February 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 to, but not limited to: our business strategies, plans and objectives; our target to fund our capital program and cash dividends from internally generated funds from operations; our dividend policy; our ability to mitigate the volatility in Western Canadian Select price differentials by transporting our crude oil to market using railways; our three key resource plays (Eagle Ford, Peace River and Lloydminster), including years of drilling inventory remaining and the number of wells to be drilled in 2015 for each play; our operational plans for 2015, including oil and natural gas production and capital expenditures, the allocation of our capital budget by area and the number of wells to be drilled by area; our oil and natural gas production for 2014 and 2015 and production growth rates; our production mix for 2015; our production by region for 2015; reserves and reserves life index; single well economics at Eagle Ford, Peace River and Lloydminster, including drilling and completion costs, initial production rates, liquids weighting, internal rates of return, payout, capital efficiency ratio and the oil price at which the projects break-even; profit to investment ratios for North American resource plays; our Eagle Ford shale play, including the growth potential of the assets, the oil price at which the type wells break-even, initial production rates from new wells, cumulative recoveries, drilling efficiency and individual well economics; our expectation regarding the effect of well downspacing, improving completion techniques and new development targets on the reserves potential of the assets; our belief that the Eagle Ford assets will be an excellent fit with our business model, will provide shareholders with exposure to a low-risk, repeatable, high-return asset with leading capital efficiencies, that the acquired assets have infrastructure in place to provide future production growth, and that such assets will provide material production, long-term growth and high quality reserves with upside potential; our Peace River heavy oil resource play, including development and operational plans, years of drilling inventory remaining, the number and type of wells to be drilled in 2015, reservoir characteristics and well economics for multi-lateral horizontal wells (including well design, drilling and completion costs, initial production rates internal rates of return, payout and capital efficiency ratio); our Lloydminster heavy oil property, including years of drilling inventory remaining, the number and type of wells to be drilled in 2015, and drilling and completion costs, initial production rates, estimated recoverable reserves, internal rates of return, payout and capital efficiency ratio for horizontal wells; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate light oil; pricing differentials for Western Canadian Select and Maya heavy crude oils; the development of rail transportation capacity in Western Canada; our ability to optimize the price received for our oil production and to manage our exposure to heavy oil price differentials by transporting our crude oil to market using trucks and railways; the existence, operation and strategy of our risk management program, including the breakdown of our heavy oil sales portfolio by market for Q4/2014 and the portion of future exposures that have been hedged; proposed pipeline infrastructure development and the timing of completing such developments; the demand outlook for Canadian heavy oil in the United States; our liquidity and financial capacity; and the sufficiency of our financial resources to fund our operations. 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.

Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time. 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: completion of the divestiture of our North Dakota assets; our ability to execute and realize on the anticipated benefits of the acquisition of the Eagle Ford assets; petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oils; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; 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; the amount of future cash dividends that we intend to pay; 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 or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated. Readers are cautioned that such assumptions, although considered reasonable by us at the time of preparation, may prove to be incorrect.

Advisory (Cont.)

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: failure to realize the anticipated benefits of the acquisition of the Eagle Ford assets; declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; a downgrade of our credit ratings; the cost of developing and operating our assets; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in government regulations that affect the oil and gas industry; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; changes in environmental, health and safety regulations; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and 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 risk factors are discussed in Baytex's Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2013, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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, 2013, of the volume of our petroleum and natural gas reserves as prepared by our independent qualified reserves evaluators, Sproule Associates Limited ("Sproule"), except for the Eagle Ford assets, which were prepared by an internal non-independent qualified reserves evaluator. These estimates have been prepared in accordance with Canadian reserves disclosure standards and definitions as set forth in National Instrument 51-101 "Standards of Disclosure for Oil and Natural Gas Activities" of the Canadian Securities Administrators ("NI 51-101"). 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, 2013 dated March 25, 2014.

This presentation contains estimates of the volumes of the "contingent resources" for our oil resource plays in the Bluesky in the Peace River area of Alberta and the Mannville group in northeast Alberta as of December 31, 2013 and for the Gemini SAGD project in Cold Lake, Alberta, as of December 31, 2012. These estimates were prepared by our independent qualified reserves evaluators, Sproule and McDaniel & Associates Consultants Ltd. ("McDaniel").

"Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook as: "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. The assigned contingent resources are categorized as economically recoverable based on economics completed at year-end 2012.

BAYTEX ENERGY CORP.

Advisory (Cont.)

A range of contingent resources estimates (low, best and high) were prepared by Sproule and McDaniel. A low estimate (C1) is considered to be a conservative estimate of the quantity of the resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources in the low estimate have the highest degree of certainty (a 90% confidence level) that the actual quantities recovered will equal or exceed the estimate. A best estimate (C2) is considered to be the best estimate of the quantity of the resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources in the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate. A high estimate (C3) is considered to be an optimistic estimate of the quantity of the resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will equal or exceed the high estimate. Those resources in the high estimate have a lower degree of certainty (a 10% confidence level) that the actual quantities recovered will equal or exceed the estimate.

The primary contingencies which currently prevent the classification of the contingent resources as reserves consist of: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; access to capital markets; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices and price differentials between light, medium and heavy gravity crude oils; future drilling program and testing results; further reservoir delineation and studies; facility design work; limitations to development based on adverse topography or other surface restrictions; and the uncertainty regarding marketing and transportation of petroleum from development areas.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated and that the resources can be profitably produced in the future.

The recovery and resources estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

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.

Non-GAAP Financial Measures

This presentation refers to funds from operations, total monetary debt and operating netback, which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). We define funds from operations ("FFO") as cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. 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 cash flow necessary to fund future dividends to shareholders and capital investments. However, funds from operations 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 funds from operations to cash flow from operating activities.

We define total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loans. Baytex believes that this measure assists in providing a more complete understanding of its cash liabilities.

We define operating netback as product sales price less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. Baytex's 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.

Baytex Key Attributes

North American Oil Focused Producer Operating for Over 20 Years

Exceptional Growth Platform	- Focus on per share growth in production, cash flow and reserves - Production growth focused on crude oil and liquids - Significant inventory of development prospects
Sector Leading Capital Efficiencies	- Sector leading efficiencies in three core resource plays: Eagle Ford, Peace River and Lloydminster - Strong capital efficiencies result in low sustaining capital; provides flexibility on discretionary capital
Sustainable Business Model	- Target to fund capital program and cash dividends from internally generated funds from operations - No near-term maturities on long-term debt; significant undrawn capacity on existing credit facilities
Active Risk Management	- Risk management policy allows hedging of up to 60% of financial exposure - Mitigate the volatility in WCS price differentials by transporting crude oil to higher value markets by rail

Corporate Profile

Market Summary

Ticker Symbol	TSX / NYSE: BTE
Average Daily Volume (1)	CAN: 1,622,348 / US: 917,234
Shares Outstanding (Current)	168 million
Market Capitalization / Enterprise Value	$3.8 billion / $6.1 billion
Total Monetary Debt (2)	$2.3 billion
Monthly Dividend / Dividend Yield (3)	$0.10 per share / 5.3%

Corporate Summary

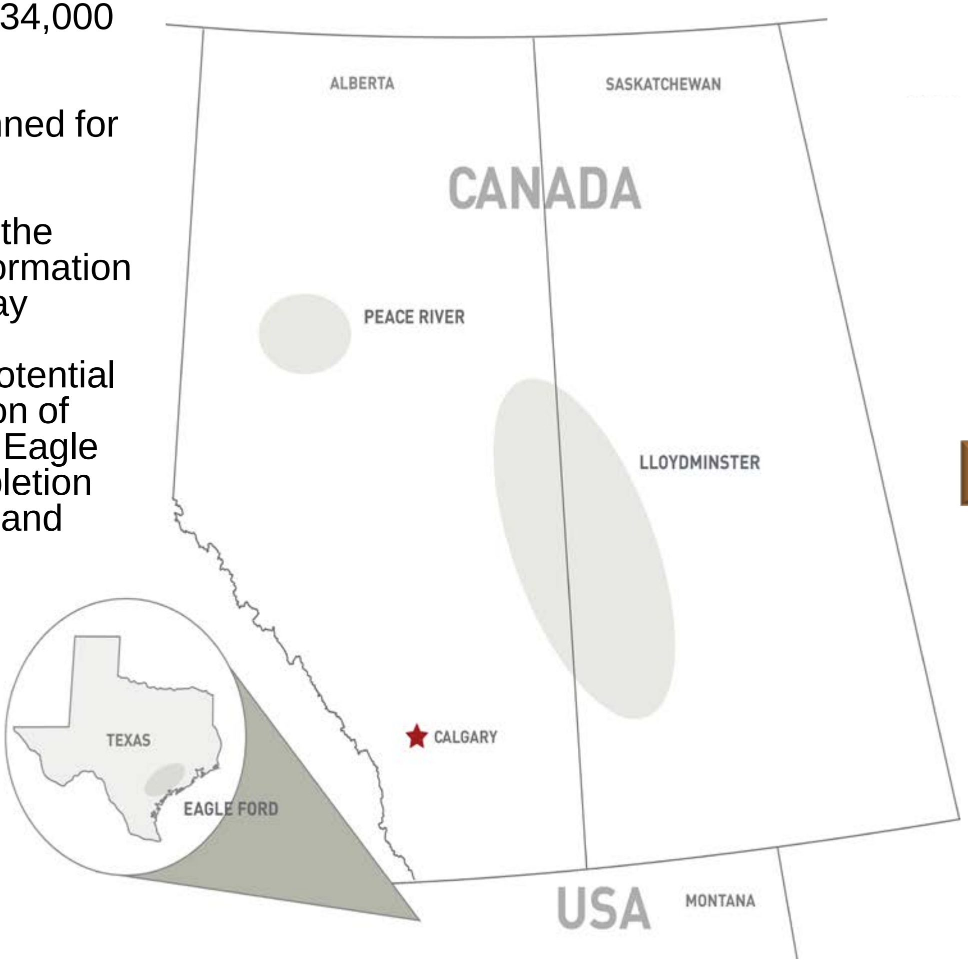
Production (4)	90,500 boe/d
Production Mix	82% oil and liquids
Reserves – 2P Gross (5)	432 mmboe

(1) Average daily trading volumes for January 1 - 30, 2015. Volumes are a composite of all exchanges in Canada and the U.S.
(2) Total monetary debt estimated as at December 31, 2014.
(3) The dividend yield is calculated by dividing the annualized dividend of C$1.20 by the closing price of Baytex shares of C$22.55 on the TSX on February 19, 2015.
(4) Production based on Q3/2014 actual results less contributions from asset sales.
(5) Reserves per NI 51-101 as at December 31, 2013 and adjusted for the Eagle Ford acquisition and North Dakota asset sale. See "Advisory – Oil and Gas Information" for more information.

