Husky Energy Raises Dividend; Reports Second Quarter 2018 Results

Husky Energy's Board of Directors has approved increasing the quarterly cash dividend to $0.125 per common share. The dividend increase recognizes the Company's low net debt and continued ability to generate strong free cash flow.

"This dividend level is affordable, and has a yield that is comparable with our peers," said CEO Rob Peabody. "We can fund the dividend, our sustaining capital requirements and the capital program in accordance with our five-year plan."

Funds from operations were $1.2 billion, a year-over-year increase of 69 percent and 35 percent higher than the first quarter of 2018.

Free cash flow was $500 million, compared to $123 million in the second quarter of 2017. Net earnings were $448 million, compared to a net loss of $93 million in the second quarter of 2017. Adjusted net earnings were $474 million, up from $10 million in the year-ago period.

"Once again, the physical integration of our Upstream and Downstream businesses, including our committed pipeline capacity, shielded us from location and quality differentials, and the stability offered by our term contracts in Asia delivered strong financial results," said Peabody.

"As we further reduce our cost structure and improve the performance of our assets – including the ongoing ramp-ups of Tucker, Sunrise and the BD Project offshore Indonesia and the early completion of the Rush Lake 2 thermal project – we remain well-positioned to execute the five-year plan we updated at our recent Investor Day."

Funds from operations and net earnings in the second quarter included approximately $53 million in pre-tax operating expenses associated with the Superior Refinery incident, which are expected to be recovered at a future date from insurance proceeds, less deductibles.

HIGHLIGHTS

Corporate

- Quarterly cash dividend increased to $0.125 per common share
- Funds from operations of approximately $1.2 billion, up 69 percent over Q2 2017
- Free cash flow of $500 million
- Capital spending of $708 million
- Oil exploration discoveries in both the Asia Pacific and Atlantic regions
- Net debt at the end of the quarter was $3.0 billion, representing 0.8 times trailing 12 months funds from operations, well below the Company's target framework of less than two times net debt to trailing 12 months funds from operations

Integrated Corridor

- Downstream EBITDA of $495 million compared to $188 million in Q2 2017
- Average realized U.S. refining and marketing margins of $16.66 US per barrel, including a pre-tax FIFO gain of $1.72 US per barrel, reflecting Husky's flexibility to access discounted Midland crude oil barrels
- Infrastructure and Marketing EBITDA of $212 million compared to $47 million in Q2 2017, demonstrating continued margin capture from long-term committed pipeline capacity
- Thermal bitumen production of 123,200 barrels per day (bbls/day, Husky working interest), including Lloydminster thermals, the Tucker Thermal Project and the Sunrise Energy Project
  - Rush Lake 2 construction completed, with steaming now under way six months ahead of initial plan
- Completion of a planned turnaround at the Lloydminster Upgrader and seasonal turnarounds at Lloyd thermal projects

Offshore

- Record production at the Liwan Gas Project, averaging 368 million cubic feet per day (mmcf/day), with associated liquids averaging 15,700 bbls/day (180 mmcf/day and 7,700 bbls/day Husky working interest). Month-to-date gross production in July 2018 averaging more than 400 mmcf/day
- Liquids-rich BD Project in the Madura Strait averaged 72 mmcf/day with 4,400 bbls/day of associated liquids production (29 mmcf/day and 1,800 bbls/day Husky working interest) in the second quarter; gas production has now reached expected target of 100 mmcf/day (40 mmcf/day Husky working interest)
- Commercial development plans under way following an oil discovery on Block 15/33 in the South China Sea
- Production Sharing Contracts (PSCs) signed for two exploration blocks offshore China in the Beibu Gulf
- Progressing assessment of the White Rose A-24 oil exploration discovery in the Atlantic region
- Completion of planned turnaround on the *SeaRose* FPSO (floating production, storage and offloading) vessel

