Barclays CEO Energy-Power Conference

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Husky Energy

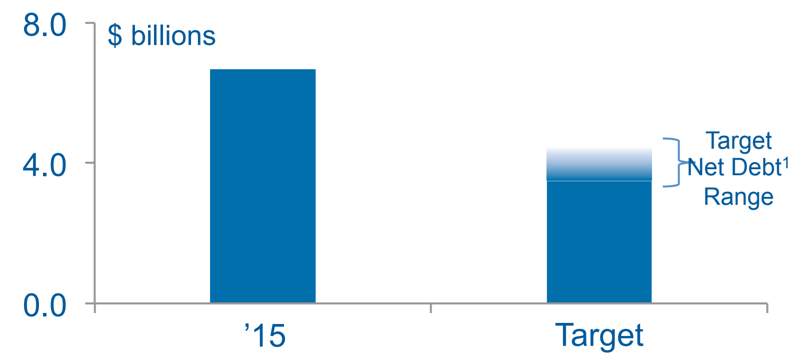
Strategy on Course

- Diverse portfolio
- Focused integration
- Transition to a low sustaining capital business

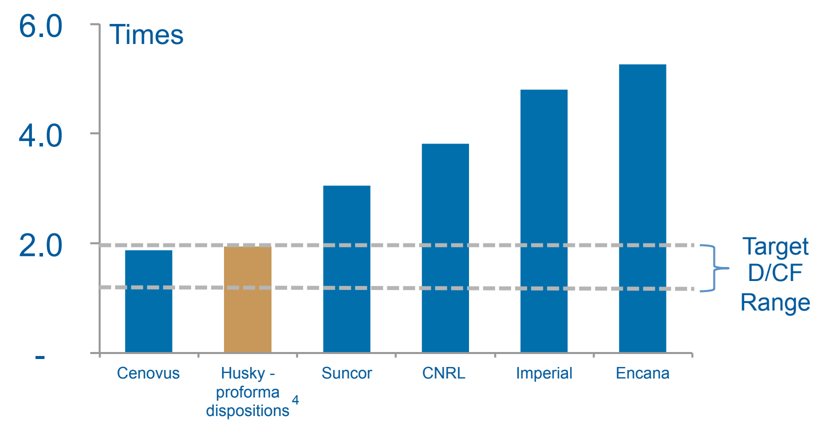
Strengthening the Balance Sheet

- Target of <2x net debt to cash flow from operations[1,2]
  - No new net debt in the near term
  - Disposition proceeds applied to debt
- Maintaining strong investment grade credit rating
  - Ratings confirmed in agency reviews
- Renewed credit facilities
  - Extended maturity date to ’20
- No major long-term bond maturities until ’19

Net Debt



Net Debt to Trailing Cash Flow from Operations[2,3]

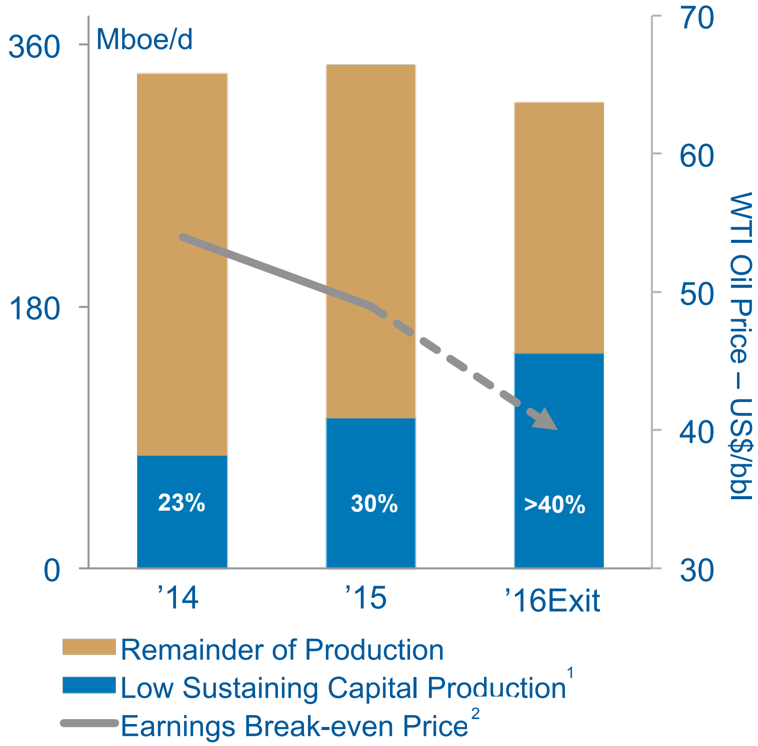


1. Net debt, a non-GAAP measure, is calculated at total debt less cash and cash equivalents. Total debt is calculated as long term debt, long term debt due within one year and short-term debt
2. Net debt to cash flow from operations, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.
3. Net debt to trailing cash flow from operations ratio calculated by dividing net debt by 12-month trailing cash flow from operations as at Jun 30, 2016. Please see Advisories for further detail.
4. Dispositions and expected gross disposition proceeds, as referred to throughout this presentation, are listed in the Advisories.

