Q3 NEWS RELEASE
Calgary, Alberta
October 24, 2019

Husky Energy Reports Third Quarter 2019 Results

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

Husky Energy continued to execute its 2019 business plan in the third quarter, with the delivery of all planned milestones in the Integrated Corridor and Offshore businesses.

Funds from operations were $1 billion, compared to $1.3 billion in the third quarter of 2018. Net earnings were $273 million. Cash flow from operating activities, including changes in non-cash working capital, was $800 million, compared to $1.3 billion in the third quarter of 2018. The reductions in funds from operations and net earnings include impacts from lower crude oil prices and lower U.S. refining margins.

"We achieved all of the milestones for the third quarter as set out at Investor Day in May, and remain on track for the rest of the year," said CEO Rob Peabody. "We also saw our work to enhance process safety translate to improved reliability across the business."

"In the Integrated Corridor, we started up our latest 10,000 barrel-per-day Saskatchewan thermal bitumen project at Dee Valley, which has already reached its nameplate capacity. We began the final tie-in of the Lima Refinery crude oil flexibility project, received permits to commence the Superior Refinery rebuild, and reached an agreement to sell the Prince George Refinery."

In the Offshore business, the *SeaRose* floating production, storage and offloading (FPSO) vessel is back up to full rates, the Liuhua 29-1 project in China is 65% complete, and the West White Rose Project is now 52% complete.

In line with the reduced capital program set out at Investor Day in May 2019, earlier this week Husky took steps to further align its organization and workforce.

THIRD QUARTER HIGHLIGHTS

- Funds from operations of $1 billion, compared to $1.3 billion in the year-ago period
- Cash flow from operating activities of $800 million, compared to $1.3 billion in the third quarter of 2018
- Net earnings of $273 million, compared to net earnings of $545 million in Q3 2018
- Capital spending of $868 million was directed towards advancing the Saskatchewan thermal portfolio, the Lima crude oil flexibility project, and progressing construction of the Liuhua 29-1 field offshore China and the West White Rose Project in the Atlantic region. Capital expenditure guidance for 2019 remains unchanged at $3.3-$3.5 billion
- Free cash flow, before dividends, of $153 million
- Successful startup of the 10,000 barrel-per-day Dee Valley thermal bitumen project, which came in ahead of schedule and under budget
- Overall Upstream production averaged 294,800 barrels of oil equivalent per day (boe/day), which takes into account the return to full production at the White Rose field in the Atlantic region, mandated production quotas in Alberta and maintenance at the Liwan Gas Project and the BD Project in the Asia Pacific region; production was approximately 310,000 boe/day at the end of the third quarter
- Downstream throughput of 356,400 barrels per day (bbls/day), compared to 350,600 bbls/day in the third quarter of 2018
- Construction commenced on the Superior Refinery rebuild project; full operations expected to resume in 2021
- Reached an agreement to sell the Prince George Refinery for $215 million in cash plus a closing adjustment for working capital, and a contingent payment of up to $60 million over two years; sale is expected to close in the fourth quarter of 2019 subject to closing conditions

	Three Months Ended			Nine Months Ended	
	Sept. 30 2019	June 30 2019	Sept. 30 2018	Sept. 30 2019	Sept. 30 2018
Upstream production, before royalties					
Total equivalent production (mboe/day)	295	268	297	283	298
Crude oil and natural gas liquids (mbbls/day)	211	189	210	200	215
Natural gas (mmcf/day)	503	475	520	498	497
Upgrader and refinery throughput (mbbls/day)	356	340	351	343	368
Revenue, net of royalties ($mm)	5,313	5,303	6,194	15,190	17,260
Operating margin[1] ($mm)	976	942	1,414	3,090	3,910
Integrated Corridor	710	703	1,028	2,356	2,774
Offshore	266	239	386	734	1,136
Funds from operations[1] ($mm)	1,021	802	1,318	2,782	3,421
Per common share – Basic ($/share)	1.02	0.80	1.31	2.77	3.40
Cash flow – operating activities ($mm)	800	760	1,283	2,105	2,821
Capital expenditures ($mm)	868	858	968	2,538	2,313
Free cash flow[1] ($mm)	153	(56)	350	244	1,108
Net earnings ($mm)	273	370	545	971	1,241
Per common share – Basic ($/share)	0.26	0.36	0.53	0.94	1.21
Net debt[1] ($ billions)	3.9	3.7	2.6	3.9	2.6
Net debt to trailing funds from operations[1](times)	1.1	1.0	0.6	1.1	0.6

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

THIRD QUARTER RESULTS

Upstream production averaged 294,800 boe/day, compared to 296,700 boe/day in the third quarter of 2018, which takes into account the start up of the 10,000 bbls/day Dee Valley thermal bitumen project in Saskatchewan and return to full production at the White Rose field in the Atlantic region, partially offset by ongoing mandated production quotas in Alberta and maintenance at Liwan and the BD Project.

