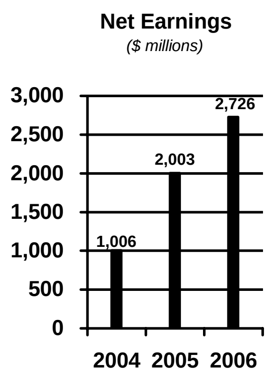
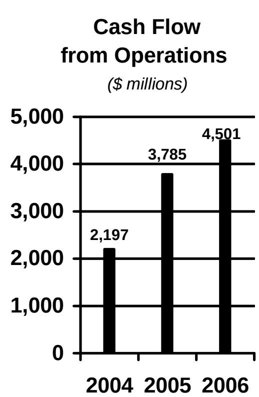
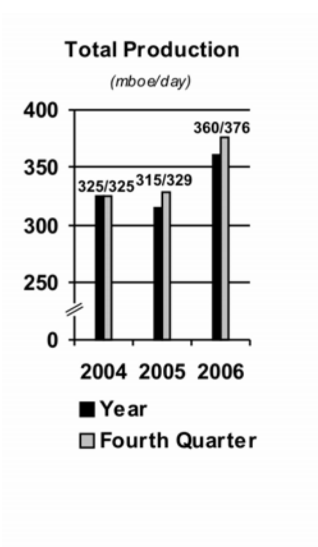
HUSKY ENERGY REPORTS 2006 ANNUAL AND FOURTH QUARTER RESULTS







Calgary, Alberta – Husky Energy Inc. is pleased to announce its annual net earnings were up 36% to $2.7 billion or $6.43 per share (diluted) compared with $2.0 billion or $4.72 per share (diluted) in 2005. Cash flow from operations improved by 19% to $4.5 billion or $10.61 per share (diluted), compared with $3.8 billion or $8.93 per share (diluted) in 2005. Sales and operating revenues, net of royalties, were $12.7 billion in 2006, an increase of 24% compared with $10.2 billion in 2005.

"It has been an exciting year for Husky," said Mr. John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc. "Our initiatives to create shareholder value in growth and diversification are delivering impressive results in annual net earnings and cash flows. Husky's vision, strong financial discipline and successful project execution will continue to provide a dynamic and enriched future for the Company and its shareholders."

Husky continues to build on its financial strength. Debt to capital employed further improved to 14% at December 31, 2006 from 20% at December 31, 2005. Debt to cash flow from operations decreased to 0.4 times at December 31, 2006 compared with 0.5 times at December 31, 2005.

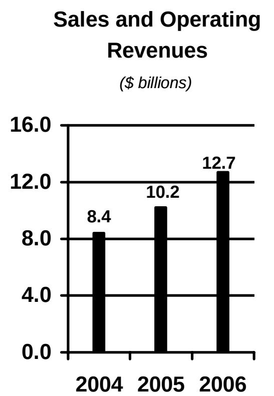
Production in 2006 was 360,000 barrels of oil equivalent per day, compared with 315,000 barrels of oil equivalent per day in 2005, an increase of 14%. Crude oil and natural gas liquids production increased 23% to 248,000 barrels per day, compared with 202,000 barrels per day in 2005. Natural gas production was relatively the same at 672 million cubic feet per day, compared with 680 million cubic feet per day in 2005.

For the fourth quarter, Husky's net earnings, mainly impacted by lower gas commodity prices, were $542 million or $1.28 per share (diluted) in 2006, compared with $669 million or $1.58 per share (diluted) in the fourth quarter of 2005. Cash flow from operations was $1.2 billion or $2.84 per share in the fourth quarter of 2006, compared with $1.2 billion or $2.82 per share in the fourth quarter of 2005. Sales and operating revenues, net of royalties, were $3.1 billion in the fourth quarter of 2006, compared with $3.2 billion in the fourth quarter of 2005.

Production for the fourth quarter of 2006 was 376,100 barrels of oil equivalent per day, compared with 328,500 barrels of oil equivalent per day in 2005, an increase of 14%. Crude oil and natural gas liquids production increased 23% to 265,700 barrels per day, compared with 215,900 barrels per day in 2005. Natural gas production was comparatively the same at 662 million cubic feet per day, compared with 675 million cubic feet per day in 2005.

The Company entered into an agreement to dispose of certain non-core properties in Western Canada for total proceeds of $339 million, currently producing approximately 5,200 barrels of oil equivalent per day. This transaction is expected to close in the first quarter of 2007.

The Tucker Oil Sands project, which was completed on-schedule and under budget, achieved its first oil at the end of 2006. Tucker will ramp up production over the next two years to achieve peak production of 30 mbbls/day of bitumen.



The Sunrise Oil Sands project front-end engineering design is expected to be completed by the third quarter of 2007. Husky plans to drill 29 stratigraphic wells in 2007. Husky continues to evaluate alternatives for the downstream portion of the project and collaboration continues with industry participants to address regional infrastructure issues.

In 2006 Husky acquired additional leases in the Saleski area increasing our acreage to 239,200 acres with discovered resource of approximately 24 billion barrels of bitumen in place within the Grosmont and Nisku carbonates. Conceptual planning and bitumen recovery process evaluation continue at Caribou Lake. Husky has selected 44 stratigraphic wells to drill during the 2007 winter drilling season. In December, Husky submitted an application to the Alberta Energy and Utilities Board and Alberta Environment for the first phase of the Caribou Lake project.

Canada's East Coast White Rose project continues to perform better than expected. During the fourth quarter, a sixth production well was brought onstream, increasing reservoir production capacity to 125,000 barrels of oil per day. A seventh production well, which will further increase the production level of the reservoir will be completed by mid 2007. Husky's 2006 delineation program contributed possible reserves of 138 million barrels of light crude oil to White Rose, which had combined proved, probable and possible reserves of 379 million barrels of light crude oil at the end of 2006.

In the fourth quarter of 2006, Husky successfully acquired three exploration blocks in the Jeanne d'Arc Basin. Husky holds a 100% working interest in Exploration Block 1099 and 50% working interest in Exploration Blocks 1100 and 1101.

Financial Highlights 2006 versus 2005

- Earnings per share to $6.43 from $4.72
- Return on equity to 31.8% from 29.2%
- Return on average capital employed to 27.0% from 22.8%
- Cash flow per share to $10.61 from $8.93
- Debt to capital employed ratio to 14% from 20%
- Debt to cash flow ratio to 0.4 from 0.5
- Market capitalization increased to $33 billion from $25 billion

Internationally, expansion of Husky's offshore acreage position in the South China Sea continued with the signing of three petroleum contracts with CNOOC (the China National Offshore Oil Corporation). The three exploration blocks cover approximately 16,871 square kilometres.

In the South China Sea, Husky made a significant hydrocarbon discovery at Liwan 3-1-1 on Block 29/26. This discovery contains contingent resource of four to six trillion cubic feet of natural gas, making it one of the largest discoveries offshore China. A major seismic program is planned for 2007 over Block 29/26 and the adjacent Block 29/06. A development program is currently proceeding and a deep water rig has been secured for a three-year term commencing in 2008.

In the Midstream segment, a turnaround is planned at the Lloydminster Upgrader in the second quarter of 2007 to complete debottleneck work which will increase throughput capacity of the upgrader to 82,000 barrels per day.

Engineering for the potential expansion of the upgrader to approximately 150,000 barrels per day will be completed by the end of 2007.