* Peer data sourced from public filings available on SEDAR.

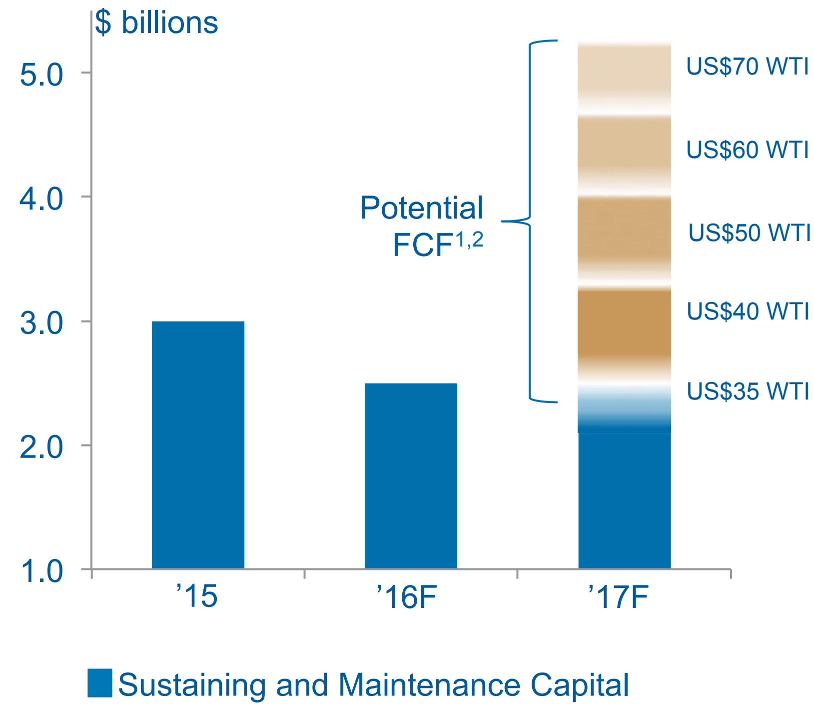
Low Earnings Break Even and Free Cash Flow Generation

Lower Earnings Break-Even



1. Low sustaining capital production, as referred to throughout this presentation, includes production from Tucker, thermals, Sunrise and Asia Pacific natural gas.
2. Earnings Break-even price, as referred to throughout this presentation, has the meaning set out in the Advisories.

