Husky Energy

NEWS RELEASE
Calgary, Alberta
December 4, 2017

# Husky Energy Announces 2018 Budget and Production Guidance

Husky is on track to exceed the 2018 targets for funds from operations and free cash flow outlined at its 2017 Investor Day.

"We are ahead of our five-year plan in delivering cost efficiencies, lower cost production, lower operating costs, lower sustaining capital requirements, and increasing free cash flow," said CEO Rob Peabody.

**2018 Plan Highlights:**

- Funds from operations are anticipated to exceed $4 billion and free cash flow is expected to be about $1 billion at pricing of $55 US WTI, $2.50 AECO and a $15 US per barrel Chicago 3:2:1 crack spread
- Capital spending of $2.9-3.1 billion: $1.0-1.1 billion growth capital and $1.9-2.0 billion sustaining and corporate capital
- Current net debt of $3.3 billion, representing approximately one times net debt to expected 2017 funds from operations, anticipated to remain well below target of less than two times 2018 funds from operations
- New project funding is contingent on meeting a forecast minimum 10 percent rate of return at $45 US WTI
- 2018 annual production is expected to average 320,000-335,000 barrels of oil equivalent per day (boe/day), despite 20,000 boe/day in 2017 asset sales expected to close by year end. Thermal bitumen production is expected to grow 12 percent and Asia Pacific production is anticipated to grow 16 percent
- 2021 production target of 400,000 boe/day, representing a seven percent compound average annual growth rate
- Average Upstream operating cost target of $13-13.50 per barrel, down 18 percent from $16.12 per barrel in 2014
- Earnings break-even oil price expected to be about $42 US WTI per barrel with cash break-even of $32 US WTI per barrel
- Two 10,000-barrels-per-day (bbls/day) Lloyd thermal bitumen projects and Liuhua 29-1 have been sanctioned and are forecast to start up in 2021

Husky's operational focus in 2018 is to ramp up the Tucker Thermal Project, Phase 1 of the Sunrise Energy Project and the BD Project in Indonesia to full rates. In addition, the Company will integrate its newly-acquired Superior Refinery, advance six Lloyd thermal projects, move forward with the Liuhua 29-1 field development offshore China and progress the West White Rose Project offshore Newfoundland and Labrador.

2018 CAPITAL INVESTMENT AND PRODUCTION[1]

| | Capital Budget ($ millions) | | Production (mbbls/day) | | |
|---|---|---|---|---|---|
| **Crude Oil and Liquids** | **2017 Budget** | **2018 Budget** | **2017 Guidance** | | **2018 Guidance** |
| Thermal bitumen (Lloyd, Tucker, Sunrise) | 560 – 590 | 895 – 930 | 120 – 127 | | 128 – 137 |
| Non-thermal heavy, light, medium, NGLs | 165 – 175 | 140 – 150 | 63 – 66 | | 67 – 69 |
| Atlantic light | 475 – 500 | 750 – 775 | 35 – 37 | | 34 – 35 |
| Asia Pacific light and NGLs | – – | – – | 13 – 15 | | 10 – 11 |
| **Total Crude Oil and Liquids** | **1,200 – 1,265** | **1,785 – 1,855** | **231 – 245** | | **240 – 252** |
| **Natural Gas** | | | (mmcf/day) | | (mmcf/day) |
| Canada | 190 – 200 | 215 – 225 | 365 – 375 | | 280 – 290 |
| Asia Pacific | 80 – 85 | 130 – 150 | 165 – 170 | | 200 – 210 |
| **Total Natural Gas** | **270 – 285** | **345 – 375** | **530 – 545** | | **480 – 500** |
| **Total Upstream** | **1,470 – 1,550** | **2,130 – 2,230** | **320 – 335** | (mboe/day) | **320 – 335** |
| **Downstream** | | | | | |
| Canada | 300 – 325 | 130 – 160 | | | |
| U.S. | 320 – 340 | 580 – 625 | | | |
| **Total Downstream** | **620 – 665** | **710 – 785** | | | |
| **Total Corporate Capital** | **95 – 110** | **100 – 110** | | | |
| **Total Capital Investment** | **2,185 – 2,325** | **2,940 – 3,125** | | | |
| **Total Sustaining Capital** | **1,750 – 1,850** | **1,775 – 1,875** | | | |

[1] *Amounts exclude asset retirement obligations, capitalized interest and administration. Some figures rounded; see full Guidance report at huskyenergy.com*

## 2018 Capital Program

Total capital spending is expected to be $2.9-3.1 billion, less than the estimated $3.3 billion annual average capital spending forecast in the five-year plan at Investor Day 2017, reflecting greater capital efficiency.

