BAYTEX

ENERGY CORP.

FOR IMMEDIATE RELEASE – CALGARY, ALBERTA – MARCH 8, 2011

BAYTEX ANNOUNCES FOURTH QUARTER 2010 RESULTS AND YEAR-END 2010 RESERVES

CALGARY, ALBERTA (March 8, 2011) - Baytex Energy Corp. ("Baytex") (TSX, NYSE: BTE) is pleased to announce its operating and financial results for the three months and year ended December 31, 2010 (in Canadian dollars unless otherwise denoted), its year-end 2010 reserves and an update to its contingent resource assessment.

Highlights

- Completed the conversion of our legal structure from an income trust to a corporation at year-end 2010;

- Produced a quarterly record of 45,015 boe/d in Q4/2010 (an increase of 5% over Q4/2009) and an annual record of 44,341 boe/d in 2010 (an increase of 7% over 2009);

- Generated funds from operations ("FFO") of $124.8 million in Q4/2010 (an increase of 11% over Q3/2010) and $454.2 million in 2010 (the highest annual FFO in Baytex history);

- Increased total proved reserves 8% to 140 million boe and total proved plus probable reserves 16% to 229 million boe. Of this increase in reserves, 17 million barrels of contingent resource were converted into proved reserves and 42 million barrels of contingent resource were converted into proved plus probable reserves during 2010. As at December 31, 2010, the estimate of contingent resource ranges from 528 million barrels of oil and bitumen in the "Low Estimate" to 1.02 billion barrels of oil and bitumen in the "High Estimate", with a "Best Estimate" of 668 million barrels of oil and bitumen;

- Replaced 271% of production though exploration and development ("E&D") activities alone while re-investing only 52% of FFO into E&D. Including acquisitions, our capital program replaced 297% of production while investing 62% of FFO;

- Recorded finding, development and acquisition ("FD&A") costs of $13.17 per boe for proved plus probable reserves including changes in future development costs ("FDC") and $5.90 per boe excluding changes in FDC. Three year average (2008 – 2010) FD&A costs are $15.92 per boe for proved plus probable reserves including changes in FDC and $9.54 per boe excluding changes in FDC;

- Realized a recycle ratio (operating netback divided by FD&A costs) based on a proved plus probable reserves (including changes in FDC) of 2.5x in 2010 and 2.0x for the three year average, and a recycle ratio based on proved plus probable reserves (excluding changes in FDC) of 5.6x in 2010 and 3.3x for the three year average;

- Effective for our final trust distribution for December 2010 operations, increased our monthly distribution to, $0.20 per unit per month, an increase of 11%. We also established our initial dividend at $0.20 per share per month, with our inaugural dividend payment in respect of January 2011 operations;

- Maintained a payout ratio of 51% (39% net of dividend reinvestment plan ("DRIP") participation) for Q4/2010 and 54% (42% net of DRIP) for the full year 2010; and

- Delivered total market return (assuming reinvestment of distributions) of 27% in Q4/2010 and 67% in 2010. Total return during the entire trust era was 876%, representing the highest total return delivered by any oil and gas trust during the 2003 to 2010 period in which Baytex was organized as a trust.

