BAYTEX

ENERGY CORP.

FOR IMMEDIATE RELEASE – CALGARY, ALBERTA – May 12, 2011

BAYTEX ANNOUNCES FIRST QUARTER 2011 RESULTS AND UPDATE TO CONTINGENT RESOURCE ASSESSMENT

CALGARY, ALBERTA (May 12, 2011) - Baytex Energy Corp. ("Baytex") (TSX, NYSE: BTE) is pleased to announce its operating and financial results for the three months ended March 31, 2011 (in Canadian dollars unless otherwise denoted).

Summary of Q1

- Produced a quarterly record of 46,902 boe/d in Q1/2011 (an increase of 4% over Q4/2010);
- Generated funds from operations ("FFO") in the first quarter of $110 million ($0.96 per basic share), despite $2 million of debt origination and transaction expenses and $13 million of reduced revenues due to heavy oil market disruptions. Excluding these items, FFO would have been $1.09 per basic share;
- Advanced our thermal production project at Seal with a third successful injection cycle on our pilot well, with higher injectivity and a projected steam-oil-ratio of 1.9 based on initial production results;
- Completed the acquisition of heavy oil assets in the Seal area of northern Alberta and the Lloydminster area of western Saskatchewan for total consideration of $155 million at accretive metrics, as previously disclosed;
- Issued US$150 million in 10 year senior unsecured debentures at par, with a coupon of 6.75%. Upon receipt of the proceeds from this issue, reduced Canadian currency drawings on our credit facilities;
- Increased the amount of our credit facilities to $650 million (from $550 million), of which $350 million remains undrawn at the end of Q1/2011;
- Updated the contingent resource assessment on three of our oil resource plays to May 1, 2011 and completed an economic assessment of our contingent resource. The net present value attributable to the "best estimate" (C2) of contingent resource (before tax, discounted at 10%) was estimated at $4.4 billion;
- Maintained a cash payout ratio in Q1/2011 of 48% net of dividend reinvestment plan ("DRIP") participation; and
- Delivered total market return (assuming reinvestment of dividends) of 23% in Q1/2011.

	Three Months Ended		
	March 31, 2011	December 31, 2010	March 31, 2010
FINANCIAL			
(thousands of Canadian dollars, except per common share or unit amounts)			
Petroleum and natural gas sales	**290,315**	263,497	261,782
Funds from operations (1)	**109,470**	123,161	106,207
Per share or unit - basic	**0.96**	1.09	0.96
Per share or unit - diluted	**0.93**	1.06	0.95
Cash dividends or distributions declared(2)	**52,002**	48,126	49,142
Per share or unit	**0.60**	0.56	0.54
Net income	**950**	21,356	29,815
Per share or unit - basic	**0.01**	0.19	0.27
Per share or unit - diluted	**0.01**	0.18	0.27
Exploration and development	**87,014**	59,350	55,356
Property acquisitions	**37,518**	3,096	2,333
Divestitures	**-**	(896)	-
Corporate acquisition	**117,346**	-	-
Total oil and gas expenditures	**241,878**	61,550	57,689
Bank loan	**298,591**	303,773	257,364
Convertible debentures	**-**	-	6,353
Long-term debt	**295,770**	150,000	150,000
Working capital deficiency	**73,709**	52,462	56,404
Total monetary debt (3)	**668,070**	506,235	470,123

Notes:

(1) *Funds from operations is a non-GAAP measure that represents cash generated from operating activities less finance costs before changes in non-cash working capital and other operating items. Baytex's funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends and capital investments. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three months ended March 31, 2011.*

(2) *Cash dividends or distributions declared are net of DRIP.*

(3) *Total monetary debt is a non-GAAP measure which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as deferred income tax assets or liabilities and unrealized gain or loss on financial derivatives, the statement of financial position value of the bank loan, the debt portion of convertible debentures and the principal amount of long-term debt.*