Upstream project spending is expected to be largely allocated to growing the Lloyd thermal portfolio, with 60,000 bbls/day of new production scheduled to be brought online between 2019 and 2021, and the construction of the 75,000-bbls/day West White Rose Project in the Atlantic region (52,500 bbls/day Husky working interest), with first oil planned in 2022.

The Board has sanctioned the Liuhua 29-1 project, the third deepwater gas field at the Liwan Gas Project. Construction is anticipated to begin in 2018, followed by first production in 2021.

The capital program remains flexible, with about 75 percent of Upstream spending directed toward short and medium-cycle projects. Downstream project spending includes the Lima crude oil flexibility project, which will add 30,000 bbls/day of additional heavy oil capacity by 2019, and a project to increase heavy oil processing capacity at the Superior Refinery.

Capital spending for 2017, not including the acquisition of the Superior Refinery, remains within guidance at $2.2-2.3 billion. Including the acquisition, which closed in November, total capital spending in 2017 is expected to be about $2.9 billion.

## 2018 Upstream Production

Average annual production is expected to be in the range of 320,000-335,000 boe/day. Adjusting for dispositions and asset sales expected to close by the end of 2017, this constitutes a six percent year-over-year increase in growth at the midpoint of this range, ahead of the Company's five-year plan.

Husky has agreed to sell the Ram River Gas Plant and select legacy assets in Western Canada representing 18,000 boe/day of gas-weighted production. The transactions, which are expected to close by the end of 2017, were not included in the five-year plan presented at Investor Day 2017.

The Western Canada asset disposition program is now substantially complete. Since December 2015, about 52,000 boe/day of higher-cost legacy production has been sold or is expected to be sold by the end of 2017, with an associated reduction in asset retirement obligations of approximately $840 million. Over the same period, Husky added approximately 66,000 boe/day of new, lower-cost production, largely from the thermal and Offshore businesses.

With the ramp-up of the Tucker Thermal Project and Sunrise Energy Project toward full capacity, average annual thermal production is expected to grow 12 percent year over year.

In Western Canada, the Company plans to drill 17 net liquids-rich gas wells in the Wilrich formation in the Ansell and Kakwa areas. In the Montney formation, eight wells are scheduled to be drilled.

In the Asia Pacific region, production is anticipated to grow 16 percent year over year as the BD Project ramps up to full capacity offshore Indonesia.

In the Atlantic region, two infill wells are planned in the Jeanne d'Arc Basin. The first is scheduled to be drilled at the North Amethyst satellite extension in the first quarter and the second well at the main White Rose field is planned in the third quarter. The net peak production rate of each well is expected to be approximately 4,400 bbls/day.

Annual production in 2017 is expected to average approximately 324,000 boe/day, within the guidance range of 320,000-335,000 boe/day, despite the sale of assets representing about 2,500 boe/day of annualized production.

The Company expects to remain on track to achieve an average annual proved reserve replacement ratio of more than 130 percent in the 2017-2021 timeframe.

**2018 Downstream Throughputs**

Downstream net throughputs are expected to increase seven percent to approximately 360,000-370,000 bbls/day, compared to average 2017 throughputs of about 342,000 bbls/day.

At the Lima Refinery, the crude oil flexibility project to increase heavy oil processing capacity from 10,000 bbls/day to 40,000 bbls/day is continuing. A project to increase heavy oil processing capacity at the Superior Refinery will be completed in the first half of 2018.

**Improving Cost Structure and Efficiencies**

Husky continues to realize efficiencies across the business as it further reduces its cost structure and invests in higher return production:

- The Company's gas price realizations in 2013, prior to the startup of the Liwan Gas Project in early 2014, averaged $3.19 per thousand cubic feet (mcf). Year to date in 2017, gas price realizations have averaged $5.39 per mcf, compared to average AECO pricing of about $2.15 per mcf. This reflects growing high-netback, fixed-price gas production in the Asia Pacific region and the disposition of legacy gas assets in Western Canada.

- The 10,000-bbls/day Rush Lake 2 thermal project has been accelerated and is expected to come on production in the first quarter of 2019.

- Improved operating efficiencies have resulted in faster drilling times at the Ansell and Kakwa resource plays. Drilling days have been reduced by 30 percent since the start of 2017, contributing to a 22 percent reduction in per-well drilling costs.

- A planned 16-well drilling program targeting the Wilrich formation was completed. Due in part to increased rig efficiency, two additional wells scheduled for 2018 were drilled in the fourth quarter of 2017.

- The Atlantic infill well drilling program has been accelerated as a result of drilling and installation efficiencies. Two wells originally planned for 2018 were advanced to 2017. The first well at the main White Rose field was drilled at the end of the third quarter and is now on production. A second well at North Amethyst is currently drilling, with first oil expected in early 2018.

