March Presentation

BAYTEX
ENERGY CORP.

Advisory

Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements made by the presenter and contained in these presentation materials (collectively, this "presentation") are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). The forward-looking statements contained in this presentation speak only as of the date of this presentation and are expressly qualified by this cautionary statement. The information contained in this presentation does not purport to be all-inclusive or to contain all information that potential investors may require.

Specifically, this presentation contains forward-looking statements relating, but not limited, to: our business strategies, plans and objectives; our key attributes, including: our stable liquidity position going forward; that we generate free cash flow at US$55/bbl; that we will have ~6% organic growth exit 2017 to exit 2018; that U.S. assets, hedging and crude by rail mitigate WCS volatility; the percentage of our 2018 capital spending allocated to the Eagle Ford; our rates of return at US $60/bbl WTI; our sustaining capital efficiencies; our 2018 guidance for our average annual production rate; that 80% of our production is oil and liquids; our 2018 exploration and development capital budget; for the Eagle Ford, Peace River and Lloydminster: our 2018 drilling plans, expected activity level and expected internal rate of return for each area at US$60/bbl WTI and a WCS differential of US$20/bbl; the capital efficiency of multi-lateral horizontal wells to be drilled in Lloydminster; for 2018: our expected exploration and development capital budget, average annual production rate, operating expense and general and administration expense; that capital expenditures are targeted to approximate adjusted funds flow; that we are allocating capital to high quality assets and the internal rates of return and capital efficiency of those assets; that $30 million of strategic infrastructure investment in Peace Rive and Lloydminster will support future development and growth; our hedged and unhedged free cash flow at certain WTI and WCS pricing scenarios in 2018; the capital expenditures required to offset production declines and maintain flat production volumes; the internal rate of return and WTI break-even price for our type wells in the Eagle Ford, Lloydminster and Peace River; the percentage of our net exposure to WTI and the WCS differential that is hedged; in Lloydminster: that multi-lateral drilling is leading to a 40% improvement in capital efficiencies and that we have a significant land position and drilling inventory; for our Kerrobert SAGD expansion: the 2019 production target, the amount of expansion capital to be spent in 2017, 2018 and 2019, the timeline for certain activities and the project economics; and the percentage of our net exposure to natural gas that is hedged. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

Although Baytex believes that the expectations and assumptions upon which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Baytex can give no assurance that they will prove to be correct.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oil; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; availability and cost of gathering, processing and pipeline systems; public perception and its influence on the regulatory regime; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; risks associated with our use of information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2017, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2018 and in our other public filings.

Advisory (Cont.)

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk 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 our 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 statements.

The above summary of assumptions and risks related to forward-looking statements in this presentation has been provided in order to provide potential investors with a more complete perspective of our current and future operations and as such information may be not appropriate for other purposes. There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

Oil and Gas Information

This presentation contains estimates, as at December 31, 2017, of the volume of our petroleum and natural gas reserves as prepared by our independent qualified reserves evaluators, Sproule Unconventional Limited ("Sproule") for our Canadian properties and Ryder Scott Company, L.P. for our United States properties. All of our oil and gas properties were evaluated or audited in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Natural Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook. The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts, including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods, is required to properly use and apply reserves definitions.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves and future production from such reserves may be greater or less than the estimates provided herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. For complete NI 51-101 reserves disclosure, please see our Annual Information Form for the year end December 31, 2017.

References herein to initial test production rates, 30-day IP rates and other short-term production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the acquired assets. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

When converting volumes of natural gas to oil equivalent amounts, Baytex has adopted a conversion factor of six million cubic feet of natural gas being equivalent to one barrel of oil, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Oil equivalent amounts may be misleading, particularly if used in isolation.

Advisory (Cont.)

Non-GAAP Financial Measures

This presentation refers to funds from operations, net debt, free cash flow, sustaining capital, operating netback and Bank EBITDA, which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP").

We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the funds flow necessary to fund future capital investments. However, adjusted funds flow should not be construed as an alternative to traditional performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income. Please refer to our most recent management's discussion and analysis of financial condition and results of operations for a reconciliation of adjsuted funds flow to cash flow from operating activities.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives and onerous contracts)) and the principal amount of both the long-term notes and the bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

We define free cash flow as adjusted funds flow less sustaining capital and sustaining capital is an estimate of the amount of exploration and development capital required to offset production declines on an annual basis and maintain flat production volumes.

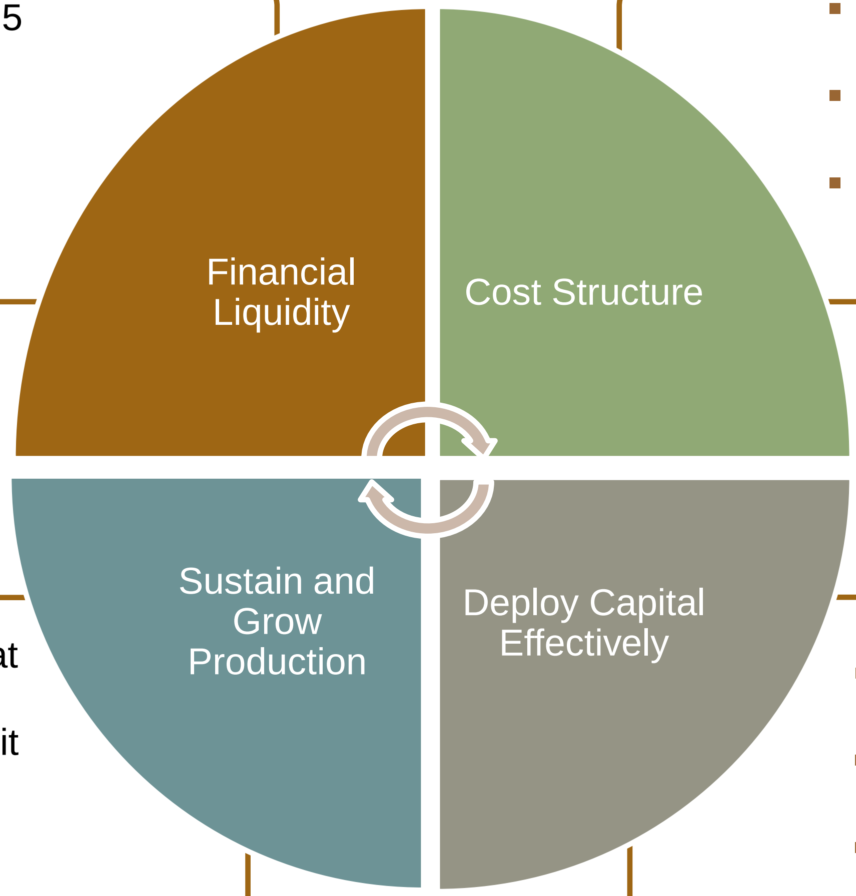
We define operating netback as petroleum and natural gas sales less blending expense, royalties, operating expense and transportation expense divided by barrels of oil equivalent sales volume for the applicable period. Our determination of operating netback may not be comparable with the calculation of similar measures by other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

We define Bank EBITDA as our consolidated net income attributable to shareholders before interest, taxes, depletion and depreciation, and certain other non-cash items as set out in the credit agreement governing our revolving credit facilities. Bank EBITDA is used by our lenders to monitor compliance with financial covenants.