In the Refined Products segment, Husky completed and commissioned the Lloydminster ethanol plant in 2006. Husky's facility is the largest wheat based ethanol facility in Western Canada with annual peak production of 130 million litres of ethanol and 134,000 tonnes of Distillers Dried Grain with Solubles (DDGS), a high protein feed supplement. A second 130 million litre per year plant is being constructed in Minnedosa, Manitoba. The new facility, which is scheduled to be completed in the third quarter of 2007, is planned to be fully operational in the fourth quarter of 2007.

SUMMARY OF RESULTS

Financial Summary (millions of dollars, except per share amounts and ratios)	Three months ended **Dec. 31 2006**	Sept. 30 2006	June 30 2006	March 31 2006	Dec. 31 2005	Sept. 30 2005	June 30 2005	March 31 2005	Year ended December 31 **2006**	2005
Sales and operating revenues, net of royalties	**$ 3,084**	$ 3,436	$ 3,040	$ 3,104	$ 3,207	$ 2,594	$ 2,350	$ 2,094	**$12,664**	$10,245
Segmented earnings										
Upstream	**$ 453**	$ 608	$ 822	$ 412	$ 533	$ 445	$ 307	$ 239	**$ 2,295**	$ 1,524
Midstream	**105**	87	140	150	135	61	130	169	**482**	495
Refined Products	**10**	28	52	16	17	27	20	18	**106**	82
Corporate and eliminations	**(26)**	(41)	(36)	(54)	(16)	23	(63)	(42)	**(157)**	(98)
Net earnings	**$ 542**	$ 682	$ 978	$ 524	$ 669	$ 556	$ 394	$ 384	**$ 2,726**	$ 2,003
Per share - Basic and diluted	**$ 1.28**	$ 1.61	$ 2.31	$ 1.24	$ 1.58	$ 1.31	$ 0.93	$ 0.91	**$ 6.43**	$ 4.72
Cash flow from operations	**1,207**	1,224	1,103	967	1,197	944	828	816	**4,501**	3,785
Per share - Basic and diluted	**2.84**	2.88	2.60	2.28	2.82	2.23	1.95	1.93	**10.61**	8.93
Dividends per common share	**0.50**	0.50	0.25	0.25	0.25	0.14	0.14	0.12	**1.50**	0.65
Special dividend per common share	**-**	-	-	-	1.00	-	-	-	**-**	1.00
Total assets	**17,933**	17,324	16,326	15,855	15,716	14,670	14,055	13,681	**17,933**	15,716
Total long-term debt including current portion	**1,611**	1,722	1,722	1,838	1,886	1,896	2,192	2,290	**1,611**	1,886
Return on equity [(1)] *(percent)*	**31.8**	34.2	34.8	29.6	29.2	22.9	20.2	18.3	**31.8**	29.2
Return on average capital employed [(1)] *(percent)*	**27.0**	28.7	28.2	23.2	22.8	17.9	15.3	13.9	**27.0**	22.8

[(1)] *Calculated for the 12 months ended for the dates shown.*

Daily Gross Production		Three months ended **Dec. 31 2006**	Sept. 30 2006	June 30 2006	March 31 2006	Dec. 31 2005
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**30.4**	30.2	29.8	31.3	30.1
Medium crude oil		**28.0**	28.1	28.5	29.4	31.0
Heavy crude oil		**109.4**	107.9	105.6	109.5	109.5
Bitumen		**0.1**	-	-	-	-
		167.9	166.2	163.9	170.2	170.6
East Coast Canada						
White Rose - light crude oil		**79.4**	75.9	53.0	46.4	19.0
Terra Nova - light crude oil		**6.7**	-	2.8	9.3	12.2
China						
Wenchang - light crude oil & NGL		**11.7**	11.1	12.1	13.5	14.1
		265.7	253.2	231.8	239.4	215.9
Natural gas	*(mmcf/day)*	**662.2**	669.1	672.8	685.4	675.3
Total	*(mboe/day)*	**376.1**	364.7	344.0	353.6	328.5

2007 FORECAST AND 2006 ACTUAL

Gross Production		Forecast 2007	Year ended December 31 **2006**	Forecast 2006
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		128 - 135	**111**	103 - 116
Medium crude oil		28 - 30	**29**	29 - 32
Heavy crude oil & bitumen		122 - 130	**108**	115 - 120
		278 - 295	**248**	247 - 268
Natural gas	*(mmcf/day)*	670 - 690	**672**	680 - 730
Total barrels of oil equivalent	*(mboe/day)*	390 - 410	**360**	360 - 390

Capital Program(1)	Forecast 2007	Year ended December 31 **2006**	Forecast 2006
Upstream			
Western Canada	$ 1,840	**$ 1,843**	$ 1,500
Oil Sands	330	**245**	230
East Coast Canada	290	**354**	350
International	160	**94**	140
	2,620	**2,536**	2,220
Midstream	380	**252**	340
Refined Products	140	**276**	260
Corporate	40	**37**	30
	$ 3,180	**$ 3,101**	$ 2,850

(1) *Excludes capitalized administration costs and capitalized interest.*

MAJOR PROJECTS

UPSTREAM

East Coast Canada Exploration and Delineation

- In November 2006 we completed drilling operations at the North Amethyst K-15 delineation well in the Significant Discovery Licence 1044 southwest of White Rose. Analysis is continuing on this reservoir.
- In October 2006 drilling operations were completed at the West Bonne Bay F-12 delineation well and the F-12Z side track well in the Significant Discovery Licence 1040 block adjacent to the Terra Nova field. Preliminary results indicate hydrocarbons in the Upper Hibernia Reservoir. Further analysis will determine more about the resources in this reservoir.
- In June 2006 we completed drilling operations at the White Rose O-28 delineation well and the O-28X side track well in the Significant Discovery Licence 1024 adjacent to the western border of the White Rose field. The O-28 well encountered a 280 metre oil column, further delineation will determine the aerial extent of the reservoir.
- We are currently in the early stages of planning to integrate satellite pools at South White Rose and North Amethyst.
- A 3-D seismic program was shot on Exploration Licence 1067, northwest of the White Rose oil field, covering 270 square kilometres and on Exploration Licence 1011 in the Fortune area, southwest of

White Rose, covering 625 square kilometres. Planning is underway for our 2007 exploration and delineation drilling program, which currently includes three locations in the Jeanne d'Arc Basin.

- At Terra Nova, we are currently participating in a delineation well in the Far East Block.

Tucker Oil Sands Project

At Tucker the first five wells of the total 32 completed well pairs were producing at the end of December and steaming of the other wells continued. Tucker will ramp up production over the next two years to achieve peak production of 30 mbbls/day of bitumen.

Sunrise Oil Sands Project

The conceptual design for the upstream development of the Sunrise Oil Sands project was completed during the fourth quarter of 2006. This aspect of the project includes options for field development, oil treatment and steam generation. Front-end engineering design has commenced and is scheduled to be complete by the third quarter of 2007.

Five water source wells were drilled and evaluated in the fourth quarter of 2006 and an additional five water source wells and 29 stratigraphic wells are planned for the current winter drilling season. Collaboration with various industry participants continues on regional infrastructure issues, including an access highway and airport.

Caribou and Saleski

During 2006 we participated in three land sales in the Saleski area and acquired leases totalling 84,320 acres increasing total leases to 239,200 acres in the Saleski area. In December we submitted an application to the Alberta Energy and Utilities Board and Alberta Environment for the first phase of the Caribou Lake project.