Average Upstream operating costs continue to decrease and are expected to be in the range of $13-$13.50 per boe, compared to 2017 year-to-date operating costs of about $14 per boe, and Husky remains on track to achieve the 2021 target set at Investor Day 2017 of less than $12 per boe.

Downstream operating costs for the Lloydminster Upgrader and U.S. refineries along the Integrated Corridor are expected to average $6-7 per barrel.

Overall sustaining capital requirements are expected to be in the range of $1.8-1.9 billion.

The Company's earnings break-even oil price is expected to be about $42 US WTI per barrel, compared to $43.60 US WTI per barrel in 2017. The cash break-even oil price is expected to be about $32 US WTI per barrel, compared to $33.50 US WTI per barrel in 2017.

**Project Update**

Husky is moving ahead with several projects expected to contribute to a compound annual production growth rate of seven percent over the next four years, with production rising to 400,000 boe/day in 2021.

| PROJECT UPDATE | | | |
|---|---|---|---|
| **Integrated Corridor** | **Net Production Capacity** (bbls/day) | **2017 Investor Day Guidance** | **Current Status** |
| **Thermal Bitumen** | | | |
| Tucker Thermal Project ramp-up | To 30,000 | YE 2018 | YE 2018 |
| Sunrise Energy Project *(14 additional wells)* | 11,500 | Q4 2017 startup | Completed |
| Rush Lake 2 | 10,000 | 1H 2019 | Accelerated to Q1 2019 |
| Dee Valley | 10,000 | 2020 | 1H 2020 |
| Spruce Lake North | 10,000 | 2020 | 2H 2020 |
| Spruce Lake Central | 10,000 | 2020 | 2H 2020 |
| Edam Central | 10,000 | Planned | 2H 2021 |
| Westhazel | 10,000 | Planned | 2H 2021 |
| Future Lloyd thermal projects | 10,000 per project | Average two per year | Planned |
| **Resource Plays** | | | |
| Ansell-Kakwa drilling program | – | 16 Wilrich wells | 18 Wilrich wells |
| Montney drilling program | – | Four wells | Finished |
| | **Net Throughputs** (bbls/day) | | |
| **Downstream** | | | |
| Lima Refinery crude oil flexibility project | 30,000 *(heavy)* | 2018-2019 | 2018-2019 |
| Superior Refinery flexibility project | Up to 5,000 *(heavy)* | N/A | 1H 2018 |
| Lloydminster Refinery asphalt expansion | 30,000 | Under consideration | Superior Refinery delivering benefits in 2018 |

| **Offshore** | **Net Production Capacity** | **2017 Investor Day Guidance** | **Current Status** |
|---|---|---|---|
| **Asia Pacific** | | | |
| Liuhua 29-1 startup | 30 mmcf/day / 1,200 bbls/day | 2021 | 2021 |
| BD Project startup | 40 mmcf/day / 2,400 bbls/day | 2H 2017 | Completed |
| MDA-MBH, MDK gas fields startup | 60 mmcf/day | 2018-2019 | 2019 |
| **Atlantic**[1] | | | |
| South White Rose infill well | 4,500 bbls/day | Q4 2017 | Completed in Q3 2017 |
| White Rose infill well | 4,500 bbls/day | Q2 2018 | Accelerated to Q4 2017 |
| North Amethyst infill well | 4,300 bbls/day | Q4 2018 | Accelerated to Q1 2018 |
| White Rose infill well | 4,500 bbls/day | Ongoing infill program | Q3 2018 |
| West White Rose Project | 52,500 bbls/day | First oil in 2022 | 2022 |

[1] *Expected net peak production rates.*

**2018 Planned Maintenance and Turnarounds**

Integrated Corridor

- A five-week partial turnaround at the Lloydminster Upgrader in the second quarter; expected utilization rate of 70 percent during the maintenance period.
- A five-week full plant turnaround at the Superior Refinery in the second quarter.
- A five-week partial turnaround at the Lima Refinery in the fourth quarter; expected utilization rate of 50 percent during the maintenance period.

Offshore

- A three-week turnaround at the *SeaRose* FPSO (floating production, storage and offloading) vessel starting in the second quarter.
- A four-week turnaround at the *Terra Nova* FPSO in the third quarter.

**CONFERENCE CALL AND INVESTOR PRESENTATION**

An investor presentation has been posted on the Company's website at www.huskyenergy.com

A conference call will be held on Monday, December 4 at 9 a.m. Mountain Time (11 a.m. Eastern Time) to discuss the Company's 2018 production and capital expenditure guidance.