	Three Months Ended			Year Ended	
	December 31, 2010	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
FINANCIAL *(thousands of Canadian dollars, except per common share or unit amounts)*					
Petroleum and natural gas sales	**263,497**	238,293	237,962	**1,005,136**	789,743
Funds from operations [(1)]	**124,776**	112,786	97,344	**454,183**	332,186
Per share or unit - basic	**1.10**	1.01	0.90	**4.08**	3.17
Per share or unit - diluted	**1.07**	0.97	0.87	**3.93**	3.10
Cash distributions declared[(2)]	**48,126**	45,795	37,286	**189,824**	137,601
Per unit	**0.56**	0.54	0.42	**2.18**	1.56
Net income	**57,589**	35,061	27,956	**177,631**	87,574
Per share or unit - basic	**0.51**	0.31	0.26	**1.59**	0.83
Per share or unit - diluted	**0.49**	0.30	0.25	**1.54**	0.82
Exploration and development	**55,175**	62,245	45,471	**236,979**	157,044
Acquisitions	**4,846**	12,875	37,143	**24,763**	133,155
Dispositions	**(896)**	(18,087)	(60)	**(19,033)**	(78)
Corporate acquisition	**-**	-	-	**40,914**	-
Total oil and gas expenditures	**59,125**	57,033	82,554	**283,623**	290,121
Bank loan	**303,773**	314,567	265,088	**303,773**	265,088
Convertible debentures	**-**	5,057	7,736	**-**	7,736
Long-term notes	**150,000**	150,000	150,000	**150,000**	150,000
Working capital deficiency	**48,417**	66,596	51,452	**48,417**	51,452
Total monetary debt [(3)]	**502,190**	536,220	474,276	**502,190**	474,276

Notes:

(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 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 year ended December 31, 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, long-term bank loan and the principal amount of long-term debt.*

	Three Months Ended			Year Ended	
	December 31, 2010	September 30, 2010	December 31, 2009	**December 31, 2010**	December 31, 2009
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**6,457**	6,600	6,541	**6,539**	6,937
Heavy oil (bbl/d)	**29,808**	28,959	26,423	**28,585**	24,678
Total oil (bbl/d)	**36,265**	35,559	32,964	**35,124**	31,615
Natural gas (mmcf/d)	**52.5**	55.4	58.5	**55.3**	58.6
Oil equivalent (boe/d @ 6:1) (1)	**45,015**	44,799	42,713	**44,341**	41,382
Average prices (before hedging)					
WTI oil (US$/bbl)	**85.17**	76.20	76.19	**79.53**	61.80
Edmonton par oil ($/bbl)	**80.73**	74.43	76.73	**77.81**	66.20
BTE light oil and NGL ($/bbl)	**68.07**	63.13	62.68	**65.90**	54.25
BTE heavy oil ($/bbl) (2)	**60.10**	57.97	57.24	**59.40**	49.88
BTE total oil ($/bbl)	**61.53**	58.93	58.31	**60.61**	50.85
BTE natural gas ($/mcf)	**3.84**	3.89	4.87	**4.32**	4.35
BTE oil equivalent ($/boe)	**53.99**	51.59	51.71	**53.39**	45.00
USD/CAD noon rate at period end	**1.0054**	0.9711	0.9555	**1.0054**	0.9555
USD/CAD average rate for period	**0.9873**	0.9624	0.9467	**0.9708**	0.8760
COMMON SHARE OR TRUST UNIT INFORMATION					
TSX					
Unit price (Cdn$)					
High	**$ 48.15**	$ 37.86	$ 30.50	**$ 48.15**	$ 30.50
Low	**$ 37.12**	$ 31.27	$ 21.57	**$ 27.72**	$ 9.77
Close	**$ 46.61**	$ 37.27	$ 29.70	**$ 46.61**	$ 29.70
Volume traded (thousands)	**32,579**	21,917	22,820	**105,385**	112,146
NYSE					
Unit price (US$)					
High	**$ 47.82**	$ 36.90	$ 29.32	**$ 47.82**	$ 29.32
Low	**$ 35.96**	$ 25.64	$ 19.83	**$ 25.64**	$ 7.84
Close	**$ 46.82**	$ 36.33	$ 28.30	**$ 46.82**	$ 28.30
Volume traded (thousands)	**5,231**	4,514	5,492	**21,489**	33,241
Common shares or trust units outstanding (thousands)	**113,712**	112,333	109,299	**113,712**	109,299

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 45,015 boe/d during the fourth quarter of 2010, as compared to 44,799 boe/d in the third quarter of 2010 and 42,713 boe/d in the fourth quarter of 2009. Production for full-year 2010 averaged 44,341 boe/d as compared to 41,382 boe/d for full-year 2009, with oil production 11% higher and natural gas production 6% lower.