In addition, conceptual development planning continued with water source and disposal well studies for both Saleski and Caribou and determination of an appropriate bitumen recovery process for Saleski. At Caribou we completed the selection of 44 stratigraphic well locations to be drilled during the 2007 winter drilling season.

Northwest Territories Exploration

A seismic program was completed during September 2006 that included our newly acquired Exploration Licence 441, which is contiguous with the eastern boundary of our Exploration Licence 397 containing the Stewart D-57 natural gas discovery. Based on the timing of this seismic program and subsequent analytical work we, with our partners, have decided to defer further exploration drilling until the winter of 2007/2008. This will allow for full incorporation of new seismic data into the prospect mapping that is currently underway.

China Exploration

In the fourth quarter the China National Offshore Oil Corporation agreed to a 3-D seismic program on Block 29/26, on which the Liwan natural gas discovery is located and also on the adjacent Block 29/06. The program will investigate several structures with characteristics similar to those of Liwan. A deep water rig has been secured for a three-year term commencing in 2008.

Indonesia Natural Gas Development

At Madura, negotiations for a natural gas sales agreement are continuing. Development of the Madura natural gas field is contingent on receiving government approval for our Plan of Development and an extension to the Production Sharing Contract. In September, Husky signed the Production Sharing Contract for the 4,254 square kilometre East Bawean II Block and is currently planning to commence a 3-D seismic program in the second half of 2007.

MIDSTREAM

Lloydminster Upgrader Expansion

The front-end engineering design for the major expansion of the Lloydminster Upgrader progressed to approximately 25% of completion. Completion of this engineering design is scheduled by the end of 2007. The expansion envisions increasing throughput capacity to 150 mbbls/day.

REFINED PRODUCTS

Lloydminster and Minnedosa Ethanol Plants

To meet the increasing demand for ethanol blended gasoline, we completed construction and commissioned our new Lloydminster, Saskatchewan ethanol plant. Additionally, we commenced construction of a second ethanol plant at Minnedosa, Manitoba. Construction of the new plant at Minnedosa is expected to be completed during the third quarter of 2007 and planned to be fully operational in the fourth quarter of 2007. Each plant is designed to have throughput capacity of 130 million litres of ethanol per year.

BUSINESS ENVIRONMENT

Husky's financial results are significantly influenced by its business environment. Average quarterly market prices were:

Average Benchmark Prices and U.S. Exchange Rate		Three months ended				
		Dec. 31 2006	Sept. 30 2006	June 30 2006	March 31 2006	Dec. 31 2005
WTI crude oil [1]	*(U.S. $/bbl)*	**60.21**	70.48	70.70	63.48	60.02
Brent crude oil [2]	*(U.S. $/bbl)*	**59.68**	69.49	69.62	61.75	56.90
Canadian par light crude 0.3% sulphur	*($/bbl)*	**65.12**	79.65	78.97	69.40	71.65
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**35.24**	49.61	48.65	26.25	29.60
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**6.56**	6.58	6.79	8.98	12.97
NIT natural gas	*($/GJ)*	**6.03**	5.72	5.95	8.79	11.08
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**21.75**	19.24	17.99	29.20	24.24
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.878**	0.892	0.891	0.866	0.852

[1] *Prices quoted are near-month contract prices for settlement during the next month.*
[2] *Dated Brent prices which are dated less than 15 days prior to loading for delivery.*

SENSITIVITY ANALYSIS

The following table indicates the relative annual effect of changes in certain key variables on our pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the fourth quarter of 2006. 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	2006 Fourth Quarter Average	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
			($ millions)	*($/share)* [(5)]	*($ millions)*	*($/share)* [(5)]
Upstream and Midstream						
WTI benchmark crude oil price	60.21	*U.S. $1.00/bbl*	99	0.23	66	0.16
NYMEX benchmark natural gas price [(1)]	6.56	*U.S. $0.20/mmbtu*	37	0.09	25	0.06
WTI/Lloyd crude blend differential [(2)]	21.75	*U.S. $1.00/bbl*	(33)	(0.08)	(22)	(0.05)
Exchange rate (U.S. $ per Cdn $) [(3)]	0.88	*U.S. $0.01*	(68)	(0.16)	(46)	(0.11)
Refined Products						
Light oil margins	0.02	*Cdn $0.005/litre*	16	0.04	11	0.02
Asphalt margins	11.65	*Cdn $1.00/bbl*	8	0.02	5	0.01
Consolidated						
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	0.86 [(4)]	*U.S. $0.01*			9	0.02

(1) *Includes decrease in earnings related to natural gas consumption.*
(2) *Includes impact of upstream and upgrading operations only.*
(3) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items.*
(4) *U.S./Canadian dollar exchange rate at December 31, 2006.*
(5) *Based on December 31, 2006 common shares outstanding of 424.3 million.*

RESULTS OF OPERATIONS

UPSTREAM

Fourth Quarter

Upstream earnings were $80 million lower in the fourth quarter of 2006 than in the fourth quarter of 2005 mainly as a result of lower natural gas prices and lower sales volume of light crude oil from Terra Nova and Wenchang offset by higher sales volume of light crude oil from White Rose and higher heavy crude oil prices.

Twelve Months

Upstream earnings were $771 million higher in 2006 than in 2005 as a result of higher sales volume of light crude oil from White Rose and higher crude oil prices partially offset by lower natural gas prices and lower sales volume of light crude oil from Terra Nova and Wenchang.

Average Sales Prices		Three months ended Dec. 31		Year ended Dec. 31	
		2006	2005	**2006**	2005
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**62.55**	63.20	**69.06**	61.56
Medium crude oil		**43.99**	43.60	**49.48**	43.44
Heavy crude oil		**35.46**	29.98	**39.92**	31.09
Total average		**49.43**	43.52	**54.08**	42.75
Natural Gas	*($/mcf)*				
Average		**6.19**	11.39	**6.47**	7.96

Upstream Earnings Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	**2006**	2005	**2006**	2005
Gross revenues	**$ 1,619**	$ 1,591	**$ 6,586**	$ 5,207
Royalties	**185**	264	**814**	840
Net revenues	**1,434**	1,327	**5,772**	4,367
Operating and administration expenses	**373**	299	**1,321**	1,050
Depletion, depreciation and amortization	**389**	313	**1,476**	1,144
Income taxes	**219**	182	**680**	649
Earnings	**$ 453**	$ 533	**$ 2,295**	$ 1,524

Unit Operating Costs

Unit operating costs were seven percent higher in the fourth quarter of 2006 compared with the same period in 2005 primarily due to higher power costs, workovers, trucking, natural gas compression, higher number of producing wells and higher service and material costs. Higher unit operating costs in Western Canada were partially offset by lower operating costs at White Rose.

Unit Depletion, Depreciation and Amortization

Unit depletion, depreciation and amortization expense increased nine percent in the fourth quarter of 2006 compared with the same period in 2005. The increase was primarily due to net growth of the capital base in 2006 as a result of increased requirements for production maintenance capital in the Western Canada Sedimentary Basin and the start-up of the White Rose oil field, which has a higher than average ratio of capital to reserves.

