

Canaccord Genuity Global Energy Conference



Miami Beach, Florida

October 12, 2011

Anthony Marino, President & Chief Executive Officer

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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.

Specifically, this presentation contains forward-looking statements relating to: our dividend policy; our effective cash income tax rate for years 2010 to 2015; our organic production growth rate for years 2011 to 2015; our production mix in 2015; our ability to fund our capital expenditures and dividends on our common shares from funds from operations; oil and natural gas production in 2011; production growth rates; capital expenditures; drilling and operational plans; reserves and reserve life index; the net present value of our reserves and contingent resource; our Seal heavy oil resource play, including original oil in place, the viability and economics of long-term commercial development using primary (cold) and thermal development, number of potential drilling locations, drilling and completion costs, initial production rates, estimated recoverable reserves, finding and development and operating costs, recovery factors, production efficiency ratios, steam-oil ratios, the timing of completing a commercial scale thermal development using a 10-well module; and our assessment of the cyclic steam pilot projects at Harmon Valley and Cliffdale; our Lloydminster heavy oil property, including reserve life index, 2011 capital expenditures, drilling and operational plans for 2011, number of potential drilling locations, efficiency ratios, netbacks and recycle ratios; our Kerrobert steam-assisted gravity drainage project, including steam-oil ratios, number of potential drilling locations, expansion of steam capacity, capital expenditures and estimated recoverable reserves; rates of return for our heavy oil projects; profit/investment ratios for North American resource plays; pricing differentials between light, medium and heavy gravity crude oils; international heavy oil production; proposed pipeline infrastructure development; the supply of crude oil from Western Canada; pipeline capacity for Western Canadian crude oil; refining and upgrading capacity for heavy oil; the demand and supply outlook for heavy oil; our Bakken/Three Forks and Viking light oil resource plays, including initial production rates, estimated recoverable reserves, drilling and completion costs per well, the number of potential drilling locations, rates of return, number of prospective sectors of land and drilling and operational plans for 2011; the existence, operation and strategy of our risk management program, including the portion of future exposures that have been hedged; our debt to EBITDA, debt to funds from operations, interest coverage, debt to reserves and debt to enterprise value ratios; our 2011 funds from operations; our 2011 year-end debt to funds from operations ratio; the sensitivity of our 2011 funds from operations to changes in West Texas Intermediate oil prices, natural gas prices, heavy oil differentials and Canada-United States foreign exchange rates; the taxation of our dividends; and our valuation based on various metrics customarily used in the oil and gas industry relative to other oil-weighted Canadian producers. 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. The level of future cash dividends will depend on the amount of funds from operations generated by our operations and our prevailing financial circumstances at the time.

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 oils; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; 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; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period 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: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and gas operations; changes in royalty rates and incentive programs relating to the oil and gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; and other factors, many of which are beyond the control of Baytex. 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, 2010, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast 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.

This presentation contains estimates as of May 1, 2011 of the volumes of, and the net present value of the future net revenue from, the "contingent resource" for three of our oil resource plays: the Bluesky in the Seal area of Alberta; the Bakken/Three Forks in North Dakota; and the Viking in southeast Alberta and southwest Saskatchewan. These estimates were prepared by our independent qualified reserves evaluator, Sproule Associates Limited ("Sproule").

"Contingent resource" is not, and should not be confused with, petroleum and natural gas reserves. "Contingent resource" is 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 resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

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

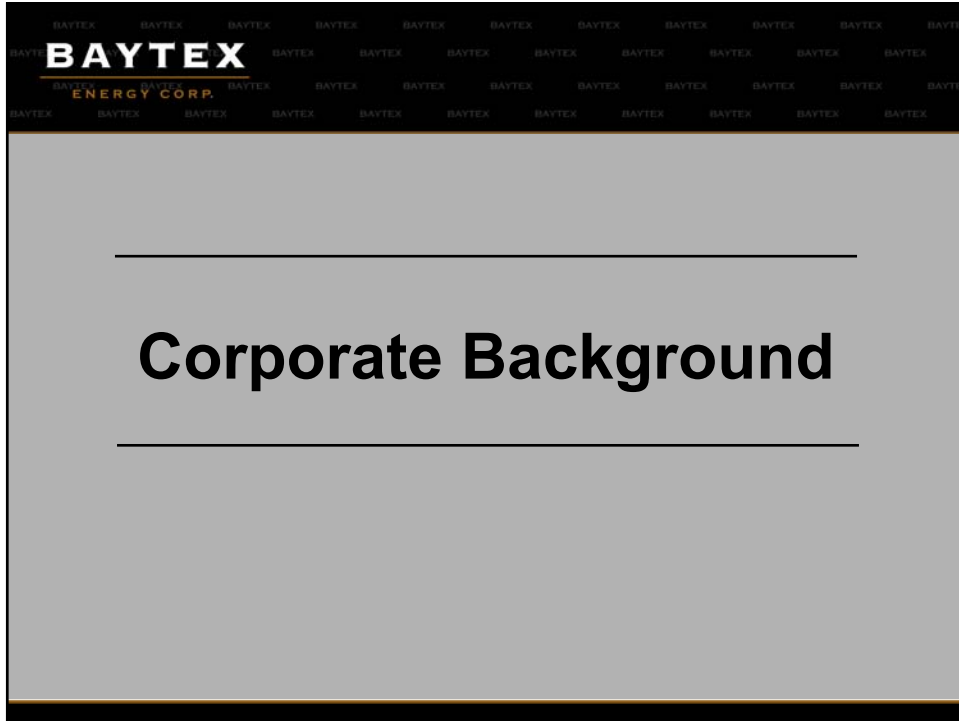
The primary contingencies which currently prevent the classification of the contingent resource as reserves consist of: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; access to capital markets; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices; demonstration of economic viability; 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 resource or that Baytex will produce any portion of the volumes currently classified as contingent resource. The estimates of contingent resource involve implied assessment, based on certain estimates and assumptions, that the resource described exists in the quantities predicted or estimated and that the resource can be profitably produced in the future. The net present value of the future net revenue from the contingent resource does not necessarily represent the fair market value of the contingent resource.

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

Baytex has adopted the standard of 6 Mcf:1 BOE when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

- **Sustainable model: Income return + oil growth**
- **Sector-leading capital efficiency**
- **Technical focus**
- **Long-term, low-cost development inventory**
 - **Significant potential in both heavy and light oil resource plays**
 - **High oil weighting, but diversified within oil complex**
- **Conservative payout ratio and strong balance sheet**
- **Long-term market out-performance and compelling valuation**



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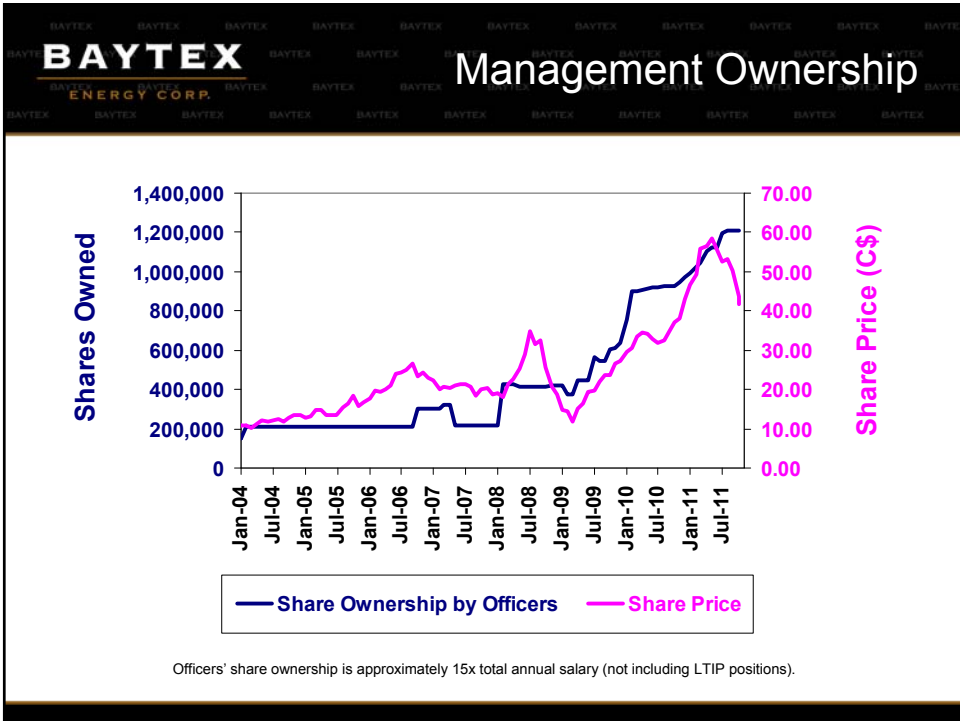
Capital Markets Information

