BAYTEX

ENERGY TRUST

FOR IMMEDIATE RELEASE – CALGARY, ALBERTA – NOVEMBER 10, 2010

BAYTEX ENERGY TRUST ANNOUNCES THIRD QUARTER 2010 RESULTS

Calgary, Alberta (November 10, 2010) - Baytex Energy Trust ("Baytex") (TSX: BTE.UN; NYSE: BTE) is pleased to announce its operating and financial results for the three months and nine months ended September 30, 2010 (in Canadian dollars unless otherwise denoted).

Highlights

- Produced a quarterly record of 44,799 boe/d in Q3/2010 (an increase of 5% from Q3/2009 and 2% from Q2/2010);
- Generated funds from operations of $112.8 million in Q3/2010 (an increase of 27% from Q3/2009 and 3% from Q2/2010);
- Declared total distributions of $45.8 million in Q3/2010, representing a payout ratio of 41% net of distribution reinvestment plan ("DRIP") participation (54% before DRIP);
- Conducted a second successful cyclic steam stimulation ("CSS") pilot in Seal;
- Divested our 50% interest in an in-situ combustion pilot in the Kerrobert area for $18 million cash and an overriding royalty in the project;
- Subsequent to the end of the third quarter, completed a steam assisted gravity drainage ("SAGD") well pair in our Kerrobert SAGD project which is currently producing approximately 1,000 bbl/d;
- Including hedging activities subsequent to the end of the third quarter, increased 2011 hedge positions to 26% of our West Texas Intermediate ("WTI") exposure, 35% of our heavy oil differential exposure and 25% of our foreign currency exposures, and established initial hedge positions for heavy oil differential for 2012 and 2013; and
- Delivered total market return, including reinvestment of distributions, of 19% for the third quarter of 2010, and 32% for the first nine months of 2010.

	Three Months Ended			Nine Months Ended	
	September 30, 2010	June 30, 2010	September 30, 2009	**September 30, 2010**	September 30, 2009
FINANCIAL *(thousands of Canadian dollars, except per unit amounts)*					
Petroleum and natural gas sales	**238,293**	241,564	208,206	**741,639**	551,781
Funds from operations [(1)]	**112,786**	109,123	88,809	**329,407**	234,842
Per unit - basic	**1.01**	0.98	0.83	**2.97**	2.26
Per unit - diluted	**0.97**	0.95	0.80	**2.87**	2.23
Cash distributions declared [(2)]	**45,795**	46,761	32,799	**141,698**	100,315
Per unit	**0.54**	0.54	0.36	**1.62**	1.14
Net income	**35,061**	33,027	40,657	**120,042**	59,618
Per unit - basic	**0.31**	0.30	0.38	**1.08**	0.57
Per unit - diluted	**0.30**	0.29	0.37	**1.05**	0.57
Exploration and development	**62,245**	62,548	34,180	**181,804**	111,573
Acquisitions	**12,875**	4,709	93,670	**19,917**	96,012
Dispositions	**(18,087)**	(50)	(8)	**(18,137)**	(18)
Corporate acquisition	**-**	40,914	-	**40,914**	-
Total oil and gas expenditures	**57,033**	108,121	127,842	**224,498**	207,567
Bank loan	**314,567**	341,919	272,918	**314,567**	272,918
Convertible debentures	**5,057**	5,864	8,799	**5,057**	8,799
Long-term notes	**150,000**	150,000	150,000	**150,000**	150,000
Working capital deficiency	**66,596**	55,660	34,573	**66,596**	34,573
Total monetary debt [(3)]	**536,220**	553,443	466,290	**536,220**	466,290