Baytex Key Attributes

- 70% undrawn on US$575 million credit facility
- First long-term note maturity not until 2021
- Expect stable liquidity position going forward

- D&C costs remain at or near all-time lows
- Operating expenses reduced to $10.50/boe
- G&A reduced to ~ $1.72/boe for 2018



- Free cash flow positive at WTI > US$55/bbl
- ~ 6% organic growth (exit 2017 to exit 2018)
- U.S. assets, hedging and active crude by rail mitigate WCS volatility

- 55% of capex allocated to the Eagle Ford
- 50% - 85% rates of return at US$60/bbl WTI
- $13,000 per boe/d sustaining capital efficiencies

Corporate Profile

Market Summary

Ticker Symbol	TSX / NYSE: BTE
Average Daily Volume [(1)]	CAN: 4,900,000 / US: 1,700,000
Shares Outstanding	236.6 million
Market Capitalization / Enterprise Value	$0.8 billion / $2.5 billion
Net Debt [(2)]	$1.7 billion

Corporate Summary

Production [(3)]	68,000 - 72,000 boe/d
Production Mix	80% oil and liquids
E&D Capital [(3)]	$325 - $375 million
Reserves – 2P Gross [(4)]	432 mmboe

(1) Average daily trading volumes for February 2018. Volumes are a composite of all exchanges in Canada and the U.S.
(2) Net debt is the principal amount of long-term notes and bank loan and includes working capital, as at December 31, 2017.
(3) Production and exploration and development capital represents our 2018 guidance range.
(4) Gross reserves are per NI 51-101 as at December 31, 2017. See "Advisory – Oil and Gas Information" for more information.

Capital Deployment Opportunities

Eagle Ford

- First call on capital
- Represents ~ 55% of 2018 budgeted E&D spending
- 2018 pace of activity expected to be similar to 2017 with ~ 30 net wells on production
- 85% IRR at US$60/bbl WTI (1)

Peace River

- 35% reduction in acquired property operating costs
- ~ 18 multi-lateral wells in 2018, double the pace of activity from 2017
- 50% IRR at US$60/bbl WTI (1)

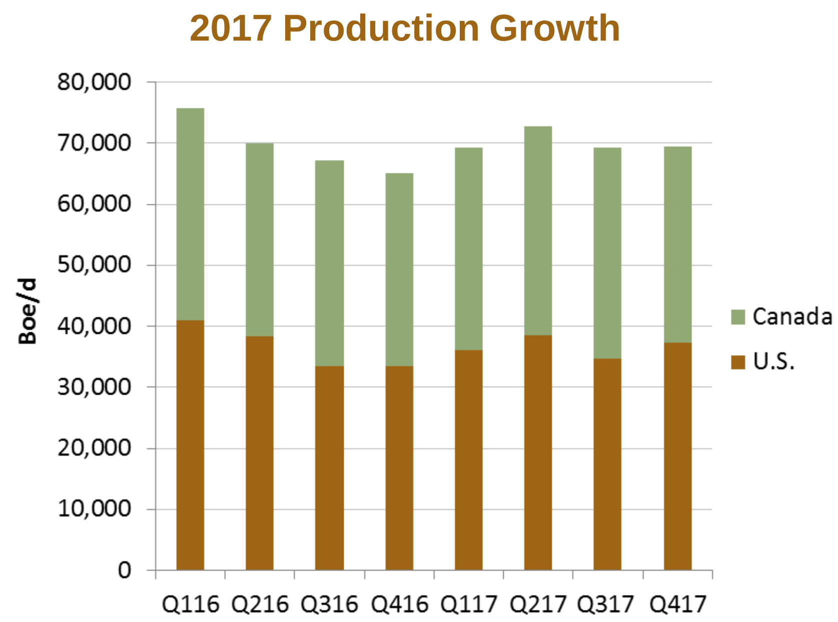
Lloydminster

- ~ 63 net wells in 2018, an 80% increase in activity from 2017
- 2018 includes ~ 16 multi-lateral horizontal wells with capital efficiencies of ~ $8,000 per boe/d
- 75% IRR at US$60/bbl WTI (1)

(1) Based on a constant WTI price of US$60/bbl and a constant WCS differential of US$20/bbl

YE 2017 Results Demonstrate Growth at US$50/bbl

- Production of 70,242 boe/d above high end of guidance range
- Adjusted funds flow of $348 million exceeded capital expenditures by $21 million
- Operational Momentum
  - Increased 2P reserves 6% to 432 mmboe (201% production replacement)
  - Recorded F&D costs of $7.26/boe and 2.7x recycle ratio
  - Decreased cash costs (operating, transportation and G&A) by 7.5% on a boe basis as compared to the mid-point of original guidance



2017 Scorecard	Annual Guidance (1)	YE 2017 Results	
E&D CapEx ($ millions)	$310-$330	$326.3	✓
Production (boe/d)	69,500-70,000	70,242	✓
Operating Expense ($/boe)	~ 10.50	10.50	✓
G&A Expense ($/boe)	~ 2.00	1.85	✓

Notes:

(1) Reflects annual guidance following the release of Q3/2017 results. Original guidance (from December 2016) - production: 66,000-70,000 boe/d, E&D capex: $300-$350 million; operating expenses: $11.00-$12.00/boe; G&A expenses: ~ $2.00/boe.

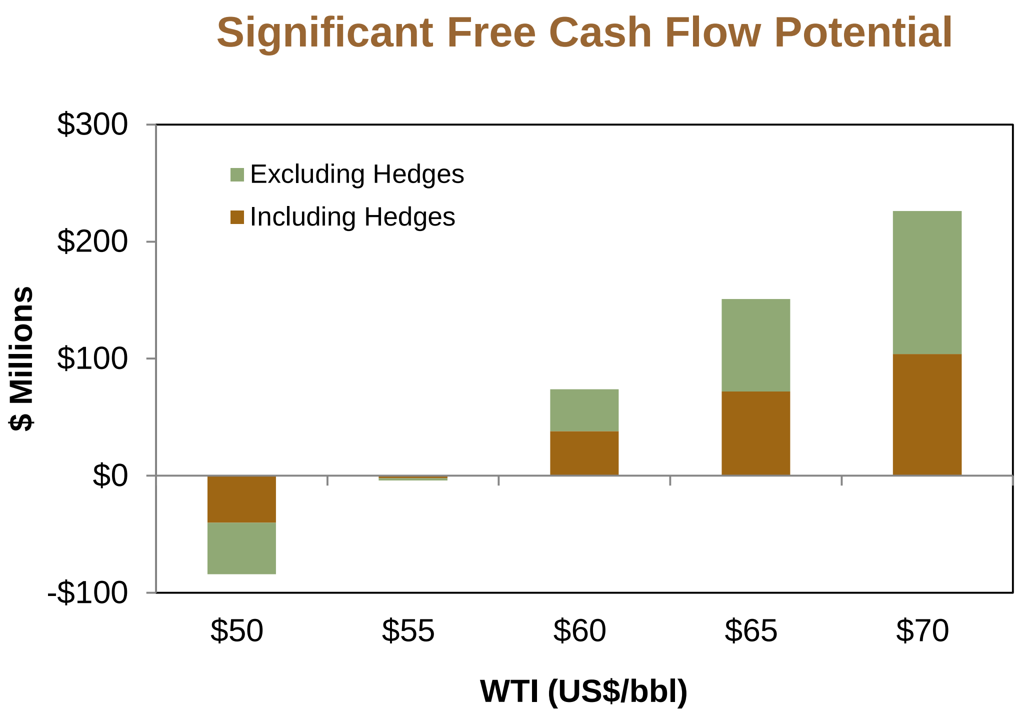
2018 Operating Budget Highlights – Building on the Momentum Established in 2017

