FOR IMMEDIATE RELEASE – CALGARY, ALBERTA – November 10, 2011

BAYTEX ANNOUNCES THIRD QUARTER 2011 RESULTS

CALGARY, ALBERTA (November 10, 2011) - Baytex Energy Corp. ("Baytex") (TSX, NYSE: BTE) is pleased to announce its operating and financial results for the three months and nine months ended September 30, 2011 (all amounts are in Canadian dollars unless otherwise noted).

Summary of Q3

- Produced record quarterly production of 52,625 boe/d in Q3/2011 (an increase of 10% over Q2/2011 and 17% over Q3/2010);
- Generated funds from operations ("FFO") of $144.8 million ($1.24 per basic share) in Q3/2011, the second highest level of quarterly FFO in the history of Baytex, and an increase of 5% over Q2/2011 and 31% over Q3/2010;
- Generated net income of $52 million ($0.45 per basic share) in Q3/2011;
- Maintained a cash payout ratio in Q3/2011 of 35% net of dividend reinvestment plan ("DRIP") participation;
- Closed a previously announced natural gas acquisition in west-central Alberta to consolidate non-operated interests at attractive acquisition metrics; and
- Subsequent to the end of the third quarter, entered into definitive agreements to sell certain primarily-undeveloped lands in Alberta and Saskatchewan for $47.1 million.

	Three Months Ended			Nine Months Ended	
	September 30, 2011	June 30, 2011	September 30, 2010	**September 30, 2011**	September 30, 2010
FINANCIAL *(thousands of Canadian dollars, except per common share or unit amounts)*					
Petroleum and natural gas sales	**313,787**	336,899	238,276	**941,001**	741,639
Funds from operations (1)	**144,825**	138,233	110,954	**392,510**	324,494
Per share or unit – basic	**1.24**	1.20	0.99	**3.40**	2.93
Per share or unit – diluted	**1.22**	1.17	0.96	**3.31**	2.83
Cash dividends or distributions declared (2)	**50,270**	52,764	45,795	**155,035**	141,698
Cash dividends or distributions declared per share or unit	**0.60**	0.60	0.54	**1.80**	1.62
Net income	**51,839**	106,863	23,319	**159,652**	210,260
Per share or unit – basic	**0.45**	0.92	0.21	**1.38**	1.90
Per share or unit – diluted	**0.44**	0.90	0.20	**1.35**	1.84
Exploration and development	**100,368**	108,453	59,559	**295,835**	172,269
Property acquisitions	**28,502**	(185)	11,452	**65,835**	19,316
Corporate acquisition	**22**	1,325	-	**118,693**	40,314
Proceeds from divestitures	**-**	-	(18,137)	**-**	(18,137)
Total oil and natural gas capital expenditures	**128,892**	109,593	52,874	**480,363**	213,762
Bank loan	**368,184**	315,073	314,567	**368,184**	314,567
Convertible debentures	**-**	-	5,057	**-**	5,057
Long-term debt	**305,835**	294,645	150,000	**305,835**	150,000
Working capital deficiency	**65,180**	72,621	72,616	**65,180**	72,616
Total monetary debt (3)	**739,199**	682,339	542,240	**739,199**	542,240

Notes:

(1) *Funds from operations is a non-GAAP measure that represents cash generated from operating activities adjusted for finance costs, changes in non-cash operating 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 and nine months ended September 30, 2011.*

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

(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 gains or losses on financial derivatives)), the principal amount of long-term debt and the balance sheet amount of any convertible debentures and long-term bank loans.*