Average realized pricing for Upstream production was $47.54 per boe compared to $50.44 per boe in the same period in 2018. Realized pricing for oil and liquids averaged $53.46 per barrel compared to $56.02 per barrel in the year-ago period, and natural gas pricing averaged $5.44 per thousand cubic feet (mcf), compared to $6.15 per mcf in Q3 2018. Upstream operating costs were $14.83 per boe compared to $14.68 per boe in the third quarter of 2018, reflecting lower production in the Atlantic region and maintenance at Liwan and the BD Project.

Upstream operating netbacks averaged $29.31 per boe compared to $31.30 per boe in the year-ago period.

Upgrader and refinery throughput was 356,400 bbls/day, compared to 350,600 bbls/day in the same period in 2018. This reflects strong performance at the Lima Refinery, which averaged 174,300 bbls/day in the third quarter.

The average realized U.S. refining and marketing margin was $12.17 US per barrel of crude oil throughput, which reflects an unfavourable first-in, first-out (FIFO) pre-tax inventory valuation adjustment of $0.13 US per barrel. This compared to $17.52 US per barrel a year ago, which included an unfavourable FIFO pre-tax inventory valuation adjustment of $0.35 US per barrel.

The Upgrader realized margin was $15.01 per barrel compared to $29.19 per barrel in the same period in 2018, which takes into account lower upgrading differentials.

Net earnings in the Infrastructure and Marketing segment were $34 million compared to $149 million in Q3 2018, due to tighter location pricing differentials.

Husky has already achieved most of its planned 2019 operational milestones and is making strong progress on its 2020 targets.

NEAR & MID-TERM MILESTONES

2019	Capacity (Husky W.I.)	Timing/ Completion	Status
Turnarounds			
Upstream		Q2 ’19	✓ Completed
Downstream		Q2 ’19	✓ Completed
White Rose infill production wells online	+6-8,000 bbls/day	Q2 ’19	✓ Completed
White Rose drill centres on full production		Q3 ’19	✓ Completed
Dee Valley thermal project	10,000 bbls/day	Q3 ’19	✓ Completed
Liuhua 29-1 initial pipeline laying		Q3 ’19	✓ Completed
Lima Refinery crude oil flexibility project	40,000 bbls/day	YE ’19	95% complete
Prince George Refinery sale		Q4 ’19	✓ Announced
Strategic review of fuels/retail business		’19	In progress
2020+	**Capacity (Husky W.I.)**	**Timing/ Completion**	**Status**
Lloyd Upgrader diesel capacity increase	6,000 –> 9,800 bbls/day	’20	45% complete
Spruce Lake Central thermal project	10,000 bbls/day	2H ’20	85% complete
Spruce Lake North thermal project	10,000 bbls/day	~YE ’20	55% complete
Liuhua 29-1 project	45 mmcf/day gas 1,800 bbls/day liquids	YE ’20	65% complete
Superior Refinery rebuild	50,000 bbls/day	’21	In progress
Spruce Lake East thermal project	10,000 bbls/day	~YE ’21	In progress
MDA-MBH & MDK fields	10,000 boe/day	’21	In progress
Edam Central thermal project	10,000 bbls/day	’22	In progress
West White Rose Project start up	52,500 bbls/day	~YE ’22	52% complete
Dee Valley 2 thermal project	10,000 bbls/day	’23	In planning

INTEGRATED CORRIDOR

- Upstream production averaged 232,100 boe/day compared to 223,300 boe/day in Q3 2018
- Operating margin of $710 million, compared to $703 million in Q2 2019 and $1.03 billion in Q3 2018
- First oil achieved at the Dee Valley thermal bitumen project in Saskatchewan, which has reached its 10,000 bbls/day nameplate capacity
- Downstream throughput of 356,400 bbls/day compared to 350,600 bbls/day in the third quarter of 2018

Thermal Production

Thermal bitumen production from Saskatchewan thermal projects, the Tucker Thermal Project and the Sunrise Energy Project averaged 126,400 bbls/day (Husky W.I.), compared to 117,300 bbls/day (Husky W.I.) in Q3 2018.

Overall production from the Saskatchewan thermal portfolio was 76,900 bbls/day compared to 74,300 bbls/day in Q3 2018. This included the startup of the new 10,000 bbls/day Dee Valley thermal project, which began production ahead of schedule in August and achieved its nameplate capacity in September.