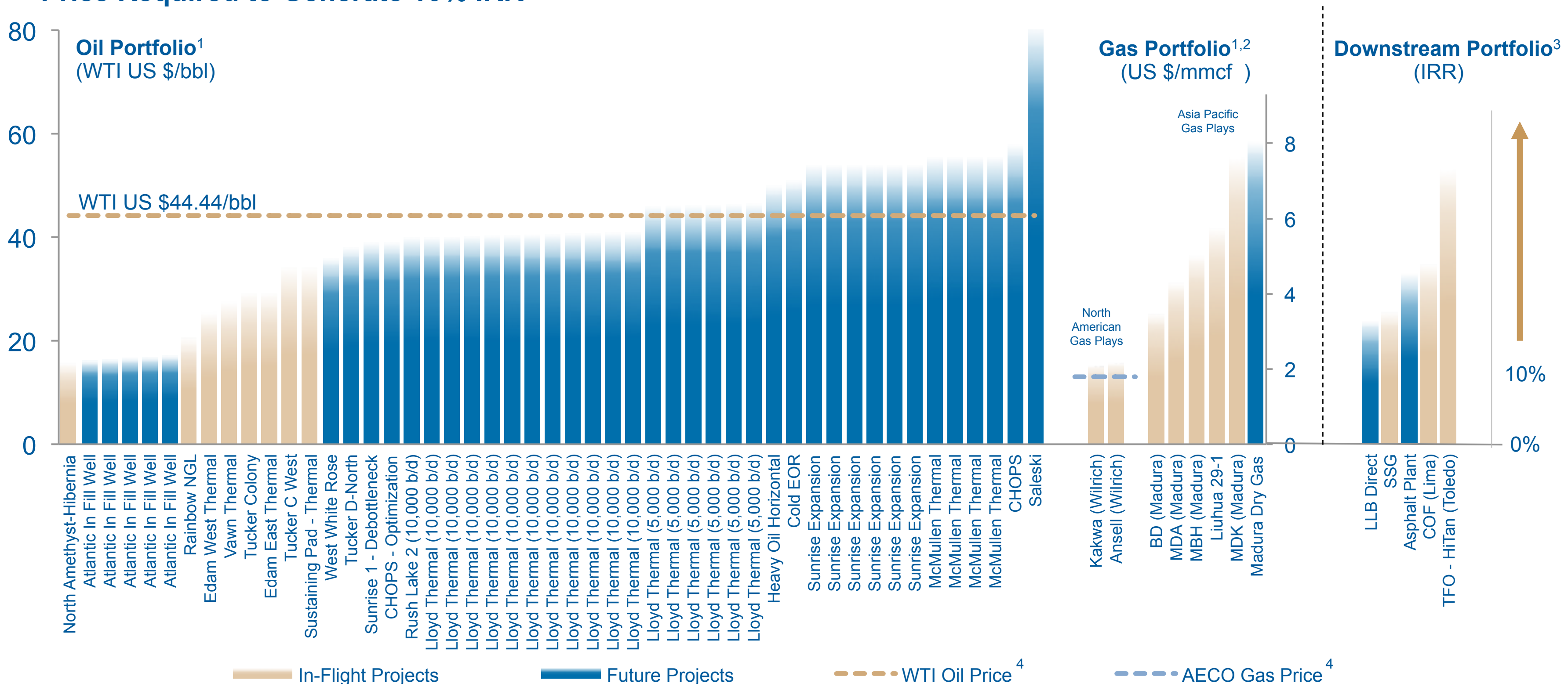
Free Cash Flow Generation



1. Free cash flow, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.
2. Potential free cash flow growth, as referred to throughout this presentation, is not linear.

Opportunity Rich . . . Even At Low Prices

Price Required to Generate 10% IRR

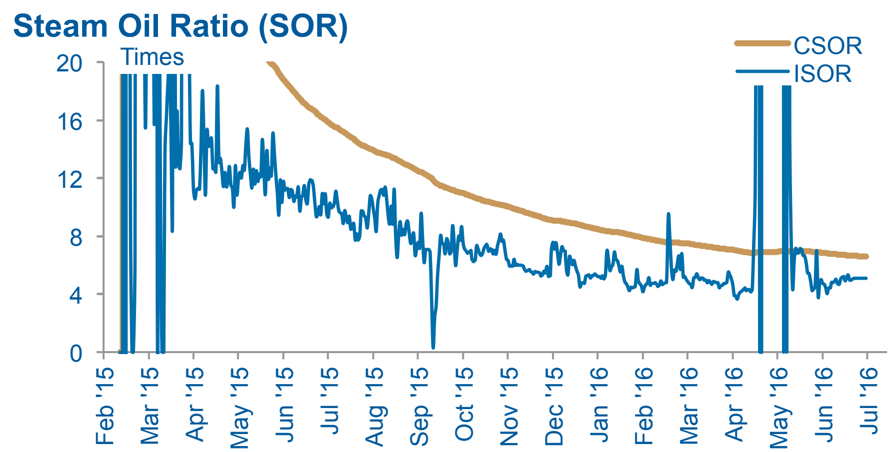


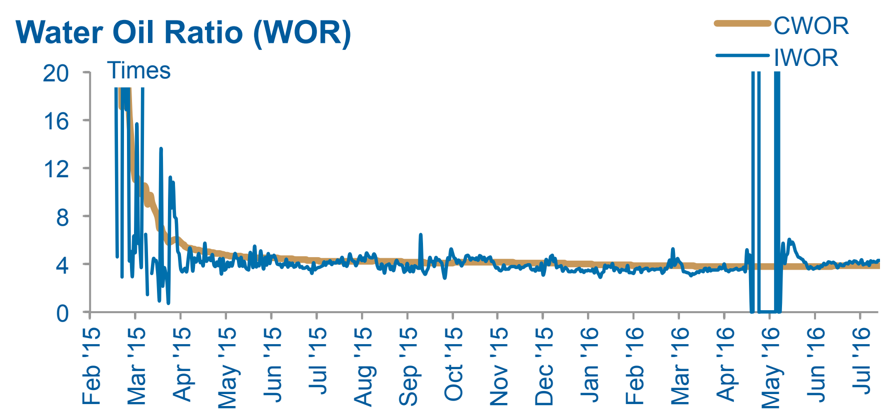
1. Other than as indicated in the Advisories, 10% IRR calculations are based on 2P reserves.
2. Gas portfolio break-even prices include assumed associated liquids prices based on US$40 WTI price scenario.
3. Downstream portfolio IRR not directly tied to oil or gas price. See Advisories for further detail.
4. WTI and AECO prices as of September 2, 2016. AECO gas price converted to US$ at a CAD/USD 0.76 exchange rate.

Operations

Steady Production Growth At Sunrise

- Paced ramp-up
- Lower temperature, lower pressure reservoir achieving expected results
- 55 well pairs on production
- Future debottlenecking opportunities