	Three Months Ended		
	March 31, 2011	December 31, 2010	March 31, 2010
OPERATING			
Daily production			
Light oil and NGL (bbl/d)	**6,606**	6,457	6,660
Heavy oil (bbl/d)	**31,792**	29,808	27,278
Total oil (bbl/d)	**38,398**	36,265	33,938
Natural gas (mmcf/d)	**51.0**	52.5	56.9
Oil equivalent (boe/d @ 6:1) (1)	**46,902**	45,015	43,425
Average prices (before hedging)			
WTI oil (US$/bbl)	**94.10**	85.17	78.71
Edmonton par oil ($/bbl)	**88.45**	80.73	80.31
BTE light oil and NGL ($/bbl)	**75.68**	68.07	68.04
BTE heavy oil ($/bbl) (2)	**59.89**	60.10	62.07
BTE total oil and NGL ($/bbl)	**62.57**	61.53	63.24
BTE natural gas ($/mcf)	**4.19**	3.84	5.31
BTE oil equivalent ($/boe)	**55.86**	53.99	56.41
USD/CAD noon rate at period end	**1.0290**	1.0054	0.9846
USD/CAD average rate for period	**1.0142**	0.9873	0.9607
COMMON SHARE OR TRUST UNIT INFORMATION			
TSX			
Share or Unit price (Cdn$)			
High	**$ 56.95**	$ 48.15	$ 36.80
Low	**$ 46.00**	$ 37.12	$ 29.50
Close	**$ 56.69**	$ 46.61	$ 34.35
Volume traded (thousands)	**34,198**	32,579	22,448
NYSE			
Share or Unit price (US$)			
High	**$ 58.52**	$ 47.82	$ 36.07
Low	**$ 46.25**	$ 35.96	$ 27.56
Close	**$ 58.38**	$ 46.82	$ 33.96
Volume traded (thousands)	**8,184**	5,231	4,452
Common shares or trust units outstanding (thousands)	**115,177**	113,712	110,650

Notes:

(1) *Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

(2) *Heavy oil wellhead prices are net of blending costs.*

Operations Review

Production averaged 46,902 boe/d during the first quarter of 2011, as compared to 43,425 boe/d in the first quarter of 2010 and 45,015 boe/d in the fourth quarter of 2010. Oil-equivalent production increased by 8% from the first quarter of 2010, with oil production 13% higher and natural gas production 10% lower than in the prior year comparative period. Oil equivalent production increased by 4% from the fourth quarter of 2010, with oil production 6% higher and natural gas production 3% lower than in the prior quarter.

Capital expenditures for exploration and development activities totaled $87.0 million for the first quarter of 2011. During the first quarter, Baytex participated in the drilling of 71 (57.8 net) wells, resulting in 60 (46.8 net) oil wells, one (1.0 net) natural gas well, six (6.0 net) stratigraphic test wells, three (3.0 net) thermal observation wells and one (1.0 net) dry and abandoned well for a 99% (98% net) success rate. In our Lloydminster heavy oil area, we drilled 31 (28.8 net) oil wells and two (2.0 net) thermal observation wells. At Seal, we drilled five (5.0 net) horizontal cold production wells, four (4.0 net) horizontal cyclic steam stimulation (“CSS”) wells, six (6.0 net) stratigraphic test wells and one (1.0 net) thermal observation well. In our light oil and gas areas in western Canada, we drilled eight (5.4 net) oil wells, one (1.0 net) natural gas well and one (1.0 net) dry and abandoned well. In North Dakota, we drilled 12 (3.6 net) oil wells.

Consistent with previous guidance, our exploration and development capital budget for 2011 is $325 million, which, together with the heavy oil acquisition completed in February, is designed to generate an average production rate of 49,000 to 50,000 boe/d for 2011. We expect quarter-to-quarter production growth throughout 2011. Due to better than anticipated heavy oil drilling results and gas plant restrictions on certain gas properties that affect both natural gas and natural gas liquids (“NGL”) production, we now project that our production mix will be comprised of 69% heavy oil, 15% light oil and NGL and 16% natural gas. To date, our production levels have not been affected by the Rainbow or Keystone pipeline interruptions.

