Husky

Q2 NEWS RELEASE
Calgary, Alberta
July 25, 2019

Husky Energy Reports Second Quarter 2019 Results

This news release contains references to the non-GAAP financial measures "funds from operations", "free cash flow", "net debt", "net debt to trailing funds from operations", "operating margin", "EBITDA" and "operating netback". Please refer to "Non-GAAP measures" at the end of this news release.

Husky Energy generated funds from operations of $802 million in the second quarter, with net earnings of $370 million. Cash flow from operating activities, including changes in non-cash working capital, was $760 million, compared to $1 billion in Q2 2018.

"We remain on track with the plan we outlined at our recent Investor Day," said CEO Rob Peabody. "This includes the acceleration of the Lloyd thermal project at Dee Valley, which is now steaming with production expected later in the third quarter.

"Our focus remains on capital discipline and consistent execution, while increasing our ability to capture higher margins across the Integrated Corridor and Offshore businesses."

Second quarter financial performance was impacted by lower production and reduced throughputs, primarily due to a heavy maintenance turnaround schedule and non-routine write offs and expenses. This maintenance program is now largely complete.

In the Downstream segment, the Lima crude oil flexibility project is on track for completion in the fourth quarter of 2019 and will provide increased heavy crude processing capacity. Construction is expected to begin on the Superior Refinery rebuild project this fall, subject to regulatory approvals.

In the Offshore business, Husky drilled the final three wells at the Liuhua 29-1 field at the Liwan Gas Project. All seven wells are expected to be completed by the end of 2019, with first production around the end of 2020. In the Atlantic region, two new infill wells were brought on production and construction advanced at the West White Rose Project.

The Company continues to deliver on the plan set out at Investor Day, including its 2019 guidance of $3.3 to $3.5 billion in capital expenditures and annual average production of 290,000-305,000 barrels of oil equivalent per day (boe/day).

SECOND QUARTER HIGHLIGHTS

- Net earnings of $370 million, including $233 million related to Alberta corporate tax reductions and non-routine after-tax negative adjustments totaling $77 million, compared to net earnings of $448 million in Q2 2018
- Cash flow from operating activities of $760 million, compared to $1 billion in the second quarter of 2018
- Funds from operations of $802 million, compared to $1.2 billion in the year-ago period. This reflects lower commodity prices, reduced production and throughputs due to turnarounds, and non-routine pre-tax negative adjustments totalling $106 million
- Capital spending of $858 million
- Net debt of $3.7 billion, representing one times trailing 12 months funds from operations
    - Liquidity of approximately $6.7 billion; $2.5 billion in cash and $4.2 billion in unused credit facilities
- Upstream production averaged 268,400 boe/day, compared to 295,500 boe/day in Q2 2018, reflecting Alberta production quotas, lower volumes from the White Rose field and planned turnarounds at Sunrise and six Lloyd thermal projects
- Downstream throughput of 340,000 barrels per day (bbls/day), compared to 355,000 bbls/day in the year-ago period, with planned maintenance turnarounds at both the Toledo and Prince George refineries
- Lima Refinery throughput of 179,800 bbls/day, reflecting improvements made in the 2018 turnaround

	Three Months Ended			Six Months Ended	
	June 30 2019	Mar. 31 2019	June 30 2018	June 30 2019	June 30 2018
Upstream production, before royalties					
Total equivalent production (mboe/day)	268	285	296	277	298
Crude oil and natural gas liquids (mbbls/day)	189	199	213	194	217
Natural gas (mmcf/day)	475	517	494	496	486
Upgrader and refinery throughput (mbbls/day)	340	334	355	337	376
Revenue, net of royalties ($mm)	5,303	4,574	5,884	9,877	11,066
Operating margin[1] ($mm)	942	1,172	1,392	2,114	2,496
Integrated Corridor	703	945	1,049	1,647	1,745
Offshore	239	227	343	467	751
Cash flow – operating activities ($mm)	760	545	1,009	1,305	1,538
Funds from operations[1] ($mm)	802	959	1,208	1,761	2,103
Per common share – Basic ($/share)	0.80	0.95	1.20	1.75	2.09
Capital expenditures ($mm)	858	812	708	1,670	1,345
Free cash flow[1] ($mm)	(56)	147	500	91	758
Net earnings ($mm)	370	328	448	698	696
Per common share – Basic ($/share)	0.36	0.32	0.44	0.68	0.68
Net debt[1] ($ billions)	3.7	3.4	3.0	3.7	3.0
Net debt to trailing funds from operations[1](times)	1.0	0.8	0.8	1.0	0.8
Dividend per common share ($/share)	0.125	0.125	0.075	0.250	0.150

