Husky Energy

Q4 NEWS RELEASE
Calgary, Alberta
February 26, 2019

Husky Energy Reports 2018 Fourth Quarter and Annual Results; Updates 2019 Guidance

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", "EBITDA", "operating netback" and "sustaining capital". Please refer to "Non-GAAP Measures" at the end of this news release.

Husky Energy generated funds from operations of $4 billion in 2018, an increase of 21 percent from 2017. Annual net earnings rose 85 percent to $1.5 billion, and free cash flow was $426 million.

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $4.1 billion in 2018 compared to $3.7 billion in 2017.

The proved reserves life index was 13.5 years, an increase from 11 years in 2017.

The 2018 proved reserves replacement ratio was 260 percent, excluding economic factors (255 percent including economic factors). Total proved reserves before royalties at the end of 2018 were 1.5 billion barrels of oil equivalent (boe). Probable reserves were 1.1 billion boe.

Fourth quarter funds from operations was $583 million, compared to $1.3 billion in the previous quarter.

The fourth quarter reduction reflects several factors:

- Integration benefits were impacted by lower synthetic crude oil prices due to Canadian pipeline constraints and associated reductions in margin capture at the Lloydminster Upgrader
- U.S. Downstream results were weakened by narrower crack spreads, a planned turnaround at the Lima Refinery, and an unfavourable first-in, first-out (FIFO) pre-tax impact of $181 million ($136 million US)
- Atlantic production volumes were impacted by approximately 10,000 barrels per day (bbls/day) over the quarter due to the suspension of operations at the *SeaRose* floating production, storage and offloading (FPSO) vessel in mid-November

Cash flow provided by operating activities, which includes changes in non-cash working capital, was $1.3 billion in the fourth quarter compared to $1.4 billion in Q4 2017.

Fourth quarter net earnings were $216 million, compared to $672 million in Q4 2017.

"It was a challenging quarter," said CEO Rob Peabody. "The oil spill on the East Coast was particularly disappointing, and we are continuing to work closely with the regulator to determine the root cause and apply learnings.

"We also saw a significant decline in Brent and WTI oil prices and extreme volatility in the WTI-WCS spread. Husky's fourth quarter earnings, adjusted for FIFO impacts, continues to show the value of the Integrated Corridor business and the strong contribution of our Asia Pacific business."

Fourth quarter operational milestones included record production at the Liwan Gas Project, the Sunrise Energy Project, the Tucker Thermal Project, and the Rush Lake 2 thermal bitumen project at Lloydminster.

Husky expects to continue to optimize its portfolio in 2019 with the strategic review and potential sale of non-core Downstream assets, along with other actions and investments aimed at further reducing the Company's break-even oil price.

	Three Months Ended			Twelve Months Ended	
	Dec. 31 2018	Sept. 30 2018	Dec. 31 2017	Dec. 31 2018	Dec. 31 2017
Daily production, before royalties					
Total equivalent production (mboe/day)	304	297	320	299	323
Crude oil and natural gas liquids (mbbls/day)	215	210	231	215	233
Natural gas (mmcf/day)	538	520	535	507	539
Upstream operating netback[1,2] ($/boe)	9.42	31.30	30.00	23.98	25.25
Refinery and Upgrader throughput (mbbls/day)	287	351	387	347	361
Cash flow – operating activities ($mm)	1,313	1,283	1,351	4,134	3,704
Funds from operations[1] ($mm)	583	1,318	1,014	4,004	3,306
Per common share – Basic ($/share)	0.58	1.31	1.01	3.98	3.29
Free cash flow[1] ($mm)	(682)	350	269	426	1,086
Net earnings ($mm)	216	545	672	1,457	786
Per common share – Basic ($/share)	0.21	0.53	0.66	1.41	0.75
Net debt[3] ($ billions)	2.9	2.6	2.9	2.9	2.9
Dividend per common share ($/share)	0.125	0.125	0.075	0.45	0.075

