence for the deepwater Mizzen field in the Flemish Pass.
- The Company increased its working interest in the Terra Nova field from 12.51 percent to 13 percent.
- Husky signed two agreements securing two mobile drilling units.
- Husky received regulatory approval for the West White Rose pilot project.
- Husky successfully secured exploration rights to a further 169,400 hectares in the Jeanne d'Arc Basin. The new exploration licences are adjacent to Company-held lands.
- The Company acquired more than 5,000 kilometres of two-dimensional seismic data on exploration licences offshore Labrador and in the Sydney Basin.
- The production vessel *SeaRose FPSO* achieved five years without a lost-time incident.

23
Significant Discovery Areas

1.6 million
hectares of total exploration acreage

Increased interest to
13%
in Terra Nova oil field

Innovative Solutions for Complex Challenges

Optimizing production from complex oil reservoirs requires creative solutions. Offshore Canada's East Coast, Husky has been employing leading-edge technologies to maximize production from the White Rose field.

The source rocks in the White Rose area are located thousands of metres below the surface, and the wells can reach more than five kilometres in length. These technologies allow the Company to access and efficiently produce reserves across multiple production zones.

Intelligent completions, sometimes known as 'smart' wells, allow companies to reach multiple targets through a single well – effectively two or more wells in one.

Husky first introduced these technologies to the region as part of the White Rose project in 2005. At the time, multi-zone completions were used for water injection wells. With the North Amethyst satellite tieback, the Company has gone to the next level – inflow control devices for production wells.

In 2010, on the North Amethyst G-25 3 well, Husky installed what was the second-longest string of inflow control device screens in the world. Inflow control devices help improve oil flow by providing an even distribution of flow along the well bore. This maximizes the amount of oil produced through the life of a well.

The recently drilled production well for West White Rose is among the most complex to date in the region and is characterized by a hairpin turn and a long horizontal section with a total distance of more than 5.5 kilometres. The well will allow Husky to reach the West White Rose satellite field from existing infrastructure in the Central Drill Centre, resulting in significant cost savings.

Pillars of Growth

South East Asia – Building a material oil and gas business

Husky has been active in South East Asia since 1997 and has developed a strategic growth plan to accelerate returns from its potentially prolific assets in the region.

The decision to retain these assets provides the Company a sound foundation to capitalize on the investments it has made offshore China and Indonesia. This strategy benefits Husky shareholders by providing a return on investment and a source of capital for the Company's significant growth opportunities.

The Company is focused on advancing three major natural gas development projects on Block 29/26 in the South China Sea, approximately 300 kilometres southeast of Hong Kong.

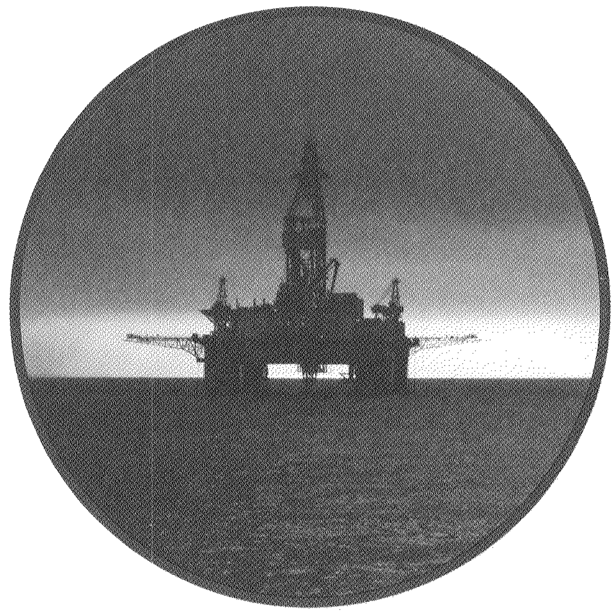
Husky's first major discovery on the block, the deepwater Liwan 3-1 gas field, is considered a cornerstone development to future growth opportunities in the region. Its sister discoveries on the same block, the Liuhua 34-2 and Liuhua 29-1 fields, will be produced in parallel and share infrastructure for greater production and cost efficiency.

Husky has partnered with China National Offshore Oil Corporation (CNOOC) to jointly develop the Block 29/26 fields. The partners have signed an agreement specifying the key principles of cooperation for funding and operation of Liwan 3-1.

First gas production is targeted in the fourth quarter of 2013, ramping up through 2014. Husky will operate the deepwater portion of the Liwan 3-1 field, including development drilling and completions, subsea equipment and controls, and subsea tie-backs to a shallow water platform. CNOOC will operate the shallow water infrastructure, including the platform, subsea pipeline to shore and the onshore gas processing plant. Husky's working interest in the deepwater development is 49 percent and 38.7 percent in the shallow water facilities.

Together, the Block 29/26 projects will allow Husky to develop natural gas resources estimated to be in the range of 2.6 to 3.0 trillion cubic feet of discovered gas-initially-in-place, while accessing significant energy markets in Mainland China and Hong Kong. Contingent resources will be assigned as facility design is completed.

During 2010, tendering began for Liwan 3-1 deepwater equipment and installation contracts. Excavation was completed at the on-shore gas processing facility site and equipment and steel were purchased for the off-shore loading facility. Development drilling of the production wells for the Liwan 3-1 field also commenced in 2010.



South East Asia represents a rich exploration and development opportunity for Husky. The Company's strong land and business position, coupled with access to growing energy markets in Mainland China and Indonesia, holds considerable promise for value creation.

Husky realized approximately 10,700 bbls/day of production from the Wenchang oil field in the South China Sea, located about 400 kilometres southwest of Hong Kong. The Company holds a 40 percent working interest in the field, which began production in 2002.

Husky has a 100 percent working interest in the unexplored Block 63/05, located in the Qiongdongnan Basin – approximately 50 kilometres south of Hainan Island in the South China Sea. The Company is planning to drill a well on this block in 2011.

In October 2010, the Company received approval from the Government of Indonesia for a 20-year extension to the existing Madura Strait Production Sharing Contract (PSC). The PSC includes the Madura BD and MDA natural gas and natural gas liquids fields offshore East Java, as well as numerous other prospects and leads. The extension provides the basis for advancing the Madura BD field toward development with first production planned for 2014.

2010 Highlights for South East Asia

- The Company is advancing three major natural gas developments: Liwan 3-1, Liuhua 34-2 and Liuhua 29-1.
- The estimated discovered natural gas-initially-in-place for Block 29/26 is in the range of 2.6-3.0 tcf of gas.
- Husky completed 3-D seismic analysis that delivered optimum well locations on Block 29/26 and Block 63/05.
- An integrated, multi-disciplinary team is working to develop Liwan 3-1.
- The Company received approval for a 20-year extension to the Madura Strait Production Sharing Contract offshore Indonesia.
- The Company identified several prospects in Indonesia with development of the Madura BD gas field and appraisal of the MDA gas field.

Producing
10,700
bbls/day from Wenchang field

20-Year
extension to the Indonesian Madura Strait Gas PSC

First gas from Liwan 3-1 expected in
2013

High-tech Teamwork Opens Deepwater Frontier

Many challenges await oil and gas companies that attempt to unlock the energy-rich resources in the South China Sea. Husky has found the key to success through rigorous planning, integrated teamwork and a commitment to best-in-class technologies.

With its landmark Liwan 3-1 field, the Company's resource evaluation team faced several challenges. The team is a multi-disciplinary workforce comprised of specialists from its Subsurface, Drilling, Logistics and Facilities departments, as well as expertise from its partner and specialist contractors. The assessment of the Liwan 3-1 field included applying high-tech seismic inversion and seismic-attribute analysis to a large, high quality 3-D seismic data set to choose optimum well locations.

After many hours of technical evaluation and re-evaluation, drilling of the first appraisal well at Liwan 3-1-2 began in 2008, just two and a half years after the drilling of the discovery well.

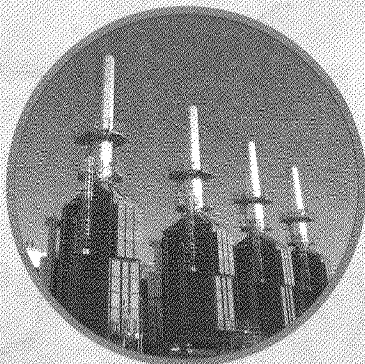
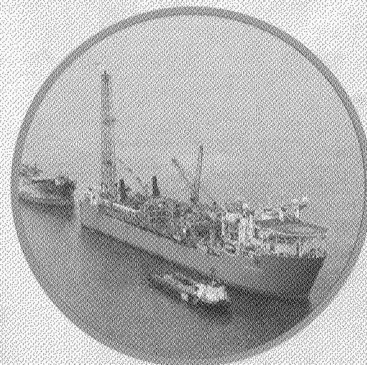
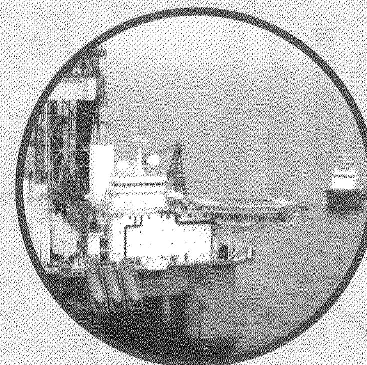
The use of advanced technologies provided the team valuable insights into the Liwan reservoir characteristics and architecture ahead of the actual drilling, resulting in a more complete picture and a clear path forward in further exploiting this frontier region.

Today, Husky is laying the groundwork to begin commercial production from its Liwan asset, the deepest natural gas discovery offshore China to date. Teamwork, collaboration, best practices and technology, all underpinned by a firm commitment to process and occupational safety, have opened up a new deepwater energy frontier for Husky in South East Asia.

Management's Discussion and Analysis

March 8, 2011

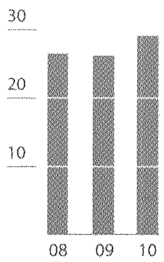
Contents

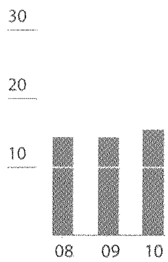
1.0 Financial Summary

1.1 Financial Position

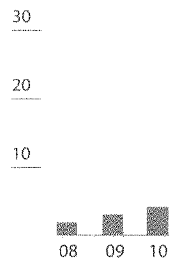
Total Assets
($ billions)



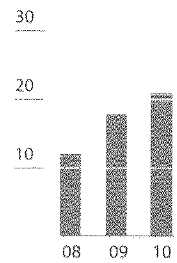
Total Equity
($ billions)



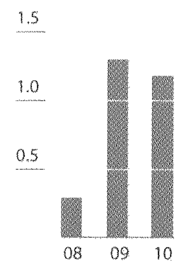
Total Long-term Debt
($ billions)



Debt to Capital Employed [1]
(%)



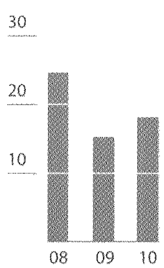
Debt to Cash Flow from Operations [1]
(times)



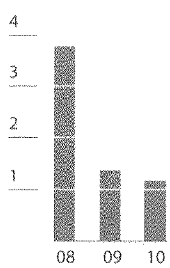
[1] *Capital employed and cash flow from operations are non-GAAP measures. (Refer to Section 11.3)*

1.2 Financial Performance

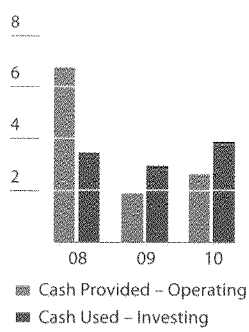
Sales & Operating Revenues
($ billions)



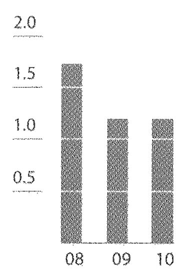
Net Earnings
($ billions)



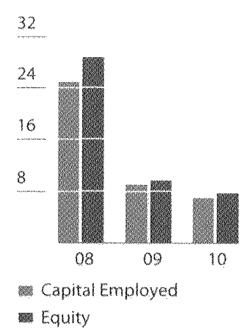
Cash Flow
($ billions)



Dividends
($ per share)



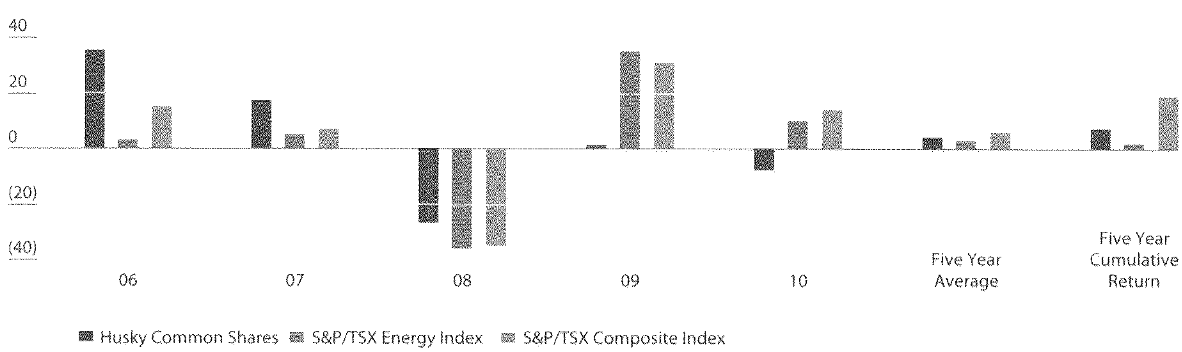
Return
(%)



1.3 Total Shareholder Returns

The following graph shows the total shareholder returns compared with the Standard and Poor's ("S&P") and the Toronto Stock Exchange ("TSX") energy and composite indices.

Total Shareholder Returns
(%)



1.4 Selected Annual Information

($ millions, except where indicated)	**2010**	2009	2008
Sales and operating revenues, net of royalties	**18,178**	15,074	24,701
Net earnings by sector			
Upstream	**1,135**	1,113	3,377
Midstream	**182**	254	470
Downstream	**95**	265	(299)
Corporate	**(192)**	(172)	142
Eliminations	**(47)**	(44)	61
Net earnings	**1,173**	1,416	3,751
Net earnings per share – basic/diluted	**1.38**	1.67	4.42
Ordinary dividends per common share	**1.20**	1.20	1.70
Cash flow from operations [1]	**3,549**	2,507	5,946
Total assets	**29,133**	26,295	26,486
Long-term debt including current portion	**4,187**	3,229	1,957
Cash and cash equivalents	**252**	392	913
Return on equity *(percent)*	**7.8**	9.8	28.9
Return on average capital employed [1] *(percent)*	**7.1**	9.1	25.1

[1] *Cash flow from operations and capital employed are non-GAAP measures. (Refer to Section 11.3)*

2.0 Husky Business Overview

Husky Energy is one of Canada's largest integrated energy companies. It is headquartered in Calgary, Alberta, and is publicly traded on the TSX under the symbol HSE. The Company operates worldwide with Upstream, Midstream and Downstream business segments. Husky uses a combination of technological innovation, prudent investment, sound project management and responsible resource development to deliver consistent shareholder returns.

- In the Upstream segment, the Company explores for, develops and produces crude oil and natural gas (Upstream business segment).
- In the Midstream segment, Husky upgrades heavy crude oil (upgrading business segment), processes and transports via pipeline heavy crude oil, as well as markets and operates storage facilities for crude oil and natural gas (infrastructure and marketing business segment).
- In the Downstream segment, 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), 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 The 2010 Business Environment

3.1 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:

Financial and Economic Risks

An adverse change in any of the following conditions could affect the Company's ability to realize the value and quantity of Husky's oil and natural gas reserves, achieve expected cash flow and financial performance, optimize project economics, sanction capital projects, and negatively impact the Company's results of operations, liquidity and financial condition:

- 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 cost and availability of capital, including access to capital markets at acceptable rates; and
- other financial risks as described in Section 8.6.

Operational Risks

An adverse change in any of the following conditions could affect the Company's ability to gain access to the resources required to increase oil and natural gas reserves and production, retain adequate markets for its products and services, gain access to capital markets and complete development projects:

- 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;
- prevailing climatic conditions in the Company's operating locations;
- 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, unplanned and extended pipeline shutdowns 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 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; and
- changes in workforce demographics.

Legislative Risks

An adverse change in any of the following conditions could affect the Company's ability to access markets, utilize its financial resources in an efficient manner, undertake exploration, development and construction projects as well as impact the Company's interests in its foreign operations and future profitability:

- potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations;
- changes to royalty regimes;
- regulations to deal with climate change issues;
- changes to government fiscal, monetary and other financial policies; and
- the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects.

3.2 Economic Sensitivities

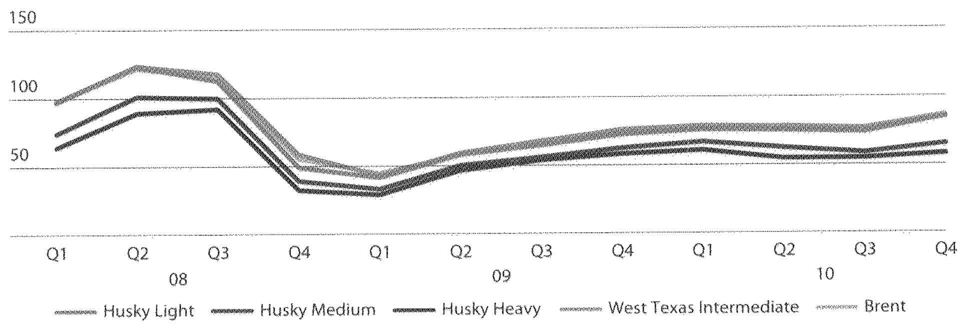
Average Benchmarks		2010	2009	2008
WTI crude oil	*(U.S. $/bbl)*	**79.46**	61.80	99.65
Brent crude oil	*(U.S. $/bbl)*	**79.42**	61.54	96.99
Canadian light crude 0.3% sulphur	*($/bbl)*	**77.75**	66.19	102.84
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**59.87**	53.60	72.44
NYMEX natural gas	*(U.S. $/mmbtu)*	**4.39**	3.99	9.04
NIT natural gas	*($/GJ)*	**3.91**	3.92	7.70
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**14.48**	9.93	20.38
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**9.64**	8.33	9.96
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**9.20**	8.43	11.17
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.971**	0.880	0.937
Canadian Equivalents				
WTI crude oil	*($/bbl)*	**81.83**	70.23	113.24
Brent crude oil	*($/bbl)*	**81.79**	69.93	110.22
WTI/Lloyd crude blend differential	*($/bbl)*	**14.91**	11.28	21.75
NYMEX natural gas	*($/mmbtu)*	**4.52**	4.53	9.65

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.

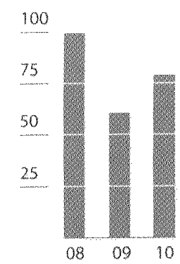
The Midstream and Downstream segments are also heavily impacted by the price of crude oil and natural gas. The largest cost factor in the midstream – upgrading business segment is the heavy crude oil feedstock, which is processed into light synthetic crude oil. The largest cost factors in the Downstream segment 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 the Lima, Ohio Refinery and approximately 50% heavy crude oil feedstock at the Toledo, Ohio Refinery. 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, Brent and Husky Average Crude Oil Prices
(US $/bbl)



Average WTI
(US $/bbl)

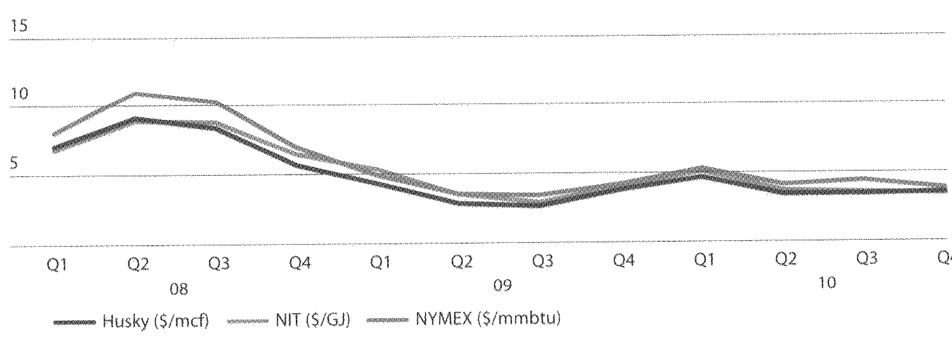


The price Husky receives for production from Western Canada is primarily driven by changes in the price of West Texas Intermediate ("WTI") while the majority of the Company's production in the Atlantic Region and offshore South East Asia is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2010 at U.S. $91.38/bbl recovering from U.S. $79.36/bbl on December 31, 2009, and averaged U.S. $79.46/bbl in 2010 compared with U.S. $61.80/bbl in 2009. The price of Brent ended 2010 at U.S. $92.55/bbl, recovering from U.S. $77.67/bbl on December 31, 2009, and averaged U.S. $79.42/bbl in 2010 compared with U.S. $61.54/bbl in 2009.

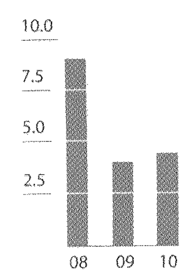
A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2010, 48% of Husky's crude oil production was heavy crude oil or bitumen compared with 47% in 2009. The light/heavy crude oil differential averaged U.S. $14.48/bbl or 18% of WTI in 2010 increasing from U.S. $9.93/bbl or 16% of WTI in 2009.

Natural Gas

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



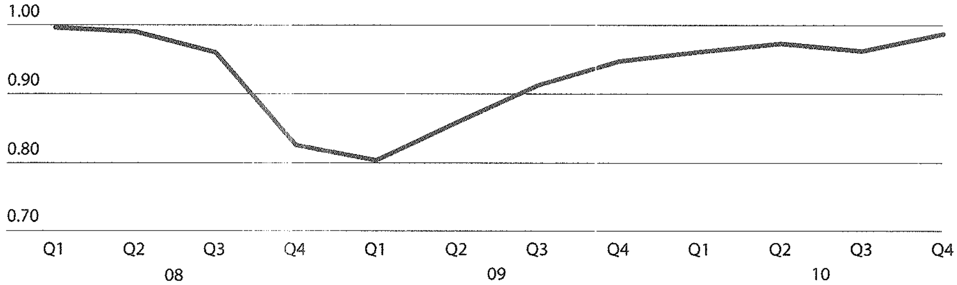
Average NYMEX
(US $/mmbtu)



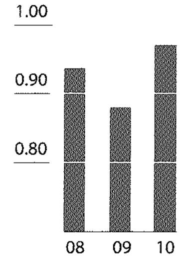
In 2010, 29% of Husky's total oil and gas production was natural gas. The near-month natural gas price quoted on the NYMEX ended 2010 at U.S. $4.41/mmbtu compared with U.S. $5.57/mmbtu at December 31, 2009. During 2010, the NYMEX near-month contract price of natural gas averaged U.S. $4.39/mmbtu compared with U.S. $3.99/mmbtu in 2009.

Foreign Exchange

Average US/Canadian Dollar Exchange Rate
(US $ per Cdn $)



Average US/Canadian Dollar Exchange Rate
(US $ per Cdn $)



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 majority of the Company's long-term debt is denominated in U.S. dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the principal amount owing of the long-term debt at maturity and the associated interest payments.

The Canadian dollar ended 2009 at U.S. $0.956 and subsequently strengthened during 2010, closing at U.S. $1.005 at December 31, 2010. In 2010, the Canadian dollar averaged U.S. $0.971 strengthening by 10% compared with U.S. $0.880 during 2009.

Increased U.S. crude oil prices were partially offset by the significant strengthening of the Canadian dollar against the U.S. dollar in 2010. The price of WTI in 2010 in U.S. dollars increased 29% compared with an increase of 17% in Canadian dollars when compared to 2009.

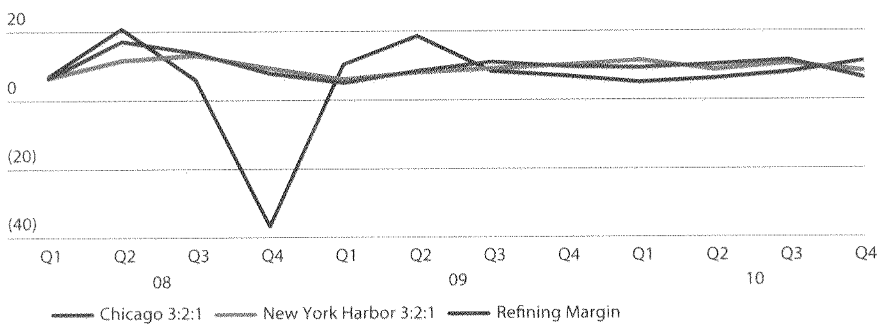
Refining Crack Spreads

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").

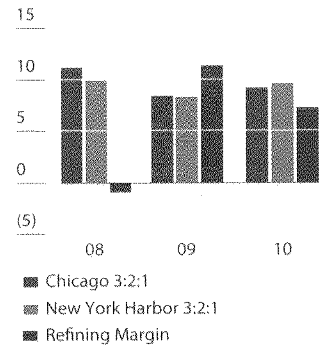
The New York Harbor 3:2:1 refining crack spread benchmark is calculated as the difference between the price of a barrel of WTI crude oil and the sum of the price of two-thirds of a barrel of reformulated gasoline and the price of one-third of a barrel of heating oil. The Chicago 3:2:1 refining crack spread benchmark is calculated based on WTI, regular unleaded gasoline and ultra low sulphur diesel. During 2010, the New York Harbor 3:2:1 refining crack spread averaged U.S. $9.64/bbl compared with U.S. $8.33/bbl in 2009. During 2010, the Chicago 3:2:1 crack spread averaged U.S. $9.20/bbl compared with U.S. $8.43/bbl in 2009.

During 2010, the 3:2:1 crack spreads were higher than 2009 reflecting the recovering U.S. economic environment which has resulted in increased demand for transportation fuel, lower inventory and stronger margins.

Chicago and New York Harbor Average Crack Spread and Husky Realized U.S. Refining Margin
(US $/bbl)



Average Crack Spread
(US $/bbl)



Cost Environment

From 2003 to 2008, the oil and gas industry experienced increasing costs that rose above the general trend of inflation. This resulted when the high level of industry activity, precipitated by escalating oil and gas prices, created demand for goods and services that exceeded supply. This increased the cost of operating the Company's oil and gas properties, processing plants and refineries. As a result of the global economic and financial crisis, the level of drilling and completions in the Western Canada Sedimentary Basin was significantly reduced in 2009, recovering in respect of oil well completions in 2010 while low natural gas prices continued to depress gas well completions. In addition, prospective capital projects including oil sands developments and major plant modifications were deferred pending cost improvements. Oil and gas prices declined rapidly in the latter half of 2008 and the first quarter of 2009, however, a corresponding decline in costs was delayed until the latter half of 2009. Crude oil prices have since recovered to the U.S. $90/bbl to U.S. $100/bbl range and industry activity, both drilling and field services, is increasing. The cost of field services is beginning to rise with higher demand, particularly in new technology driven plays.

Enbridge Line 6A/6B Shutdowns

During the third quarter of 2010, a crude oil release occurred on both Line 6A near Romeoville, Illinois and Line 6B near Marshall, Michigan. The pipelines in those vicinities were shut down until appropriate repairs were made. Line 6A was shut down on September 9 and returned to service on September 17. Line 6B was shut down on July 26 and resumed service on September 27. Since resuming service, Line 6B has continued to operate at less than full capacity.

The Enbridge Line 6A/6B shutdowns caused a widening in the light/heavy crude oil differential which negatively impacted medium and heavy crude oil and bitumen realized prices in the Upstream business segment. The shutdowns also reduced throughput at the Toledo Refinery in the third quarter of 2010 due to limited heavy crude oil availability and increased feedstock costs as heavy oil was partially replaced with light oil where available. In the fourth quarter, the widened differential resulted in lower feedstock costs which benefited the Midstream and Downstream segments as unit margins increased for the Lloydminster Upgrader and Lloydminster and Toledo Refineries, which partially offset the negatively impacted medium and heavy crude oil and bitumen realized prices in Upstream. The shutdowns also increased Husky's inventory volumes at the end of the year as the Company increased storage volumes to mitigate the impact of selling medium and heavy crude oil and bitumen at distressed prices to third parties as a result of the widened differential. The result of the Enbridge Line 6A/6B shutdowns was an approximate $53 million reduction to Husky's net earnings ($60 million reduction in Upstream, $10 million increase in Midstream, $3 million reduction in Downstream) in 2010.

Global Economic and Financial Environment

During 2010 WTI spot prices fluctuated between U.S. $91.50/bbl and U.S. $64.80/bbl and in the first two months of 2011 averaged U.S. $89.44/bbl. In the February 8, 2011 Short-term Energy Outlook[1] the Energy Information Administration ("EIA") indicated that it expects markets for crude oil and liquid fuels to tighten over the next two years. The EIA expects world oil consumption to grow an average of 1.5 mmbbls/day through 2012 and for supply from non-Organization of the Petroleum Exporting Countries ("non-OPEC") to increase marginally. As a result the market will need to draw on inventories and increased supply from OPEC. OPEC spare productive capacity averaged an estimated 4.7 mmbbls/day during 2010 and is expected to average 4.7 mmbbls/day in 2011 and 4.2 mmbbls/day in 2012. OPEC liquid fuel supply, which is not subject to OPEC's production policy, is expected to add marginally to total OPEC supply through 2012. At its meeting on December 11, 2010, OPEC agreed to maintain its current production policy and is scheduled to meet again on June 2, 2011. The EIA estimates that Organization for Economic Cooperation and Development ("OECD") countries held 2.7 billion barrels of commercial oil inventories at the end of 2010. This represents approximately 57 days of forward cover. The EIA expects OECD oil inventories to remain close to the middle of the past five year range throughout the forecast period, ending 2012 with 55 days of forward cover.

In the EIA's February 8, 2011 Short-term Energy Outlook, natural gas consumption in U.S. markets is expected to remain flat through 2012. Higher consumption in the industrial and electrical generation sectors is mostly offset by expected reductions in the residential and commercial sectors. Natural gas production in the U.S. is expected to level off in the near term, increasing by 2% from 2010 to 2012. Imports of both pipeline natural gas and liquefied natural gas into the United States are expected to decline over the forecast period. In its Weekly Natural Gas Storage Report[2] released February 3, 2011, the EIA reported that natural gas stocks were equal to the five year average and 2.8% below the previous year. The EIA expects continued natural gas price volatility in the near term.

There are a number of uncertainties that could result in higher or lower commodity prices. They include decisions made by OPEC regarding their production levels, the rate of global and U.S. economic recovery, the response by governments to various fiscal issues, the effect of China's efforts to address its growth and inflation and the general political stability of certain key strategic areas in the world.

Additionally, recent developments in Egypt, Libya and other North African and Middle East countries add uncertainty to oil and natural gas supply and demand. The Company closely monitors the developments in these areas.

Note:

(1) *Energy Information Administration, Short-Term Energy Outlook DOE/EIA – February 8, 2011 Release.*
(2) *"Weekly Natural Gas Storage Report", February 3, 2011, Energy Information Administration, U.S. Department of Energy.*

3.3 Sensitivities by Segment for 2010 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 2010. The table below shows what the effect would have been on 2010 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2010. 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

	2010 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)	$ 79.46	*U.S. $1.00/bbl*	62	0.07	45	0.05
NYMEX benchmark natural gas price (2)	$ 4.39	*U.S. $0.20/mmbtu*	25	0.03	18	0.02
WTI/Lloyd crude blend differential (3)	$ 14.48	*U.S. $1.00/bbl*	(10)	(0.01)	(9)	(0.01)
Downstream						
Canadian light oil margins	$ 0.029	*Cdn $0.005/litre*	14	0.02	10	0.01
Asphalt margins	$ 15.74	*Cdn $1.00/bbl*	8	0.01	6	0.01
New York Harbor 3:2:1 crack spread (4)	$ 9.64	*U.S. $1.00/bbl*	79	0.09	49	0.06
Consolidated						
Exchange rate (U.S. $ per Cdn $) (1)	$ 0.971	*U.S. $0.01*	(51)	(0.06)	(38)	(0.04)
Interest rate		*100 basis points*	(10)	(0.01)	(8)	(0.01)

(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 890.7 million common shares outstanding as of December 31, 2010.*

4.0 Capability to Deliver Results

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

4.1 Upstream

- Large base of crude oil producing properties in Western Canada that continues to produce with existing technology and has responded well to the application of increasingly sophisticated exploitation techniques such as horizontal drilling. 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 Energy Project that is in the development phase. The Sunrise Energy Project is proceeding 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 and West White Rose satellite fields 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 (collectively referred to as "Atlantic Region");
- A growing position in Western Canada gas resource plays with approximately 800,000 acres associated with both liquids-rich and dry gas positions;
- A growing oil resource play position with existing activities in the Viking, Bakken, Lower Shaunavon, and Cardium formations;
- Expertise and experience exploring and developing the high-impact natural gas potential in the Alberta Deep Basin, foothills, and northwest plains of Alberta and British Columbia;
- Position offshore China that includes a production interest in the Wenchang oil field, significant natural gas discoveries at the Liwan 3-1 and Liuhua 34-2 fields in Block 29/26 where development has commenced, significant natural gas discovery at the Liuhua 29-1 field within Block 29/26, and a Production Sharing Contract ("PSC") in Block 63/05; and
- Offshore Indonesia where Husky holds two exploration licences. The Madura BD natural gas and natural gas liquids discovery, in which the Company holds a 40% interest, is the current focus for development.