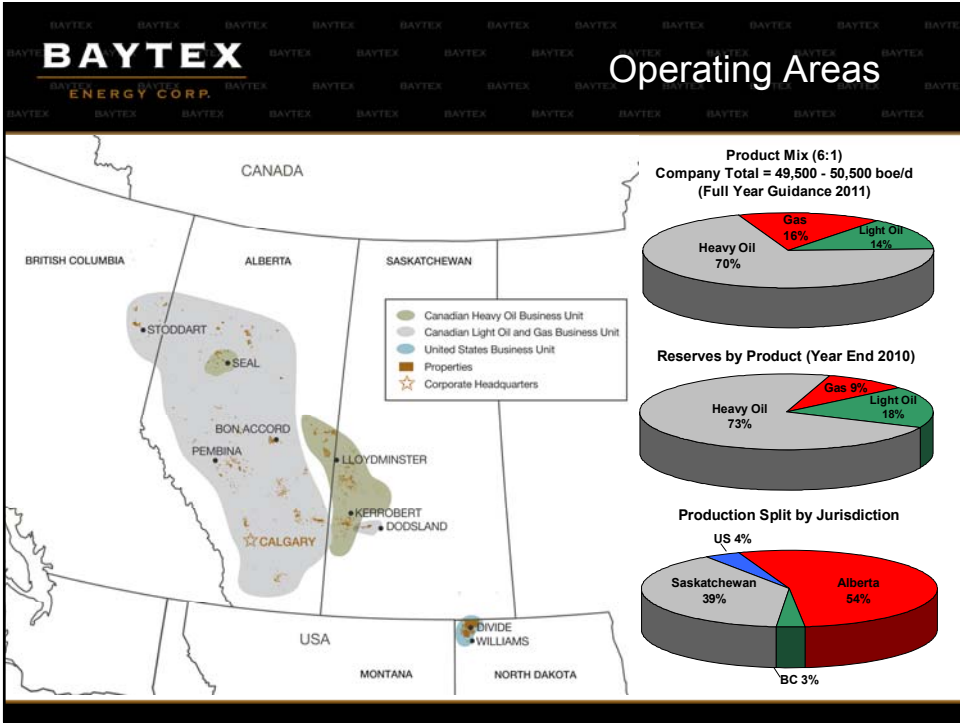
Common Shares	
Trading Symbol	TSX / NYSE: BTE
Average Daily Volume ⁽¹⁾	TSX: 739,400 / NYSE: 412,700
Shares Outstanding (Current)	116.8 million
Market Value of Equity / Enterprise Value	C\$4.9 billion / C\$5.6 billion
Monthly Dividend	C\$0.20/share
Cash-on-Cash Yield ⁽²⁾	5.7%
Cumulative Cash Distributions / Dividends	C\$1.2 billion
9.15% Series A Senior Unsecured Debentures ⁽³⁾	
Principal Outstanding	C\$150 million
Maturity Date	August 2016
Current Price / Yield-to-Worst	\$107.38 / 6.6%
6.75% Series B Senior Unsecured Debentures	
Principal Outstanding	US\$150 million
Maturity Date	February 2021
Current Price / Yield-to-Worst	\$100.81 / 6.7%

⁽¹⁾ Average daily trading volumes for September, 2011. Volumes are a composite of all exchanges in Canada and the U.S.
⁽²⁾ The cash-on-cash yield is calculated by dividing the annualized dividend of C\$2.40 by the closing price of Baytex shares of C\$41.82 on the TSX on October 3, 2011.
⁽³⁾ The US\$180 million 9.625% Senior Subordinated Notes due July 15, 2010 were redeemed on September 25, 2009.

BAYTEX **Corporate History**
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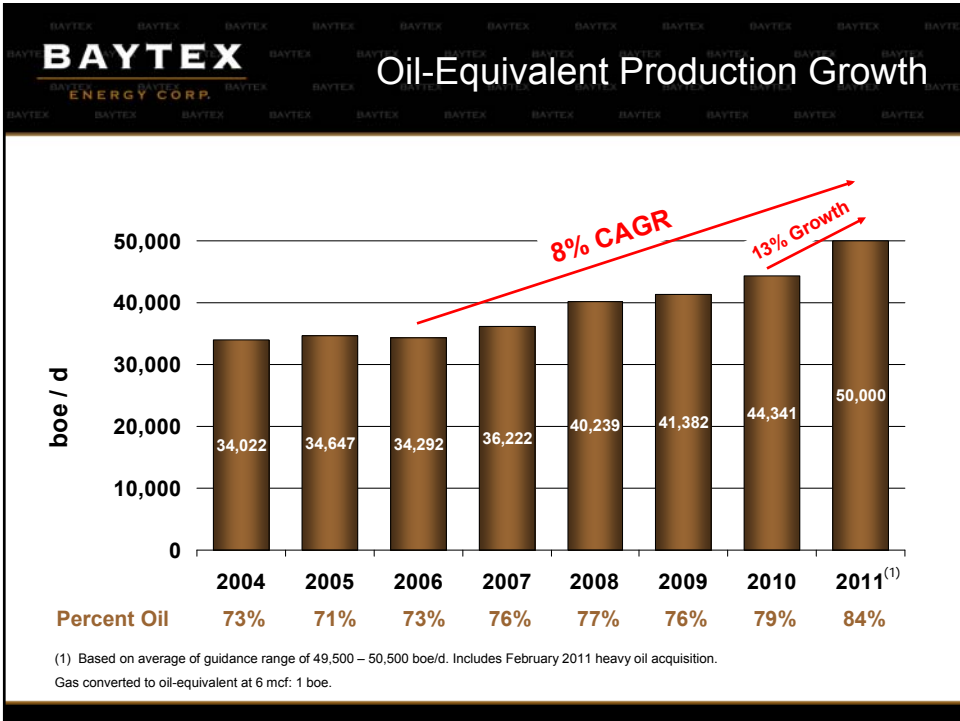
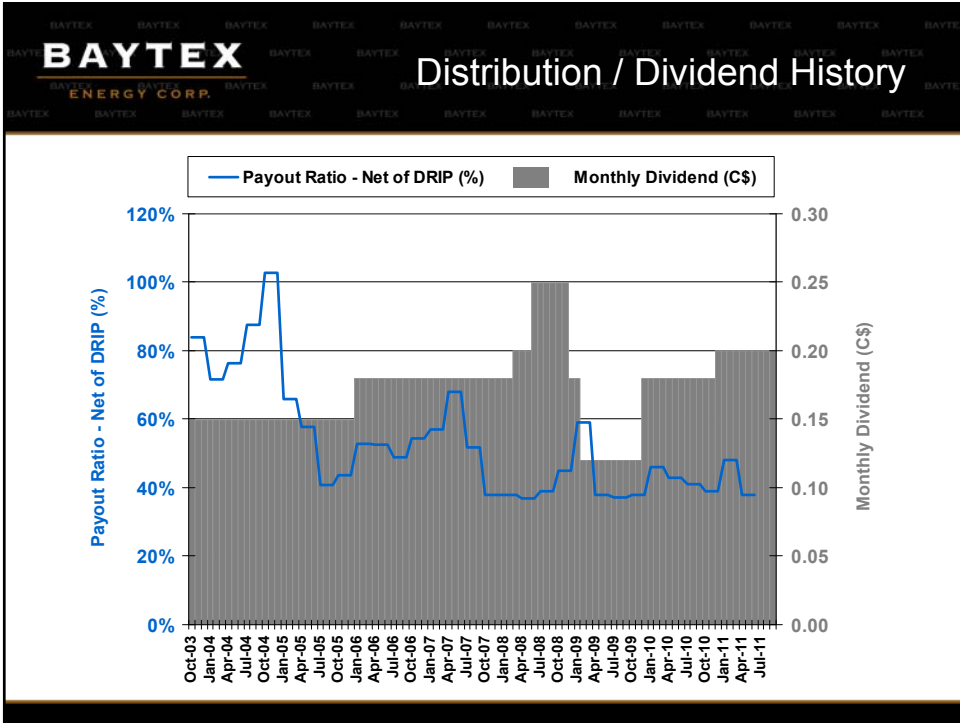
- **Baytex Energy Ltd. – Publicly-traded E&P corporation from 1993-2003**
 - One of only six independent E&P names from 1993 that are still traded on the TSX
 - Heavy oil emphasis and infrastructure development began in 1997
- **Baytex Energy Trust – Income trust from 2003-2010**
 - Baytex Energy Trust and Crew Energy Inc. created from Baytex Energy Ltd.
 - BTE listed on NYSE in March 2006
 - Highest total return among oil and gas trusts during Baytex Energy Trust era
- **Baytex Energy Corp. – Publicly-traded E&P corporation since January 2011**
- **Desirable attributes for an energy investment regardless of legal structure**