	Three Months Ended			Six Months Ended	
	June 30 2018	Mar. 31 2018	June 30 2017	June 30 2018	June 30 2017
Daily production, before royalties					
Total equivalent production (mboe/day)	296	300	320	298	327
Crude oil and NGLs (mbbls/day)	213	221	234	217	239
Natural gas (mmcf/day)	494	477	515	486	529
Upstream operating netback[1,2] ($/boe)	31.31	24.37	23.53	27.83	23.85
Refinery and Upgrader throughput (mbbls/day)	355	398	316	376	341
Funds from operations[1] ($mm)	1,208	895	715	2,103	1,401
Per common share – Basic ($/share)	1.20	0.89	0.71	2.09	1.39
Adjusted net earnings[1] ($mm)	474	245	10	719	83
Per common share – Basic ($/share)	0.47	0.24	0.01	0.72	0.08
Net earnings (loss) ($mm)	448	248	(93)	696	(22)
Per common share – Basic ($/share)	0.44	0.24	(0.10)	0.68	(0.04)
Net debt[1] ($ billions)	3.0	3.2	3.5	3.0	3.5
Dividend per common share ($/share)	0.125	0.075	0.00	0.20	0.00

[1]*Non-GAAP measure; refer to advisory.*
[2]*Operating netback includes results from Upstream Exploration and Production and excludes Upstream Infrastructure and Marketing.*

SECOND QUARTER RESULTS

Upstream production averaged 295,500 barrels of oil equivalent per day (boe/day), which takes into account seasonal maintenance and weather-related impacts, the expiry of the Company's participation in Wenchang in the Asia Pacific region in the fourth quarter of 2017, and the completion of a scheduled three-week turnaround at the *SeaRose* FPSO in the Atlantic region. This compared to 319,500 boe/day in the year-ago period, which was prior to asset dispositions in Western Canada during the second half of 2017. Second quarter production also reflects the Company's ongoing structural transformation to focus on higher margin barrels.

Average realized pricing for Upstream production was $49.74 per boe, compared to $41.58 per boe in Q2 2017. Realized pricing for oil and liquids averaged $53.83 per boe, while natural gas averaged $6.53 per thousand cubic feet (mcf).

Upstream operating costs averaged $14.22 per boe compared to $14.65 per boe in the year-ago period. Upstream operating netbacks averaged $31.31 per boe compared to $23.53 per boe in Q2 2017.

Downstream throughput was 355,000 bbls/day, compared to 316,000 bbls/day a year ago, which included a planned five-week partial turnaround in the second quarter at the Lloydminster Upgrader and the suspension of operations at the Superior Refinery in Wisconsin in late April 2018.

The Chicago 3:2:1 crack spread averaged $18.30 US per barrel compared to $14.36 US per barrel in the year-ago period.

Average realized U.S. refining and marketing margins were $16.66 US per barrel, which takes into account a pre-tax FIFO gain of $1.72 US per barrel. This compared to $8.27 US per barrel a year ago, which included a pre-tax FIFO loss of $1.37 US per barrel.

Upgrading net earnings were $84 million, compared to $5 million in Q2 2017. Upgrading margins were $30.69 per barrel, compared to $22.63 per barrel in the second quarter of 2017.

Net earnings in the Infrastructure and Marketing segment were $154 million, compared to $33 million in Q2 2017. This was partially due to the wider WTI/WCS differential, which averaged $24.87 compared to $14.96 in the year-ago period. Infrastructure and Marketing realized margins were $219 million, compared to $17 million in Q2 2017, reflecting value captured from the Company's long-term 75,000 bbls/day committed capacity on the Keystone pipeline and 160 mmcf/day in natural gas pipeline capacity to U.S. markets.

Net debt at the end of the quarter was $3.0 billion.

INTEGRATED CORRIDOR

- Upstream average production of 230,500 boe/day
- Upstream operating netback of $21.79 per boe, including an operating netback of $30.58 per barrel from thermal operations
- Downstream throughput of 355,000 bbls/day
- Downstream upgrading/refining margin of $23.75 per barrel

Thermal Production

Thermal bitumen production from Lloyd thermal projects, Tucker and Sunrise averaged 123,200 bbls/day (Husky working interest), compared to 117,400 bbls/day (Husky working interest) in the second quarter of 2017. This takes into account planned seasonal maintenance at several plants.

Overall thermal operating costs were $11.10 per barrel.