4.2 Midstream

- Heavy oil upgrading facility located in the Lloydminster, Saskatchewan heavy oil producing region with a throughput capacity of 82 mbbls/day;
- Integrated heavy oil pipeline systems in the Lloydminster producing region;
- Natural gas storage in excess of 50 bcf, owned and leased;
- Petroleum marketer balancing the needs of both customers and suppliers; and
- Supplier of crude oil, natural gas, petroleum coke, sulphur and electrical power for the Company's plants and facilities.

4.3 Downstream

- Refinery at Lima, Ohio, and a 50% interest in the BP-Husky Refinery in Toledo, Ohio each with a gross crude oil throughput capacity of 160 mbbls/day;
- Refinery at Prince George, British Columbia with throughput of 12 mbbls/day producing low sulphur gasoline and ultra low sulphur diesel;
- Largest marketer of paving asphalt in Western Canada with a 29 mbbls/day capacity asphalt refinery located at Lloydminster, Alberta 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 555 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. At the end of 2010, Husky completed the rebranding of 98 sites in Eastern Canada acquired in late 2009.

4.4 Corporate

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

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

5.0 Strategic Plan

Husky's current strategy is to continue to exploit oil and gas assets in Western Canada, while advancing its three major growth pillars in the Oil Sands, the Atlantic Region and South East Asia. Husky is an integrated company in a specialized sense. The Company is not integrated on a barrel-for-barrel basis and seeks to operate and maintain Midstream and Downstream assets which provide specialized support and value to its Upstream assets. The Company's strategy is to maximize the efficiency of its Midstream and Downstream operations and extract the greatest value from production.

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

5.1 Upstream

Husky's current strategy is to continue to exploit oil and gas assets in Western Canada, while advancing its three major growth pillars in the Oil Sands, the Atlantic Region and South East Asia.

Husky has an extensive portfolio of oil sands leases, encompassing 2,500 square kilometres in northern Alberta. The Company took a significant step toward unlocking the potential of this vast resource in 2010 with the sanctioning of Phase I of the Sunrise Energy Project. Husky will focus on Sunrise, which is a premier, in-situ oil sands development and represents a transformational opportunity for the Company. The first phase, representing an investment of $2.5 billion, is expected to produce about 60,000 barrels per day beginning in 2014. Husky's working interest is 50%. Sunrise will use proven steam-assisted gravity drainage ("SAGD") technology, keeping site disturbance to a minimum.

The Atlantic Region stretches from Greenland to the Sydney Basin, south of Newfoundland. North Amethyst was brought on production in May 2010 and is expected to reach its peak production rate in 2011 as more wells are drilled and brought into production. In 2010, Husky received approval for a two-well pilot project at its next satellite development, West White Rose. Production is expected to come on stream in mid-2011. The Atlantic Region continues to represent a growth opportunity, with the Company holding 20 Exploration Licences and interests in six Production Licences and 23 Significant Discovery Areas. Work is well under way to identify new and innovative ways to further develop the significant resources in the basin.

Husky made an important decision in 2010 to retain its assets in South East Asia in order to continue to build a material oil and natural gas business in this resource-rich region. The Company is moving forward with plans to develop the Liwan 3-1 natural gas project on Block 29/26 in the South China Sea. The Liwan 3-1 field, located approximately 300 kilometres southeast of Hong Kong, is an important component of the Company's mid-term production growth strategy and a key step in accessing the burgeoning energy markets in Hong Kong and Mainland China. Husky has partnered with China National Offshore Oil Corporation ("CNOOC") on the development and first gas production is anticipated in late 2013. Combined with the producing Wenchang oil field, further natural gas discoveries on Block 29/26, and growth opportunities in Indonesia including the extension of the Madura Strait PSC, South East Asia represents a strong growth engine for Husky.

5.2 Midstream

Husky's strategic plan for Midstream is focused on supporting heavy oil and oil sands production and making prudent reinvestment. Husky is not planning major expansions in 2011. The Company's spending will be focused on maintenance and optimizing existing infrastructure.

5.3 Downstream

Husky's strategic plan for Downstream is focused on supporting heavy oil and oil sands production and making prudent reinvestments. 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.

5.4 Financial

Husky is committed to ensuring adequate liquidity and financial flexibility to fund the Company's growth and support dividend payments. Over the business cycle, the Company's objective is to maintain a debt to cash flow from operations ratio of less than 2.5 times and a debt to capital employed target of 25% to 35%.

The Company also aims to retain investment grade credit ratings. The Company continues to focus on the existing financial discipline around costs and the efficiency of Husky's operations and, at the same time, emphasizing the Company's focus on its return on capital.

6.0 Key Growth Highlights

The 2010 capital program was established with a view of maintaining Husky's balance sheet and taking advantage of opportunities as economic conditions improved and financial uncertainty abated. Capital expenditures continued to focus on those projects offering the highest potential for returns and mid to long-term growth. During 2010, as a result of an ongoing comprehensive review of the Company's operations and business strategies, Husky increased its capital program and redirected a portion of it to focus on delivering near-term production growth. Husky's 2011 capital program has been established with a view of enabling the Company to build on the momentum achieved in 2010 with respect to accelerating near-term production growth as well as continuing to advance its three major growth pillars in the Oil Sands, the Atlantic Region and South East Asia.

6.1 Upstream

Atlantic Region

White Rose Development Projects

Drilling in the North Amethyst satellite subsea tie-back project continued in early 2010 with the use of the *GSF Grand Banks* drilling rig. First production was achieved on May 31, 2010 with one production well and a water injection well, while a second production well was completed in September 2010 and a second water injector completed and brought on production in January 2011. Production is tied back to the existing *SeaRose FPSO* infrastructure. A total of 11 wells are planned for North Amethyst, including two to three wells in 2011.

Husky continues to progress plans for a staged development of the West White Rose field. In August 2010, the Company received regulatory approval for a two-well pilot project to be drilled from the existing infrastructure at the White Rose field. The E-18-10 production well was drilled to total depth in 2010 and will be completed in 2011. These wells will provide additional information on the reservoir to refine development plans for the full West White Rose field. A production licence was received in the fourth quarter of 2010, and first production is anticipated mid-2011.

Exploration

Husky continues to evaluate its exploration opportunities offshore Newfoundland and Labrador and in January 2010 spudded the Glenwood H-69 exploration well northwest of the White Rose field. The well was suspended in March 2010 and the well data continues to be evaluated.

Husky, along with Suncor and Statoil Canada announced plans to enter into a second rig sharing agreement for the mobile semi-submersible drilling rig *Henry Goodrich*. The agreement will keep the rig in the Atlantic Region until November 2013. Husky intends to use its portion of rig time to pursue a combination of exploration, appraisal and development drilling opportunities.

In 2010, Husky completed a 3,000 kilometre two-dimensional ("2-D") seismic acquisition survey in the Sydney Basin between Newfoundland and Nova Scotia. Husky also acquired over 2,500 kilometres of 2-D seismic surveys on exploration acreage offshore Labrador. Exploration rights for these areas were awarded to Husky during land sales in 2008.

In February 2010, the Canada-Newfoundland and Labrador Offshore Petroleum Board ("C-NLOPB") issued a Significant Discovery Licence ("SDL") for the Mizzen prospect. In late 2010, Husky was successful in acquiring a new SDL for the Mizzen prospect and exploration rights in three additional parcels of land in the C-NLOPB November land sale. The exploration properties are adjacent to other Husky land holdings in the Jeanne d'Arc Basin and Flemish Pass. The new SDL extends the previous Mizzen SDL awarded in February 2010. An appraisal well is planned at Mizzen in the third quarter of 2011. Husky holds a 35% working interest in the Mizzen property.

The evaluation of a 7,000 kilometre 2-D seismic program acquired in the third quarter of 2008 on Blocks 5 and 7 offshore Greenland is complete. Evaluation of an airborne gravity and magnetics survey that was acquired in the second quarter of 2009 is nearing completion. In November 2009, Husky completed the acquisition of a 2,200 square kilometre 3-D seismic program over Block 5 and Block 7. This survey is the first 3-D seismic survey conducted offshore Greenland and utilizes a new dualsensor "Geostreamer" technology. Final processing of the 3-D seismic for Block 7 was completed in the fourth quarter of 2010. Final processing of Block 5 data is expected to be completed in the first quarter of 2011. Preliminary evaluation of the seismic data has identified several leads and potential drilling locations will be identified over the course of the first quarter of 2011. 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.

Heavy Oil

Construction of the 8,000 bbls/day South Pikes Peak project was approximately 49% complete at the end of 2010. Production is expected to commence in the first half of 2012. Horizontal well developments progressed through 2010, targeting new geological horizons in existing regions. A total of 101 horizontal wells were drilled in 2010.

Husky continued to operate two solvent EOR pilots through 2010 at Edam and Mervin. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction with expected completion in the third quarter of 2011. This liquefied CO_2 is to be used in the ongoing piloting program. A microbial EOR pilot in Wainwright, Alberta continued in 2010 with nine wells continuing to show a substantial response eight months after treatment. A second pilot in Devonia Lake has commenced with two cycles of treatments completed. The preliminary results show a 20% increase in oil production.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages and sanctioned Phase I in November 2010. Husky reached an agreement with Enbridge, IPF, and Keyera on the movement of diluted bitumen to market and transportation of diluent to the Sunrise oil sands site. Husky also awarded major engineering and construction contracts to Snamprogetti Canada for the central processing facilities and to Worley Parsons for the field facilities. Husky has initiated conceptual development engineering for subsequent phases and is expecting a comprehensive full field development plan to be established by the end of 2011.

Bitumen production from Phase I is planned at approximately 60 mbbls/day gross and is expected to commence in the first quarter of 2014. Regulatory approval is in place to increase total gross production to 200 mbbls/day. Husky and BP are equal partners in the Sunrise Energy Project, with Husky operating Sunrise.

Tucker Oil Sands Project

Based on a greater understanding of the Tucker reservoir, Husky is addressing production challenges by remediating older wells with innovative new stimulation techniques, drilling new wells and initiating new start up procedures. The results will be evaluated over the next six to twelve months. During 2010, Husky drilled 32 wells (16 well pairs) and is planning to drill an additional eight wells (four pairs) in 2011. Three well pairs commenced production in late September 2010 and are exceeding the performance of well pairs previously drilled. Production at Tucker for December 2010 was 6.1 mboe/day compared to 5.0 mboe/day in December 2009. Several applications to the Energy Resources Conservation Board ("ERCB") have been approved or are proceeding for additional drilling and field development through to 2015.

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 drilling project and an air injection pilot. An additional 79 cold production wells were drilled in 2010 and up to 64 wells are scheduled for 2011. Cold production from eastern McMullen for December 2010 was 2,900 bbls/day.

Husky has submitted an application and received ERCB approval for an air injection pilot. Construction will be proceeding in the first quarter of 2011 with ignition scheduled for late in the second quarter of 2011.

Sale of Oil Sands Leases

On January 14, 2011, the Company completed an agreement to sell 23 square miles of mining leases in Alberta for a consideration of $200 million.

Western Canada and the United States (excluding Heavy Oil and Oil Sands)

Asset Acquisitions

In November 2010, Husky announced that a purchase and sale agreement had been signed with ExxonMobil Canada Ltd. to acquire oil and natural gas properties in Alberta and northeast British Columbia. The acquired assets will add 16.3 mboe/day to natural gas production, 4.8 mboe/day to oil production and 0.8 mboe/day to natural gas liquids production. Based on reserve estimates at December 1, 2010, the acquisition will contribute 104 mmboe of proved reserves and nine mmboe of probable reserves to a core producing area. The acquisition closed on February 4, 2011.

The purchase of natural gas properties in west central Alberta closed on November 30, 2010. The acquisition added 10.8 mboe/day of natural gas production, 32.6 mmboe of proved reserves and 10.8 mmboe of probable reserves to a core producing area. The reserve estimates are as at December 31, 2010.

Husky recognizes the operational results from the natural gas properties post the closing date; the operational results between the effective date and the closing date are deducted from the purchase price.

Gas Resource Plays

Husky continues to build its gas resource play inventory. In 2010, the Company acquired over 69,000 acres of additional land in several of its British Columbia and Alberta plays. At the end of 2010, the Company had a total of approximately 800,000 net acres of gas resource play inventory.

Husky is accelerating exploration and development drilling in the NGL-rich Ansell area. As part of this program, a total of 20 Cardium formation development wells were drilled and a further 14 exploration wells were drilled in 2010 to test the deeper multi-zone potential in the area. Drilling operations are continuing into 2011, with four rigs active on the property. Export capacity expansion work proceeded through 2010 with approximately 70% of the detailed engineering completed and a majority of the long lead equipment orders placed.

At Kakwa, the first well in a multi-well exploration program was spud in late December 2010. This program will test the multi-zone Cretaceous potential that targets the same formations as Husky's exploration program at Ansell. In British Columbia, a partner operated horizontal well was drilled to further evaluate the Montney formation on the Company's Cypress lands. Completion of this well occurred in the first quarter of 2011, and the well is currently being flow tested. Also, near the end of 2010, 3-D seismic programs were initiated in the Ansell, Komie (Horn River), and Sierra areas. Husky is also actively drilling development wells in the Greater Bivouac area with 11 gross (nine net) wells drilled in 2010, targeting the Jean Marie formation. One rig continues to drill in the Bivouac area in the first quarter of 2011.

Oil Resource Plays

Oil resource play evaluation and testing activity continued in Western Canada in 2010. Twenty-three Viking horizontal wells at Redwater, Alberta and 13 Viking wells in the Dodsland/Elrose area of Saskatchewan were brought into production in 2010. Three evaluation wells are currently under production testing to assess the Cardium zone at Lanaway, Alberta. In 2011, four Viking wells have been drilled in the Elrose area with three more scheduled before spring break up.

Production and evaluation of the Lower Shaunavon and Bakken zones continues in southern Saskatchewan. In the Lower Shaunavon zone, three successful horizontal wells were brought on production in 2010 with three additional wells to be drilled in the first quarter of 2011. In the Bakken zone, four successful horizontal wells were drilled with two put into production in 2010 and the two remaining wells expected to be put in production in the first quarter of 2011. Two additional Bakken wells are to be drilled in the first quarter of 2011. At the end of 2010, the Company had approximately 500,000 net acres of oil resource play inventory.

Northeastern British Columbia

Husky participated in a well in the Grizzly Valley located in the foothills of northeastern British Columbia where it has a 42% working interest. The well has been tested at a rate of 33 mmcf/day and tie-in of the well was completed in mid-January 2011. Husky successfully acquired four additional drilling licences in the Grizzly Valley area during 2010.

Alkaline Surfactant Polymer Floods

Husky's Alkaline Surfactant Polymer ("ASP") EOR Program is underway with active projects at Warner, Crowsnest in southern Alberta and Gull Lake, Saskatchewan. 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. Future floods under development include Fosterton and Bone Creek, Saskatchewan. At Fosterton, the facility design work is nearing completion and long lead equipment orders have been placed. Facility construction is expected to commence in 2011 with an expected start up in the first half of 2012. Husky is the operator and holds a 62.4% working interest in this project. Bone Creek, where Husky holds a 95% working interest, is in the initial design phase with a potential start up in early 2013.

United States

Husky continues to evaluate its Columbia River Basin holdings in Washington and Oregon. The results of the Grey 31-23 well, which was drilled in 2009, are being incorporated into this evaluation. Husky holds up to a 50% working interest in this area.

South East Asia

Offshore China Exploration, Delineation and Development

In January 2010, a significant new natural gas discovery was discovered at Liuhua 29-1, approximately 43 kilometres to the northeast of the Liwan 3-1 field. The discovery well tested natural gas at an equipment restricted rate of 57 mmcf/day, with indications that future well deliveries could exceed 90 mmcf/day. In February 2010, the Liuhua 34-2-2 delineation well was drilled, which was abandoned without testing, followed by the Liwan 3-3-1 exploration well, which resulted in a non-commercial gas discovery in April 2010.

In May 2010, Husky successfully completed the drilling and testing of the Liuhua 29-1-2 appraisal well. This appraisal well, the first on the Liuhua 29-1 field, tested natural gas at an equipment restricted rate of 55 mmcf/day.

Following the drilling of the Liuhua 29-1-2 appraisal well, a new exploration well was drilled at Liwan 5-2-1, which did not encounter hydrocarbons and was plugged and abandoned. This was followed by the successful drilling of the Liuhua 34-3-1 exploration well which encountered natural gas. The well is located approximately 24 kilometres northeast of the Liwan 3-1 gas field, the Company's first major discovery in Block 29/26. This well was later suspended pending further evaluation of the suitability to develop this new field as part of the overall Block 29/26 deepwater gas development project.

After the Liuhua 34-3-1 exploration well, the Liwan 3-1-10 well was drilled, which is the first development well on the Liwan 3-1 field. This well was successfully cased and will be used as a future producing well. Husky then drilled the Liuhua 29-1-3 appraisal well, the second appraisal well on the Liuhua 29-1 field. The well encountered quality reservoir sands with approximately 60 metres of gas pay and was cased for possible future re-entry and completion as a producing well. The well was drilled approximately three kilometers north of the initial Liuhua 29-1 discovery.

In November 2010, Husky successfully drilled the Liwan 3-1-11 appraisal well with the aim of testing the eastern part of the Liwan 3-1 field. The well encountered a quality gas charged reservoir and was cased for future re-entry and completion as a producing well. In December 2010, the Liwan 3-1-9 development well and in late January 2011 the Liwan 3-1-5 development well were completed as part of the nine well development program for the Liwan 3-1 field. Husky is currently drilling the Liwan 3-1-8 development well.

Liwan 3-1 is the first deepwater development offshore project in China. Following field delineation of the Liwan 3-1 natural gas field, Husky submitted the Original Gas In-Place report to the Government of China in late 2009 which was approved in 2010. In early December 2010, Husky Oil China Ltd. ("HOCL") signed a Heads of Agreement with CNOOC which specifies key principles of the joint venture to fund, develop and operate the Liwan 3-1 deep water gas field, shallow water and onshore gas processing facilities. This document is a precursor to the Supplemental Development Agreement ("SDA") which will be the definitive agreement governing these issues. The SDA is currently in the drafting stage. Husky expects the plan of development for the Liwan 3-1 field to be submitted in the first quarter of 2011 and is currently tendering all of the deep water equipment and installation activity. Under the current plan, the Liwan 3-1 and Liuhua 34-2 fields on Block 29/26 will be developed in parallel, with first gas production targeted in late 2013. The plan of development for the Liuhua 29-1 field is targeted for submission in 2012, after appraisal drilling and evaluation work has been completed.

The Liwan 3-1 natural gas field, which is located approximately 300 kilometres southeast of Hong Kong, will use a subsea production system connected to a central shallow water platform by flow lines. The platform will be connected by pipeline to an onshore gas plant with access to the energy markets of Hong Kong and Mainland China. Husky and development partner, CNOOC, have established a joint marketing group for the sale of Liwan 3-1 natural gas and associated natural gas liquids. The Liuhua 34-2 and Liuhua 29-1 discoveries will be tied into the proposed Liwan 3-1 shallow water infrastructure.

On Block 63/05 in the Qiongdongnan Basin, 50 kilometres south of Hainan Island, processing of new 2-D and 3-D seismic data has been completed and the data is currently being interpreted. A decision will be made in the first quarter of 2011 on the drilling of an exploration well which is planned for later in the year. Husky holds a 100% interest in Block 63/05, for which CNOOC has the right to participate up to 51%.

On Block 04/35 in the East China Sea, a decision was made to relinquish the block at the end of the first exploration term of the PSC following the results of the HZ 8-1-1 exploration well which was drilled in April 2010 and did not encounter hydrocarbons.

Indonesia Exploration and Development

In October 2010, the Government of Indonesia approved the extension of the existing Madura Strait PSC that was originally awarded in 1982. The approval provides Husky and its partner, CNOOC, a 20-year extension to the existing contract which would have expired in 2012. This extension provides the basis for the development of the Madura BD field as the gas sales agreements are in place and the plan of development has been approved by the Indonesian government. Front end engineering was completed in 2010. The engineering tendering process is currently underway.

Both Husky and CNOOC agreed to sell a 10% equity stake in Husky Oil (Madura) Ltd. ("HOML") to Samudra Energy Ltd., through its affiliate SMS Development Ltd. Following the completion of the sale in January 2011, Husky and CNOOC each hold a 40% equity interest in HOML with the remaining 20% held by SMS Development Ltd.

In late 2009, Husky acquired 1,020 kilometres of new 2-D seismic on the North Sumbawa II Block. Husky will use this data to define an exploration prospect for future drilling, which is currently planned to commence in 2012. Husky holds a 100% interest in the North Sumbawa II Block, comprised of 5,000 square kilometres in the East Java Sea, and may seek to farm-out part of its working interest prior to drilling.

6.2 Midstream

In 2010, Husky commenced its pipeline commitment on the Keystone Pipeline system which ships Canadian crude oil from Hardisty, Alberta to Patoka, Illinois. In 2010, Husky received regulatory approval to add an additional 300,000 barrel storage tank at Hardisty. This tank will be connected to the Keystone Pipeline. Construction of the new tank is expected to be completed in 2012.

6.3 Downstream

Lima, Ohio Refinery

The Lima, Ohio Refinery successfully completed a turnaround on the fluid catalytic cracker, coker and associated units in 2010. Several large safety, environmental, reliability, and optimization projects were completed. The refinery continues to advance short term reliability and profitability projects and is evaluating a staged repositioning approach pending an improvement in the light/heavy crude differential outlook. Front-end engineering design has now begun on a 20 mbbls/day kerosene hydrotreater, which will improve distillate production capability and flexibility at the Lima Refinery. The engineering is expected to be completed in the first quarter of 2011.

Toledo, Ohio Refinery

Husky and BP announced the sanction of the Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery in the first quarter of 2010. This 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 a 42 mbbls/day continuous catalyst regeneration reformer system plant. The project is continuing as planned and construction formally commenced in August 2010. The refinery continues to advance a multi-year program to improve operational integrity and plant performance and reduce operating costs and environmental impacts.

Retail

At the end of 2010, Husky completed the rebranding of all 98 sites in Eastern Canada acquired in late 2009. The Company's total number of fuel outlets at the end of 2010 was 555.

7.0 Results of Operations

7.1 Segment Earnings

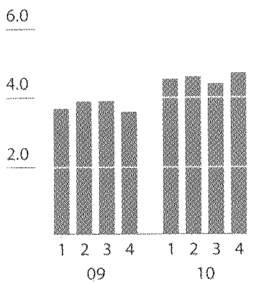
Segment Earnings

	Earnings (Loss) before Income Taxes			Net Earnings (Loss)			Capital Expenditures [1]		
($ millions)	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Upstream	**1,597**	1,560	4,757	**1,135**	1,113	3,377	**3,171**	2,326	3,580
Midstream									
Upgrading	**31**	77	351	**22**	54	246	**176**	69	99
Infrastructure and Marketing	**219**	279	321	**160**	200	224	**40**	25	94
Downstream									
Canadian Refined Products	**156**	198	143	**115**	141	104	**245**	81	155
U.S. Refining and Marketing	**(32)**	195	(635)	**(20)**	124	(403)	**257**	260	133
Corporate, Eliminations and Interest Expense	**(413)**	(352)	208	**(239)**	(216)	203	**67**	36	47
Total	**1,558**	1,957	5,145	**1,173**	1,416	3,751	**3,956**	2,797	4,108

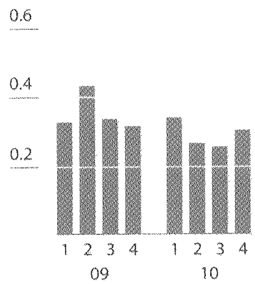
[1] *Excludes capitalized costs related to asset retirement obligations incurred during the period and the BP joint venture transaction.*

7.2 Summary of Quarterly Results

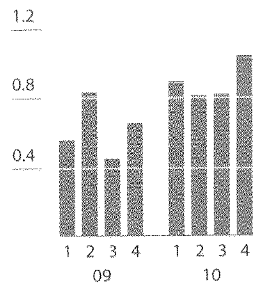
Sales & Operating Revenues
($ billions)



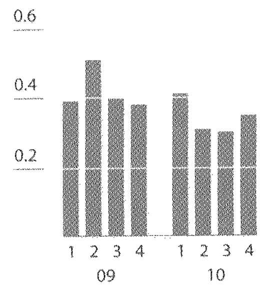
Net Earnings
($ billions)



Cash Flow from Operations[1]
($ billions)



Net Earning Per Share
($ per share)

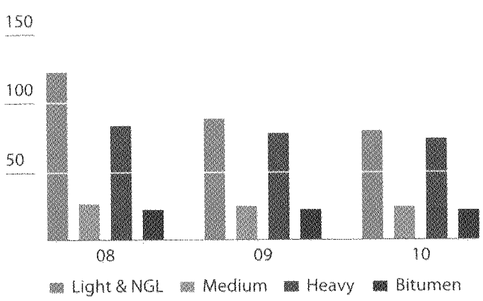


[1] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*

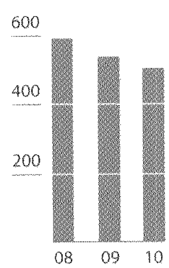
7.3 Upstream

2010 Earnings $1,135 Million

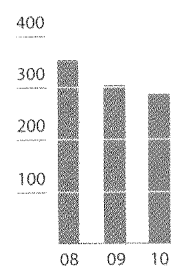
Production
Oil
(mbbls/day)



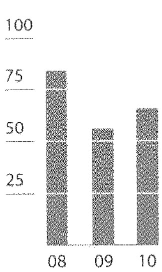
Production
Natural Gas
(mmcf/day)



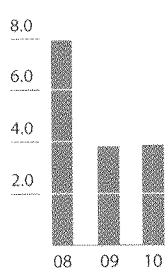
Production
Combined
(mboe/day)



Average Price Realized
Crude Oil
($/bbl)



Average Price Realized
Natural Gas
($/mcf)



Average Sales Prices Realized	2010	2009	2008
Crude oil *($/bbl)*			
Light crude oil & NGL	**76.90**	62.70	97.28
Medium crude oil	**64.92**	56.37	81.79
Heavy crude oil [(1)]	**58.91**	52.54	71.98
Bitumen [(1)]	**57.84**	51.90	70.24
Total average	**66.70**	57.11	84.96
Natural gas *($/mcf)*			
Average	**3.86**	3.83	7.94

[(1)] *A portion of the Company's heavy crude oil production meets the U.S. Securities and Exchange Commission's definition of bitumen.*

Upstream Earnings Summary

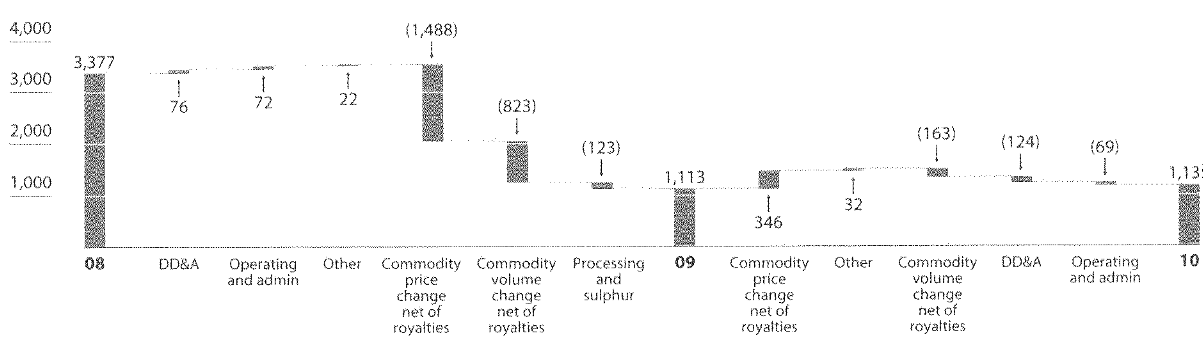
($ millions)	2010	2009	2008
Gross revenues	**5,744**	5,313	9,932
Royalties	**978**	861	2,043
Net revenues	**4,766**	4,452	7,889
Operating and administration expenses	**1,599**	1,495	1,596
Depletion, depreciation and amortization	**1,572**	1,397	1,505
Other (income) expense	**(2)**	–	31
Income taxes	**462**	447	1,380
Net earnings	**1,135**	1,113	3,377

Upstream earnings were $22 million higher in 2010 compared with 2009 primarily due to the higher average prices realized on crude oil and bitumen and the settlement of redetermined participation interests for Terra Nova, partially offset by lower crude oil and natural gas production in 2010 compared with 2009, the impact of the Enbridge Line 6A/6B shutdowns and increased depletion in South East Asia.

During 2010, the average realized price increased 17% to $66.70/bbl for crude oil, NGL and bitumen compared with $57.11/bbl during the same period in 2009. Realized natural gas prices averaged $3.86/mcf during 2010 compared with $3.83/mcf in 2009. Higher U.S. dollar crude oil and natural gas pricing was partially offset by the strengthening of the Canadian dollar against the U.S. dollar.

The Enbridge Line 6A/6B shutdowns caused a widening in the light/heavy crude oil differential which negatively impacted medium and heavy crude oil and bitumen realized prices as a result of industry wide inventory buildup in Western Canada. This resulted in an estimated $60 million negative impact to Upstream net earnings for the year.

After Tax Earnings Variance Analysis
($ millions)



Daily Gross Production

		2010	2009	2008
Crude oil	*(mbbls/day)*			
Western Canada				
Light crude oil & NGL		**23.0**	22.8	24.6
Medium crude oil		**25.4**	25.4	26.9
Heavy crude oil [1]		**74.5**	78.6	84.3
Bitumen [1]		**22.3**	23.1	22.7
		145.2	149.9	158.5
Atlantic Region				
White Rose – light crude oil		**31.2**	45.2	73.2
North Amethyst – light crude oil		**7.0**	–	–
Terra Nova – light crude oil		**8.5**	10.0	12.9
		46.7	55.2	86.1
China				
Wenchang – light crude oil & NGL		**10.7**	11.1	12.2
		202.6	216.2	256.8
Natural gas	*(mmcf/day)*	**506.8**	541.7	594.4
Total	*(mboe/day)*	**287.1**	306.5	355.9

[1] *A portion of the Company's heavy crude oil production meets the U.S. Securities and Exchange Commission's definition of bitumen.*

Upstream Revenue Mix

Percentage of Upstream Net Revenues

	2010	2009	2008
Crude oil			
Light crude oil & NGL	**36%**	35%	41%
Medium crude oil	**11%**	10%	8%
Heavy crude oil	**29%**	29%	24%
Bitumen	**8%**	9%	6%
	84%	83%	79%
Natural gas	**16%**	17%	21%
	100%	100%	100%

During 2010, crude oil, bitumen and NGL production decreased by 13.6 mbbls/day or 6% compared with 2009, primarily due to the decline in production from White Rose as a result of declines from peak production rates post the 2009 turnaround and natural reservoir declines, partially offset by production at North Amethyst, which commenced production on May 31, 2010. At Terra Nova, scheduled maintenance and operational (H_2S contamination) issues resulted in reduced production in 2010 relative to the prior year.

During 2010, crude oil and NGL production from Western Canada decreased by 4.7 mbbls/day or 3% compared with 2009 primarily due to decreased heavy oil production which was impacted by extremely wet weather conditions in the third quarter and the subsequently delayed drilling program in the fourth quarter of 2010.

Production from natural gas decreased by 34.9 mmcf/day or 6% in 2010 compared with 2009 due to lower capital expenditures on development and natural reservoir decline, partially offset by additional production from the west central Alberta acquisition which closed on November 30, 2010.