Heavy Oil

In the first quarter of 2011, heavy oil production averaged 31,792 bbl/d, an increase of 17% over the first quarter of 2010 and 7% over the fourth quarter of 2010. During the first quarter of 2011, we drilled 40 (37.8 net) producing wells, six (6.0 net) stratigraphic test wells and three (3.0 net) thermal observation wells on our heavy oil properties for a success rate of 100%.

Production from our Seal properties (excluding production from the properties acquired in the first quarter) averaged 10,445 bbl/d in the first quarter, an increase of 3% from the fourth quarter of 2010 and 44% from the first quarter of 2010. In the first quarter of 2011, Seal drilling included six (6.0 net) stratigraphic test wells and five (5.0 net) cold horizontal producers, with 11 to 15 laterals per well. Two of the new wells have established average 30-day peak production rates of approximately 630 bbl/d per well. The remaining three cold horizontal drills were put on production subsequent to the end of the first quarter, and have not recorded full 30-day production rates, but are among the highest production rate wells that we have drilled at Seal. For the remainder of 2011, we plan to drill at least 15 additional multi-lateral cold horizontal wells at Seal. A third rig was added to the Seal horizontal drilling operations after the end of the first quarter, up from an average rig count of two during the first quarter.

In our Cliffdale CSS project at Seal, we completed our third steam injection cycle in our pilot well, and placed the well back on production at the end of the first quarter. Injectivity continued to improve in this third cycle, with the injected steam slug size being 72% greater than in the second cycle and 110% greater than in the first cycle. Subsequent to the first quarter of 2011, the pilot well reached peak oil rates of approximately 435 bbl/d, with cumulative oil production through the first month approximately 20% higher than in the second cycle. Based on the results to date, we project a steam-oil-ratio of 1.9 for the third cycle, approximately the same as in the second cycle. In the first quarter of 2011, we drilled one (1.0 net) thermal observation well and four (4.0 net) horizontal CSS wells at Cliffdale. The new horizontal CSS wells were placed on cold production at rates of approximately 25 bbl/d per well, and are scheduled for steam injection upon completion of our steam facility expansion. To complete our first 10-well commercial module, we plan to drill an additional five horizontal CSS wells in 2011 once our final drilling permits are received.

On February 3, 2011, we closed the acquisition of heavy oil assets located in the Seal and Lloydminster areas. The assets were acquired through a combination of a corporate acquisition of a private company and an asset acquisition from another private company for aggregate cash consideration of $155 million. The acquisition contributed approximately 1,400 bbl/d to first quarter production and is expected to contribute approximately 2,600 bbl/d (100% heavy oil) for the remainder of 2011. The acquisition included approximately 158 sections of oil sands leases at Seal.

Light Oil & Natural Gas

During the first quarter of 2011, light oil and natural gas production averaged 15,110 boe/d, which was comprised of 6,606 bbl/d of light oil and NGL and 51.0 mmcf/d of natural gas. Compared to the first quarter of 2010, light oil and NGL production declined by 0.8% and natural gas production declined by 10.4%. Compared to the fourth quarter of 2010, light oil and NGL production increased by 2% and natural gas production declined by 3%. In the case of light oil and NGL production, declines in conventional fields and in NGL from natural gas production were offset by increasing production from light oil resource plays. In the first quarter of 2011, we drilled 20 (9.0 net) oil wells, one (1.0 net) natural gas well and one (1.0 net) dry and abandoned well for a 95% (91% net) success rate.

We continued development activities to advance our light oil resource plays. In our Cardium play in Alberta, we drilled and completed three (3.0 net) horizontal Cardium wells in the first quarter. Two of the wells were placed on production and established 30-day average peak rates of approximately 230 boe/d per well. We plan to drill approximately five additional Cardium horizontal wells in 2011.

In the first quarter of 2011, we drilled and completed one (1.0 net) unstimulated Viking multi-lateral well in Alberta, but it has not been on production long enough to establish a 30-day average peak rate. We plan to drill approximately 15 additional Viking light oil horizontal wells in 2011, the majority of which will be unstimulated multi-lateral wells in Alberta.