[1]*Non-GAAP measure; refer to advisory.*

SECOND QUARTER RESULTS

Upstream production averaged 268,400 boe/day, compared to 295,500 boe/day in the second quarter of 2018, which takes into account the impacts from Alberta production quotas, lower volumes from the White Rose field and planned maintenance and turnarounds.

Average realized pricing for Upstream production was $53.35 per boe compared to $49.74 per boe in the year-ago period. Realized pricing for oil and liquids averaged $60.13 per barrel compared to $53.83 per barrel in the year-ago period, and natural gas pricing averaged $6.19 per thousand cubic feet (mcf), compared to $6.53 per mcf in Q2 2018. Upstream operating costs of $15.83 per boe were 11% higher than the year-ago period, primarily due to Alberta production quotas, increased costs related to turnarounds, and lower production in Western Canada and the Offshore business. Upstream operating netbacks averaged $33.61 per boe compared to $31.31 per boe in the second quarter of 2018.

Upgrader and refinery throughput of 340,000 bbls/day reflected planned turnarounds at the Prince George and Toledo refineries and the continued suspension of operations at the Superior Refinery.

The average realized U.S. refining and marketing margin was $14.16 US per barrel of crude oil throughput, which reflects a favourable first-in, first-out (FIFO) pre-tax inventory valuation adjustment of $0.60 US per barrel. This compared to $16.66 US per barrel a year ago, which included a favourable FIFO pre-tax inventory valuation adjustment of $1.96 US per barrel.

The Upgrader realized margin was $12.38 per barrel compared to $30.69 per barrel in the year-ago period, reflecting tighter Canadian heavy oil differentials.

Net earnings in the Infrastructure and Marketing segment were a loss of $38 million compared to a gain of $154 million in Q2 2018, due to a non-routine $43 million after-tax provision associated with a lump-sum contract for the Saskatchewan Gathering System expansion, as well as tighter heavy oil location differentials.

Capital spending of $858 million was focused on thermal bitumen project development in Saskatchewan, Downstream margin capture initiatives including the Lima crude oil flexibility project, construction of the Liuhua 29-1 field at Liwan, and advancing construction of the West White Rose Project.

INTEGRATED CORRIDOR

- Upstream production averaged 214,000 boe/day compared to 230,500 boe/day in Q2 2018, which takes into account Alberta production quotas and turnarounds at six Lloyd thermal projects in Saskatchewan
- Steaming commenced at the 10,000 bbls/day Dee Valley Lloyd thermal project
- The Lima crude oil flexibility project is 85% complete
- The Superior Refinery rebuild is expected to begin this fall, subject to regulatory approvals; a return to full operations is expected in 2021. The rebuild costs are expected to be substantially covered by property damage insurance

Thermal Production

Thermal bitumen production from Lloyd thermal projects, Tucker and Sunrise averaged about 120,000 bbls/day (Husky W.I.), compared to 123,200 bbls/day (Husky W.I.) in the second quarter of 2018. This takes into account mandatory government production quotas in Alberta and turnaround and maintenance work at six Lloyd thermal projects, which were synchronized to coincide with water supply infrastructure maintenance.

Production at Sunrise averaged 45,400 bbls/day (22,700 bbls/day Husky W.I.). At Tucker, production averaged 24,000 bbls/day.

In Saskatchewan, five new Lloyd thermal projects with a combined design capacity of 50,000 bbls/day are being advanced.

Resource Plays

The Company continues to pace investments in its liquids-rich resource play business with an ongoing focus on lowering costs, optimizing production rates and reducing cycle times.

In the second quarter, four wells were completed at Kakwa in the Spirit River formation and a planned turnaround at the Rainbow Lake gas processing plant was successfully completed.