2011 Production Guidance and 2010 Actual

Gross Production

		Guidance 2011	Year ended December 31 2010	Guidance 2010
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		75 – 80	**81**	81 – 84
Medium crude oil		25 – 30	**25**	25 – 27
Heavy crude oil & bitumen		95 – 105	**97**	94 – 97
		195 – 215	**203**	200 – 208
Natural gas	*(mmcf/day)*	560 – 610	**507**	510 – 520
Total barrels of oil equivalent	*(mboe/day)*	290 – 315	**287**	285 – 295

Husky's 2011 guidance is consistent with the Company's target of three to five percent annual growth. Recent acquisitions will offset the base production decline and increased capital expenditures in late 2010 and early 2011 will begin to contribute to production in late 2011. The Company's production for the year ended December 31, 2010 is within the revised production guidance set by the Company in the second quarter of 2010.

Factors that could potentially impact Husky's production performance for 2011 include, but are not limited to:

- Performance on recently commissioned facilities, new wells brought onto production and unanticipated reservoir response from existing fields.
- Unplanned or extended maintenance and turnarounds at any of the Company's production, upgrading, refining, pipeline or offshore assets.
- Business interruptions due to unexpected events such as severe weather, fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events.
- Significant declines in crude oil and natural gas commodity prices which may result in the decision to temporarily shut-in production.
- Foreign operations and related assets which are subject to a number of political, economic and socio-economic risks.

Royalties

Royalty rates averaged 17% of gross revenue in 2010 compared with 16% in 2009. Royalty rates in Western Canada averaged 15% compared with 13% in 2009 primarily as a result of increased commodity prices. In the Atlantic Region, the average rate was 24% in 2010 compared with 25% in 2009. The lower rate is attributable to the North Amethyst field which is subject to a basic royalty rate of 1%, while Terra Nova and White Rose, being mature fields, are subject to higher rates. Rates at North Amethyst will increase and reach the same level as Terra Nova and White Rose after certain project payouts as prescribed in the royalty regulations are met. Royalty rates in Wenchang averaged 23% compared with 17% in 2009 due to the sliding scale royalty clause in the PSC that results in higher rates in a higher commodity price environment.

Operating Costs

(millions of dollars)	2010	2009	2008
Western Canada	**1,199**	1,124	1,249
Atlantic Region	**176**	177	157
International	**24**	23	22
Total	**1,399**	1,324	1,428
Unit operating costs *($/boe)*	**13.33**	11.82	10.93

Total Upstream operating costs in 2010 increased to $1,399 million from $1,324 million. Total upstream unit operating costs in 2010 averaged $13.33/boe compared with $11.82/boe in 2009 due to higher costs combined with lower production. Operating costs in Western Canada increased to $1,199 million from $1,124 million and averaged $14.42/boe in 2010 compared with $12.83/boe in 2009 primarily as a result of increased energy, servicing, treating and maintenance costs, increased handling, transportation and disposal of increased water and emulsion production, as well as lower production in 2010 compared with 2009. The increase is also due to additional well work overs resulting from acquisitions, and additional perforation activity to stimulate production at Tucker.

Operating costs in the Atlantic Region averaged $10.33/boe or $176 million in 2010 compared with $8.73/boe or $177 million in 2009 primarily as a result of lower production as well as increased vessel costs, servicing and maintenance costs at White Rose and North Amethyst offset by lower fuel and labour costs.

Operating costs at the South China Sea offshore operations were $24 million or $6.06/boe in 2010 compared with $23 million or $5.35/boe in 2009 primarily as a result of lower production.

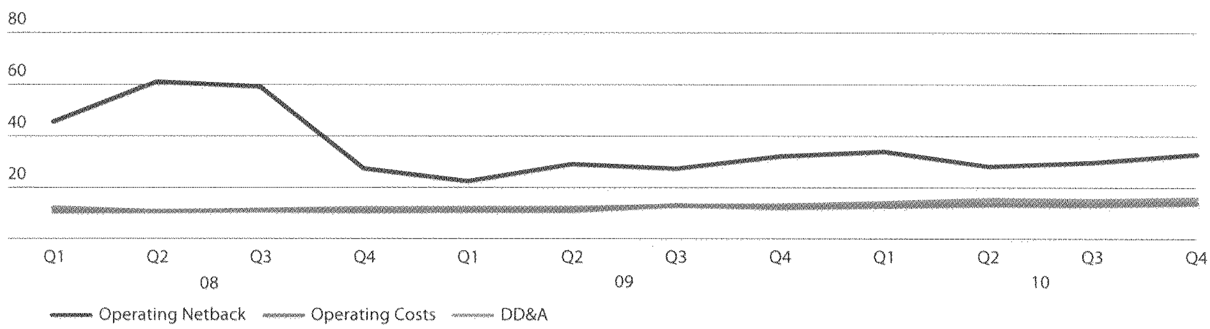
Depletion, Depreciation and Amortization ("DD&A")

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 2010, total unit DD&A was $15.00/boe compared with $12.49/boe during 2009. The higher DD&A rate in 2010 was primarily due to a larger full cost base in China and the Atlantic Region compared with 2009 primarily as a result of relinquished exploration blocks and dry holes in China as well as additions related to the development program at North Amethyst.

At December 31, 2010, capital costs in respect of unproved properties and major development projects were $4.2 billion compared with $4.0 billion at the end of 2009. 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
($/boe)



[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 HOML to CNOOC Southeast Asia Limited in 2008.

Upstream Capital Expenditures

In 2010, Upstream capital expenditures were $3,171 million relative to the revised 2010 capital expenditure program of $3,150 million. Upstream capital expenditures were $2,235 million (70%) in Western Canada, $492 million (16%) in the Atlantic Region and $444 million (14%) in South East Asia. Husky's major projects remain on schedule.

Upstream Capital Expenditures [1]

($ millions)	**2010**	2009	2008
Exploration			
Western Canada	**441**	266	680
Atlantic Region	**96**	95	160
Northwest United States	–	25	60
International	**381**	495	225
	918	881	1,125
Development			
Western Canada	**1,794**	923	1,881
Atlantic Region	**396**	510	569
International	**63**	12	5
	2,253	1,445	2,455
	3,171	2,326	3,580

[1] *Excludes capitalized costs related to asset retirement obligations incurred during the period and the BP joint venture transaction.*

Western Canada and Oil Sands Drilling *(wells)*		2010 Gross	2010 Net	2009 Gross	2009 Net	2008 Gross	2008 Net
Exploration	Oil	**60**	**51**	18	9	80	70
	Gas	**37**	**31**	37	22	102	79
	Dry	**8**	**8**	7	6	27	23
		105	**90**	62	37	209	172
Development	Oil	**815**	**722**	315	278	685	578
	Gas	**73**	**53**	122	61	435	270
	Dry	**10**	**9**	7	7	36	36
		898	**784**	444	346	1,156	884
Total		**1,003**	**874**	506	383	1,365	1,056

Western Canada

During 2010, Husky invested $2,235 million on exploration and development throughout the Western Canada Sedimentary Basin compared with $1,189 million in 2009. Of this, $943 million was invested on oil exploration and development and $426 million was invested on natural gas exploration and development compared with $408 million for oil exploration and development and $375 million for natural gas exploration and development in 2009. The Company drilled 874 net wells in the basin resulting in 773 net oil wells and 84 net natural gas wells compared with 287 net oil wells and 83 net natural gas wells in 2009. In addition, $134 million was spent on production optimization initiatives in 2010. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $331 million and $401 million was primarily spent on acquisition of natural gas properties in west central Alberta.

Husky's major gas resource and conventional high impact exploration program is conducted in various regions along the foothills and northern plains of Alberta and British Columbia and in the deep basin region of Alberta. In 2010, $208 million of the capital expenditures was invested for exploration in these natural gas prone areas, approximately 87% of which was invested on gas resource plays. Capital expenditures on gas resource plays with natural gas liquids potential accounted for 65% of exploration spending in this area. An additional $47 million of the natural gas exploration and development capital expenditures was spent on follow-up activities in these regions during 2010 including tie-ins, facility installation and development drilling.

During 2010, capital expenditures for the Sunrise Energy Project were $66 million compared with $29 million in the same period of 2009. Capital expenditures at Tucker were $117 million compared with $11 million in the same period in 2009. This increase is due to remediating older wells and drilling 32 new wells in 2010, compared to the drilling of three wells in 2009.

The following table discloses Husky's offshore and international drilling activity during 2010:

Offshore and International Drilling Activity

Canada - Atlantic Region			
Glenwood H-69	WI 100%	Stratigraphic test	Exploratory
North Amethyst G-25-1	WI 68.875%	Water injection	Development
North Amethyst G-25-2	WI 68.875%	Production	Development
North Amethyst G-25-3	WI 68.875%	Production	Development
North Amethyst G-25-4	WI 68.875%	Water injection	Development
North Amethyst H-14	WI 68.875%	Stratigraphic test	Delineation
West White Rose E-18-10	WI 68.875%	Production	Development
South East Asia - China			
Liuhua 29-1-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 34-2-2 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-3-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 29-1-2 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 5-2-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 34-3-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 3-1-10 Block 29/26	WI 49%	Production	Development
Liuhua 29-1-3 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-1-11 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-1-9 Block 29/26	WI 49%	Production	Development
Liwan 3-1-5 Block 29/26	WI 49%	Production	Development
Liwan 3-1-8 Block 29/26	WI 49%	Production	Development
HZ 8-1-1 Block 04/35	WI 100% (1)	Stratigraphic test	Exploratory

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

Atlantic Region Development
During 2010, $396 million was invested for Atlantic Region 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 drilling, advancing engineering design and planning.

Atlantic Region Exploration
During 2010, Husky spent $96 million primarily on the Glenwood H-69 exploration well northwest of the West White Rose field and geological and geophysical data and studies.

Offshore China and Indonesia
During 2010, $444 million was spent on offshore China projects, the drilling of four exploration, four delineation and three development wells on Block 29/26 in the South China Sea and one exploration well on Block 04/35 in the East China Sea.

2011 Upstream Capital Program

($ millions)		
Western Canada	– oil and gas	2,450
	– oil sands	415
Atlantic Region		350
International		1,180
Total Upstream capital expenditures		4,395

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

The 2011 capital program will enable Husky to build on the momentum achieved in accelerating near-term production, and represents an increase of over 20% from the 2010 program, including the acquisition of producing properties in Alberta and northeast British Columbia from ExxonMobil Canada Ltd. which closed in the first quarter of 2011. The capital program enables the Company to advance its three major growth pillars in the Oil Sands, Atlantic Region and in South East Asia.

Upstream capital spending for Western Canada is targeted at opportunities offering the highest potential returns and focuses on the Company's heavy oil, oil and liquid-rich gas resources plays. Highlights include Phase I of the Sunrise Energy Project, heavy oil investment, including an increased focus on the use of horizontal wells to access producing zones, and advancement of the 8,000 bbls/day South Pikes Peak heavy oil thermal project. Spending has also been allocated to advance the Company's liquid rich gas resource play developments and new oil resource play exploration and development.

In the Atlantic Region, spending is concentrated on the continued development drilling at North Amethyst and West White Rose.

In South East Asia, capital spending is focused on continuing the development of the deep water Liwan Gas Project and exploration and development programs offshore China and Indonesia.

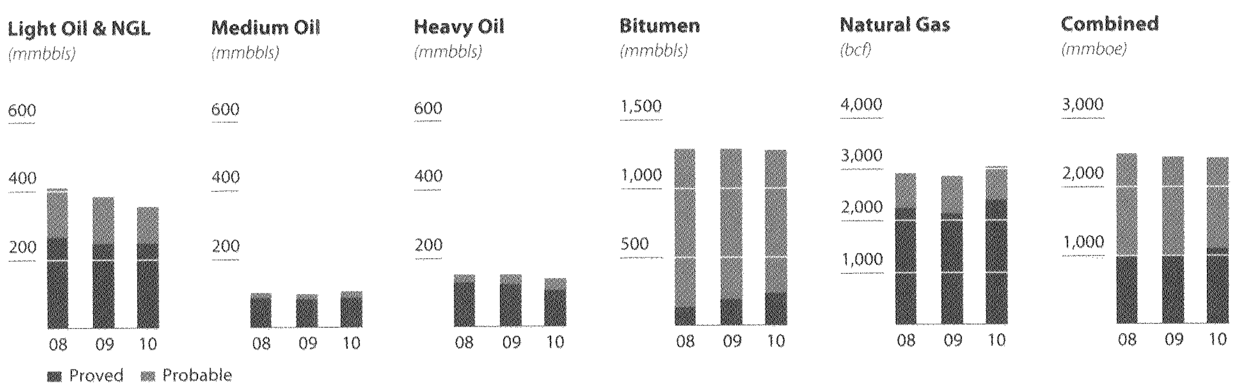
Upstream Planned Turnarounds

The annual maintenance turnaround for the *SeaRose FPSO* is scheduled for 16 days in July 2011. The next turnaround at Terra Nova is scheduled to commence in July 2011.

Off-station turnaround planning for the *SeaRose FPSO* for 2012, to address the maintenance of the propulsion system, is currently being progressed. Husky continues to investigate the various options available for this work.

Oil and Gas Reserves

The following oil and gas reserves disclosure has been prepared in accordance with Canadian Securities Administrators' National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") effective December 31, 2010. In prior years Husky applied for and was granted an exemption from certain of the provisions of NI 51-101, which permitted the Company to present oil and gas reserves disclosures in accordance with the rules of the United States Securities and Exchange Commission guidelines and the United States Financial Accounting Standards Board (the "U.S. Rules"). This exemption is no longer available for the Company's reserves reporting in Canada, although the Company has received an exemption from the Canadian Securities Administrators which allows the Company to also disclose its reserves under the U.S. Rules as supplementary disclosure to the reserves and oil and gas activities disclosure required by NI 51-101. The information in accordance with the U.S. Rules is included in the Company's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com .

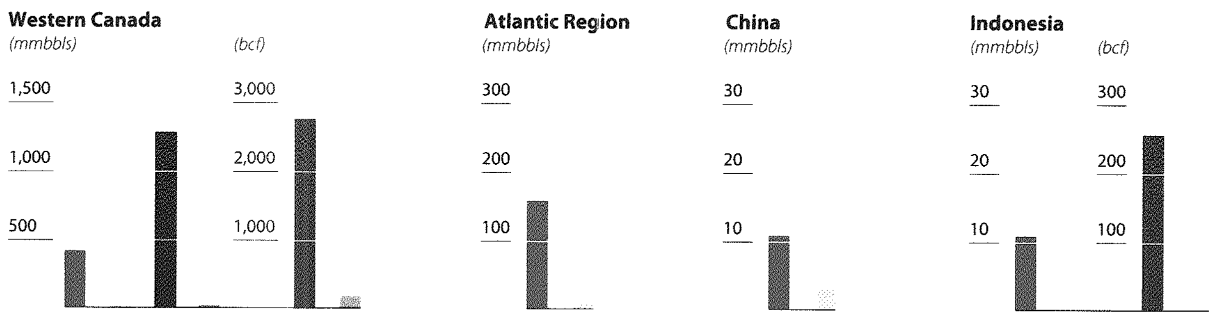


The Company's complete Statement of Oil and Gas Reserves Data and Other Oil and Gas Information in accordance with NI 51-101 is contained in Husky's Annual Information Form available at www.sedar.com or Husky's Form 40-F available at www.sec.gov or on the Company's website at www.huskyenergy.com.

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 as set out in the Canadian Oil and Gas Evaluation Handbook.

At December 31, 2010, Husky's proved oil and gas reserves were 1,081 mmboe, up from 1,004 mmboe at the end of 2009. The net addition to proved reserves, including acquisitions and divestitures, represents 174% of 2010 production. Major additions to proved reserves in 2010 included:

- the extension through additional drilling and seismic interpretation of the Sunrise Energy Project that resulted in booking 56 mmbbls of bitumen to proved undeveloped reserves;
- the booking of 44 mmboe of natural gas and natural gas liquids to proved undeveloped reserves at Madura following the extension of the PSC;
- the acquisition in the Ram River area in west central Alberta, which resulted in booking of proved natural gas reserves of 197 bcf; and
- the extension of proved reserves at Ansell in the Alberta Deep Basin area resulting in the booking of 17 mmboe of natural gas and natural gas liquids.



Oil & NGL ■ Reserves ■ Production
Bitumen ■ Reserves ■ Production
Natural Gas ■ Reserves ■ Production

Note: Reserves are total proved plus probable.

Reconciliation of Proved Reserves

	Canada						International		Total		
	Western Canada					Atlantic Region					
(forecast prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved reserves at December 31, 2009	145	84	121	200	2,113	93	9	–	652	2,113	1,004
Revision of previous estimate	(11)	4	1	(13)	(14)	8	2	–	(9)	(14)	(11)
Purchase of reserves in place	1	–	–	–	206	–	–	–	1	206	36
Sale of reserves in place	–	–	–	–	(2)	–	–	–	–	(2)	–
Discoveries, extensions and improved recovery	7	9	15	68	142	4	9	209	112	351	170
Price revision	–	–	–	–	(74)	–	–	–	–	(74)	(13)
Production	(9)	(9)	(27)	(8)	(185)	(17)	(4)	–	(74)	(185)	(105)
Proved reserves at December 31, 2010	**133**	**88**	**110**	**247**	**2,186**	**88**	**16**	**209**	**682**	**2,395**	**1,081**
Proved and probable reserves at December 31, 2010	**176**	**108**	**143**	**1,287**	**2,766**	**159**	**22**	**258**	**1,895**	**3,024**	**2,399**
At December 31, 2009	191	100	152	1,294	2,638	167	24	258	1,928	2,896	2,411

Reconciliation of Proved Developed Reserves

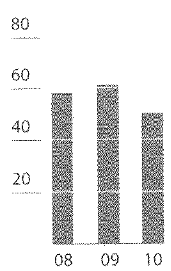
(forecast prices and costs before royalties)	Canada – Western Canada – Light Crude Oil & NGL (mmbbls)	Canada – Western Canada – Medium Crude Oil (mmbbls)	Canada – Western Canada – Heavy Crude Oil (mmbbls)	Canada – Western Canada – Bitumen (mmbbls)	Canada – Western Canada – Natural Gas (bcf)	Canada – Atlantic Region – 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, 2009	123	79	87	67	1,667	64	9	–	429	1,667	707
Revision of previous estimate	(8)	5	15	(10)	46	17	2	–	21	46	28
Purchase of reserves in place	1	–	–	–	204	–	–	–	1	204	35
Sale of reserves in place	–	–	–	–	(2)	–	–	–	–	(2)	–
Discoveries, extensions and improved recovery	4	4	7	2	59	–	–	–	17	59	27
Price revision	–	–	–	–	(68)	–	–	–	–	(68)	(11)
Production	(9)	(9)	(27)	(8)	(185)	(17)	(4)	–	(74)	(185)	(105)
Proved developed reserves at December 31, 2010	**111**	**79**	**82**	**51**	**1,721**	**64**	**7**	–	**394**	**1,721**	**681**

7.4 Midstream

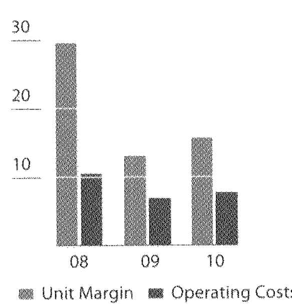
2010 Earnings $182 Million

Total Midstream net earnings in 2010 were $182 million, down from $254 million in 2009. The decrease is primarily due to increased Upgrader depreciation and amortization in 2010 compared to 2009 as well as unrealized losses on natural gas storage contracts in 2010 compared with unrealized gains in 2009, partially offset by increased upgrader and pipeline margins.

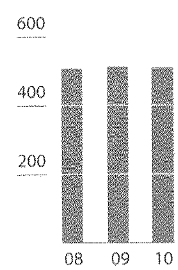
Upgrader
Synthetic Crude Sales
(mbbls/day)



Upgrader
Unit Margin & Operating Costs
($/bbl)



Pipelines
Daily Throughput
(mbbls/day)



Upgrading Earnings Summary

($ millions, except where indicated)		**2010**	2009	2008
Gross revenues		**1,570**	1,572	2,435
Gross margin		**311**	296	633
Operating and administration expenses		**185**	188	255
Other recoveries		**(5)**	(3)	(4)
Depreciation and amortization		**100**	34	31
Income taxes		**9**	23	105
Net earnings		**22**	54	246
Upgrader throughput [1]	*(mbbls/day)*	**65.4**	74.1	71.1
Synthetic crude oil sales	*(mbbls/day)*	**54.1**	61.8	58.7
Upgrading differential	*($/bbl)*	**14.52**	11.89	28.77
Unit margin	*($/bbl)*	**15.73**	13.11	29.48
Unit operating cost [2]	*($/bbl)*	**7.76**	6.92	10.54

[1] *Throughput includes diluent returned to the field.*
[2] *Based on throughput.*

Upgrading earnings in 2010 decreased by $32 million compared with 2009 due primarily to an increase in depreciation and amortization as a result of changes in the estimated remaining life of certain components of the Upgrader. The Enbridge Line 6A/6B shutdowns caused a widening in the upgrading differentials which resulted in an estimated $10 million increase to net earnings in 2010. The decrease in throughput was primarily due to a 53-day major scheduled turnaround at the Upgrader that commenced in late August and was completed on October 22, 2010.

Unlike heavy crude oil, synthetic crude oil is a higher value feedstock for many refineries in Canada and the United States. During 2010, the price of Husky's synthetic crude oil averaged $80.97/bbl (2009 – $68.92/bbl) compared with the average cost of blended heavy crude oil from the Lloydminster area of $66.45/bbl (2009 – $57.03/bbl). This resulted in an average synthetic/heavy crude differential of $14.52/bbl (2009 – $11.89/bbl) and a gross unit margin of $15.73/bbl (2009 – $13.11/bbl). Gross unit margin includes secondary products. The cost of upgrading averaged $7.76/bbl compared with $6.92/bbl in 2009, which results in a net margin for upgrading Lloydminster heavy crude of $7.97/bbl, up 29% compared with $6.19/bbl in 2009.

In early February 2011, a fire occurred at the Lloydminster Upgrader. Physical damage to the Upgrader was not extensive, but the Upgrader will run at lower than capacity rates until required repairs and inspection are completed. The duration for which the Upgrader will be under repair and the financial impact of the damage and resulting reduction in sales volumes cannot be reasonably estimated at this time.

Infrastructure and Marketing Earnings Summary

($ millions, except where indicated)		**2010**	2009	2008
Gross revenues		**7,854**	6,984	13,544
Gross margin				
Pipeline		**124**	106	120
Other		**193**	195	249
		317	301	369
Operating and administration expenses		**21**	19	17
Depreciation and amortization		**43**	36	31
Other (income) expense		**34**	(33)	–
Income taxes		**59**	79	97
Net earnings		**160**	200	224
Commodity volumes marketed	*(mboe/day)*	**952**	912	1,103
Aggregate pipeline throughput	*(mbbls/day)*	**512**	514	507

Infrastructure and marketing net earnings in 2010 decreased by $40 million compared with 2009 due primarily to an unrealized loss of $34 million (gain of $32 million in 2009) resulting from the Company's commodity price risk management activities. Pipeline margins increased due to higher pipeline blending differentials and broker margins.

Midstream Capital Expenditures

Midstream capital expenditures totalled $216 million in 2010 compared to $94 million in 2009. At the Lloydminster Upgrader, Husky spent $84 million primarily for facility reliability projects and $92 million was spent on the scheduled major turnaround. The remaining $40 million was spent on the acquisition of equipment used for sulphur operations and various pipeline upgrades.

Midstream Planned Turnaround

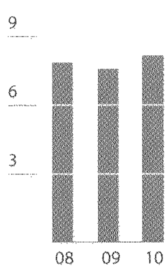
Husky is scheduled to complete a minor turnaround in the third quarter of 2011, primarily for inspection and equipment maintenance. During this time the Upgrader is expected to be at 70% capacity. The next major turnaround is scheduled to commence in the fall of 2013.

7.5 Downstream

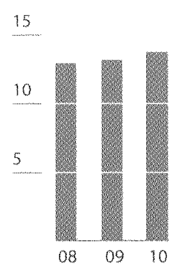
2010 Earnings $95 Million

Total downstream earnings in 2010 were $95 million, down from $265 million in 2009. The decrease is primarily due to lower realized fuel and asphalt gross margins for Canadian Refined Products, lower realized refining margins for U.S. Refining and Marketing, partially offset by higher refinery throughput in 2010 compared with 2009.

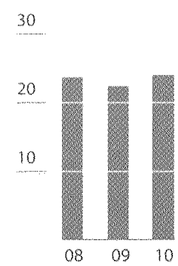
Light Oil Product Marketing
Volume
(millions of litres/day)



Light Oil Product Marketing
Volume per Outlet
(thousands of litres/day)



Asphalt Products
Volume
(mbbls/day)



Canadian Refined Products

Canadian Refined Products Earnings Summary

($ millions, except where indicated)		**2010**	2009	2008
Gross revenues		**2,975**	2,495	3,564
Gross margin				
Fuel		**87**	111	96
Ethanol		**64**	62	26
Ancillary		**46**	43	41
Asphalt		**160**	169	133
		357	385	296
Operating and administration expenses		**110**	94	72
Depreciation and amortization		**91**	93	81
Income taxes		**41**	57	39
Net earnings		**115**	141	104
Number of fuel outlets [1]		**508**	482	492
Refined products sales volume				
Light oil products	*(million litres/day)*	**8.2**	7.6	7.9
Light oil products per outlet	*(thousand litres/day)*	**13.8**	13.2	13.0
Asphalt products	*(mbbls/day)*	**24.1**	22.6	24.0
Refinery throughput				
Prince George refinery	*(mbbls/day)*	**10.0**	10.3	10.1
Lloydminster refinery	*(mbbls/day)*	**27.8**	24.1	26.1
Ethanol production	*(thousand litres/day)*	**619.3**	676.9	627.2

[1] *Average number of fuel outlets for period indicated.*

During 2010, fuel gross margins were lower than in 2009 primarily due to lower realized market margins, partially offset by higher sales volumes.

Asphalt gross margins slightly decreased compared to the same period in 2009 primarily due to higher input costs resulting in lower realized margins, partially offset by higher sales volumes. The Enbridge Line 6A/6B shutdowns caused a widening in the heavy to light oil crude price differential which resulted in lower feedstock costs to the Lloydminster Refinery. This positively impacted asphalt net earnings by an estimated $15 million in the second half of 2010.

Ethanol gross margins increased in 2010 primarily due to lower input costs which were mostly offset by lower ethanol production. Included in ethanol gross margins in 2010 was $50 million related to government assistance grants compared with $53 million in 2009.

Operating and administration expenses increased primarily as a result of the rebranding of the retail sites in Eastern Canada acquired in late 2009.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary

($ millions, except where indicated)		2010	2009	2008
Gross revenues		**7,107**	5,349	7,802
Gross refining margin		**547**	852	(58)
Processing costs		**378**	423	417
Operating and administration expenses		**8**	7	3
Interest - net		**2**	3	3
Depreciation and amortization		**191**	194	154
Other expense		**-**	30	-
Income taxes		**(12)**	71	(232)
Net earnings (loss)		**(20)**	124	(403)
Selected operating data:				
Lima Refinery throughput	*(mbbls/day)*	**136.6**	114.6	136.6
Toledo Refinery throughput [(1)]	*(mbbls/day)*	**64.4**	64.9	60.6
Refining margin	*(U.S. $/bbl crude throughput)*	**7.29**	11.37	(0.86)
Refinery inventory (feedstocks and refined products)	*(mmbbls)*	**11.9**	12.3	11.9

[(1)] *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.*

U.S. refining and marketing earnings decreased in 2010 compared with 2009 as a result of lower realized refining margins and the impact of the Enbridge Line 6A/6B shutdowns on the Toledo Refinery partially offset by higher total throughput. In the third quarter of 2010, the Enbridge Line 6A/6B shutdowns resulted in reduced throughput at the Toledo Refinery due to limited crude oil availability and increased feedstock costs as heavy oil was partially replaced with light oil where available. In the fourth quarter of 2010, the Toledo Refinery benefited from lower feedstock costs resulting from the widening of the heavy to light crude oil differential. The impact to the Toledo Refinery for 2010 was an estimated reduction to net earnings of $18 million. Other expenses in 2009 included $30 million of realized losses on forward contracts for feedstock purchases.

Realized refining margins reflect differences in product configuration, location differences and FIFO accounting for the purchase of crude oil.

The product slate produced at the Lima and Toledo refineries contains approximately 10% to 15% of other products which are sold at discounted market prices compared with gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

The Chicago 3:2:1 crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI while on a FIFO basis crude oil feedstock costs reflect purchases made earlier in the year.

In 2010, Husky's realized refining margin relative to the Chicago 3:2:1 market crack spread was negatively impacted primarily by the product slate at the Lima and Toledo Refinery, which includes products produced that are sold at discounted market prices. In 2009, Husky's realized refining margin relative to the Chicago 3:2:1 market crack spread benefited primarily from the significant rise in WTI during the year, which resulted in higher realized refining margins calculated under FIFO accounting.

In addition, the 10% strengthening of the Canadian dollar against the U.S. dollar compared with 2009 had a negative impact on the translation of U.S. dollar financial results into Canadian dollars.

Downstream Capital Expenditures

Downstream capital expenditures totalled $502 million for 2010 compared to $341 million in 2009.

In Canada, capital expenditures were $245 million related to the acquisition and rebranding of retail outlets acquired in 2009 as well as upgrades and environmental protection at the retail outlets, refineries and ethanol plants.

In the United States, capital expenditures totalled $257 million. At the Lima Refinery, $132 million was spent on various debottleneck projects, optimizations and environmental initiatives, and $46 million was spent on a scheduled turnaround. At the

Toledo Refinery, capital expenditures totalled $79 million (Husky's 50% share) primarily for engineering work on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection.

Downstream Planned Turnarounds

The Lloydminster Refinery will have a major turnaround in the spring of 2013. The refinery will be shut down during the turnaround for inspections and equipment repair. The turnaround is scheduled to last approximately 21 days.

The Prince George Refinery will have two minor turnarounds for maintenance work in 2011. The first turnaround is scheduled in the second quarter, which is expected to last approximately nine days. The second turnaround is scheduled in the third quarter and is expected to last approximately 14 days. The next major turnaround will occur in 2012 during the third and fourth quarters. The refinery is scheduled to be shut down for inspections and equipment repair for approximately 30 days.

The next major turnaround at the Toledo Refinery is expected to occur in 2012.

The Lima Refinery will have a major turnaround in 2014 on the Naphtha Hydrotreater, Hydrocracker, Reformer and Diesel Hydrotreater units. The turnaround is scheduled to last approximately 40 days and the refinery will be shut down. Another minor turnaround will occur in 2015 for the Coker and Gasoline Distillation units. The turnaround is scheduled to last approximately 35 days. The remaining process units will operate at 80% capacity during the outage.

7.6 Corporate

2010 Expense $239 Million

Corporate Earnings Summary

($ millions) income (expense)	**2010**	2009	2008
Intersegment eliminations – net	**(47)**	(44)	61
Administration expenses	**(89)**	(69)	(95)
Other income (expense)	**3**	(1)	48
Stock-based compensation	**–**	(1)	33
Depreciation and amortization	**(76)**	(51)	(30)
Interest – net	**(206)**	(191)	(144)
Foreign exchange	**2**	5	335
Income taxes	**174**	136	(5)
Net earnings (loss)	**(239)**	(216)	203

The corporate segment reported a loss in 2010 of $239 million compared with a loss of $216 million in 2009. Administration expenses increased due to higher software expenses, professional services, corporate services, and corporate communications. 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 2010 is due to higher debt levels compared to 2009. 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)	**2010**	2009	2008
(Gain) loss on translation of U.S. dollar denominated long-term debt	**(90)**	(265)	134
(Gain) loss on contribution receivable	**67**	216	(228)
Other (gains) losses	**21**	44	(241)
Foreign exchange gain	**(2)**	(5)	(335)
U.S./Canadian dollar exchange rates:			
At beginning of year	**U.S. $0.956**	U.S. $0.817	U.S. $1.012
At end of year	**U.S. $1.005**	U.S. $0.956	U.S. $0.817

Consolidated Income Taxes
Consolidated income taxes decreased in 2010 to $385 million from $541 million in 2009 resulting in an effective tax rate of 24.7% for 2010 and 27.6% for 2009.