Capital expenditures for E&D activities totaled $55.2 million for the fourth quarter of 2010 and $237.0 million for the full year of 2010. During the fourth quarter, Baytex participated in the drilling of 39 (25.9 net) wells, resulting in 32 (19.1 net) oil wells, three (2.8 net) natural gas wells, one (1.0 net) stratigraphic test well and three (3.0 net) dry and abandoned wells for a 92% (88% net) success rate. Fourth quarter drilling included fifteen (12.0 net) oil wells, one (0.8 net) natural gas well and three (3.0 net) dry and abandoned wells in our Lloydminster heavy oil area, one (1.0 net) stratigraphic test well at Seal, 11 (6.1 net) wells in our light oil and gas areas in western Canada and eight (3.0 net) oil wells in North Dakota. For the full year 2010, Baytex participated in the drilling of 155 (118.2 net) wells, resulting in 132 (97.2 net) oil wells, seven (5.6 net) natural gas wells, seven (7.0 net) stratigraphic test wells, five (5.0 net) service wells, and four (3.4 net) dry and abandoned wells for a success rate of 97% (97% net).

Consistent with previous guidance, our exploration and development capital budget for 2011 is $325 million, which is designed to generate an average production rate of 49,000 to 50,000 boe/d, including the contribution from our heavy oil acquisition which closed in February 2011.

Heavy Oil

In the fourth quarter of 2010, heavy oil production averaged 29,808 bbl/d, an increase of 3% over the third quarter of 2010 and 13% over the fourth quarter of 2009. During the fourth quarter of 2010, we drilled 16 (12.8 net) producing wells, one (1.0 net) stratigraphic test well, and three (3.0 net) dry and abandoned wells on our heavy oil properties for a success rate of 85% (82% net).

For full-year 2010, heavy oil production averaged 28,585 bbl/d, an increase of 16% over the full-year 2009 average. During 2010, we drilled 90 (79.7 net) wells in our heavy oil areas, resulting in 74 (63.9 net) oil wells, one (0.8 net) natural gas well, seven (7.0 net) stratigraphic test wells, five (5.0 net) service wells and three (3.0 net) dry and abandoned wells, for a success rate of 97% (96% net).

Production from Seal averaged approximately 10,200 bbl/d in the fourth quarter, an increase of 100 bbl/d over the third quarter of 2010, and 60% higher than the fourth quarter of 2009. Production at Seal for full-year 2010 averaged 9,100 bbl/d, 78% higher than the 2009 average rate of 5,100 bbl/d. In the fourth quarter, we re-entered three existing Seal producers and drilled ten to sixteen new laterals per well to access previously undrained areas of the reservoir. Production from the re-entered wells increased from an average of approximately 50 bbl/d per well prior to the workovers to a 30-day average peak rate of approximately 450 bbl/d per well after the workovers. Two wells drilled in the third quarter commenced production in the fourth quarter with 30-day average peak rates of approximately 320 bbl/d per well. In the first quarter of 2011, we plan to drill approximately five cold horizontal producers and seven stratigraphic test wells at Seal. For full-year 2011, we plan to drill a total of approximately 20 multi-lateral cold horizontal Seal producers.

In our Cliffdale cyclic steam stimulation ("CSS") project at Seal, we continued the second CSS production cycle in our pilot well. This cycle reached our targeted steam-oil-ratio of 1.9 barrels of steam per barrel of oil in the first quarter of 2011, and we have commenced our third steam injection cycle in this well. In the fourth quarter of 2010, we drilled one stratigraphic test well in Cliffdale in preparation for drilling additional CSS wells. In the fourth quarter, we received required regulatory approvals for additional CSS drilling at Cliffdale. We plan to drill at least two additional CSS wells at Cliffdale during the first quarter of 2011. A total of nine CSS wells are planned for 2011.