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

FOURTH QUARTER HIGHLIGHTS

- Cash flow from operating activities of $1.3 billion
- Funds from operations of $583 million included an unfavourable first-in, first-out (FIFO) pre-tax impact of $181 million ($136 million US)
- Capital spending of $1.3 billion reflected higher than anticipated spending at the West White Rose Project and for U.S. Downstream maintenance
- Net debt of $2.9 billion represented 0.7 times trailing 12 months funds from operations
- Upstream production of 304,300 boe/day
- Overall operating costs of $13.75 per boe; $11.09 per barrel for thermal bitumen projects
- Record production from several major assets:
  - Sunrise surpassed its design capacity of 60,000 bbls/day, with a record peak daily rate of 62,600 bbls/day (31,300 bbls/day Husky working interest)
  - Tucker surpassed its design capacity of 30,000 bbls/day, with Q4 production averaging 25,200 bbls/day
  - Rush Lake 2 surpassed its design capacity of 10,000 bbls/day
  - Liwan achieved a new quarterly production record, averaging 403 million cubic feet per day (mmcf/day) of natural gas, with associated liquids averaging 19,200 bbls/day (197 mmcf/day and 9,300 bbls/day Husky working interest)
- Lloydminster asphalt refinery margin of $41.50 per barrel, compared to $15.79 per barrel in Q4 2017
- Downstream throughput of approximately 287,000 bbls/day; completed major planned turnaround at the Lima Refinery
- The Lima Refinery is now able to process up to 175,000 bbls/day, up from 165,000 bbls/day
- Sanctioned 10,000 bbls/day thermal project at Spruce Lake East; first oil expected around the end of 2021

FOURTH QUARTER RESULTS

Upstream production averaged 304,300 boe/day, compared to 320,400 boe/day in the fourth quarter of 2017. This takes into account the temporary suspension of production at the *SeaRose* FPSO, which returned to operations at the end of January 2019 and will continue to ramp up through the second quarter of 2019.

Upstream operating netbacks averaged $9.42 per boe, compared to $30 per boe in Q4 2017, which reflects lower realized heavy oil pricing in the quarter. Average realized pricing for Upstream production was $25.47 per boe, compared to $46.69 per boe in the year-ago period. Realized pricing for oil and liquids averaged $18.93 per barrel, and natural gas averaged $6.86 per thousand cubic feet (mcf).

Upstream operating costs averaged $13.75 per boe, up from $13.20 per boe in the fourth quarter of 2017 primarily due to reduced Atlantic production volumes.

Total Downstream throughput was 286,900 bbls/day compared to 387,100 bbls/day in Q4 of 2017. This reflects impacts from a major planned turnaround at the Lima Refinery that was completed in the fourth quarter, and the continued suspension of operations at the Superior Refinery.

The Chicago 3:2:1 crack spread averaged $13.38 US per barrel compared to $20.28 US per barrel in Q4 2017. The average realized U.S. refining and marketing margin was $9.12 US per barrel of crude throughput, which takes into account an unfavourable first-in, first-out (FIFO) pre-tax inventory valuation adjustment of $8.51 US per barrel. This compared to $14.89 US per barrel a year ago, which included a favourable first-in, first-out (FIFO) pre-tax inventory valuation adjustment of $2.40 US per barrel.

The Upgrading realized margin was $29.13 per barrel, compared to $20.65 per barrel in the year-ago period.

In the Infrastructure and Marketing segment, EBITDA was $172 million compared to a negative EBITDA of $38 million in the fourth quarter of 2017, primarily reflecting the value captured from the Company's long-term 75,000 bbls/day committed export capacity on the Keystone pipeline and 160 mmcf/day in natural gas pipeline capacity to U.S. markets.

Capital spending of $1.3 billion primarily reflected investments in Lloyd thermal projects, Western Canada resource play drilling, the Lima Refinery turnaround, the Lima crude oil flexibility project, and the West White Rose Project.

Net debt was $2.9 billion, representing 0.7 times trailing 12 months funds from operations.

INTEGRATED CORRIDOR

- Upstream average production of 240,100 boe/day
- Overall upstream operating netback loss of $3.79 per boe driven by record wide differentials
- Downstream throughput of 286,900 bbls/day
- Downstream upgrading/refining margin of $21.46 per barrel

Thermal Production

Total thermal bitumen production from Lloyd thermal projects, Tucker and Sunrise averaged about 133,000 bbls/day (Husky working interest), compared to about 121,000 bbls/day (Husky working interest) in the fourth quarter of 2017. Overall operating costs at Sunrise, Tucker and 11 producing Lloyd thermal projects were approximately $11 per barrel.

At Sunrise, average production in the quarter was 54,400 bbls/day (27,200 bbls/day Husky working interest), with a record peak daily rate of 62,600 bbls/day. Tucker achieved its design capacity of 30,000 bbls/day in the fourth quarter.