($ millions)	**2010**	2009	2008
Income taxes as reported	**385**	541	1,394
Cash taxes paid	**783**	1,323	615

Taxable income from Canadian operations is primarily generated through partnerships, with the related income taxes payable in a future period. Accrued liabilities includes nil of cash tax payable in 2011 relating to 2010 taxable income. In 2011, cash tax instalments of $280 million are payable in respect of the 2010 reported earnings, which are not taxable until 2011.

Corporate Capital Expenditures
Corporate capital expenditures of $67 million in 2010 were primarily for computer hardware and software, office furniture, renovations, equipment and system upgrades, construction of a new building in Lloydminster and capitalized interest.

7.7 Fourth Quarter

Consolidated net earnings during the fourth quarter of 2010 were $305 million, an increase of 19% from the previous quarter, but slightly lower compared with the same period in 2009 as a result of lower realized natural gas prices, the stronger Canadian dollar relative to the U.S. dollar, lower Upstream production, increased depletion in South East Asia and the Enbridge Line 6A/6B shutdowns, partially offset by higher average crude oil prices, increased realized refining margins and increased volume in U.S. Downstream and the settlement of the redetermined participation interest for Terra Nova.

Net earnings from the Upstream segment were $322 million in the fourth quarter of 2010, a decrease of $12 million from the same period in 2009. Lower upstream earnings in the fourth quarter of 2010 were largely due to a decrease in total production, the impact of the Enbridge Line 6A/6B shutdowns on realized medium and heavy crude oil and bitumen prices partially offset by increased realized prices for light crude oil, and the settlement of the redetermined participation interests in Terra Nova resulting in a gain of $31.8 million, net of tax. Production for the fourth quarter of 2010 was 280,500 boe/day compared to 291,500 boe/day in the fourth quarter of 2009. The average realized price for the fourth quarter was $68.87/bbl for crude oil, NGL and bitumen compared with $66.65/bbl in the same period in 2009 with higher realized prices for light crude oil partially offset by lower realized prices for medium and heavy crude oil and bitumen. Operating costs were higher in Western Canada and the Atlantic Region in the fourth quarter of 2010 compared to the same period in 2009 due to increased energy, treating, maintenance, labour, and transportation costs. Depletion was higher due to a larger full cost base in the Atlantic Region and China compared with the same period in 2009.

Upgrading recorded a net loss of $7 million in the fourth quarter of 2010 compared to net earnings of $14 million in the same period in 2009. Lower earnings were mainly due to a decrease in the Upgrader throughput of 55.7 mbbls/day in the fourth quarter of 2010 compared to 77.4 mbbls/day in the same period in 2009. The decrease in throughput was due to a scheduled 53-day turnaround at the Lloydminster Upgrader. The decrease in earnings is also attributed to an increase in the depreciation and amortization due to changes in the estimated remaining life of certain components of the Upgrader.

Canadian Refined Products net earnings were $44 million in the fourth quarter compared to $10 million in the same period in 2009 due to higher retail and wholesale market prices. The higher realized market prices were offset by lower government grants, and lower ethanol gross margins due to lower production as a result of a scheduled 39-day turnaround at the Lloydminster Ethanol Plant. Asphalt gross margins were also higher in the fourth quarter due to higher realized market prices, higher sales volumes and lower feedstock costs due to the widening of the heavy to light crude oil price differential resulting from the Enbridge Line 6A/6B shutdowns.

U.S. Refining and Marketing net earnings were $22 million in the fourth quarter compared to a loss of $43 million in the same period in 2009. The increase in earnings was due to higher realized refining margins, higher market crack spreads, and higher total throughput. Throughput was higher in the fourth quarter of 2010 due to a major turnaround completed in the fourth quarter of 2009 at the Lima Refinery.

Corporate net expenses were $122 million in the fourth quarter compared to an expense of $44 million in the same period in 2009. The increase in expenses was due to an increase in administrative expenses, foreign exchange losses, depreciation and amortization, and intersegment eliminations. Administrative expenses increased due to higher software expenses, professional services, corporate services, and corporate communications. Foreign exchange losses increased due to the strengthening of the Canadian dollar and its impact on cash and working capital transactions in the quarter. The increase in depreciation and amortization was a result of adjustments to the book value of legacy sites that have been deemed inactive. Intersegment eliminations are profit included in inventory that has not been sold to third parties at the end of the period. The increase in the fourth quarter of 2010 compared to the fourth quarter of 2009 was due in large part to additional inventory in Western Canada held for storage and in pipelines to mitigate the impact of selling crude oil to third parties at distressed spot prices due to the impact of the Enbridge Line 6A/6B shutdowns on medium and heavy crude oil and bitumen prices.

7.8 Results of Operations for 2009 compared with 2008

Net earnings in 2009 were $1,416 million compared with $3,751 million in 2008. The decrease of $2,335 million was attributable to the following:

- Upstream earnings decreased by $2,264 million due to lower crude oil and natural gas production, lower average realized prices for commodities, partially offset by a decrease in operating costs and lower DD&A.
- Midstream earnings decreased by $216 million due to lower upgrading differentials and lower margins realized on crude oil and natural gas trading contracts as a result of lower commodity prices, partially offset by a decrease in operating costs due to lower energy costs.
- Downstream earnings increased by $564 million. In Canada, earnings increased by $37 million due primarily to higher margins. Net earnings in the U.S. increased by $527 million due to improved product margins offsetting reduced sales volumes.
- Corporate earnings decreased by $419 million due primarily to lower foreign exchange gains due to the strengthening of the Canadian dollar in 2009 and higher interest expense due to higher debt levels in 2009 compared to 2008.

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

In 2010, Husky funded its capital programs, including acquisitions, and dividend payments by cash generated from operating activities, cash on hand, common share issuance, and long-term and short-term debt. At December 31, 2010, Husky had total debt of $4,187 million partially offset by cash on hand of $252 million for $3,935 million of net debt. Husky has no long-term debt maturing until 2012. At December 31, 2010 the Company had $2.7 billion in unused committed credit facilities, $166 million in unused short-term uncommitted credit facilities, unused capacity under the debt shelf prospectuses filed in Canada and the U.S. in 2009 of $300 million and U.S. $1.5 billion respectively, and unused capacity under the universal short form base shelf prospectus filed in Canada in 2010 of $2.7 billion. (Refer to Section 8.2).

		2010	2009	2008
Cash flow	– operating activities *($ millions)*	**2,703**	1,918	6,778
	– financing activities *($ millions)*	**1,085**	594	(2,559)
	– investing activities *($ millions)*	**(3,928)**	(3,033)	(3,514)
Debt to capital employed *(percent)*		**21.3**	18.3	12.0
Debt to cash flow from operations *(times)*		**1.2**	1.3	0.3
Corporate reinvestment ratio *(percent)* (1)		**111**	111	66
Interest coverage ratios on long-term debt only (2)				
Earnings		**7.8**	11.1	34.4
Cash flow		**13.7**	17.4	50.9
Interest coverage on ratios of total debt (3)				
Earnings		**7.6**	10.7	33.4
Cash flow		**13.3**	16.7	49.3

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

(2) *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.*

(3) *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 income 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 amounted to $2.7 billion in 2010 compared with $1.9 billion in 2009. Higher cash flow from operating activities was primarily due to higher crude oil prices, offset by lower production.

Cash Flow from Financing Activities

Cash provided by financing activities was $1,085 million in 2010 compared with $594 million in 2009. The increase was primarily due to the issuance of common shares, partially offset by lower long-term debt issued in 2010 compared to 2009. In March 2010, $700 million of medium-term notes were issued compared to $1.5 billion of long-term notes issued in May 2009.

Cash Flow used for Investing Activities

Cash used for investing activities for 2010 was $3.9 billion compared with $3.0 billion in 2009. Cash invested in both periods was primarily for capital expenditures.

8.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2010, Husky's working capital was $1,256 million compared with $726 million at December 31, 2009.

Movement in Working Capital

($ millions)	**December 31, 2010**	December 31, 2009	**Increase/ (Decrease) in Working Capital**
Cash and cash equivalents	**252**	392	(140)
Accounts receivable	**1,529**	987	542
Inventories	**1,935**	1,520	415
Prepaid expenses	**34**	12	22
Accounts payable and accrued liabilities	**(2,494)**	(2,185)	(309)
Net working capital	**1,256**	726	530

The decrease in cash was primarily a result of the Company's capital spending exceeding cash flow generated from operating and financing activities. Accounts receivable increased largely as a result of increased crude oil sales and tax instalment advances in 2010. The increase in inventory was due to the increase in inventory in transit on the Keystone Pipeline, and a higher volume of inventory on hand due to mitigation activities in respect of the Enbridge Line 6A/6B shutdowns in 2010. The increase in accounts payable and accrued liabilities was mainly due to higher capital expenditures, higher commodity prices and an increase in inventory compared to 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, and to repay maturing debt and pay dividends. Husky's upstream capital programs are funded principally by cash provided from operating activities, long-term debt, common share issuance, and available committed and uncommitted credit facilities. During times of low oil and gas prices, a portion 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 investment plan during periods of low commodity prices. As a result, Husky frequently evaluates the options with respect to sources of long and short-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines. At December 31, 2010, no production was hedged.

At December 31, 2010 Husky had the following available credit facilities:

($ millions)	Available	Unused
Operating facilities	415	299
Syndicated bank facilities	2,750	2,370
Bilateral credit facilities	150	150
Total	3,315	2,819

Cash and cash equivalents at December 31, 2010 totalled $252 million compared with $392 million at the beginning of the year.

At December 31, 2010, Husky had unused committed long and short-term borrowing credit facilities totalling $2.7 billion. In addition, a further $166 million of uncommitted short-term borrowing facilities were available of which a total of $49 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, 2010, 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 applicable securities regulators in each of the provinces of Canada 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, 2010, $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020 had been issued under this shelf prospectus (refer to Note 13 to the Consolidated Financial Statements).

On November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $3 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 2012. During the 25-month period that the shelf prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. On December 7, 2010, Husky issued 11.9 million common shares at a price of $24.50 per share for total gross proceeds of $293 million via an overnight-marketed public offering under this shelf prospectus. The public offering was conducted under the shelf prospectus and supplement to the shelf prospectus. The Company concurrently issued a total of 28.9 million common shares to the principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. at a price of $24.50 per share for total gross proceeds of $707 million. The pubic offering and the private placement closed on December 7, 2010.

Asia Pacific Energy Ltd. and HOCL, subsidiaries of Husky, each have an uncommitted demand revolving facility of U.S. $10 million available for general purposes. As of December 31, 2010, there was no balance outstanding under these facilities.

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. As of December 31, 2010, there was no balance outstanding under this facility.

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 billion in 2010. 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.

In the Special Meeting of Shareholders held on February 28, 2011, Husky's shareholders approved amendments to the common share terms, which provide the shareholders with the ability to receive dividends in common shares or in cash. Quarterly dividends would be declared in an amount expressed in dollars per common share and would be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares would be calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares. A shareholder must deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend confirming they will accept the dividend in common shares. Failure to do so will result in such shareholder receiving the dividend paid in cash.

Capital Structure

($ millions)	December 31, 2010 Outstanding	Available [1]
Total short-term and long-term debt	4,187	2,819
Common shares, retained earnings and accumulated other comprehensive income	15,493	

[1] *Available short and long-term debt includes committed and uncommitted credit facilities.*

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)	2011	2012-2013	2014-2015	Thereafter	Total
Long-term debt and interest on fixed rate debt	232	1,205	1,389	3,325	6,151
Operating leases	105	169	121	117	512
Firm transportation agreements	166	274	331	3,197	3,968
Unconditional purchase obligations [1]	1,970	1,280	50	122	3,422
Lease rentals and exploration work agreements	98	115	238	491	942
Asset retirement obligations [2]	63	117	117	7,293	7,590
	2,634	3,160	2,246	14,545	22,585

[1] *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling rig services and natural gas purchases.*

[2] *Asset retirement obligation 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 2011 commodity price forecast, the Company believes that its non-cancellable contractual obligations, other commercial commitments and 2011 capital program will be funded by cash flow from operating activities and, to the extent required, by available committed credit facilities, the issuance of long-term debt and by hybrid debt instruments. In the event of significantly lower cash flow, Husky would be able to defer certain projected capital expenditures without penalty.

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 18 to the Consolidated Financial Statements.

Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery LLC (refer to Note 8 to the Consolidated Financial Statements) which is payable between December 31, 2010 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, 2010, 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 ("ARO"). 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 13 to the Consolidated Financial Statements). Subsequent to this offering, U.S. $65 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, 2010, the senior notes were included in long-term debt on the Company's balance sheet.

On December 7, 2010, the Company issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million via a private placement to its principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

A related party 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 2010, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $44 million (2009 - $90 million). At December 31, 2010, the total value of accounts receivables related to these transactions was nil (2009 - nil).

In February 2011, Husky and TACLP agreed to sell the Meridian cogeneration facility to a related party. Completion of the transaction is subject to consent from Saskatchewan Power Corporation as well as regulatory approval. The transaction is expected to be completed by April 2011.

Husky did not have any customers that constituted more than 10% of total sales and operating revenues during 2010.

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 3.0, "The 2010 Business Environment"). From time to time, the Company will use derivative instruments to manage its exposure to these risks.

Political Risk
Husky is exposed to risk factors associated with operating in developed and developing countries, as well as political and regulatory instability. The Company monitors the changes to regulations and government policies in the areas within which it operates.

Environmental Risk
Husky's offshore operations are subject to the risk of blowouts and other catastrophic events, resulting from actions of the Company or its contractors or agents, or those of third parties, that could result in suspension of operations, damage to equipment and harm to personnel, and damage to the natural environment. The consequences of such catastrophic events occurring in deep water operations, in particular, can be more costly and time-consuming to remedy, the remedy may be made

more difficult or uncertain by the extreme pressures and cold temperatures encountered in deep water operations, shortages of equipment and specialist personnel required to work in these conditions, or the absence of appropriate and proven means to effectively remedy such consequences. The costs associated with such events could be material and Husky may not maintain sufficient insurance to address such costs. With the exception of Husky's Mizzen prospect, of which Husky is a non-operator, the Company currently does not participate in offshore deep water drilling operations in Canada; however, Husky's development program in China includes deep water drilling.

The Deepwater Horizon oil spill in the Gulf of Mexico has led to numerous public and governmental expressions of concern about the safety and potential environmental impact of offshore oil operations. Stricter regulation of offshore oil and gas operations has already been implemented in the Gulf of Mexico. Further regulation, increased financial assurance requirements and increased caps on liability are likely to be applied to offshore oil and gas operations in the Gulf of Mexico. In the event that similar changes in environmental regulation occur with respect to Husky's operations in the Atlantic Region or in the South China Sea, such changes could increase the cost of complying with environmental regulation in connection with these operations and have a material adverse impact on Husky's operations.

The United States Environmental Protection Agency ("EPA") has promulgated the so-called 'Tailoring Rule', which, beginning on January 2, 2011, phases in over time restrictions on greenhouse gas emissions from stationary sources, including power plants and petroleum refineries, beginning with the largest emitters, where such sources are required to obtain a new or modified permit based on non-greenhouse gas emissions. The EPA has also promulgated regulations requiring data collection, beginning January 1, 2010, and reporting, beginning March 31, 2011, of greenhouse gas emissions from stationary sources in the oil and gas industry emitting more than 25,000 tons per year of greenhouse gases in carbon dioxide equivalent. This reporting requirement applies to Husky's U.S. operations. However, these regulations are subject to challenge in Congress and the courts. Congress is expected to consider in the coming session proposals to block or delay the EPA's regulation of greenhouse gas emissions. Among several legal challenges, the State of Texas, the National Association of Manufacturers and other organizations are seeking a stay of the Tailoring Rule and the EPA's other regulations relating to greenhouse gas emissions from stationary sources. It is not possible to predict the ultimate outcome of these challenges. While these EPA regulations are currently in effect, they have not yet had a material impact on Husky and the pending and anticipated challenges could result in the staying of the regulations. Husky's operations may be impacted by future United States greenhouse gas legislation applying to the oil and gas industry or the consumption of petroleum products or by these or any further restrictive regulations issued by the EPA. Such legislation or regulation could require Husky's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

Financial Risk

Husky's financial risks are largely related to commodity prices, refinery crack spreads, foreign exchange rates, interest rates, credit risk, changes in fiscal policy related to royalties and taxes and others. From time to time, Husky uses financial and derivative instruments to manage its exposure to these risks.

Commodity Price Risk Management

Husky uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

At December 31, 2010, the Company had third party physical purchase and sale natural gas contracts and financial natural gas storage contracts.

The third party physical purchase and sale contracts have been recorded at their fair value in accrued liabilities and accounts receivable respectively. At December 31, 2010, the balance sheet position of these contracts was $31 million recorded in accounts receivable (2009 - $13 million in accounts receivable). The change in the fair value of these contracts resulted in an unrealized gain of $18 million (2009 - unrealized loss of $38 million) which has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Natural gas inventories held in storage relating to the financial natural gas storage contracts are recorded at fair value. At December 31, 2010, the fair value of the inventories was $131 million (2009 – $173 million). The cumulative fair value change on this inventory as of December 31, 2010 was an unrealized loss of $6 million (2009 – unrealized gain of $45 million). The change in the fair value of inventory resulted in an unrealized loss of $51 million (2009 – unrealized gain of $69 million) which has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

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 $2 million (2009 - $4 million gain) has been recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income. The crude oil inventory held in storage is recorded at fair value.

At December 31, 2010, the fair value of the inventory was $30 million (2009 – $124 million), resulting in a $2 million unrealized loss (2009 – $1 million loss) recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income.

The Company enters into certain crude oil and purchase sale contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities. At December 31, 2010, the Company had three mmbbls of purchase and sale contracts resulting in an unrealized loss of $8 million recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income. A portion of the crude oil inventory is sold to third parties and is considered held for trading. This inventory has been recorded at its fair value as the Company is considered a broker-trader. At December 31, 2010, the fair value of the inventory was $72 million, resulting in a $6 million unrealized gain recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

The Company has entered into contracts for future crude oil purchases, whereby there is a requirement to pay the difference between the price paid at delivery of the crude oil and the current market price at a future settlement date. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at December 31, 2010, the fair value of these contracts was $1 million resulting in a loss of $1 million (2009 – $30 million loss) recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Foreign Currency Risk Management
At December 31, 2010, 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, 2010, the cost of a U.S. dollar in Canadian currency was $0.9946.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. For the year ending December 31, 2010, the impact of these contracts was a realized gain of $26 million (2009 – gain of $16 million) recorded in foreign exchange expense.

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, 2010, 74% or $3.1 billion of Husky's outstanding debt was denominated in U.S. dollars (100% or $3.2 billion at December 31, 2009). The percentage of the Company's debt exposed to the Cdn/U.S. exchange rate decreases to 67% when cross currency swaps are considered (2009 – 88%).

At December 31, 2010, the Company has designated U.S. $987 million of its U.S. debt as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. In 2010, the unrealized foreign exchange gain arising from the translation of the debt was $44 million, net of tax expense of $7 million (2009 – gain of $104 million, net of tax expense of $18 million), 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, 42% of long-term debt is exposed to changes in the Cdn/U.S. exchange rate (2009 – 57%).

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, 2010, Husky's share of this receivable was U.S. $1.3 billion (2009 – 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, 2010 Husky's share of this obligation was U.S. $1.4 billion (2009 – U.S. $1.4 billion) including accrued interest.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet 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, 2010:

Financial Liability *($ millions)*	2011	2012	2013	2014	2015	After 2015
Accounts payable and accrued liabilities	2,494	–	–	–	–	–
Cross currency swaps	–	447	–	–	–	–
Long-term debt	–	782	–	753	303	2,349

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

Interest Rate Risk Management

At December 31, 2010, Husky had the following interest rate swaps in place:

- U.S. $200 million of long-term debt whereby a fixed interest rate of 7.55% was swapped for rates ranging from LIBOR + 399 bps to LIBOR + 430 bps until November 15, 2016.
- U.S. $300 million of long-term debt whereby a fixed interest rate of 6.20% was swapped for rates ranging from LIBOR + 255 bps to LIBOR + 275 bps until September 15, 2017.
- U.S. $150 million of long-term debt whereby a fixed interest rate of 5.90% was swapped for rates ranging from LIBOR + 349 bps to LIBOR + 350 bps until June 15, 2014.
- CAD $300 million of long-term debt whereby a fixed interest rate of 3.75% was swapped for rates ranging from CDOR + 0.80% to CDOR + 0.85% until March 12, 2015.

During 2010, these swaps resulted in an offset to interest expense of $23 million compared to an offset of less than $1 million in 2009. The amortization of previous interest rate swap terminations resulted in an additional $2 million (2009 – offset of $3 million) interest expense in 2010.

Cross currency swaps resulted in an addition to interest expense of $6 million (2009 – $4 million) in 2010.

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 cash flow 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 28, 2011

• common shares	890,708,795
• preferred shares	none
• stock options	28,594,260
• stock options exercisable	16,845,105

At February 28, 2011, 49.2 million common shares were reserved for issuance under the stock option plan. Other than in respect of the performance based options, 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 17 to the Consolidated Financial Statements).

8.8 Liquidity Summary

The following information relating to Husky's credit ratings is provided as it relates to Husky's financing costs, liquidity and operations. Specifically, credit ratings affect Husky's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of Husky to engage in certain collateralized business activities on a cost effective basis depends on Husky's credit ratings. A reduction in the current rating on Husky's debt by its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in Husky's ratings outlook could adversely affect Husky's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect Husky's ability to, and the associated costs of, (i) entering into ordinary course derivative or hedging transactions and may require Husky to post additional collateral under certain of its contracts, and (ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

	Rating	Last Review	Last Rating Change
Moody's:			
Outlook	Under Review	December 15, 2010	March 5, 2010
Senior Unsecured Debt	Baa2	March 5, 2010	April 25, 2001
Standard and Poor's:			
Outlook	Stable	November 30, 2010	July 27, 2006
Senior Unsecured Debt	BBB+	November 30, 2010	July 27, 2006
Dominion Bond Rating Service:			
Trend	Stable	November 26, 2009	March 31, 2008
Senior Unsecured Debt	A (low)	November 26, 2009	March 31, 2008

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

On December 15, 2010 Moody's placed Husky Energy Inc.'s Baa2 senior unsecured rating and Ba1 junior subordinated rating on review for a possible downgrade. At this time the outcome of the review is not yet determined.

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 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. Canadian GAAP provides for the recognition, measurement and disclosure requirements for financial instruments and hedge accounting. Refer to Note 20 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 estimates 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 Transition to International Financial Reporting Standards

In February 2008, the CICA Accounting Standards Board ("AcSB") confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), for fiscal periods beginning on or after January 1, 2011.

The Company is progressing in its IFRS transition project in preparation for timely completion of the first IFRS interim financial report in the first quarter of 2011. The impact assessment of IFRS accounting policies chosen by the Company has been completed for the January 1, 2010 and December 31, 2010 balance sheets and 2010 year-end results based on the accounting standards and interpretations in effect as at December 31, 2010. The impact of transition to IFRS as presented in the financial statements may require adjustment before comprising part of the first IFRS financial statements reported to shareholders as a result of early adoption of any IFRS issued but not effective until after December 31, 2011 or as a result of changes in financial reporting requirements arising from new or revised standards issued by the IASB or interpretations issued by the International Financial Reporting Interpretations Committee.

The Company has completed its risk assessment of key processes that will be impacted by IFRS. Conversion impacts have been incorporated into existing internal controls over financial reporting and disclosure controls and procedures. No material changes to the internal control framework or entity-level controls have been noted as a result of transition to IFRS.

Refer to Note 24 of the Consolidated Financial Statements for the Company's assessment of the impacts of the transition to IFRS as at January 1, 2010 and December 31, 2010 and for the year ended December 31, 2010. The impact of the transition to IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Specifically, amounts recorded for depletion, depreciation, amortization, accretion expense, asset retirement obligations, fair value measurements, employee future benefits and amounts used in impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. By their nature, these estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change on the financial statements.

Based on the critical accounting estimates outlined in Section 9.0 above, the Company noted that the transition to IFRS result in additional considerations in underlying estimates from those under Canadian GAAP as follows:

Depletion Expense

Eligible costs associated with oil and gas activities are capitalized on a unit of measure basis. Depletion expense is subject to estimates including petroleum and natural gas reserves, future petroleum and natural gas prices, estimated future remediation costs, future interest rates as well as other fair value assumptions. Under IFRS, the aggregate of capitalized costs, net of accumulated DD&A, less estimated salvage values, is charged to DD&A over the life of the proved reserves using the unit of production method.

Withheld Costs

Costs related to exploration and evaluation activities and major development projects are excluded from costs subject to depletion until technical feasibility and commercial viability is assessed and production commences. At that time, costs are either transferred to property, plant, and equipment or their value is impaired. Impairment is charged directly to profit or loss under IFRS.

Impairment of Long-lived Assets

Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre exceeds its recoverable amount under IFRS. 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. The determination of the recoverable amount for impairment purposes under IFRS involves the use of numerous assumptions and judgments including future net cash flows from oil and gas reserves, future third-party pricing, inflation factors, discount rates and other uncertainties. Future revisions to these assumptions impact the recoverable amount.

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 and growth opportunities; anticipated results of the Company's 2011 capital program; annual growth targets; production guidance; factors that could impact the Company's 2011 production performance; the potential effect of risks and other factors on the Company's ability to deliver results in its Upstream, Midstream and Downstream business units; strategic plans for the upstream, midstream and downstream business segments; reserve estimates; exploration, development, and production plans in South East Asia, Western Canada, the Oil Sands and the Atlantic Region; development and production plans; production capacity and timing of production for the Sunrise Energy Project; production volumes and anticipated timing of peak production at North Amethyst; anticipated timing of production at West White Rose and Liwan; drilling plans at North Amethyst and the White Rose; exploration plans at Mizzen and offshore Greenland; timing of submission of development plans for Liwan; development plans and timing of production in Block 29/26; transportation plans at Liwan; potential farm-outs at North Sumbawa II; drilling plans and anticipated timing of production in Western Canada; production optimization and drilling plans for the Tucker Oil Sands Project; testing and implementation of various enhanced recovery techniques in Western Canada; development, drilling and 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; expansion plans for the Company's facility at Hardisty; reconfiguration plans for the Lima Refinery; Continuous Catalyst Regeneration Reformer Project plans; planned turnarounds to the *SeaRose* FPSO and at Terra Nova; planned turnarounds to the Lloydminster, Lima, Prince George and Toledo refineries; anticipated impacts of and timing of repairs from the February 2011 fire at the Lloydminster upgrader; plans to reposition and upgrade the Toledo Refinery; expectations in respect of the timing of the Terra Nova redetermination; 2011 production guidance; 2011 capital expenditure guidance; the Company's financial strategy and ability to maintain credit ratings; 2011 payments to be made pursuant to existing contractual obligations; anticipated timing and effect of closing of the sale of the Meridian cogeneration facility; and expected effects of the transition to IFRS.

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

In the past, Husky has sought and been granted by the Canadian Securities Administrators permission to make certain disclosure of its oil and gas activities in accordance with U.S. disclosure requirements. This permission ceased to be available after January 1, 2011, although the Company received an exemption from the Canadian Securities Administrators which allows the Company to also disclose its reserves using U.S. disclosure requirements as supplementary disclosure to the reserves and oil and gas activities disclosure required by NI 51-101. The reserve estimates and related disclosures in this document have been prepared in accordance with Canadian Securities Administrators' NI 51-101 effective December 31, 2010. Please refer to "Disclosure of Exemption under National Instrument 51-101" in the Annual Information Form for the year ended December 31, 2010 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 average capital employed, debt to capital employed, debt to capitalization, debt to cash flow from operations 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. The non-GAAP measurements do not have a standardized meaning prescribed by GAAP and therefore are unlikely to be comparable to similar measures presented by other users. 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)		**2010**	2009	2008
Non-GAAP	Cash flow from operations	**3,549**	2,507	5,946
	Settlement of asset retirement obligations	**(60)**	(41)	(56)
	Change in non-cash working capital	**(786)**	(548)	888
GAAP	Cash flow – operating activities	**2,703**	1,918	6,778

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 28, 2011. 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 2010, 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, 2010 and 2009 and Husky's financial position as at December 31, 2010 and at December 31, 2009.

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 Capital Employed	*Total debt divided by capital employed*
Debt to Capitalization	*Total debt divided by total debt and shareholders' equity*
Debt to Cash Flow from Operations	*Total debt divided by cash flow from operations*
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 Average Capital Employed	*Net earnings plus after tax interest expense divided by average capital employed*
Return on Equity	*Net earnings divided by average shareholder's 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*
bpd	*barrels per day*
bps	*basis points*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
bcf	*billion cubic feet*
tcf	*trillion cubic feet*
boe	*barrels of oil equivalent*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mmboe	*million barrels of oil equivalent*
mcfge	*thousand cubic feet of gas equivalent*
mmbtu	*million British Thermal Units*
mmlt	*million long tons*
tcfe	*trillion cubic feet equivalent*
ASP	*alkali surfactant polymer*
CDOR	*Certificate of Deposit Offered Rate*
CHOPS	*cold heavy oil production with sand*
CNOOC	*China National Offshore Oil Corporation*
EOR	*enhanced oil recovery*
FEED	*Front end engineering design*
FPSO	*Floating production, storage and offloading vessel*
GAAP	*Generally Accepted Accounting Principles*
GJ	*gigajoule*
LIBOR	*London Interbank Offered Rate*
MD&A	*Management's Discussion and Analysis*
MW	*megawatt*
NGL	*natural gas liquids*
NIT	*NOVA Inventory Transfer*
NYMEX	*New York Mercantile Exchange*
OPEC	*Organization of Petroleum Exporting Countries*
PSC	*production sharing contract*
PIIP	*Petroleum initially-in-place*
SAGD	*Steam assisted gravity drainage*
SEDAR	*System for Electronic Document Analysis and Retrieval*
WI	*working interest*
WTI	*West Texas Intermediate*
C-NLOPB	*Canada-Newfoundland and Labrador Offshore Petroleum Board*

11.5 Disclosure 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, 2010, 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, 2010, 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, 2010, 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) which attests to management's assessment of Husky's internal controls over financial reporting.