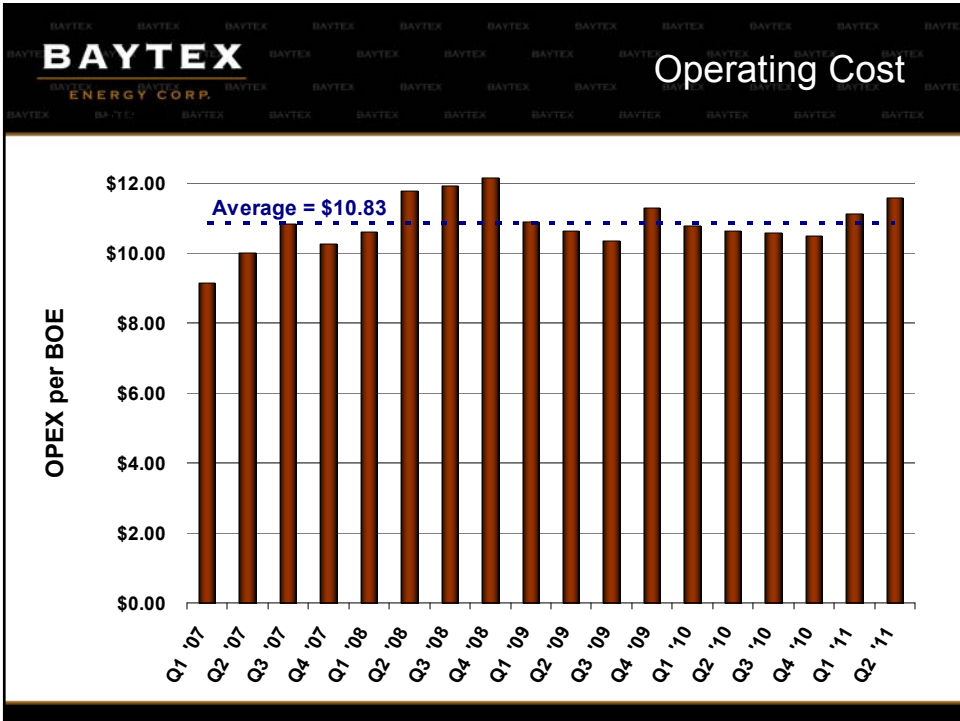
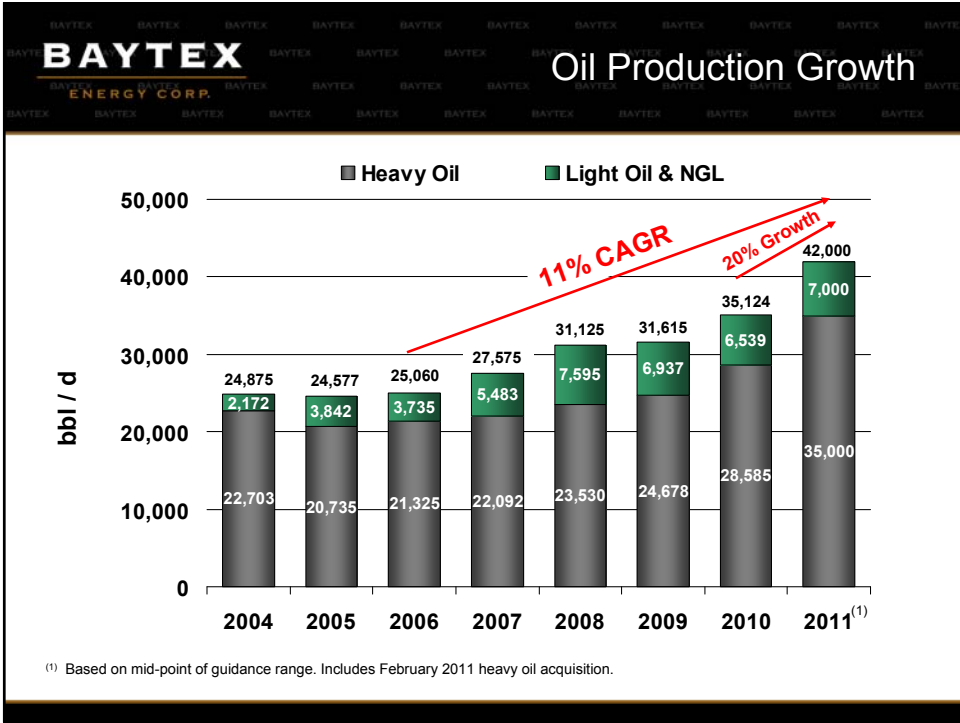




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Historical Performance





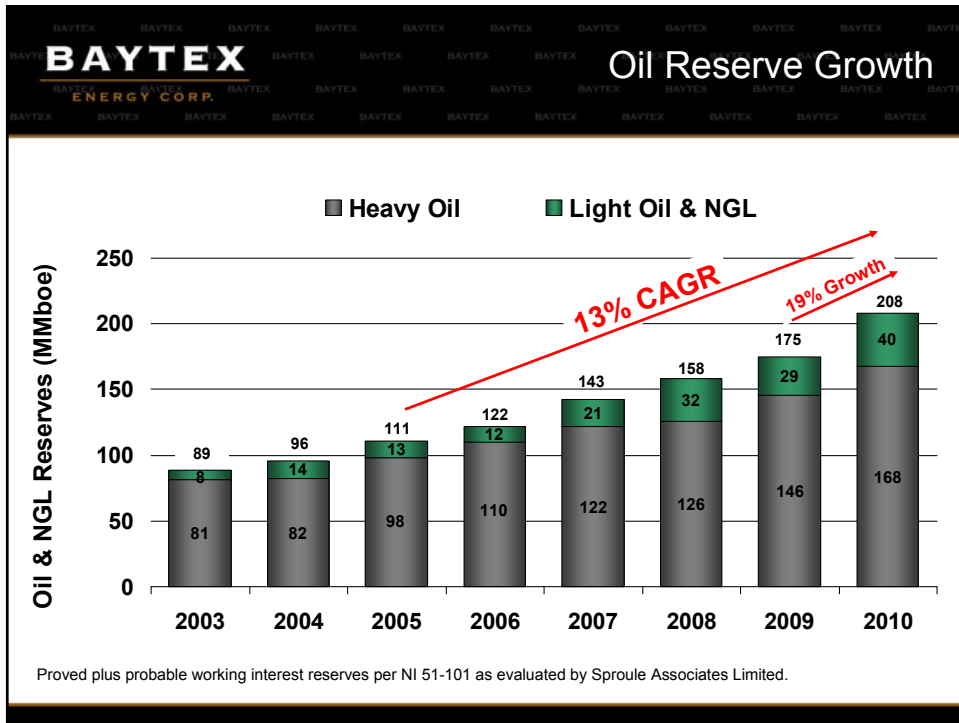
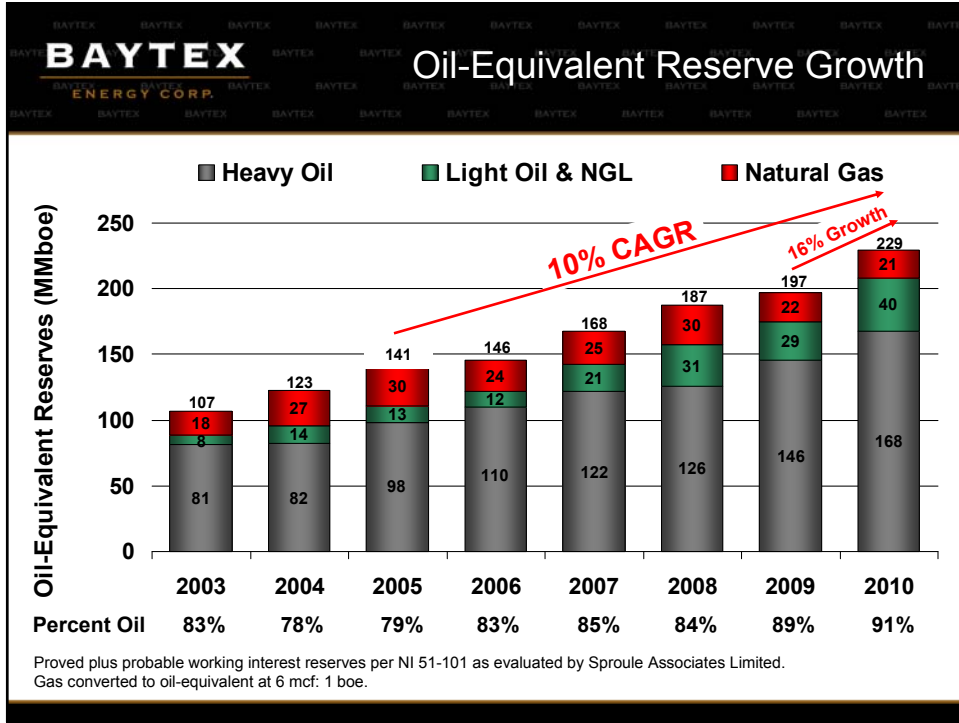
Capital Program Efficiency

	2008	2009	2010	3-Year Average 2008-10	5-Year Average 2006-10	Trust Era 2004-10
FD&A Cost (P + P) ⁽¹⁾						
Excluding FDC (C\$/boe)	13.11	11.63	5.90	9.54	9.59	9.00
Including FDC (C\$/boe)	16.06	21.00	13.17	15.92	14.99	13.61
Recycle Ratio (P + P) ⁽¹⁾						
Excluding FDC	2.6	2.4	5.6	3.3	3.1	3.0
Including FDC	2.1	1.3	2.5	2.0	2.0	2.0
CAPEX as a % of FFO ⁽²⁾						
Exploration & Development	43%	49%	52%	48%	49%	51%
Acquisitions	61%	40%	10%	37%	39%	42%
Total	104%	89%	62%	85%	88%	93%
Production Replacement (P+P)						
Exploration & Development	119%	113%	271%	170%	157%	142%
Acquisitions	114%	52%	26%	63%	68%	84%
Total	233%	165%	297%	233%	225%	226%

⁽¹⁾ Includes both E&D and acquisition CAPEX.

⁽²⁾ Funds From Operations ("FFO") includes realized hedging gains / losses.