Three Key Resource Plays

Eagle Ford

- Q3/14 production ~ 34,000 boe/d
- 39-45 net wells planned for 2015
- Actively developing the Lower Eagle Ford formation in the core of the play
- Significant upside potential via further delineation of Austin Chalk/Upper Eagle Ford, ongoing completion design optimization and down-spacing



Peace River

- Q3/14 production ~26,000 boe/d
- ~8 net wells planned for 2015
- Developed via multi-lateral horizontal wells
- Strong capital efficiencies

Lloydminster

- Q3/14 production ~20,000 boe/d
- ~26 net wells planned for 2015
- Conventional heavy oil targeting multiple stacked pay formations
- Expanding use of multi-lateral drilling techniques with encouraging initial results

2015 Capital Budget & Commentary

Capital Budget (February 2015)

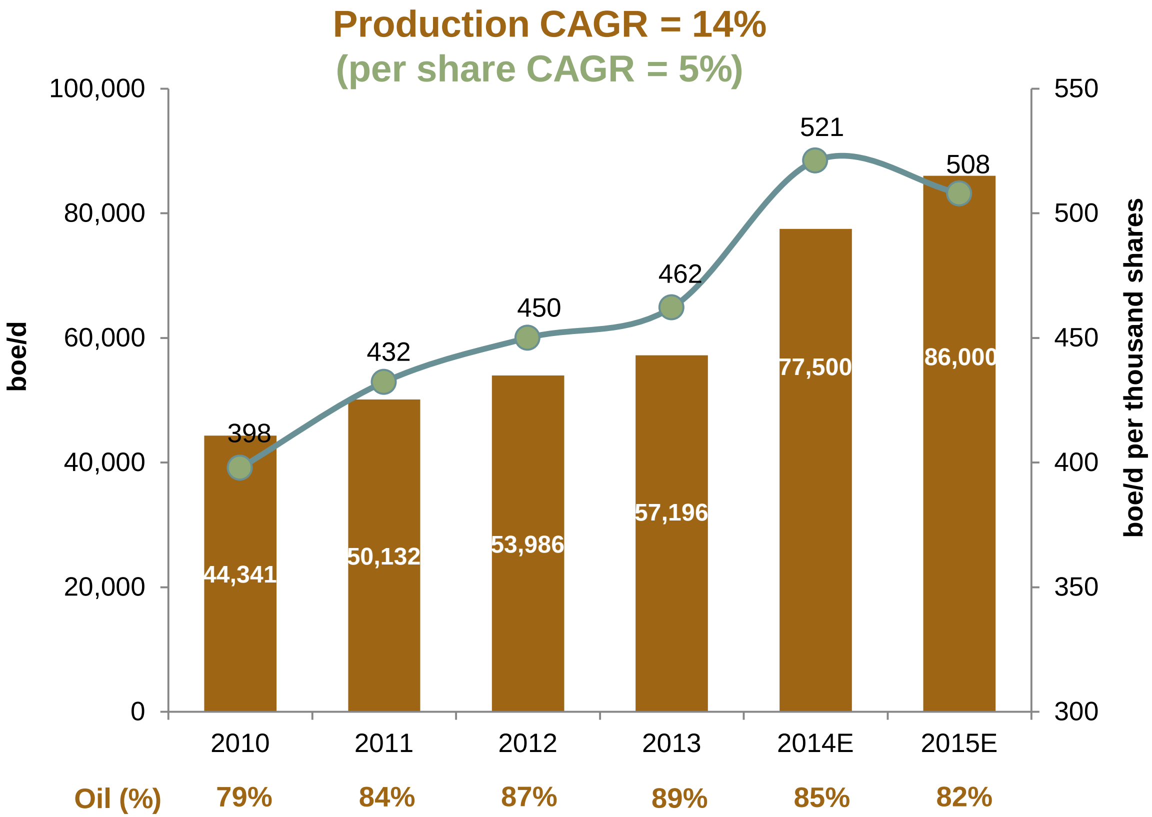
Operating Area	Amount ($ millions)	Wells Drilled (net)
United States	$400 - $450	39 – 45
Canada [1]	$100 - $125	35 – 48
Total	$500 - $575	74 - 93

[1] Includes 8 - 12 stratigraphic and service wells

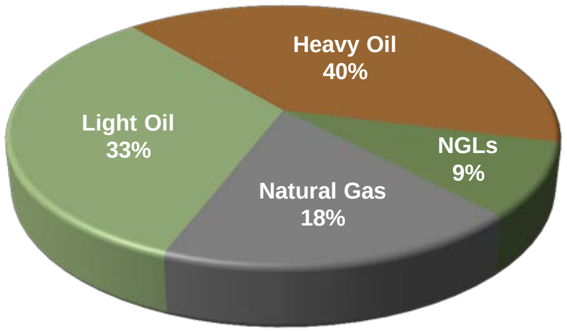
Commentary

- In response to continued weakness and volatility in oil prices since the release of our 2015 capital budget in early December we are further reducing expenditures by approximately 12% to preserve financial flexibility.
- We expect to generate average production of 84,000 – 88,000 boe/d, which includes the shut-in of approximately 2,000 boe/d of uneconomic volumes.
- Approximately 80% of our budget will be directed towards our Eagle Ford operations. At current commodity prices the Eagle Ford represents the strongest capital efficiencies and highest netbacks in our portfolio.
- Approximately 20% of our budget will be directed towards our heavy oil operations at Peace River and Lloydminster.

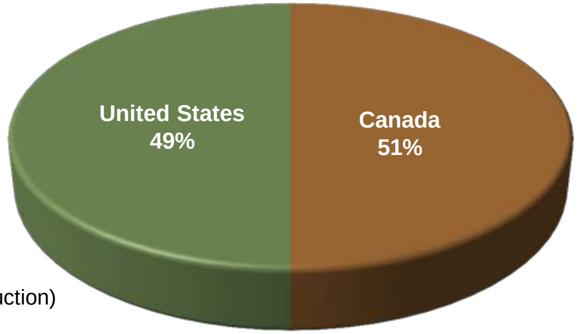
Production Growth



Production Breakdown 2015 Guidance 84,000 – 88,000 boe/d



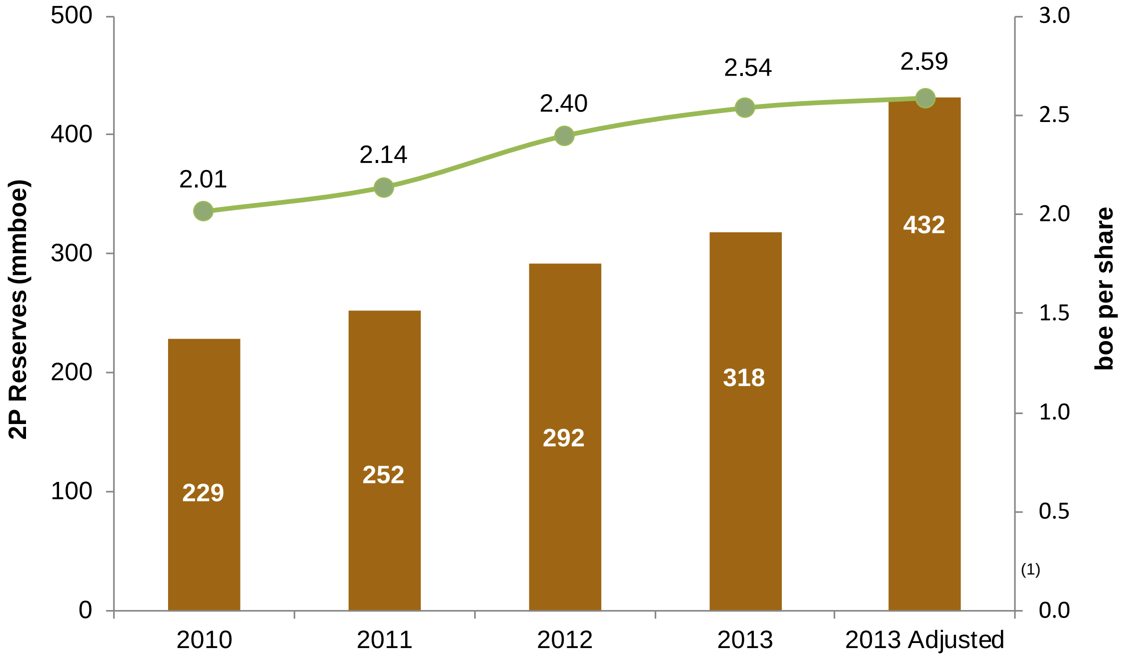
Production by Region 2015 Guidance (boe/d)



2014E based on mid point of guidance range of 77,000–78,000 boe/d.
2015E based on mid point of guidance range of 84,000–88,000 boe/d (includes the shut-in of 2,000 boe/d of uneconomic production)
Gas production converted at energy equivalence ratio of 6 mcf to 1 boe.

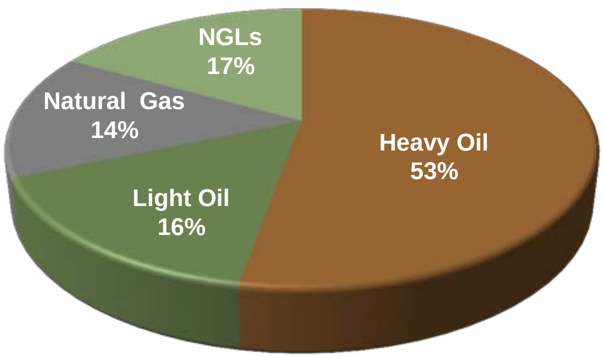
Reserves Growth / Contingent Resources

Reserve CAGR = 17%
(per share CAGR = 8%)



	2010	2011	2012	2013	2013 Adjusted
Oil (%)	91%	92%	93%	90%	86%
RLI (yrs) [3]	13.9	13.0	14.5	14.9	13.1

2P Reserve Breakdown [1]
Company Total = 432 MMboe



Economic Contingent Resources [2]

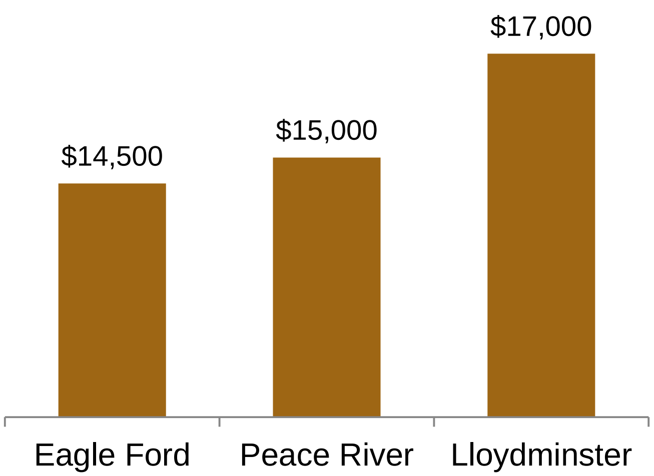
(Millions of barrels of bitumen)	Best Estimate
Peace River, Alberta	553
Northeast Alberta	125
Angling Lake, Alberta	87
Total	764

(1) 2013 Adjusted Reserves as at December 31, 2013 including Eagle Ford acquisition and 2014 divestitures.
(2) Contingent Resource at December 31, 2013 adjusted for 2014 divestitures. See “Advisory – Oil and Gas Information for more information on contingent resources.
(3) RLI’s are based on Q4 production rate for each year. 2013 Adjusted RLI based on Q3/2014 production adjusted for divestitures.