The Company is currently developing six 10,000 bbls/day Lloyd thermal bitumen projects, representing a combined design capacity of 60,000 bbls/day.

- At Rush Lake 2, steaming is under way. First oil is expected early in the fourth quarter of 2018 with a ramp-up to its 10,000 bbls/day design capacity anticipated by the first quarter of 2019.
- At Dee Valley, construction of the Central Processing Facility is progressing, with first oil expected in the first half of 2020.
- At Spruce Lake Central, site clearing is complete and module fabrication is under way. At Spruce Lake North, site grading is set to begin in the third quarter. Both projects are expected to start production in the second half of 2020.
- Two additional 10,000 bbls/day projects remain on track to be brought online in the second half of 2021.

Production at Tucker averaged 23,400 bbls/day and is continuing to ramp up, with new production from the remaining five wells on a new 15-well pad. Following planned de-bottlenecking work in the third quarter, Tucker is expected to reach a peak daily rate of 30,000 bbls/day by the end of 2018.

Sunrise recorded a peak daily rate of 54,000 bbls/day (27,000 bbls/day Husky working interest) prior to commencing a program of well workovers. Average production in the quarter was 49,400 bbls/day (24,700 bbls/day Husky working interest) compared to 38,200 bbls/day (19,100 bbls/day Husky working interest) in the year-ago period.

Sunrise remains on track to reach a peak daily rate of 60,000 bbls/day by the end of 2018 (30,000 bbls/day Husky working interest).

Resource Plays

The Company remains focused on capital efficient operations in three core hubs in Western Canada at Edson, Grande Prairie and Rainbow Lake. Operating costs decreased five percent to $13.85 per boe in the second quarter, compared to $14.60 per boe in the year-ago period.

An 18-well drilling program in the Ansell and Kakwa areas of the Wilrich formation is progressing, with seven wells drilled and four completed to date in 2018. In the oil and liquids-rich Montney formation, two wells have been drilled as part of a 2018 program of up to eight wells, primarily in the Wembley and Karr areas.

The new Corser gas processing plant is now under construction by Husky Midstream Limited Partnership in the Ansell area of Central Alberta. It is expected to add 120 mmcf/day of processing capacity when it starts up in the fourth quarter of 2019.

Downstream

Throughput at the Lloydminster Upgrader averaged 72,500 bbls/day, including a planned five-week partial turnaround.

Total U.S. refining throughput was 246,800 bbls/day. At the Lima Refinery, throughput averaged 171,200 bbls/day compared to 174,100 bbls/day in the second quarter of 2017. A crude oil flexibility project to increase heavy oil processing capacity from 10,000 bbls/day to 40,000 bbls/day by the end of 2019 remains on schedule.

At the partner-operated Toledo refinery, throughput averaged 65,500 bbls/day (Husky working interest), compared to 71,100 bbls/day in Q2 2017.

On April 26, 2018, operations were suspended following an incident at the Superior Refinery. An investigation into the cause is ongoing and the Company is making steady progress to secure and stabilize the site. Once the investigation and cleanup are complete, repair work will begin. The refinery is not expected to resume normal operations for at least 18 to 24 months. Husky has insurance to cover business interruption, third-party liability and property damage.

OFFSHORE

- Average production of 65,000 boe/day
- Operating netback of $65.05 per boe
    - Asia Pacific operating netback of $68.44 per boe
    - Atlantic operating netback of $57.79 per barrel

Asia Pacific

China

At the Liwan Gas Project, gross production from the two producing fields averaged 368 mmcf/day in sales gas volumes, with associated liquids averaging 15,700 bbls/day (180 mmcf/day and 7,700 bbls/day Husky working interest). High gas sales and production rates were achieved as gas demand in China remains strong. The Company realized gas pricing of $13.96 Cdn per mcf with liquids pricing of $71.88 Cdn per barrel.

At Liuhua 29-1, the third deepwater field at Liwan, contracts have been signed for long-lead items, and fabrication and construction of equipment is under way.