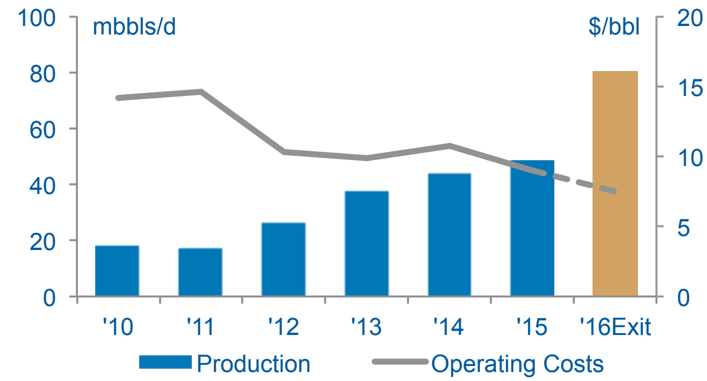




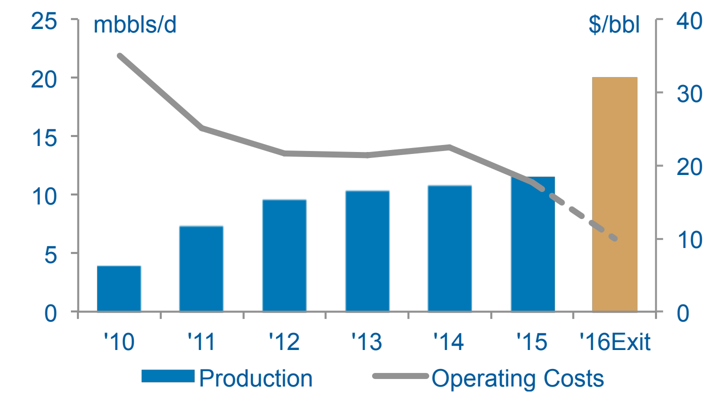
Thermal Transformation

- Thermal growth from ~22,000 bbls/d in ’10 to more than 100,000 bbls/d by end ’16
  - Lloyd projects in-flight to add ~24,500 bbls/d of nameplate capacity by the end of ’16
  - Tucker production has exceeded ’16 target of 20,000 bbls/d
- Identified runway for future growth
  - 8 x 10,000 bbls/d, 6 x 5,000 bbls/d projects[1]
- Advantaged capital efficiencies
  - Lowering sustaining capital
  - Reducing operating costs
  - Long life resources
  - Higher price realizations (vs. bitumen)