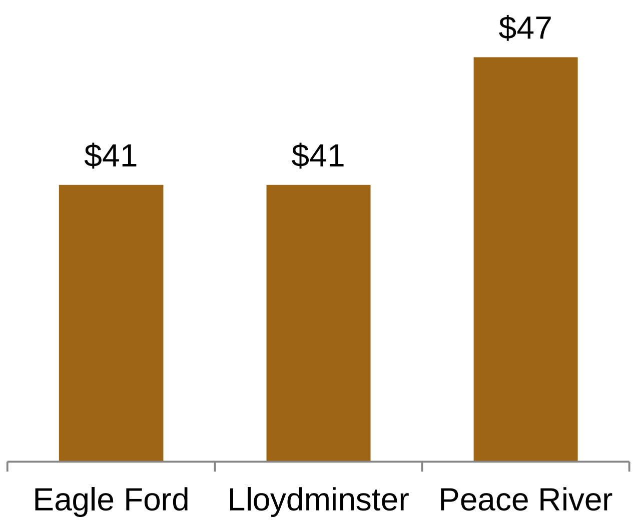
High Quality Investment Opportunities

	Eagle Ford	Peace River	Lloydminster
Well Cost ($ millions)	US$7.0	$3.1	$0.9
Production (boe/d)			
IP30	1,000 – 1,200	300 - 500	70 - 80
% Liquids	60% - 70%	100%	100%

Annual Capital Efficiencies (1)



Break Even Oil Price (US$/bbl) (2)

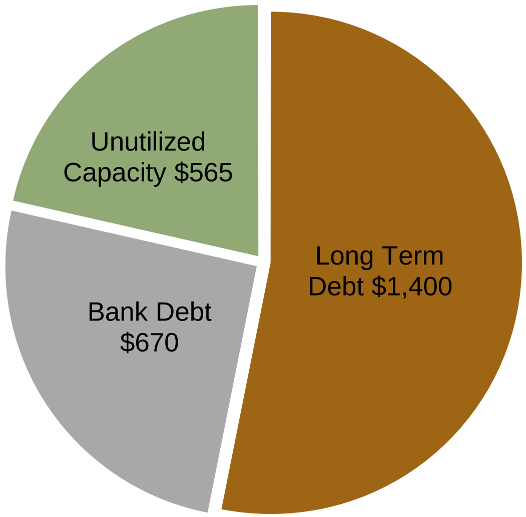


(1) Capital efficiency represents the drill, complete and equip cost per well divided by the average annual daily production rate per well (C$/boe/d).
(2) Break even price represents the oil price (WTI) at which the net present value of a well is zero at a 10% discount rate.

Balance Sheet Strength

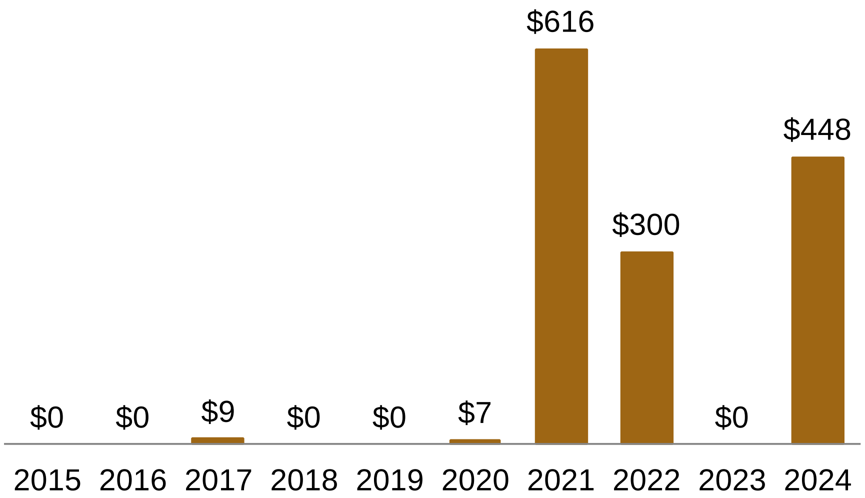
Debt Composition ($ millions)

Credit Capacity $2.6 billion



Long-Term Debt Maturity Schedule ($ millions)

No material repayments required until 2021



We have unsecured revolving credit facilities consisting of a $1.0 billion Canadian facility and a US$200 million U.S. facility that mature June 2018. At the end of December, we had approximately $565 million in undrawn capacity on these facilities. The revolving credit facilities do not require any mandatory principal payments prior to maturity and can be further extended beyond June 2018 with the consent of the lenders.

2015 Funds from Operations Sensitivities

Sensitivities (including effect of hedging)	Estimated Effect on Annual Funds Flow ($ Millions)	Estimated Effect on Annual Funds Flow (Per Share)
Change of US$1.00/bbl WTI crude oil	$15.0	$0.09
Change of 1% WCS heavy oil differential	$9.0	$0.05
Change of US$0.25/mcf NYMEX natural gas	$7.5	$0.04
Change of $0.01 in the US$/C$ exchange rate	$12.0	$0.07

Crude Oil Hedge Portfolio

	H1 2015	H2 2015	2015
Fixed Hedges			
Volumes (bbl/d)	14,000	4,000	9,000
Hedge (%) [1]	29%	8%	18%
Fixed Price ($US/bbl)	$96.47	$95.98	$96.36
Floating Hedges			
Volumes (bbl/d)	5,822	1,656	3,739
Hedge (%) [1]	12%	3%	8%
Floating Price ($US/bbl) [2]	WTI + $11/bbl	WTI + $10/bbl	WTI + $10.50/bbl

Total Hedged Volumes (bbl/d)	19,822	5,656	12,739

Total Hedged Volumes (%) [1]	41%	12%	26%

[1] Percentage of hedged volumes are based on 2015 production guidance, net of royalties.

[2] Hedges reflect our exposure when WTI is less than $US80/bbl.

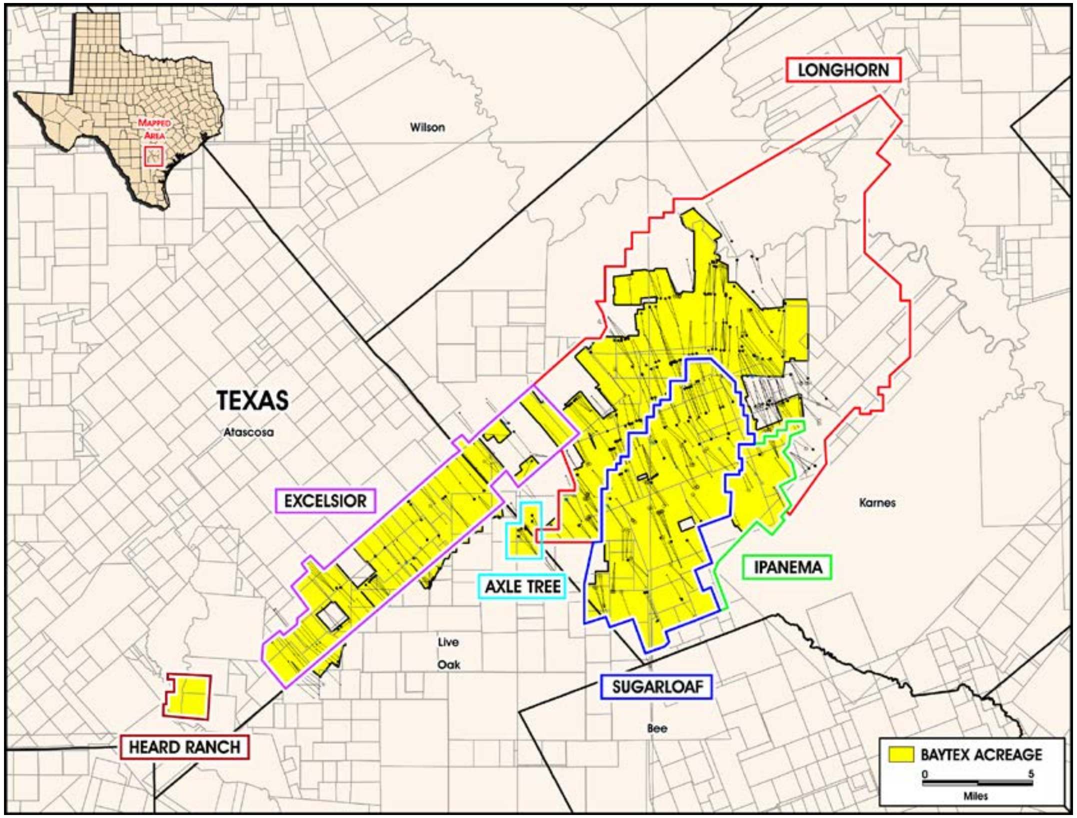
The Eagle Ford

Eagle Ford Acreage Position

The Eagle Ford Provides Baytex With Exposure to a World Class Oil Resource Play

Overview of Acreage

- 23,000 net contiguous acres in the Sugarkane Field in the core of the liquids-rich Eagle Ford shale.
- The Sugarkane Field has been largely delineated which is expected to facilitate future production growth.
- Extensive infrastructure in place across the acreage position, including centralized processing facilities, disposal wells and infield gathering systems.
- 97% of acreage is held by production