In our Bakken/Three Forks play in North Dakota, we participated in the drilling of twelve (3.6 net) horizontal oil wells in the first quarter, five of which were Baytex-operated. At the end of the first quarter of 2011, eleven (4.1 net) wells were waiting for multi-stage fracture treatments. We have fracture treatment dates scheduled in the second quarter for at least seven of these wells. A 1280-acre spacing well that was drilled in the fourth quarter of 2010 established a 30-day average peak rate in the first quarter in 2011 of 775 bbl/d (290 bbl/d net). To date, Baytex-interest wells on 640-acre spacing have established 30-day average peak rates of 260 bbl/d and Baytex-interest wells on 1280-acre spacing have established 30-day average peak rates of 435 bbl/d.

Financial Review

The financial statements for the first quarter of 2011 are Baytex's first financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"). Comparative periods in 2010 have been restated to conform to IFRS presentation. Reconciliations from IFRS to the previously reported financial results are shown in the notes to our financial statements. The adoption of IFRS did not have a material impact on the amounts reported as FFO.

We generated FFO of $110 million ($0.96 per basic share) in the first quarter of 2011, an increase of 3% compared to the first quarter of 2010, and a decrease of 11% compared to the fourth quarter of 2010. The decrease in FFO relative to the fourth quarter of 2010 primarily related to lower realized hedging gains in the first quarter as several favorable hedging contracts, primarily for forward US currency sales, matured at the end of 2010. Also, in the first quarter we incurred approximately $2 million in non-recurring expenses related to amendments to our credit facilities and fees for advisory services on the acquisition completed in the first quarter.

The average WTI price for the first quarter of 2011 was US$94.10/bbl, a 20% increase from the first quarter of 2010, and a 10% increase from the fourth quarter 2010. We received an average oil price of $62.57/bbl in the first quarter of 2011 (inclusive of our physical hedging gains), down from $63.24/bbl for the first quarter of 2010 and up from $61.53/bbl for the fourth quarter of 2010. We also received an average natural gas price of $4.19/mcf in the first quarter of 2011, a decrease of 21% from the first quarter of 2010 and an increase of 9% from the prior quarter. The discount for heavy oil, as measured by the Western Canadian Select price differential to WTI, averaged 24.3% for the first quarter of 2011, as compared to 12.0% in the first quarter of 2010 and 21.5% in the fourth quarter of 2010.

Although our average realized heavy oil price including financial hedges for the first quarter of $59.89/bbl was modestly lower than the $60.10/bbl we realized in the fourth quarter of 2010, our first quarter 2011 heavy oil revenues were lower than expected for two reasons. First, the spot market for heavy oil was negatively impacted by high inventories resulting from the Enbridge pipeline leaks in the fall of 2010. These inventories persisted for longer than expected because of downtime for pipeline repairs conducted by Enbridge in the first quarter of 2011. Due to our concerns about potential pipeline apportionment, we sold some volumes at daily spot market prices and into lower value delivery points such that our price realizations were less than monthly index pricing. Second, we incurred higher condensate blending costs due to colder than normal weather and lower condensate quality in the first quarter. We estimate that these marketing factors resulted in first quarter revenues (net of royalties) being approximately $13 million lower than if we had sold all of our heavy oil at monthly index prices and with customary condensate conditions. After completion of the pipeline repairs and the resulting drawdown in inventories, price realizations to date in the second quarter have closely tracked index pricing.

In the first quarter, our cash payout ratio was 48% net of DRIP participation. Under current pricing conditions, we expect to realize FFO in excess of our needs for our exploration and development capital program and our cash dividend payments.

During the first quarter of 2011, we generated net income of $1.0 million. Net income was reduced by the recognition of $46 million in unrealized mark-to-market losses from our WTI hedging program. The FFO impact of those WTI financial contracts could be realized in future periods as those contracts mature.