2018 Budget	
E&D CapEx ($ millions)	$325 - $375 million
Production (boe/d)	68,000 - 72,000 boe/d
Operating Expense ($/boe)	10.50 - 11.25/boe
G&A Expense ($/boe)	~ 1.72/boe

- Targeting capital program within adjusted funds flow
- Allocating capital to high quality assets
  - IRR's 50% - 85% on a per well basis (1)
  - Capital efficiencies of $12,000 per boe/d on an annual basis ($14,000 per boe/d including facilities)
  - $30 million of strategic infrastructure investment in Peace River and Lloydminster to support future development and growth
- Generating production growth of 6% (to 72,000-73,000 boe/d, 2018 exit rate)

(1) Based on a constant WTI price of US$60/bbl and a constant WCS differential of US$20/bbl

2018 Free Cash Flow Scenarios



- Free cash flow provides flexibility to invest in organic growth and/or debt repayment
- Free cash flow positive > WTI US$55/bbl
- Unhedged free cash flow demonstrates cash generating capability of our assets as oil prices improve
- Sustaining capital expenditures of ~ $300 million per year with capital efficiencies of ~ $13,000 per boe/d

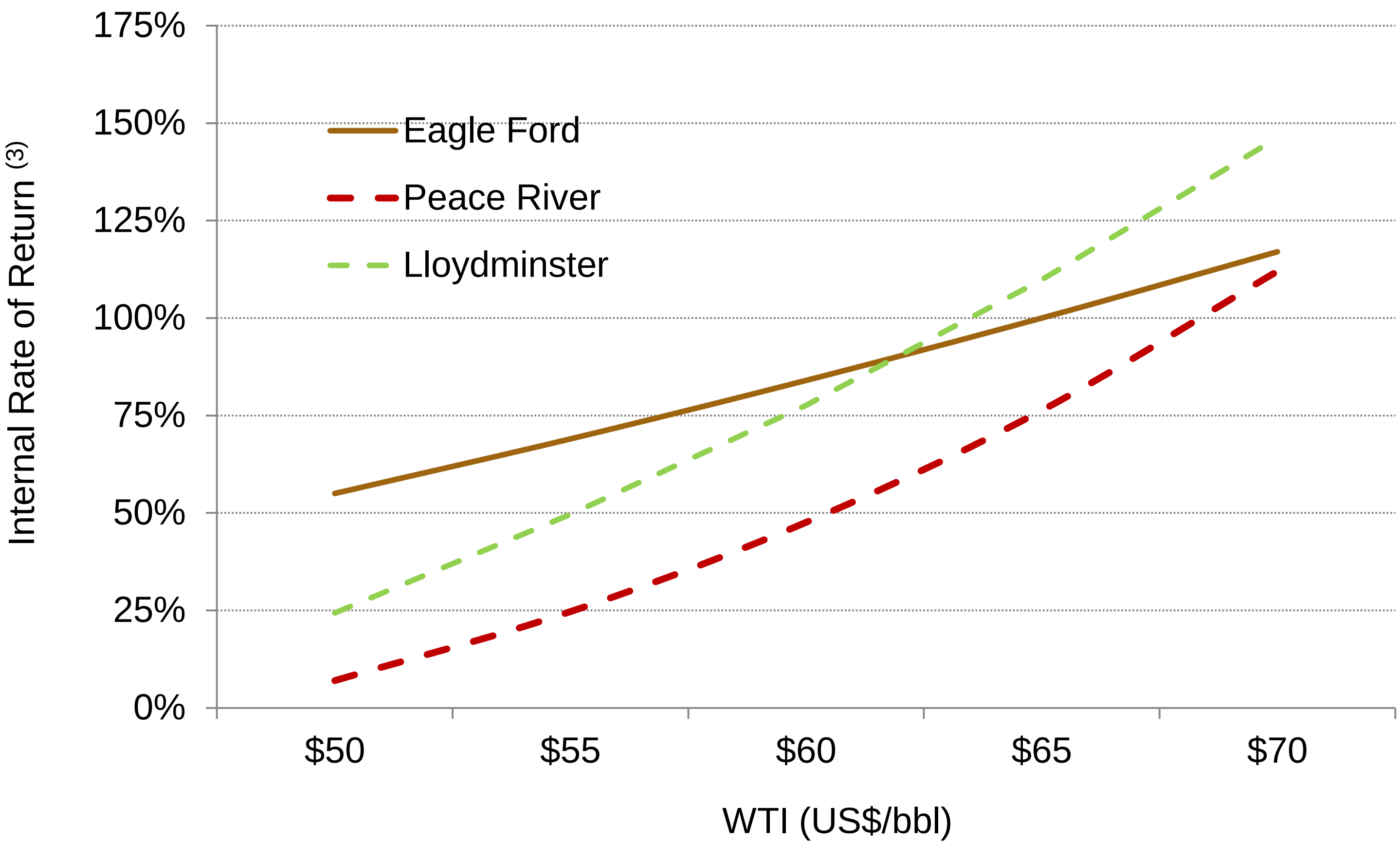
Notes:

(1) Free Cash Flow is defined as adjusted funds flow less sustaining capital (estimated at $300 million).

(2) Sustaining capital is an estimate of the amount of exploration and development capital required to offset production declines on an annual basis and maintain flat production volumes.

(3) Pricing assumptions: for the chart NYMEX gas = US$2.80/mcf, WCS differential = US$20/bbl, FX Rate (C$/US$) = 1.275.

Strong Rates of Return Across Portfolio



(1) Individual well economics for the chart based on constant pricing and costs. Pricing assumptions: NYMEX gas = US$3.00/mcf, WCS differential = US$20/bbl, FX Rate (C$/US$) = 1.275.

(2) Type curve assumptions: Eagle Ford: well cost US$5.2 million (normalized 5,500 foot lateral), 30-day IP rate ~ 1,200 boe/d, EUR ~ 800 mboe. Peace River: well cost $2.6 million (multi-lateral horizontal), 30-day IP rate ~ 350 boe/d, EUR ~ 250 mboe. Lloydminster: well cost $700,000 (single lined horizontal), 30-day IP rate ~ 60 boe/d, EUR ~ 70 mboe. Baytex internal estimates.

(3) Internal rate of return ("IRR") is a rate of return measure used to compare the profitability of an investment and represents the discount rate at which the net present value of costs equals the net present value of the benefits. The higher a project's IRR, the more desirable the project.

Crude Oil Hedge Portfolio

	Q1/18	Q2/18	Q3/18	Q4/18	2018
WTI Fixed Hedges					
Volumes (bbl/d)	13,667	14,000	14,000	14,000	13,917
Fixed Price (US$/bbl)	$52.10	$52.31	$52.31	$52.31	$52.26
WTI 3-Way Option					
Volumes (bbl/d)	2,000	2,000	2,000	2,000	2,000
Average Ceiling/Floor/Sold Floor (US$/bbl)[1]	$60/$54/$40	$60/$54/$40	$60/$54/$40	$60/$54/$40	$60/$54/$40
Brent Fixed Hedges					
Volumes (bbl/d)	4,000	4,000	4,000	4,000	4,000
Fixed Price (US$/bbl)	$61.31	$61.31	$61.31	$61.31	$61.31
Total Hedge Volumes (bbl/d)	19,667	20,000	20,000	20,000	19,917
Hedge (%) [2]	54%	54%	54%	54%	54%

WCS Differential Hedges					
Volumes (bbl/d)	10,000	10,000	8,000	8,000	7,000
WCS Price Relative to WTI(US$/bbl)	($14.19)	($14.19)	($14.18)	($14.18)	($14.19)
Hedge (%) [2]	38%	38%	28%	28%	33%

[1] WTI 3-way option consists of a sold call, a bought put and a sold put. In a $60/$50/$40 example, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives WTI when WTI is between $50/bbl and $60/bbl; and Baytex receives $60/bbl when WTI is above US$60/bbl.