Operating Netbacks

Three months ended Dec. 31	Western Canada 2006	Western Canada 2005	East Coast 2006	East Coast 2005	International 2006	International 2005	Total 2006	Total 2005
Light Crude Oil *(per boe)* [(1)]								
Sales Price	**$ 53.74**	$ 69.42	**$ 64.62**	$ 63.05	**$ 66.01**	$ 60.03	**$ 62.37**	$ 65.03
Royalties	**7.25**	12.02	**1.96**	6.25	**10.57**	5.67	**3.93**	8.45
Operating costs	**15.92**	11.94	**4.14**	6.30	**4.90**	4.64	**6.78**	8.26
	30.57	45.46	**58.52**	50.50	**50.54**	49.72	**51.66**	48.32
Medium Crude Oil *(per boe)* [(1)]								
Sales Price	**43.84**	44.69	**-**	-	**-**	-	**43.84**	44.69
Royalties	**7.40**	8.05	**-**	-	**-**	-	**7.40**	8.05
Operating costs	**15.42**	11.84	**-**	-	**-**	-	**15.42**	11.84
	21.02	24.80	**-**	-	**-**	-	**21.02**	24.80
Heavy Crude Oil *(per boe)* [(1)]								
Sales Price	**35.53**	30.23	**-**	-	**-**	-	**35.53**	30.23
Royalties	**4.49**	3.53	**-**	-	**-**	-	**4.49**	3.53
Operating costs	**12.10**	10.97	**-**	-	**-**	-	**12.10**	10.97
	18.94	15.73	**-**	-	**-**	-	**18.94**	15.73
Total Crude Oil *(per boe)* [(1)]								
Sales Price	**39.94**	39.80	**64.62**	63.05	**66.01**	60.03	**49.09**	44.43
Royalties	**5.45**	5.87	**1.96**	6.25	**10.57**	5.67	**4.55**	5.91
Operating costs	**13.34**	11.32	**4.14**	6.30	**4.90**	4.64	**9.98**	10.17
	21.15	22.61	**58.52**	50.50	**50.54**	49.72	**34.56**	28.35
Natural Gas *(per mcfge)* [(2)]								
Sales Price	**6.32**	11.20	**-**	-	**-**	-	**6.32**	11.20
Royalties	**1.20**	2.38	**-**	-	**-**	-	**1.20**	2.38
Operating costs	**1.39**	1.06	**-**	-	**-**	-	**1.39**	1.06
	3.73	7.76	**-**	-	**-**	-	**3.73**	7.76
Equivalent Unit *(per boe)* [(1)]								
Sales Price	**39.15**	50.41	**64.62**	63.05	**66.01**	60.03	**45.83**	52.03
Royalties	**6.14**	9.14	**1.96**	6.25	**10.57**	5.67	**5.32**	8.71
Operating costs	**11.36**	9.40	**4.14**	6.30	**4.90**	4.64	**9.51**	8.90
	$ 21.65	$ 31.87	**$ 58.52**	$ 50.50	**$ 50.54**	$ 49.72	**$ 31.00**	$ 34.42

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

Operating Netbacks (continued)

Year ended Dec. 31	Western Canada		East Coast		International		Total	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005
Light Crude Oil *(per boe)* [(1)]								
Sales Price	**$ 59.89**	$ 60.74	**$ 71.18**	$ 62.61	**$ 73.60**	$ 63.15	**$ 68.51**	$ 61.86
Royalties	**7.34**	8.66	**1.95**	5.91	**12.17**	5.93	**4.49**	7.22
Operating costs	**11.89**	9.86	**5.48**	5.14	**3.81**	2.92	**6.96**	6.88
	40.66	42.22	**63.75**	51.56	**57.62**	54.30	**57.06**	47.76
Medium Crude Oil *(per boe)* [(1)]								
Sales Price	**48.97**	43.67	**-**	-	**-**	-	**48.97**	43.67
Royalties	**8.61**	7.77	**-**	-	**-**	-	**8.61**	7.77
Operating costs	**13.09**	10.97	**-**	-	**-**	-	**13.09**	10.97
	27.27	24.93	**-**	-	**-**	-	**27.27**	24.93
Heavy Crude Oil *(per boe)* [(1)]								
Sales Price	**39.91**	31.22	**-**	-	**-**	-	**39.91**	31.22
Royalties	**5.16**	3.75	**-**	-	**-**	-	**5.16**	3.75
Operating costs	**11.10**	9.90	**-**	-	**-**	-	**11.10**	9.90
	23.65	17.57	**-**	-	**-**	-	**23.65**	17.57
Total Crude Oil *(per boe)* [(1)]								
Sales Price	**44.90**	38.91	**71.18**	62.61	**73.60**	63.15	**53.55**	42.83
Royalties	**6.14**	5.41	**1.95**	5.91	**12.17**	5.93	**5.28**	5.49
Operating costs	**11.60**	10.10	**5.48**	5.14	**3.81**	2.92	**9.53**	9.13
	27.16	23.40	**63.75**	51.56	**57.62**	54.30	**38.74**	28.21
Natural Gas *(per mcfge)* [(2)]								
Sales Price	**6.65**	8.02	**-**	-	**-**	-	**6.65**	8.02
Royalties	**1.37**	1.76	**-**	-	**-**	-	**1.37**	1.76
Operating costs	**1.18**	1.04	**-**	-	**-**	-	**1.18**	1.04
	4.10	5.22	**-**	-	**-**	-	**4.10**	5.22
Equivalent Unit *(per boe)* [(1)]								
Sales Price	**42.91**	42.53	**71.18**	62.61	**73.60**	63.15	**49.34**	44.69
Royalties	**6.97**	7.45	**1.95**	5.91	**12.17**	5.93	**6.19**	7.29
Operating costs	**9.79**	8.59	**5.48**	5.14	**3.81**	2.92	**8.77**	8.12
	$ 26.15	$ 26.49	**$ 63.75**	$ 51.56	**$ 57.62**	$ 54.30	**$ 34.38**	$ 29.28

[(1)] *Includes associated co-products converted to boe.*
[(2)] *Includes associated co-products converted to mcfge.*

Upstream Capital Expenditures Summary [1]	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	**2006**	2005	**2006**	2005
Exploration				
Western Canada	**$ 37**	$ 123	**$ 497**	$ 389
East Coast Canada and Frontier	**38**	20	**79**	66
International	**8**	16	**77**	55
	83	159	**653**	510
Development				
Western Canada	**593**	525	**1,675**	1,618
East Coast Canada	**28**	131	**279**	579
International	**-**	16	**20**	23
	621	672	**1,974**	2,220
	$ 704	$ 831	**$ 2,627**	$ 2,730

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

Western Canada Wells Drilled [1] [2]		Three months ended Dec. 31				Year ended Dec. 31			
		2006		2005		**2006**		2005	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**30**	**29**	26	25	**101**	**99**	89	85
	Gas	**52**	**42**	153	60	**330**	**192**	392	196
	Dry	**2**	**2**	10	10	**26**	**24**	36	36
		84	**73**	189	95	**457**	**315**	517	317
Development	Oil	**210**	**209**	181	167	**590**	**543**	466	433
	Gas	**183**	**159**	168	150	**565**	**490**	610	551
	Dry	**5**	**5**	17	16	**25**	**22**	42	39
		398	**373**	366	333	**1,180**	**1,055**	1,118	1,023
Total		**482**	**446**	555	428	**1,637**	**1,370**	1,635	1,340

(1) *Excludes stratigraphic test wells.*
(2) *Includes non-operated wells.*

MIDSTREAM

Upgrading

Fourth Quarter

Upgrading earnings in the fourth quarter of 2006 were $23 million lower than the fourth quarter of 2005 due to a narrower upgrading differential partially offset by higher sales volume of synthetic crude oil, lower costs for natural gas and thermal energy and lower income taxes.