The Rush Lake 2 Lloyd thermal project began production in October 2018 and achieved its 10,000 bbls/day design capacity the following month.

Five additional 10,000 bbls/day Lloyd thermal projects are being advanced through 2022, with a combined design capacity of 50,000 bbls/day. These long-life thermal projects are being phased to optimize capital efficiency and project execution.

- At Dee Valley, construction is progressing ahead of schedule and first oil is on track for the fourth quarter of 2019
- At Spruce Lake Central, the central processing facility is under construction with first production anticipated in 2020
- At Spruce Lake North, site clearing has been completed with first oil planned around the end of 2020
- A new 10,000 bbls/day thermal project at Spruce Lake East is set for first production around the end of 2021
- At Edam Central, regulatory approval has been received, with first production expected in 2022

Resource Plays

In the Ansell and Kakwa areas of the Wilrich formation, 21 wells were drilled and 25 completed in 2018. In the oil and liquids-rich Montney formation, seven wells were drilled and six completed in the Wembley and Karr areas.

Downstream

Canadian refining throughput, including the Lloydminster Upgrader and asphalt refinery, averaged 107,800 bbls/day. EBITDA was $252 million.

U.S. refining throughput averaged 179,100 bbls/day. The U.S. refining segment realized EBITDA of $379 million, which included $331 million in pre-tax insurance proceeds for property damage, rebuild costs, and business interruption at the Superior Refinery. The refinery is expected to resume operations in 2020.

Throughput at the Lima Refinery averaged 105,900 bbls/day compared to 164,500 bbls/day in the fourth quarter of 2017, which takes into account a major scheduled turnaround that began in mid-September 2018. The 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 is on track, with the 2018 work scope successfully completed.

OFFSHORE

- Average production of 64,200 boe/day
- Operating netback of $58.48 per boe
  - Asia Pacific operating netback of $67.42 per boe
  - Atlantic operating netback of $23.19 per barrel

Asia Pacific

China
Sales gas production from the two producing fields at the Liwan Gas Project averaged a record 403 mmcf/day, with associated liquids averaging 19,200 bbls/day (197 mmcf/day and 9,300 bbls/day Husky working interest). Realized gas pricing was $13.85 Cdn per mcf, with liquids pricing of $69.76 Cdn per barrel.

At the Liuhua 29-1 field, three final wells are scheduled to begin drilling in the first quarter of 2019. Altogether, seven wells will be tied into the existing Liwan infrastructure, with first gas expected around the end of 2020. Target production from this third deepwater field at Liwan is 45 mmcf/day of gas and 1,800 bbls/day of liquids when fully ramped up, reflecting Husky's 75 percent working interest.

Indonesia
Gas sales at the liquids-rich BD Project averaged 91 mmcf/day, with liquids production of 7,700 bbls/day (38 mmcf/day and 2,800 bbls/day Husky working interest). BD production was sold into the East Java market at contracted rates for a realized gas price of $9.76 Cdn per mcf, with liquids pricing of $96.83 Cdn per barrel.

Atlantic

West White Rose Project
At the West White Rose Project, construction work on the drilling and wellhead platform, topsides and living quarters is being advanced. First oil is anticipated in 2022, with the project expected to reach peak production of 75,000 bbls/day (52,500 bbls/day Husky working interest) as development wells are drilled and brought online.

Two additional infill wells at the White Rose field are expected to be brought online before mid-year 2019. These are part of a program to offset reservoir declines at the White Rose field and its satellite extensions until the startup of the West White Rose Project.

SeaRose Update
Production at the *SeaRose* FPSO was suspended on November 16 following an oil release from a flowline connector in the South White Rose Extension Drill Centre. Operations resumed at the end of January from the Central Drill Centre, with production expected to continue ramping up through the second quarter as additional subsea drill centres are brought online.