Lloyd Thermal Production



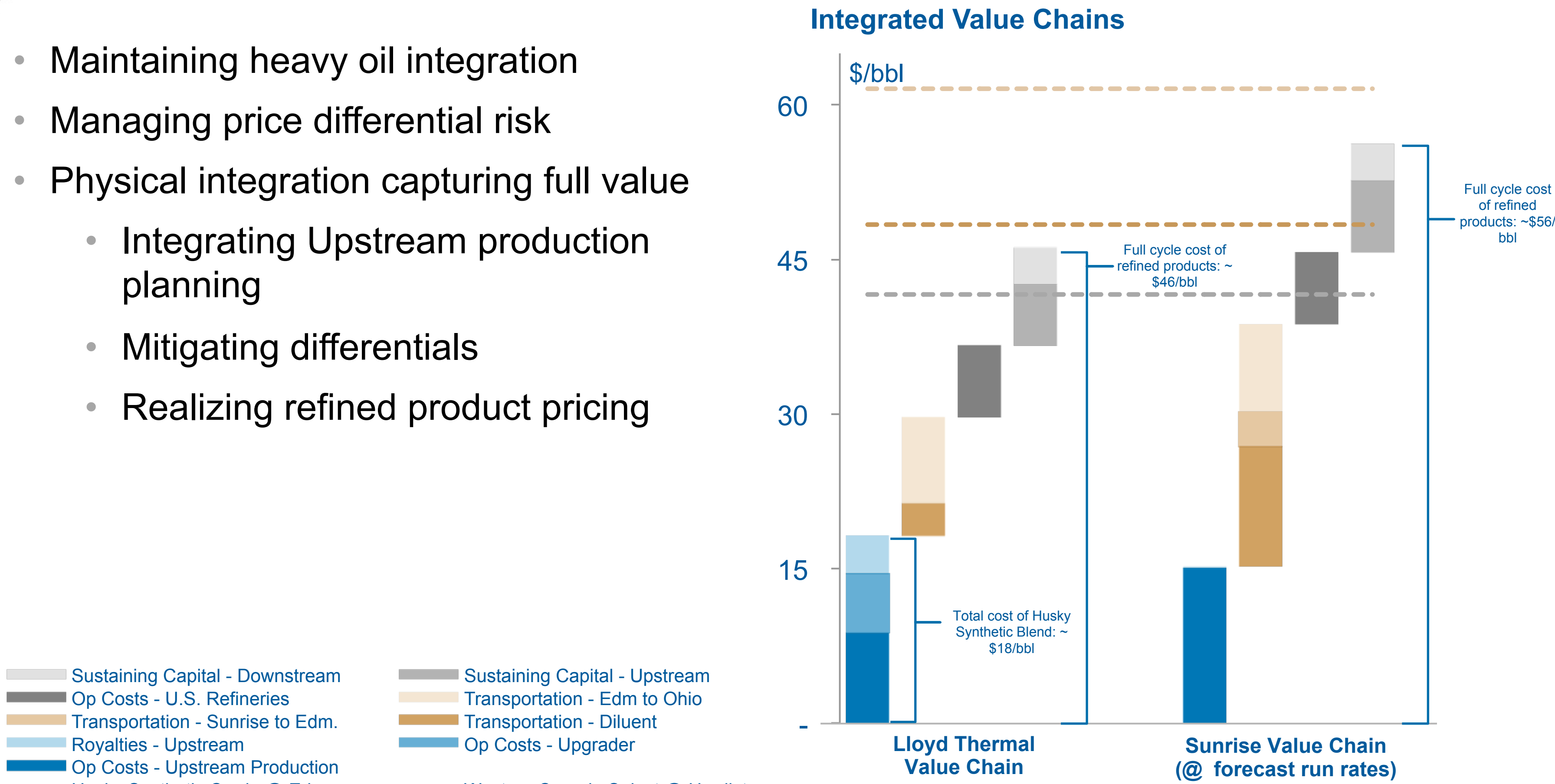
Tucker Production



1. Reflects facility nameplate capacity.

Focused Integration Enhancing Returns

- Maintaining heavy oil integration
- Managing price differential risk
- Physical integration capturing full value
  - Integrating Upstream production planning
  - Mitigating differentials
  - Realizing refined product pricing



- All crude prices and $/bbl costs reflect 2Q/2016 averages. All values in $CAD based on 0.76 CAD/USD exchange rate.

Western Canada: Expanding Resource Play Production

- Targeting high return, high productivity wells
- Identifying further efficiencies
- Transitioning legacy asset base
- Focusing on fewer plays in key areas
  - Ansell Wilrich

Ansell

Asia Pacific Portfolio

China

- Liwan Gas Project
  - Fixed price contract
  - Take or pay volumes, 300-330 mmcf/d (gross)
- Wenchang (light oil)
  - Net production of 7,100 bbls/d (Q2 '16)

Madura Strait block (Indonesia)

- Fixed price contracts, US$6.50-$7.00/mmbtu
- Target of 100 mmcf/d, 2,400 bbls/d ('19)
  - BD liquids rich field ('17)
  - MDA-MBH and MDK fields ('18-'19)
- Three additional gas discoveries
- Anugerah block exploration

Asia Pacific Operations

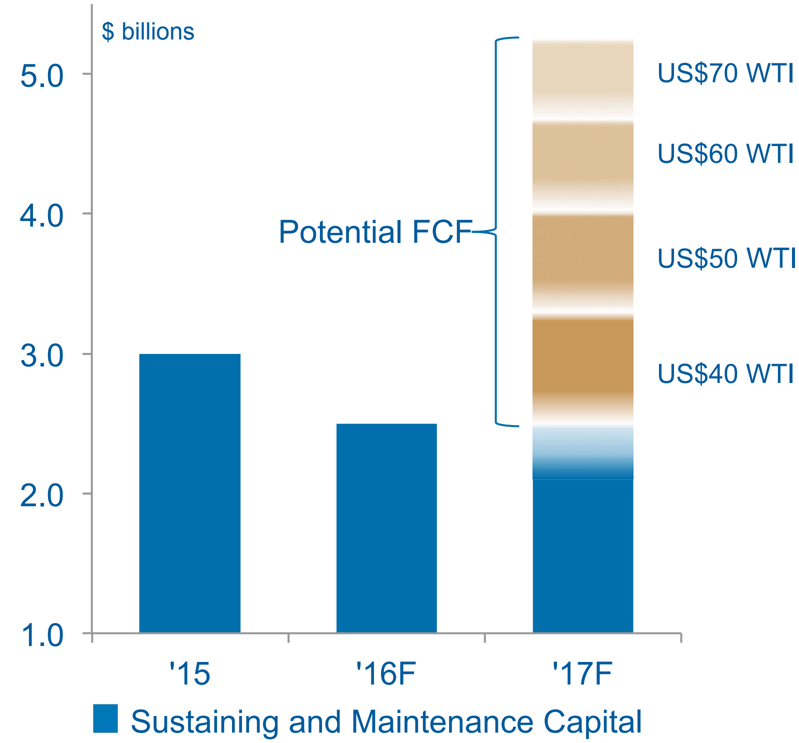
Atlantic Region: High Netback Production

- Infill drilling to maintain production
  - North Amethyst Hibernia formation
    - Drilling underway
    - Target production of ~5,000 bbls/d (net)
  - Five additional White Rose infill wells planned
- West White Rose Extension evolution
  - Two development options under evaluation
  - Potential for additional ~40,000 bbls/d (net)
- Flemish Pass exploration
  - Appraisal program completed; results being evaluated

SeaRose FPSO

Stronger and More Resilient Business

- Business strategy on course
- Structural changes leading to free cash flow
- Strong balance sheet
- Diverse portfolio of high quality growth projects
- Establish a sustainable cash dividend



Advisories

Forward-Looking Statements and Information

Certain statements in this presentation 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 presentation 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", "schedules" and "outlook"). In particular, forward-looking statements in this presentation include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; forecasted earnings breakeven for year end 2016; forecasted sustaining and maintenance capital costs through 2017; anticipated proportion of total production from low sustaining capital cost projects by year end 2016; forecasted free cash flow generated for range of WTI prices for 2017; planned establishment of a sustainable cash dividend; the Company's pro forma net debt to trailing cash flow from operations; targeted net debt and net debt to cash flow from operations ranges; projected prices required to generate targeted IRR for the Company's listed in-flight and future projects; planned use of midstream, royalty and Western Canada disposition proceeds; and costs and time frames to develop, and other factors affecting the development of, the Company's contingent resources;