Twelve Months

Upgrading earnings in 2006 were $28 million less than 2005 due to narrower differentials and increased electrical energy costs offset by higher sales volume of synthetic crude, lower costs for natural gas and thermal energy and lower income taxes.

Upgrading Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)		**2006**	2005	**2006**	2005
Gross margin		**$ 145**	$ 198	**$ 624**	$ 692
Operating costs		**55**	77	**224**	228
Other recoveries		**(2)**	(2)	**(6)**	(6)
Depreciation and amortization		**6**	6	**24**	21
Income taxes		**27**	35	**97**	136
Earnings		**$ 59**	$ 82	**$ 285**	$ 313
Selected operating data:					
Upgrader throughput [(1)]	*(mbbls/day)*	**70.8**	74.7	**71.0**	66.6
Synthetic crude oil sales	*(mbbls/day)*	**64.1**	62.2	**62.5**	57.5
Upgrading differential	*($/bbl)*	**$ 23.81**	$ 33.31	**$ 26.16**	$ 30.70
Unit margin	*($/bbl)*	**$ 24.57**	$ 34.59	**$ 27.35**	$ 33.01
Unit operating cost [(2)]	*($/bbl)*	**$ 8.39**	$ 11.08	**$ 8.65**	$ 9.38

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

Infrastructure and Marketing

Fourth Quarter

Infrastructure and marketing earnings in the fourth quarter of 2006 decreased by $7 million compared with the same period in 2005 primarily due to lower earnings from sales of blended heavy crude oil partially offset by higher cogeneration earnings and crude oil and NGL trading earnings.

Twelve Months

Infrastructure and marketing earnings in 2006 increased by $15 million compared with 2005 primarily due to higher crude oil pipeline margins, higher natural gas marketing earnings, higher cogeneration earnings and lower income taxes partially offset by lower earnings from blended heavy crude oil marketing.

Infrastructure and Marketing Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)		**2006**	2005	**2006**	2005
Gross margin	- pipeline	**$ 24**	$ 24	**$ 104**	$ 92
	- other infrastructure and marketing	**56**	63	**208**	217
		80	87	**312**	309
Other expenses		**3**	2	**11**	10
Depreciation and amortization		**7**	5	**24**	21
Income taxes		**24**	27	**80**	96
Earnings		**$ 46**	$ 53	**$ 197**	$ 182
Selected operating data:					
Aggregate pipeline throughput	*(mbbls/day)*	**465**	480	**475**	474

Midstream Capital Expenditures

Midstream capital expenditures totaled $252 million in 2006; $184 million at the Lloydminster Upgrader, primarily for debottleneck and reliability projects and front-end engineering design for a potential expansion project and $68 million on pipelines and infrastructure.

REFINED PRODUCTS

Fourth Quarter

Refined Products earnings in the fourth quarter of 2006 decreased by $7 million compared with the fourth quarter of 2005 due to lower margins for gasoline and distillates partially offset by higher margins for asphalt products.

Twelve Months

Refined Products earnings in 2006 increased by $24 million compared with 2005 due to higher margins for gasoline and distillates and higher sales volume of asphalt products partially offset by lower sales volume of gasoline and distillates.

Refined Products Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)		**2006**	2005	**2006**	2005
Gross margin - fuel sales		**$ 17**	$ 32	**$ 138**	$ 126
- ancillary sales		**10**	8	**36**	34
- asphalt sales		**23**	20	**94**	91
		50	60	**268**	251
Operating and other expenses		**21**	20	**74**	75
Depreciation and amortization		**14**	13	**48**	47
Income taxes		**5**	10	**40**	47
Earnings		**$ 10**	$ 17	**$ 106**	$ 82
Selected operating data:					
Number of fuel outlets				**505**	515
Light oil sales	*(million litres/day)*	**8.6**	9.0	**8.7**	8.9
Light oil retail sales per outlet	*(thousand litres/day)*	**12.8**	12.9	**12.9**	12.7
Prince George refinery throughput	*(mbbls/day)*	**11.2**	9.7	**9.0**	9.7
Asphalt sales	*(mbbls/day)*	**21.0**	22.4	**23.4**	22.5
Lloydminster refinery throughput	*(mbbls/day)*	**28.1**	27.4	**27.1**	25.5
Ethanol production	*(thousand litres/day)*	**159.3**	25.9	**59.7**	25.6

Refined Products Capital Expenditures

Refined Products capital expenditures totaled $285 million in 2006; $94 million at the Lloydminster ethanol plant, $94 million at the Minnedosa ethanol plant, $57 million for marketing outlet and facilities upgrades and at the Prince George refinery $40 million.

CORPORATE

Corporate Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars) income (expense)	**2006**	2005	**2006**	2005
Intersegment eliminations - net	**$ 36**	$ 3	**$ 20**	$ (50)
Administration expenses	**(16)**	(4)	**(35)**	(19)
Stock-based compensation	**(35)**	6	**(138)**	(171)
Accretion	**(1)**	-	**(3)**	(2)
Other - net	**(4)**	(2)	**(23)**	49
Depreciation and amortization	**(10)**	(6)	**(27)**	(23)
Interest on debt	**(27)**	(40)	**(125)**	(148)
Interest capitalized	**3**	23	**33**	114
Interest income	**-**	1	**-**	2
Foreign exchange - realized	**(12)**	5	**7**	9
Foreign exchange - unrealized	**4**	(10)	**17**	22
Income taxes	**36**	8	**117**	119
Earnings (loss)	**$ (26)**	$ (16)	**$ (157)**	$ (98)

Foreign Exchange Rates	Three months ended Dec. 31		Year ended Dec. 31	
	2006	2005	**2006**	2005
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.897**	U.S. $0.861	**U.S. $0.858**	U.S. $0.831
At end of period	**U.S. $0.858**	U.S. $0.858	**U.S. $0.858**	U.S. $0.858

Credit Ratings

Based on successful completion of the White Rose project and the Company’s internal growth prospects, competitive full cycle cost and consistently moderate financial risk profile, Standard and Poor’s Rating Services upgraded the Company’s long-term corporate credit and senior unsecured debt rating to BBB+ with a stable outlook.

Corporate Capital Expenditures

Corporate capital expenditures totaled $37 million in 2006 primarily for various office and information system upgrades.

ADDITIONAL INFORMATION

OIL AND GAS RESERVES

Reconciliation of Proved Reserves ***[(1)]***

	Canada										
	Western Canada					East Coast	International		Total		
	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Bitumen	Natural Gas	Light Crude Oil	Light Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Equivalent Units
	(mmbbls)	*(mmbbls)*	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(bcf)*	*(mmboe)*
Proved reserves at December 31, 2005	167	91	217	48	2,136	89	17	-	629	2,136	985
Technical revisions	(3)	(1)	(2)	(1)	(87)	31	2	-	26	(87)	11
Purchase of reserves in place	1	1	-	-	25	-	-	-	2	25	6
Sale of reserves in place	(1)	-	-	-	(3)	-	-	-	(1)	(3)	(1)
Discoveries, extensions and improved recovery	13	6	37	13	317	12	-	-	81	317	134
Production	(11)	(10)	(39)	-	(245)	(25)	(5)	-	(90)	(245)	(131)
Proved reserves at December 31, 2006	**166**	**87**	**213**	**60**	**2,143**	**107**	**14**	**-**	**647**	**2,143**	**1,004**
Proved plus probable reserves **At December 31, 2006**	**219**	**102**	**289**	**1,187**	**2,533**	**186**	**23**	**93**	**2,006**	**2,626**	**2,444**
At December 31, 2005	225	105	291	951	2,542	207	30	167	1,809	2,709	2,260