Downstream

Total Downstream throughput was 340,000 bbls/day, compared to 355,000 bbls/day in the second quarter of 2018.

U.S. refinery throughput averaged 237,300 bbls/day, including 179,800 bbls/day at the Lima Refinery. The Toledo Refinery averaged 115,000 bbls/day (57,500 bbls/day Husky W.I.), reflecting impacts from the extended planned maintenance turnaround.

The operating margin for the U.S. refining segment was $224 million. Pre-tax insurance proceeds of $71 million, primarily for business interruption at the Superior Refinery, was accounted for in the $300 million of EBITDA recorded in the quarter.

The Lima crude oil flexibility project to increase heavy oil processing capacity to 40,000 bbls/day is 85% complete and on track for completion by the end of 2019.

Canadian throughput, including the Lloydminster Upgrader and asphalt refinery, averaged 103,000 bbls/day, which takes into account an extended planned turnaround at the Prince George Refinery.

The operating margin for the combined Upgrading and Canadian Refined Products segments was $62 million.

OFFSHORE

- Production averaged 54,400 boe/day, compared to 65,000 boe/day in the second quarter of 2018
- Final three wells drilled at the seven-well Liuhua 29-1 field development; pipeline laying under way
- West White Rose Project more than 40% complete

Asia Pacific

China
Natural gas sales from the two producing fields at Liwan averaged 330 million cubic feet per day (mmcf/day), with associated liquids averaging 14,200 bbls/day (162 mmcf/day and 7,100 bbls/day Husky W.I.)

Realized gas pricing at Liwan was $14.05 per mcf, with liquids pricing of $69.77 per barrel. Operating costs were $5.25 per boe, with an operating netback of $71.66 per boe.

At the Liuhua 29-1 field, the final three wells were drilled and pipeline laying is expected to be finished in the third quarter. Altogether, seven wells will be tied in to existing Liwan infrastructure, with first gas expected around the end of 2020. Target production is 45 mmcf/day of gas and 1,800 bbls/day of liquids when fully ramped up, reflecting Husky's 75% working interest.

Indonesia
Natural gas sales at the BD Project in the Madura Strait averaged 87 mmcf/day, with liquids production of 6,500 bbls/day (34 mmcf/day and 2,500 bbls/day, Husky W.I.) Realized gas pricing at BD was $9.94 per mcf, with liquids pricing of $101.07 per barrel. Operating costs were $9.52 per boe, with an operating netback of $53.77 per boe.

First gas production from the combined MDA-MBH and MDK fields in the Madura Strait is expected in 2021.

Atlantic

Overall average net production in the Atlantic region was approximately 12,200 bbls/day, which included two new infill production wells that were brought onstream in May 2019.

The Central Drill Centre and the Southern Drill Centre have resumed normal operations. With the installation earlier this month of a new subsea flowline connector, the drill centres at North Amethyst and the South White Rose extension are expected to be brought back into service in the third quarter of 2019.

The Tiger's Eye exploration well did not encounter commercial hydrocarbons and was written off. Husky has a 40 percent ownership interest in the well.

West White Rose Project
Construction work on the concrete gravity structure and related topsides is progressing, with the overall project more than 40% complete as it advances towards first oil around the end of 2022.

CORPORATE DEVELOPMENTS

A strategic review continues of the potential sale of the Canadian retail and commercial fuels business and the Prince George Refinery.

The Board of Directors has approved a quarterly dividend of $0.125 per common share for the three-month period ended June 30, 2019. The dividend will be payable October 1, 2019 to shareholders of record at the close of business on September 3, 2019.

Regular dividend payments on each of the Cumulative Redeemable Preferred Shares – Series 1, Series 2, Series 3, Series 5 and Series 7 – will be paid for the three-month period ended September 30, 2019. The dividends will be payable on September 30, 2019 to holders of record at the close of business on September 3, 2019.