- with respect to the Company's Asia Pacific Region: planned timing of first gas from the Madura Strait MDA-MBH, MDK and BD fields; and targeted 2019 combined daily production from the Madura Strait developments;

- with respect to the Company's Atlantic Region: target net peak daily production from the Company's North Amethyst Hibernia well project; additional planned White Rose infill wells; and estimated potential increase in daily production with the West White Rose Extension options;

- with respect to the Company's Heavy Oil properties: strategic plans and growth strategy for the Company's Lloyd thermals; forecasted thermal production for year end 2016; forecasted production from, and operating costs for, Tucker and Lloyd thermals for year-end 2016; anticipated added nameplate capacity by year-end 2016 from the Company's in-flight thermal projects; and forecasted nameplate capacity for the Company's potential future Lloyd thermal projects; and

- with respect to the Company's Western Canadian oil and gas resource plays: the Company's strategic plans for its Western Canada portfolio.

Advisories

Forward-Looking Statements and Information

In addition, statements relating to “reserves” “and” “resources” are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves or resources described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and resources 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 reserve, resource and production estimates. In addition, with respect to the type curves, there is no certainty that future well will generate results to match type curves presented herein.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this presentation 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, regulators and other sources.

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 Husky.

The Company’s Annual Information Form for the year ended December 31, 2015 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.

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. 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 its assessment of the future considering all information then available.

The purpose of pro forma net debt to trailing cash flow from operations is to provide readers with disclosure of the Company’s anticipated net debt as at June 30, 2016 assuming completion of the Midstream assets and Western Canada assets dispositions and the receipt, as at June 30, 2016, of the corresponding gross proceeds that (i) were realized subsequent to June 30, 2016: Midstream assets ($1.7 billion); and (ii) are expected to be realized prior to September 30, 2016: Midstream assets ($1.7 billion) and Western Canada assets ($295 million). Readers are cautioned that these estimates may not be appropriate for other purposes.

Non-GAAP Measures

This presentation contains certain terms which do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of cash flow from operations, and free cash flow, there are no comparable measures to these non-GAAP measures in accordance with IFRS. These non-GAAP measures are considered to be useful as complementary measures in assessing Husky's financial performance, efficiency and liquidity. These terms include:

- The term "cash flow 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. Cash flow from operations is presented in the Company’s financial reports to assist management and investors in analyzing operating performance by business in the stated period. Cash flow from operations equals net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment, unrealized mark to market gains and losses, and other non-cash items.

Advisories

- The term 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 in this presentation to assist management and investors in analyzing operating performance by business in the stated period. Free cash flow equals net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment, unrealized mark to market gains and losses, and other non-cash items less capital expenditures.

  The following table shows the reconciliation of cash flow – operating activities to cash flow from operations and the reconciliation of free cash flow – operating activities to cash flow from operations for the six months ended June 30, 2016 and the year ended December 31, 2015:

  Cash Flow from Operations and Free Cash Flow

		1H 2016	2015
GAAP	Net earnings (loss)	(654)	(3,850)
	Items not affecting cash:	-	
	Accretion	67	121
	Depletion, depreciation and amortization	1,419	8,644
	Inventory write-down to net realizable value	-	22
	Exploration and evaluation expenses	30	242
	Deferred income taxes	(115)	(1,827)
	Foreign exchange	13	27
	Stock-based compensation	25	(39)
	Loss/(gain) on sale of assets	98	(16)
	Unrealized mark to market	40	(14)
	Other	(1)	19
Non-GAAP	**Cash flow from operations**	**922**	3,329
	Capital expenditures (1)	(1,074)	(3,042)
Non-GAAP	**Free cash flow**	(152)	287

(1) Includes expenditures on exploration and evaluation assets (1H 2016 - $27 million, 2015 - $205 million), expenditures on property, plant and equipment (1H 2016 - $978 million, 2015 - $2,800 million) and expenditures on investment in joint venture (1H 2016 - $69 million, 2015 - $37 million).

- Net debt to cash flow from operations is a non-GAAP measure that equals total debt less cash and cash equivalents divided by cash flow from operations. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

Advisories

Disclosure of Oil and Gas Information

Unless otherwise stated, reserve and resource estimates in this presentation, 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, 2015 and represent Husky's share. Unless otherwise noted, projected and historical production numbers given represent Husky's share. Unless otherwise noted, historical production numbers are for the year ended December 31, 2015.