Reserves / Contingent Resources



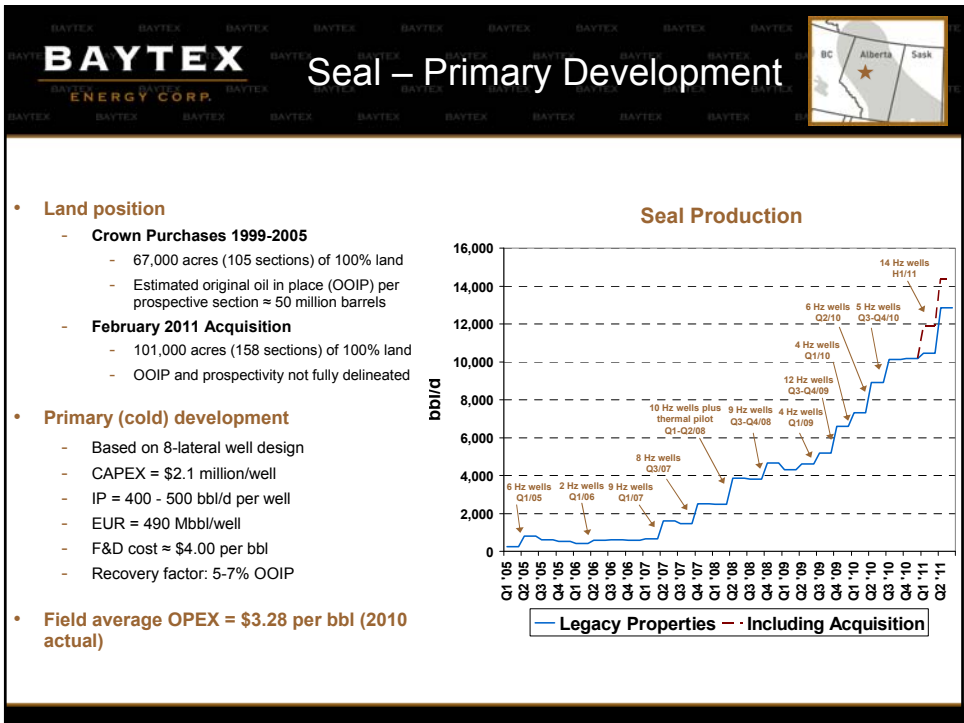
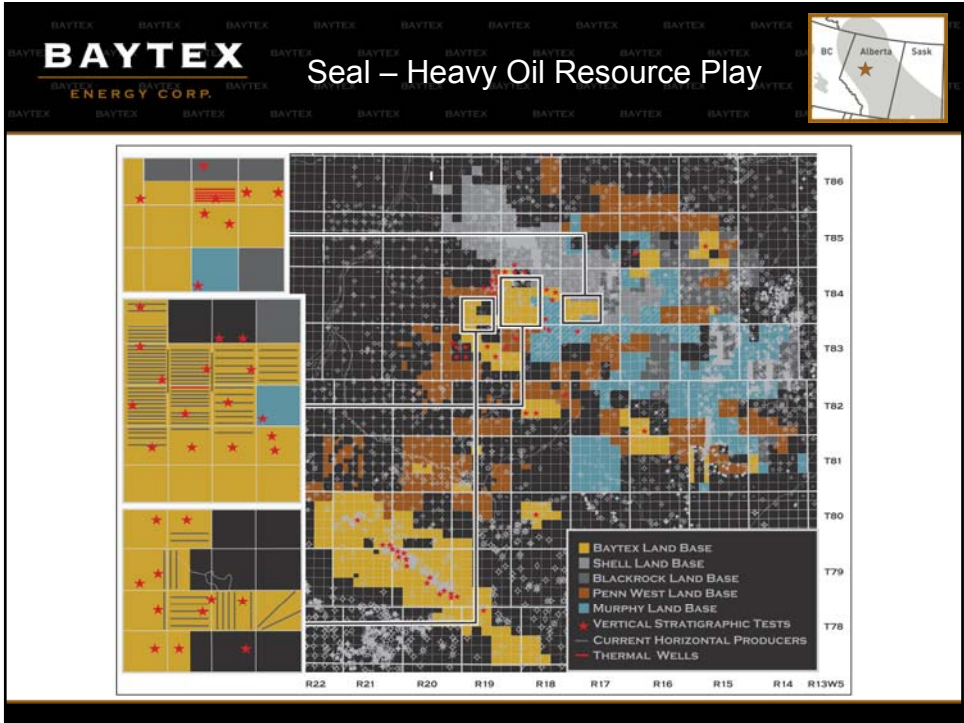
BAYTEX ENERGY CORP.			
Contingent Resource Assessment (Recoverable Volumes From Three Resource Plays)			
(millions of barrels of oil equivalent and bitumen) ⁽¹⁾	Contingent Resources ⁽²⁾ As at May 1, 2011		
	Low (C1) <u>Estimate</u>	Best (C2) <u>Estimate</u>	High (C3) <u>Estimate</u>
Bluesky – Seal, Alberta (excluding 2011 acquisition)	478	583	846
Bakken/Three Forks – Divide/Williams County, ND, USA	59	138	254
Viking			
Redwater, Alberta	6	12	23
Dodsland/Kerrobert, Saskatchewan	<u>5</u>	<u>12</u>	<u>25</u>
Viking Total	<u>11</u>	<u>24</u>	<u>48</u>
Total	548	745	1,148
Percent Oil	99%	98%	98%

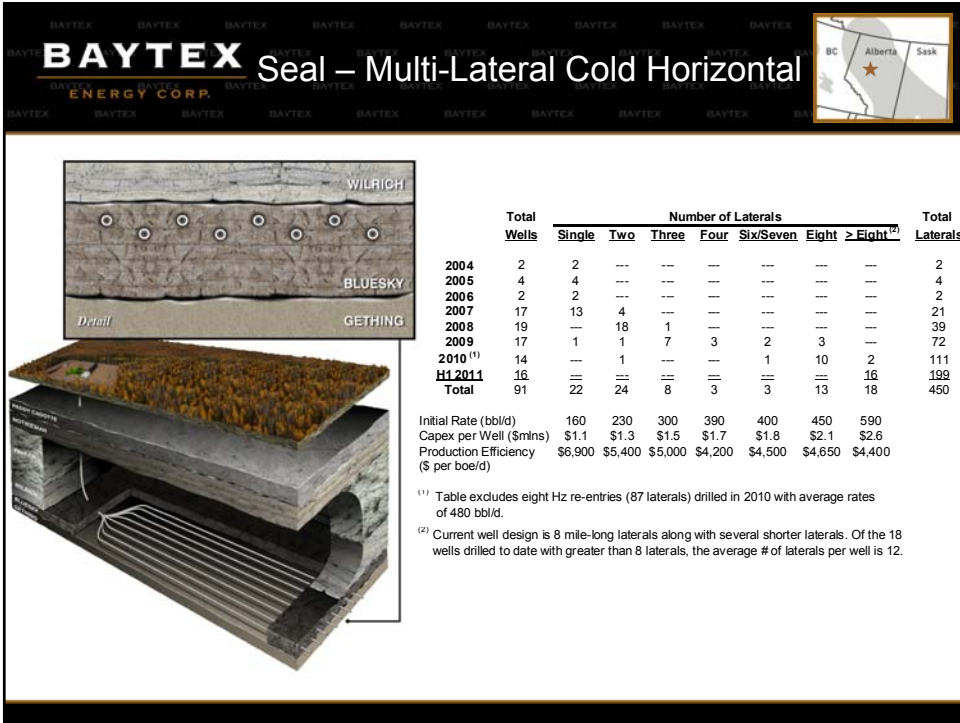
⁽¹⁾ Under National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"), naturally occurring hydrocarbons with a viscosity greater than 10,000 centipoise are classed as bitumen. The majority of the contingent resource at Seal expected to be recovered by thermal processes has a viscosity greater than this value; therefore, this component of the contingent resource is classified as bitumen under NI 51-101.

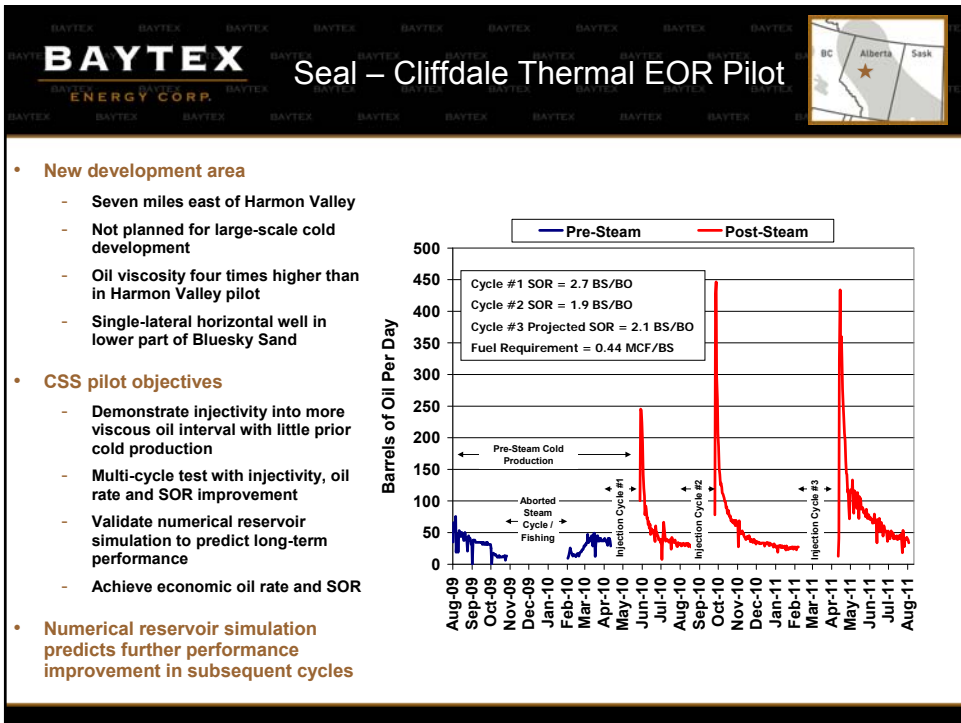
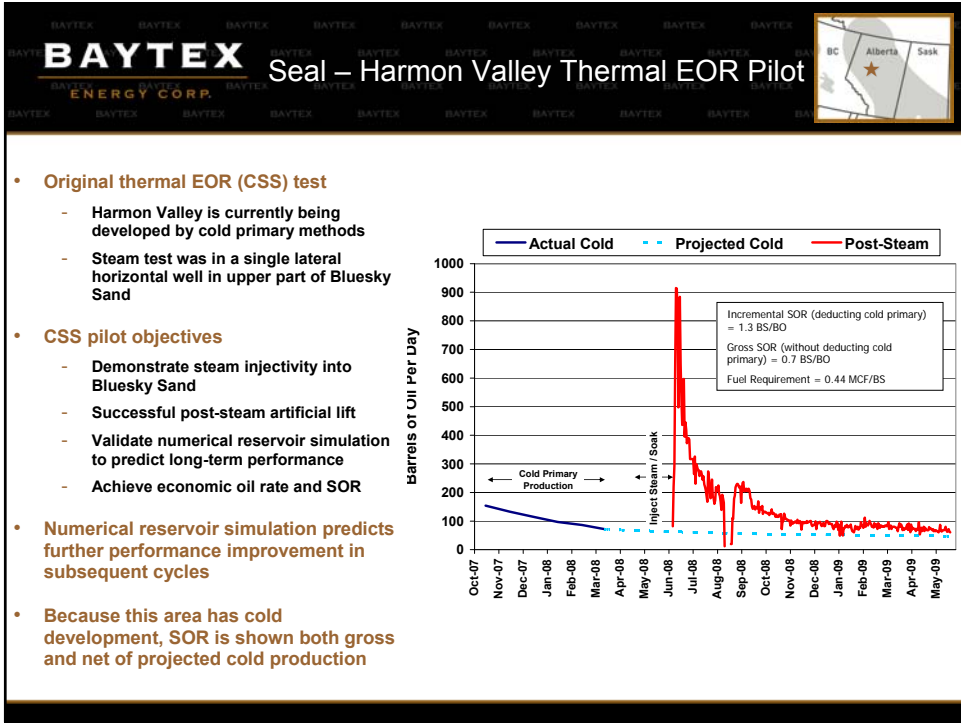
⁽²⁾ Sprule prepared the estimates of contingent resource shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table.