2018 ANNUAL HIGHLIGHTS

Integrated Corridor

- Increased annual average production from Lloyd thermal bitumen projects, Tucker and Sunrise to 124,200 bbls/day, compared to 119,100 bbls/day in 2017
- First oil ahead of schedule at the 10,000 bbls/day Rush Lake 2 thermal project
- Commenced construction of the 10,000 bbls/day thermal projects at Dee Valley and Spruce Lake Central; completed site clearing at Spruce Lake North
- Sanctioned the new 10,000 bbls/day Spruce Lake East thermal project, with first production targeted around the end of 2021
- The Sunrise Energy Project reached and surpassed targeted 60,000 bbls/day (30,000 bbls/day Husky working interest)
- Record throughput of 75,600 bbls/day at the Lloydminster Upgrader; EBITDA of $620 million, up 147 percent over 2017
- Increased Upgrading margin of $30.15 per barrel, compared to $18.28 per barrel in 2017
- Strong margin capture in the Infrastructure and Marketing segment, reflecting Husky's long-term 75,000 bbls/day committed export capacity on the Keystone pipeline

Offshore

- Successful oil exploration discoveries in both the Asia Pacific and Atlantic regions
- Completed slip-forming on the West White Rose fixed wellhead platform to a height of 46 metres
- Record sales gas production from the Liwan and BD projects contributed to an overall annual Asia Pacific operating netback of $67.79 per boe
- Increased working interest at Liuhua 29-1 to 75 percent from 49 percent, providing additional exposure to growing gas markets in Asia
- Signed Production Sharing Contracts for two exploration blocks offshore China in the Beibu Gulf

2018 RESERVES REPLACEMENT

The proved reserves life index was 13.5 years, an increase from 11 years in 2017.

Total proved reserves before royalties at the end of 2018 were 1.5 billion boe. Probable reserves were 1.1 billion boe.

The 2018 proved reserves replacement ratio was 260 percent, excluding economic factors (255 percent including economic factors). The average five-year proved reserves replacement ratio was 144 percent, excluding economic factors (135 percent including economic factors). These take into account acquisitions and the disposition in Western Canada of 62 million boe of proved reserves in 2017 and 90 million boe of proved reserves in 2016.

The five-year annual average proved reserves replacement ratio continues to exceed the target of more than 130 percent.

Proved reserves additions and revisions of 279 million boe, including economic factors, take into account additions related to two newly sanctioned Lloyd thermal bitumen projects and improved performance in the existing projects, the booking of proved reserves for the Liuhua 29-1 project, and future development opportunities added at Sunrise, Lloyd thermal bitumen projects, Ansell, Kakwa, Wembley and other fields, offset by economic factors.

2019 GUIDANCE UPDATE

Husky's 2019 priorities are safe and reliable operations and capital discipline.

Average annual production in 2019 is expected to be in the range of 290,000-305,000 boe/day, with capital spending anticipated to be in the range of $3.3-$3.5 billion.

Production reflects reductions associated with the Government of Alberta's mandatory oil production curtailments. Husky believes that this abandonment of free market principles has impacted investor confidence and created several business challenges, including the Company's ability to process and transport its production to markets unimpeded, and profitably. Curtailment rules disproportionately impact companies, like Husky, with significant Downstream and midstream investments relative to producers who have not made these investments.

Furthermore, the government's curtailment formula does not consider Husky's production growth over the year at Sunrise and Tucker, which are now at full capacity, and does not consider costs related to marketing commitments, or the closure, restart or early abandonment of wells and facilities.

Husky continues to engage with the Alberta Energy Regulator and Alberta government to address the inequities, costs and other unintended consequences of production curtailment.

Production also takes into account the temporary suspension of operations at the *SeaRose* FPSO in the first quarter of 2019.

2019 CAPITAL BUDGET ($ millions)

Upstream	2019 Guidance
Thermal and Oil Sands[1]	730 – 760
Conventional Heavy Oil[1]	100 – 110
Atlantic Region	1,120 – 1,190
Asia Pacific	350 – 370
Western Canada	180 – 190
Total Upstream	**2,480 – 2,620**
Downstream	
Canada	145 – 155
U.S.[2]	545 – 580
Total Downstream	**690 – 735**
Corporate Capital	130 – 145
Total Capital Investment[2,3]	**3,300 – 3,500**
Total Sustaining Capital	**$1.8B**

[1] *Includes reductions related to government-mandated curtailments in Alberta.*
[2] *Excludes Superior Refinery rebuild capital of $199 million.*
[3] *Excludes asset retirement obligations, capitalized interest and administration.*

PRODUCTION SUMMARY

Crude Oil and Liquids (mbbls/day)	2019 Guidance
Thermal and Oil Sands[1]	129 – 135
Conventional Medium and Heavy Oil[1]	29 – 31
Atlantic Light Oil	18 – 20
Western Canada Resource Play Liquids	20 – 21
Asia Pacific Light and natural gas liquids	9 – 10
Total Crude Oil and Liquids	**205 – 217**
Natural Gas (mmcf/day)	
Canada	297 – 307
Asia Pacific	210 – 220
Total Natural Gas	**507 – 527**
Total Upstream	**290 – 305**