Three additional wells are scheduled to be drilled beginning in the fourth quarter of 2018, adding to four previously drilled wells. All three wells will be tied into the existing Liwan infrastructure. First gas is anticipated around the end of 2020, with target net production of 45 mmcf/day gas and 1,800 bbls/day liquids when fully ramped up.

Production will be transported through the existing Liwan subsea infrastructure and processed at the onshore Gaolan Gas Plant, and delivered to buyers in the Pearl River Mouth Basin area. Husky has a 75 percent working interest in the development of the field, with its partner CNOOC Limited holding the remaining 25 percent.

The Company is progressing commercial development plans following the drilling of two oil exploration wells on Block 15/33 in the South China Sea, approximately 160 kilometres southeast of Hong Kong. The first well showed four oil-bearing zones with a combined net pay thickness of about 70 metres, and had two drill stem tests with a combined rate of more than 9,000 bbls/day. Each drill stem test was flowed for over 22 hours. A second well drilled on a separate structure did not encounter commercial hydrocarbons. Husky is the operator during the exploration phase, with a working interest of 100 percent in the wells. CNOOC may assume operatorship and up to a 51 percent working interest later in the life of the field, with exploration cost recovery from production allocated to Husky.

At the nearby Block 16/25, a rig is currently on location preparing to spud two exploration wells.

In addition, Husky and CNOOC signed PSCs for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea.

- Block 22/11 covers an area of 1,663 square kilometres with a water depth of 40-80 metres.
- Block 23/07 covers an area of 1,210 square kilometres with a water depth of 20-40 metres.

Under the PSCs, Husky will act as operator during the exploration period. In the event of a commercial discovery, CNOOC Limited may assume a participating interest up to 51 percent.

Indonesia

Gross gas sales at the liquids-rich BD Project averaged 72 mmcf/day with 4,400 bbls/day of associated liquids production (29 mmcf/day and 1,800 bbls/day Husky working interest). BD gas was sold into the East Java market at contracted rates for a realized price of $9.82 Cdn per mcf. Liquids pricing was $98.37 Cdn per barrel. Current net daily sales gas production has now reached the Company's target of 100 mmcf/day (40 mmcf/day Husky working interest), with higher than anticipated liquids production.

At the combined MDA-MBH fields in the Madura Strait, the two platforms and topsides have been installed. A rig has been contracted to drill seven production wells beginning in the second half of 2018.

Atlantic

A planned three-week turnaround at the *SeaRose* FPSO was completed on schedule.

Initial construction work is progressing at the West White Rose Project, with first oil anticipated in 2022. West White Rose is expected to reach peak production of 75,000 bbls/day (52,500 bbls/day Husky working interest) in 2025 as development wells are drilled and brought online.

The Company is assessing a successful exploration well drilled in the second quarter. The White Rose A-24 well, which is located approximately 10 kilometres north of the *SeaRose*, encountered a net pay thickness of more than 85 metres of oil-bearing sandstone. Additional delineation of the north White Rose area is planned. Husky has a 68.875 percent ownership interest in White Rose A-24, with partners Suncor Energy (26.125 percent) and Nalcor Energy Oil and Gas (five percent).

A program of infill wells and workover activities at the White Rose field and its satellite extensions is offsetting reservoir declines until the startup of West White Rose in 2022. A well drilled at the North Amethyst field in the second quarter encountered a high water cut and is currently shut-in pending further intervention activities.

2018 PLANNED MAINTENANCE AND TURNAROUNDS

Integrated Corridor

- A three-week turnaround and de-bottlenecking activities are scheduled at Tucker in the third quarter
- A five-week partial turnaround is planned at the Lima Refinery in the fourth quarter, with throughput expected to average 40 percent during the work period

Offshore

- A four-week turnaround is scheduled to start in early August at the *Terra Nova* FPSO

CORPORATE DEVELOPMENTS

The Board of Directors has approved a quarterly dividend of $0.125 per common share for the three-month period ended June 30, 2018. The dividend will be payable on October 1, 2018 to shareholders of record at the close of business on August 27, 2018.

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, 2018. The dividends will be payable on October 1, 2018 to holders of record at the close of business on August 27, 2018.