	Three Months Ended			Nine Months Ended	
	September 30, 2011	June 30, 2011	September 30, 2010	**September 30, 2011**	September 30, 2010
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**7,170**	6,055	6,600	**6,612**	6,567
Heavy oil (bbl/d)	**37,280**	33,839	28,959	**34,324**	28,172
Total oil and NGL (bbl/d)	**44,450**	39,894	35,559	**40,936**	34,739
Natural gas (mmcf/d)	**49.0**	47.8	55.4	**49.3**	56.2
Oil equivalent (boe/d @ 6:1) (1)	**52,625**	47,853	44,799	**49,147**	44,113
Average prices (before hedging)					
WTI oil (US$/bbl)	**89.76**	102.56	76.20	**95.48**	77.65
Edmonton par oil ($/bbl)	**92.45**	102.63	74.43	**94.85**	76.73
BTE light oil and NGL ($/bbl)	**80.48**	89.11	63.13	**81.53**	65.18
BTE heavy oil ($/bbl) (2)	**59.92**	71.02	57.97	**63.45**	59.15
BTE total oil and NGL ($/bbl)	**63.26**	73.78	58.93	**66.45**	60.29
BTE natural gas ($/mcf)	**4.20**	4.36	3.89	**4.25**	4.47
BTE oil equivalent ($/boe)	**57.31**	65.84	51.59	**59.61**	53.18
USD/CAD noon rate at period end	**0.9626**	1.0370	0.9711	**0.9626**	0.9711
USD/CAD average rate for period	**1.0220**	1.0334	0.9624	**1.0231**	0.9654
COMMON SHARE OR TRUST UNIT INFORMATION					
TSX					
Share or Unit price (Cdn$)					
High	**$ 55.93**	$ 58.76	$ 37.86	**$ 58.76**	$ 37.86
Low	**$ 41.71**	$ 47.59	$ 31.27	**$ 41.71**	$ 27.72
Close	**$ 43.81**	$ 52.72	$ 37.27	**$ 43.81**	$ 37.27
Volume traded (thousands)	**27,710**	22,857	21,917	**84,765**	72,806
NYSE					
Share or Unit price (US$)					
High	**$ 59.04**	$ 61.95	$ 36.90	**$ 61.95**	$ 36.90
Low	**$ 40.31**	$ 48.63	$ 25.64	**$ 40.31**	$ 25.64
Close	**$ 41.67**	$ 54.44	$ 36.33	**$ 41.67**	$ 36.33
Volume traded (thousands)	**11,771**	9,851	4,514	**29,806**	16,258
Common shares or trust units outstanding (thousands)	**116,755**	116,004	112,333	**116,755**	112,333

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 52,625 boe/d during the third quarter of 2011, as compared to 44,799 boe/d in the third quarter of 2010 and 47,853 boe/d in the second quarter of 2011. Oil-equivalent production increased by 17% from the third quarter of 2010, with oil and natural gas liquids ("NGL") production 25% higher and natural gas production 12% lower. Oil equivalent production increased by 10% from the second quarter of 2011, with oil and NGL production 11% higher and natural gas production 3% higher.

Capital expenditures for exploration and development activities totaled $100.4 million for the third quarter of 2011. During the third quarter, Baytex participated in the drilling of 48 (39.4 net) wells, resulting in 46 (37.4 net) oil wells and two (2.0 net) service wells for a 100% success rate.

In our Lloydminster heavy oil area, we drilled 19 (19.0 net) oil wells and two (2.0 net) service wells. In our Seal heavy oil area, we drilled seven (7.0 net) horizontal cold production wells. In our light oil and gas areas in western Canada, we drilled 15 (9.9 net) oil wells. We drilled five (1.5 net) oil wells in our Bakken/Three Forks play in North Dakota.

Our previous production guidance for 2011 was a range of 49,500 to 50,500 boe/d. Based on production performance for the first nine months of 2011, we can now narrow our full-year 2011 guidance to a range of 50,000 to 50,500 boe/d. We continue to project that our production mix will be comprised of approximately 70% heavy oil, 14% light oil and NGL and 16% natural gas. Our exploration and development capital budget for 2011 remains at $355 million. We plan to provide production and capital budget guidance for 2012 on or about December 6, 2011, following approval of our 2012 development plan by our Board of Directors.

Heavy Oil

In the third quarter of 2011, heavy oil production averaged 37,280 bbl/d, an increase of 29% over the third quarter of 2010 and 10% over the second quarter of 2011. During the third quarter of 2011, we drilled 26 (26.0 net) oil wells and two (2.0 net) service wells on our heavy oil properties for a success rate of 100%.

Production from our Seal properties averaged approximately 17,800 bbl/d, an increase of 24% from the second quarter of 2011. In the third quarter of 2011, we drilled seven (7.0 net) cold horizontal producers at Seal, including our first drilling on the Reno-area properties acquired earlier this year. Our most common multi-lateral well design includes eight approximately 1,400 meter-long laterals, which are often augmented with several shorter "stubby" laterals to drain the region around the intermediate casing point to the starting point of the 1,400 meter-long laterals. Three of the wells drilled in the third quarter and two of the wells drilled in the second quarter established average 30-day peak production rates of approximately 340 bbl/d per well. Although we have not yet recorded a 30-day peak production rate on any wells drilled on the lands acquired at Reno earlier this year, the first two wells drilled have initial production rates averaging approximately 375 bbl/d per well, based on the first two weeks of production. The two Reno wells had an average of six full-length horizontal laterals per well, plus an average of four "stubbies" per well. During the remainder of 2011, we plan to drill approximately five additional multi-lateral cold horizontal wells at Seal.