CEO Rob Peabody, CFO Jon McKenzie and COO Rob Symonds 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. Dec. 4)**

Canada and U.S. Toll Free: 1-800-319-6413
Outside Canada and U.S.: 1-604-638-9010
Passcode: 1907
Duration: Available until January 4, 2018
Audio webcast: Available for 90 days at www.huskyenergy.com

**Investor and Media Inquiries:**

Rob Knowles, Manager, Investor Relations
587-747-2116

Mel Duvall, 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", "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "is estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "schedules" 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; anticipated funds from operations and free cash flow for 2018; capital spending guidance for 2017 and 2018, including anticipated growth capital and sustaining and corporate capital; expected total capital spending for 2017; expected net debt to 2017 and 2018 funds from operations; conditions to new project funding; expected 2017 and 2018 average annual production; production target for 2021; expected average Upstream operating costs for 2018; average Upstream operating cost target for 2021; expected earnings break-even and cash break-even oil prices for 2018;

expected average annual proved reserve replacement ratio for the 2017-2021 timeframe; expected overall sustaining capital requirements for 2018; allocation of Upstream and Downstream spending; and the expected contribution of several projects to the compound annual production growth rate over the next four years (including the net production capacity of each project and the expected timing of first production from each project);

- with respect to the Company's thermal bitumen production in the Integrated Corridor: the anticipated timing of start-up, and design capacity, of two Lloyd thermal bitumen projects; expected thermal production to be brought online between 2019 and 2021; expected average annual growth of thermal production; and the anticipated timing of first production from, and design capacity of, the Rush Lake 2 thermal project;

- with respect to the Company's resource plays in the Integrated Corridor: the expected timing of closing of the sales of the Ram River assets and select legacy assets in Western Canada; and drilling plans;

- with respect to the Company's Downstream operations in the Integrated Corridor: expected growth in net throughputs in 2018; the expected timing of completion of a project to increase heavy oil processing capacity at the Superior Refinery; expected average downstream operating costs for the Lloydminster Upgrader and U.S. refineries for 2018; the anticipated timing and duration of turnarounds at the Lloydminster Upgrader, Superior Refinery and Lima Refinery; and the expected utilization rates at the Lloydminster Upgrader and Lima Refinery during their respective maintenance periods;

- with respect to the Company's Offshore business in Asia Pacific: the anticipated timing of commencement of construction at and first production from Liuhua 29-1; the anticipated growth rate of production year over year as the BD Project ramps up to full capacity; and

- with respect to the Company's Offshore business in the Atlantic: the expected timing of first oil and volume of peak production from the West White Rose Project; the expected timing of drilling and net peak production rates of two new infill wells at the North Amethyst satellite extension and the main White Rose field; the expected timing of first oil from a second well at North Amethyst; and the anticipated timing and duration of turnarounds at the *SeaRose* FPSO and *Terra Nova* FPSO.

Certain of the information in this news release is “financial outlook” within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding the Company’s reasonable expectations as to the anticipated results of its proposed business activities. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

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, 2016 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", "net debt", "net debt to funds from operations", "earnings break-even oil price" and "cash break-even oil price", 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. With the exception of funds from operations and free cash flow, there are no comparable measures to these non-GAAP measures in accordance with 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 to assist management and investors in analyzing operating performance of the Company in the stated period. Funds from operations equals cash flow – operating activities plus change in non-cash working capital.

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

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.

Net debt to funds from operations is a non-GAAP measure that equals net debt divided by funds from operations. Net debt to funds from operations is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

Earnings break-even oil price reflects the estimated WTI oil price per barrel priced in US dollars required in order to generate a net income of Cdn$0 over a 12-month period ending December 31. This assumption is based on holding several variables constant throughout the period, including foreign exchange rate, light-heavy oil differentials, realized refining margins, forecast utilization of downstream facilities, estimated production levels and other factors consistent with normal oil and gas company operations. Earnings break-even is used to assess the impact of changes in WTI oil prices on the net earnings of the Company and could impact future investment decisions.

Cash break-even oil price reflects the estimated WTI oil price per barrel priced in US dollars required in order to generate funds flow from operations equal to the Company's sustaining capital requirements in Canadian dollars over a 12-month period ending December 31. This assumption is based on holding several variables constant throughout the period, including foreign exchange rate, light-heavy oil differentials, realized refining margins, forecast utilization of downstream facilities, estimated production levels and other factors consistent with normal oil and gas company operations. Cash break-even is used to assess the impact of changes in WTI oil prices on the net earnings of the Company and could impact future investment decisions.

**DISCLOSURE OF OIL AND GAS INFORMATION**

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 "reserve replacement ratio", which is consistent with other oil and gas companies' disclosures. Reserve replacement ratios for a given period are determined by taking the Company's incremental proved reserves additions for that period divided by the Company's upstream gross production for the same period. The reserve 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 reserve replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserve replacement ratio only measures the amount of reserves added to a company's reserves base during a given period.

Unless otherwise indicated, projected and historical production volumes provided represent the Company's working interest share before royalties.

All currency is expressed in Canadian dollars unless otherwise indicated.