On February 3, 2011, we closed the acquisition of heavy oil assets located in the Seal area of northern Alberta and the Lloydminster area of western Saskatchewan (the "2011 Heavy Oil Acquisition"). 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 $159.4 million. The acquired assets are expected to produce approximately 2,600 bbl/d (100% heavy oil) for the remainder of 2011, of which 65% is from the Seal area and 35% is from the Lloydminster area.

Light Oil & Natural Gas

During the fourth quarter of 2010, light oil and natural gas production averaged 15,207 boe/d, which was comprised of 6,457 bbl/d of light oil and natural gas liquids ("NGL") and 52.5 mmcf/d of natural gas. Light oil and NGL production declined by 2% and natural gas production declined by 5% compared to the prior quarter. Compared to the fourth quarter of 2009, light oil and NGL production declined by 1% and natural gas production declined by 10%.

In the fourth quarter of 2010, we drilled 17 (7.1 net) oil wells and two (2.0 net) natural gas wells for a 100% success rate, not including one natural gas well drilled in our Lloydminster heavy oil area.

For full-year 2010, light oil, NGL and natural gas production averaged 15,756 boe/d, which was comprised of 6,539 bbl/d of light oil and NGL and 55.3 mmcf/d of natural gas, a decrease of 6% in both light oil and NGL and natural gas production as compared to full-year 2009 average production rates. During 2010, we drilled 65 (38.5 net) wells, resulting in 58 (33.3 net) oil wells, six (4.8 net) natural gas wells and one (0.4 net) dry and abandoned well for a success rate of 98% (99% net).

We continued development activities in our light oil resource plays in the fourth quarter. In our Cardium play in Alberta, we drilled and completed two (1.5 net) horizontal Cardium wells in the fourth quarter and conducted multi-stage fracture treatments on two Cardium wells that were drilled in the third quarter. The four wells produced at 30-day average peak rates of approximately 120 boe/d per well. We plan to drill approximately five Cardium horizontal wells in 2011.

In the fourth quarter, we applied multi-stage fracture treatments to two Saskatchewan Viking horizontal wells that were drilled in the third quarter. The wells produced at 30-day average peak rates of approximately 45 bbl/d per well. We plan to drill approximately 15 Viking light oil horizontal wells in 2011, the majority of which will be unstimulated multi-lateral wells in our Viking play in Alberta.

In our Bakken/Three Forks play in North Dakota, we participated in drilling eight (3.0 net) horizontal oil wells in the fourth quarter, five of which were Baytex-operated. Including two wells which were drilled in the third quarter of 2010, four Baytex-operated 640-acre spacing wells were completed in the fourth quarter, establishing 30-day average peak rates of 210 bbl/d per well. In the third quarter of 2010, we also re-entered an existing open-hole horizontal well and installed a liner and packer system. This well was fracture-treated in the fourth quarter, increasing production from five bbl/d before the workover to 90 bbl/d after the fracture stimulation. Subsequent to the end of the fourth quarter, we fracture-treated two Baytex-operated 1280-acre wells, establishing 30-day average peak rates of 320 bbl/d per well. In 2011, we plan to drill approximately 22 gross (9.4 net) wells in the Bakken/Three Forks in North Dakota.

Financial Review

Funds from operations were $124.8 million in the fourth quarter of 2010, an increase of 11% compared to the third quarter of 2010 and 28% compared to the fourth quarter of 2009. The increase in funds from operations was driven by increases in production and in oil prices. The WTI average price for the fourth quarter of 2010 was US$85.17/bbl, a 12% increase from both the third quarter 2010 and fourth quarter 2009. We received an average oil price of $61.53/bbl for our crude in the fourth quarter of 2010 (inclusive of our physical hedging loss), up from $58.93/bbl and $58.31/bbl for the third quarter of 2010 and fourth quarter of 2009, respectively. We also received an average natural gas price of $3.84/mcf in the fourth quarter of 2010, a decrease of 1% from the prior quarter and 21% from the fourth quarter of 2009.