During the first quarter of 2011, we continued to improve our capital structure through two initiatives. First, we entered into agreements with our lending syndicate to increase the amount of our credit facilities to $650 million (from $550 million), to decrease interest rate margins on advances referenced to prime lending rates, bankers' acceptance rates and LIBOR rates and to decrease standby fees. Second, we issued US$150 million of 10 year senior unsecured debentures at par bearing a coupon rate of 6.75%, and used the net proceeds from this issue to repay a portion of the amount drawn in Canadian currency on our credit facilities.

On February 3, 2011, Baytex completed a previously disclosed heavy oil acquisition for total consideration of $155 million (net of adjustments). The acquisition was funded by drawing on Baytex's existing credit facilities.

At the end of the first quarter of 2011, total monetary debt was $668 million and undrawn credit facilities were $351 million. This level of debt represents a debt-to-FFO ratio of 1.4 times, based on trailing twelve months FFO. All of these debt levels are well within our leverage and liquidity targets, and provide ample capacity to finance our operations.

Contingent Resource Assessment

Sproule Associates Limited ("Sproule"), our independent reserves evaluator, prepared an assessment of contingent resource effective December 31, 2010 on 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.

The contingent resource assessment has been updated by Sproule effective May 1, 2011 to include the net present value of the future net revenue attributable to the contingent resource. The updated assessment of contingent resource does not include the lands at Seal, Alberta that were acquired in the first quarter of 2011.

For the total of these three plays, Sproule's estimate of contingent resource (oil, bitumen, NGL and natural gas) for the three plays ranges from 548 million boe in the "low estimate" (C1) to 1.15 billion boe in the "high estimate" (C3), with a "best estimate" (C2) of 745 million boe. These estimates increased by 3%, 11% and 12%, respectively, as compared to the contingent resource estimates from December 31, 2010 primarily due to the assessment of 1280-acre spacing development in North Dakota and the inclusion of solution gas and NGL volumes on both light oil plays. Contingent resource does not include any volumes currently booked as reserves.

The table below summarizes Sproule's estimates of contingent resource for the three plays by geographic area and the net present value before tax of the future net revenue attributable to the contingent resource using forecast prices and costs.

	Contingent Resource At May 1, 2011[1]		**Net Present Value of Future Net Revenue**[3] **At May 1, 2011 Forecast prices and costs (before income taxes discounted at (%/year))**			
	Gross[2] **(mmboe)**	**% Oil, Bitumen and NGL**	**0%**	**5%**	**8%**	**10%**
			($ millions)			
Bluesky – Seal, Alberta						
Low estimate (C1)[4]	478.3	100	9,684.5	4,511.1	2,880.9	2,133.6
Best estimate (C2)[5]	583.3	100	12,856.1	6,173.1	4,043.6	3,060.9
High estimate (C3)[6]	845.9	100	21,783.6	9,559.8	6,038.3	4,492.1
Bakken/Three Forks – North Dakota, USA						
Low estimate (C1)[4]	59.2	90	1,953.6	706.2	404.5	284.0
Best estimate (C2)[5]	138.1	90	7,642.8	2,534.7	1,455.0	1,041.4
High estimate (C3)[6]	253.8	90	16,834.0	5,009.3	2,789.8	1,976.7

	Contingent Resource At May 1, 2011[1]		Net Present Value of Future Net Revenue[3] At May 1, 2011 Forecast prices and costs (before income taxes discounted at (%/year))			
	Gross[2] (mmboe)	% Oil, Bitumen and NGL	0%	5%	8%	10%
			($ millions)			
Viking – Redwater, Alberta						
Low estimate (C1)[4]	5.4	92	159.1	97.6	73.8	61.5
Best estimate (C2)[5]	11.3	92	548.8	338.8	262.8	224.5
High estimate (C3)[6]	22.7	92	1,290.8	741.7	567.7	484.3
Viking – Dodsland/Kerrobert, Saskatchewan						
Low estimate (C1)[4]	5.1	100	80.3	22.2	9.6	5.0
Best estimate (C2)[5]	12.2	100	430.9	149.6	83.3	57.4
High estimate (C3)[6]	25.7	100	1,336.3	472.1	269.9	190.7
Total						
Low estimate (C1)[4]	548.0	99	11,877.5	5,337.1	3,368.8	2,484.1
Best estimate (C2)[5]	744.9	98	21,478.6	9,196.2	5,844.7	4,384.2
High estimate (C3)[6]	1,148.1	98	41,244.7	15,782.9	9,665.7	7,143.8

Notes:

(1) The contingent resource assessment was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101").