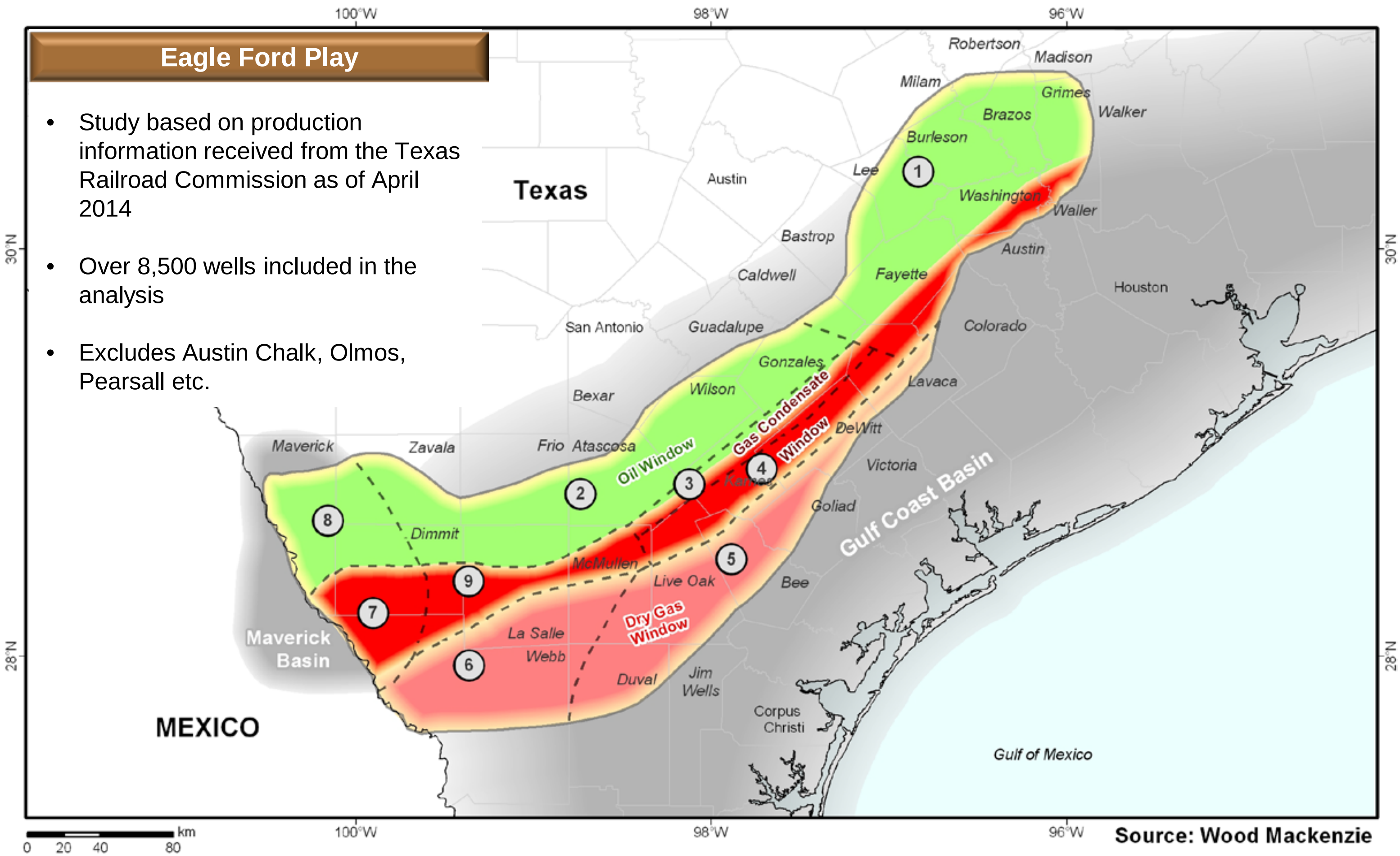


Eagle Ford – Gas/Liquids Window Map

Nine Eagle Ford Sub-Play Areas

Eagle Ford Play

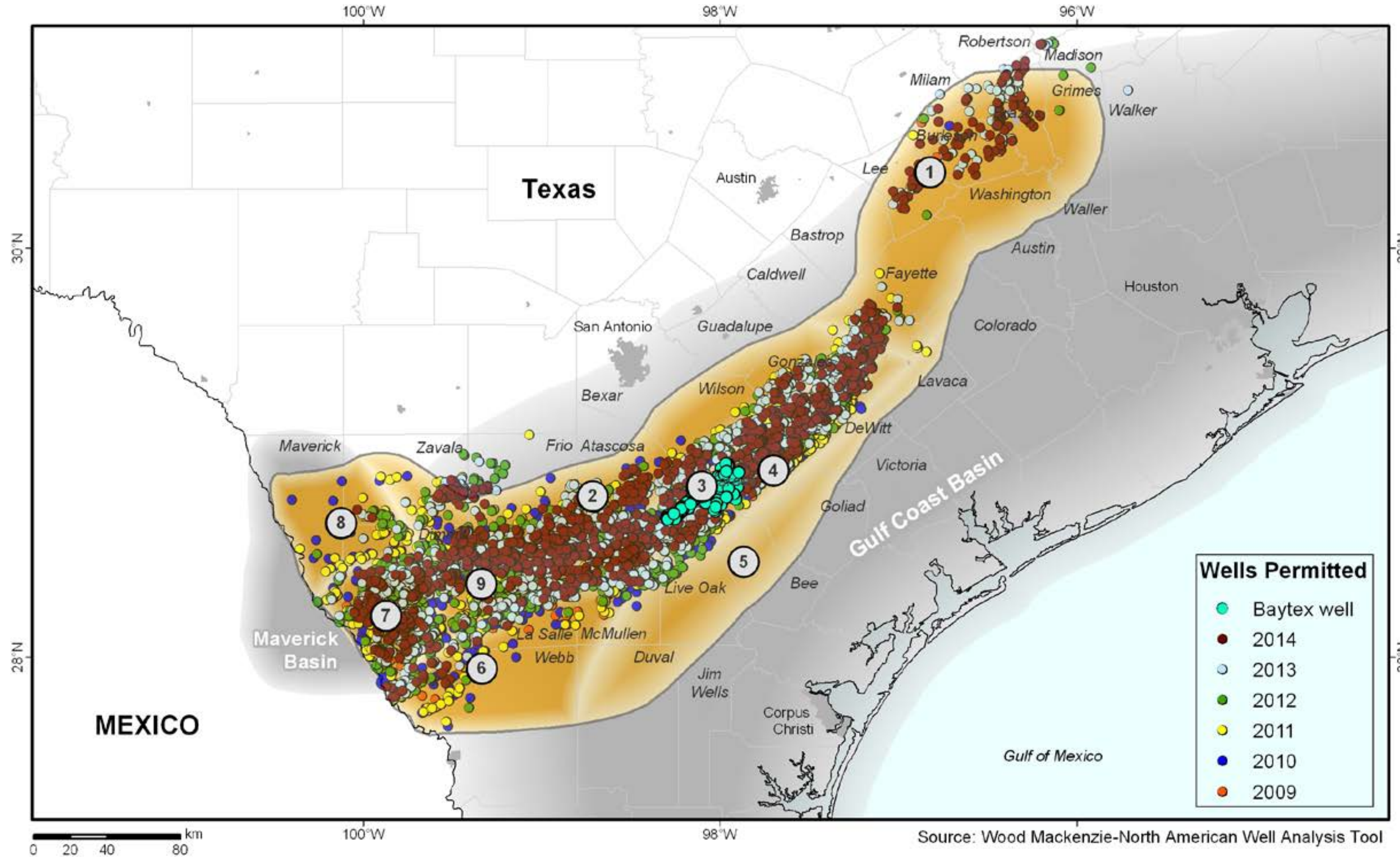
- Study based on production information received from the Texas Railroad Commission as of April 2014
- Over 8,500 wells included in the analysis
- Excludes Austin Chalk, Olmos, Pearsall etc.



Source: Wood Mackenzie

Wood Mackenzie breaks the Eagle Ford into nine distinct sub-play areas: (1) Northeast Oil, (2) Black Oil, (3) Karnes Trough Condensate, (4) Edwards Condensate, (5) Southeast Gas, (6) Southwest Gas, (7) Maverick Condensate, (8) Maverick Oil and (9) Hawkville Condensate. Baytex's Eagle Ford acreage falls largely within the Karnes Trough sub-play area.

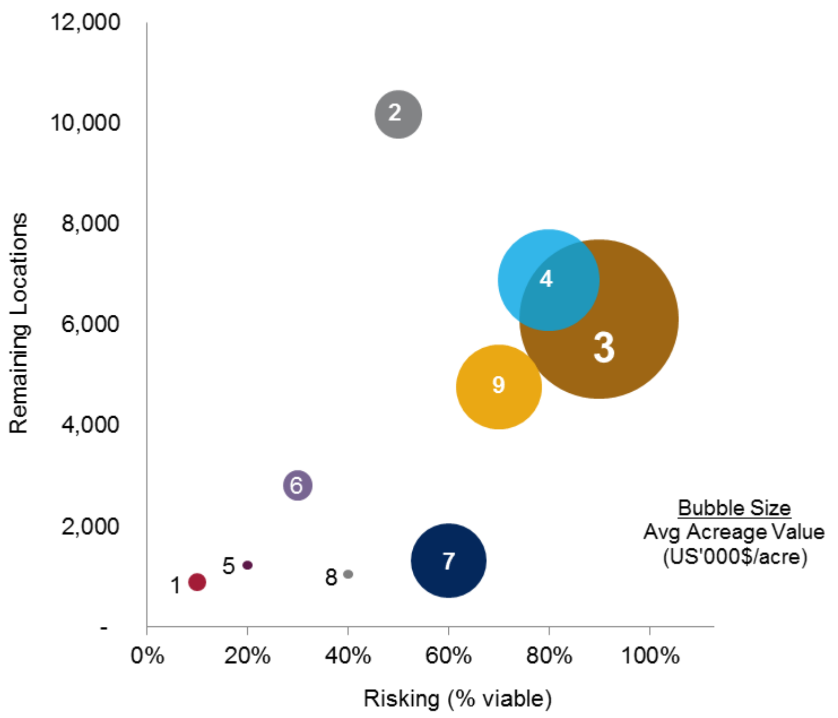
Eagle Ford - Wells Completed 2009 to 2014



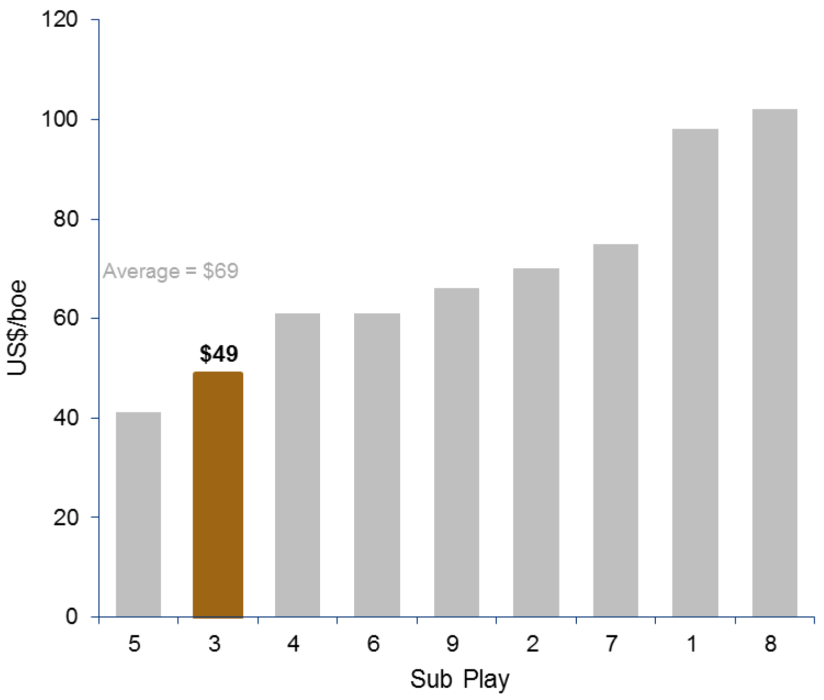
Wood Mackenzie breaks the Eagle Ford into nine distinct sub-play areas: (1) Northeast Oil, (2) Black Oil, (3) Karnes Trough Condensate, (4) Edwards Condensate, (5) Southeast Gas, (6) Southwest Gas, (7) Maverick Condensate, (8) Maverick Oil and (9) Hawkville Condensate. Baytex's Eagle Ford acreage falls largely within the Karnes Trough sub-play area.

Eagle Ford – Sub Play Economics

Sub-Play Analysis



Type Well Breakeven



Source: Wood Mackenzie.

Wood Mackenzie breaks the Eagle Ford into nine distinct sub-play areas: (1) Northeast Oil, (2) Black Oil, (3) Karnes Trough Condensate, (4) Edwards Condensate, (5) Southeast Gas, (6) Southwest Gas, (7) Maverick Condensate, (8) Maverick Oil and (9) Hawkville Condensate. Baytex's Eagle Ford acreage falls largely within the Karnes Trough sub-play area. Sub-play analysis and type well break-even represents the entire acreage in the sub-play areas and may not be representative of Baytex's Eagle Ford position.