The heavy oil price differential, as measured by Western Canadian Select ("WCS") prices, averaged 21% of WTI for the fourth quarter of 2010, as compared to 21% in the third quarter of 2010 and 16% in the fourth quarter of 2009. The fourth quarter differential was negatively impacted by transportation constraints resulting from service disruptions on key oil export pipelines, which temporarily curtailed shipments to U.S. mid-continent refineries. During the fourth quarter, these pipelines were repaired and deliveries resumed. The forward strip suggests a WCS differential of approximately 20% for the April to December 2011 period.

In the fourth quarter, total cash distributions declared were $48.1 million, or $0.56 per trust unit, representing a payout ratio of 51% (39% net of DRIP). During the fourth quarter, Baytex increased its monthly distribution by 11%, to $0.20 per unit commencing with the distribution in respect of December operations. The distribution increase was supported by the improvement in oil prices and the strength of our operational results. Based on the current commodity price strip, we expect to generate sufficient funds from operations in 2011 to fully fund our exploration and development capital program and our dividends.

At the end of the fourth quarter, total monetary debt was $502.2 million, which offers us undrawn credit facilities of $246.2 million and represents a debt-to-FFO ratio of 1.1 times based on trailing twelve months FFO. Both of these metrics are well within our leverage and liquidity targets, and provide ample capacity to finance our operations.

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 fourth quarter, we have expanded our 2011 hedge positions to approximately 40% of our WTI exposure (at a weighted average price of US$90.09/bbl) and 33% 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$16.69/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% 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 16% of WTI for 2012 and the first six months of 2013. We have also hedged 40% of our 2011 natural gas pricing exposure (at a weighted average price of $5.37/mcf) and 23% of our 2011 U.S. dollar currency exposures (with USD sold at a weighted average USD/CAD exchange rate of 0.9358).

On December 31, 2010, Baytex Energy Trust (the "Trust") completed the conversion of its legal structure from an income trust to a corporation in connection with a Plan of Arrangement under the Business Corporations Act (Alberta). As a result of this conversion, all outstanding trust units were exchanged for common shares of Baytex on a one-for-one basis. The reorganization into a corporation has been accounted for on a continuity of interest basis and, accordingly, the consolidated financial statements reflect the financial position, results of operations, and cash flows as if Baytex had always carried on the business formerly carried on by the Trust.

On February 3, 2011, Baytex completed the 2011 Heavy Oil Acquisition for total consideration of $159.4 million (net of adjustments). This acquisition was funded by drawing on Baytex's existing revolving credit facility.

Subsequent to year-end, Baytex continued the improvement in the structure of its balance sheet through several initiatives. First, Baytex entered into a series of agreements with its lending syndicate to increase the amount of its credit facilities to $650 million (from $550 million), to decrease its margins on advances based on prime lending rates, bankers' acceptance rates and LIBOR rates and to decrease standby fees. Second, we issued US$150 million in 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. Following these events, and considering the 2011 Heavy Oil Acquisition we have approximately $335 million in undrawn credit facilities, which represents a debt to FFO ratio of 1.1 times based on projected 2011 FFO, using the current commodity price strip. We believe that this positions us to take advantage of future potential investment opportunities as we move forward into the corporate era of Baytex.

Year-End 2010 Reserves

Baytex's year-end 2010 reserves are evaluated by Sproule Associates Limited ("Sproule"), the independent reserves evaluator for all of Baytex's oil and gas properties, in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"). Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2010, which will be filed in late March 2011. The December 31, 2010 reserve disclosure herein excludes the 2011 Heavy Oil Acquisition.