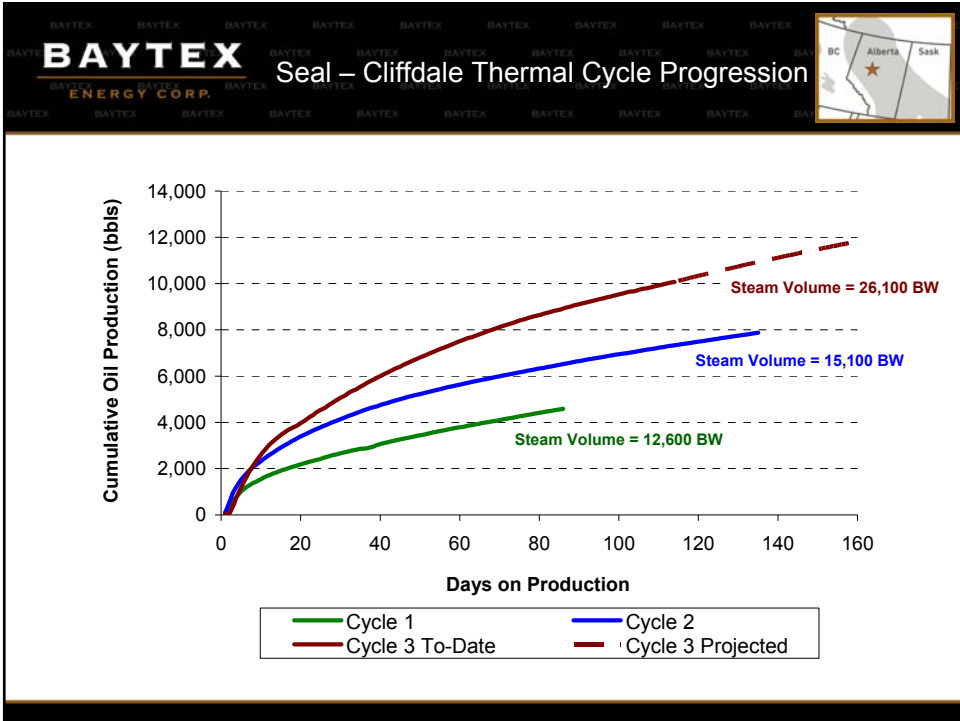
See "Advisory – Oil and Gas Information" for more information about contingent resources.

BAYTEX ENERGY CORP.			
<hr/> <h1 style="margin: 0;">Heavy Oil Projects</h1> <hr/>			









BAYTEX ENERGY CORP. Seal – Reserves Recognition

	Dec 31/05	Dec 31/06	Dec 31/07	Dec 31/08	Dec 31/09	Dec 31/10
Reserves (MMbbl)						
Total Proved	2.2	8.5	20.2	27.0	31.2	45.0
Proved plus Probable	4.0	13.0	28.7	39.2	54.7	83.9
Locations Assigned Reserves						
Proved Producing	6	8	25	44	60	77
Total Proved	14	62	103	106	137	167
Proved plus Probable	20	64	109	134	196	218
Land Assigned Reserves						
Sections (640 acres)	4	8	12	15	20	23

Notes: Proved volumes for 2010 include 5.1 MMbbls of thermally-enhanced oil recovery covering approximately one half section of land (20 locations). Proved plus probable volumes for 2010 include 30.3 MMbbls of thermally-enhanced oil recovery covering approximately 1.5 sections of land (60 locations). All other reserve volumes are for cold development.

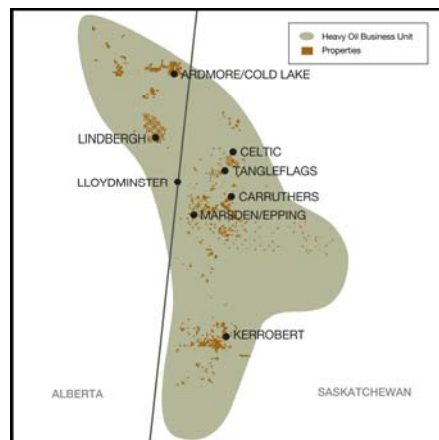
Contingent Resource Assessment for Seal, prepared by Sproule Associates Limited as at May 1, 2011 = 478.3 MMboe of oil and bitumen (low estimate), 583.3 MMboe of oil and bitumen (best estimate) and 845.9 MMboe of oil and bitumen (high estimate). See "Advisory – Oil and Gas Information" for more information about contingent resources.



**Baytex Seal Thermal Project
Non-Mining Oil Sands Development**



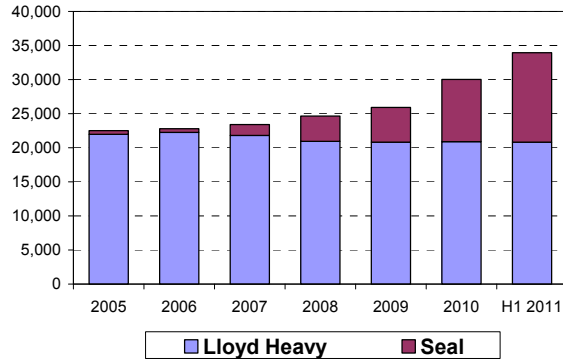
- H1 2011 Production = 20,800 boe/d (44% of total Baytex volumes)
- Oil Gravity = 11 to 18 °API
- YE 2010 Reserves (2P) = 85 mmboe (37% of total Baytex reserves)
- Reserve Life Index (2P) = 11.2 years
- Land Position = 513,600 net acres
- 2010 Drilling: 67 gross (56.7 net) wells
95% success rate
40% horizontal wells
- 2011 E&D CAPEX: ≈ \$90 million
- 2011 Drilling: ≈ 90 gross (85 net) wells
≈ 50% horizontal wells