Share Series	Dividend Type	Rate (%)	Dividend Paid ($/share)
Series 1	Regular	2.404	$0.15025
Series 2	Regular	3.030	$0.19093
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 take place on Thursday, July 26 at 10 a.m. Mountain Time (12 p.m. Eastern Time) to discuss Husky's 2018 second quarter results. CEO Rob Peabody, COO Rob Symonds and Acting CFO Jeff Hart will participate in the call.

To listen live:

Canada and U.S. Toll Free: 1-800-319-4610
Outside Canada and U.S.: 1-604-638-5340

To listen to a recording (after 11 a.m. MT on July 26):

Canada and U.S. Toll Free: 1-800-319-6413
Outside Canada and U.S.: 1-604-638-9010
Passcode: 2426
Duration: Available until August 26, 2018
Audio webcast: Available for 90 days at huskyenergy.com

Investor and Media Inquiries:

Dan Cuthbertson, Senior Manager, Investor Relations and External Communications
403-523-2395

Mel Duvall, Senior Manager, Media & Issues
403-513-7602

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", "is 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, including funding needs and sources, further reduction in cost structure and further improvement in performance; and target framework for net debt to trailing funds from operations;

- with respect to the Company's thermal developments in the Integrated Corridor: the expected timing of first oil and ramp-up to design capacity at Rush Lake 2; the expected timing of first oil at Dee Valley; the expected timing of site grading at Spruce Lake North and expected timing of first production at Spruce Lake Central and Spruce Lake North; the expected timing for two additional 10,000 bbls/day projects to be brought online; the expected timing and duration of turnaround and de-bottlenecking activities at the Tucker Thermal Project; and the expected volumes and timing of peak daily production at the Tucker Thermal Project and the Sunrise Energy Project;

- with respect to the Company's resource plays in the Integrated Corridor, 2018 drilling plans in the Ansell, Kakwa, Wembley and Karr areas;

- with respect to the Company's Infrastructure and Marketing business, the expected timing of start-up of the Ansell Corser plant and the expected processing capacity of such plant;

- with respect to the Company's Downstream operations in the Integrated Corridor: the expected recovery from insurance proceeds of pre-tax operating expenses associated with the Superior Refinery; the expected timing of completion of the crude oil flexibility project at the Lima Refinery; the expected timing of resumption of normal operations at the Superior Refinery; and the expected timing and duration of a partial turnaround, and the expected average throughput during such turnaround, at the Lima Refinery;

- with respect to the Company's Offshore business in the Asia Pacific region: the expected timing of drilling new wells and of first gas production, and target net production once fully ramped up, at Liuhua 29-1; drilling plans at Block 16/25 and at the combined MDA-MBH fields;

- with respect to the Company's Offshore business in the Atlantic region: the expected timing of first oil, and the expected volume and timing of peak production, at the West White Rose Project; plans for additional delineation of north White Rose area; and the expected timing and duration of a turnaround at the *Terra Nova* FPSO.

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, 2017 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe 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", "adjusted net earnings", "net debt", "net debt to trailing funds from operations", "EBITDA" and "operating netback", which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS") and are therefore unlikely to be comparable to similar measures presented by other issuers. 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. There is no comparable measure in accordance with IFRS for operating netback.

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 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.

Funds from operations was restated in the second quarter of 2017 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of adjustments for settlement of asset retirement obligations and deferred revenue. Prior periods have been restated to conform to current presentation.

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 and investment in joint ventures.