Husky's Lloydminster Heavy Oil and Gas thermal bitumen unrisked best estimate contingent resources consist of 250 million barrels of economic development pending contingent resources and 570 million barrels of economic status undetermined development unclarified contingent resources. The figures represent Husky's working interest volumes. The development pending category consists of seven steam assisted gravity drainage (SAGD) projects and one combined SAGD and cyclic steam stimulation (CSS) project that have been scheduled for initial production starting in 2019 through to 2024. The first two projects have a total capital cost to first production of $800 million based upon the pre-development studies. The economic status undetermined development unclarified projects require additional technical and commercial analysis of the conceptual SAGD or CSS studies. Of these, the first project requires $0.4 billion to achieve commercial production in 2030. The remaining projects are to be developed over more than 50 years in accordance with the conceptual studies for this large resource. In total, 220 million barrels of heavy crude oil are based upon pre-development studies while an additional 600 million barrels of heavy crude oil are based upon conceptual plans. Specific contingencies preventing the classification of contingent resources at the Company's Lloydminster Heavy Oil thermal contingent resources as reserves include the need for further reservoir studies, delineation drilling, verification of sub-zone continuity and quality that would enable feasible implementation of a thermal scheme, the formulation of concrete development plans and facility designs to pursue development of the large inventory of opportunities, the Company's capital commitment, development over a time frame much greater than the reserve timing window and regulatory applications and approvals. Positive and negative factors relevant to the contingent resource estimates include potential reservoir heterogeneity in sub-zones which may limit the applicability of thermal schemes, a higher level of uncertainty in the estimates as a result of lower drilling density in some projects and current lack of development plans in the unclarified contingent resources. The main risks are the low well density and the associated geological uncertainties in certain projects, the production performance and recovery long term, future commodity prices and the capital costs associated with wells and facilities planned over an extended future period of time.

McMullen contains unrisked best estimate economic development pending contingent resources of 44 million barrels of bitumen for Phase 1 of the development with a further 1.3 billion barrels of bitumen of unrisked best estimate economic status undetermined development unclarified contingent resources. McMullen is a thermal play in the Wabiskaw formation covering over 130 sections southwest of Wabasca. Husky has a working interest of 100 percent. The cost to first production for Phase 1, based upon the pre-development study, is approximately $512 million for the initial commercial demonstration facility and horizontal cyclic steam stimulation (HCSS) wells in 2025. The subsequent phases are based upon a conceptual development plan at this time and each has the same capital estimate with initial production scheduled for 2030 for Phase 2. The remaining commercial facilities and wells will be developed over more than 50 years in accordance with the conceptual study for this large resource. The development of these projects depends on the results of the technical analysis, future heavy oil prices and the Company's commitment to dedicate capital to this large inventory of projects. Specific contingencies preventing the classification of contingent resources at the McMullen thermal development project as reserves include the need for further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory applications and approvals and Company approvals. Positive and negative factors relevant to the estimates of these resources include a higher level of uncertainty in the estimates as a result of lower core-hole drilling density. The main risks are the low well density and the associated geological uncertainties, the production performance and recovery long term and the capital costs associated with wells and facilities planned over an extended future period of time.

Saleski contains unrisked best estimate economic development on hold contingent resources of 10 billion barrels of bitumen in the Grosmont formation. Saleski is located north of Wabasca. Husky has a working interest of 100 percent. Based on a pre-development study it is estimated that a total cost of approximately $825 million would be required to develop the initial commercial facility and corresponding HCSS wells with first production scheduled in 2025. Due to the large extent of the resource, staged development of additional facilities and wells are included in the pre-development study and extend the overall estimated production life beyond 50 years. The development is on hold due to low bitumen prices and future development will depend on prices and the Company's commitment to dedicate capital to this project. Specific contingencies preventing the classification of contingent resources at the Saleski oil sands project as reserves include the need for further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory applications and Company approvals. Positive and negative factors relevant to the estimate of contingent resources include a higher level of uncertainty in the estimates as a result of lower core-hole drilling density. The main risks are the low well density and the associated geological uncertainties, the production performance and long term recovery and the capital costs associated with wells and facilities planned over an extended future period of time.

Advisories

The Ansell liquids-rich natural gas resource play is located in the deep basin Cretaceous formations of west-central Alberta, and Husky has an average 92 percent working interest. Husky is actively developing Ansell. This producing property contains unrisked best estimate economic development pending contingent resources of 400 million barrels of oil equivalent, comprised of 2.2 tcf of natural gas and 48 million barrels of NGL. The initial contingent resource fracture stimulated horizontal wells are scheduled to be drilled starting in 2023, following the development of the proved and probable reserves. The cost to achieve initial commercial production is the cost of the first well of $7 million. The remaining wells (approximately 500 working interest wells) will be drilled over the next 10 to 20 years in accordance with the pre-development study for the resource play. Specific contingencies preventing the classification of contingent resources in the Ansell liquids-rich resource play as reserves include the timing of development which is outside the timing allowed for booking as reserves and final Company approvals of capital expenditures. Positive and negative factors relevant to the estimate of Ansell contingent resources include a lower level of uncertainty in the estimates as a result of the large number of producing wells, extensive production history from the property, Husky's large contiguous land base and Husky's ownership of existing infrastructure in the area. Key risks include the performance of future wells when the play is expanded and reducing costs to achieve optimal results in a low gas and natural gas liquids price environment.