Highlights of the 2010 reserve report include:

- Total proved reserves increased 8% to 140 million boe, while total proved plus probable reserves increased 16% to 229 million boe;

- Inclusive of acquisitions, replaced 297% of production, with finding, development and acquisition costs ("FD&A") of $13.17 per boe for proved plus probable reserves including changes in FDC. Three-year average (2008 – 2010) FD&A costs are $15.92 per boe for proved plus probable reserves including changes in FDC;

- FD&A costs of $5.90 per boe for proved plus probable reserves excluding changes in FDC. Three-year average FD&A costs are $9.54 per boe for proved plus probable reserves excluding changes in FDC;

- Replaced 271% of production through exploration and development ("E&D") activities alone, while reinvesting only approximately 52% of FFO into E&D;

- Reserve life index is 13.2 years for proved plus probable reserves and 8.1 years for proved reserves, based on year-end reserves and the mid-point of our 2011 production guidance as at December 31, 2010 of 47,500 boe/d;

- Year-end 2010 reserves are comprised of 91% oil (including NGLs) on a proved plus probable basis, and 90% oil (including NGLs) on a proved basis;

- Generated a recycle ratio (operating netback divided by FD&A costs) based on proved plus probable reserves (including changes in FDC) of 2.5x in 2010 and 2.0x for the three-year average; and

- Generated a recycle ratio based on proved plus probable reserves (excluding changes in FDC) of 5.6x in 2010 and 3.3x for the three-year average.

Capital expenditures in 2010 totaled $284 million, with $237 million spent on exploration and development activities, and $47 million spent on property acquisitions (net of proceeds of disposition).

Heavy Oil

Year-end 2010 reserves reflect continued growth of our heavy oil reserves to 167 million barrels of proved plus probable reserves, an increase of 15% over 2009, and 105 million barrels of proved reserves, an increase of 8% over 2009.

At Seal, year-end 2010 proved reserves increased 44% to 45.0 million barrels and proved plus probable reserves increased 56% to 83.9 million barrels. Proved reserves consist of 39.9 million barrels of primary (cold) reserves and 5.1 million barrels of reserves from thermally-enhanced oil recovery ("TEOR"). There were no proved reserves from TEOR booked at Seal at year-end 2009. The proved plus probable reserves consist of 53.6 million barrels of primary (cold) reserves and 30.3 million barrels of reserves from TEOR. There were 8.2 million barrels of proved plus probable reserves from TEOR booked at Seal at year-end 2009. The steady reserve growth we have recorded since beginning development in 2005 is consistent with our view that this property holds significant long-term growth potential. At year-end 2010, primary (cold) reserves were included on only 21 of our 105 sections of oil sands leasehold at Seal, and thermal reserves were included on only 1.5 sections. The table below summarizes the steady reserve growth we have realized at Seal.

	Dec 31 2005	**Dec 31 2006**	**Dec 31 2007**	**Dec 31 2008**	**Dec 31 2009**	**Dec 31 2010**
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
Land Assigned Reserves						
Sections (640 acres)	4	8	12	15	20	23

We will continue to focus on development of this potential at Seal, and note that Seal will attract a larger percentage of our 2011 capital budget than any other project in our asset portfolio. In 2011, we expect to drill approximately 20 horizontal wells at Seal, largely comprised of multi-lateral wells. In addition, we intend to re-enter several existing single-leg horizontal wells and drill additional horizontal legs at closer inter-well spacing to increase recovery from these older wells. We also intend to complete our first 10-well module of CSS development at Seal during 2011.

Light Oil and Natural Gas Liquids

In combination, our proved plus probable light oil and NGL reserves increased by approximately six million barrels, or 39%, to 40 million barrels at year-end 2010.

In our light oil resource plays, the year-end 2010 reserves report reflects a 78% increase in proved plus probable reserves to 22.0 million boe for our Bakken/Three Forks development in North Dakota and a 92% increase in proved plus probable reserves to 4.2 million boe for our Viking development project in southeastern Alberta. Our year-end 2010 report includes 2.5 million boe of proved plus probable reserves for our southwest Saskatchewan Viking oil resource play. There were no undeveloped reserves booked for the Viking in southwest Saskatchewan at year-end 2009.