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, 2010, 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 Financial Information

	Upstream				Midstream							
					Upgrading				Infrastructure and Marketing			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
2010												
Sales and operating revenues, net of royalties	1,276	1,152	1,086	1,252	366	291	405	508	1,936	1,872	1,959	2,087
Costs and expenses												
Operating, cost of sales, selling and general	419	399	396	383	334	284	354	467	1,860	1,827	1,895	2,010
Depletion, depreciation and amortization	404	399	394	375	42	33	16	9	13	10	10	10
Interest - net	–	–	–	–	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–	–	–	–	–
	823	798	790	758	376	317	370	476	1,873	1,837	1,905	2,020
Earnings (loss) before income taxes	453	354	296	494	(10)	(26)	35	32	63	35	54	67
Current income taxes (recoveries)	(68)	13	16	16	(20)	(4)	15	10	15	16	16	15
Future income taxes (reduction)	199	89	70	127	17	(3)	(5)	(1)	2	(6)	(2)	3
Net earnings (loss)	322	252	210	351	(7)	(19)	25	23	46	25	40	49
Capital expenditures [2]	1,280	719	490	682	50	101	16	9	15	10	12	3
Total assets	18,179	17,038	16,768	16,611	2,075	1,360	1,424	1,465	1,368	1,678	1,692	1,549
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 (recoveries)	96	252	270	291	57	18	17	19	26	25	25	25
Future income taxes (reduction)	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

[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.*

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
835	834	700	606	1,824	1,683	1,881	1,719	(1,506)	(1,424)	(1,463)	(1,701)	4,731	4,408	4,568	4,471
758	741	659	570	1,739	1,633	1,856	1,718	(1,400)	(1,413)	(1,484)	(1,664)	3,710	3,471	3,676	3,484
18	22	25	26	51	47	47	46	19	19	19	19	547	530	511	485
–	–	–	–	–	1	–	1	50	53	55	48	50	54	55	49
–	–	–	–	–	–	–	–	7	11	(19)	(1)	7	11	(19)	(1)
776	763	684	596	1,790	1,681	1,903	1,765	(1,324)	(1,330)	(1,429)	(1,598)	4,314	4,066	4,223	4,017
59	71	16	10	34	2	(22)	(46)	(182)	(94)	(34)	(103)	417	342	345	454
12	14	15	15	•–	–	–	–	24	24	22	22	(37)	63	84	78
3	5	(11)	(12)	12	1	(8)	(17)	(84)	(64)	(49)	(69)	149	22	(5)	31
44	52	12	7	22	1	(14)	(29)	(122)	(54)	(7)	(56)	305	257	266	345
80	84	65	16	122	62	51	22	51	10	4	2	1,598	986	638	734
1,582	1,472	1,473	1,442	5,078	5,080	5,122	4,918	851	559	626	963	29,133	27,187	27,105	26,948
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

Segmented Operational Information

		2010				2009			
		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream									
Daily production, before royalties									
Light crude oil & NGL *(mbbls/day)*		**75.1**	**84.4**	**78.7**	**84.3**	76.7	62.5	99.3	119.0
Medium crude oil *(mbbls/day)*		**25.3**	**25.7**	**25.1**	**25.3**	24.8	24.8	25.6	26.3
Heavy crude oil *(mbbls/day)*		**74.6**	**72.4**	**74.6**	**76.4**	78.6	75.7	78.1	82.1
Bitumen *(mbbls/day)*		**23.1**	**21.9**	**21.5**	**22.6**	23.3	24.0	22.2	22.7
		198.1	**204.4**	**199.9**	**208.6**	203.4	187.0	225.2	250.1
Natural gas *(mmcf/day)*		**494.2**	**505.5**	**503.9**	**523.7**	528.7	535.0	552.3	551.2
Total production *(mboe/day)*		**280.5**	**288.7**	**283.9**	**295.9**	291.5	276.2	317.2	342.0
Average sales prices									
Light crude oil & NGL *($/bbl)*		**82.90**	**73.88**	**75.61**	**76.72**	73.98	67.56	65.32	50.42
Medium crude oil *($/bbl)*		**65.75**	**60.88**	**63.90**	**69.30**	65.78	61.28	58.32	40.68
Heavy crude oil *($/bbl)*		**58.82**	**56.96**	**56.18**	**63.31**	61.55	59.21	54.22	35.80
Bitumen *($/bbl)*		**59.14**	**55.41**	**52.58**	**61.82**	60.70	58.44	53.32	34.23
Natural gas *($/mcf)*		**3.52**	**3.50**	**3.45**	**4.81**	3.94	2.84	3.26	5.31
Operating costs *($/boe)*		**13.85**	**13.24**	**13.41**	**12.81**	12.24	13.14	11.05	11.10
Operating netbacks [(1)]									
Light crude oil *($/boe)* [(2)]		**53.37**	**47.42**	**43.96**	**46.02**	46.94	38.37	40.58	32.95
Medium crude oil *($/boe)* [(2)]		**38.62**	**33.43**	**32.45**	**38.02**	39.87	32.47	33.55	17.64
Heavy crude oil *($/boe)* [(2)]		**33.91**	**32.32**	**31.80**	**38.16**	37.16	37.21	33.85	18.16
Bitumen *($/boe)* [(2)]		**29.88**	**28.09**	**26.14**	**31.49**	26.59	38.10	33.75	14.54
Natural gas *($/mcfge)* [(3)]		**2.02**	**1.55**	**1.60**	**2.93**	2.29	1.16	1.73	2.72
Total *($/boe)* [(2)]		**32.83**	**29.67**	**28.17**	**33.83**	32.02	27.30	29.03	22.44
Net wells drilled [(4)]									
Exploration	Oil	**12**	**17**	**3**	**19**	5	1	1	2
	Gas	**9**	**6**	**1**	**15**	–	1	3	18
	Dry	**–**	**1**	**–**	**7**	1	–	–	5
		21	**24**	**4**	**41**	6	2	4	25
Development	Oil	**257**	**235**	**52**	**179**	116	72	19	71
	Gas	**38**	**6**	**–**	**9**	8	2	2	49
	Dry	**2**	**2**	**–**	**5**	2	1	–	4
		297	**243**	**52**	**193**	126	75	21	124
		318	**267**	**56**	**234**	132	77	25	149
Success ratio *(percent)*		**99**	**99**	**100**	**95**	98	99	100	94
Midstream									
Synthetic crude oil sales *(mbbls/day)*		**45.1**	**21.0**	**58.0**	**68.6**	64.5	58.6	63.1	61.0
Upgrading differential *($/bbl)*		**16.39**	**13.80**	**15.44**	**12.54**	13.06	10.16	8.31	16.74
Pipeline throughput *(mbbls/day)*		**501**	**489**	**537**	**524**	498	498	534	529
Canadian Refined Products									
Refined products sales volumes									
Light oil products *(million litres/day)*		**8.7**	**8.5**	**7.8**	**7.6**	7.7	7.8	7.4	7.6
Asphalt products *(mbbls/day)*		**27.5**	**30.9**	**19.2**	**18.7**	18.9	32.4	17.5	21.7
Refinery throughput									
Lloydminster refinery *(mbbls/day)*		**29.0**	**28.9**	**26.1**	**27.0**	22.2	27.5	17.8	28.8
Prince George refinery *(mbbls/day)*		**11.5**	**11.9**	**6.9**	**9.7**	10.4	10.2	10.0	10.6
Refinery utilization *(percent)*		**99**	**100**	**80**	**90**	82	94	70	99

(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 and Oil Sands*

Segmented Capital Expenditures

($ millions)	**2010** Q4	Q3	Q2	Q1	2009 Q4	Q3	Q2	Q1
Upstream								
Western Canada	**1,022**	**502**	**287**	**424**	579	152	109	349
Atlantic Region	**107**	**124**	**108**	**150**	95	111	160	208
Northwest United States	**–**	**–**	**–**	**–**	10	3	7	5
International	**151**	**93**	**95**	**108**	157	146	129	106
	1,280	**719**	**490**	**682**	841	412	405	668
Midstream								
Upgrader	**50**	**101**	**16**	**9**	20	17	12	19
Infrastructure and Marketing	**15**	**10**	**12**	**3**	–	7	5	14
	65	**111**	**28**	**12**	20	24	17	33
Downstream								
Canadian Refined Products	**80**	**84**	**65**	**16**	38	18	20	5
U.S. Refining and Marketing	**122**	**62**	**51**	**22**	137	54	43	26
	202	**146**	**116**	**38**	175	72	63	31
Corporate	**51**	**10**	**4**	**2**	14	9	7	6
	1,598	**986**	**638**	**734**	1,050	517	492	738

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

MANAGEMENT'S REPORT

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

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

The Company maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that our internal control over financial reporting was effective as of December 31, 2010. The system of internal controls is further supported by an internal audit function.

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

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

Asim Ghosh
President & Chief Executive Officer

Alister Cowan
Vice President & Chief Financial Officer

Calgary, Alberta, Canada

March 8, 2011

Independent Auditors' Report of Registered Public Accounting Firm

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

We have audited the accompanying consolidated financial statements of Husky Energy Inc. ("the Company") and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2010, 2009 and 2008, the consolidated statements of earnings and comprehensive income, changes in shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company and its subsidiaries as at December 31, 2010, 2009 and 2008 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, Alberta, Canada

March 8, 2011

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

As at December 31 (millions of dollars)	**2010**	2009	2008
Assets			
Current assets			
Cash and cash equivalents *(note 9)*	**252**	392	913
Accounts receivable *(notes 5, 20)*	**1,529**	987	1,344
Inventories *(note 6)*	**1,935**	1,520	1,032
Prepaid expenses	**34**	12	11
	3,750	2,911	3,300
Property, plant and equipment, net *(notes 1, 7)*	**23,259**	21,254	20,839
Goodwill *(notes 1, 10)*	**663**	689	779
Contribution receivable *(notes 8, 20)*	**1,284**	1,313	1,448
Other assets *(note 20)*	**177**	128	120
	29,133	26,295	26,486
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes 12, 20)*	**2,494**	2,185	2,896
Long-term debt *(notes 13, 20)*	**4,187**	3,229	1,957
Contribution payable *(notes 8, 20)*	**1,427**	1,500	1,659
Other long-term liabilities *(note 14)*	**1,417**	1,036	898
Future income taxes *(note 15)*	**4,115**	3,932	4,713
Commitments and contingencies *(note 16)*			
Shareholders' equity			
Common shares *(note 17)*	**4,574**	3,585	3,568
Retained earnings	**10,985**	10,832	10,436
Accumulated other comprehensive income	**(66)**	(4)	359
	15,493	14,413	14,363
	29,133	26,295	26,486

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

On behalf of the Board:

Asim Ghosh

Director

R.D. Fullerton

Director

Consolidated Statements of Earnings and Comprehensive Income

Year ended December 31 (millions of dollars, except share data)	**2010**	2009	2008
Sales and operating revenues, net of royalties	**18,178**	15,074	24,701
Costs and expenses			
Cost of sales and operating expenses *(note 14)*	**14,013**	10,865	17,706
Selling and administration expenses	**305**	265	284
Stock-based compensation *(note 17)*	**–**	1	(33)
Depletion, depreciation and amortization *(notes 1, 7)*	**2,073**	1,805	1,832
Interest - net *(note 13)*	**208**	194	147
Foreign exchange *(note 13)*	**(2)**	(5)	(335)
Other - net *(note 20)*	**23**	(8)	(45)
	16,620	13,117	19,556
Earnings before income taxes	**1,558**	1,957	5,145
Income taxes (recoveries) *(note 15)*			
Current	**188**	1,262	901
Future	**197**	(721)	493
	385	541	1,394
Net earnings	**1,173**	1,416	3,751
Other comprehensive income (loss)			
Cumulative foreign currency translation adjustment	**(112)**	(469)	607
Hedge of net investment, net of tax *(note 20)*	**44**	104	(165)
Derivatives designated as cash flow hedges, net of tax *(note 20)*	**6**	2	(6)
	(62)	(363)	436
Comprehensive income	**1,111**	1,053	4,187
Earnings per share			
Basic and diluted	**1.38**	1.67	4.42
Weighted average number of common shares outstanding *(millions)*			
Basic and diluted	**852.7**	849.7	849.2

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

Consolidated Statements of Changes in Shareholders' Equity

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Common shares			
Beginning of year	**3,585**	3,568	3,551
Common shares issued, net of share issue costs	**988**	–	–
Options exercised	**1**	17	17
End of year	**4,574**	3,585	3,568
Retained earnings			
Beginning of year	**10,832**	10,436	8,154
Net earnings	**1,173**	1,416	3,751
Dividends on common shares *(note 17)*	**(1,020)**	(1,020)	(1,469)
End of year	**10,985**	10,832	10,436
Accumulated other comprehensive income			
Beginning of year	**(4)**	359	(77)
Other comprehensive income			
Cumulative foreign currency translation adjustment	**(112)**	(469)	607
Hedge of net investment, net of tax *(note 20)*	**44**	104	(165)
Derivatives designated as cash flow hedges, net of tax *(note 20)*	**6**	2	(6)
	(62)	(363)	436
End of year	**(66)**	(4)	359
Shareholders' equity	**15,493**	14,413	14,363

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

Consolidated Statements of Cash Flows

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Operating activities			
Net earnings	**1,173**	1,416	3,751
Items not affecting cash			
Accretion *(note 14)*	**53**	48	54
Depletion, depreciation and amortization	**2,073**	1,805	1,832
Future income taxes (recoveries)	**197**	(721)	493
Foreign exchange	**(24)**	(48)	(94)
Other	**77**	7	(90)
Settlement of asset retirement obligations *(note 14)*	**(60)**	(41)	(56)
Change in non-cash working capital *(note 9)*	**(786)**	(548)	888
Cash flow - operating activities	**2,703**	1,918	6,778
Financing activities			
Long-term debt issuance	**6,108**	3,604	949
Long-term debt repayment	**(5,028)**	(1,866)	(2,205)
Proceeds from issuance of common shares, net of share issue costs *(note 17)*	**988**	–	–
Proceeds from monetization of financial instruments	–	41	12
Dividends on common shares	**(1,020)**	(1,020)	(1,469)
Contribution receivable repayment *(note 8)*	**38**	–	–
Other	**(1)**	2	8
Change in non-cash working capital *(note 9)*	–	(167)	146
Cash flow - financing activities	**1,085**	594	(2,559)
Investing activities			
Expenditures on property, plant and equipment	**(3,852)**	(2,762)	(4,060)
Joint venture arrangement *(note 8)*	–	–	127
Asset sales	**7**	28	37
Contribution payable repayment *(note 8)*	**(85)**	–	–
Other	**(65)**	(10)	11
Change in non-cash working capital *(note 9)*	**67**	(289)	371
Cash flow - investing activities	**(3,928)**	(3,033)	(3,514)
Increase (decrease) in cash and cash equivalents	**(140)**	(521)	705
Cash and cash equivalents at beginning of year	**392**	913	208
Cash and cash equivalents at end of year	**252**	392	913

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Segmented Financial Information

	Upstream			Midstream					
				Upgrading			Infrastructure and Marketing		
Year ended December 31 ($ millions)	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Sales and operating revenues, net of royalties	**4,766**	4,452	7,889	**1,570**	1,572	2,435	**7,854**	6,984	13,544
Costs and expenses									
Operating, cost of sales, selling and general	**1,597**	1,495	1,627	**1,439**	1,461	2,053	**7,592**	6,669	13,192
Depletion, depreciation and amortization	**1,572**	1,397	1,505	**100**	34	31	**43**	36	31
Interest - net	**–**	–	–	**–**	–	–	**–**	–	–
Foreign exchange	**–**	–	–	**–**	–	–	**–**	–	–
	3,169	2,892	3,132	**1,539**	1,495	2,084	**7,635**	6,705	13,223
Earnings (loss) before income taxes	**1,597**	1,560	4,757	**31**	77	351	**219**	279	321
Current income taxes (recoveries)	**(23)**	909	585	**1**	111	84	**62**	101	126
Future income taxes (reduction)	**485**	(462)	795	**8**	(88)	21	**(3)**	(22)	(29)
Net earnings (loss)	**1,135**	1,113	3,377	**22**	54	246	**160**	200	224
Property, plant and equipment -As at December 31									
Cost	**30,711**	27,478	25,283	**1,963**	1,774	1,704	**1,100**	956	931
Accumulated depletion, depreciation and amortization	**14,189**	12,688	11,432	**644**	544	510	**437**	365	330
Net	**16,522**	14,790	13,851	**1,319**	1,230	1,194	**663**	591	601
Expenditures on property, plant and equipment -Year ended December 31 (2)	**3,171**	2,326	3,580	**176**	69	99	**40**	25	94
Total assets - As at December 31	**18,179**	16,338	15,653	**2,075**	1,427	1,322	**1,368**	1,712	1,486

(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 (note 14) and corporate acquisitions.*

Geographical Financial Information

	Canada			United States			Other International		
($ millions)	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Year ended December 31									
Sales and operating revenues, net of royalties	**10,405**	8,856	15,213	**7,522**	5,981	9,172	**251**	237	316
Expenditures on property, plant and equipment (1)	**3,252**	1,974	3,685	**257**	285	193	**447**	538	230
As at December 31									
Property, plant and equipment, net	**18,523**	16,624	16,234	**3,477**	3,587	4,093	**1,259**	1,043	512
Goodwill (2)	**160**	160	160	**503**	529	619	**–**	–	–
Total assets	**22,674**	20,239	20,208	**5,486**	5,363	5,744	**973**	693	534

(1) *Excludes capitalized costs related to asset retirement obligations incurred during the period (note 14) and corporate acquisitions.*

(2) *Goodwill relates to Western Canada in the upstream segment and the Lima Refinery in the downstream segment - U.S. Refining and Marketing.*

Downstream						Corporate and Eliminations [1]			Total		
Canadian Refined Products			U.S. Refining and Marketing								
2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
2,975	2,495	3,564	**7,107**	5,349	7,802	**(6,094)**	(5,778)	(10,533)	**18,178**	15,074	24,701
2,728	2,204	3,340	**6,946**	4,957	8,280	**(5,961)**	(5,663)	(10,580)	**14,341**	11,123	17,912
91	93	81	**191**	194	154	**76**	51	30	**2,073**	1,805	1,832
–	–	–	**2**	3	3	**206**	191	144	**208**	194	147
–	–	–	**–**	–	–	**(2)**	(5)	(335)	**(2)**	(5)	(335)
2,819	2,297	3,421	**7,139**	5,154	8,437	**(5,681)**	(5,426)	(10,741)	**16,620**	13,117	19,556
156	198	143	**(32)**	195	(635)	**(413)**	(352)	208	**1,558**	1,957	5,145
56	38	28	**-**	3	(24)	**92**	100	102	**188**	1,262	901
(15)	19	11	**(12)**	68	(208)	**(266)**	(236)	(97)	**197**	(721)	493
115	141	104	**(20)**	124	(403)	**(239)**	(216)	203	**1,173**	1,416	3,751
2,053	1,767	1,691	**3,939**	3,875	4,249	**519**	439	406	**40,285**	36,289	34,264
832	755	669	**543**	377	229	**381**	306	255	**17,026**	15,035	13,425
1,221	1,012	1,022	**3,396**	3,498	4,020	**138**	133	151	**23,259**	21,254	20,839
245	81	155	**257**	260	133	**67**	36	47	**3,956**	2,797	4,108
1,582	1,430	1,375	**5,078**	4,771	5,380	**851**	617	1,270	**29,133**	26,295	26,486

Total		
2010	2009	2008
18,178	15,074	24,701
3,956	2,797	4,108
23,259	21,254	20,839
663	689	779
29,133	26,295	26,486

Note 2 Nature of Operations and Organization

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

Management has segmented the Company's business based on differences in products and services and management responsibility. The Company's business is conducted predominantly through three major business segments – Upstream, Midstream and Downstream.

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

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

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

Note 3 Significant Accounting Policies

a) Principles of Consolidation and the Preparation of Financial Statements

The consolidated financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

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

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

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

b) Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Specifically, amounts recorded for depletion, depreciation, amortization of accretion expense, asset retirement obligations, fair value measurements, employee future benefits and amounts used in impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value assumptions. By their nature, these estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change on the financial statements.

c) Cash and Cash Equivalents

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

d) Inventories

Crude oil, natural gas, refined petroleum products and purchased sulphur inventories, other than commodity inventory held for trading, are valued at the lower of cost and net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. Materials, parts and supplies are valued at the lower of average cost and net realizable value. Cost consists of raw material, labour, direct overhead and transportation. Previous impairment write-downs are reversed when there is a change in the situation that caused the impairment. Commodity inventory held for trading purposes is carried at fair value less cost to sell. Any changes in fair value are included as gains or losses in other expenses during the period of change. Unrealized intersegment profits in inventories are eliminated.

e) Precious Metals

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

f) Property, Plant and Equipment

i) Oil and Gas

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

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

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

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

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

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

- the fair value of proved and probable reserves calculated using a present value technique that uses the cash flows expected to result from production of the proved reserves and a portion of the probable reserves discounted using a risk free rate; and
- the cost, less impairment, of unproved properties and major development projects that do not have probable reserves attributed to them.

ii) Other Plant and Equipment

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

iii) Asset Retirement Obligations

The recognition of the fair value of legal obligations associated with the retirement of tangible long-lived assets as calculated using the current estimated costs to retire the asset inflated to the estimated retirement date discounted using a credit-adjusted risk free rate, is recorded in the period that the asset is put into use, with a corresponding increase to the carrying value of the related asset. The obligations recognized are legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in cost of sales and operating expenses. The liability will also be adjusted to reflect revisions to the previous estimates of the undiscounted obligation. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion, depreciation and amortization of the underlying asset. Actual retirement expenditures are charged to the accumulated liability as incurred.

iv) Capitalized Interest

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

g) Impairment or Disposal of Long-lived Assets

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

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

h) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill is subject to impairment tests on at least an annual basis or sooner if there are indicators of impairment. The Company tests impairment annually in the fourth quarter of each year. To assess impairment, the fair values of the assets and liabilities of the reporting unit are compared to their carrying amounts. If the excess of the reporting unit's fair value over its carrying amounts is greater than the carrying amount of the goodwill then there is no impairment. Any amount that the carrying amount of the goodwill exceeds the excess of the reporting unit's fair value over its carrying amount is permanent goodwill impairment. Impairment losses would be recognized in current period earnings.

i) Derivative Financial Instruments and Hedging Activities

i) Financial Instruments

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

A held for trading financial instrument includes one of the following criteria:

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

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

ii) Derivative Instruments and Hedging Activities

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

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

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

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

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

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

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

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments related to foreign exchange are recorded in foreign exchange expense in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The remaining portion of the gain or loss is recorded in Accumulated Other Comprehensive Income and is adjusted for changes in the fair value of the instrument over the life of the debt.

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

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

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

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

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

iii) Embedded Derivatives

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

iv) Comprehensive Income

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

j) Employee Future Benefits

In Canada, the Company provides a defined contribution pension plan and other post-retirement benefits to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. In the United States, the Company provides defined contribution plans (401(k)), a defined benefit pension plan and other post-retirement benefits.

The cost of the pension benefits earned by employees in the defined contribution pension plans is expensed as incurred. The cost of the benefits earned by employees in the other post-retirement and defined benefit plans is charged to earnings as services are rendered using the projected benefit method prorated on service. The pension expense for the defined benefit pension plans and other post-retirement benefits is based on management's best estimate of expected plan investment performance, salary escalation, retirement age, attrition, future health care costs and mortality.

The future benefit obligation is discounted using a market interest rate of high quality corporate debt securities that match the amount and timing of future benefit payments. Adjustments arising from plan amendments are amortized over the expected average remaining service lifetime ("EARSL"). Net actuarial gains and losses that exceed 10% of the greater of the fair value of the plan assets and the benefit obligation are amortized over the EARSL of the participating employees.

k) Future Income Taxes

The Company follows the liability method of accounting for income taxes. Future income tax assets and liabilities are recognized at expected tax rates in effect when temporary differences between the tax basis and the carrying value of the Company's assets and liabilities reverse. The effect of a change to the tax rate on the future tax assets and liabilities is recognized in earnings when substantively enacted. A valuation allowance is recorded to the extent that it is considered more likely than not that the Company will be unable to utilize future tax assets.

l) Non-monetary Transactions

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

m) Revenue Recognition

Revenues from the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recorded when title passes to an external party and payment has either been received or collection is reasonably certain. Sales between the business segments of the Company are eliminated from sales and operating revenues and cost of sales. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

n) Foreign Currency Translation

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

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

o) Stock-based Compensation

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

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

The Company's long-term incentive program consists of a Performance Share Unit ("PSU") Plan that provides a time-vested award to certain officers and employees of the Company. PSUs entitle participants to receive cash based on the Company's share price at the time of vesting. The amount of cash is contingent on the Company's total shareholder return relative to a peer group of companies. A liability for expected cash payments is accrued over the vesting period of the PSUs based on the market price of the Company's common shares and an expected vesting percentage. The liability is revalued to reflect changes in the market price of the Company's common shares and the expected vesting percentage. When PSUs vest, a cash payment is made to the participants and the outstanding liability is reduced by the payment amount. Accrued compensation for a PSU that is forfeited is adjusted to earnings by decreasing the compensation expense in the period of forfeiture. Compensation expense is recognized in selling and administration expenses.

p) Earnings per Share

Basic common shares outstanding are the weighted average number of common shares outstanding for each period. The calculation of basic earnings per common share is based on net earnings divided by the weighted average number of common shares outstanding.

Diluted common shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. However, since the Company has a tandem stock option plan and accrues a liability for expected cash settlements, the potential common shares issuable upon exercise associated with the stock options are not included in diluted common shares outstanding. Shares that were potentially issuable on the settlement of the capital securities were not included in the determination of diluted earnings per common share, as the Company had neither the obligation nor intention to settle amounts due through the issuance of shares.

Note 4 International Financial Reporting Standards

In February 2008, the Canadian Institute of Chartered Accountants ("CICA") Accounting Standards Board ("AcSB") confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), for fiscal periods beginning on or after January 1, 2011.

The Company has selected IFRS accounting policies and evaluated the first-time adoption exemptions and elections available under IFRS 1, "First-Time Adoption of International Financial Reporting Standards." The resulting anticipated impact of transition to IFRS as at January 1, 2010 and for the year ended December 31, 2010 is presented in Note 24 in accordance with IFRS in effect as at

December 31, 2010. The accounting policies and IFRS 1 election choices are subject to change as the Company is required to comply with new or revised standards or interpretations of IFRS standards that are effective up to December 31, 2011.

Note 5 Accounts Receivable

($ millions)	**2010**	2009	2008
Trade receivables	**1,159**	948	1,135
Allowance for doubtful accounts	**(19)**	(18)	(22)
Derivatives due within one year	**35**	22	111
Income taxes receivable	**346**	23	106
Other	**8**	12	14
	1,529	987	1,344

Sale of Accounts Receivable

Husky has chosen not to renew its securitization agreement, which expired on March 31, 2009. No accounts receivable had been sold under the program during 2009 and 2008.

Note 6 Inventories

($ millions)	**2010**	2009	2008
Crude oil	**1,540**	812	480
Natural gas	**134**	172	222
Refined petroleum products	**148**	451	263
Materials, supplies and other	**113**	85	67
	1,935	1,520	1,032

Write-downs of inventories to net realizable value in 2010 amounted to $35 million (2009 – $106 million; 2008 – $721 million).

Note 7 Property, Plant and Equipment

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

Administrative costs related to exploration and development activities capitalized in 2010 were $51 million (2009 – $48 million; 2008 – $43 million).

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

($ millions)	**2010**	2009	2008
Canada	**3,406**	3,125	2,703
International	**836**	827	485
	4,242	3,952	3,188

Included in International are costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. All costs, net of any associated revenues, in these cost centres have been capitalized. As at December 31, 2010, $57 million was allocated to undeveloped properties with proved reserves and $779 million was allocated to undeveloped properties without proved reserves in International. Ultimate recoverability of these costs will be dependent upon the finding and development of proved oil and natural gas reserves. For the year ended December 31, 2010, the Company completed its impairment review of pre-production cost centres and determined that there was no impairment required.

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2010 were:

Canada	2011	2012	2013	2014	2015	Price increase 2015 to 2030 *(percent)*
Crude oil *($/bbl)*	75.99	76.90	76.24	76.22	75.95	1.6
Natural gas *($/mcf)*	3.89	4.55	5.01	5.84	6.06	2.6

Note 8 Joint Ventures

a) BP

On March 31, 2008, the Company completed a transaction with BP, which resulted in the formation of a 50/50 joint venture upstream entity and a 50/50 joint venture downstream entity. Both joint ventures are being accounted for using proportionate consolidation. The amounts recorded in the consolidated financial statements represent the Company's 50% interest in the joint ventures.

The upstream entity is a partnership to which Husky has contributed the Sunrise oil sands assets with a fair value of U.S. $2.5 billion as at January 1, 2008, plus capital expenditures for the three-month period ended March 31, 2008 of $15 million. BP's contribution was U.S. $250 million cash and a contribution receivable for the balance of U.S. $2.25 billion and $15 million. The contribution receivable accretes at a rate of 6% and is payable between December 31, 2010 and December 31, 2015 with the final balance due and payable by December 31, 2015. The upstream entity is included as part of the upstream segment.

The downstream entity is a limited liability company ("LLC") to which BP has contributed the Toledo Refinery plus inventories and other net assets, less accounts payable and adjusted net earnings. Husky's contribution was U.S. $250 million cash and a contribution payable for the balance of U.S. $2.6 billion. Husky's share of the value of the amounts contributed at March 31, 2008 by both entities to the downstream LLC is described below:

($ millions)	
Cash	129
Inventory	199
Property, plant and equipment (including adjusted earnings)	1,928
Partner contribution receivable	1,331
Other assets	2
Inventory related payables	(12)
Future income tax liability	(658)
Total contribution to downstream joint venture	2,919

The contribution payable accretes at a rate of 6% and is payable between December 31, 2010 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. The downstream entity is included as part of the U.S. Refining and Marketing segment. This entity is a self-sustaining foreign operation and has a U.S. dollar functional currency.

Summarized below are the results of operations, cash flows and financial position relating to the Company's proportional interests in its downstream joint venture:

Results of Operations *($ millions)*	**2010**	2009	2008
Revenues	**2,063**	1,799	1,843
Expenses	**2,105**	1,761	2,020
Proportionate share of net income (loss)	**(42)**	38	(177)

Cash Flows *($ millions)*	**2010**	2009	2008
Cash flow – operating activities	**(2)**	76	(90)
Cash flow – investing activities	**(86)**	(55)	(58)
Proportionate share of increase (decrease) in cash and cash equivalents	**(88)**	21	(148)

Financial Position ($ millions)	**2010**	2009	2008
Current assets	**424**	351	245
Long-term assets	**1,800**	1,910	2,292
Current liabilities	**(218)**	(179)	(42)
Long-term liabilities	**(481)**	(528)	(666)
Proportionate share of net assets	**1,525**	1,554	1,829

Contribution Receivable ($ millions)	**2010**	2009	2008
Beginning	**1,313**	1,448	–
Additions	**–**	–	1,220
Accretion	**76**	81	–
Received	**(38)**	–	–
Foreign exchange	**(67)**	(216)	228
Ending	**1,284**	1,313	1,448

Contribution Payable ($ millions)	**2010**	2009	2008
Beginning	**(1,500)**	(1,659)	–
Additions	**–**	–	(1,398)
Accretion	**(87)**	(91)	–
Paid	**85**	–	–
Foreign exchange	**75**	250	(261)
Ending	**(1,427)**	(1,500)	(1,659)

b) CNOOC Southeast Asia Limited

In April 2008, a subsidiary of the Company, Husky Oil Madura Partnership ("HOMP"), entered into an agreement with CNOOC Southeast Asia Limited ("CNOOCSE"), which resulted in the acquisition by CNOOCSE of a 50% equity interest in Husky Oil (Madura) Limited ("HOML"), a subsidiary of HOMP, for a consideration of $127 million (U.S. $125 million) resulting in a gain of $69 million included in other - net in the Consolidated Statements of Earnings and Comprehensive Income. HOML holds a 100% interest in the Madura Strait Production Sharing Contract. The resulting joint venture arrangement is being accounted for using the proportionate consolidation method.

In 2010, both HOMP and CNOOCSE agreed to each sell a 10% equity share in HOML to Samudra Energy Ltd., through its affiliate SMS Development Ltd. (Refer to Note 23 c).

c) Results of Joint Ventures

The results of Husky's proportionate share of its downstream joint venture with BP are described in Note 8 a). The results from the upstream joint venture with BP and the joint venture arrangement with CNOOCSE are considered to be in the pre-production phase. As a result, any impact on the financial results of the Company subsequent to entering into these joint ventures is considered immaterial.

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

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

($ millions)	**2010**	2009	2008
Decrease (increase) in non-cash working capital			
Accounts receivable	**(530)**	235	453
Inventories	**(481)**	(651)	522
Prepaid expenses	**(17)**	–	2
Accounts payable and accrued liabilities	**309**	(588)	428
Change in non-cash working capital	**(719)**	(1,004)	1,405
Relating to:			
Operating activities	**(786)**	(548)	888
Financing activities	–	(167)	146
Investing activities	**67**	(289)	371

b) Other cash flow information:

($ millions)	**2010**	2009	2008
Cash taxes paid	**783**	1,323	615
Cash interest paid	**232**	200	159

Cash and cash equivalents at December 31, 2010 included $185 million of cash (2009 – $65 million; 2008 – $269 million) and $67 million of short-term investments with maturities less than three months (2009 – $327 million; 2008 – $644 million).

Note 10 Goodwill

($ millions)	**2010**	2009	2008
Balance at beginning of year	**689**	779	660
Foreign currency translation of goodwill in self-sustaining U.S. operations	**(26)**	(90)	119
Balance at end of year	**663**	689	779

Note 11 Bank Operating Loans

At December 31, 2010, the Company had unsecured short-term borrowing lines of credit with banks totalling $415 million (2009 – $395 million; 2008 – $370 million) and letters of credit under these lines of credit totalled $116 million (2009 – $133 million; 2008 – $166 million). As at December 31, 2010, bank operating loans (excluding reclassified outstanding cheques) were nil (2009 and 2008 – nil). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. During 2010, the weighted average interest rate on short-term borrowings was approximately 4.1% (2009 – 6.5%; 2008 – 7.1%).

Asia Pacific Energy Ltd. and Husky Oil China Ltd., subsidiaries of Husky, each have an uncommitted demand revolving facility of U.S. $10 million available for general purposes. As at December 31, 2010 there was no balance outstanding under these facilities. The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. As at December 31, 2010, there was no balance outstanding under this credit facility (2009 and 2008 – nil).