Share Series	Dividend Type	Rate (%)	Dividend Paid ($/share)
Series 1	Regular	2.404	$0.15025
Series 2	Regular	3.417	$0.21532
Series 3	Regular	4.50	$0.28125
Series 5	Regular	4.50	$0.28125
Series 7	Regular	4.60	$0.28750

CONFERENCE CALL

A conference call will be held on Thursday, July 25 at 9 a.m. Mountain Time (11 a.m. Eastern Time) to discuss Husky's 2019 second quarter results. CEO Rob Peabody, COO Rob Symonds and CFO Jeff Hart will participate in the call.

To listen live:

Canada and U.S. Toll Free: 1-855-327-6838
Outside Canada and U.S.: 1-604-235-2082

To listen to a recording (after 10 a.m. MT on July 25):

Canada and U.S. Toll Free: 1-800-319-6413
Outside Canada and U.S.: 1-604-638-9010
Passcode: 3349
Duration: Available until August 25, 2019
Audio webcast: Available for 90 days at www.huskyenergy.com

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FORWARD-LOOKING STATEMENTS

Certain statements in this news release are forward-looking statements and 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 forward-looking statements contained in this news release are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by 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", "is targeting", "estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "scheduled" and "outlook"). In particular, forward-looking statements in this news release include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: general strategic plans and growth strategies; and expected capital expenditures and production guidance for 2019;
- with respect to the Company's thermal developments, the expected timing of first production from the Dee Valley project;
- with respect to the Company's Offshore business in Asia Pacific: the expected timing of completion of, and first production from, the seven wells at Liuhua 29-1; target production from Liuhua 29-1 when fully ramped up; and the expected timing of first gas production from the combined MDA-MBH and MDK fields;

- with respect to the Company's Offshore business in Atlantic: the expected timing of return to service of the drill centres at North Amethyst and the South White Rose extension; and the expected timing of first oil at the West White Rose Project; and

- with respect to the Company's Downstream operations: the expected timing of completion of the crude oil flexibility project at the Lima Refinery; the expected timing of commencement of the rebuild of the Superior Refinery and expected insurance recoveries; the expected timing of resumption of full operations at the Superior Refinery; and the potential sale of the Canadian retail and commercial fuels business and the Prince George Refinery.

There are numerous uncertainties inherent in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this news release 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. Information used in developing forward-looking statements has been acquired from various sources, including third-party consultants, suppliers and regulators, among others.

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. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to the Company.

The Company's Annual Information Form for the year ended December 31, 2018 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe some of the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

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. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, 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.

NON-GAAP MEASURES

This news release contains references to the terms "funds from operations", "free cash flow", "net debt", "net debt to trailing funds from operations", "operating margin", "EBITDA" and "operating netback". None of these measures is used to enhance the Company's reported financial performance or position. These measures are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. With the exception of funds from operations, free cash flow, net debt and operating margin, there are no comparable measures to these non-GAAP measures under IFRS.

Funds from operations is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, cash flow – operating activities as determined in accordance with IFRS, as an indicator of financial performance. Funds from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance of the Company in the stated period. Funds from operations equals cash flow – operating activities plus change in non-cash working capital.

Free cash flow is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, cash flow – operating activities as determined in accordance with IFRS, as an indicator of financial performance. Free cash flow is presented to assist management and investors in analyzing operating performance by the business in the stated period. Free cash flow equals funds from operations less capital expenditures.

Free cash flow was restated in the fourth quarter of 2018 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of investment in joint ventures. Prior periods have been restated to conform to current presentation.

The following table shows the reconciliation of net earnings to funds from operations and free cash flow, and related per share amounts, for the periods indicated:

	Three months ended			Six months ended	
($ millions)	**June 30 2019**	**Mar. 31 2019**	**June 30 2018**	**June 30 2019**	**June 30 2018**
Net earnings	370	328	448	698	696
Items not affecting cash:					
Accretion	26	27	25	53	49
Depletion, depreciation, amortization and impairment	643	630	639	1,273	1,257
Exploration and evaluation expenses	23	-	7	23	7
Deferred income taxes	(250)	43	138	(207)	215
Foreign exchange gain	(2)	(12)	(2)	(14)	(1)
Stock-based compensation	13	7	33	20	54
Gain on sale of assets	-	(2)	-	(2)	(4)
Unrealized mark to market loss (gain)	(4)	57	(26)	53	(112)
Share of equity investment gain	(23)	(22)	(26)	(45)	(35)
Other	5	(9)	19	(4)	21
Settlement of asset retirement obligations	(41)	(72)	(22)	(113)	(71)
Deferred revenue	(5)	(16)	(25)	(21)	(45)
Distribution from equity investment	47	-	-	47	72
Change in non-cash working capital	(42)	(414)	(199)	(456)	(565)
Cash flow - operating activities	760	545	1,009	1,305	1,538
Change in non-cash working capital	42	414	199	456	565
Funds from operations	802	959	1,208	1,761	2,103
Capital expenditures	(858)	(812)	(708)	(1,670)	(1,345)
Free cash flow	(56)	147	500	91	758
Weighted average number of common shares outstanding	1,005.1	1,005.1	1,005.1	1,005.1	1,005.1
Funds from operations					
Per common share - Basic ($/share)	0.80	0.95	1.20	1.75	2.09

Net debt is a non-GAAP measure that equals the sum of long-term debt, long-term debt due within one year and short-term debt, less cash and cash equivalents. Net debt is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

The following table shows the reconciliation of net debt as at the dates indicated:

($ millions)	**June 30 2019**	**Mar. 31 2019**	**June 30 2018**
Short-term debt	200	200	200
Long-term debt due within one year	1,382	1,803	394
Long-term debt	4,598	4,661	5,015
Cash and cash equivalents	(2,512)	(3,245)	(2,583)
Net debt	3,668	3,419	3,026

Net debt to trailing funds from operations is a non-GAAP measure that equals net debt divided by the 12-month trailing funds from operations as at June 30, 2019. Net debt to trailing funds from operations is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

Operating Margin is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "revenue, net of royalties" as determined in accordance with IFRS, as an indicator of financial performance. Operating Margin is presented to assist management and investors in analyzing operating performance of the Company in the stated period. Operating Margin equals revenues net of royalties less purchases of crude oil and products, production, operating and transportation expenses, and selling general and administrative expenses.

The following table shows the reconciliation of operating margin for the periods indicated:

	Three months ended								
	June 30, 2019			**March 31, 2019**			**June 30, 2018**		
($ millions)	Integrated Corridor	Offshore	Total	Integrated Corridor	Offshore	Total	Integrated Corridor	Offshore	Total
Revenue, net of royalties	5,527	328	5,855	4,696	322	5,018	5,920	434	6,354
Less:									
Purchases of crude oil and products	4,074	-	4,074	2,989	-	2,989	4,130	-	4,130
Production and operating expenses	662	81	743	668	86	754	654	80	734
Selling, general and administrative expenses	88	8	96	94	9	103	87	11	98
Operating Margin	703	239	942	945	227	1,172	1,049	343	1,392

	Six months ended					
	June 30, 2019			**June 30, 2018**		
($ millions)	Integrated Corridor	Offshore	Total	Integrated Corridor	Offshore	Total
Revenue, net of royalties	10,223	650	10,873	11,011	915	11,926
Less:						
Purchases of crude oil and products	7,063	-	7,063	7,873	-	7,873
Production and operating expenses	1,331	166	1,497	1,217	145	1,362
Selling, general and administrative expenses	182	17	199	175	20	195
Operating Margin	1,647	467	2,114	1,745	751	2,496

EBITDA is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "net earnings (loss)" as determined in accordance with IFRS, as an indicator of financial performance. EBITDA is presented to assist management and investors in analyzing operating performance by business in the stated period. EBITDA equals net earnings (loss) plus finance expenses (income), provisions for (recovery of) income taxes, and depletion, depreciation and amortization.

Operating netback is a common non-GAAP measure used in the oil and gas industry. Management believes this measure assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as gross revenue less royalties, production and operating and transportation costs on a per unit basis.

DISCLOSURE OF OIL AND GAS INFORMATION

Unless otherwise indicated: (i) projected and historical production volumes provided are gross, which represents the total or the Company's working interest share, as applicable, before deduction of royalties; and (ii) all Husky working interest production volumes quoted are before deduction of royalties.

The Company uses the term "barrels of oil equivalent" (or "boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not represent value equivalency at the wellhead.

All currency is expressed in Canadian dollars unless otherwise indicated.