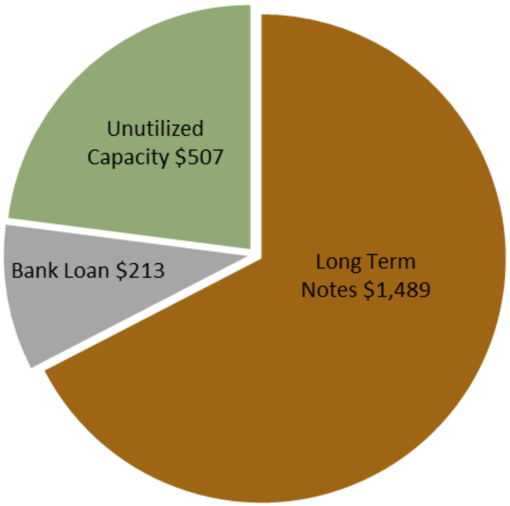
[2] Percentage of hedged volumes are based on 2018 annual production guidance (excluding NGL), net of royalties.

Balance Sheet / Debt Composition

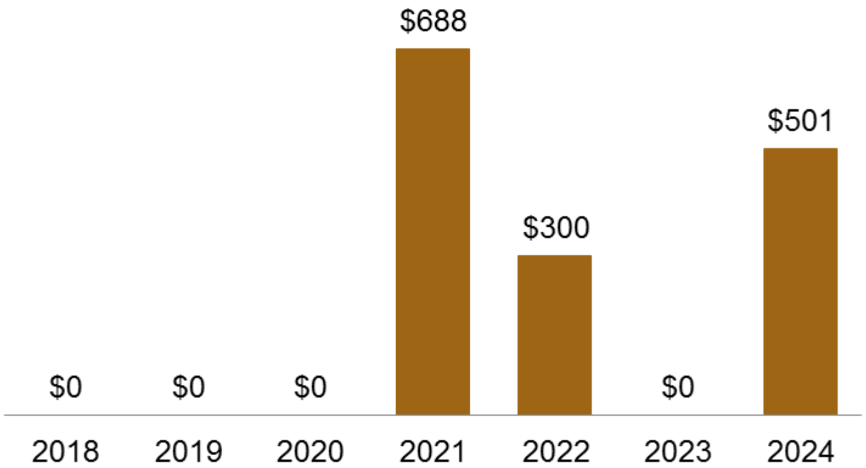
Significant Liquidity, No Near-Term Maturities and Financial Covenant Flexibility

Senior Secured Debt (1) to Bank EBITDA (2)	0.5x (maximum permitted ratio of 5.0:1.0, steps down to 3.5:1.0 after December 31, 2018)
Interest Coverage (3)	4.5x (minimum required ratio of 1.25:1.0. steps up to 2.0:1.0 after December 31, 2018)

Debt Composition(4) and Unutilized Capacity



Long-Term Notes Maturity Schedule ($ Millions)



(1) "Senior Secured Debt" is defined as the principal amount of our bank loan and other secured obligations under the credit facilities. At December 31, 2017, our Senior Secured Debt totaled $228 million.

(2) "Bank EBITDA" is calculated based on terms and conditions set out in the credit agreement which adjusts net income for interest expense, income taxes, certain non-cash items and acquisition and disposition activity. Bank EBITDA is calculated based on a trailing twelve month basis and was $454 million for the twelve months ended December 31, 2017.

(3) "Interest Coverage" is computed as the ratio of Bank EBITDA to financing and interest expense on our Senior Secured Debt and long-term notes. Financing and interest expense for the trailing twelve months ended December 31, 2017 was $100 million.

(4) Debt composition as at December 31, 2017. We have secured revolving credit facilities totaling US$575 million that mature June 2019. The revolving credit facilities do not require any mandatory principal payments prior to maturity and can be further extended beyond June 2019 with the consent of the lenders.

2018E Adjusted Funds Flow Sensitivities

Sensitivities	Estimated Effect on Annual Adjusted Funds Flow ($ Millions)	
	Excluding Hedges	Including Hedges
Change of US$1.00/bbl WTI crude oil	$17.1	$8.7
Change of US$1.00/bbl WCS heavy oil differential	$10.0	$6.9
Change of US$0.25/mcf NYMEX natural gas	$8.2	$6.5
Change of $0.01 in the C$/US$ exchange rate	$6.2	$5.9

Price Assumptions: WTI crude oil - US$60/bbl, WCS heavy oil differential - US$20/bbl, NYMEX natural gas - US$2.80/mcf, Exchange Rate (C$/US$) – 1.275.

The Eagle Ford

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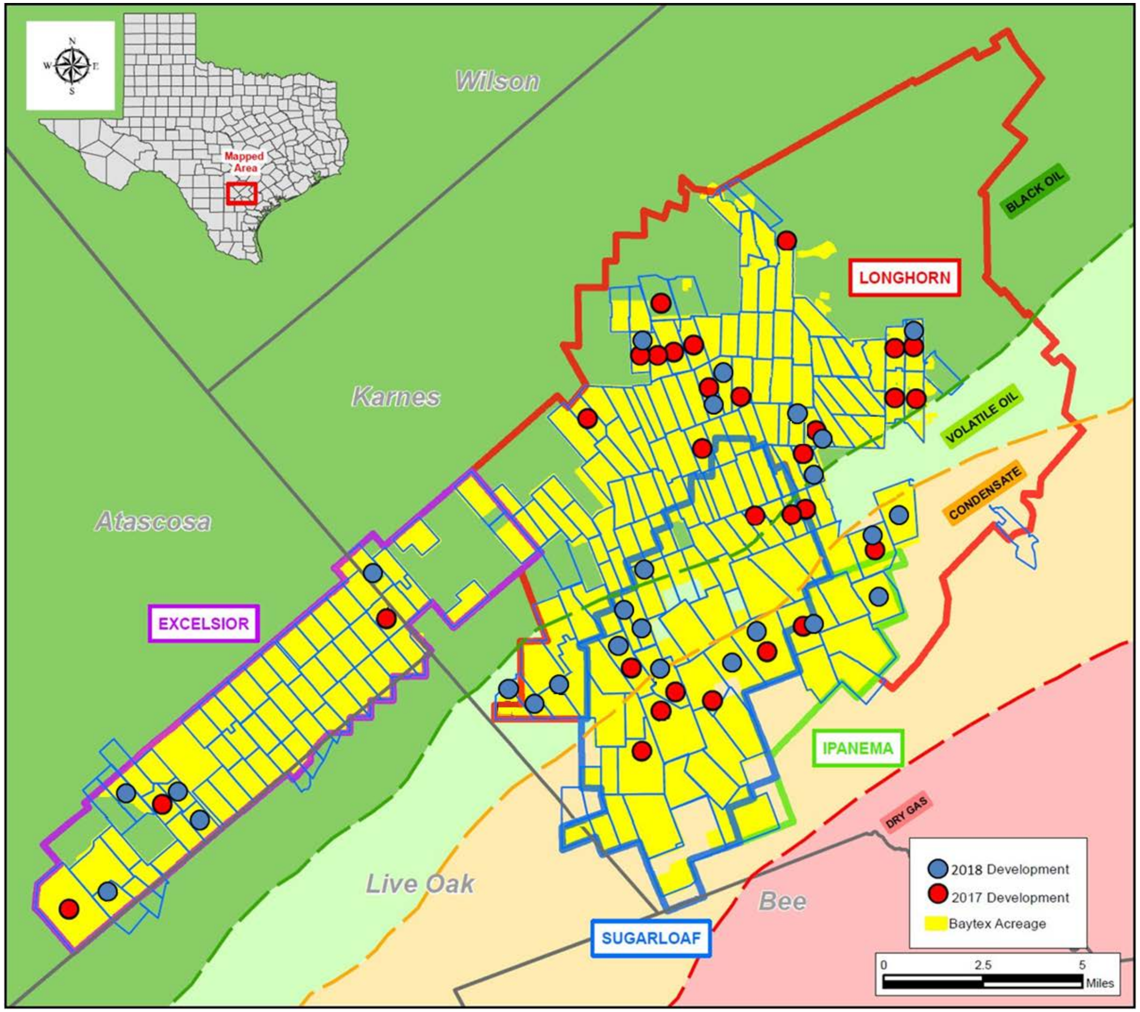
Improved Performance and Growth in the Eagle Ford