In our Cliffdale cyclic steam stimulation ("CSS") project at Seal, we continued production operations during the pilot well's third cycle. Consistent with our numerical reservoir simulation, we project a steam-oil ratio ("SOR") of approximately 1.9 for this cycle. Four additional CSS-project wells drilled in the first quarter continued pre-steam cold production in the third quarter at rates of approximately 20 bbl/d per well, while awaiting completion of our steam generation facility. We have now received regulatory approvals to install oil and water handling facilities and steam distribution piping at our Cliffdale facility. Construction has commenced, and we expect to begin steam injection late in the fourth quarter of 2011. To complete our first 10-well commercial CSS module, we also plan to drill an additional five horizontal CSS wells in the fourth quarter of 2011.

At our Kerrobert steam-assisted gravity drainage ("SAGD") project, the well pair which commenced production in October 2010 continues to operate at oil rates in excess of 800 bbl/d. Two additional SAGD well pairs were drilled during the second quarter and placed on production in the third quarter at average rates of approximately 950 bbl/d per well. Current SOR for the Kerrobert SAGD project is 2.4. We drilled two stratigraphic test wells in the third quarter and plan to drill two additional stratigraphic test wells in the fourth quarter to optimize the placement of future SAGD well pairs. Design work is being conducted for steam plant expansion to allow the drilling of additional SAGD well pairs.

Light Oil & Natural Gas

During the third quarter of 2011, light oil, NGL and natural gas production averaged 15,345 boe/d, which was comprised of 7,170 bbl/d of light oil and NGL and 49.0 mmcf/d of natural gas. Compared to the third quarter of 2010, light oil and NGL production increased by 9% and natural gas production declined by 12%. Compared to the second quarter of 2011, light oil and NGL production increased by 18% and natural gas production increased by 3%.

In the third quarter of 2011, we drilled five (4.0 net) Viking multi-lateral wells in eastern Alberta. Two of the wells drilled in the third quarter and two of the wells drilled in the second quarter established average 30-day peak rates of approximately 120 bbl/d per well. We plan to drill two more Viking light oil horizontal wells in eastern Alberta in the fourth quarter of 2011.

We drilled three Viking light oil horizontal wells in Saskatchewan in the third quarter, two of which were fracture-stimulated and commenced production early in the fourth quarter but have not yet established 30-day peak rates. One of the Saskatchewan Viking wells was an unstimulated five-lateral well which had a 30-day peak production rate of approximately 20 bbl/d.

We participated in seven (2.9 net) Cardium light oil horizontal wells in the third quarter, two of which were operated. The operated wells will be fracture-stimulated and put on production in the fourth quarter.

In our Bakken/Three Forks play in North Dakota, in the third quarter we participated in the drilling of five (1.5 net) horizontal oil wells, four of which were Baytex-operated, and the fracture-stimulation of six wells. During the third quarter, three operated 640-acre spacing wells established average 30-day peak production rates of 350 bbl/d per well and one operated 1,280-acre spacing well established an average 30-day peak production rate of 430 bbl/d. We plan to participate in the drilling of approximately seven (2.0 net) additional Bakken/Three Forks wells in the fourth quarter.

Acquisition and Divestiture Activity

As previously announced, in the third quarter we closed the acquisition of predominantly natural gas assets located in the Brewster area of west-central Alberta. Prior to the acquisition, we had non-operated interests in most of these assets. As a result of the acquisition, we are now the operator of all of the acquired assets. The total consideration for the acquisition (net of adjustments) was $22.4 million, which was funded by drawing on our credit facilities. The purchase price is a multiple of approximately three times projected net operating income from the acquired properties for 2011. The acquired assets are producing approximately 800 boe/d of production (80% natural gas). We estimate remaining proved plus probable reserves to be approximately 2.5 million boe. The acquired assets include 72,000 net acres of undeveloped land, a 64 kilometer gathering system and two compressor stations.

Subsequent to the end of the third quarter, we entered into and closed the sale of six sections of leasehold, including five sections with Duvernay rights, in the Kaybob South area of west central Alberta for $11.1 million. Five of the six sections faced lease expiry within the next year. There is no production on the divested lands.