Natural Gas

Natural gas reserves declined year-over-year by eight Bcf, or 6%, to 126 Bcf on a proved plus probable basis. During 2010, we directed our efforts and capital toward oil development, and our reduced natural gas weighting and reserves reflect this focus.

Petroleum and Natural Gas Reserves as at December 31, 2010

	Forecast Prices and Costs					
	Light and Medium Crude Oil		Heavy Oil		Natural Gas Liquids	
Reserve Category	Gross (1) (Mbbl)	Net (2) (Mbbl)	Gross (1) (Mbbl)	Net (2) (Mbbl)	Gross (1) (Mbbl)	Net (2) (Mbbl)
Proved						
Developed Producing	7,011	5,764	35,751	29,030	2,057	1,461
Developed Non-Producing	634	509	14,610	12,281	337	247
Undeveloped	10,771	9,062	54,618	46,073	430	307
Total Proved	18,416	15,335	104,978	87,384	2,825	2,015
Probable	17,943	14,957	62,435	51,284	1,215	863
Total Proved Plus Probable	36,359	30,292	167,414	138,668	4,040	2,878

	Forecast Prices and Costs			
	Natural Gas		Oil Equivalent (3)	
Reserve Category	Gross (1) (Bcf)	Net (2) (Bcf)	Gross (1) (Mboe)	Net (2) (Mboe)
Proved				
Developed Producing	62.2	52.5	55,184	45,007
Developed Non-Producing	7.9	6.7	16,900	14,152
Undeveloped	13.7	11.1	68,106	57,290
Total Proved	83.8	70.3	140,190	116,449
Probable	43.5	36.1	88,835	73,118
Total Proved Plus Probable	127.3	106.4	229,025	189,567

Notes:
(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.
(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs 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.

Reserve Reconciliation

Reconciliation of Gross Company Interest Reserves [1] [2]
By Principal Product Type
Forecast Prices and Costs

	Light and Medium Crude Oil			Heavy Oil		
	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)
December 31, 2009	14,568	10,233	24,801	97,054	48,542	145,596
Extensions	4,931	9,073	14,004	14,142	2,533	16,675
Discoveries	-	-	-	93	38	131
Improved Recoveries	-	-	-	1,641	19,058	20,699
Technical Revisions	(219)	(2,764)	(2,983)	1,314	(8,252)	(6,938)
Acquisitions	754	1,381	2,135	1,483	772	2,255
Dispositions	-	-	-	(102)	(34)	(136)
Economic Factors	43	19	62	(213)	(222)	(435)
Production	(1,660)	-	(1,660)	(10,434)	-	(10,434)
December 31, 2010	18,417	17,942	36,359	104,978	62,435	167,413

	Natural Gas Liquids			Natural Gas including solution gas		
	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)	Proved (mmcf)	Probable (mmcf)	Proved + Probable (mmcf)
December 31, 2009	2,817	1,501	4,318	89,659	44,090	133,748
Extensions	253	143	396	7,278	9,247	16,525
Discoveries	-	-	-	-	-	-
Improved Recoveries	-	-	-	-	-	-
Technical Revisions	554	(396)	158	11,088	(8,439)	2,648
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(74)	(32)	(106)	(4,015)	(1,445)	(5,460)
Production	(726)	-	(726)	(20,185)	-	(20,185)
December 31, 2010	2,824	1,216	4,040	83,825	43,453	127,278