Performance Drivers

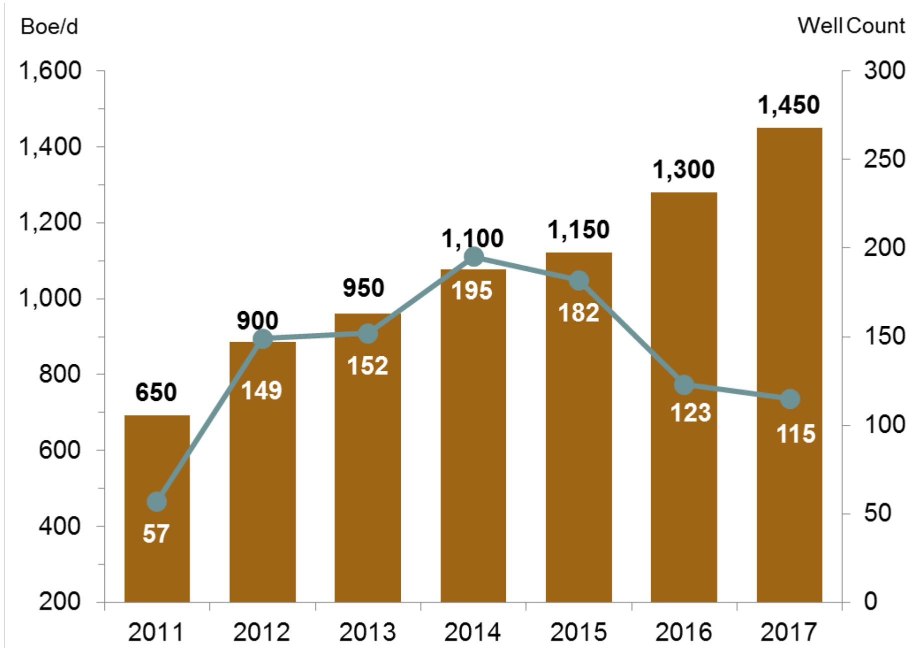
- Q4/2017 production up 12% from Q4/2016 to 37,000 boe/d
- Improved performance from higher intensity frac's in the northern oil window
- Q4/2017 activity 3-4 drilling rigs and 1-2 completion crews (155 gross wells onstream in 2017)
- 2018 DC&E costs ~ US$5.2 million (normalized 5,500 foot lateral)

Eagle Ford Improved Performance

- Q4/2017 delivered some of the highest productivity wells drilled to-date on our lands
  - 5 pads (total 25 wells) delivered average 30-day IP rates of 1,700 boe/d per well
  - Two wells in Austin Chalk fracture trend demonstrated 30-day IP rates of ~2,400 boe/d per well

- Enhanced completions drive improved well performance
  - Average lateral length ~ 6,000 feet
  - Effective # of frac stages has increased to ~ 30 stages (from 22 stages in H1/2016)
  - Proppant per completed foot has increased to ~ 2,000 pounds (1,000 pounds in H1/2016)

Production (30-day IP)



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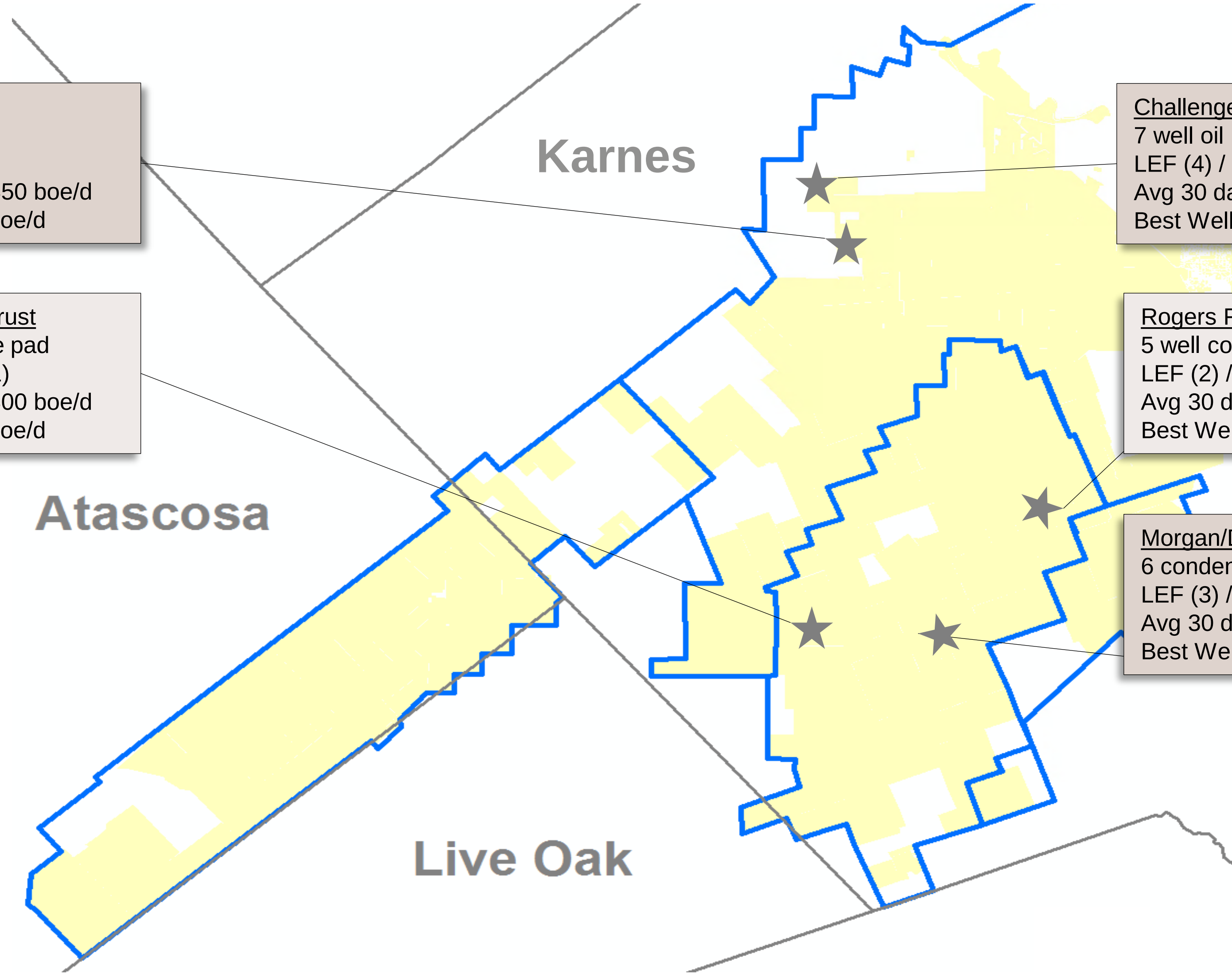
Eagle Ford Q4/2017 Well Performance