Note 12 Accounts Payable and Accrued Liabilities

($ millions)	2010	2009	2008
Trade payables	**105**	37	93
Accrued liabilities	**2,060**	1,545	1,813
Dividend payable	**255**	255	425
Stock-based compensation	**–**	1	24
Current income taxes	**–**	270	419
Other	**74**	77	122
	2,494	2,185	2,896

Note 13 Long-term Debt

		Cdn $ Amount			U.S. $ Denominated		
($ millions)	Maturity	2010	2009	2008	2010	2009	2008
Long-term debt							
Syndicated credit facility	2012	**380**	–	–	**–**	–	–
6.25% notes [1]	2012	**398**	419	490	**400**	400	400
5.90% notes [2]	2014	**750**	785	–	**750**	750	–
3.75% medium-term notes [2]	2015	**308**	–	–	**–**	–	–
7.55% debentures [2]	2016	**209**	208	245	**200**	200	200
6.20% notes [2]	2017	**316**	312	367	**300**	300	300
6.15% notes	2019	**298**	314	367	**300**	300	300
7.25% notes	2019	**746**	785	–	**750**	750	–
5.00% medium-term notes	2020	**400**	–	–	**–**	–	–
6.80% notes	2037	**385**	405	474	**387**	387	387
Debt issue costs [3]		**(26)**	(26)	(18)	**–**	–	–
Unwound interest rate swaps		**23**	27	32	**–**	–	–
		4,187	3,229	1,957	**3,087**	3,087	1,587

[1] *A portion of the Company's debt is designated in a cash flow hedging relationship for foreign currency risk management. Refer to Note 20.*
[2] *A portion of the Company's debt is designated in a fair value hedging relationship for interest rate risk management and recorded at fair value. Refer to Note 20.*
[3] *Calculated using the effective interest rate method.*

There is no long term debt due within one year as at December 31, 2010 (2009 and 2008 – nil).

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

($ millions)	2010	2009	2008
Interest expense			
Long-term debt	**226**	193	154
Contribution payable	**87**	92	63
Short-term debt	**6**	8	5
	319	293	222
Amount capitalized	**(30)**	(16)	–
	289	277	222
Interest income			
Contribution receivable	**(77)**	(81)	(55)
Other	**(4)**	(2)	(20)
	(81)	(83)	(75)
Interest – net	**208**	194	147

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

($ millions)	2010	2009	2008
(Gain) loss on translation of U.S. dollar denominated long-term debt	**(90)**	(265)	134
(Gain) loss on contribution receivable	**67**	216	(228)
Other (gains) losses	**21**	44	(241)
Gain	**(2)**	(5)	(335)

Other gains and losses include realized and unrealized foreign exchange gains and losses on working capital.

Interest coverage ratios [1]:

	2010	2009	2008
Interest coverage ratios on long-term debt [2] [4]			
Earnings	**7.8**	11.1	34.4
Cash flow	**13.7**	17.4	50.9
Interest coverage ratios on total debt [3] [4]			
Earnings	**7.6**	10.7	33.4
Cash Flow	**13.3**	16.7	49.3

[1] *Interest coverage ratios are presented in compliance with Section 8.4 of National Instrument 44-102 Shelf Distributions.*

[2] *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.*

[3] *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 income taxes divided by interest expense on total debt and capitalized interest. Total debt includes short and long-term debt.*

[4] *Calculated for the 12 months ended for the dates shown.*

Credit Facilities

The Company's revolving syndicated credit facility allows it to borrow up to $1.25 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a five-year committed revolving credit facility. In August 2010, Husky added a second revolving syndicated credit facility that allows the Company to borrow up to $1.5 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a four-year committed revolving credit facility. Interest rates under both revolving syndicated credit facilities vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain rating agencies to the Company's senior unsecured debt.

The Company's $150 million revolving bilateral credit facilities have substantially the same terms as the $1.25 billion syndicated credit facility.

As at December 31, 2010, the Company had borrowings of $380 million under its $1.25 billion revolving syndicated credit facility and no borrowings under its $1.5 billion facility or its bilateral credit facilities. See Note 21 for debt covenants.

In July 2007, the Company obtained U.S. $1.5 billion of short-term bridge financing at an interest rate based on U.S. LIBOR, maturing June 26, 2008, to facilitate closing the acquisition of the Lima, Ohio refinery. On September 11, 2007, the Company refinanced U.S. $750 million with long-term notes. The remaining bridge financing of U.S. $750 million was repaid in June 2008.

Notes and Debentures

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. In 2009, U.S. $1.5 billion of senior notes were issued under this shelf prospectus. The notes are unsecured and rank equally with all of Husky's other unsecured and unsubordinated indebtedness.

On December 21, 2009, Husky filed an additional debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $1 billion of debt securities in Canada until January 21, 2012. 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. On March 12, 2010, Husky issued $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020. The notes are redeemable at the option of the Company at any time, subject to a make whole provision. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of Husky's other unsecured and unsubordinated indebtedness.

On November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $3 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 2012. During the 25-month period that the shelf prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. As of December 31, 2010, only common shares had been issued under the prospectus. (Refer to Note 17).

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

The 5.90% and the 7.25% notes issued in 2009 represent unsecured securities under a trust indenture dated September 11, 2007. Interest is payable semi-annually.

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

The 6.20% and the 6.80% notes represent unsecured securities under a trust indenture dated September 11, 2007. During 2008, the Company repurchased U.S. $63 million of the 6.80% notes. Interest is payable semi-annually.

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

The Company's notes, debentures, credit facilities and short-term lines of credit rank equally.

Note 14 Other Long-term Liabilities

($ millions)	**2010**	2009	2008
Asset retirement obligations	**1,150**	793	711
Cross currency swaps *(note 20)*	**102**	92	33
Employee future benefits *(note 18)*	**92**	81	81
Capital lease obligations	**34**	36	44
Other	**39**	34	29
	1,417	1,036	898

Asset Retirement Obligations

At December 31, 2010, the estimated total undiscounted inflation-adjusted amount required to settle outstanding asset retirement obligations was $7.6 billion (2009 – $5.9 billion; 2008 – $5.4 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using credit-adjusted risk free rates ranging from 6.2% to 9.6%.

Changes to the asset retirement obligations were as follows:

($ millions)	2010	2009	2008
Asset retirement obligations at beginning of year	**793**	711	662
Liabilities incurred/acquired, net of revisions	**365**	79	56
Liabilities disposed	**(1)**	(4)	(5)
Liabilities settled	**(60)**	(41)	(56)
Accretion [1]	**53**	48	54
Asset retirement obligations at end of year	**1,150**	793	711

[1] *Accretion is included in cost of sales and operating expenses.*

Note 15 Income Taxes

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

($ millions)	2010	2009	2008
Earnings (loss) before income taxes			
Canada	**1,875**	2,195	5,687
United States	**(251)**	(51)	(820)
Other foreign jurisdictions	**(66)**	(187)	278
	1,558	1,957	5,145
Statutory income tax rate *(percent)*	**29.0**	30.0	30.6
Expected income tax	**452**	587	1,574
Effect on income tax of:			
Change in statutory tax rate	**-**	(1)	–
Rate benefit on partnership earnings	**(26)**	(27)	(60)
Capital gains and losses	**(5)**	(11)	(19)
Foreign jurisdictions	**(19)**	19	(102)
Other - net	**(17)**	(26)	1
Income tax expense	**385**	541	1,394

In 2009, a tax rate benefit of approximately $1 million was recognized related to a reduction in the Ontario provincial corporate tax rate.

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

($ millions)	2010	2009	2008
Future tax liabilities			
Property, plant and equipment	**4,694**	4,478	5,226
Foreign exchange gains taxable on realization	**91**	81	92
Other temporary differences	**3**	23	2
	4,788	4,582	5,320
Future tax assets			
Asset retirement obligations	**325**	230	207
Loss carry forwards	**311**	369	348
Other temporary differences	**37**	51	52
	673	650	607
	4,115	3,932	4,713

At December 31, 2010, the Company had $818 million of U.S. tax losses that will expire between 2028 and 2030.

Note 16 Commitments and Contingencies

At December 31, 2010, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

($ millions)	2011	2012	2013	2014	2015	After 2015	Total
Interest on fixed rate long-term debt	232	220	207	185	158	998	2,000
Operating leases	105	96	73	64	57	117	512
Firm transportation agreements	166	142	132	161	170	3,197	3,968
Unconditional purchase obligations [1]	1,970	1,126	154	29	21	122	3,422
Lease rentals and exploration work agreements	98	66	49	160	78	491	942
	2,571	1,650	615	599	484	4,925	10,844

[1] *Includes purchases of refined petroleum products, processing services, distribution services, insurance premiums, drilling rig services and natural gas purchases.*

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

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

Note 17 Share Capital

The Company's authorized share capital is as follows:

Common shares – an unlimited number of no par value.

Preferred shares – an unlimited number of no par value, with no shares outstanding as at December 31, 2010.

Common Shares

Changes to issued common shares were as follows:

($ millions)	Number of Shares	Amount
December 31, 2007	848,960,310	3,551
Options exercised	394,500	17
December 31, 2008	849,354,810	3,568
Options exercised	506,125	17
December 31, 2009	849,860,935	3,585
Common shares issued, net of share issue costs	40,816,326	988
Options exercised	31,534	1
December 31, 2010	**890,708,795**	**4,574**

With respect to the Securities referred to in Note 13, Husky issued 11.9 million common shares at a price of $24.50 per share for total gross proceeds of $293 million via an overnight-marketed public offering. The Company also issued a total of 28.9 million common shares to the principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. at a price of $24.50 per share for total gross proceeds of $707 million.

Stock Options

At December 31, 2010, 49.2 million common shares were reserved for issuance under the Company stock option plan. The stock option plan is a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the weighted average trading price of the Company's common shares during the five trading days prior to the date of the award. For options granted prior to 2010, when the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. For options granted in 2010, when the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares for the five trading days following the surrender date and the exercise price of the option.

Under the terms of the original stock option plan, the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year. Performance options granted may vest in up to one-third increments if the Company's annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to its industry peer group. The ultimate number of performance options that vest will depend upon the Company's performance measured over three calendar years. If the Company's performance is below the specified level compared with its industry peer group, the performance options awarded will be forfeited. If the Company's performance is at or above the specified level compared with its industry peer group, the number of performance options exercisable shall be determined by the Company's relative ranking. Stock compensation expense related to the performance options is accrued based on the price of the common shares at the end of the period and the anticipated performance factor. This expense is recognized over the three-year vesting period of the performance options.

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

	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Options Exercisable *(thousands)*
December 31, 2007	30,131	$ 37.18	4	4,494
Granted	7,596	$ 41.18	5	
Exercised for common shares	(395)	$ 13.65	1	
Surrendered for cash	(4,132)	$ 22.50	1	
Forfeited	(2,373)	$ 41.58	3	
December 31, 2008	30,827	$ 40.10	3	7,239
Granted	1,187	$ 30.32	4	
Exercised for common shares	(506)	$ 12.57	–	
Surrendered for cash	(765)	$ 13.16	–	
Forfeited	(2,344)	$ 41.59	2	
December 31, 2009	28,399	$ 40.78	3	14,917
Granted	8,870	$ 27.95	4	
Exercised for common shares	(31)	$ 24.14	–	
Surrendered for cash	(39)	$ 23.24	–	
Forfeited	(7,658)	$ 40.50	2	
December 31, 2010	**29,541**	**$ 37.04**	**3**	**17,325**

As at December 31, 2010	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices
$25.41 - $29.99	9,277	$ 28.08	4	102	$ 29.81
$30.00 - $34.99	1,692	$ 31.65	3	928	$ 31.96
$35.00 - $39.99	881	$ 38.48	1	680	$ 38.04
$40.00 - $42.99	14,557	$ 41.58	1	13,976	$ 41.61
$43.00 - $45.02	3,134	$ 45.02	3	1,639	$ 45.02
	29,541	**$ 37.04**	**3**	**17,325**	**$ 41.20**

Performance Share Units

In May 2010, the Board of Directors of Husky established the Performance Share Unit Plan for certain officers and employees of the Company. A PSU is a time-vested award entitling participants to receive cash based on the Company's share price at the time of vesting. The amount of cash is contingent on the Company's total shareholder return relative to a peer group of companies. During 2010, 245,000 PSUs were granted to senior management and 25,000 PSUs were forfeited. As at December 31, 2010, 220,000 PSUs were outstanding.

Dividends

During 2010, the Company declared dividends of $1.20 per common share (2009 – $1.20 per common share; 2008 – $1.73 per common share).

Note 18 Employee Future Benefits

At December 31, 2010, the accrued benefit liability for the post-retirement health and dental care plan in Canada was $59 million (2009 – $50 million; 2008 – $43 million). The accrued benefit liabilities for the defined benefit pension plan and the post-retirement welfare plan in the U.S. were $2 million (2009 – $1 million; 2008 – less than $1 million) and $31 million (2009 – $30 million; 2008 – $38 million) respectively. The total employee future benefits liability for the Company included in other long-term liabilities was $92 million at December 31, 2010 (2009 – $81 million; 2008 – $81 million).

Canada

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

a) Defined Benefit Pension Plan

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

	2010	2009	2008
Discount rate for pension benefit expense *(percent)*	**5.7**	6.3	5.0
Discount rate for accrued benefit obligation at December 31 *(percent)*	**5.0**	5.7	6.3
Long-term rate of increase in compensation levels *(percent)*	**5.0**	5.0	5.0
Long-term rate of return on plan assets *(percent)*	**7.0**	7.0	7.0

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

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

Benefit Obligation *($ millions)*	**2010**	2009	2008
Benefit obligation, beginning of year	**141**	132	150
Current service cost	**1**	2	2
Interest cost	**8**	8	8
Benefits paid	**(9)**	(10)	(9)
Actuarial (gains) losses	**12**	9	(19)
Benefit obligation, end of year	**153**	141	132

Fair Value of Plan Assets *($ millions)*	**2010**	2009	2008
Fair value of plan assets, beginning of year	**119**	110	141
Contributions	**11**	5	6
Benefits paid	**(9)**	(10)	(9)
Expected return on plan assets	**8**	8	10
Gain (loss) on plan assets	**5**	6	(38)
Fair value of plan assets, end of year	**134**	119	110

Funded Status of Plan *($ millions)*	**2010**	2009	2008
Fair value of plan assets	**134**	119	110
Benefit obligation	**(153)**	(141)	(132)
Excess obligation	**(19)**	(22)	(22)
Unrecognized past service costs	**1**	2	2
Unrecognized losses	**48**	46	50
Accrued benefit asset	**30**	26	30

Husky adheres to a Statement of Investment Policies and Procedures (the "Policy"). The assets are allocated in accordance with the long-term nature of the obligation and comprise a balanced investment based on interest rate and inflation sensitivities. The Policy explicitly prescribes diversification parameters for all classes of investment.

The measurement date of the plan assets and the accrued benefit obligation was December 31, 2010. The most recent actuarial valuation of the plan was December 31, 2009 and the next actuarial valuation is scheduled to occur no later than December 31, 2012.

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

	2010	2009	2008
U.S. common equities	**–%**	–%	1%
Canadian common equities	**37**	32	26
International equity mutual funds	**20**	21	23
Canadian government bonds	**13**	15	18
Canadian corporate bonds	**6**	5	4
International fixed income	**–**	1	1
Canadian fixed income mutual funds	**23**	25	25
Cash and receivables	**1**	1	2
Total	**100%**	100%	100%

During 2010, Husky contributed $11.4 million to the defined benefit pension plan assets, $10.1 million of which was in respect of additional contributions as a result of the plan's deficiency. Husky currently plans to contribute $9.2 million in 2011.

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

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

b) Post-retirement Health and Dental Care Plan

The discount rate used in the calculation of the benefit obligation at December 31, 2010 was 5.2%. The average health care cost trend rate used was 9.0% for 2011, which is reduced by 0.5% per year for eight years to 5.0% in 2019 and thereafter. The average dental care cost trend used was 4%, which remains constant.

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

Benefit Obligation *($ millions)*	2010	2009	2008
Benefit obligation, beginning of year	**65**	53	54
Current service cost	**5**	4	4
Interest cost	**4**	4	3
Benefits paid	**(1)**	(1)	(1)
Actuarial (gains) losses	**10**	5	(7)
Benefit obligation, end of year	**83**	65	53

Funded Status of Plan *($ millions)*	2010	2009	2008
Benefit obligation	**(83)**	(65)	(53)
Unrecognized losses	**24**	15	10
Accrued benefit liability	**(59)**	(50)	(43)

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

($ millions)	1% Increase	1% Decrease
Effect on total service and interest cost components	2.0	(1.4)
Effect on post-retirement benefit obligation	14.9	(12.0)

c) Pension Expense and Post-retirement Health and Dental Care Expense

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

Pension Expense *($ millions)*	2010	2009	2008
Defined benefit pension plan			
Employer current service cost	**1**	2	2
Interest cost	**8**	8	8
Expected return on plan assets	**(8)**	(8)	(10)
Amortization of net actuarial losses	**6**	7	3
	7	9	3
Defined contribution pension plan	**22**	21	20
Total expense	**29**	30	23

Post-retirement Health and Dental Care Expense *($ millions)*	2010	2009	2008
Employer current service cost	**5**	4	4
Interest cost	**4**	4	3
Amortization of net actuarial losses	**–**	–	1
Total expense	**9**	8	8

d) Future Benefit Payments

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

($ millions)	Defined Benefit Pension Plan	Post-retirement Health and Dental Care Plan
2011	10	1
2012	10	2
2013	10	2
2014	10	2
2015	11	3
2016 - 2020	54	18

United States

a) Defined Benefit Pension Plan

As at December 31, 2010, the benefit obligation was $13 million (2009 – $8 million; 2008 – $5 million) and the fair value of the plan assets was $8 million (2009 – $5 million; 2008 – $4 million). The discount rate used at the end of 2010 to determine the accrued benefit obligation was 4.7% (2009 – 5.4%; 2008 – 6.0%). During 2010 Husky contributed $3 million to the defined benefit pension plan assets and currently plans to contribute $3 million in 2011.

Pension expense for 2010 was $4 million (2009 – $3 million; 2008 – $2 million).

The measurement date of the plan assets and the accrued benefit obligation was December 31, 2010. The most recent actuarial valuation of the plan was January 1, 2010 and the next actuarial valuation is scheduled to occur no later than January 1, 2011.

b) Defined Contribution Pension Plan

The Company's contribution to the U.S. 401(k) plan was $2.9 million in 2010 (2009 – $3.3 million; 2008 – $2.6 million).

c) Post-retirement Welfare Plan

As at December 31, 2010, the benefit obligation was $12 million (2009 – $11 million; 2008 – $13 million). The discount rate used at the end of 2010 to determine the accrued benefit obligation was 4.9% (2009 – 5.4%; 2008 – 6.1%).

Post-retirement welfare expense for 2010 was a recovery of $2 million (2009 – $2 million recovery; 2008 – $3 million expense).

Note 19 Related Party Transactions

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. These notes were offered through an existing base shelf prospectus, which was filed with the U.S. Securities and Exchange Commission in February 2009. The coupon rates offered were 5.90% and 7.25% for the 5- and 10-year tranches respectively. Subsequent to this offering, U.S. $65 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. 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, 2010, the senior notes are included in long-term debt on the Company's balance sheet.

On December 7, 2010, Husky issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million via a private placement to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

A related party 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. These transactions occur in the normal course of business and have been measured at the exchange amount. For 2010, the total value of natural gas sales to the

Meridian and other cogeneration facilities owned by TACLP was $44 million (2009 – $90 million; 2008 – $125 million). At December 31, 2010, the total value of accounts receivables related to these transactions was nil (2009 and 2008 – nil). The Company and TACLP agreed to sell the Meridian cogeneration facility in February 2011. (Refer to Note 23 d).

Note 20 Financial Instruments and Risk Factors

Details of the Company's significant accounting policies and risk management for the recognition and measurement of financial instruments and the basis for which income and expense are recognized are disclosed in Note 3, "Significant Accounting Policies."

Risk Management Overview

The Company is exposed to market risks related to the volatility of commodity prices, interest rates and foreign exchange rates. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks. The Company employs risk management strategies and policies to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels. Risk management is ultimately established by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

Husky is exposed to risk factors associated with operating in developing countries, political and regulatory instability. The Company monitors the changes to regulations and government policies in the areas within which it operates.

Fair Value of Financial Instruments

The Company's financial instruments as at December 31, 2010 included cash and cash equivalents, accounts receivable, contribution receivable, accounts payable and accrued liabilities, long-term debt, contribution payable, the derivative portion of cash flow hedges, fair value hedges and freestanding derivatives.

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

At December 31, 2010, the carrying value of the contribution receivable and contribution payable was $1.3 billion (2009 – $1.3 billion; 2008 – $1.5 billion) and $1.4 billion (2009 – $1.5 billion; 2008 – $1.7 billion) respectively. The fair value of these financial instruments is not readily determinable due to uncertainties regarding timing of the cash flows. Refer to Note 8, "Joint Ventures."

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 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.

The financial instruments recorded at fair value on the balance sheet at December 31 was as follows:

($ millions)	**2010**	2009	2008
Financial assets at fair value			
Trading derivatives	**34**	22	111
Financial liabilities at fair value			
Trading derivatives	**12**	16	23

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability.

The fair value of long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability. The estimated fair value of long-term debt at December 31 was as follows:

	2010		2009		2008	
($ millions)	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	**4,187**	**4,578**	3,229	3,559	1,957	1,739

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk and other price risk, for example, commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns.

In certain instances, the Company uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

The Company's results will also be impacted by a decrease in the price of crude oil. The Company holds crude oil inventories that are feedstock or part of the in-process inventories at its refineries. These inventories are subject to a lower of cost or net realizable value test on a monthly basis and the Company is exposed to declining crude prices.

The Company's results are affected by the exchange rate between the Canadian and U.S. dollar. 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. The majority of the Company's expenditures are in Canadian dollars.

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related interest expense. In order to mitigate the Company's exposure to long-term debt affected by the U.S./Canadian dollar exchange rate, the Company has entered into cash flow hedges using cross currency debt swaps. In addition, a portion of the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment in a self-sustaining foreign operation and the unrealized foreign exchange gain is recorded in OCI.

To mitigate risk related to interest rates, the Company may enter into fair value hedges using interest rate swaps. The Company's objectives, processes and policies for managing market risk have not changed from the previous year.

Commodity Price Risk Management

a) Natural Gas Contracts

At December 31, 2010, the Company had the following third party offsetting physical purchase and sale natural gas contracts, which met the definition of a derivative instrument:

($ millions)	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	14,696	(1)
Physical sale contracts	(14,696)	2

These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized loss of $2 million (2009 – gain of $1 million; 2008 – gain of less than $1 million) has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

b) Natural Gas Storage Contracts

At December 31, 2010, the Company had the following third party physical purchase and sale natural gas storage contracts:

($ millions)	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	2,504	–
Physical sale contracts	(37,255)	31

The third party physical purchase and sale contracts have been recorded at their fair value in accrued liabilities and accounts receivable respectively. At December 31, 2010, the balance sheet position of these contracts was $31 million recorded in accounts receivable (2009 – $13 million in accounts receivable; 2008 – $51 million in accounts receivable). The change in the fair value of these contracts resulted in an unrealized gain of $18 million (2009 – unrealized loss of $38 million; 2008 – unrealized gain of $50 million) which has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

At December 31, 2010, the Company also had financial natural gas storage contracts. Natural gas inventories held in storage relating to these contracts are recorded at fair value. At December 31, 2010, the fair value of the inventories was $131 million (2009 – $173 million; 2008 – $222 million). The cumulative fair value change on this inventory as of December 31, 2010 was an unrealized loss of $6 million (2009 – unrealized gain of $45 million; 2008 – unrealized loss of $24 million). The change in the fair value of inventory resulted in an unrealized loss of $51 million (2009 – unrealized gain of $69 million; 2008 – unrealized loss of $24 million) which has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

c) Oil Contracts

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.

At December 31, 2010, the Company had the following third party crude oil purchase contracts which have been designated as a fair value hedge:

($ millions)	Volumes *(bbls)*	Fair Value
Physical purchase contracts	326,382	(2)

These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of $2 million (2009 - gain of $4 million; 2008 – n/a) 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, 2010, the fair value of the inventory was $30 million (2009 – $124 million; 2008 – n/a), resulting in an unrealized loss of $2 million (2009 – loss of $1 million; 2008 – n/a) recorded in earnings in the Consolidated Statements of Earnings and Comprehensive Income.

The Company enters into certain crude oil purchases and sale contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered.

($ millions)	Volumes *(mbbls)*	Fair Value
Physical purchase contracts	3,001	(271)
Physical sale contracts	(3,001)	248

These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities. At December 31, 2010, a resulting unrealized loss of $8 million was recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income. A portion of the crude oil inventory is sold to third parties. This inventory is considered held for trading and as such, has been recorded at its fair value. At December 31, 2010, the fair value of inventory was $72 million, resulting in a $6 million unrealized gain recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

The Company has 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. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at December 31, 2010, the fair value of these contracts was $1 million resulting in a loss of $1 million (2009 – loss of $30 million) recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Interest Rate Risk Management

At December 31, 2010, the Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the long-term debt was swapped to floating rates with the following terms:

Notional Amount *($ millions)*		Swap Maturity	Swap Rate [1] *(percent)*	Fair Value *($ millions)*
U.S.	200	November 15, 2016	LIBOR + 417 bps	10
U.S.	300	September 15, 2017	LIBOR + 264 bps	18
U.S.	150	June 15, 2014	LIBOR + 350 bps	5
Cdn	300	March 12, 2015	CDOR + 0.83%	8

[1] *Weighted average rate.*

During 2010, these swaps resulted in an offset to interest expense amounting to $23 million (2009 – offset of less than $1 million; 2008 – offset of less than $1 million). The amortization of previous interest rate swap terminations resulted in an addition to interest expense of $2 million (2009 – offset of $3 million; 2008 – offset of $5 million).

The Company had a freestanding derivative that required the payment of amounts based on a floating interest rate of CDOR + 175 bps in exchange for receipt of payments based on a fixed interest rate of 6.95% on $200 million of long-term debt effective February 8, 2002 that expired on July 14, 2009. In 2008, the interest rate swap was discontinued as a fair value hedge as the underlying debt was redeemed. For the year ended December 31, 2009, the Company recognized a loss of less than $1 million (2008 – gain of $1 million) on the interest swap arrangements recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Foreign Currency Risk Management

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

At December 31, 2010, the Company had a cash flow hedge using the following cross currency debt swaps:

Debt	Swap Amount *($ millions)*		Canadian Equivalent *($ millions)*	Swap Maturity	Interest Rate *(percent)*	Fair Value *($ millions)*
6.25% notes	U.S.	150	211	June 15, 2012	7.41	(68)
6.25% notes	U.S.	75	89	June 15, 2012	5.65	(14)
6.25% notes	U.S.	50	59	June 15, 2012	5.67	(8)
6.25% notes	U.S.	75	88	June 15, 2012	5.61	(12)

These contracts have been recorded at fair value in other long-term liabilities. The effective portion of the gain or loss related to measuring the contract at fair value has been included in OCI. As at December 31, 2010, the unrealized foreign exchange gain of $6 million (2009 – $2 million gain; 2008 – $6 million loss), net of tax of $2 million (2009 – $1 million; 2008 – $2 million) is recorded in OCI. At December 31, 2010, the balance in Accumulated Other Comprehensive Income was $2 million (2009 – $7 million; 2008 – $10 million), net of tax of less than $1 million (2009 – $3 million; 2008 – $4 million).

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. For the year ended December 31, 2010, the impact of these contracts was a realized gain of $26 million (2009 – gain of $16 million; 2008 – loss of $34 million) recorded in foreign exchange expense.

As at December 31, 2010, the Company has designated U.S. $987 million (2009 – $687 million) of its U.S. debt as a hedge of the Company's net investments in the U.S. refining operations, which are considered self-sustaining. In 2010, the unrealized foreign exchange gain arising from the translation of the debt was $44 million (2009 – gain of $104 million), net of tax expense of $7 million (2009 – expense of $18 million), which was recorded in OCI.

Sensitivity Analysis

A sensitivity analysis for foreign currency, commodities and interest rate risks has been calculated by increasing or decreasing the interest rate or foreign currency exchange rate, as appropriate, in the fair value methodologies described in the "Fair Value of Financial Instruments" section of this note. These sensitivities represent the effect resulting from changing the relevant rates with all other variables held constant and have been applied only to financial instruments. The Company's process for determining these sensitivities has not changed during the year. All calculations are on a pre-tax basis.

The Company is exposed to interest rate risk on its interest rate swaps. As at December 31, 2010, had interest rates been 50 basis points higher and assuming all other variables remained constant, the impact to earnings before tax would have been $21 million lower (2009 – $12 million lower; 2008 – less than $1 million lower). Had interest rates been 50 basis points lower and assuming all other variables remained constant, the impact to earnings before tax would have been $24 million higher (2009 – $14 million higher; 2008 – less than $1 million higher).

The Company is exposed to interest rate and foreign currency risk on its cross currency debt swaps. As at December 31, 2010, had the Canadian dollar been 1% stronger versus the U.S. dollar and assuming all other variables remained constant, the impact to OCI would have been $1 million lower (2009 – $5 million lower; 2008 – $4 million lower). Had the Canadian dollar been 1% weaker versus the U.S. dollar and assuming all other variables remained constant, the impact to OCI would have been $6 million higher (2009 – $5 million higher; 2008 – $7 million higher). As at December 31, 2009, had the interest rates been 50 basis points higher and assuming all other variables remained constant, the impact to OCI would have been $2 million higher (2008 and 2009 – $2 million higher). Had the interest rates been 50 basis points lower and assuming all other variables remained constant, the impact to OCI would have been less than $1 million lower (2009 – $1 million lower; 2008 – $7 million lower).

The Company is exposed to foreign currency risk on its forward purchases of U.S. dollars. As at December 31, 2010, had the Canadian dollar been 1% stronger relative to the U.S. dollar and assuming all other variables remained constant, the impact to earnings before tax would have been less than $1 million lower (2009 – less than $1 million lower; 2008 – $2 million lower). Equal and offsetting impacts would have occurred had the Canadian dollar been 1% weaker relative to the U.S. dollar and assuming all other variables remained constant.

The Company is exposed to commodity price risk on its natural gas storage contracts. As at December 31, 2010, had the forward price been $0.20/mmbtu higher, the impact to earnings before tax would have been $3 million lower (2009 and 2008 – $7 million lower). Had the forward price been $0.20/mmbtu lower, the impact to earnings before tax would have been $3 million higher (2009 and 2008 – $7 million higher).

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet 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 meet 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.

Since the Company operates in the upstream oil and gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production and develop reserves, to acquire strategic oil and gas assets, to repay maturing debt and to pay dividends. The Company's upstream capital programs are funded principally by cash provided from operating activities and available credit facilities. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of long and short-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines.

The Company has the following available credit facilities as at December 31, 2010:

Credit Facilities *($ millions)*	Available	Unused
Operating facilities	415	299
Syndicated bank facilities	2,750	2,370
Bilateral credit facilities	150	150
Total	3,315	2,819

In addition to the credit facilities listed above, the Company has unused capacity under shelf prospectuses of U.S. $1.5 billion and $3.0 billion, the availability of which is dependent on market conditions. The Company believes it has sufficient funding through the use of these facilities to meet its future borrowing requirements. The following are the contractual maturities of financial liabilities as at December 31, 2010:

Financial Liability *($ millions)*	2011	2012	2013	2014	2015	After 2015
Accounts payable and accrued liabilities	2,494	–	–	–	–	–
Cross currency swaps	–	447	–	–	–	–
Long-term debt	–	782	–	753	303	2,349

The following are contractual maturities of non-financial liabilities as at December 31, 2010:

Non-Financial Liability *($ millions)*	2011	2012	2013	2014	2015	After 2015
Asset retirement obligations	10	9	9	9	9	1,105

The Company's contribution payable to the joint venture with BP (refer to Note 8) is payable between December 31, 2010 and December 31, 2015, with the final balance due and payable by December 31, 2015.

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

Credit Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial instrument, in owing an amount to the Company, fail to meet or discharge their obligation to the Company. The Company's accounts receivable are broad based with customers in the energy industry, midstream and end user segment and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial reassurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company did not have any customers that constituted more than 10% of total sales and operating revenues during 2010.

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

Cash and cash equivalents include cash bank balances and short-term deposits with original maturities of less than 90 days. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits.

The carrying amount of accounts receivable, contribution receivable, and cash and cash equivalents represents the maximum credit exposure. The Company's accounts receivable excluding income taxes receivable and doubtful accounts was aged as follows:

Aging *($ millions)*	Dec. 31, 2010
Current	**1,110**
Past due (1 - 30 days)	**68**
Past due (31 - 60 days)	**5**
Past due (61 - 90 days)	**4**
Past due (more than 90 days)	**15**
Total	**1,202**

The movement in the Company's allowance for doubtful accounts for 2010 was as follows:

($ millions)	
Balance at January 1, 2010	18
Provisions and revisions	1
Balance at December 31, 2010	**19**

The Company did not write off any uncollectible receivables in 2010.