Subsequent to the end of the third quarter, we entered into a definitive agreement to sell approximately 32,600 net acres of leasehold in the "halo" of the Dodsland field in southwest Saskatchewan for $36 million. As at December 31, 2010, the properties had booked proved plus probable reserves of approximately 1.5 million boe (9% proved developed producing). Current production from the lands is approximately 60 bbls/day. This disposition is expected to close on or about November 25, 2011. After the sale, we will continue to hold significant undeveloped land for Viking light oil development in the Kerrobert and Whiteside areas of southwest Saskatchewan.

Financial Review

The financial statements for the third quarter of 2011 have been 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 interim condensed consolidated financial statements. The adoption of IFRS did not have a material impact on the amounts reported as FFO.

We generated FFO of $145 million ($1.24 per basic share) in the third quarter of 2011, an increase of 31% compared to the third quarter of 2010, and an increase of 5% compared to the second quarter of 2011. The increase in FFO relative to the second quarter of 2011 is primarily the result of increased sales volumes which more than offset the lower commodity prices realized in the third quarter. Consistent with our practice prior to the adoption of IFRS, FFO is presented net of financing costs, which totaled $10.4 million in the third quarter.

The average WTI price for the third quarter of 2011 was US$89.76/bbl, an 18% increase from the third quarter of 2010, and a 12% decrease from the second quarter of 2011. We received an average oil and NGL price of $63.26/bbl in the third quarter of 2011 (inclusive of our physical hedging gains), up from $58.93/bbl for the third quarter of 2010 and down from $73.78/bbl for the second quarter of 2011. We received an average natural gas price of $4.20/mcf in the third quarter of 2011, a modest decrease from the second quarter of 2011.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 19.6% for the third quarter of 2011, as compared to 20.6% in the third quarter of 2010 and 17.2% in the second quarter of 2011. Looking forward, demand for Canadian heavy oil by US refiners in the midcontinent region is expected to increase in late 2011 through 2013 with the commissioning of heavy oil refining projects in the region. The impact of those refining projects is already being noted in the market, as the current heavy oil differential is approximately 12% of WTI, and the forward markets are suggesting similar levels for the first half of 2012.

Baytex continues to actively hedge its exposure to commodity prices, heavy oil differentials and interest and foreign exchange rates with the objective of reducing the volatility of its funds from operations, which are used to finance capital expenditures and dividend payments. Contracts currently in place have locked in pricing on approximately 24% of our 2012 WTI price, 22% of our heavy oil differential exposure, 32% of our natural gas price exposure, and 19% of our exposure to currency movements between the Canadian and US dollar. Details of those contracts are contained in the notes to our interim condensed consolidated financial statements. We continue to monitor the markets for opportunities to add to this hedging program for 2012 and later years.

At the end of the third quarter of 2011, total monetary debt was $739 million and undrawn credit facilities were $332 million. This level of debt represents a debt-to-FFO ratio of 1.4 times, based on trailing twelve months FFO. This level of debt and undrawn credit facilities are within our leverage and liquidity targets, and provide ample capacity to finance our operations.

Additional Information

Our unaudited interim condensed consolidated financial statements for the three months and nine months ended September 30, 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 average production rate for 2011; our product mix for 2011; our exploration and development capital expenditures for 2011; initial production rates from wells drilled; development plans for our properties, including the number of wells to be drilled in the fourth quarter of 2011; our Cliffdale cyclic steam stimulation project at Seal, including our assessment of the results of the third steam injection cycle for our pilot well, the steam-oil ratio for the third steam injection cycle and the completion of a 10-well commercial module of CSS development, including the commencement of steam injection into four additional wells and the drilling of five additional CSS wells; our Kerrobert steam-assisted gravity drainage project, including the steam-oil ratio, our ability to optimize the placement of SAGD well pairs by drilling stratigraphic test wells and the expansion of the steam plant; the natural gas-weighted acquisition in west-central Alberta, including the 2011 net operating income from the acquired assets and the remaining proved plus probable reserves attributable to the acquired assets; the completion of the disposition of assets in the Dodsland area of Saskatchewan; the demand for Canadian heavy oil by U.S. refiners; the outlook for the pricing differential between Canadian heavy oil and West Texas Intermediate; the existence, operation and strategy of our risk management program for commodity prices, heavy oil differentials and interest and foreign exchange rates; the amount of our undrawn credit facilities at September 30, 2011; our debt to FFO ratio; 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. 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.

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