<u>Labus Pittman</u>
4 well oil pad
LEF(2) / ULEF (2)
Avg 30 day IP: 1,850 boe/d
Best Well: 2,000 boe/d

<u>Challenger C</u>
7 well oil pad
LEF (4) / ULEF (1) / AC (2)
Avg 30 day IP: 1,600 boe/d
Best Well: 2,400 boe/d

<u>Rancho Grande Trust</u>
3 well condensate pad
LEF (2) / ULEF (1)
Avg 30 day IP: 2,300 boe/d
Best Well: 2,800 boe/d

<u>Rogers Foester</u>
5 well condensate pad
LEF (2) / ULEF (3)
Avg 30 day IP: 1,650 boe/d
Best Well: 1,850 boe/d

<u>Morgan/Direct Assets</u>
6 condensate pad
LEF (3) / ULEF (2) / AC (1)
Avg 30 day IP: 1,450 boe/d
Best Well: 2,000 boe/d

Heavy Oil Overview

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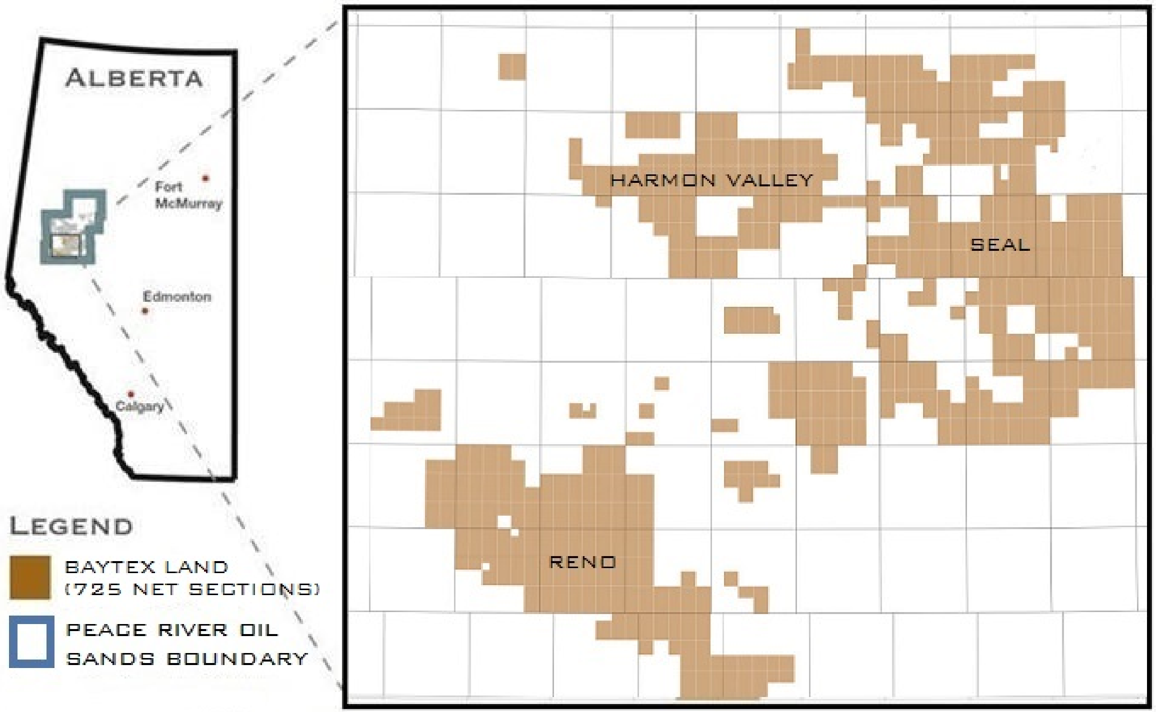
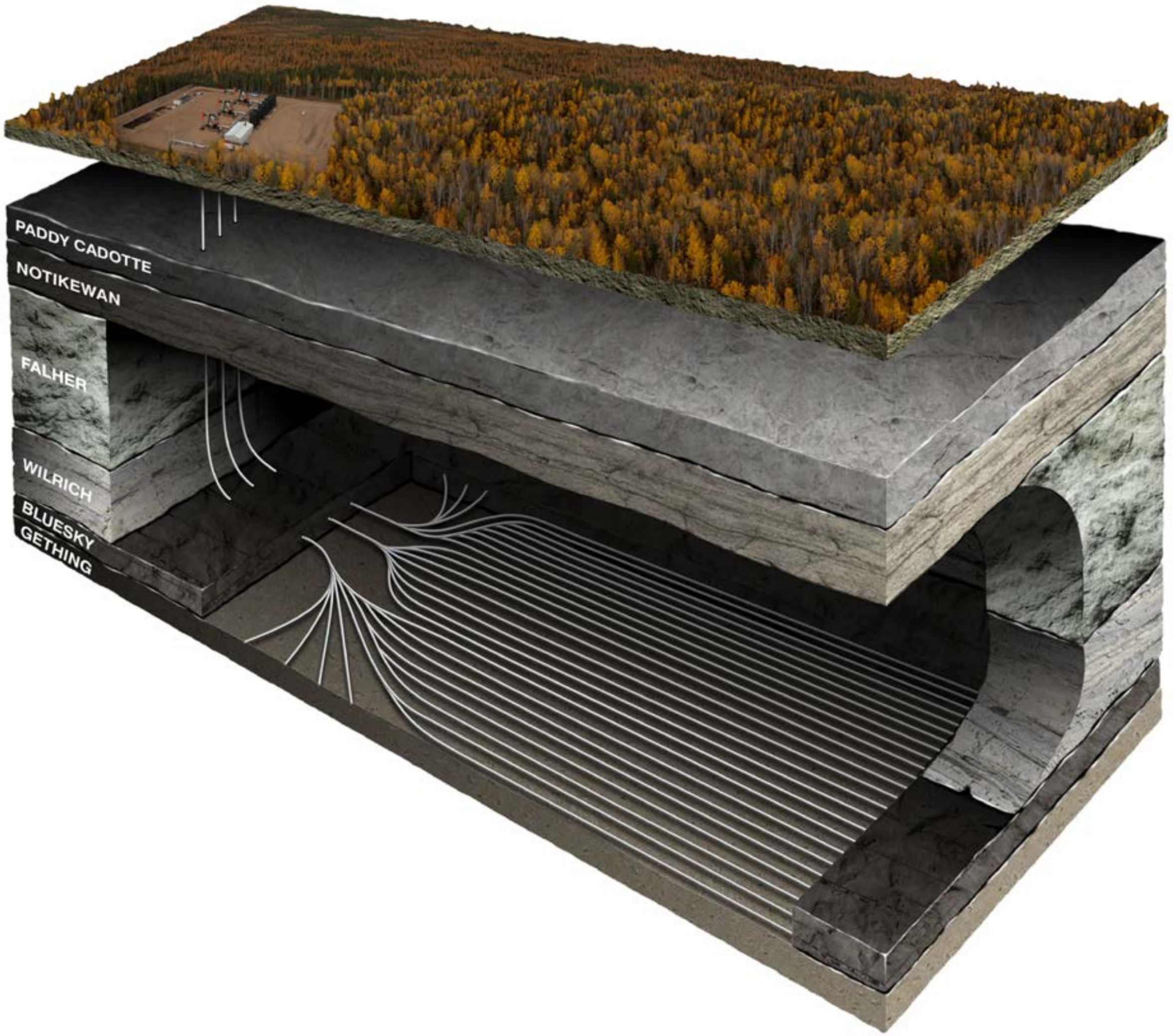
Peace River: Driving Production Growth and Cost Reductions