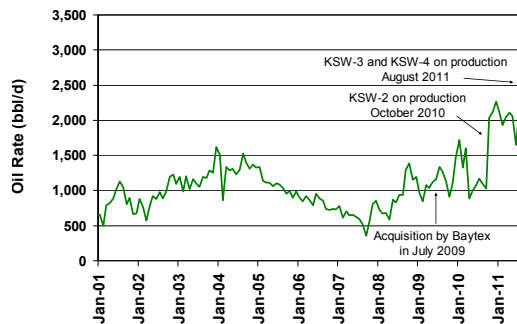


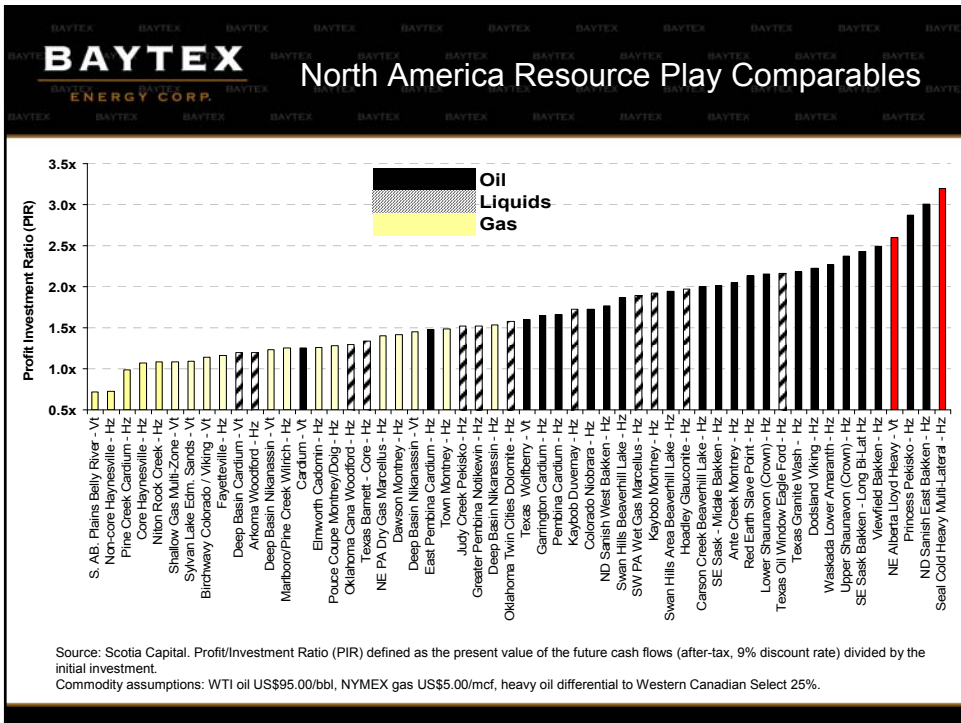
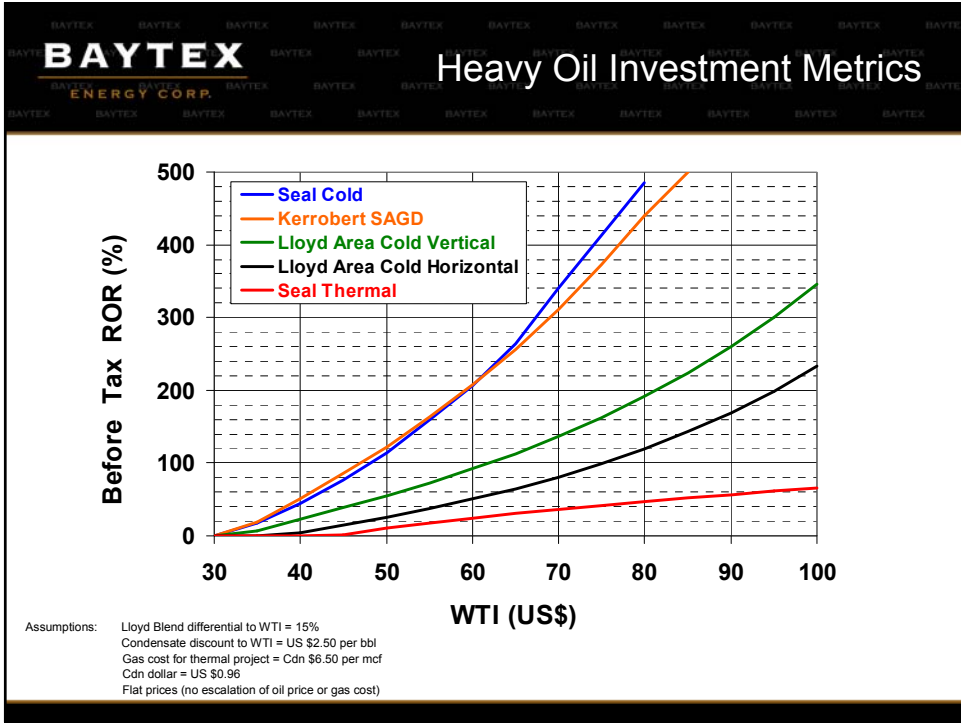
- > 5 year drilling inventory
- Drilling inventory has increased by 75% over the past five years
- Development includes vertical & horizontal cold / waterflood / thermal (SAGD)
- Efficiency ratios (half cycle):
 - \$12,100 per boe/d
 - \$10.10/boe based on 2P reserves
- 2010 netback of \$34.50/boe generates a recycle ratio of 3.4x

Area Production (boe/d)



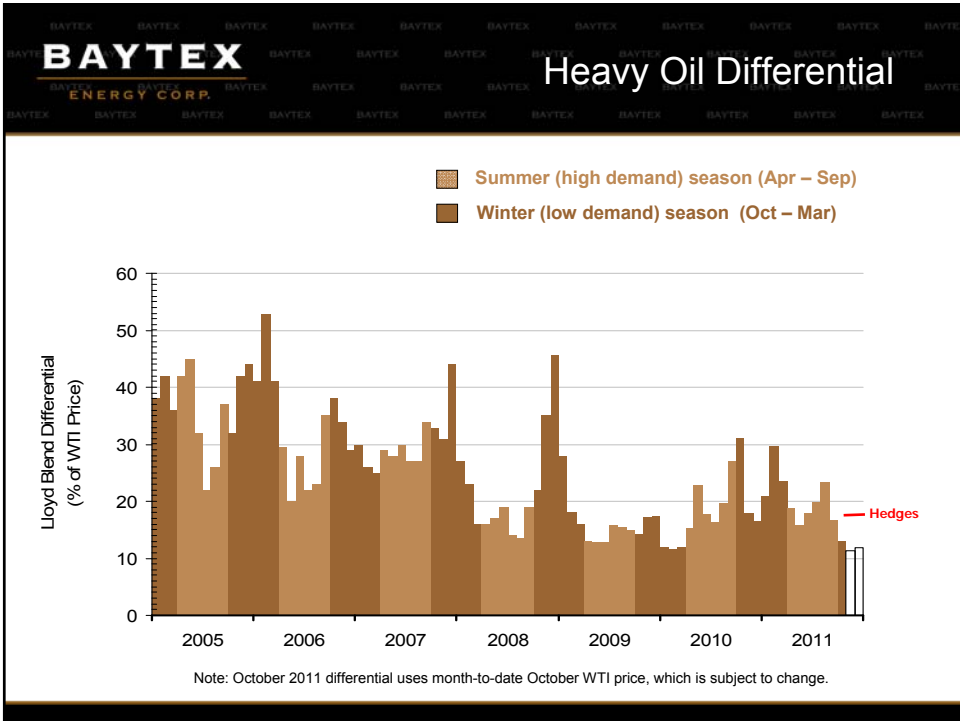
- **Obtained as part of SW Saskatchewan acquisition in July 2009**
- **Baytex redevelopment to date**
 - Drilled, completed and equipped 3 new well pairs and 2 stratigraphic tests
 - Expanded steam distribution system
 - Optimized steam use from existing plant
 - Total CAPEX to date = \$19 million
 - Current field SOR = 2.2 (based on dry steam)
- **Planned future development**
 - 9 new well pairs and 4 stratigraphic tests
 - 67% steam capacity expansion via feedwater pre-heater
 - Total future CAPEX = \$40 million
 - Oil to be developed = 8.4 million bbls (2P reserves)

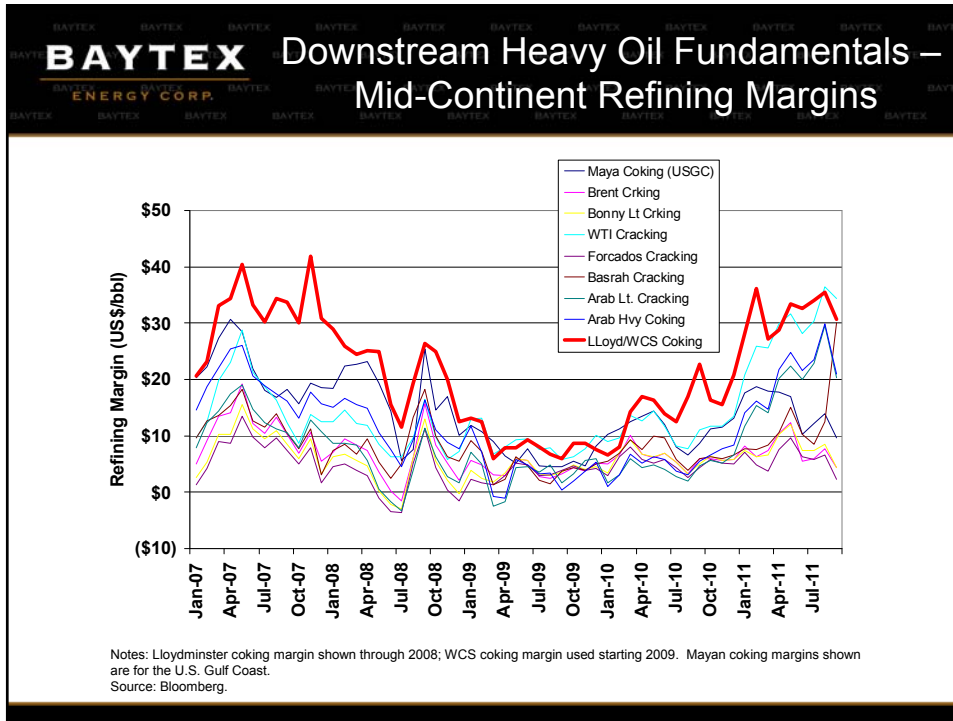






Heavy Oil Pricing





BAYTEX Heavy Oil Demand – Supply Balance

- Refinery/upgrader expansions to run additional heavy blend and raw heavy oil**
 - Does not include potential US Gulf Coast refinery demand
 - Values shown are average additional capacity during each calendar year

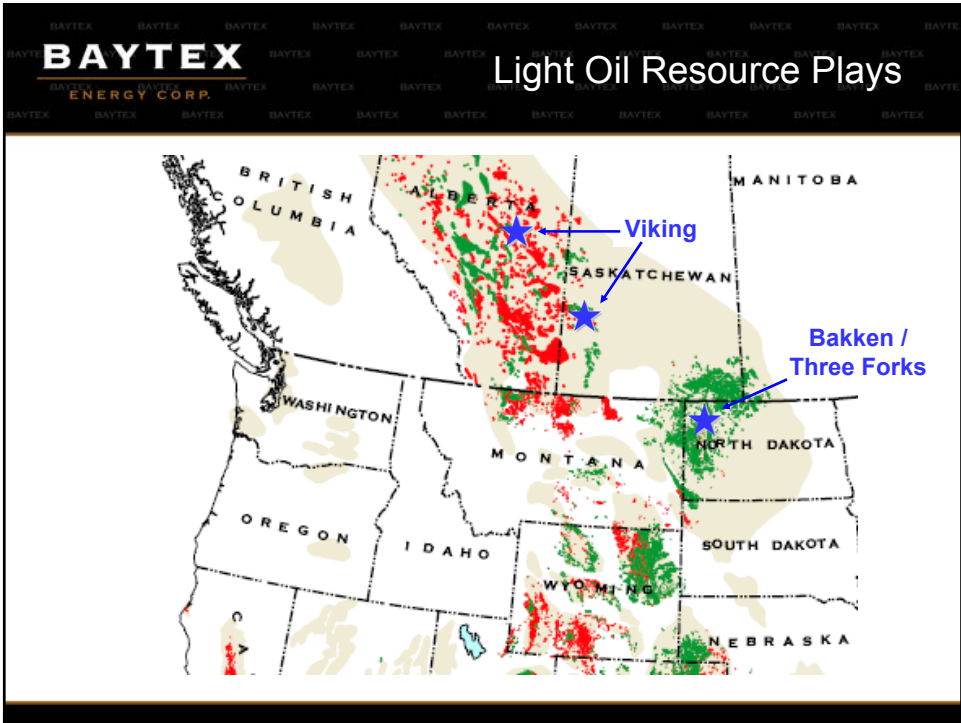
	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
Conoco Wood River Refinery (CORE Project)	15	135	-	-	-
Marathon Detroit Refinery (HOUP)	-	20	60	-	-
BP Whiting Refinery (Modernization Project)	-	-	120	120	-
Holly Artesia (Navajo Refining)	15	-	-	-	-
Canadian upgraders raw heavy (Shell AOSP, CNRL/NW Upgrader)	100	-	-	10	40
Annual heavy refining capacity growth (thousand bbls/d)	130	155	180	130	40
- CAPP demand/supply forecast supports tightening heavy blend market**
 - Does not include incremental demand from PADD III (excludes impact of Keystone XL and potential Cushing-to-Gulf Coast pipelines)