	Three Months Ended			Nine Months Ended	
	September 30, 2010	June 30, 2010	September 30, 2009	**September 30, 2010**	September 30, 2009
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**6,600**	6,443	7,021	**6,567**	7,071
Heavy oil (bbl/d)	**28,959**	28,263	25,532	**28,172**	24,090
Total oil (bbl/d)	**35,559**	34,706	32,553	**34,739**	31,161
Natural gas (mmcf/d)	**55.4**	56.4	60.4	**56.2**	58.6
Oil equivalent (boe/d @ 6:1) (4)	**44,799**	44,104	42,623	**44,113**	40,934
Average prices (before financial hedging)					
WTI oil (US$/bbl)	**76.20**	78.03	68.18	**77.65**	56.98
Edmonton par oil ($/bbl)	**74.43**	75.46	71.70	**76.73**	62.79
BTE light oil and NGL ($/bbl)	**63.13**	64.38	57.50	**65.18**	51.63
BTE heavy oil ($/bbl) (5)	**57.97**	57.59	55.12	**59.15**	47.11
BTE total oil ($/bbl)	**58.93**	58.84	55.64	**60.29**	48.15
BTE natural gas ($/mcf)	**3.89**	4.19	3.42	**4.47**	4.18
BTE oil equivalent ($/boe)	**51.59**	51.67	47.27	**53.18**	42.61
USD/CAD noon rate at period end	**0.9711**	0.9429	0.9327	**0.9711**	0.9327
USD/CAD average rate for period	**0.9624**	0.9733	0.9113	**0.9654**	0.8547
TRUST UNIT INFORMATION					
TSX					
Unit price (Cdn$)					
High	**$ 37.86**	$ 36.31	$ 25.35	**$ 37.86**	$ 25.35
Low	**$ 31.27**	$ 27.72	$ 17.80	**$ 27.72**	$ 9.77
Close	**$ 37.27**	$ 31.80	$ 23.60	**$ 37.27**	$ 23.60
Volume traded (thousands)	**21,917**	28,441	24,885	**72,806**	89,326
NYSE					
Unit price (US$)					
High	**$ 36.90**	$ 36.23	$ 23.69	**$ 36.90**	$ 23.69
Low	**$ 25.64**	$ 25.64	$ 15.20	**$ 25.64**	$ 7.84
Close	**$ 36.33**	$ 29.95	$ 22.04	**$ 36.33**	$ 22.04
Volume traded (thousands)	**4,514**	7,292	5,778	**16,258**	27,748
Units outstanding (thousands)	**112,333**	111,259	107,777	**112,333**	107,777

(1) Funds from operations is a non-GAAP measure that represents cash generated from operating activities 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 distributions 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, 2010.

(2) Cash distributions declared are net of DRIP.

(3) Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative contracts gains or losses)), the balance sheet value of the convertible debentures and the principal amount of long-term debt.

(4) 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.

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

Operations Review

Production averaged 44,799 boe/d during the third quarter of 2010, as compared to 44,104 boe/d in the second quarter of 2010, a 2% increase in oil equivalent production. Oil production increased by 2% and natural gas production declined by 2% as compared to the prior quarter.

Capital expenditures for exploration and development activities totaled $62.2 million for the third quarter of 2010. During the quarter, Baytex participated in the drilling of 36 (28.0 net) wells, resulting in 32 (24.6 net) oil wells, one (1.0 net) natural gas well, two (2.0 net) service wells and one (0.4 net) dry and abandoned well for a 97% (99% net) success rate. Third quarter drilling included eight (8.0 net) oil wells and one (1.0 net) service well in our Lloydminster heavy oil area, four (4.0 net) producing wells and one (1.0 net) service well at Seal, one (1.0 net) horizontal oil well at Tangent, 11 (9.0 net) wells in our light oil and gas areas in western Canada and nine (3.6 net) oil wells and one (0.4 net) dry and abandoned well in North Dakota.

Consistent with previous guidance, our exploration and development capital budget for 2010 is $235 million. In our first and second quarter press releases, we increased guidance for 2010 average production from the original level of 43,500 boe/d to a range of 44,000 boe/d to 44,500 boe/d. We are now guiding 2010 average production to a range of 44,250 boe/d to 44,500 boe/d.

Heavy Oil

In the third quarter of 2010, heavy oil production averaged 28,959 bbl/d, an increase of 13% over the third quarter of 2009, and 2% over the second quarter of 2010. During the third quarter of 2010, we drilled 13 (13.0 net) producing wells and two (2.0 net) service wells on our heavy oil properties for a 100% success rate.