2019 PLAN HIGHLIGHTS

- Capital spending in the range of $3.3-3.5 billion, including approximately $1.8 billion in sustaining and corporate capital
- Mid-range average annual 2019 production of approximately 295,000 boe/day includes reductions related to government-mandated curtailments in Alberta, and the temporary suspension of operations at the *SeaRose* FPSO in the Atlantic region in the first quarter and staged ramp-up through the second quarter
- Average Upstream operating cost target in the range of $14.25-$15 per barrel; average Downstream operating cost target for the Lloydminster Upgrader and U.S. refineries along the Integrated Corridor in the $7.50-$8 per barrel range

Growth capital in 2019 includes progressing five 10,000 bbls/day Lloyd thermal projects in Saskatchewan to be brought online through 2022, completing the crude oil flexibility project at the Lima Refinery, development of the Liuhua 29-1 field offshore China, and advancement of the West White Rose Project in the Atlantic region.

Husky expects to achieve its targeted average annual proved reserves replacement ratio of more than 130 percent.

STRATEGIC ASSET REVIEW

As part of its increasing focus on its core heavy oil projects and Downstream assets in the Integrated Corridor business, the Company has announced plans to market and potentially sell its Canadian retail and commercial fuels business and the Prince George Refinery.

No timeline has been determined for the closure of any potential transactions, which were not reflected in the five-year plan presented at Investor Day in May 2018.

2019 PLANNED MAINTENANCE AND TURNAROUNDS

Integrated Corridor

- Four-week partial turnaround at Sunrise in the second quarter
- Four-week turnaround at the Prince George Refinery in the second quarter
- Three-week turnaround at the Rainbow Lake processing facility in the second quarter
- 45-day full shutdown at the Lima Refinery in the fourth quarter for work related to the crude oil flexibility project, with concurrent maintenance; anticipated throughput impact of 79,000 bbls/day over the quarter
- Planned turnaround at the Toledo Refinery

Offshore

- Seven-day maintenance at the Liwan Gas Project in the second quarter
- 12-day maintenance at the BD Project in the first quarter
- Eight-day turnaround at the *SeaRose* FPSO in the third quarter
- Two-week turnaround at the *Terra Nova* FPSO in the second quarter

CORPORATE DEVELOPMENTS

The Board of Directors has approved a quarterly dividend of $0.125 per common share for the three-month period ended December 31, 2018. The dividend will be payable April 1, 2019 to shareholders of record at the close of business on March 19, 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 March 31, 2019. The dividends will be payable on April 1, 2019 to holders of record at the close of business on March 19, 2019.

Share Series	Dividend Type	Rate (%)	Dividend Paid ($/share)
Series 1	Regular	2.404	$0.15025
Series 2	Regular	3.443	$0.21224
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 Tuesday, Feb. 26 at 9 a.m. Mountain Time (11 a.m. Eastern Time) to discuss Husky's 2018 fourth quarter and annual 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 Feb. 26):

Canada and U.S. Toll Free: 1-800-319-6413
Outside Canada and U.S.: 1-604-638-9010
Passcode: 2892
Duration: Available March 26, 2019
Audio webcast: Available for 90 days at 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; 2019 production guidance, including guidance for specified areas and product types; 2019 capital expenditure budget; 2019 average Upstream and average Downstream operating cost targets; and expectations regarding the 2019 average annual proved reserves replacement ratio;

- with respect to the Company's thermal developments: estimated production and expected timing of first production from the Dee Valley, Spruce Lake Central, Spruce Lake North, Spruce Lake East and Edam Central projects; and the expected timing and duration of the turnaround at Sunrise;

- with respect to the Company's Western Canada resource plays, the expected timing and duration of the turnaround at the Rainbow Lake processing facility;

- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of drilling of the remaining three wells at, and first gas production from, Liuhua 29-1; target production from Liuhua 29-1 when fully ramped up; and the expected timing and duration of maintenance at the Liwan Gas Project and the BD Project;

- with respect to the Company's Offshore business in Atlantic: the expected timing of first production, and the expected volume of peak production, at the West White Rose Project; the expected timing that two additional infill wells will be brought online at the White Rose field; the expected timing of production ramp-up at the *SeaRose* FPSO; and expected timing and duration of turnarounds at the *SeaRose* FPSO and the *Terra Nova* FPSO; and

- with respect to the Company's Downstream operations: the potential sale of non-core Downstream assets; the expected timing that operations will resume at the Superior Refinery; the expected timing of completion of the crude oil flexibility project at the Lima Refinery; the expected timing and duration of the turnaround at the Prince George Refinery; the expected timing and duration, and the anticipated impact on throughput, of the full shutdown at the Lima Refinery; and the planned turnaround at the Toledo Refinery.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserves and 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", "operating netback", "net debt", "net debt to trailing funds from operations", "EBITDA" and "sustaining capital". 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 and net debt, 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.