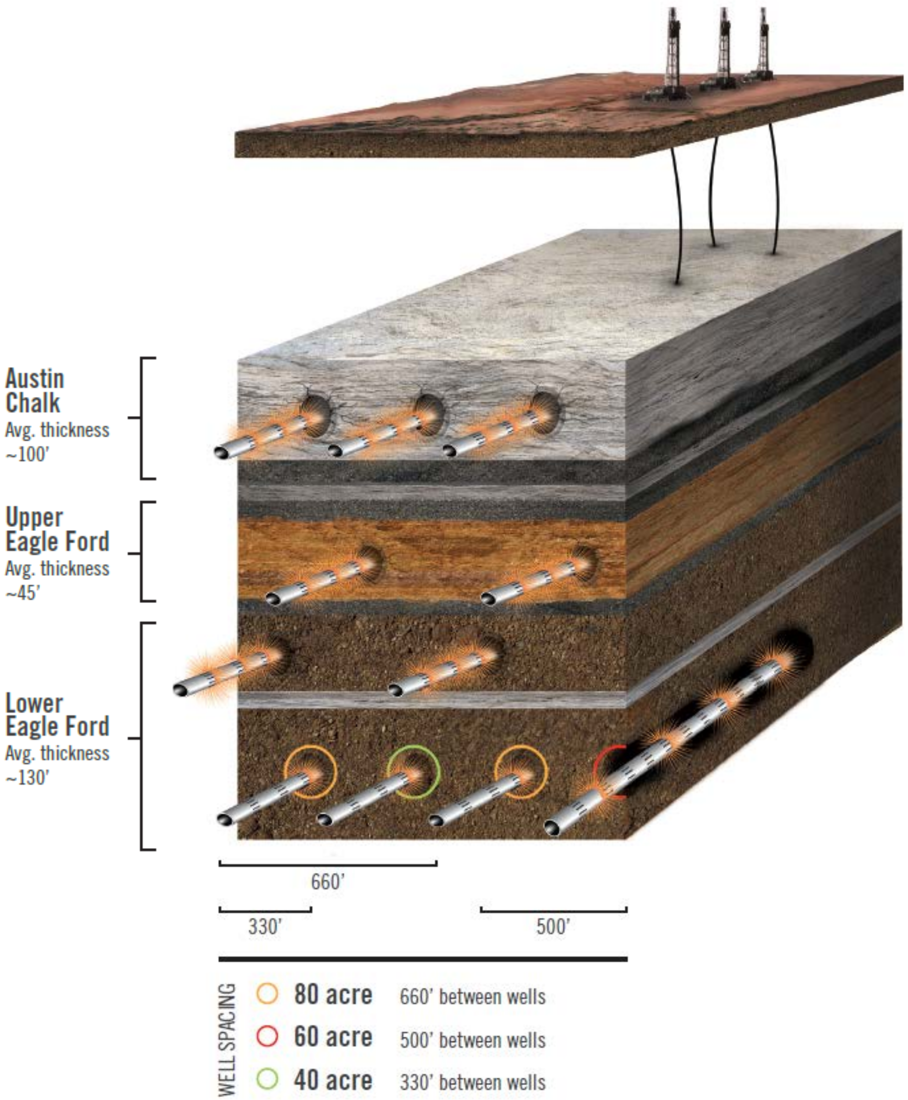
Eagle Ford Development

Development to date has targeted the Lower Eagle Ford

- Originally developed at 80-acre spacing; current development is now 60-acre spacing (volatile oil) and 40-acre spacing (condensate gas)

Extending Lower Eagle Ford / Austin Chalk success

- YTD we are seeing an approximate 20% improvement in 30-day IP rates
- Eight Austin Chalk wells drilled in Q3/2014 with 30-day IP rates of 800 to 1,300 boe/d
- Austin Chalk now delineated on approximately 50% of our acreage
- Stack and Frac pilots to include Austin Chalk, Upper Eagle Ford and Lower Eagle Ford formations

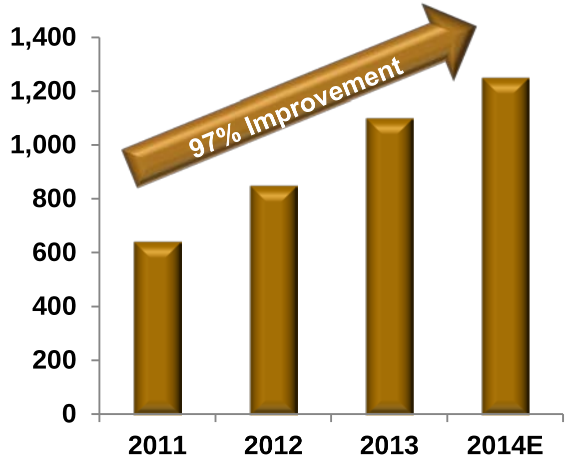


Eagle Ford Performance

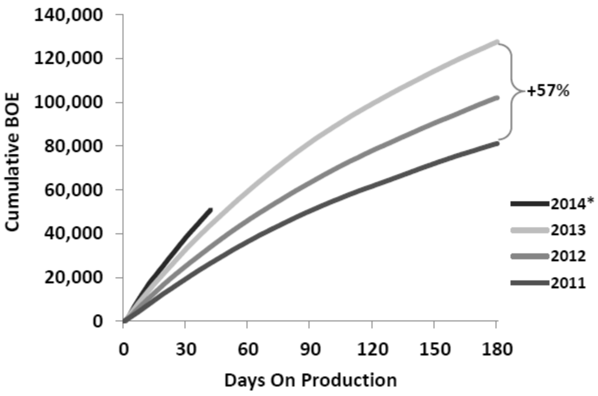
Increasing Development Performance and Recovery

- Continuous improvements in drilling and completion design have increased 30-day IP rates by approximately 97% since Q4/2011 with 180-day cumulative recovery increasing 57% over the same time period
- Drilling times have decreased by 50% since Q4/2011 resulting in reduced completed well costs

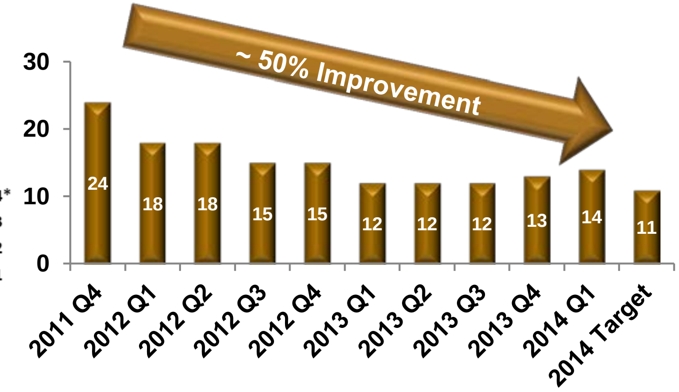
Production (30-day IP, boe/d)



Cumulative Recovery (boe)



Drilling Efficiency (Spud to TD – days)



Source: Marathon Oil investor presentation, May 20, 2014. The information presented is based on Marathon's operated Eagle Ford acreage, not just the properties in which Baytex holds an interest, and therefore may not be representative of Baytex's Eagle Ford position.

Heavy Oil Overview

BAYTEX
ENERGY CORP.

Peace River Oil Sands

BAYTEX ENERGY CORP.

Multi-Lateral Drilling Drives Strong Capital Efficiencies

Area Statistics

Land Holdings	308 net sections
Production (Q3/2014)	26,000 bbl/d
2P Reserves (YE13) (1)	114 mmbbls
Drilling Inventory (2)	~ 5 years

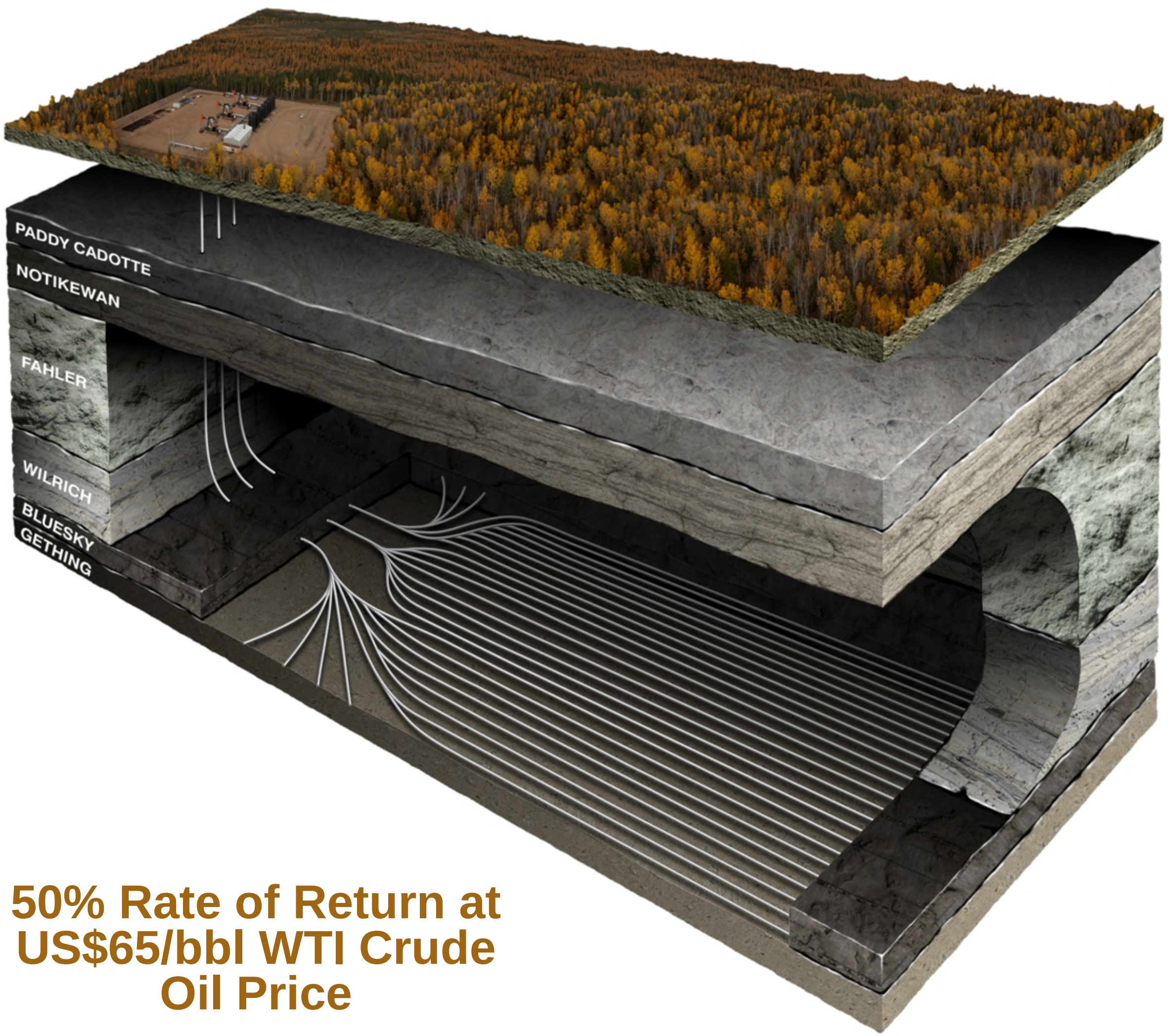
(1) 2P Reserve breakdown = 67 million barrels (primary) and 47 million barrels (thermal).