Contingent resource is defined in the COGE Handbook as those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or 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.

Under 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 that will 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.

Sproule 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.

(2) Gross means the company's working interest share in the contingent resource before deducting royalties.

(3) The net present value of future net revenue attributable to the contingent resource does not necessarily represent the fair market value of the contingent resource. Estimated abandonment and reclamation costs have been included in the evaluation.

(4) Low estimate (C1) is considered to be a conservative estimate of the quantity of 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.

(5) Best estimate (C2) is considered to be the best estimate of the quantity of 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.

(6) High estimate (C3) is considered to be an optimistic estimate of the quantity of 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.

There is no certainty that it will be commercially viable to produce any portion of the contingent resource or that we will produce any portion of the volumes currently classified as contingent resource. The recovery and resource estimates provided herein are estimates. 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.

Pricing Assumptions

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, heavy oil, natural gas and natural gas liquids benchmark reference pricing, as at March 31, 2011, inflation and exchange rates utilized by Sproule in the contingent resource assessment were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT MARCH 31, 2011

	OIL			NATURAL GAS		
	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Lloydblend at Hardisty 20.5° API ($Cdn/bbl)	AECO-C ($Cdn/MMbtu)	INFLATION RATES (1) (%/year)	EXCHANGE RATE (2) ($US/$Cdn)
2011 (9 months)	103.32	103.14	88.70	3.71	1.5	0.984
2012	102.86	102.65	88.27	4.29	1.5	0.984
2013	100.84	100.57	84.48	4.65	1.5	0.984
2014	95.66	95.29	78.14	5.95	1.5	0.984
2015	95.52	95.14	78.01	6.34	1.5	0.984
2016	96.96	96.57	79.19	6.44	1.5	0.984
2017	98.41	98.03	80.39	6.55	1.5	0.984
2018	99.89	99.51	81.60	6.66	1.5	0.984
2019	101.38	101.02	82.83	6.77	1.5	0.984
2020	102.91	102.54	84.08	6.88	1.5	0.984
2021	104.45	104.09	85.35	6.99	1.5	0.984
Thereafter				Escalation rate of 1.5%		

Notes:

(1) Inflation rates for forecasting prices and costs.

(2) Exchange rate used to generate the benchmark reference prices in this table.

Additional Information

Our unaudited interim condensed consolidated financial statements for the three ended March 31, 2011 and 2010 and related Management's Discussion and Analysis of the operating and financial results can be accessed immediately on our website at www.baytex.ab.ca and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Advisory Regarding 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 in this press release 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"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to: our exploration and development capital expenditures for 2011; our average production rate for 2011; the growth profile of our 2011 production; our product mix for 2011; initial production rates from wells drilled; development plans for our properties, including the number of wells to be drilled in 2011; our heavy oil resource play at Seal, including our assessment of the results of the third steam injection cycle for our pilot well, including the steam-oil ratio, and the completion of a 10-well module of CSS development; production from the heavy oil assets acquired on February 3, 2011 for the last nine months of 2011; our light oil resource play in North Dakota, including the timing of completing multi-stage fracture treatments on wells previously drilled; our ability to fund our capital expenditures and dividends from funds from operations in 2011; the existence, operation and strategy of our risk management program for commodity prices and foreign exchange rates; the amount of our undrawn credit facilities at March 31, 2011; our debt to FFO ratio; our liquidity and *financial capacity; and the sufficiency of our financial resources to finance 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. 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 differentials between light, medium and heavy oil prices; 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.

Contingent Resource

This press release contains estimates of "contingent resource". "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." 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. A "best estimate" of contingent resource means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

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.

Notice to United States Readers: The United States Securities and Exchange Commission does not permit the inclusion of estimates of resources in reports filed with it by United States companies.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

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