Funds from operations has been 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.

Free cash flow has been 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 (loss) to funds from operations and free cash flow, and related per share amounts, for the periods indicated:

($ millions)	Three months ended Dec. 31 2018	 Sept. 30 2018	 Dec. 31 2017	12 months ended Dec. 31 2018	 Dec. 31 2017
Net earnings	216	545	672	1,457	786
Items not affecting cash:					
Accretion	25	23	28	97	112
Depletion, depreciation, amortization and impairment	662	672	647	2,591	2,882
Inventory write-down to net realizable value	60	-	-	60	-
Exploration and evaluation expenses	22	-	-	29	6
Deferred income taxes (recoveries)	25	156	(360)	396	(359)
Foreign exchange loss (gain)	1	(6)	1	(6)	(4)
Stock-based compensation	(50)	40	25	44	45
Gain on sale of assets	-	-	(13)	(4)	(46)
Unrealized mark to market loss (gain)	(16)	(22)	57	(150)	56
Share of equity investment gain	(16)	(18)	(1)	(69)	(61)
Gain on insurance recoveries for damage to property	(253)	-	-	(253)	-
Other	2	(2)	8	21	16
Settlement of asset retirement obligations	(65)	(45)	(45)	(181)	(136)
Deferred revenue	(30)	(25)	(5)	(100)	(16)
Distribution from joint ventures	-	-	-	72	25
Change in non-cash working capital	730	(35)	337	130	398
Cash flow - operating activities	1,313	1,283	1,351	4,134	3,704
Change in non-cash working capital	(730)	35	(337)	(130)	(398)
Funds from operations	583	1,318	1,014	4,004	3,306
Capital expenditures	(1,265)	(968)	(745)	(3,578)	(2,220)
Free cash flow	(682)	350	269	426	1,086
Weighted average number of common shares outstanding	1,005.1	1,005.1	1,005.1	1,005.1	1,005.3
Funds from operations					
Per common share - Basic ($/share)	0.58	1.31	1.01	3.98	3.29

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.

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)	Dec. 31 2018	Sept. 30 2018	Dec. 31 2017
Short-term debt	200	200	200
Long-term debt due within one year	1,433	388	-
Long-term debt	4,114	4,964	5,240
Cash and cash equivalents	(2,866)	(2,916)	(2,513)
Net debt	2,881	2,636	2,927

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 December 31, 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 (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.

Sustaining capital is the additional development capital that is required by the business to maintain production and operations at existing levels. Development capital includes the cost to drill, complete, equip and tie-in wells to existing infrastructure. Sustaining capital does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

DISCLOSURE OF OIL AND GAS INFORMATION

Unless otherwise indicated: (i) reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, have an effective date of December 31, 2018 and represent the Company's working interest share; (ii) 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; (iii) all Husky working interest production volumes quoted are before deduction of royalties; and (iv) historical production volumes provided are for the year ended December 31, 2018.

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.

The Company uses the term "proved reserves life index", which is consistent with other oil and gas companies' disclosures. The Company's proved reserves life index for a given period is determined by taking the Company's total proved reserves at the end of that period divided by the Company's upstream gross production for the same period. Readers are cautioned that the term proved reserves life index may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not reflect the actual life of the reserves.

The Company uses the term "reserves replacement ratio", which is consistent with other oil and gas companies' disclosures. Reserves replacement ratios for a given period are determined by taking the Company's incremental proved reserve additions for that period divided by the Company's upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserves base during a given period. Reserves replacement ratios presented as excluding economic factors exclude the impact that changing oil and gas prices, inflation and regulations have on reserves amounts.

NOTE TO U.S. READERS

The Company reports its reserves and resources information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*, adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the SEC.

All currency is expressed in Canadian dollars unless otherwise indicated.