(1) *Constant price before royalties.*

NON-GAAP MEASURES

Disclosure of Cash Flow from Operations

Management's Discussion and Analysis contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than "cash flow - operating activities" as determined in accordance with generally accepted accounting principles as an indicator of our financial performance. Our 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 periods noted:

		Year ended December 31	
(millions of dollars)		**2006**	2005
Non-GAAP	Cash flow from operations	**$ 4,501**	$ 3,785
	Settlement of asset retirement obligations	**(36)**	(41)
	Change in non-cash working capital	**544**	(94)
GAAP	Cash flow - operating activities	**$ 5,009**	$ 3,650

TERMS AND ABBREVIATIONS

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

Bitumen	*A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. It is more viscous than 10 degrees API*
Coalbed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Front-end Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
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*
Hectare	*One hectare is equal to 2.47 acres*
Feedstock	*Raw materials which are processed into petroleum products*
Design rate capacity	*Maximum continuous rated output of a plant based on its design*
Gross reserves/production	*A company's working interest share of reserves/production before deduction of royalties*
Gross/net acres/wells	*Gross refers to the total number of acres/wells in which an interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Possible reserves	*Are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves*
Discovered resource	*Are those quantities of oil and gas estimated on a given date to be remaining in, plus those quantities already produced from, known accumulations. Discovered resources are divided into economic and uneconomic categories, with the estimated future recoverable portion classified as reserves and contingent resources, respectively*
Contingent resource	*Are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but not currently economic*
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*
Equity	*Shares and retained earnings*
Total Debt	*Long-term debt including current portion and bank operating loans*

In this news release the pronouns "we", "our" and "us" and the terms "Husky" and "the Company" denote Husky Energy Inc. and its subsidiaries and partnership interests on a consolidated basis.

All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.

Prices quoted include or exclude the effect of hedging as indicated.

Unless otherwise indicated, all production and reserves volume quoted are gross, which represent the Company's working interest share before royalties.

Natural gas is converted on the basis that six mcf equals one barrel of oil.

FORWARD-LOOKING STATEMENTS OR INFORMATION

Certain statements in this release and Interim Report are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in these forward-looking statements. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as: "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intend," "plan," "projection," "could," "vision," "goals," "objective" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. In particular, forward-looking statements include: our general strategic plans, our projection for production for the Tucker in-situ oil sands project, our Sunrise oil sands project design schedule and water evaluation and stratigraphic drilling plans, our conceptual development planning for Saleski and Caribou, our Caribou oil sands drilling plans, our White Rose oil field drilling, development and production plans, the schedule for our offshore China geophysical and drilling programs, the schedule and our plans for expanding our heavy crude oil mainline and expected results and schedule of our Lloydminster Upgrader expansion design plans, our Lloydminster ethanol plant production schedule and planned purchase of grain feedstock and our Minnedosa plant commissioning schedule. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this release and Interim Report. Among the key factors that have a direct bearing on our results of operations are the nature of our involvement in the business of exploration for, and development and production of crude oil and natural gas reserves and the fluctuation of the exchange rates between the Canadian and United States dollar.

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

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

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

CAUTIONARY NOTE REQUIRED BY NATIONAL INSTRUMENT 51-101

The Company uses the terms barrels of oil equivalent ("boe") and thousand cubic feet of gas equivalent ("mcfge"), which are calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the terms boe and mcfge may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the well head.

Husky's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to Husky by Canadian securities regulatory authorities, which permits Husky to provide disclosure required by and consistent with those of the United States Securities and Exchange Commission and the Financial Accounting Standards Board in the United States in place of much of the disclosure expected by National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Please refer to "Disclosure of Exemption under National Instrument 51-101" at page 2 of our Annual Information Form for the year ended December 31, 2005 filed with securities regulatory authorities for further information.

CAUTIONARY NOTE TO U.S. INVESTORS

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

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars)	**December 31 2006**	December 31 2005
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 442**	$ 168
Accounts receivable	**1,284**	856
Inventories	**428**	471
Prepaid expenses	**25**	40
	2,179	1,535
Property, plant and equipment - (full cost accounting)	**25,552**	22,375
Less accumulated depletion, depreciation and amortization	**10,002**	8,416
	15,550	13,959
Goodwill	**160**	160
Other assets	**44**	62
	$ 17,933	$ 15,716
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 2,574**	$ 2,310
Long-term debt due within one year *(note 5)*	**100**	274
	2,674	2,584
Long-term debt *(note 5)*	**1,511**	1,612
Other long-term liabilities *(note 6)*	**756**	730
Future income taxes	**3,372**	3,270
Commitments and contingencies *(note 8)*		
Shareholders' equity		
Common shares *(note 9)*	**3,533**	3,523
Retained earnings	**6,087**	3,997
	9,620	7,520
	$ 17,933	$ 15,716
Common shares outstanding *(millions) (note 9)*	**424.3**	424.1

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

Consolidated Statements of Earnings

(millions of dollars, except per share amounts)	Three months ended Dec. 31 2006	Three months ended Dec. 31 2005	Year ended Dec. 31 2006	Year ended Dec. 31 2005
	(unaudited)	(unaudited)	(unaudited)	(audited)
Sales and operating revenues, net of royalties	**$ 3,084**	$ 3,207	**$ 12,664**	$ 10,245
Costs and expenses				
Cost of sales and operating expenses	**1,760**	1,903	**7,169**	5,917
Selling and administration expenses	**47**	29	**162**	138
Stock-based compensation	**35**	(6)	**138**	171
Depletion, depreciation and amortization	**426**	343	**1,599**	1,256
Interest - net *(note 5)*	**24**	16	**92**	32
Foreign exchange *(note 5)*	**8**	5	**(24)**	(31)
Other - net	**3**	2	**22**	(50)
	2,303	2,292	**9,158**	7,433
Earnings before income taxes	**781**	915	**3,506**	2,812
Income taxes *(note 7)*				
Current	**54**	77	**678**	297
Future	**185**	169	**102**	512
	239	246	**780**	809
Net earnings	**$ 542**	$ 669	**$ 2,726**	$ 2,003
Earnings per share				
Basic and diluted	**$ 1.28**	$ 1.58	**$ 6.43**	$ 4.72
Weighted average number of common shares outstanding *(millions)*				
Basic and diluted	**424.3**	424.1	**424.2**	424.0

Consolidated Statements of Retained Earnings

(millions of dollars)	Three months ended Dec. 31 2006	Three months ended Dec. 31 2005	Year ended Dec. 31 2006	Year ended Dec. 31 2005
	(unaudited)	(unaudited)	(unaudited)	(audited)
Beginning of period	**$ 5,757**	$ 3,858	**$ 3,997**	$ 2,694
Net earnings	**542**	669	**2,726**	2,003
Dividends on common shares - ordinary	**(212)**	(106)	**(636)**	(276)
- special	**-**	(424)	**-**	(424)
End of period	**$ 6,087**	$ 3,997	**$ 6,087**	$ 3,997