	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
CAPP heavy blend annualized demand growth (thousand bbls/d)	142	67	120	218	114
CAPP heavy blend annualized supply growth (thousand bbls/d)	32	87	112	207	92
Annualized net demand growth (thousand bbls/d)	110	(20)	8	11	22
Cumulative net demand growth (thousand bbls/d)	110	90	98	109	131

Sources: Canadian Association of Petroleum Producers "Crude Oil Forecast, Markets and Pipelines Report" (June 2011), Macquarie Capital (USA) Inc. and internal Baytex research.

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Light Oil Projects



	Light Oil Resource Potential						
	Initial Rate ⁽¹⁾ (Boe/d / well)	Estimated Recovery ⁽¹⁾ (Mboe/well)	Well Cost ⁽¹⁾ (\$Mln/well)	Potential Net Locations ⁽¹⁾	Contingent Resource ⁽²⁾ (millions of barrels of oil)		
					Low (C1) Estimate	Best (C2) Estimate	High (C3) Estimate
Bakken / Three Forks ⁽³⁾	420	420	US\$5.7	100 - 300	59.2	138.1	253.8
Viking (AB) ⁽⁴⁾	100	100	C\$1.3	105	5.4	11.3	22.7
Viking (SK) ⁽⁴⁾	60	50	C\$1.1	230	<u>5.1</u>	<u>12.2</u>	<u>25.7</u>
Total					69.7	161.6	302.2

⁽¹⁾ Initial 30-day rate, estimated recovery per well, well cost, and potential net locations all reflect Baytex internal estimates.

⁽²⁾ Contingent Resource Assessment prepared by Sproule Associates Limited as at May 1, 2011. See "Advisory – Oil and Gas Information" for more information about contingent resources.

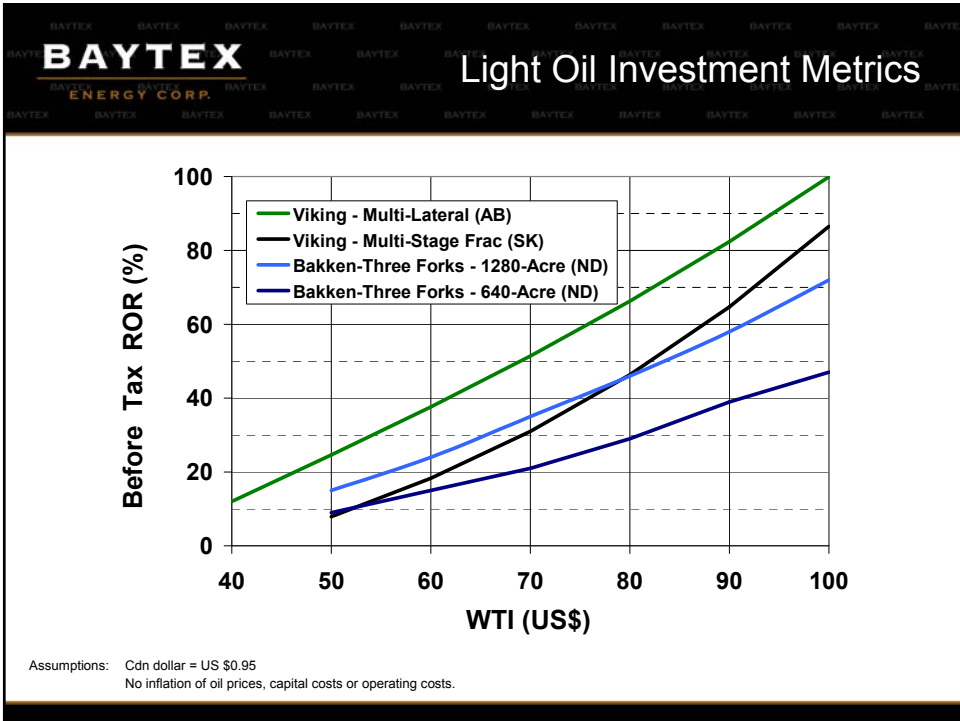
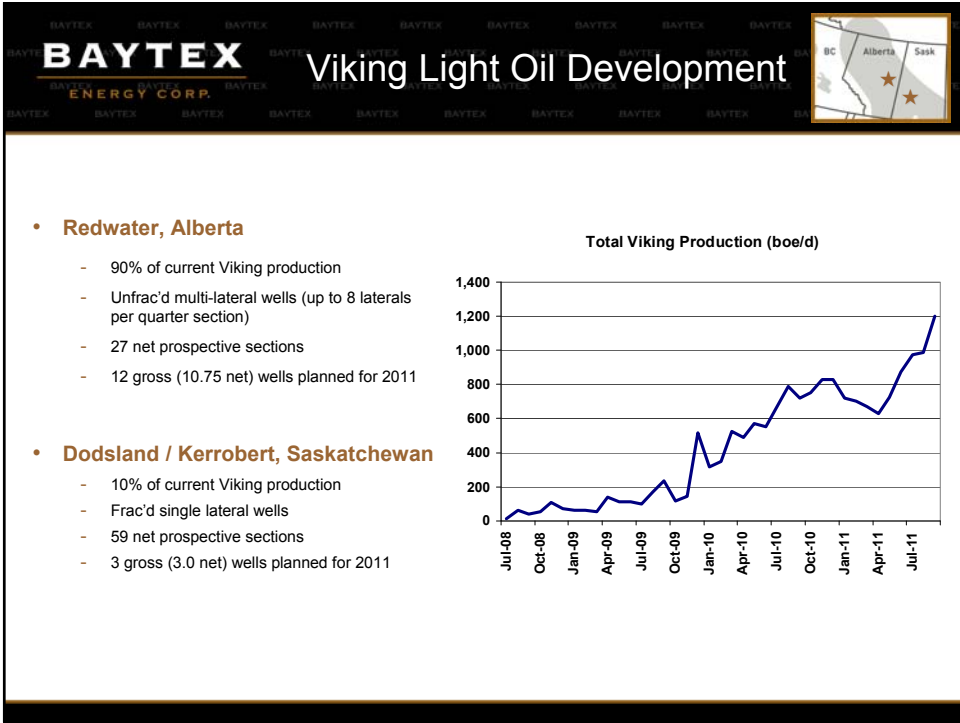
⁽³⁾ Bakken-Three Forks initial rate and EUR based on 1280-acre well (two-mile long) performance. Potential net locations based on spacing of 1 to 3 wells per 2-section drilling spacing unit (DSU).


⁽⁴⁾ Alberta Viking uses unfrac'd multi-lateral wells; Saskatchewan Viking uses frac'd single lateral wells.

BAYTEX Bakken / Three Forks Light Oil


- 132,000 net acres in Bakken / Three Forks Play
- 95% of net acreage is in North Dakota / 5% is in SE Saskatchewan
- Approximately 55% of acreage is Baytex-operated
- Approximately 57% of current production is Baytex-operated