Held-for-Trading Financial Liabilities

The Company's cross currency swaps have been designated as a cash flow hedge and the derivative component of the hedge meets the definition of a held-for-trading financial liability. The cross currency swap counterparties' credit profiles have not materially changed since the past year or since inception. As a result, the amount of change during the period and cumulatively in the fair value of the cross currency swaps has not been materially impacted by changes resulting from credit risk. At December 31, 2010, the amount the Company would be contractually required to pay under the cross currency swaps at maturity was $346 million higher (December 31, 2009 – $356 million higher; December 31, 2008 – $414 million higher) than their carrying amount.

Embedded Derivative

During the fourth quarter of 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 $71 million, after tax, was recorded in 2008 compared with a gain of $71 million, after tax, for the same period in 2007.

Note 21 Capital Disclosures

The Company's objectives when managing capital are: (i) to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk; and (ii) to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of its underlying assets. The Company considers its capital structure to include shareholders' equity and debt. To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors capital based on the current and projected ratios of debt to cash flow from operations (defined as total debt divided by earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital) and debt to capital employed (defined as total debt divided by total debt and shareholders' equity). The Company's objective is to maintain a debt to cash flow from operations ratio of less than 2.5 times and a debt to capital employed target of 25% to 35%. At December 31, 2010, debt to capital employed was 21.3% (2009 – 18.3%; 2008 – 12.0%) which was below the long-term range, providing the financial flexibility to fund the Company's capital program and profitable growth opportunities. At December 31, 2010, debt to cash flow from operations was 1.2 times (2009 – 1.3 times; 2008 – 0.3 times). The ratio may increase at certain times as a result of acquisitions. To facilitate the management of this ratio, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions; however the bilateral credit facilities and the syndicated credit facilities include a debt to cash flow covenant. The Company was fully compliant with this covenant at December 31, 2010.

There were no changes in the Company's approach to capital management from the previous year.

Note 22 Government Assistance

Husky has government assistance programs in place where it receives funding based on ethanol sales volume from the Lloydminster and Minnedosa ethanol plants. Applications for funding from the Department of Natural Resources and the Government of Manitoba are submitted on a monthly and quarterly basis, respectively. The programs expire in 2015. Prior to the second quarter of 2010, funding received was based on ethanol production margins. In the second quarter of 2010, amendments were made to the terms under these programs which require funding to be based on ethanol sales volume. The following government funding was received during the year:

($ millions)	**2010**	2009	2008
First Quarter	**17**	11	–
Second Quarter	**15**	16	–
Third Quarter	**9**	13	1
Fourth Quarter	**9**	13	17
Total funding received	**50**	53	18

Prior to the second quarter of 2010, funding received under these programs was recorded in cost of sales; beginning in the second quarter of 2010, the company recorded funding received under these programs in sales in the Consolidated Statements of Earnings and Comprehensive Income.

Note 23 Subsequent Events

a) ExxonMobil Asset Acquisition

On November 29, 2010, the Company announced that it had signed a purchase and sale agreement with ExxonMobil Canada Ltd. to acquire oil and natural gas properties in Alberta and northeast British Columbia for $860 million. The effective date of the transaction was December 1, 2010. The transaction closed on February 4, 2011. Total consideration at closing was $826 million.

b) Sale of Oil Sands Leases

On January 14, 2011, the Company completed a sales agreement to sell 23 square miles of mining leases in Alberta for a consideration of $200 million resulting in a gain, subject to adjustments, of approximately $177 million accounted for under IFRS. The first installment of $100 million was received on January 14, 2011; the second installment of $100 million is due and payable on January 13, 2012.

c) Completion of 10% Interest Sale of HOML

In October 2010, both HOMP and CNOOCSE agreed to each sell a 10% equity share in HOML to Samudra Energy Ltd. through its affiliate, SMS Development Ltd. ('SMS"). Following the completion of the sale, HOMP and CNOOCSE will each hold a 40% equity interest in HOML with the remaining 20% balance held by SMS. This sale closed on January 13, 2011, resulting in a gain of approximately $10 million for the Company accounted for under IFRS. Husky's share of the consideration was U.S. $12.5 million in cash and a deferred purchase price for the balance of U.S. $12.5 million which bears interest at a rate of 5% and is payable to the Company from SMS's share of future distributions.

d) Sale of the Meridian Cogeneration Facility

Husky holds a 50% interest in the Meridian cogeneration facility, a 215 MW natural gas fired cogeneration facility at the site of the Lloydminster Upgrader. TACLP is the Company's joint venture partner for the Meridian cogeneration facility. In February 2011, Husky and TACLP agreed to sell the cogeneration facility to a related party. Completion of the transaction is subject to consent from Saskatchewan Power Corporation as well as regulatory approval. The transaction is expected to be completed by April 2011.

e) Amendments to Common Share Terms

In the Special Meeting of Shareholders held on February 28, 2011, Husky's shareholders approved amendments to the common share terms, which provide the shareholders with the ability to receive dividends in common shares or in cash. Quarterly dividends would be declared in an amount expressed in dollars per common share and would be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares would be calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares. A shareholder must deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend confirming they will accept the dividend in common shares. Failure to do so will result in such shareholder receiving the dividend paid in cash.

Note 24 First-Time Adoption of International Financial Reporting Standards

As part of the Company's transition to IFRS, the Company has prepared the Consolidated Balance Sheets as at January 1, 2010 and December 31, 2010 and the Statement of Total Comprehensive Income for the year ended December 31, 2010 to establish the opening balance sheet of the Company and the comparative 2010 results expected to be presented to the shareholders as part of the Company's first IFRS interim report as at March 31, 2011 and IFRS financial statements as at December 31, 2011.

For all periods up to and including the year ended December 31, 2010, the Company has prepared its financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). Together with other publicly reportable enterprises in Canada starting in 2011, the Company is required to prepare consolidated financial statements in accordance with IFRS. Accordingly, in advance of the first IFRS reporting date for purposes of preparing comparative 2010 IFRS information, the Company has prepared Consolidated Balance Sheets as at January 1, 2010 and December 31, 2010 and a Statement of Total Comprehensive Income for the year ended December 31, 2010, using the following IFRS accounting policies and IFRS 1 elections.

The IFRS accounting policies provided in this note are only those policies that are expected to differ from the Company's stated Canadian GAAP accounting policies. The Company has chosen accounting policies based on the IFRSs in effect as at December 31, 2010 and prepared an assessment of the adjustments to be made by the Company to its Canadian GAAP Consolidated Balance Sheets as at January 1, 2010 and December 31, 2010 and its comparative Canadian GAAP Total Comprehensive Income for the year ended December 31, 2010 to comply with IFRS.

The impact of transition to IFRS presented in this note may require adjustment when it is incorporated as part of the first IFRS financial statements reported to shareholders in 2011. The adjustment may arise as a result of early adoption of any IFRS issued in 2011 that become effective after December 31, 2011 or as a result of new standards, amendments to standards or interpretations thereto issued by the IASB.

Key First-Time Adoption Exemptions to be Applied

IFRS 1 allows first-time adopters certain exemptions from retrospective application of certain IFRSs.

The Company plans to apply the following exemptions:

- Certain oil and gas assets in property, plant and equipment on the balance sheet were recognized and measured on a full cost basis in accordance with Canadian GAAP. The Company has elected to measure its Canadian properties at the amount determined under Canadian GAAP as at January 1, 2010. Costs included in the full cost pool on January 1, 2010 were allocated on a pro-rata basis to the underlying assets on the basis of proved developed reserve volumes as at January 1, 2010. Associated decommissioning assets were also measured at their carrying value under previous Canadian GAAP while all decommissioning liabilities were measured using a consistent credit-adjusted risk free rate, with a corresponding adjustment recorded to opening retained earnings. The Company has elected not to apply the IFRS 1 full cost exemption to its International upstream properties.
- IFRS 3, "Business Combinations," has not been applied to acquisitions of subsidiaries or interests in joint ventures that occurred before January 1, 2010.
- The Company has elected to apply International Accounting Standards ("IAS") 23, "Borrowing Costs," with an effective date of January 1, 2003 which requires mandatory capitalization of borrowing costs directly attributable to the acquisition, construction or production of qualifying assets. De-recognition of previously capitalized borrowing costs in accordance with Canadian GAAP did not have a material impact to the Company.
- The Company has recognized all cumulative actuarial gains and losses on pensions and other post-retirement benefits in retained earnings as at January 1, 2010.
- Cumulative currency translation differences for all foreign operations are deemed to be zero as at January 1, 2010. Accordingly, all cumulative foreign exchange gains and losses in the Company's cumulative foreign currency translation account have been recognized in retained earnings at January 1, 2010.
- IFRS 2, "Share-based Payment," has not been applied to equity instruments related to stock-based compensation arrangements that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2010. For cash-settled share-based payment transactions, the Company has not applied IFRS 2 to liabilities that were settled before January 1, 2010.
- The Company has not reassessed any arrangements to determine whether they contain a lease if they have already been assessed under Canadian GAAP. Additionally, any arrangements that have not been assessed under Canadian GAAP have been assessed under International Financial Reporting Interpretations Committee ("IFRIC") 4, "Determining Whether an Arrangement Contains a Lease," based on terms and conditions existing at January 1, 2010.

Significant Changes in Accounting Policies

Please refer to the notes that follow the detailed reconciliations.

Reconciliation of Equity at January 1, 2010 (Date of Transition to IFRS)

(millions of dollars)	Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets			
Current assets			
Cash and cash equivalents	392	–	392
Accounts and notes receivable	987	–	987
Inventories	1,520	–	1,520
Prepaid expenses	12	–	12
	2,911	–	2,911
Exploration and evaluation assets *(notes a, d, j)*	–	1,943	1,943
Property, plant and equipment *(notes a, c, d, e, f, h)*	21,288	(2,704)	18,584
Goodwill	689	–	689
Contribution receivable	1,313	–	1,313
Other assets *(note b)*	94	(26)	68
	26,295	(787)	25,508
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes d, f, g)*	1,915	26	1,941
Income taxes payable	270	–	270
	2,185	26	2,211
Long-term debt	3,229	–	3,229
Other long-term financial liabilities	96	–	96
Other long-term liabilities *(notes b, c, d, g, i)*	147	137	284
Contribution payable	1,500	–	1,500
Asset retirement obligations *(notes d, f)*	793	(26)	767
Deferred tax liabilities *(note l)*	3,932	(227)	3,705
	11,882	(90)	11,792
Shareholders' equity			
Common shares	3,585	–	3,585
Retained earnings *(note m)*	10,832	(733)	10,099
Other reserves *(note d)*	(4)	36	32
	14,413	(697)	13,716
	26,295	(787)	25,508

Reconciliation of Equity at December 31, 2010

(millions of dollars)	Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets			
Current assets			
Cash and cash equivalents	252	–	252
Accounts and notes receivable	1,529	–	1,529
Inventories	1,935	–	1,935
Prepaid expenses	34	–	34
	3,750	–	3,750
Exploration and evaluation assets *(notes a, d, j)*	–	472	472
Property, plant and equipment *(notes a, c, d, e, f, h, j)*	23,299	(1,529)	21,770
Goodwill	663	–	663
Contribution receivable	1,284	–	1,284
Other assets *(note b)*	137	(26)	111
	29,133	(1,083)	28,050
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes d, f, g)*	2,494	12	2,506
Long-term debt	4,187	–	4,187
Other long-term financial liabilities	102	–	102
Other long-term liabilities *(notes b, c, d, g, i)*	165	124	289
Contribution payable	1,427	–	1,427
Asset retirement obligations *(notes d, f)*	1,150	48	1,198
Deferred tax liabilities *(note l)*	4,115	(348)	3,767
	13,640	(164)	13,476
Shareholders' equity			
Common shares	4,574	–	4,574
Retained earnings *(note m)*	10,985	(959)	10,026
Other reserves *(notes b, d)*	(66)	40	(26)
	15,493	(919)	14,574
	29,133	(1,083)	28,050

Reconciliation of Total Comprehensive Income for the Year ended December 31, 2010

(millions of dollars)	Canadian GAAP	Effects of Transition to IFRS	IFRS
Revenues, net of royalties *(notes d, k)*	18,178	(854)	17,324
Costs and expenses			
Purchase of crude oil and products *(notes d, k)*	11,651	(854)	10,797
Production and operating expenses	2,309	–	2,309
Selling, general and administrative expenses *(notes d, g)*	305	(14)	291
Depletion, depreciation and amortization *(notes a, c, d, e, h)*	2,073	(81)	1,992
Exploration and evaluation expenses *(note a)*	–	438	438
Other - net *(notes f, i)*	23	(38)	(15)
	16,361	(549)	15,812
Profit from operating activities	1,817	(305)	1,512
Financial items			
Net foreign exchange gains (losses) *(note d)*	2	(51)	(49)
Finance income	79	–	79
Finance expenses *(notes d, f, j, i)*	(340)	15	(325)
	(259)	(36)	(295)
Profit before income taxes	1,558	(341)	1,217
Provisions for (recovery of) income taxes			
Current	188	–	188
Deferred *(note l)*	197	(115)	82
Profit	1,173	(226)	947
Other comprehensive income (loss)			
Exchange differences on translation of foreign operations, net of tax *(note d)*	(112)	21	(91)
Actuarial gains (losses) on pension plans, net of tax *(note b)*	–	(14)	(14)
Hedge of net investment, net of tax *(note d)*	44	(3)	41
Derivatives designated as cash flow hedges, net of tax	6	–	6
Total comprehensive income for the year	1,111	(222)	889

Notes to the Reconciliations of Equity and Total Comprehensive Income from Canadian GAAP to IFRS

a) IFRS 6 Adjustments – Exploration for and Evaluation of Mineral Resources

i) Accounting for Oil and Gas Properties

Under Canadian GAAP, the Company followed the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves were capitalized and accumulated within cost centres on a country-by-country basis. Depletion of oil and gas properties was calculated using the unit-of-production method based on proved oil and gas reserves for each cost centre. Under IFRS, pre-exploration and evaluation costs, which include all exploratory costs incurred prior to the acquisition of the legal right to explore, are expensed as incurred. After the legal right to explore is acquired, land acquisition costs and expenditures directly associated with exploratory wells will be capitalized as exploration and evaluation assets. Geological and geophysical and other exploration costs will be immediately recognized in exploration and evaluation expenses. Land acquisition costs will remain capitalized until the Company has chosen to discontinue all exploration activities in the associated area. Land acquisition costs associated with successful exploration are reclassified into property, plant and equipment. Exploratory wells will remain capitalized until the drilling operation is complete and the results have been evaluated. If the well does not encounter reserves of commercial quantity, either on its own or in combination with other exploration wells associated with the same area of exploration, the costs of drilling the well or wells will be written-off to exploration and evaluation expenses. Wells that result in commercial quantities of reserves remain capitalized and reclassified into property, plant, and equipment.

The Company has elected to apply the IFRS 1 exemption for its Canadian oil and gas assets. For international cost centres where the Company has elected not to apply the IFRS 1 deemed cost exemption, previously capitalized costs related to unsuccessful exploration drilling, geological and geophysical expenditures, exploratory seismic and lease rental expenses have been recorded as a reduction to property, plant and equipment and opening retained earnings upon adoption of IFRS 6. As a result, inception to January 1, 2010 exploration activities that would have been expensed under IFRS totaled \$516 million. For the year ended December 31, 2010, the Company reduced net property, plant, and equipment by \$438 million, in accordance with IFRS 6, and recognized these amounts as exploration and evaluation expenses for all cost centres.

ii) Depletion Expense

The application of IFRS oil and gas accounting policies resulted in differences in the carrying costs subject to depletion under IFRS as compared to full cost accounting. Additionally, differences in depletion arose from the determination of depletion at the field level under IFRS versus a country level under full cost accounting. For the year ended December 31, 2010, the Company has recognized reduced depletion, depreciation and amortization of \$173 million under IFRS when compared to full cost accounting for international oil and gas properties and increased depletion, depreciation and amortization of \$129 million under IFRS when compared to full cost accounting for Canadian oil and gas properties. This net reduction in depletion expense can be explained in part due to the opening adjustment to international oil and gas assets as described above.

iii) Exploration and Evaluation Assets

Under IFRS 6, management has assessed the classification of activities designated as developmental or exploratory, which then determines the appropriate accounting treatment and classification of the costs incurred. For capitalized costs associated with exploratory activities, the Company has presented these costs separately on the balance sheet. Costs totalling \$1,939 million as at January 1, 2010 and \$477 million as at December 31, 2010 were reclassified from property, plant, and equipment to exploration and evaluation assets.

Consolidated Statement of Total Comprehensive Income *(\$ millions)*	For the year ended December 31, 2010
Increase in exploration and evaluation expenses	438
Decrease in depletion, depreciation and amortization	(44)
Adjustment before income taxes	394

Consolidated Balance Sheets *(\$ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease/(increase) in exploration and evaluation assets	(1,939)	(477)
Decrease in property, plant and equipment	2,455	1,387
Decrease in retained earnings	516	910

b) IAS 19 Adjustments – Employee Benefits

Unamortized net actuarial loss and past service costs
IAS 19 allows the Company to recognize the unamortized net actuarial loss and past service costs for its defined benefit pension plans immediately in other comprehensive income. Canadian GAAP requires amortization of these losses and costs to net earnings over the estimated average remaining service life, with disclosure of the total cumulative unrecognized amount in the notes to the consolidated financial statements. Upon adoption of IAS 19 at January 1, 2010, the Company recognized a decrease of \$65 million and an increase of \$12 million in opening retained earnings related to the Company's cumulative unrecognized actuarial losses and past service cost recoveries, respectively. An additional charge to other comprehensive income of \$20 million (before taxes of \$6 million) was recorded in other comprehensive income representing unamortized net actuarial loss for the year ended December 31, 2010.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in other comprehensive income, before income taxes	20
Adjustment before income taxes	20

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease in other assets	26	26
Increase in other long-term liabilities	27	47
Decrease in retained earnings	53	53
Decrease in other reserves	–	20

c) IAS 20 Adjustments – Government Grants

Under IAS 20, government grants are recognized when there is reasonable assurance that the entity will comply with the conditions attached to them and the grants will be received. Under Canadian GAAP, government grants are recognized when received. The Company received government grants for the expansion of its ethanol plants which are subject to repayments dependent on the profitability of its operations as assessed annually until 2015. The Company does not have reasonable assurance of the amounts repayable on the grant until the repayment requirements are fulfilled. At January 1, 2010, the Company de-recognized these government grants until reasonable assurance of the measurement of repayments is determinable which increased property, plant, and equipment and other long-term liabilities by \$15 million as at January 1, 2010 and December 31, 2010. The reclassification from property, plant, and equipment would have resulted in increased depletion, depreciation and amortization of \$2 million from inception to January 1, 2010; this amount was recorded as a reduction of property, plant, and equipment and opening retained earnings. For the year ended December 31, 2010, the reclassification of government grants increased depletion, depreciation and amortization by less than \$1 million.

d) IAS 21 Adjustments – The Effects of Changes in Foreign Exchange Rates

Under IFRS, the functional currency of an entity is determined by focusing on the primary economic environment in which it operates and less precedence is placed on factors regarding the financing from and operational involvement of the reporting entity which consolidates the entity in its financial statements. Under Canadian GAAP, equal precedence is placed on all factors. The effect of this change to IFRS resulted in two entities having a different functional currency than the Company's functional currency. As such, the translation of the results and balance sheet of the foreign operations into the Company's presentation currency requires a translation of all assets and liabilities at the closing rate at each reporting date with all resulting foreign exchange gains or losses recognized in other comprehensive income. Revenues and expenses of foreign operations are translated using average monthly foreign exchange rates, which approximate the foreign exchange rates on the dates of the transactions with foreign exchange differences recognized in other comprehensive income. The retrospective application of IAS 21 resulted in a cumulative foreign currency exchange loss on revaluation of \$29 million as at January 1, 2010 which was recognized in other reserves prior to applying the IFRS 1 exemption.

The Company elected to utilize the IFRS 1 exemption to deem all foreign currency translation differences of \$36 million that arose prior to the date of transition with respect to all foreign operations to be nil at the date of transition. The Company reversed the balance of exchange differences on translation of foreign operations within other reserves and recorded a decrease to opening retained earnings of \$65 million.

For the year ended December 31, 2010, net foreign exchange losses of $53 million and gains of $21 million were attributed to the above mentioned entities that were assessed as having a different functional currency than the Company's functional currency under IFRS; these amounts were recorded to profit and other comprehensive income (loss) respectively.

For the year ended December 31, 2010, the Company reclassified $3 million of foreign exchange loss on translation of its foreign operations from other reserves to profit under Canadian GAAP. Under IFRS, this reclassification is not required until the foreign operation is partially or fully disposed. The Company recorded increased net foreign exchange gains and reduced other comprehensive income of $3 million under IFRS for the year ended December 31, 2010.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in revenues, net of royalties	2
Increase/(decrease) in purchases of crude oil and other products	(2)
Increase/(decrease) in selling, general and administrative expenses	(1)
Increase/(decrease) in depletion, depreciation and amortization	(1)
Decrease in net foreign exchange gains	51
Increase in finance expenses	1
Adjustment before income taxes	50

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease in exploration and evaluation assets	39	11
Decrease/(increase) in property, plant and equipment	(4)	58
Increase/(decrease) in accounts payable and other accrued liabilities	3	–
Increase/(decease) in asset retirement obligations	(9)	(8)
Decrease in retained earnings	65	115
Decrease (increase) in other reserves	(36)	(54)

e) IAS 36 Adjustments – Impairment of Assets

Under Canadian GAAP, impairment of long-lived assets is assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of the impairment. Under IFRS, impairment is assessed based on discounted cash flows compared with the asset's carrying amount to determine the recoverable amount and measure the amount of the impairment. In addition under IFRS, where a long-lived asset does not generate largely independent cash inflows, the Company is required to perform its test at a cash generating unit level, which is the smallest identifiable grouping of assets that generates largely independent cash inflows. Canadian GAAP impairment is based on undiscounted cash flows using asset groupings with both independent cash inflows and cash outflows.

With the adoption of IAS 36, the Company recorded impairments on its ethanol plants decreasing property, plant, and equipment by $91 million as at January 1, 2010 based on their recoverable amounts using a fair value less cost to sell valuation based on a 39 year cash flow projection discounted at a pre-tax rate of 11%. For the year ended December 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation and amortization of $3 million.

The adoption of IAS 36 and application of the full cost exemption also resulted in an impairment of the carrying value of oil and gas properties in the East Central Alberta and Foothills West districts decreasing property, plant, and equipment by $66 million as at January 1, 2010. The recoverable amounts were based on fair value less cost to sell valuations using proved plus probable reserve life discounted at pre-tax rates ranging from 13% to 14%. For the year ended December 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation and amortization of $7 million.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in depletion, depreciation and amortization	(10)
Adjustment before income taxes	(10)

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease in property, plant and equipment	157	147
Decrease in retained earnings	157	147

f) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets

i) Asset Retirement Obligations

Consistent with IFRS, decommissioning provisions (asset retirement obligations) have been previously measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition. Under IAS 37, asset retirement obligations will continue to be discounted using a credit-adjusted risk free rate, however, the liability is required to be re-measured based on changes in estimates including discount rates.

For asset retirement obligations associated with Canadian oil and gas properties where the IFRS 1 exemption was utilized, the Company re-measured asset retirement obligations as at January 1, 2010 under IAS 37 with a corresponding adjustment to opening retained earnings. The carrying values of Canadian oil and gas assets associated with asset retirement obligations under Canadian GAAP were not adjusted on transition to IFRS. This resulted in a decrease in asset retirement obligations and an increase in opening retained earnings of $13 million as at January 1, 2010. Accordingly for the year ended December 31, 2010, the Company recorded reduced accretion of $3 million under IFRS. At December 31, 2010, the Company re-measured the asset retirement obligations based on a change in the discount rate from 6.4% to 6.2% which increased property, plant, and equipment and asset retirement obligations by $66 million.

The total impact of this change to asset retirement obligations of Canadian oil and gas assets subject to the IFRS 1 exemption is summarized as follows:

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in finance expenses	3
Adjustment before income taxes	3

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Increase in property, plant and equipment	–	66
Decrease/(increase) in asset retirement obligations	13	(50)
Increase in retained earnings	13	16

For asset retirement obligations associated with international oil and gas assets, midstream, downstream and corporate assets that were not subject to the IFRS 1 exemption, a retrospective application of IAS 37 was performed. This resulted in an increase in net property, plant, and equipment of $38 million as at January 1, 2010 and an incremental increase of $11 million during the year ended December 31, 2010. Asset retirement obligations decreased by $4 million as at January 1, 2010 and increased by an incremental $10 million for the year ended December 31, 2010. For the year ended December 31, 2010, the Company recorded reduced accretion of $1 million in pre-tax finance expenses.

The total impact of this change to asset retirement obligations associated with international oil and gas assets, midstream, downstream and corporate assets is summarized as follows:

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in finance expenses	1
Adjustment before income taxes	1

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Increase in property, plant, and equipment	38	49
Decrease/(increase) in asset retirement obligations	4	(6)
Increase in retained earnings	42	43

Under Canadian GAAP accretion of the asset retirement obligations was included in cost of sales and operating expenses; however, under IFRS accretion is now classified in finance expenses.

ii) Onerous Contracts

Under IAS 37, contracts that are deemed loss-making or onerous are recognized as a present obligation when the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received from the contract. There are no equivalent requirements under Canadian GAAP. The Company recorded a provision for a drilling rig commitment that was deemed onerous resulting in an increase in provisions of $1 million at January 1, 2010 recorded in accounts payable and accrued liabilities with a corresponding decrease in retained earnings. For the year ended December 31, 2010, the Company recognized an additional provision of $1 million with a corresponding expense recorded to other - net.

g) IFRS 2 Adjustments – Share-Based Payments

The Company has granted cash-settled share-based payments to certain employees in the past. Under IFRS the related liability is adjusted to reflect the fair value of the outstanding cash-settled shared-based payment using an option pricing model. Canadian GAAP permitted share-based payments to be accounted for by reference to their intrinsic value.

The impact of this change is summarized as follows:

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in selling, general and administrative expenses	(13)
Adjustment before income taxes	(13)

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Increase in accounts payable and accrued liabilities	22	10
Increase in other long-term liabilities	10	9
Decrease in retained earnings	32	19

h) IAS 16 Adjustments – Property, Plant and Equipment

The Company reviewed the major components and useful lives of items of property, plant, and equipment. As a result of the retroactive treatment of component depreciation, the Company decreased property, plant and equipment by $144 million with an adjustment to opening retained earnings.

The Company also reviewed replacement of major components to determine if assets replaced prior to the end of their useful life required derecognition under IFRS. The Company determined that asset components with a net book value of $3 million required derecognition which was recorded as a decrease to opening retained earnings.

As a result of these adjustments which reduced the net book value of assets on transition to IFRS, the Company recognized reduced pre-tax depletion, depreciation and amortization of $26 million for the year ended December 31, 2010. For the year ended December 31, 2010, the Company recognized $2 million on component disposal recorded as an expense to other - net.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in depletion, depreciation and amortization	(26)
Increase in other - net	2
Adjustment before income taxes	(24)

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease in property, plant and equipment	147	123
Decrease in retained earnings	147	123

i) IFRS 3 Adjustments – Business Combinations

Given that the Company elected to apply the IFRS 1 exemption which permits no adjustments to amounts recorded for acquisitions that occurred prior to January 1, 2010, no retrospective adjustments are required. The Company acquired the remaining interest in the Lloydminster upgrader from the Minister of Natural Resources in 1995 and is required to make payments to the Minister from 1995 to 2014 based on average differentials between heavy crude oil feedstock and the price of synthetic crude oil sales. Under IFRS, the Company is required to recognize this contingent consideration at its fair value as part of the acquisition and record a corresponding liability. Under Canadian GAAP, any contingent consideration is not required to be recognized unless amounts are resolved and payable on the date of acquisition. On transition to IFRS, Husky recognized a liability of $85 million, based on the fair value of remaining upside interest payments, with an adjustment to opening retained earnings. For the year ended December 31, 2010, the Company recognized pre-tax accretion of $9 million in finance expenses under IFRS. Changes in forecast differentials used to determine the fair value of the remaining upside interest payments resulted in the recognition of a pre-tax gain of $41 million recorded to other income for the year ended December 31, 2010.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Increase in finance expenses	9
Increase/(decrease) in other - net	(41)
Adjustment before income taxes	(32)

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Increase in other long-term liabilities	85	53
Decrease in retained earnings	85	53

j) IAS 23 Adjustments – Borrowing Costs

The Company has elected to commence mandatory capitalization of all major capital projects as at January 1, 2003, representing the date the Company commenced incurring capital expenditures on its Madura and Liwan projects, as permitted under IFRS 1. As a result, borrowing costs on major capital International upstream exploratory projects increased exploration and evaluation assets by $43 million as at January 1, 2010 with an adjustment to opening retained earnings.

During the year ended December 31, 2010, the major capital projects with capitalized borrowing costs under IFRS were transferred to the development phase and therefore $43 million of capitalized borrowing costs were reclassified to property, plant and equipment. Additionally, the Company capitalized incremental borrowing costs of $6 million in exploration and evaluation assets and $15 million in property, plant, and equipment under IFRS with a corresponding adjustment to finance expenses for the year ended December 31, 2010.

Consolidated Statement of Total Comprehensive Income ($ millions)	For the year ended December 31, 2010
Decrease in finance expenses	21
Adjustment before income taxes	21

Consolidated Balance Sheets ($ millions)	As at January 1, 2010	As at December 31, 2010
Increase in exploration and evaluation assets	43	6
Increase in property, plant and equipment	–	58
Increase in retained earnings	43	64

k) IAS 18 Adjustments – Revenue

Under IFRS, realized and unrealized gains and losses on natural gas purchase and sale contracts are recorded on a net basis against sales and operating expenses. Under Canadian GAAP, these gains and losses are recorded on a gross basis. For the year ended December 31, 2010, the Company reclassified $852 million of losses on natural gas purchase contracts from purchases of crude oil and products to revenues.

l) IAS 12 Adjustments – Income Taxes

Nearly all recognized IFRS conversion adjustments as discussed in this transition note have related effects on deferred taxes. The tax impact of the above changes (increased)/decreased the deferred tax liability as follows:

(millions of dollars)	As at Jan. 1, 2010	For the year ended, Dec. 31, 2010	As at Dec. 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	154	114	268
Depletion of oil and gas properties *(note a)*	–	(11)	(11)
Employee benefits *(note b)*	16	6	22
Foreign currency translation *(note d)*	7	13	20
Impairment of assets *(note e)*	47	(3)	44
Asset retirement obligations *(note f)*	(16)	(1)	(17)
Share-based payments *(note g)*	10	(4)	6
Property, plant and equipment *(note h)*	44	(7)	37
Business combinations *(note i)*	25	(8)	17
Borrowing costs *(note j)*	(13)	(5)	(18)
Uncertain tax positions *(note l)*	(47)	27	(20)
Decrease in deferred tax liability	227	121	348

Under IFRS, the Company records and measures income tax uncertainties based on a single best estimate. Under Canadian GAAP the Company recorded uncertain tax positions if such positions were probable of being sustained. The impact of this change increased the deferred tax liability by $47 million as at January 1, 2010 and $20 million as at December 31, 2010 under IFRS.

m) Opening Retained Earnings Adjustments

The above changes (increased)/decreased retained earnings (each net of related tax) as follows:

(millions of dollars)	As at Jan. 1, 2010	For the year ended, Dec. 31, 2010	As at Dec. 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	362	324	686
Depletion of oil and gas properties *(note a)*	–	(33)	(33)
Employee benefits *(note b)*	37	–	37
Government grants *(note c)*	2	–	2
Foreign currency translation *(note d)*	58	37	95
Impairment of assets *(note e)*	110	(7)	103
Asset retirement obligations *(note f)*	(39)	(3)	(42)
Provisions – onerous contracts *(note f)*	1	1	2
Share-based payments *(note g)*	22	(9)	13
Property, plant and equipment *(note h)*	103	(17)	86
Business combinations *(note i)*	60	(24)	36
Borrowing costs *(note j)*	(30)	(16)	(46)
Uncertain tax positions *(note l)*	47	(27)	20
Decrease in retained earnings	733	226	959

n) Reclassifications

Certain amounts have been reclassified to conform with current presentation.

o) Adjustments to the Company's Cash Flow Statement under IFRS

The highlighted reconciling items discussed above between Canadian GAAP and IFRS policies have no net impact on the cash flows generated by the Company.