(2) Drilling inventory in years based on identified drilling locations (cold horizontal multi-lateral wells) and 2014 drilling plans.

2015 Development

2015 Drilling Program	~ 8 multi-lateral horizontal wells
	8-12 stratigraphic and service wells

Multi-Lateral Cold Horizontal Wells



50% Rate of Return at US$65/bbl WTI Crude Oil Price

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%

Well Economics at US$65/bbl [1]

Well Design	~ 12 laterals
Completed Well Cost	~ $3.4 MM
Production (IP30)	~ 400 bbl/d
IRR (before tax)	50%
Payout	1.7 years
Capital Efficiency (based on IP365)	$16,000 per boe/day

(1) Baytex internal estimates.

Lloydminster Heavy Oil

Shift to Horizontal Drilling Expands Inventory

Area Statistics

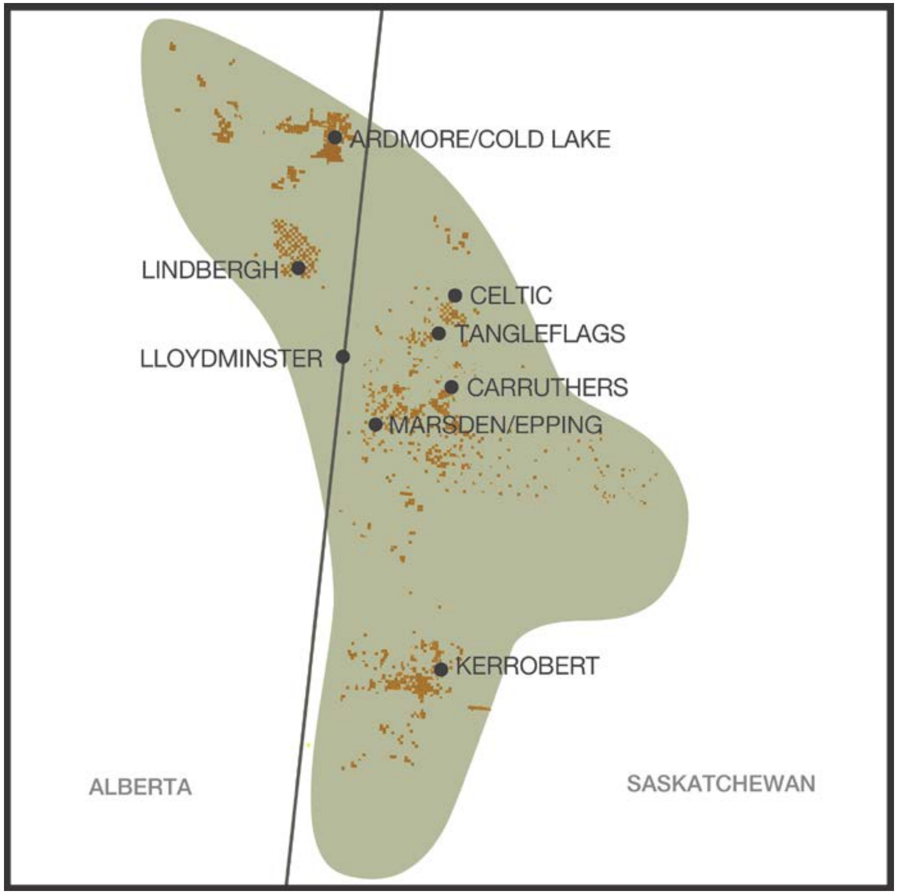
Land Position	730 net sections
Production (Q3/2014)	20,000 boe/d
2P Reserves (YE13) [1]	114 mmbbls
Drilling Inventory [2]	~ 6.5 years

(1) Includes SAGD projects at Gemini (44 million barrels) and Kerrobert (12 million barrels)

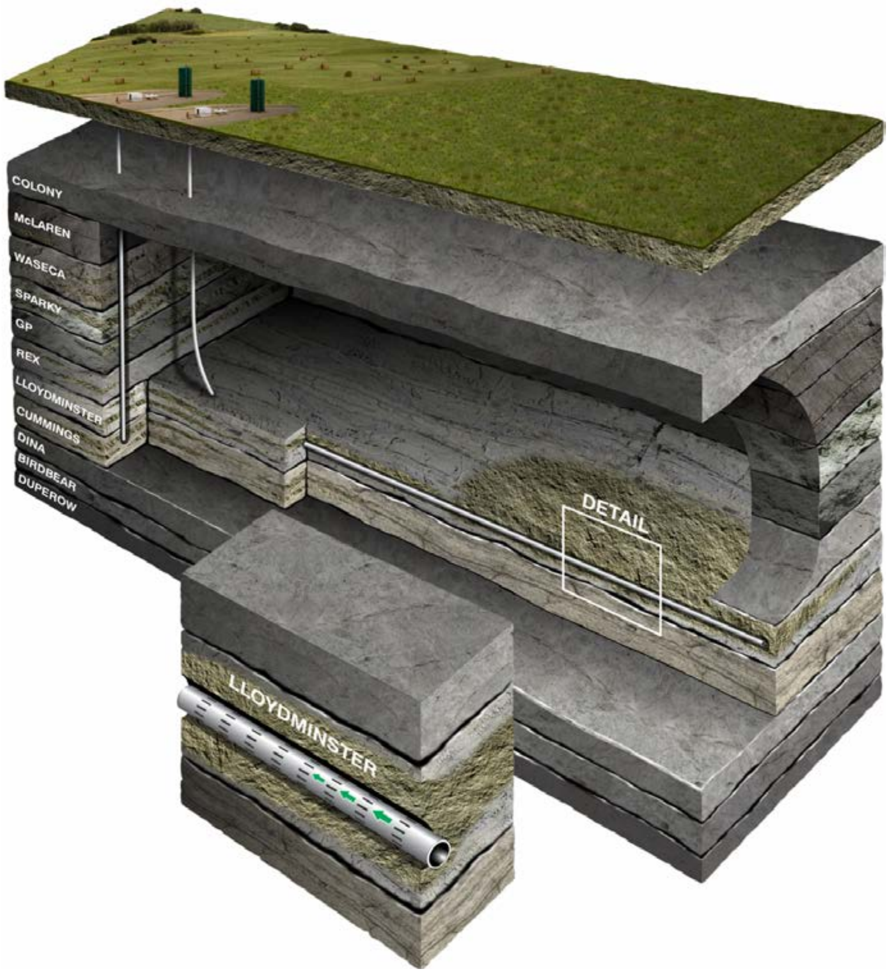
(2) Drilling inventory in years based on identified drilling locations and 2014 drilling plans.

2015 Development

Drilling	~ 26 net wells
% Horizontal/Vertical	80% / 20%



Lloydminster Development



Increased Multi-Lateral Drilling at Lloydminster is Leading to an ~ 20% Improvement in Capital Efficiencies

Reservoir Characteristics (1)

Formation	Mannville Group
Depth	350 – 800 metres
Completion	Horizontal Slotted Liner / Vertical Stacked Pays
Oil Quality	11 – 18 °API
Average Porosity	30%
Permeability	0.5 – 5.0 darcies
Oil Saturation	70%

Horizontal Well Economics at US$65/bbl (1)

Completed Well Cost	$950,000
Production (IP30)	70-80 bbl/d
IRR (before tax)	80%
Payout	1.3 years
Capital Efficiency (based on IP365)	$18,500 per bbl/day

(1) Baytex internal estimates.

Why Invest in Baytex?

Superior Asset Base

- ✓ Significant inventory of high quality, low risk, oil-focused development locations
- ✓ Sector leading capital efficiencies and robust asset level returns across all three core resource plays
- ✓ Significant unconventional resource potential

Total Return Focus

- ✓ Value creation via profitable growth and income business model
- ✓ Focus on per share growth in production, cash flow and reserves
- ✓ Provide a meaningful dividend to investors
- ✓ Target to fund capital program and cash dividends from funds from operations

Proven Track Record

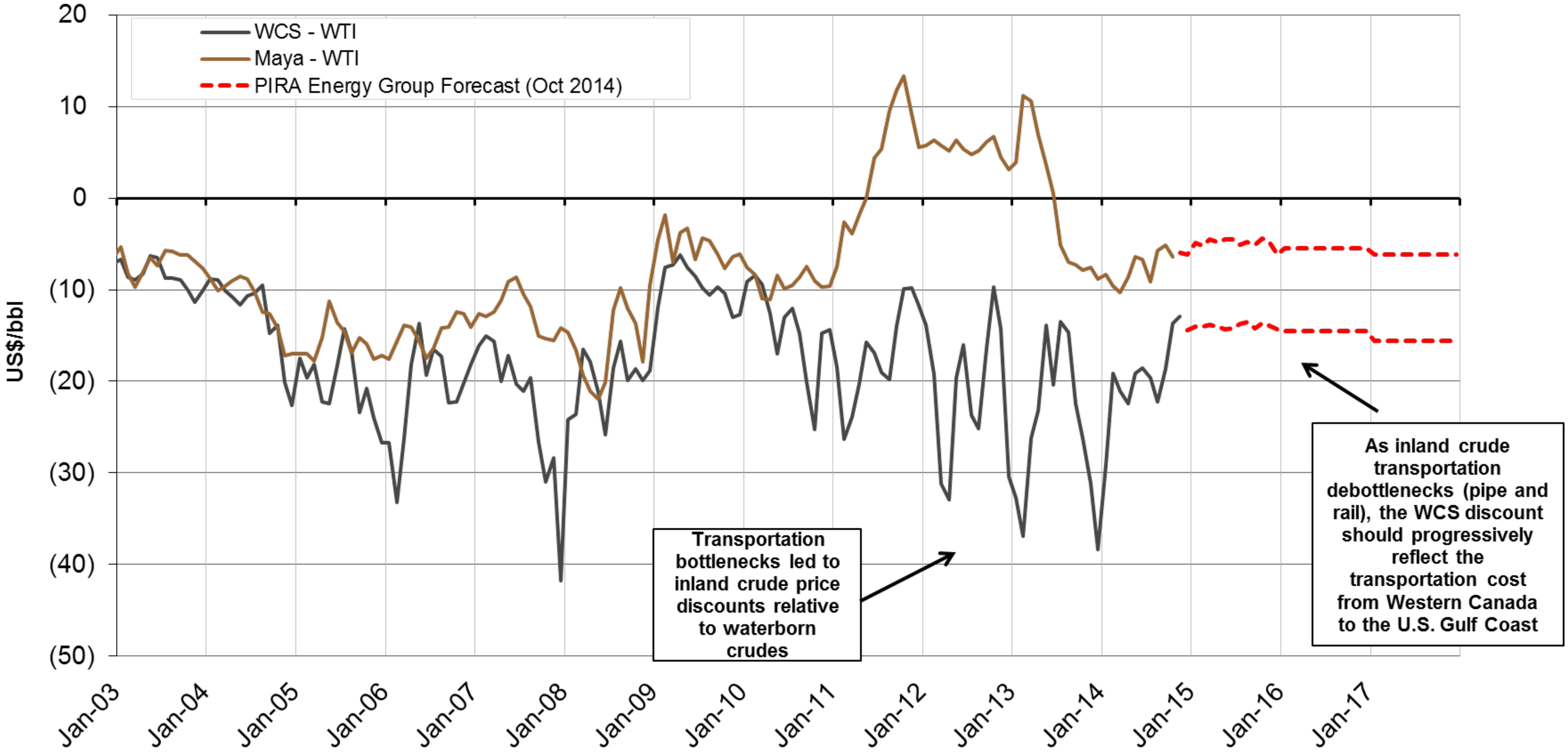
- ✓ Long-term track record of value creation and operational excellence
- ✓ Impressive growth in both production and reserves
- ✓ Sophisticated marketing expertise
- ✓ Over $2.0 billion distributed to shareholders in the last 10 years