Free cash flow was restated in the first 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 addition 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)	Jun. 30 2018	Mar. 31 2018	Dec. 31 2017	Sep. 30 2017	Jun. 30 2017	Jun. 30 2018	Jun. 30 2017
Net earnings (loss)	448	248	672	136	(93)	696	(22)
Items not affecting cash:							
Accretion	25	24	28	27	29	49	57
Depletion, depreciation, amortization and impairment	639	618	647	673	862	1,257	1,562
Exploration and evaluation expenses	7	-	-	1	4	7	5
Deferred income taxes	138	77	(360)	52	(57)	215	(51)
Foreign exchange loss (gain)	(2)	1	1	(3)	15	(1)	(2)
Stock-based compensation	33	21	25	11	8	54	9
Loss (gain) on sale of assets	-	(4)	(13)	(2)	(33)	(4)	(31)
Unrealized mark to market loss (gain)	(26)	(86)	57	31	18	(112)	(32)
Share of equity investment gain	(26)	(9)	(1)	(12)	(23)	(35)	(48)
Other	19	2	8	9	5	21	(1)
Settlement of asset retirement obligations	(22)	(49)	(45)	(23)	(20)	(71)	(68)
Deferred revenue	(25)	(20)	(5)	(9)	-	(45)	(2)
Distribution from joint ventures	-	72	-	-	-	72	25
Change in non-cash working capital	(199)	(366)	337	3	98	(565)	58
Cash flow - operating activities	1,009	529	1,351	894	813	1,538	1,459
Change in non-cash working capital	199	366	(337)	(3)	(98)	565	(58)
Funds from operations	1,208	895	1,014	891	715	2,103	1,401
Capital expenditures	(708)	(637)	(745)	(511)	(580)	(1,345)	(964)
Investment in joint ventures	-	(40)	(9)	(12)	(12)	(40)	(60)
Free cash flow	500	218	260	368	123	718	377
Weighted average number of common shares outstanding - Basic	1005.1	1005.1	1005.1	1,005.2	1,005.5	1005.1	1,005.5
Per common share - Basic ($/share)	1.20	0.89	1.01	0.89	0.71	2.09	1.39

Adjusted net earnings is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with IFRS, as an indicator of financial performance. Adjusted net earnings consists of net earnings and excludes items such as after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on sale of assets which are not considered to be indicative of the Company’s ongoing financial performance. Adjusted net earnings is a complementary measure used in assessing the Company's financial performance through providing comparability between periods. Adjusted net earnings was redefined in the second quarter of 2016. Previously, adjusted net earnings was defined as net earnings plus after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs.

The following table shows the reconciliation of net earnings to adjusted net earnings for the periods indicated:

($ millions)	Three months ended Jun. 30 2018	 Mar. 31 2018	 Jun. 30 2017	Six months ended Jun. 30 2018	 Jun. 30 2017
Net earnings (loss)	448	248	(93)	696	(22)
Impairment of property, plant and equipment, net of tax	21	-	123	21	123
Exploration and evaluation asset write-downs, net of tax	5	-	3	5	3
Gain on sale of assets, net of tax	-	(3)	(23)	(3)	(21)
Adjusted net earnings	474	245	10	719	83
Weighted average number of common shares outstanding - Basic	1005.1	1005.1	1,005.5	1005.1	1,005.5
Per common share - Basic ($/share)	0.47	0.24	0.01	0.72	0.08

Net debt is a non-GAAP measure that equals total debt less cash and cash equivalents. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. 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 total debt to net debt as at the dates indicated:

($ millions)	Jun. 30 2018	Mar. 31 2018	Jun. 30 2017
Short-term debt	200	200	200
Long-term debt due within one year	394	-	390
Long-term debt	5015	5,343	5,362
Total debt	5,609	5,543	5,952
Cash and cash equivalents	(2,583)	(2,301)	(2,500)
Net debt	3,026	3,242	3,452

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, 2018. 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.

EBITDA is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with IFRS, as an indicator of financial performance. EBITDA is presented in this news release to assist management and investors in analyzing operating performance by business in the stated period. EBITDA equals net earnings 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. 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 noted, projected and historical production volumes provided represent the Company's working interest share before 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.

This news release includes estimates of net pay thickness at Block 15/33 in the South China Sea and at White Rose A-24, which estimates may be considered to be anticipated results under National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The estimates were prepared internally. The risks and uncertainties associated with recovery of resources from Block 15/33 and A-24 include, but are not limited to: that Husky may encounter unexpected drilling results; the occurrence of unexpected events in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems; and other difficulties in producing petroleum reserves.

References in this news release to production test rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which wells will commence production and decline after testing and are not indicative of long term performance or of ultimate recovery. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results should be considered to be preliminary.

All currency is expressed in Canadian dollars unless otherwise indicated.