Production from Seal averaged approximately 10,100 bbl/d in the third quarter, an increase of 1,200 bbl/d over the second quarter of 2010. In the third quarter, we drilled four horizontal producers at Seal, encompassing a total of 34 horizontal laterals. Two of the wells drilled in the third quarter and one drilled in the second quarter commenced production in the third quarter with 30-day average peak rates of approximately 480 bbl/d per well. During the third quarter, we also re-entered an existing well and drilled fifteen new laterals to access previously undrained areas of the reservoir. Production from the re-entered well increased from approximately 38 bbl/d prior to the workover to a 30-day average peak rate of 490 bbl/d after the workover. In the fourth quarter, we plan to re-enter three more wells to drill new laterals at Seal.

We conducted a second successful steam injection pilot at Seal during the second and third quarters. This test was conducted in the Cliffdale area, located seven miles to the east of our first steam pilot in the Harmon Valley area. Cliffdale is an area in which, at this point, we do not envision large-scale cold development. Oil viscosities at the subsurface elevation steamed at Cliffdale are approximately four times higher than in the Harmon Valley test and prior removal of cold oil through primary production at Cliffdale was minimal. The objectives of the test were four-fold: 1) to prove that steam injectivity, in the bottom half of the Bluesky Sand and at higher oil viscosities than in the earlier Harmon Valley pilot, would hit target levels; 2) to conduct a multi-cycle test with improvement in injectivity and production in the second cycle; 3) to validate our numerical reservoir simulation so that long-term performance on subsequent cycles can be more accurately predicted; and 4) to achieve economic levels of production and Steam-Oil Ratio ("SOR"). All of these objectives were met in the Cliffdale pilot test. The cost of the pilot was $7.7 million, which included installation of much of the infrastructure and steam plant to be used in a permanent project at this site.

At Cliffdale, because of the minimal cold production prior to the steam test, we conducted two "mini-cycles" to gradually heat the reservoir. After an initial attempted injection cycle was aborted due to a parted tubing string which had to be fished, we recorded the results shown in the table below. SOR for the second cycle is projected to the end of the cycle at approximately year-end 2010, at which time we plan to resume steam injection for the third "mini-cycle".

Cycle	Injected Steam (bbl water)	Maximum Daily Oil Rate (bbl/d)	Steam-Oil Ratio
1	12,560	250	2.7
2	15,120	450	1.9

Our numerical reservoir simulation indicates that injectivity, oil rate and SOR should continue to improve on subsequent cycles as heating of the reservoir progresses. We are in the permitting phase for a 10-well commercial module, which we plan to have in place by the end of 2011. Cost for the remaining nine wells and completion of the infrastructure and steam plant is projected to be approximately $23 million.

On September 30, 2010, we closed the sale of our 50% interest in the lands and wells comprising Phase 1 of an in-situ combustion project at Kerrobert for $18 million and a gross overriding royalty on the divested lands. The disposition will have a negligible impact on production, capital expenditures and funds from operations for 2010. We retained our 50% interest in the area of mutual interest surrounding the Phase 1 lands. Our other Kerrobert interests, including our 100% working interest in our SAGD project, were unaffected by the sale.

In our Kerrobert SAGD project, we placed a new well pair on production late in the third quarter. Subsequent to the end of the quarter, this well pair produced at a 30-day average rate of approximately 1,000 bbl/d. The SOR for the new well pair is currently 2.2 barrels of steam per barrel of oil. Cost of the well pair was $6.8 million, which included an expansion of the steam distribution system which will serve future well pairs. We believe that, through the remaining life of this project, we can drill 11 additional well pairs with incremental costs of approximately $3.6 million per well pair.

Light Oil & Natural Gas

During the third quarter of 2010, light oil and natural gas production averaged 15,840 boe/d, which was comprised of 6,600 bbl/d of light oil and NGL and 55.4 mmcf/d of natural gas. On an oil-equivalent basis, production of light oil, NGL and natural gas was the same as the previous quarter. Compared to the second quarter, light oil and NGL production increased 2% and natural gas production decreased by 2%. In the third quarter, we drilled 19 (11.6 net) oil wells, one (1.0 net) natural gas well and one (0.4 net) dry and abandoned well for a 95% (97% net) success rate.

We continued development activities in each of our light oil resource plays in the third quarter. In our Cardium play in Alberta, we drilled two horizontal wells in the Pembina area which will receive multi-stage fracture treatments in the fourth quarter. A Cardium well that was drilled in the first quarter was put on production during the third quarter at a 30-day average peak rate of approximately 175 boe/d.