Appendix: Crude Oil Marketing

WCS Heavy Oil Differentials

- **Forward market for 2015 suggests a WCS differential ~ US$15/bbl**
  - Q1/2015 = US$14.73/bbl
  - Balance of Year ~ US$15.00/bbl
- **Positive catalysts in 2014 have contributed to lower differentials and stronger heavy oil pricing**
  - BP Whiting repositioning adds ~ 250,000 bbl/d of heavy oil demand
  - Enbridge Flanagan South pipeline; capacity of 585,000 bbl/d
  - Enbridge mainline capacity showing substantial gains
  - Rail capacity of Canadian crude increases with new projects targeting Q4/2014 and Q1/2015 start-up
  - Line 9 reversal (Sarnia to Montreal) to add incremental end-use refiner demand

Heavy Oil Differential – WCS and Maya

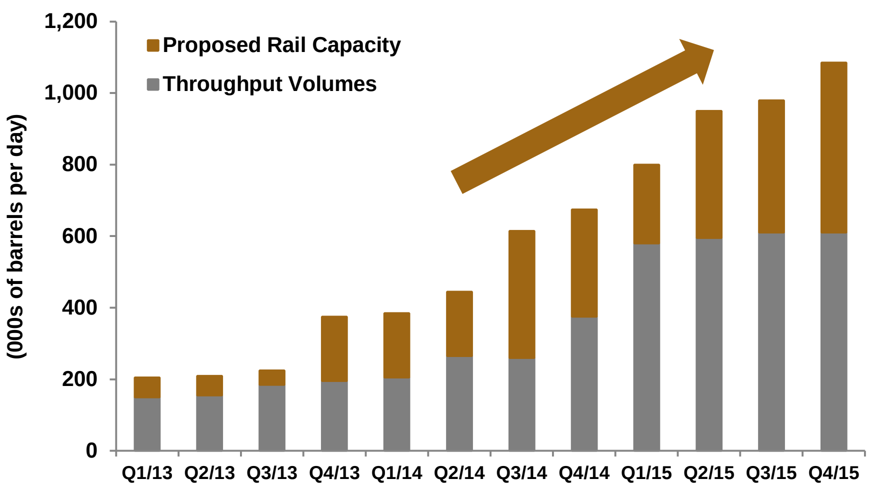


Sources: Net Energy Inc., Argus Media, PIRA

Crude by Rail in Western Canada

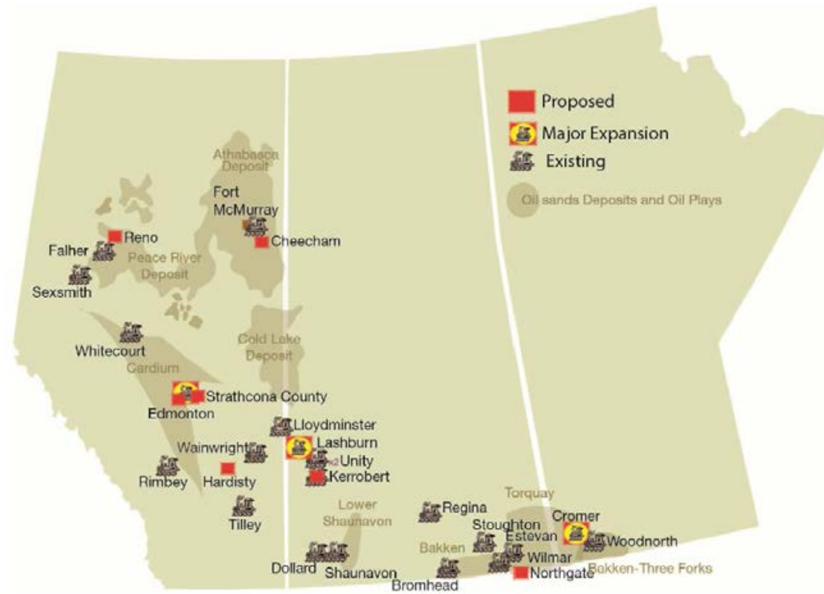
Industry Outlook

- Rail is playing a meaningful role in the transportation of crude oil in Western Canada as major pipeline expansions are unlikely to be in place for many years.
- Significant infrastructure investment suggests growth in rail capacity; several large unit train loading facilities and expansions recently announced in Western Canada.
- Rail uploading capacity of ~600 mbbl/d is expected to nearly double to over 1.1 mmbbl/d by the end of 2015 (and is further expandable to 1.4 mmbbl/d).



Source: CAPP Forecasts, Baytex Energy Estimates

Major Loading Terminals



Operator(s)	Location	Capacity[1] (mbbl/d)	Operational
Kinder Morgan / Imperial	Strathcona, AB	210	Q1/15
TORQ Transloading	Kerrobert, SK	168	Q3/14
Gibsons / USDG	Hardisty, AB	120	Q2/14
Altex	Lashburn, SK	90	Q1/15
Canexus	Bruderheim, AB	65	Q3/14
Kinder Morgan / Keyera	Edmonton, AB	40	Q3/14

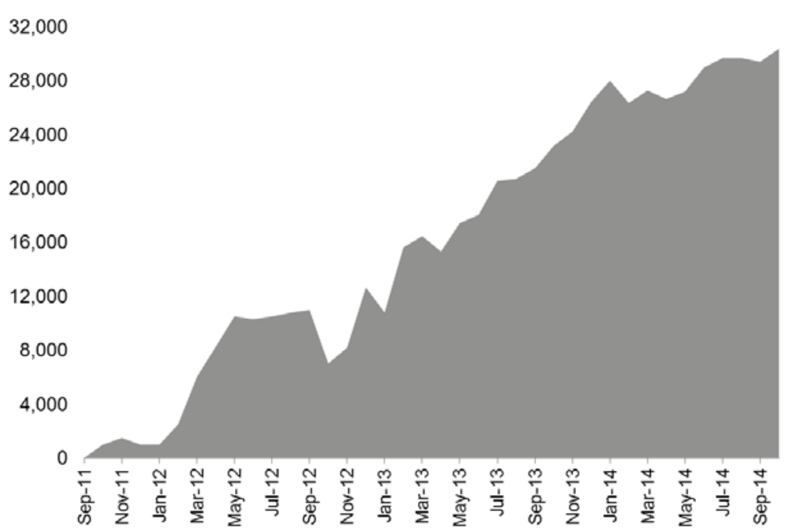
(1) Proposed capacities as per CAPP forecasts

Marketing - Crude by Rail

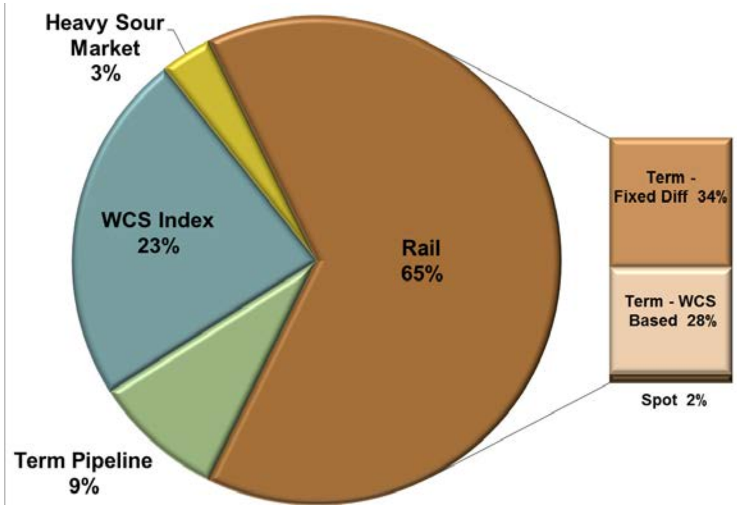
Rail a Key Component of Market Access

- Trucking flexibility helps optimize value of production
- Rail has become an effective vehicle for management of heavy oil differentials
- Undiluted heavy oil sales provide Baytex with a sustainable competitive advantage

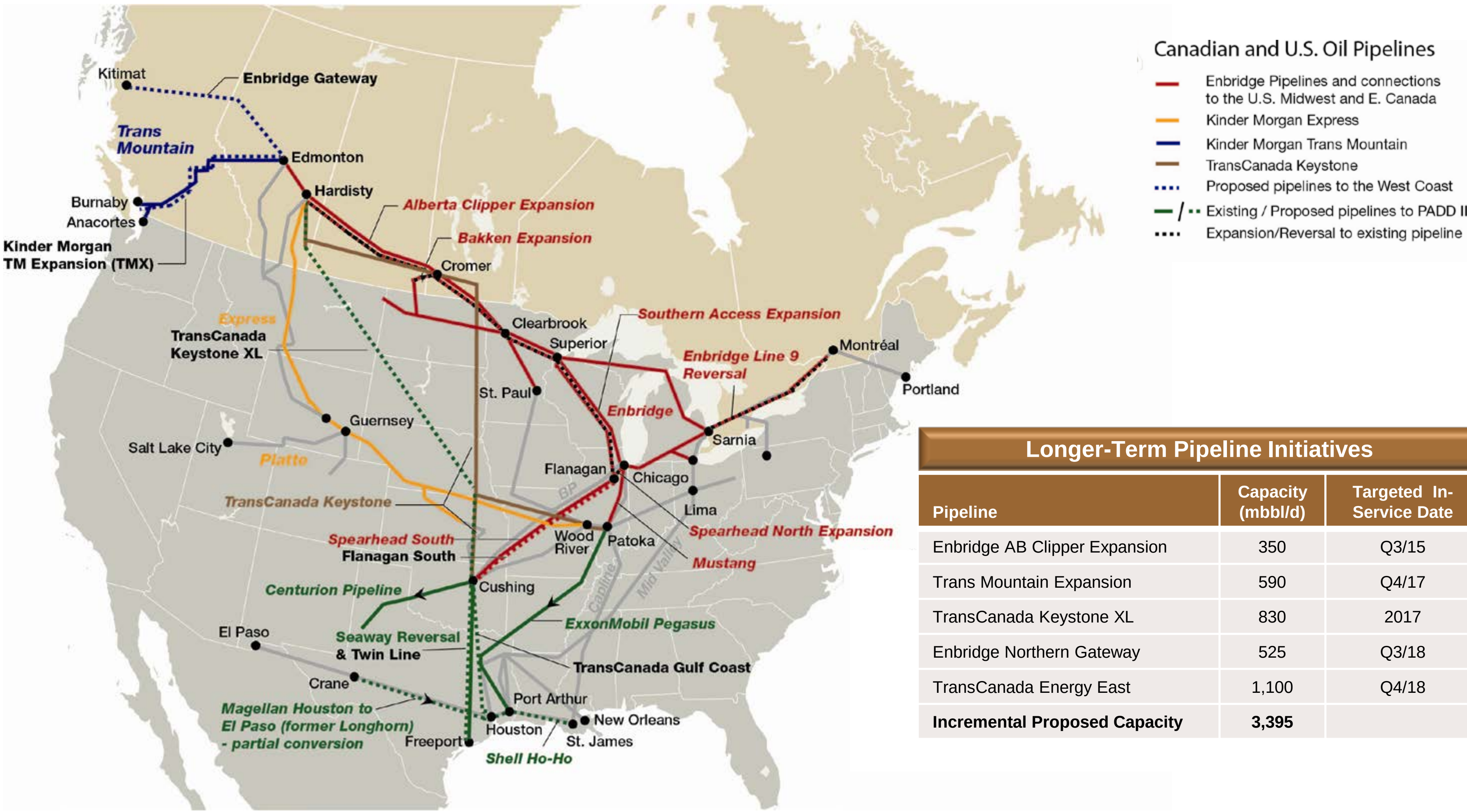
Baytex Heavy Oil Volumes on Rail (bbl/d)