Liuhua 29-1, located in the South China Sea approximately 300 km southeast of the Hong Kong Special Administrative Region, contains unrisked best estimate economic development pending contingent resources of 28 million barrels of oil equivalent, comprised of 139 Bcf of natural gas and 5 million barrels of condensate. Husky has a working interest of 49 percent. The project uses conventional offshore gas wells and will be connected to the producing Liwan gas field. Based on the pre-development study, the cost to first production to complete and tie-in the well is approximately $617 million with an on-stream date in 2019. The development of this project depends on the Company's and partners commitment to dedicate capital to this project. Specific contingencies preventing the classification of contingent resources for Liuhua 29-1 are the signing of a Gas Sales Agreement and regulatory approvals. Positive and negative factors relevant to the estimates of these resources include a higher level of certainty in the estimates as a result of extensive appraisal drilling and testing. The main risk is the production performance and recovery long term.

Madura Strait, located offshore East Java, south of Madura Island, Indonesia, contains unrisked best estimate economic development pending contingent resources of 11 million barrels of oil equivalent, comprised of 62 Bcf of natural gas and 0.4 million barrels of condensate. Husky has a working interest of 40 percent. The project uses conventional offshore gas wells and will be connected the infrastructure currently under construction for the pools booked as reserves. First production associated with the reserves in the Madura Strait Block is anticipated in 2017. The pre-development study for the contingent resources has first production commencing in 2019 at a cost of $124 mm. The development of this project depends on the Company's and partners commitment to dedicate capital to this project. Specific contingencies preventing the classification of contingent resources for Madura Contingent Resources are the signing of a Gas Sales Agreement and regulatory approvals. Positive and negative factors relevant to the estimates of these resources include the development in conjunction with the reserves properties in the field and the reliance on volumetric estimates. The main risks include obtaining all approvals and the production performance and recovery long term.

Husky's Lloydminster Heavy Oil cold heavy oil production with sand (CHOPs) and Horizontal well opportunity includes 166 million barrels (Husky's working interest) of unrisked economic best estimate contingent resources in the development pending sub-class and a further 593 million barrels (Husky's working interest) of unrisked best estimate contingent resources in the development unclarified sub-class with the economic status undetermined. A typical CHOPS well has a cost estimate to drill, complete and equip of $588,000 while a 5 well horizontal pad has a cost estimate of $7.1 million with the first developments online in 2026 based on a pre-development study. This is a continuation of the CHOPs and horizontal well development programs which have been proven to be successful in the Lloydminster area. The timing of development and company approvals are the main contingencies preventing the booking of these volumes as reserves. Positive and negative factors relevant to these contingent resources include a lower level of uncertainty in the estimates as a result of the large number of producing wells, extensive production history from the property, Husky's large contiguous land base and Husky's ownership of existing infrastructure in the area. The key risk is the execution of a multi-year program and reducing capital and operating costs in a low heavy oil price environment.

Heavy Oil Cold EOR, located in the Lloydminster area, contains 231 million barrels (Husky's working interest) of unrisked economic best estimate contingent resources in the development unclarified sub-class. Cold EOR Solvent Injection is a cyclic process utilizing CO_2 which has been demonstrated to be technically successful in the area. The wells and area have been identified in the conceptual development study but more detailed development plans are required for each field. The first phase of the projects is planned for 2021 with a capital cost of $207 million to reach first oil production in one of the identified fields. The timing of development, regulatory and company approvals are the specific contingencies preventing the booking of these volumes as reserves as well as the need for additional assessment for the area where the economic status is undetermined. Positive and negative factors include the extensive land base and infrastructure while the ultimate recovery for this technology is still being evaluated in the field. Key risks include the range of uncertainty in the ultimate recovery and accessing a long term supply of CO_2 for the projects.

There is uncertainty that it will be commercially viable to produce any portion of the resources (referred to in the above paragraphs).

Advisories

The Company uses the terms barrels of oil equivalent (“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.

In this presentation, the Company uses the term operating costs per barrel, which is consistent with other oil and gas producer disclosures, and is calculated by dividing total operating costs for the Company’s Heavy Oil thermal or non-thermal production, as applicable, by the total barrels of such thermal or non-thermal production, as applicable. The term is used to express operating costs on a per barrel basis that can be used for comparisons.

IRR calculations shown reflect a net present value of $0 using a 10% discount rate applied to before tax cash flows. IRR calculations are based on holding certain variables constant throughout the period, including: estimated WTI oil price per barrel priced in US dollars, 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. This measurement is used to assess potential return generated from investment opportunities and could impact future investment decisions. This measure does not have any standardized meaning and should not be used to make comparisons to similar measures presented by other issuers.
Steam-oil ratio (“SOR”) measures the average volume of steam required to produce a barrel of oil. Water-oil ratio (“WOR”) measures the average volume of water produced per a barrel of oil. These measures do not have any standardized meanings and should not be used to make comparisons to similar measures presented by other issuers.

Earnings break-even reflects the estimated WTI oil price per barrel priced in US dollars required in order to generate a net income of CAD $0 in the 12 month period ending December 31, 2016. 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. This measurement is used to assess the impact of changes in WTI oil prices to the net earnings of the Company and could impact future investment decisions.

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 Disclosure", 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 directed.