Performance Drivers

- Peace River production averaged 17,550 boe/d for 2017
- Acquired properties producing ~ 3,800 boe/d, up 26% due to well workovers and production optimization
- Drilled 8 wells in 2017 with average 30-day IP's of ~ 400 bbl/d; 2018 plans include 18 wells
- Achieved 35% reduction in operating costs on acquired properties in 2017

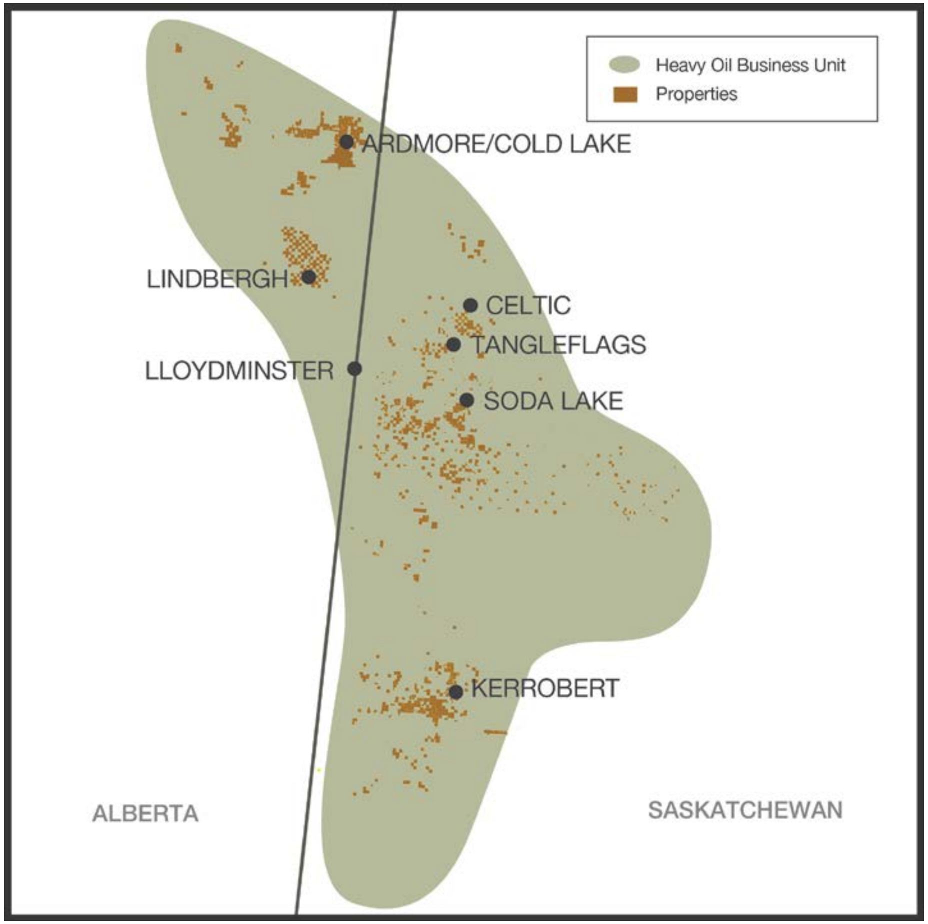
Multi-Lateral Horizontal Wells



Reservoir Characteristics [1]	
Formation	Bluesky
Depth	~ 600 metres
Completion	Open Hole
Oil Quality	11 °API
Average Porosity	28%
Permeability	1 - 5 darcies
Oil Saturation	70%
Recovery Factor	5 - 7%

[1] Baytex internal estimates.

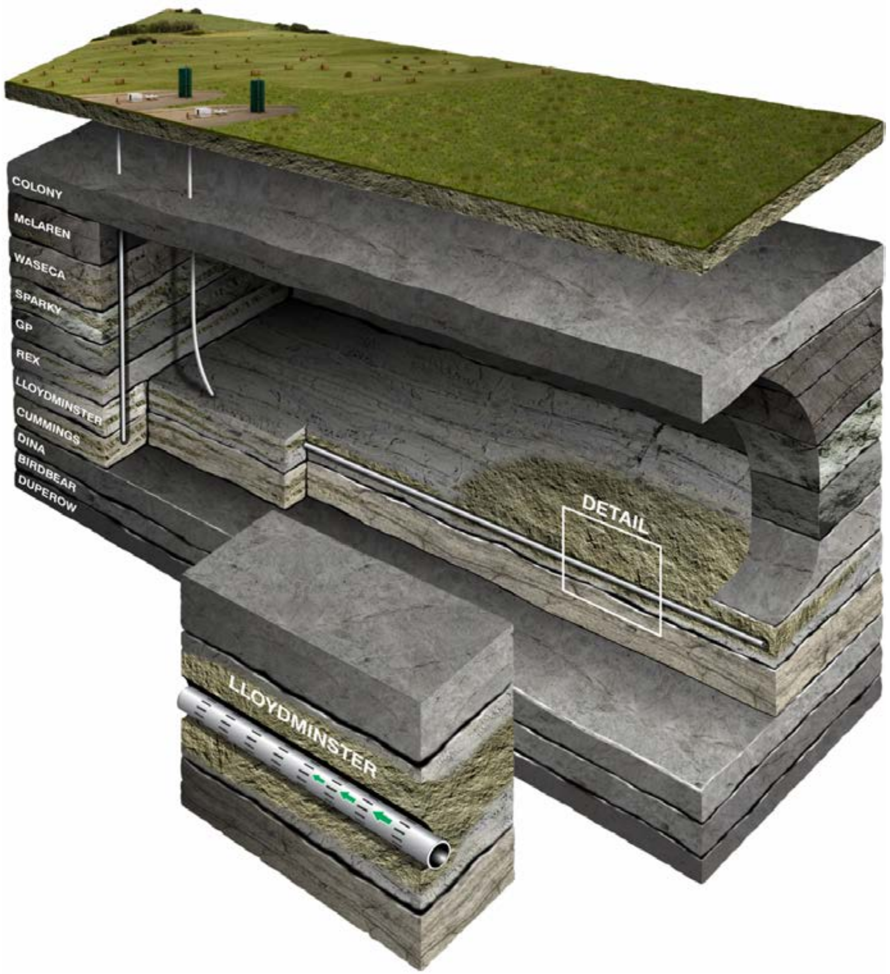
Lloydminster: Significant Land Position and Drilling Inventory