Q4 2014 Heavy Oil Sales Portfolio



Midstream Heavy Oil Fundamentals – Infrastructure Development



Longer-Term Pipeline Initiatives

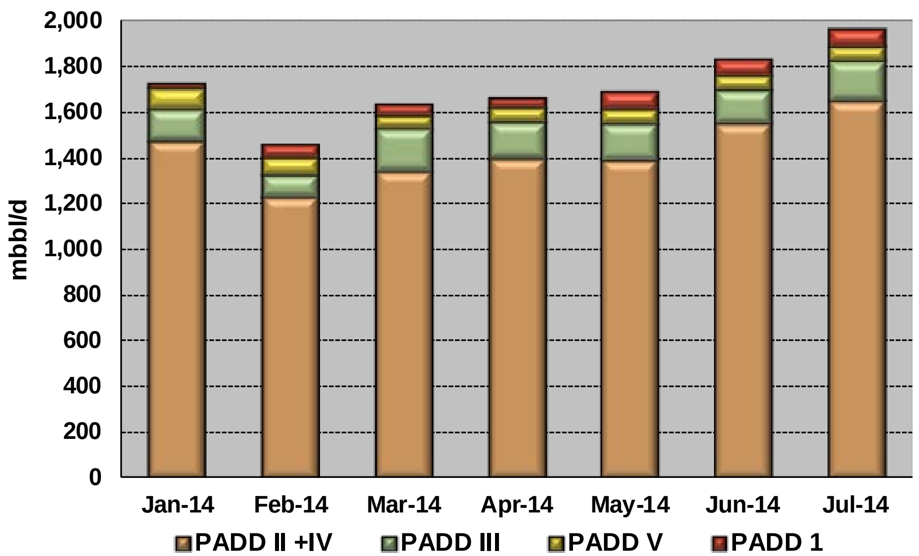
Pipeline	Capacity (mbbl/d)	Targeted In-Service Date
Enbridge AB Clipper Expansion	350	Q3/15
Trans Mountain Expansion	590	Q4/17
TransCanada Keystone XL	830	2017
Enbridge Northern Gateway	525	Q3/18
TransCanada Energy East	1,100	Q4/18
Incremental Proposed Capacity	**3,395**	

Source: Canadian Association of Petroleum Producers "Crude Oil Forecast, Markets and Pipelines Report", June 2014

U.S. Gulf Coast Heavy Oil Demand

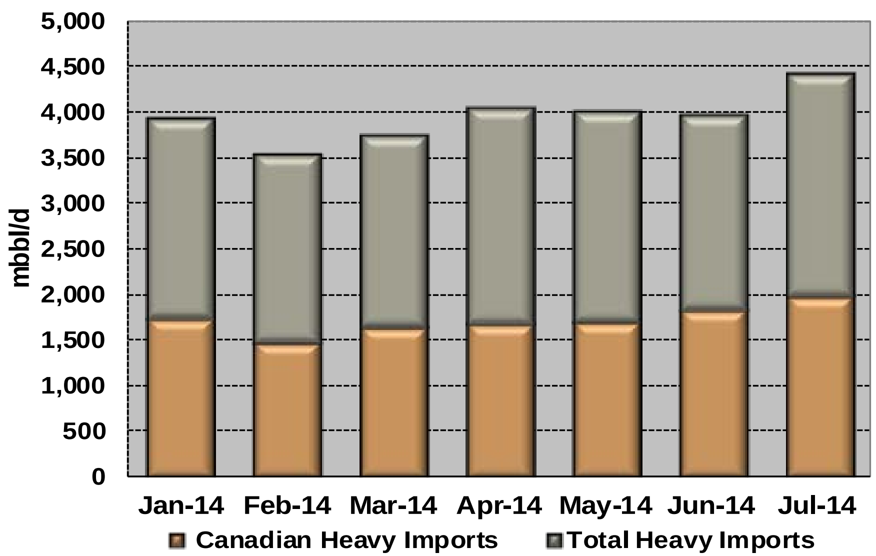
- U.S. imports of Canadian heavy oil rose to 1.93 mb/d in July 2014, and has averaged 1.71 mb/d over 2014 YTD
- Market penetration to U.S. Coasts (PADD's 1,3 and 5) is showing signs of growth and refiner interest remains strong
- Total U.S. heavy oil imports averaged 3.94 million bbl/d over 2014 YTD, 43% originated from Canada
- PADD 3 heavy oil imports averaged 2.01 million bbl/d over 2014 YTD (35% Venezuela, 32% Mexico, 8% Columbia, 8% Canada, 4% Brazil)

Canadian Heavy Oil (<27 API) Imports by PADD Region



Source: EIA data

U.S. Imports of Heavy Oil (<27 API)



Source: EIA data

Supplementary Information - Financial

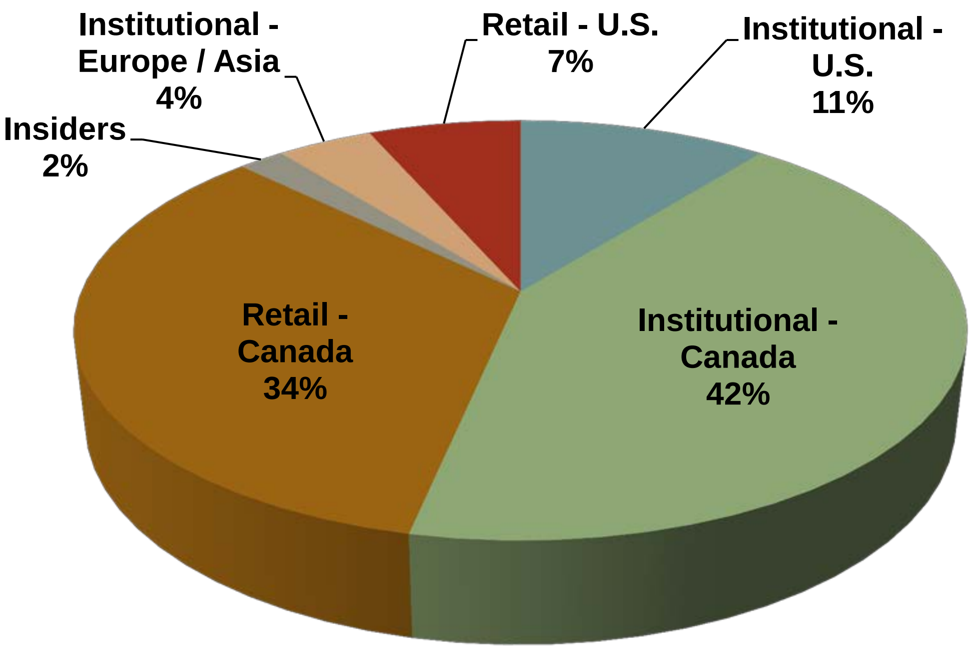
BAYTEX ENERGY CORP.

Other Commodities / FOREX Hedge Coverage

	Q4/2014	Q1/2014	FY 2015
Natural Gas			
% of Volumes Hedged at Fixed Price (1)	42%	32%	12%
Average Fixed Price (US$/mmBtu)	4.15	4.19	4.19
% of Volumes Hedged Using Collars (1)	12%	0%	0%
Average Collar Floor/Ceiling	3.90/4.50	-	-
Foreign Exchange			
% of Foreign Exchange Hedged	34%	19%	11%
Hedged Amount (US$ millions)	82.5	45.5	115.0
Average Protected Rate (CAD per USD)	1.0770	1.1040	1.1050
Average Collar Floor (CAD per USD)	1.0480	-	-
Interest Rate			
Hedged Amount (US$ millions)	0	0	0
Fixed Rate	-	-	-

(1) Percentage of volumes hedged are based on company production guidance, net of royalties (i.e., hedgeable volumes).

Share Ownership Breakdown



Ownership Breakdown

Institutional	57%
Retail	41%
Insiders	2%
	100%
Canada	76%
U.S.	18%
Europe/Asia	4%
Insiders	2%
	100%

Baytex shareholder base, estimated as at September 1, 2014. Sources: IPREO and Baytex internal data.

Ownership breakdown is based on fully-diluted shares.

Capital Program Efficiency

	2011	2012	2013	3-Year Average 2011-13
Capital Expenditures ($millions)				
Exploration and development	367.9	418.6	550.9	1,337.4
Acquisitions (net of dispositions)	148.8	(170.9)	(39.1)	(61.2)
Total	516.6	247.7	511.8	1,276.1
Proved plus Probable Reserve Additions (mboe)				
Exploration and development	30,033	33,659	48,396	112,628
Acquisitions (net of dispositions)	11,415	25,523	(1,540)	35,398
Total	41,448	59,182	47,396	147,027
Finding & Development (F&D) Costs ($/boe) (1)	19.02	19.69	19.30	19.34
Finding, Development & Acquisition (FD&A) Costs ($/boe) (1)	18.57	11.51	18.28	15.65
Ratios – based on Proved plus Probable Reserves				
Production Replacement	227%	300%	227%	251%
Recycle Ratio	1.9x	2.7x	1.8x	2.1x

(1) Includes Change in Future Development Costs (“FDC”)

Contact Information

BAYTEX ENERGY CORP.

Suite 2800, Centennial Place
520 – 3rd Avenue S.W.
Calgary, Alberta T2P 0R3

T: (587) 952-3000   1-800-524-5521

www.baytexenergy.com

James L. Bowzer
President & Chief Executive Officer
(587) 952-3000

Rodney D. Gray
Chief Financial Officer
(587) 952-3160

Brian G. Ector
Senior Vice President, Capital Markets and Public Affairs
(587) 952-3237