Supplemental Financial and Operating Information

Segmented Financial Information

	Upstream					Midstream									
						Upgrading					Infrastructure and Marketing				
($ millions)	**2010**	2009	2008	2007	2006	**2010**	2009	2008	2007	2006	**2010**	2009	2008	2007	2006
Year ended December 31															
Sales and operating revenues, net of royalties	**4,766**	4,452	7,889	6,222	5,772	**1,570**	1,572	2,435	1,524	1,679	**7,854**	6,984	13,544	10,217	9,559
Costs and expenses															
Operating, cost of sales, selling and general	**1,597**	1,495	1,627	1,308	1,321	**1,439**	1,461	2,053	1,146	1,260	**7,592**	6,669	13,192	9,838	9,258
Depletion, depreciation and amortization	**1,572**	1,397	1,505	1,615	1,476	**100**	34	31	25	24	**43**	36	31	28	24
Interest – net	**–**	–	–	–	–	**–**	–	–	–	–	**–**	–	–	–	–
Foreign exchange	**–**	–	–	–	–	**–**	–	–	–	–	**–**	–	–	–	–
	3,169	2,892	3,132	2,923	2,797	**1,539**	1,495	2,084	1,171	1,284	**7,635**	6,705	13,223	9,866	9,282
Earnings (loss) before income taxes	**1,597**	1,560	4,757	3,299	2,975	**31**	77	351	353	395	**219**	279	321	351	277
Current income taxes (recoveries)	**(23)**	909	585	122	519	**1**	111	84	10	53	**62**	101	126	68	79
Future income taxes (reductions)	**485**	(462)	795	581	161	**8**	(88)	21	75	48	**(3)**	(22)	(29)	30	1
Net earnings (loss)	**1,135**	1,113	3,377	2,596	2,295	**22**	54	246	268	294	**160**	200	224	253	197
Total assets - As at December 31	**18,179**	16,338	15,653	14,395	13,920	**2,075**	1,427	1,322	1,377	982	**1,368**	1,712	1,486	1,134	1,329

[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.*

Downstream									Corporate and Eliminations [1]					Total				
Canadian Refined Products					U.S. Refining and Marketing													
2010	2009	2008	2007	2006	**2010**	2009	2008	2007	**2010**	2009	2008	2007	2006	**2010**	2009	2008	2007	2006
2,975	2,495	3,564	2,916	2,575	**7,107**	5,349	7,802	2,383	**(6,094)**	(5,778)	(10,533)	(7,744)	(6,921)	**18,178**	15,074	24,701	15,518	12,664
2,728	2,204	3,340	2,607	2,383	**6,946**	4,957	8,280	2,167	**(5,961)**	(5,663)	(10,580)	(7,542)	(6,742)	**14,341**	11,123	17,912	9,524	7,480
91	93	81	66	48	**191**	194	154	47	**76**	51	30	25	27	**2,073**	1,805	1,832	1,806	1,599
–	–	–	–	–	**2**	3	3	1	**206**	191	144	129	92	**208**	194	147	130	92
–	–	–	–	–	**–**	–	–	–	**(2)**	(5)	(335)	(51)	(24)	**(2)**	(5)	(335)	(51)	(24)
2,819	2,297	3,421	2,673	2,431	**7,139**	5,154	8,437	2,215	**(5,681)**	(5,426)	(10,741)	(7,439)	(6,647)	**16,620**	13,117	19,556	11,409	9,147
156	198	143	243	144	**(32)**	195	(635)	168	**(413)**	(352)	208	(305)	(274)	**1,558**	1,957	5,145	4,109	3,517
56	38	28	17	19	**–**	3	(24)	28	**92**	100	102	102	8	**188**	1,262	901	347	678
(15)	19	11	33	20	**(12)**	68	(208)	35	**(266)**	(236)	(97)	(193)	(125)	**197**	(721)	493	561	105
115	141	104	193	105	**(20)**	124	(403)	105	**(239)**	(216)	203	(214)	(157)	**1,173**	1,416	3,751	3,201	2,734
1,582	1,430	1,375	1,332	1,110	**5,078**	4,771	5,380	3,058	**851**	617	1,270	370	578	**29,133**	26,295	26,486	21,666	17,919

Upstream Operating Information

	2010	2009	2008	2007	2006
Daily production, before royalties					
Light crude oil & NGL *(mbbls/day)*	**80.4**	89.1	122.9	138.7	111.0
Medium crude oil *(mbbls/day)*	**25.4**	25.4	26.9	27.1	28.5
Heavy crude oil *(mbbls/day)*	**74.5**	78.6	84.3	86.5	88.5
Bitumen *(mbbls/day)*	**22.3**	23.1	22.7	20.4	19.6
	202.6	216.2	256.8	272.7	247.6
Natural gas *(mmcf/day)*	**506.8**	541.7	594.4	623.3	672.3
Total production *(mboe/day)*	**287.1**	306.5	355.9	376.6	359.7
Average sales prices					
Light crude oil & NGL *($/bbl)*	**76.90**	62.70	97.28	73.54	69.06
Medium crude oil *($/bbl)*	**64.92**	56.37	81.79	51.12	49.48
Heavy crude oil *($/bbl)*	**58.91**	52.54	71.98	40.43	40.12
Bitumen *($/bbl)*	**57.84**	51.90	70.24	38.96	39.03
Natural gas *($/mcf)*	**3.86**	3.83	7.94	6.19	6.47
Operating costs *($/boe)*	**13.33**	11.82	10.93	9.09	8.77
Operating netbacks [1]					
Light crude oil *($/boe)* [2]	**47.62**	39.06	65.03	57.52	57.06
Medium crude oil *($/boe)* [2]	**35.62**	30.81	50.40	27.61	27.27
Heavy crude oil *($/boe)* [2]	**34.08**	31.45	47.22	23.84	24.56
Bitumen *($/boe)* [2]	**28.94**	28.39	36.89	14.09	19.40
Natural gas *($/mcfge)* [3]	**2.03**	1.97	5.02	3.80	4.10

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

Western Canada and Oil Sands Wells Drilled

		2010		2009		2008		2007		2006	
		Gross	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	**60**	**51**	18	9	80	70	79	79	101	99
	Gas	**37**	**31**	37	22	102	79	114	92	330	192
	Dry	**8**	**8**	7	6	27	23	14	12	26	24
		105	**90**	62	37	209	172	207	183	457	315
Development	Oil	**815**	**722**	315	278	685	578	571	530	590	543
	Gas	**73**	**53**	122	61	435	270	343	251	565	490
	Dry	**10**	**9**	7	7	36	36	31	29	25	22
		898	**784**	444	346	1,156	884	945	810	1,180	1,055
		1,003	**874**	506	383	1,365	1,056	1,152	993	1,637	1,370
Success ratio *(percent)*		**98**	**98**	97	97	95	94	96	96	97	97

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	**2010**	2009	2008	2007	2006	2005	2004	2003	2002	2001
Financial Highlights										
Sales and operating revenues, net of royalties	**18,178**	15,074	24,701	15,518	12,664	10,245	8,440	7,658	6,384	6,596
Net earnings	**1,173**	1,416	3,751	3,201	2,734	1,996	1,001	1,374	794	633
Earnings per share										
Basic	**1.38**	1.67	4.42	3.77	3.21	2.35	1.18	1.64	0.95	0.76
Diluted	**1.38**	1.67	4.42	3.77	3.21	2.35	1.18	1.63	0.95	0.76
Expenditures on PP&E [1]	**3,956**	2,797	4,108	2,974	3,201	3,099	2,379	1,902	1,707	1,474
Total debt	**4,187**	3,229	1,957	2,814	1,611	1,886	2,204	2,094	2,740	2,572
Debt to capital employed *(percent)*	**21**	18	12	19	14	20	26	27	37	38
Reinvestment ratio *(percent)* [2]	**111**	111	66	86	71	80	112	92	79	79
Return on average capital employed *(percent)*	**7.1**	9.1	25.1	25.6	27.1	22.7	13.0	18.9	12.3	10.9
Return on equity *(percent)*	**7.8**	9.8	28.9	30.1	31.9	29.2	17.0	26.5	17.9	16.4
Upstream										
Daily production, before royalties										
Light crude oil & NGL *(mbbls/day)*	**80.4**	89.1	122.9	138.7	111.0	64.6	66.2	71.6	65.4	46.4
Medium crude oil *(mbbls/day)*	**25.4**	25.4	26.9	27.1	28.5	31.1	35.0	39.2	44.8	47.2
Heavy crude oil *(mbbls/day)*	**74.5**	78.6	84.3	86.5	88.5	88.0	90.2	85.1	76.1	67.0
Bitumen *(mbbls/day)*	**22.3**	23.1	22.7	20.4	19.6	18.0	18.7	14.8	19.0	16.8
	202.6	216.2	256.8	272.7	247.6	201.7	210.1	210.7	205.3	177.4
Natural gas *(mmcf/day)*	**507**	542	594	623	672	680	689	611	569	573
Total production *(mboe/day)*	**287.1**	306.5	355.9	376.6	359.7	315.0	325.0	312.5	300.2	272.8
Total proved reserves, before royalties *(mmboe)* [3]	**1,081**	933	896	1,014	1,004	985	791	887	918	927
Midstream										
Synthetic crude oil sales *(mbbls/day)*	**54.1**	61.8	58.7	53.1	62.5	57.5	53.7	63.6	59.3	59.5
Upgrading differential *($/bbl)*	**14.52**	11.89	28.77	30.73	26.16	30.70	17.79	12.88	10.81	17.91
Pipeline throughput *(mbbls/day)*	**512**	514	507	501	475	474	492	484	457	537
Canadian Refined Products										
Light oil products sales *(million litres/day)*	**8.2**	7.6	7.9	8.7	8.7	8.9	8.4	8.2	7.7	7.6
Asphalt products sales *(mbbls/day)*	**24.1**	22.6	24.0	21.8	23.4	22.5	22.8	22.0	20.8	21.4
Refinery throughput										
Prince George refinery *(mbbls/day)*	**10.0**	10.3	10.1	10.5	9.0	9.7	9.8	10.3	10.1	10.2
Lloydminster refinery *(mbbls/day)*	**27.8**	24.1	26.1	25.3	27.1	25.5	25.3	25.7	22.0	23.7
Refinery utilization *(percent)*	**92**	86	91	90	90	101	100	103	92	97

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

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

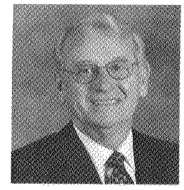
(3) *Total proved reserves, before royalties for 2010 were prepared in accordance with the Canadian Securities Administrators' National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Years including 2009 and prior were prepared in accordance with the rules of the United States Securities and Exchange Commission guidelines and the United States Financial Accounting Standards Board. Refer to Section 7.3 of the Management's Discussion and Analysis for a discussion.*

Netback Analysis

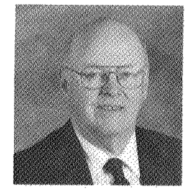
	2010	2009	2008
Total			
Crude oil equivalent *($/boe)* [1]			
Gross price	**53.77**	47.06	74.57
Royalties	**9.31**	7.70	15.52
Net sales price	**44.46**	39.36	59.05
Operating costs [2]	**13.33**	11.82	10.93
	31.13	27.54	48.12
DD&A	**15.00**	12.49	11.56
Administration expenses and other [2]	**0.95**	1.15	0.05
Earnings before income taxes	**15.18**	13.90	36.51
Canada			
Crude oil equivalent *($/boe)* [1]			
Gross price	**52.86**	46.21	73.72
Royalties	**8.95**	7.53	15.09
Net sales price	**43.91**	38.68	58.63
Operating costs [2]	**13.74**	12.09	11.14
Operating netback	**30.17**	26.59	47.49
Western Canada			
Crude oil (per boe) [1]			
Light crude oil			
Gross price	**59.66**	52.28	82.97
Royalties	**10.11**	6.03	11.53
Net sales price	**49.55**	46.25	71.44
Operating costs [2]	**15.03**	15.79	13.90
Operating netback	**34.52**	30.46	57.54
Medium crude oil			
Gross price	**62.97**	54.88	79.91
Royalties	**11.11**	8.67	13.91
Net sales price	**51.86**	46.21	66.00
Operating costs [2]	**16.24**	15.40	15.60
Operating netback	**35.62**	30.81	50.40
Heavy crude oil			
Gross price	**58.09**	51.95	71.45
Royalties	**8.50**	7.24	10.55
Net sales price	**49.59**	44.71	60.90
Operating costs [2]	**15.51**	13.26	13.68
Operating netback	**34.08**	31.45	47.22
Bitumen			
Gross price	**57.84**	51.90	70.24
Royalties	**8.53**	7.13	10.42
Net sales price	**49.31**	44.77	59.82
Operating costs [2]	**20.37**	16.38	22.93
Operating netback	**28.94**	28.39	36.89
Natural gas *($/ mcfge)* [3]			
Gross price	**4.33**	4.08	8.21
Royalties	**0.45**	0.42	1.60
Net sales price	**3.88**	3.66	6.61
Operating costs [2]	**1.85**	1.69	1.59
Operating netback	**2.03**	1.97	5.02
Atlantic Region			
Light crude oil *($/boe)* [1]			
Gross price	**80.63**	64.60	100.12
Royalties [4]	**19.25**	16.34	28.45
Net sales price	**61.38**	48.26	71.67
Operating costs [2]	**10.33**	8.73	4.99
Operating netback	**51.05**	39.53	66.68
International			
Light crude oil *($/boe)* [1]			
Gross price	**83.12**	69.74	98.70
Royalties	**18.94**	12.01	27.46
Net sales price	**64.18**	57.73	71.24
Operating costs [2]	**6.06**	5.49	4.86
Operating netback	**58.12**	52.24	66.38

[1] *Includes associated and co-products converted to boe.*
[2] *Operating costs exclude accretion, which is included in administration expenses and other.*
[3] *Includes associated co-products converted to mcfge.*
[4] *During March 2008, White Rose and Terra Nova achieved payout status for Tier 2 royalties.*

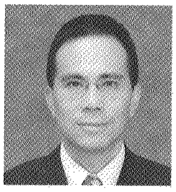
Board of Directors



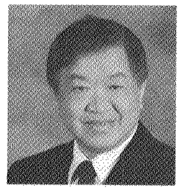
William Shurniak



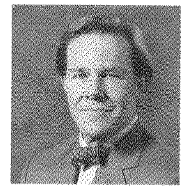
R. Donald Fullerton



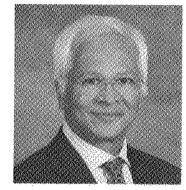
Victor T.K. Li



Canning K.N. Fok



Stephen E. Bradley



Asim Ghosh

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

Canning K.N. Fok [2], Co-Chairman,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Fok is Group Managing Director and Executive Director of Hutchison Whampoa Limited. He is Chairman and a Director of Hutchison Harbour Ring Limited, Hutchison Telecommunications Hong Kong Holding Limited, Hutchison Telecommunications (Australia) Limited, and Power Assets Holdings Limited (formerly known as Hongkong Electric Holdings Limited). Mr. Fok is the Deputy Chairman and a Director of Cheung Kong Infrastructure Holdings Limited and a Director of Cheung Kong (Holdings) Limited.

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

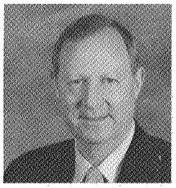
Stephen E. Bradley, Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since July 2010. Mr. Bradley is a Director of Broadlea Group Ltd., Senior Representative (China), Grosvenor Ltd., Vice Chairman, ICAP (Asia Pacific) and a Director of Swire Properties Ltd. and Special Advisor to the Chief Executive Officer of Rio Tinto Ltd.

R. Donald Fullerton [1], Director,
a resident of Toronto, has been a Director of Husky Energy Inc. since 2003. During his career, Mr. Fullerton has served as a Director of a number of public and private companies both domestic and international and is currently a Director of the Li Ka Shing (Canada) Foundation and 3 Italia S.p.A.

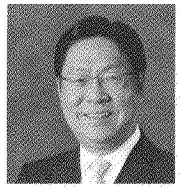
Asim Ghosh, President &
Chief Executive Officer, Director,
a resident of Calgary, Alberta, has been a Director of Husky Energy Inc. since May 2009. Mr. Ghosh is an independent Director of Kotak Mahindra Bank Limited, a listed bank in India.

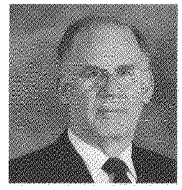
The Management Information Circular and the Annual Information Form contain additional information regarding the Directors.

[1] *Audit Committee*
[2] *Compensation Committee*
[3] *Corporate Governance Committee*
[4] *Health, Safety & Environment Committee*

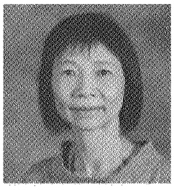

Martin J.G. Glynn

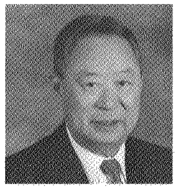

Eva L. Kwok

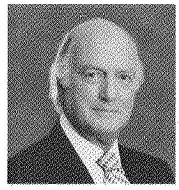

Frederick S-H Ma


Colin S. Russel


Frank J. Sixt


Poh Chan Koh


Stanley T.L. Kwok


George C. Magnus


Wayne E. Shaw

Martin J.G. Glynn [2][3], Director,
a resident of Vancouver, British Columbia, has been a Director of Husky Energy Inc. since 2000. Mr. Glynn is a Director of Hathor Exploration Limited, the VinaCapital Vietnam Opportunity Fund Limited, MF Global Holdings Ltd., Sun Life Financial Inc. and Sun Life Assurance Company of Canada.

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

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

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

Frederick S-H Ma [1][4], Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since July 2010. Mr. Ma is a prominent figure in Hong Kong, having served in senior positions in the private sector and has held Principal Official positions (minister equivalent) with the Hong Kong SAR Government. Mr. Ma is currently a member of the International Advisory Council of China Investment Corporation, China's Sovereign Fund, as well as an Honourary Professor of the University of Hong Kong.

George C. Magnus [1], Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since July 2010. Mr. Magnus has been a Non-executive Director of Cheung Kong (Holdings) Limited since November 2005. He is also a Non-executive Director of Hutchison Whampoa Limited, Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited (formerly known as Hongkong Electric Holdings Limited), all listed companies.

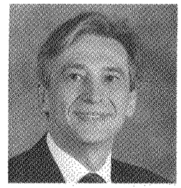
Colin S. Russel [1][4], Director,
a resident of the United Kingdom, has been a Director of Husky Energy Inc. since 2008. Mr. Russel is the founder and Managing Director of Emerging Markets Advisory Services Ltd. Mr. Russel is a Director of Cheung Kong Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd.

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

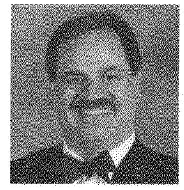
Frank J. Sixt [2], Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Sixt is Group Finance Director and Executive Director of Hutchison Whampoa Limited. He is the Non-executive Chairman and a Director of TOM Group Limited and Executive Director of Cheung Kong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

Officers/ Executives

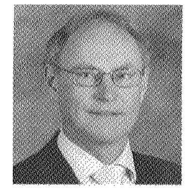
Robert J. Peabody



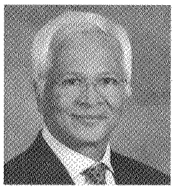
James D. Girgulis



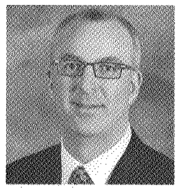
Bob I. Baird



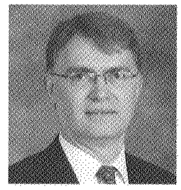
Edward T. Connolly



Asim Ghosh



Alister Cowan



Brad Allison

Ronald J. Butler

Husky Energy Inc.

Asim Ghosh, President & Chief Executive Officer

Mr. Ghosh has been on the Board of Directors of Husky Energy since May 2009 and President and Chief Executive Officer since June 2010. He is the former Managing Director and Chief Executive Officer of Vodafone Essar Limited. Mr. Ghosh started his career with Procter & Gamble in Canada and subsequently became a Senior Vice President of Carling O'Keefe. He later became founding Chief Executive Officer of Pepsi Foods' start up operations in India. He served in senior executive positions and as Chief Executive Officer of the AS Watson consumer packaged goods subsidiary of Hutchison Whampoa. From 1991 to 1998 he managed a group of 13 business units, and expanded the group's operations from Hong Kong to China and Europe. He is a member of the Board of Directors of Kotak Mahindra Bank Limited.

Robert J. Peabody, Chief Operating Officer

Appointed in 2006, Rob Peabody is responsible for leading Husky Energy's Upstream including Western Canada Conventional and Unconventional, Heavy Oil, Oil Sands, Atlantic Region and Exploration. He is also responsible for the Engineering, Project Management and Procurement functions. Prior to joining Husky, he led four major businesses for BP plc in Europe and the United States. Mr. Peabody is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Alister Cowan, Vice President & Chief Financial Officer

Alister Cowan was appointed Vice President & Chief Financial Officer, Husky Energy in July 2008. He was previously Executive Vice President and Chief Financial Officer, British Columbia Hydro & Power Authority. He joined the Institute of Chartered Accountants of Scotland in 1988 and is a Past Chair of the Financial Executives International (FEI) Canada Committee on Corporate Reporting.

James D. Girgulis, Q.C., Vice President, Legal & Corporate Secretary

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

Husky Oil Operations Limited

Brad Allison, Vice President, Exploration

Mr. Allison was appointed Vice President, Exploration in June 2010 with responsibilities for resource capture and appraisal as well as geological and geophysical services and business development. Mr. Allison joined Husky in 2002 as Deep Basin Exploration Manager and prior to his appointment, he was General Manager, Canadian/ International Exploration. Mr. Allison started his career with Imperial Oil Limited where he held a number of technical and management roles involving Western Canada exploration, Canadian Frontiers, Oil Sands and an assignment with Esso UK in the Central North Sea. Mr. Allison holds a Professional Geologist designation and is a member of the CSPG and AAPG.

Bob I. Baird, Vice President, Downstream

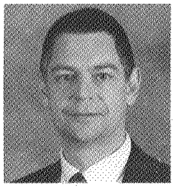
Bob I. Baird was appointed Vice President, Downstream in 2010. He was previously Vice President, Upgrading and Refining for Canada. He is responsible for overseeing all Canadian upgrading and refining operations, and providing oversight on the operation of Husky's U.S. refineries. Prior to joining Husky, Mr. Baird worked in several senior refining and strategy roles for Royal Dutch Shell in Canada and Europe.

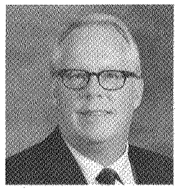
Ronald J. Butler, Vice President, Corporate Administration

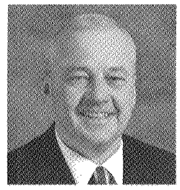
Ron Butler is responsible for Human Resources, Health, Safety & Environment, Real Estate, Risk Management, Diversity and Corporate Services. Mr. Butler is an experienced human resources practitioner and leader with extensive oil and gas experience. Prior to joining Husky, Mr. Butler was Vice President, Human Resources with BP Canada and formerly Manager, Human Resources of Amoco (U.K.) Exploration Company. Mr. Butler is a past president and current member of the Human Resources Association of Calgary and a past director of the Human Resources Institute of Alberta.

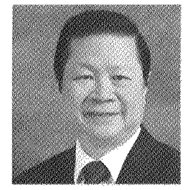
Edward T. Connolly, Vice President, Heavy Oil

Edward T. Connolly joined Husky as Vice President, Heavy Oil in 2006 and has responsibility for managing the heavy oil reserves and production portfolio. Mr. Connolly was previously Manager, Drilling, Well Completions and Facilities Construction with Talisman Energy Canada, and Facilities Construction Project Manager with BP Canada Ltd.

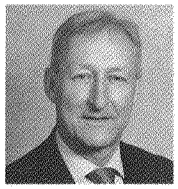

Terrance E. Kutryk


John Myer


Roy C. Warnock


John C.S. Lau


Terry Manning


Paul J. McCloskey


Robert Hinkel

Terrance E. Kutryk, Vice President, Midstream & Refined Products
Terrance E. Kutryk was appointed Vice President, Midstream & Refined Products in 2008. He was formerly General Manager, Facilities & New Ventures, and was Vice President, Refined Products & New Ventures with Husky Marketing & Supply Company. He is a member of the American Society of Mechanical Engineers, Canadian Institute of Mining, Metallurgy and Petroleum, Canadian Heavy Oil Association and the CFA Institute. He is Chairman of the Board of Sultran Ltd. and Pacific Coast Terminals Co. Ltd.

Terry Manning, Vice President, Engineering & Procurement Management
Terry Manning was appointed Vice President, Engineering & Procurement Management in January 2009 with responsibilities for procurement, material and services management, project management and technical services for Husky. He was previously Vice President, Capital Projects with Barrick Gold Corporation; General Manager, Project Management Office with Suncor Energy Inc., and Director of Projects at Agrium. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Association of Professional Engineers and Geoscientists of British Columbia.

John Myer, Vice President, Oil Sands
Mr. Myer was appointed Vice President, Oil Sands in November 2010 with responsibilities to develop and operate the Sunrise SAGD asset and advance Husky's portfolio of emerging properties in the Oil Sands region. Prior to his appointment at Husky he was with Suncor Energy for 20 years including roles as Vice President Exploration and Development, Vice President In-situ and Vice President Production. Mr. Myer is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, Society of Petroleum Engineers and Canadian Heavy Oil Association.

Paul J. McCloskey, Vice President, Atlantic Region
Paul J. McCloskey was appointed Vice President, Atlantic Region in 2009. Prior to joining Husky, he was Managing Director at North Alamein Petroleum Company (NALPETCO). Previous to that, he led various businesses in Hess Corporation and LASMO, where he was Group General Manager for Production & Development, and held senior engineering roles at Conoco. A member of the Society of Petroleum Engineers, he served as a Director of the Board of the Aberdeen (Scotland) section.

Roy C. Warnock, Vice President & General Manager, Lima Refining Company
Mr. Warnock was appointed Vice President & General Manager, Lima Refining Company, in 2007. Previously, he served as Vice President, Upgrading & Refining, responsible for the operations of the Husky Lloydminster Refinery, Lloydminster Upgrader, Lloydminster Meridian Cogeneration Facility, Prince George Refinery and the Lloydminster and Minnedosa ethanol plants. Prior to joining the Company in 1983, he held a number of engineering and operations positions with Imperial Oil and Bechtel Canada Ltd. Mr. Warnock is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Husky Asia Pacific

John C.S. Lau, President & Chief Executive Officer
John C.S. Lau is responsible for leading the development of the Company's oil and natural gas businesses in the Asia Pacific region including existing business in Indonesia and the South China Sea. He was appointed President & Chief Executive Officer, Asia Pacific in May 2010 when he stepped down as Chief Executive Officer of Husky Energy Inc. after 18 years in the position. Prior to joining Husky, Mr. Lau served in various senior executive roles in Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies. He is a Fellow member of the Institute of Chartered Accountants in Australia.

Robert Hinkel, Chief Operating Officer
Mr. Hinkel was appointed Chief Operating Officer, Asia Pacific in December, 2010. Immediately prior to joining Husky, Mr. Hinkel held the position of Senior Vice President – Operations for Asia Pacific Exploration Company, a private exploration and production company. From 2003 to 2007, he was the President and CEO of Enventure Global Technology, a subsidiary of the Shell Group. Mr. Hinkel spent 21 years with Unocal in various positions including Senior Vice President. He is also an active member of the Society of Petroleum Engineers.

Investor Information

Common Share Information

Year ended December 31		**2010**	2009	2008
Share price *(dollars)*	High	**30.88**	36.09	54.24
	Low	**24.21**	24.78	26.50
	Close at December 31	**26.55**	30.08	30.87
Average daily trading volumes *(thousands)*		**1,173**	1,232	1,391
Number of common shares outstanding, December 31 *(thousands)*		**890,709**	849,861	849,355
Weighted average number of common shares outstanding *(thousands)*				
	Basic	**852,670**	849,679	849,170
	Diluted	**852,670**	849,679	849,170

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

Toronto Stock Exchange Listing: HSE

Outstanding Shares

The number of common shares outstanding at December 31, 2010 was 890,708,795.

Transfer Agent and Registrar

Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company N.A. Share certificates may be transferred at Computershare's principal offices in Calgary, Toronto, Montreal and Vancouver, and at Computershare's principal office in Denver, Colorado, in the United States.

Queries regarding share certificates, dividends and estate transfers should be directed to Computershare Trust Company at 1.800-564-6253 (in Canada) and 1-514-982-7555 (outside Canada).

Corporate Office

Husky Energy Inc.
P.O. Box 6525, Station D
707 Eighth Avenue S.W.
Calgary, Alberta T2P 3G7
Telephone: (403) 298-6111
Fax: (403) 298-7464

Investor Relations

Telephone: (403) 298-6817
Fax: (403) 298-6515
E-mail: investor.relations@huskyenergy.com

Corporate Communications

Telephone: (403) 298-6111
Fax: (403) 298-6515
E-mail: corpcom@huskyenergy.com

Website

Visit Husky Energy online at www.huskyenergy.com

Auditors

KPMG LLP
2700, 205 Fifth Avenue S.W.
Calgary, Alberta T2P 4B9

Annual Meeting

The annual meeting of shareholders will be held at 10:30 a.m. on Wednesday, April 27, 2011, in the Palomino Room, at the BMO Centre, 13th Avenue and 3rd Street S.E., Calgary, Alberta.

Additional Publications

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

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

Dividends

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

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

Declaration Date	Quarter Dividend	Special Dividend
February 2011	$ 0.300	
October 2010	0.300	
July 2010	0.300	
April 2010	0.300	
February 2010	0.300	
October 2009	0.300	
July 2009	0.300	
April 2009	0.300	
February 2009	0.300	
October 2008	0.500	
July 2008	0.500	
April 2008	0.400	
February 2008	0.330	
October 2007	0.330	
August 2007	0.250	
May 2007	0.250	
February 2007	0.250	$ 0.250
October 2006	0.250	
July 2006	0.250	
April 2006	0.125	
February 2006	0.125	
October 2005	0.125	0.500
July 2005	0.070	
April 2005	0.070	
February 2005	0.060	
November 2004	0.060	0.270
July 2004	0.060	
April 2004	0.060	
February 2004	0.050	

ADVISORIES

Forward-Looking Information

Certain statements in this Annual Report are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable securities legislation. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as: "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intend," "plan," "projection," "could," "vision," "goals," "objective" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

In particular, this Annual Report includes forward-looking statements relating to the Company's general strategic and business plans; 2011 drilling plans; development and reclamation plans at the Company's Oil Sands, Atlantic Region and South East Asia operations as well as other locations; the expected timing and volumes of production and peak production at the Company's properties in Western Canada, the Oil Sands, the Atlantic Region and South East Asia; the Company's 2011 capital expenditure program; organic and inorganic growth opportunities; production growth rates and reserve replacement rates; arrangements to issue dividends in cash or shares; anticipated timing and effect of acquisitions; expected effects of enhanced oil recovery projects and other new techniques on the recovery rate of reserves and resources; and the impact of added investment in organic production.

Although Husky believes that the expectations reflected by the forward-looking statements presented in this Annual Report are reasonable, Husky'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 Husky about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.

Husky's Annual Information Form and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the risks, material assumptions and other factors that could influence actual results and which 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 securities laws, Husky disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. 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.

Non-GAAP Measures

Certain terms used in this Annual Report, including "Cash flow from Operations", "Return on Average Capital Employed", "Debt to Capital Employed" and "Debt to Cash flow from Operations", are non-GAAP measurements. For further information please see section 11.3 Non-GAAP Measures in Husky's Management's Discussion and Analysis for the year ended December 31, 2010, which section is incorporated by reference herein.

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

Unless otherwise stated, reserve and resource estimates in this Annual Report have an effective date of December 31, 2010. Unless otherwise noted, historical production numbers given represent Husky's share.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is at least a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Discovered petroleum initially-in-place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and contingent resources; the remainder is unrecoverable. A recovery project cannot be defined for these volumes of discovered petroleum initially-in-place at this time. There is no certainty that it will be commercially viable to produce any portion of the resources.

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 wellhead.

Husky Energy

707 Eighth Avenue S.W. Calgary, Alberta T2P 3G7
www.huskyenergy.com

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