Five new Saskatchewan thermal bitumen projects with a combined nameplate capacity of 50,000 bbls/day are being advanced through 2023, including the Spruce Lake Central development, scheduled for startup in the second half of 2020, and the Spruce Lake North project, which is planned to start up around the end of 2020.

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 while supporting the natural gas requirements of its thermal operations in Western Canada.

In the oil and liquids-rich Montney formation, one well was drilled in the Karr area, completing the planned 2019 Montney drilling program. Ten Montney wells at Wembley and Karr are expected to be brought on production in the fourth quarter.

Downstream

The Downstream operating margin was $244 million, compared to $286 million in Q2 2019 and $471 million in Q3 2018.

U.S. refinery throughput averaged 241,100 bbls/day, including average throughput of 174,300 bbls/day at the Lima Refinery. The Lima Refinery crude oil flexibility project to increase heavy oil processing capacity to 40,000 bbls/day is in its final stages and scheduled to conclude by the end of 2019.

The operating margin for the U.S. refining segment was $121 million.

The Superior Refinery rebuild has commenced, with a return to full operations expected in 2021. Rebuild costs are expected to be substantially covered by property damage insurance.

Pre-tax business interruption insurance proceeds of $132 million for the Superior Refinery was accounted for in $410 million of Downstream EBITDA.

Canadian throughput, including the Lloydminster Upgrader and asphalt refinery, averaged 115,300 bbls/day. A project is under way at the Upgrader to increase diesel production from 6,000 bbls/day to nearly 10,000 bbls/day in 2020.

The operating margin for the combined Upgrading and Canadian Refined Products segments was $123 million.

Husky continued to increase its focus on core assets in the Integrated Corridor business with the agreement to sell the Prince George Refinery for $215 million in cash plus a closing adjustment for working capital and a contingent payment of up to $60 million over two years. The sale is expected to close in the fourth quarter of 2019 subject to closing conditions and regulatory approvals. Proceeds will be used in accordance with Husky's funding priorities, which include maintaining the strength of the balance sheet and returning value to shareholders.

A strategic review of the potential sale of the Canadian retail and commercial fuels business continues to progress.

OFFSHORE

- Overall average net production of 62,700 boe/day, compared to 73,400 boe/day in the third quarter of 2018
- Operating netback of $55.53 per boe
  - Asia Pacific operating netback of $62.59 per boe
  - Atlantic operating netback of $41.64 per barrel
- White Rose field returned to full operations

Asia Pacific

China

Natural gas sales from the two producing fields at the Liwan Gas Project averaged 323 million cubic feet per day (mmcf/day), with associated liquids averaging 14,300 bbls/day (158 mmcf/day and 6,600 bbls/day Husky W.I.). Realized gas pricing at Liwan was $13.28 per mcf, with liquids pricing of $61.81 per barrel. Operating costs were $6.10 per boe, with an operating netback of $65.67 per boe.

At the Liuhua 29-1 field at Liwan, all seven wells have been drilled, with final completions under way. The wells will be tied in to the existing subsea infrastructure, with first gas expected by 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 86 mmcf/day, with liquids production of 7,000 bbls/day (35 mmcf/day and 2,800 bbls/day, Husky W.I.). Volumes were impacted by maintenance to the leased FPSO vessel. Realized gas pricing at BD was $9.82 per mcf, with liquids pricing of $83.03 per barrel. Operating costs were $6.22 per boe, with an operating netback of $51.98 per boe.

Atlantic

Overall average production in the Atlantic region was approximately 21,000 bbls/day (Husky W.I.), reflecting the return to operations in August of the final two drill centres in the White Rose field.

West White Rose Project
Construction work on the concrete gravity structure and related topsides is progressing. The third quadrant of the concrete gravity structure (CGS) and two interior decks were completed, and the fourth and final CGS quadrant was completed in October. The project is now 52% complete as it advances towards first oil around the end of 2022.

CORPORATE DEVELOPMENTS

The Board of Directors has approved a quarterly dividend of $0.125 per common share for the three-month period ended September 30, 2019. The dividend will be payable on January 2, 2020 to shareholders of record at the close of business on December 2, 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 December 31, 2019. The dividends will be payable on December 31, 2019 to holders of record at the close of business on December 2, 2019.