Performance Drivers

- Applying multi-lateral horizontal drilling and production techniques from Peace River
- 40% improvement in individual well capital efficiencies compared to single-lateral horizontal wells
- In Q4/17, seven operated wells (including four multi-lateral horizontal wells) generated 30-day IP's of ~ 180 bbl/d
- 80% increase in 2018 drilling activity with ~ 63 net wells (including 16 multi-laterals)

Lloydminster Development



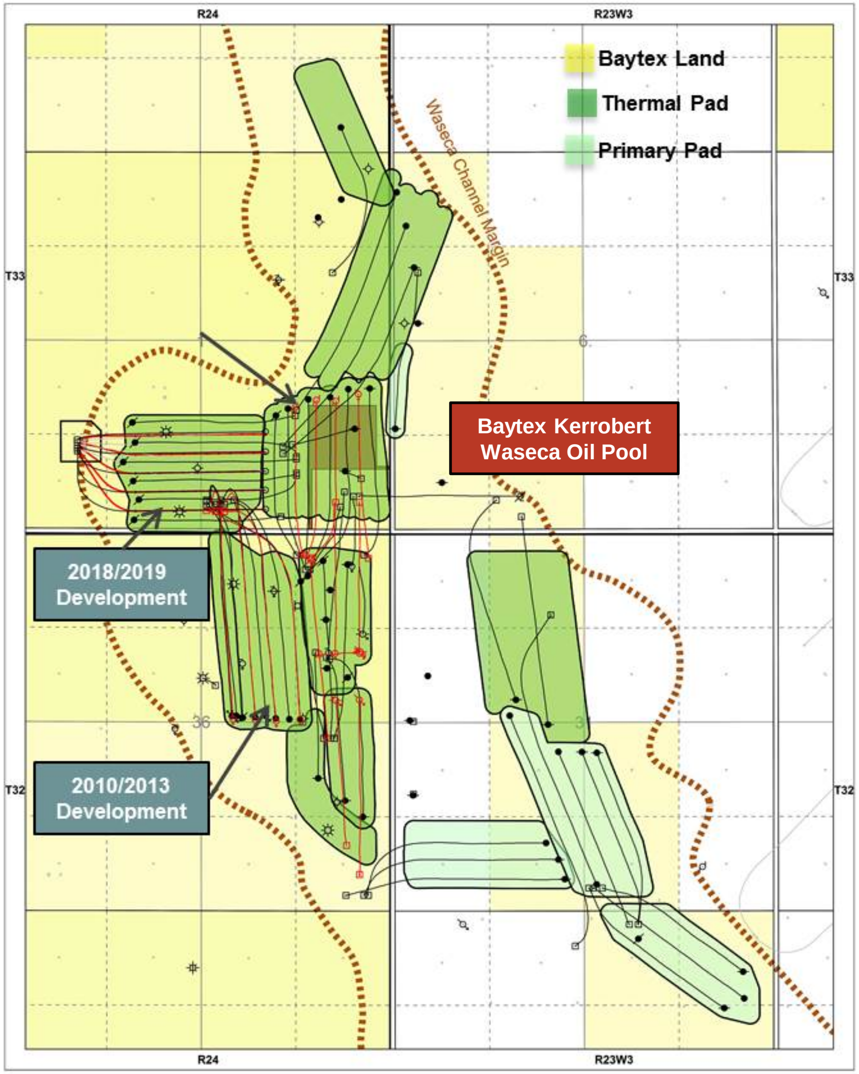
Reservoir Characteristics [1]

Formation	Mannville Group
Depth	350 – 800 metres
Completion	Horizontal Slotted Liner / Vertical Stacked Pays
Oil Quality	10 – 16 °API
Average Porosity	30%
Permeability	0.5 – 5.0 darcies
Oil Saturation	70%

(1) Baytex internal estimates.

Kerrobert Thermal – SAGD Expansion

- Production
  - Current (Nov 2017): 800 bbl/d
  - Target (2019): 2,500 bbl/d
- Expansion Capital
  - Total Project: $25 million
  - 2017 - $4 million; 2018 - $14 million; 2019 - $7 million
- Timeline
  - Q1/2018 - 3 SAGD well pairs
  - Q3/2018 - facility construction and first steam
  - Q4/2018 - first production from 3 new well pairs
  - Q1/2019 – 2 additional SAGD well pairs
- Project Economics
  - IRR - 50% @ US$55/bbl flat WTI
  - Capital Efficiency (IP365) - $8,000 per boe/d
  - F&D - $8.50/boe



Summary

- Allocating capital to high quality assets
  - 50% - 85% ROR's [1] across our three core assets
  - 2018 capital efficiencies of $12,000 per boe/d ($14,000 per boe/d including facilities)
  - Generating production growth of 6% (to 72,000-73,000 boe/d, 2018 exit rate)
- Generating Free Cash Flow
  - U.S. assets, hedging and active crude by rail mitigate WCS volatility
  - Free cash flow positive (with sustaining capex of $300 million) at WTI > US$55/bbl
  - Expect stable liquidity positon going forward

(1) Based on a constant WTI price of US$60/bbl and a constant WCS differential of US$20/bbl

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Supplementary Information

Natural Gas Hedge Portfolio

	Q1/18	Q2/18	Q3/18	Q4/18	2018
AECO Fixed Hedges					
Volumes (GJ/day)	5,000	5,000	5,000	5,000	5,000
Price (C$/GJ)	$2.67	$2.67	$2.67	$2.67	$2.67
NYMEX Fixed Hedges					
Volumes (mmbtu/d)	13,333	15,000	15,000	15,000	14,583
Price (US$/mmbtu)	$3.01	$3.01	$3.01	$3.01	$3.01
Total Hedge Volume (mmbtu/d)	18,072	19,739	19,739	19,739	19,322
Hedge (%) [1]	27%	29%	29%	29%	28%

[1] Percentage of hedged volumes are based on 2018 annual production guidance, net of royalties and fuel purchases.

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Capital Program Efficiency

	2015	2016	2017	3-Year Total / Average 2014-16
Capital Expenditures ($millions)				
Exploration and development	521.0	224.8	326.3	1,072.1
Acquisitions (net of dispositions)	1.6	(63.6)	59.9	(2.1)
Total	522.7	161.2	386.1	1,070.0
Proved plus Probable Reserve Additions (mboe)				
Exploration and development	15,782	17,253	34,398	67,433
Acquisitions (net of dispositions)	126	(2,408)	17,204	14,922
Total	15,908	14,845	51,602	82,355
Finding & Development (F&D) Costs ($/boe) (1)	7.68	19.33	7.26	10.45
Finding, Development & Acquisition (FD&A) Costs ($/boe) (1)	7.75	18.33	9.11	10.51
Ratios – Proved plus Probable Reserves				
Production Replacement Ratio (2)	52%	58%	201%	100%
Recycle Ratio (3)	2.9x	0.9x	2.7x	2.2x

(1) Includes Change in Future Development Costs.

(2) Calculated as total reserve additions (including acquisitions and divestitures) divided by annual average production.

(3) Calculated as operating netback (including hedging gains/losses) divided by F&D costs.

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