In Alberta, we drilled four Viking horizontal multi-lateral wells in the third quarter with open-hole completions. Three of the wells were placed on production during the quarter and have established 30-day average peak rates of approximately 90 bbl/d per well. To date in the Alberta Viking play, we have drilled nine wells with sufficient history to establish a 30-day average peak rate of approximately 110 bbl/d per well.

In the Viking play in Saskatchewan, our recent drilling has been focused on validating licenses acquired during 2008 that were approaching expiry. Our drilling has now validated all of the licenses acquired at that time, converting them to leases with new five-year terms. During the third quarter, we drilled two horizontal Viking wells. Wet conditions delayed completion activities on one of the wells. The second well, drilled in the Herschel area approximately 13 miles to the east of the Dodsland field, produced at very low oil rates after hydraulic fracturing. To date in the Saskatchewan Viking play, excluding the sub-economic well at Herschel, we have achieved a 30-day average peak rate of 75 bbl/d per well from five wells that have been fully completed and placed on production.

In our Bakken/Three Forks play in North Dakota, we participated in drilling nine (3.6 net) horizontal oil wells in the third quarter. Due to constraints in fracturing services, only three of these wells were fracture-stimulated during the third quarter, and none of the third quarter wells was on production long enough to establish 30-day peak production rates. Four wells that were completed earlier in 2010 established 30-day production rates in the third quarter. Two Baytex operated wells drilled on 640-acre spacing units produced at a 30-day average peak rate of approximately 250 bbl/d per well, and two partner-operated wells drilled on 1280-acre spacing units produced at a 30-day average peak rate of approximately 400 bbl/d. To-date in this play, the nine Baytex-operated 640-acre wells that have sufficient data to establish 30-day peak rates have averaged 270 bbl/d per well. To-date, five partner-operated 1280-acre wells have averaged 410 bbl/d per well for their peak 30-day periods. As of the end of the third quarter, six (2.5 net) wells were awaiting fracture stimulation. In the fourth quarter of 2010, we plan to participate in the drilling of seven (1.9 net) wells in the Bakken/Three Forks, including our first operated 1280-acre well. In non-Bakken/Three Forks drilling in North Dakota, Baytex participated in one (0.4 net) dry hole targeting the Lodgepole formation, a shallower conventional zone.

Financial Review

Funds from operations (“FFO”) were $112.8 million in the third quarter of 2010, an increase of 3% compared to the second quarter of 2010. The increase in funds from operations was largely driven by increased production. The average WTI price for the quarter was US$76.20/bbl, a 2% decrease from the second quarter of 2010. We received an average oil price of $58.93/bbl in the third quarter of 2010 (inclusive of our physical hedging loss), no change from the second quarter of 2010. We also received an average natural gas price of $3.89/mcf in the third quarter of 2010, a decrease of 7% from the prior quarter.

The heavy oil price differential, as measured by Western Canadian Select ("WCS") prices, averaged 21% of WTI for the third quarter of 2010, compared to 18% in the second quarter of 2010 and 15% in the third quarter of 2009. The third quarter differential was negatively impacted by transportation constraints resulting from Enbridge pipeline leaks, which temporarily curtailed shipments to United States mid-continent refineries. Subsequent to the end of the third quarter, these leaks were repaired and pipeline deliveries resumed. Upon completion of repairs and announcement of resumption of operations on these pipelines, differentials have returned to about 18% of WTI. Our hedging program largely protected our revenues from the adverse financial impacts of this temporary widening of differentials, limiting the negative revenue impact from the pipeline leaks to approximately $2.5 million in the third quarter.

Our realized heavy oil price for the third quarter benefited from a reduction in diluent blending costs, both as a result of lower condensate pricing, and lower blend ratios due to better condensate quality since the commencement of shipments on the Southern Lights condensate pipeline. We expect that the lower blend ratios should be largely sustainable for the foreseeable future.

Our financial position continues to improve. At the end of the third quarter, total monetary debt amounted to $536 million, down from $553 million at the end of the second quarter. Our debt level at the end of the third quarter represents 1.2 times third quarter annualized funds from operations, leaving us with approximately $168 million in available undrawn credit facilities.