Share Series	Dividend Type	Rate (%)	Dividend Paid ($/share)
Series 1	Regular	2.404	$0.15025
Series 2	Regular	3.368	$0.21223
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, Oct. 24 at 9 a.m. Mountain Time (11 a.m. Eastern Time) to discuss Husky's 2019 third 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: 1-800-319-4610
Outside Canada and U.S.: 1-604-638-5340

To listen to a recording (after 10 a.m. MT on Oct. 24):

Canada and U.S. Toll Free: 1-800-319-6413
Outside Canada and U.S.: 1-604-638-9010
Passcode: 3602
Duration: Available until November 23, 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 guidance for 2019;
- with respect to the Company's thermal developments, the expected timing of completion of the Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central and Dee Valley 2 projects;
- with respect to the Company's Western Canada resource plays, the expected timing of production at 10 Montney wells at Wembley and Karr;
- with respect to the Company's Offshore business in Asia Pacific: the expected timing of first production at Liuhua 29-1; target production volumes at Liuhua 29-1 when fully ramped up; the expected timing of first production from the combined MDA-MBH and MDK fields; and expected production capacity at the MDA-MBH and MDK fields;
- with respect to the Company's Offshore business in Atlantic, expected production capacity 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 resumption of full operations at the Superior Refinery, expected throughput capacity once full operations have resumed and expected insurance recoveries related to the rebuild costs; the contingent payment of up to $60 million as part of the consideration for, the expected timing of closing of and the expected use of proceeds from the sale of the Prince George Refinery; the expected timing of completion of the crude oil flexibility project at the Lima Refinery and the expected heavy oil processing capacity resulting therefrom; the expected timing of completion of the strategic review of the potential sale of the Canadian retail and commercial fuels business; and the expected timing of completion of the Lloydminster Upgrader diesel capacity project, and the expected increase in diesel production resulting therefrom.

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", "operating margin", "net debt", "net debt to trailing funds from operations", "operating netback" and "EBITDA". 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 excluding 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:

($ millions)	Three months ended Sept. 30 2019	June 30 2019	Sept. 30 2018	Nine months ended Sept. 30 2019	Sept. 30 2018
Net earnings	273	370	545	971	1,241
Items not affecting cash:					
Accretion	26	26	23	79	72
Depletion, depreciation, amortization and impairment	703	643	672	1,976	1,929
Exploration and evaluation expenses	-	23	-	23	7
Deferred income taxes	22	(250)	156	(185)	371
Foreign exchange gain	(1)	(2)	(6)	(15)	(7)
Stock-based compensation	(9)	13	40	11	94
Gain on sale of assets	(3)	-	-	(5)	(4)
Unrealized mark to market loss (gain)	4	(4)	(22)	57	(134)
Share of equity investment gain	(19)	(23)	(18)	(64)	(53)
Gain on insurance recoveries for damage to property	(13)	-	-	(13)	-
Other	5	5	(2)	1	19
Settlement of asset retirement obligations	(73)	(41)	(45)	(186)	(116)
Deferred revenue	(7)	(5)	(25)	(28)	(70)
Distribution from equity investment	113	47	-	160	72
Change in non-cash working capital	(221)	(42)	(35)	(677)	(600)
Cash flow - operating activities	800	760	1,283	2,105	2,821
Change in non-cash working capital	221	42	35	677	600
Funds from operations	1,021	802	1,318	2,782	3,421
Capital expenditures	(868)	(858)	(968)	(2,538)	(2,313)
Free cash flow	153	(56)	350	244	1,108
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)	1.02	0.80	1.31	2.77	3.40

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								
	Sept. 30, 2019			June 30, 2019			Sept. 30, 2018		
($ millions)	Integrated Corridor	Offshore	Total	Integrated Corridor	Offshore	Total	Integrated Corridor	Offshore	Total
Revenue, net of royalties	5,488	362	5,850	5,527	328	5,855	6,241	474	6,715
Less:									
Purchases of crude oil and products	4,043	-	4,043	4,074	-	4,074	4,470	-	4,470
Production and operating expenses	638	88	726	662	81	743	662	78	740
Selling, general and administrative expenses	97	8	105	88	8	96	81	10	91
Operating margin	710	266	976	703	239	942	1,028	386	1,414

	Nine months ended					
	Sept. 30, 2019			Sept. 30, 2018		
($ millions)	Integrated Corridor	Offshore	Total	Integrated Corridor	Offshore	Total
Revenue, net of royalties	15,711	1,012	16,723	17,252	1,389	18,641
Less:						
Purchases of crude oil and products	11,106	-	11,106	12,343	-	12,343
Production and operating expenses	1,969	254	2,223	1,878	224	2,102
Selling, general and administrative expenses	279	25	304	257	29	286
Operating margin	2,356	734	3,090	2,774	1,136	3,910

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)	**Sept. 30 2019**	**June 30 2019**	**Sept. 30 2018**
Short-term debt	200	200	200
Long-term debt due within one year	1,393	1,382	388
Long-term debt	4,635	4,598	4,964
Cash and cash equivalents	(2,362)	(2,512)	(2,916)
Net debt	3,866	3,668	2,636

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 September 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 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.

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.

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.