Baytex Lands





Hedging


Hedge Coverage

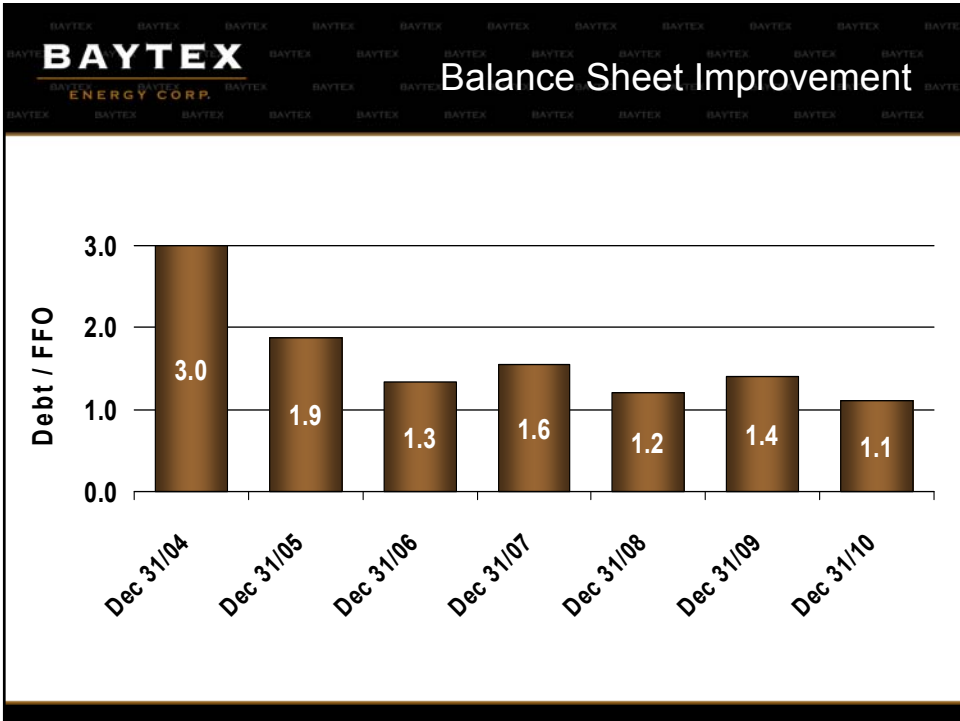
	2nd Half <u>2011</u>	Full-Year <u>2012</u>	Full-Year <u>2013</u>	Full-Year <u>2014</u>
WTI Crude Oil				
% of Crude Oil Volumes Hedged ⁽¹⁾				
Fixed Price (<i>2H2011 average: US\$91.17/bbl, 2012 average: US\$92.46/bbl</i>)	29%	18%	0%	0%
Costless Collars (<i>Floor-Ceiling: 2011: US\$85.00/bbl - US\$117.00/bbl, 2012: US\$97.50/bbl - US\$105.92/bbl</i>)	16%	4%	0%	0%
	45%	21%	0%	0%
Heavy Oil Differentials				
% of Heavy Oil Volumes Hedged ⁽¹⁾	39%	20%	21%	6%
Equivalent Fixed Differential to WTI (US\$/bbl)	15.67	17.42	18.67	19.36
Equivalent Percent Differential, % of WTI	18.2%	20.7%	21.4%	22.1%
<i>(equivalent differentials using WTI prices: 2H2011: US\$86.18/bbl, 2012: US\$84.18/bbl, 2013: US\$87.27bbl, 2014: US\$87.47bbl)</i>				
Natural Gas				
% of Natural Gas Volumes Hedged ⁽¹⁾				
Costless Collars (<i>Floor-Ceiling: 2011 C\$5.80/mcf - C\$7.49/mcf</i>)	6%	0%	0%	0%
Fixed Price (<i>Average Price: 2011: C\$4.76/mcf, 2012: C\$4.39/mcf</i>)	31%	17%	0%	0%
Sold Calls (<i>Average Strike/Premium: 2011: US\$5.67mmbtu/ US\$0.50mmbtu; 2012: US\$5.25mmbtu/ US\$</i>	15%	15%	0%	0%
Total Natural Gas	52%	32%	0%	0%
Condensate Purchases				
% of Condensate Requirement Purchased	46%	0%	0%	0%
Equivalent Premium (Discount) to WTI (US\$/bbl)	2.18			
Foreign Exchange				
% of Foreign Exchange Hedged	37%	18%	9%	0%
Hedged Amount (US\$ millions)	151	151	70	0
Average Swap Rate (USD/CAD)	0.9699	0.9747	0.9919	-

⁽¹⁾ Percentage of 2011 volumes hedged are based on 50,000 boe/d (mid-point of company guidance), net of royalties (i.e., hedgeable volumes).

⁽²⁾ Average WTI collar ranges are: **2011:** US\$89.46/bbl (floor) and US\$95.66/bbl (ceiling), and **2012:** US\$98.92/bbl (floor) and US\$104.92/bbl (ceiling). See notes to financial statements for individual collar contracts.

BAYTEX ENERGY CORP.

Balance Sheet



	Dec 31 2004	Dec 31 2005	Dec 31 2006	Dec 31 2007	Dec 31 2008	Dec 31 2009	Dec 31 2010	Jun 30 2011
Credit Facility (C\$ Millions)								
Approved credit facility	250	250	300	370	485	515	550	700
Bank line undrawn	89	127	173	128	277	250	246	385
Debt to EBITDA	2.6	1.5	1.2	1.4	1.0	1.3	1.1	1.4 ⁽¹⁾
Debt to Funds From Operations	3.0	1.9	1.3	1.6	1.2	1.4	1.1	1.4 ⁽¹⁾
Interest Coverage Ratio	8.4	8.6	8.8	9.1	16.6	11.1	17.0	13.0 ⁽¹⁾
Debt / Reserves (\$/boe)								
Proved	4.89	4.18	3.58	3.83	4.24	3.67	3.92	4.66 ⁽²⁾
Proved + Probable	3.45	3.03	2.53	2.64	2.85	2.41	2.40	2.85 ⁽²⁾
Debt / Enterprise Value	33%	26%	18%	22%	27%	13%	9%	10%

(1) 12 month trailing, including pro forma 12 month contribution from assets acquired in H1 2011.
(2) Includes reserve volumes acquired in H1 2011.

Financial Projections

BAYTEX ENERGY CORP. **2011E Funds From Operations (C\$ Millions)**

		H2/11 Heavy Oil Differential (% of WTI)		
		10%	15%	20%
H2/11 WTI (US\$/bbl)	\$70	\$503	\$490	\$476
	\$80	\$536	\$521	\$505
	\$90	\$570	\$552	\$535

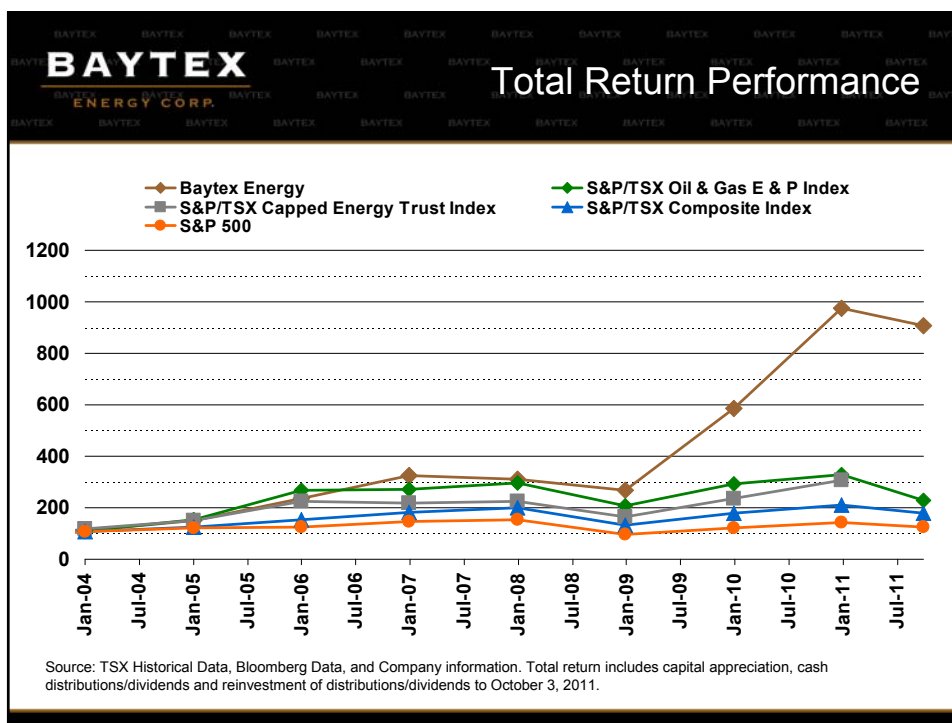
2011 Funds From Operations using October 6, 2011 strip = C\$540 million. Full-year prices for 2011 are WTI = US\$92.25/bbl, NYMEX = US\$4.11/mmbtu, FX = US\$1.004/C\$ and Heavy Oil Differential = 18.2% of WTI. Full-year 2011 WTI is a composite of US\$95.48/bbl January-September actual and US\$82.59/bbl based on the October-December forward strip. Full-year 2011 heavy oil differential is a composite of 20.4% January-September actual and 11.7% based on the October-December forward market.

Notes:

- (1) Table is constructed using first half actual FFO plus projected second half FFO at matrix prices.
- (2) Table assumes 2011 average NYMEX = US\$4.11/mmbtu and 2011 average FX = US\$1.004/C\$.
- (3) BTE 2011E cash requirements total \$562 million: E&D CAPEX = \$355 million and cash dividends net of dividend reinvestment plan = \$207 million (based on 25% DRIP participation).
- (4) Table includes impact of hedge positions (both financial and physical).

BAYTEX ENERGY CORP.

Relative Performance / Valuation



BAYTEX ENERGY CORP. Value Comparison to Oil-Weighted Canadian Corporations

	Baytex	EV-Weighted Group Average (Range)
EV / Production (C\$/boe/d)	\$112,500	\$138,700 (<i>\$22,400 – \$271,800</i>)
EV + FDC / P+P Reserves (C\$/boe)	\$29.89	\$27.84 (<i>\$3.98 – \$218.17</i>)
EV/DACF 2011(e)	9.4x	10.0x (<i>2.2x – 20.1x</i>)
Debt / CF 2011(e)	1.1x	1.6x (<i>0.0x – 3.1x</i>)
Yield 2011(e)	5.7%	5.7% (<i>0.0% – 14.2%</i>)
Oil Weighting	84%	82% (<i>63% – 100%</i>)

Source: Scotia Capital research as at October 3, 2011. Comparison group is Scotia Capital's Canadian oil-weighted producers group and includes Baytex, BlackPearl, Bonterra, Crescent Point, Emerge, Legacy, Longview, MEG, Penn West, PetroBakken, Pinecrest, Rock, Vermilion and Wild Stream. Average is based on enterprise value weighting. In calculating EV/P+P Reserves, Scotia Capital includes future development costs ("FDC") in the enterprise value.
2011 Commodity assumptions: WTI oil US\$92.72/bbl, Nymex gas US\$4.16/mmbtu, US\$1.01/Cdn\$, heavy oil differential 19%.



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