In the third quarter of 2010, total cash distributions declared were $45.8 million, or $0.54 per unit, representing a payout ratio of 41% net of DRIP participation (54% before DRIP). Based on the current commodity price strip, we expect to generate sufficient funds from operations for the full year in 2010 to fully fund our exploration and development capital program and our cash distributions, as we have done for the first nine months of 2010.

We continuously monitor the commodity and currency markets for favorable conditions to add to our risk management positions. Including hedge contracts entered into subsequent to the end of the third quarter, we have expanded our 2011 hedge positions to approximately 26% of our WTI exposure (at a weighted average price of US$86.31/bbl) and 35% of our heavy oil differential exposure. Under the majority of the heavy oil differential contracts, we will sell WCS at a weighted average fixed dollar discount to WTI of US$15.53/bbl. In the balance of the contracts, the differential is expressed as a percentage of WTI. Combining the two types of contracts, our 2011 differential hedges result in a weighted average discount of 17.3% of WTI based on the current WTI strip. In addition, we have contracted to sell a portion of our WCS volumes beyond 2011, resulting in the sale of 2,000 bbl/d of WCS blend for 2012 at a fixed differential of US$16.50/bbl and 3,000 bbl/d of WCS blend from January to June of 2013 at a fixed differential of US$17.00/bbl. At the current commodity strip, these fixed differentials represent approximately 18% of WTI for 2012 and the first six months of 2013. We have also hedged 28% of our 2011 natural gas pricing exposure (at a weighted average price of $5.16/mcf) and 25% of our 2011 U.S. dollar currency exposures (with USD sold at a weighted average USD/CAD exchange rate of 0.9365).

We have recently announced our planned conversion from the current trust structure to a corporate legal form pursuant to a Plan of Arrangement. An Information Circular regarding the Plan of Arrangement has been mailed to unitholders. A special meeting of the unitholders is scheduled for 3:00 p.m. MT on December 9, 2010 to vote on the terms of the Plan of Arrangement. Assuming receipt of all required unitholder, court, stock exchange and other regulatory approvals, we expect that the conversion will be completed on December 31, 2010.

Additional Information

Our unaudited Consolidated Financial Statements for the three months and nine months ended September 30, 2010 and 2009 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.

Conference Call

Baytex will hold a conference call and question and answer session at 2:00 p.m. MT (4:00 p.m. ET) on Wednesday, November 10, 2010 to discuss our third quarter 2010 results. The conference call will be hosted by Anthony Marino, President and Chief Executive Officer, and Derek Aylesworth, Chief Financial Officer. Interested parties are invited to participate by calling toll-free across North America at 1-888-340-9655 or within the Toronto area at 416-340-8527. An archived recording of the call will be available until November 17, 2010 by dialing 1-800-408-3053 within North America or 416-695-5800 within the Toronto area and entering reservation code 7282326. The conference call will also be archived on Baytex's website at www.baytex.ab.ca.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's unitholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this document 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 document speak only as of the date of this document 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 2010; our production level for 2010; our heavy oil resource play at Seal, including production rates from new and re-entered wells and drilling plans for the fourth quarter of 2010; our steam injection pilot project at Seal, including our assessment of the results achieved to-date, the steam-oil ratio for the second cycle, the continued improvement in injectivity, production rates and steam-oil ratios for subsequent cycles and the timing of completing a 10-well commercial module; our Kerrobert SAGD project, including production rates from new well pairs, the number of additional well pairs to be drilled and the cost of drilling a well pair; our Cardium light oil resource play in Alberta, including well completion plans and production rates from new wells; our Viking light oil resource play in Alberta and Saskatchewan, including initial production rates from new wells; our Bakken/Three Forks light oil resource play in North Dakota, including initial production rates from new wells and drilling plans for the fourth quarter of 2010; heavy oil price differentials; our expectation of continued access to better quality condensate will result in lower blend ratios; our liquidity and financial capacity; our ability to fund our capital expenditures and distributions from funds from operations in 2010; our risk management program, including the portion of our forecast 2011 exposures that have been hedged; and our plan to convert to a corporate legal form, including the timing of the conversion. 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.

These forward-looking statements are based on certain key assumptions regarding, among other things: the receipt of all necessary unitholder, court, stock exchange and other third party approvals; 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 distributions 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: failure to receive all necessary unitholder, court, stock exchange and other third party approvals; 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, Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2009, 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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