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

Consolidated Statements of Cash Flows

(millions of dollars)	Three months ended Dec. 31 **2006**	Three months ended Dec. 31 2005	Year ended Dec. 31 **2006**	Year ended Dec. 31 2005
	(unaudited)	*(unaudited)*	*(unaudited)*	*(audited)*
Operating activities				
Net earnings	**$ 542**	$ 669	**$ 2,726**	$ 2,003
Items not affecting cash				
Accretion *(note 6)*	**11**	8	**45**	33
Depletion, depreciation and amortization	**426**	343	**1,599**	1,256
Future income taxes *(note 7)*	**185**	169	**102**	512
Foreign exchange	**39**	5	**(3)**	(37)
Other	**4**	3	**32**	18
Settlement of asset retirement obligations	**(12)**	(17)	**(36)**	(41)
Change in non-cash working capital *(note 4)*	**(89)**	(129)	**544**	(94)
Cash flow - operating activities	**1,106**	1,051	**5,009**	3,650
Financing activities				
Bank operating loans financing - net	**-**	(23)	**-**	(101)
Long-term debt issue	**-**	208	**1,226**	3,235
Long-term debt repayment	**(171)**	(226)	**(1,493)**	(3,401)
Settlement of cross currency swap	**(47)**	-	**(47)**	-
Proceeds from exercise of stock options	**-**	1	**3**	6
Proceeds from monetization of financial instruments	**-**	9	**-**	39
Dividends on common shares	**(212)**	(530)	**(636)**	(700)
Other	**(1)**	(1)	**(1)**	(1)
Change in non-cash working capital *(note 4)*	**(14)**	466	**(678)**	255
Cash flow - financing activities	**(445)**	(96)	**(1,626)**	(668)
Available for investing	**661**	955	**3,383**	2,982
Investing activities				
Capital expenditures	**(882)**	(959)	**(3,171)**	(3,068)
Asset sales	**-**	4	**34**	74
Other	**-**	(8)	**(12)**	(31)
Change in non-cash working capital *(note 4)*	**119**	176	**40**	211
Cash flow - investing activities	**(763)**	(787)	**(3,109)**	(2,814)
Increase (decrease) in cash and cash equivalents	**(102)**	168	**274**	168
Cash and cash equivalents at beginning of period	**544**	-	**168**	-
Cash and cash equivalents at end of period	**$ 442**	$ 168	**$ 442**	$ 168

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

Notes to the Consolidated Financial Statements

Year ended December 31, 2006 *(unaudited)*

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

Note 1 Segmented Financial Information

	Upstream		Midstream				Refined Products		Corporate and Eliminations [(1)]		Total	
			Upgrading		Infrastructure and Marketing							
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Three months ended Dec. 31												
Sales and operating revenues, net of royalties	**$ 1,434**	$ 1,327	**$ 385**	$ 414	**$ 2,377**	$ 2,512	**$ 579**	$ 632	**$ (1,691)**	$ (1,678)	**$ 3,084**	$ 3,207
Costs and expenses												
Operating, cost of sales, selling and general	**373**	299	**293**	291	**2,300**	2,427	**550**	592	**(1,671)**	(1,681)	**1,845**	1,928
Depletion, depreciation and amortization	**389**	313	**6**	6	**7**	5	**14**	13	**10**	6	**426**	343
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**24**	16	**24**	16
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**8**	5	**8**	5
	762	612	**299**	297	**2,307**	2,432	**564**	605	**(1,629)**	(1,654)	**2,303**	2,292
Earnings (loss) before income taxes	**672**	715	**86**	117	**70**	80	**15**	27	**(62)**	(24)	**781**	915
Current income taxes	**62**	46	**(31)**	3	**22**	-	**2**	-	**(1)**	28	**54**	77
Future income taxes	**157**	136	**58**	32	**2**	27	**3**	10	**(35)**	(36)	**185**	169
Net earnings (loss)	**$ 453**	$ 533	**$ 59**	$ 82	**$ 46**	$ 53	**$ 10**	$ 17	**$ (26)**	$ (16)	**$ 542**	$ 669
Capital expenditures - Three months ended Dec. 31	**$ 704**	$ 831	**$ 65**	$ 35	**$ 27**	$ 13	**$ 83**	$ 86	**$ 14**	$ 7	**$ 893**	$ 972
Year ended Dec. 31												
Sales and operating revenues, net of royalties	**$ 5,772**	$ 4,367	**$ 1,679**	$ 1,488	**$ 9,559**	$ 7,383	**$ 2,575**	$ 2,345	**$ (6,921)**	$ (5,338)	**$ 12,664**	$ 10,245
Costs and expenses												
Operating, cost of sales, selling and general	**1,321**	1,050	**1,273**	1,018	**9,258**	7,084	**2,381**	2,169	**(6,742)**	(5,145)	**7,491**	6,176
Depletion, depreciation and amortization	**1,476**	1,144	**24**	21	**24**	21	**48**	47	**27**	23	**1,599**	1,256
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**92**	32	**92**	32
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(24)**	(31)	**(24)**	(31)
	2,797	2,194	**1,297**	1,039	**9,282**	7,105	**2,429**	2,216	**(6,647)**	(5,121)	**9,158**	7,433
Earnings (loss) before income taxes	**2,975**	2,173	**382**	449	**277**	278	**146**	129	**(274)**	(217)	**3,506**	2,812
Current income taxes	**519**	215	**53**	16	**79**	(14)	**19**	(3)	**8**	83	**678**	297
Future income taxes	**161**	434	**44**	120	**1**	110	**21**	50	**(125)**	(202)	**102**	512
Net earnings (loss)	**$ 2,295**	$ 1,524	**$ 285**	$ 313	**$ 197**	$ 182	**$ 106**	$ 82	**$ (157)**	$ (98)	**$ 2,726**	$ 2,003
Capital employed - As at Dec. 31	**$ 9,482**	$ 8,741	**$ 553**	$ 510	**$ 843**	$ 390	**$ 561**	$ 481	**$ (208)**	$ (716)	**$ 11,231**	$ 9,406
Capital expenditures - Year ended Dec. 31	**$ 2,627**	$ 2,730	**$ 184**	$ 120	**$ 68**	$ 37	**$ 285**	$ 191	**$ 37**	$ 21	**$ 3,201**	$ 3,099
Total assets - As at Dec. 31	**$ 13,920**	$ 12,887	**$ 992**	$ 844	**$ 1,329**	$ 866	**$ 1,114**	$ 834	**$ 578**	$ 285	**$ 17,933**	$ 15,716

[(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.*

Note 2 Significant Accounting Policies

The interim consolidated financial statements of Husky Energy Inc. ("Husky" or "the Company") have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2005, except as noted below. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in the Company's annual report for the year ended December 31, 2005. Certain prior years' amounts have been reclassified to conform with current presentation.

Note 3 Change in Accounting Policies

Non-monetary Transactions

Effective January 1, 2006, the Company adopted the revised recommendations of the Canadian Institute of Chartered Accountants section 3831, "Non-monetary Transactions" which replaced section 3830 of the same name. The new recommendations require that all non-monetary transactions are measured based on 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. The guidance was effective for all non-monetary transactions initiated in periods beginning on or after January 1, 2006.

Note 4 Cash Flows - Change in Non-cash Working Capital

	Three months ended Dec. 31		Year ended Dec. 31	
	2006	2005	**2006**	2005
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ (282)**	$ (297)	**$ (428)**	$ (410)
Inventories	**9**	(21)	**43**	(197)
Prepaid expenses	**34**	20	**14**	17
Accounts payable and accrued liabilities	**255**	811	**277**	962
Change in non-cash working capital	**$ 16**	$ 513	**$ (94)**	$ 372
Relating to:				
Operating activities	**$ (89)**	$ (129)	**$ 544**	$ (94)
Financing activities	**(14)**	466	**(678)**	255
Investing activities	**119**	176	**40**	211
b) Other cash flow information:				
Cash taxes paid	**$ 52**	$ 9	**$ 215**	$ 154
Cash interest paid	**46**	44	**147**	147

Note 5 Long-term Debt

	Maturity	December 31 2006	2005	2006	2005
Long-term debt		*Cdn $ Amount*		*U.S. $ Denominated*	
Medium-term notes	2007-9	**$ 300**	$ 300	**$ -**	$ -
6.25% notes	2012	**466**	467	**400**	400
7.55% debentures	2016	**233**	233	**200**	200
6.15% notes	2019	**350**	350	**300**	300
8.90% capital securities	2028	**262**	262	**225**	225
7.125% notes		**-**	175	**-**	150
8.45% senior secured bonds		**-**	99	**-**	85
Total long-term debt		**1,611**	1,886	**$ 1,125**	$ 1,360
Amount due within one year		**(100)**	(274)		
		$ 1,511	$ 1,612		

Interest - net consisted of:

	Three months ended Dec. 31 2006	2005	Year ended Dec. 31 2006	2005
Long-term debt	**$ 30**	$ 39	**$ 130**	$ 144
Short-term debt	**1**	1	**5**	4
	31	40	**135**	148
Amount capitalized	**(3)**	(23)	**(33)**	(114)
	28	17	**102**	34
Interest income	**(4)**	(1)	**(10)**	(2)
	$ 24	$ 16	**$ 92**	$ 32

Foreign exchange consisted of:

	Three months ended Dec. 31 2006	2005	Year ended Dec. 31 2006	2005
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ 60**	$ 7	**$ (7)**	$ (51)
Cross currency swaps	**(22)**	(2)	**4**	14
Other (gains) losses	**(30)**	-	**(21)**	6
	$ 8	$ 5	**$ (24)**	$ (31)

On September 21, 2006, Husky filed a shelf prospectus, which replaces the Company's shelf prospectus dated August 11, 2004, and will enable Husky to offer up to U.S. $1.0 billion of debt securities in the United States until October 21, 2008. During the 25-month period that the prospectus remains effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. As at December 31, 2006, there were no debt securities issued under this shelf prospectus.

Note 6 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Year ended December 31	
	2006	2005
Asset retirement obligations at beginning of year	**$ 557**	$ 509
Liabilities incurred	**35**	63
Liabilities disposed	**(1)**	(7)
Liabilities settled	**(36)**	(41)
Revisions	**22**	-
Accretion	**45**	33
Asset retirement obligations at end of year	**$ 622**	$ 557

At December 31, 2006, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $3.8 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2 to 6.5%.

Note 7 Income Taxes

In the second quarter of 2006, a recovery of future taxes resulted from recording non-recurring tax benefits of $328 million that arose due to changes in the tax rates for the governments of Canada ($198 million), Alberta ($90 million) and Saskatchewan ($40 million). All of this tax legislation received royal assent and was, therefore, substantively enacted in the second quarter of 2006.

Note 8 Commitments and Contingencies

The Company has no material litigation other than 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.

Note 9 Share Capital

The Company's authorized share capital consists of an unlimited number of no par value common and preferred shares.

Common Shares

Changes to issued common shares were as follows:

	Year ended December 31			
	2006		2005	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	424,125,078	$ 3,523	423,736,414	$ 3,506
Exercised - options and warrants	143,431	10	388,664	17
Balance at December 31	**424,268,509**	**$ 3,533**	424,125,078	$ 3,523

Stock Options

A summary of the status of the Company's stock option plan is presented below:

	Year ended December 31			
	2006		2005	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of year	7,285	$ 25.81	9,964	$ 22.61
Granted	902	$ 71.42	670	$ 48.14
Exercised for common shares	(144)	$ 22.31	(359)	$ 15.84
Surrendered for cash	(1,951)	$ 23.95	(2,443)	$ 19.05
Forfeited	(264)	$ 42.82	(547)	$ 24.10
Outstanding at December 31	**5,828**	**$ 32.81**	7,285	$ 25.81
Options exercisable at December 31	**2,232**	**$ 24.96**	1,533	$ 22.72

	December 31, 2006				
	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
$13.96 - $14.99	64	$ 14.60	1	64	$ 14.60
$15.00 - $22.99	96	$ 19.87	2	96	$ 19.87
$23.00 - $23.99	4,164	$ 23.83	2	1,882	$ 23.83
$24.00 - $39.99	294	$ 32.22	3	95	$ 31.69
$40.00 - $55.99	378	$ 52.17	4	95	$ 52.90
$56.00 - $76.74	832	$ 72.04	4	-	$ -
	5,828	**$ 32.81**	**3**	**2,232**	**$ 24.96**

Note 10 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended Dec. 31		Year ended Dec. 31	
	2006	2005	**2006**	2005
Employer current service cost	**$ 8**	$ 5	**$ 21**	$ 18
Interest cost	**2**	1	**9**	8
Expected return on plan assets	**(4)**	(1)	**(8)**	(7)
Amortization of net actuarial losses	**3**	1	**3**	3
	$ 9	$ 6	**$ 25**	$ 22

Note 11 Financial Instruments and Risk Management

Recognized gains (losses) on risk management activities were as follows:

	Year ended December 31	
	2006	2005
Commodity price risk management		
Power consumption	**$ 6**	$ 4
Natural gas	**-**	(17)
Interest rate risk management	**1**	13
Foreign currency risk management	**(3)**	1

Unrecognized gains (losses) on derivative instruments were as follows:

	December 31	
	2006	2005
Interest rate risk management		
Interest rate swaps	**$ 5**	$ 7
Foreign currency risk management		
Foreign exchange contracts	**(26)**	(32)

Commodity Price Risk Management

Power Consumption

At December 31, 2006, the Company had hedged power consumption as follows:

	Notional Volumes *(MW)*	Term	Price
Fixed price purchase	20.0	Apr. to Jun. 2007	$63.63/MWh

Natural Gas Contracts

At December 31, 2006, the unrecognized gains (losses) on external offsetting physical purchase and sale natural gas contracts were as follows:

	Volumes *(mmcf)*	Unrecognized Gain (Loss)
Physical purchase contracts	25,509	$ 5
Physical sale contracts	(25,509)	$ 1

Sale of Accounts Receivable

The Company has a securitization program to sell up to $350 million of accounts receivable to a third party on a revolving basis. As at December 31, 2006, no accounts receivable had been sold under the program compared with $350 million in accounts receivable sold at December 31, 2005.

Husky Energy Inc. will host a conference call for analysts and investors on Tuesday, February 6, 2007 at 4:15 p.m. Eastern time to discuss Husky's fourth quarter results. To participate please dial 1-800-319-4610 beginning at 4:05 p.m. Eastern time.

Mr. John C.S. Lau, President & Chief Executive Officer, and other officers will be participating in the call.

A live audio webcast of the conference call will be available via Husky's website, www.huskyenergy.ca, under Investor Relations. The webcast will be archived for approximately 90 days.

Those unable to listen to the call live may listen to a recording by dialing 1-800-319-6413 one hour after the completion of the call, approximately 5:30 p.m. (EST), then dialing account number 4279. The Postview will be available until Tuesday, March 6, 2007.

Media are invited to listen to the conference call by dialing 1-800-597-1419 beginning at 4:05 p.m. Eastern time.

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For further information, please contact:

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