	Oil Equivalent [3]		
	Proved (mboe)	Probable (mboe)	Proved + Probable (mboe)
December 31, 2009	129,382	67,624	197,007
Extensions	20,539	13,290	33,829
Discoveries	93	38	131
Improved Recoveries	1,641	19,058	20,699
Technical Revisions	3,497	(12,819)	(9,322)
Acquisitions	2,237	2,153	4,390
Dispositions	(102)	(34)	(136)
Economic Factors	(913)	(476)	(1,389)
Production	(16,184)	-	(16,184)
December 31, 2010	140,190	88,835	229,025

Notes:
(1) Gross Company interest reserves include solution gas but do not include royalty interests.
(2) Reserve information as at December 31, 2010 and 2009 is prepared in accordance with NI 51-101.
(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reserve Life Index

The following table sets forth our reserve life index based on total proved and proved plus probable reserves and the mid-point of our 2011 production guidance as at December 31, 2010 of 47,500 boe/d. This guidance was increased to a mid-point of 49,500 boe/d following the 2011 Heavy Oil Acquisition.

	2011 Production Target	Reserve Life Index (years) Total Proved	Proved Plus Probable
Oil and NGL (bbl/d)	39,500	8.8	14.4
Natural Gas (mmcf/d)	48.0	4.8	7.3
Oil Equivalent (boe/d)	47,500	8.1	13.2

Capital Program Efficiency

Based on the evaluation of our petroleum and natural gas reserves prepared in accordance with NI 51-101 by our independent reserve evaluator, Sproule, the efficiency of our capital programs is summarized as follows:

	2010	**2009**	**2008**	**Three Year Average 2008 - 2010**
Excluding Future Development Costs				
FD&A costs – Proved ($/boe)				
Exploration and development[(1)]	**$ 9.54**	$ 12.54	$ 14.26	$ 11.50
Acquisitions (net of dispositions)	**21.84**	21.27	22.99	22.32
Total	**$ 10.52**	$ 15.45	$ 18.37	$ 14.57
FD&A costs – Proved plus probable ($/boe)				
Exploration and development[(1)]	**$ 5.41**	$ 9.25	$ 10.53	$ 7.39
Acquisitions (net of dispositions)	**10.96**	16.70	15.83	15.35
Total	**$ 5.90**	$ 11.63	$ 13.11	$ 9.54
Operating netback per boe[(2)]	**$ 32.79**	$ 27.64	$ 33.76	$ 31.42
Recycle ratio based on operating netback[(2)]				
Proved plus probable	**5.6**	2.4	2.6	3.3
Including Future Development Costs				
FD&A costs – Proved ($/boe)				
Exploration and development[(1)]	**$ 15.22**	$ 22.96	$ 11.01	$ 16.06
Acquisitions (net of dispositions)	**32.71**	28.28	27.87	28.52
Total	**$ 16.61**	$ 24.73	$ 18.95	$ 19.59
FD&A costs – Proved plus probable ($/boe)				
Exploration and development[(1)]	**$ 12.44**	$ 20.01	$ 12.09	$ 14.00
Acquisitions (net of dispositions)	**20.68**	23.12	20.23	21.09
Total	**$ 13.17**	$ 21.00	$ 16.06	$ 15.92
Recycle ratio based on operating netback[(2)]				
Proved plus probable	**2.5**	1.3	2.1	2.0

Notes:
(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.
(2) Recycle ratio is calculated as operating netback divided by FD&A costs (proved plus probable excluding FDC). Operating netback is calculated as revenue (including realized hedging gains and losses) minus royalties, operating expenses and transportation expenses.

Net Present Value of Reserves (Forecast Prices and Costs)

	Summary of Net Present Value of Future Net Revenue As at December 31, 2010 Before Income Taxes and Discounted at (%/year)				
Reserve Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	2,037,270	1,684,270	1,460,841	1,304,643	1,187,953
Developed Non-Producing	616,756	453,024	346,684	274,295	223,029
Undeveloped	2,298,669	1,599,073	1,172,832	897,447	708,885
Total Proved	4,952,695	3,736,367	2,980,357	2,476,385	2,119,867
Probable	3,244,722	1,835,564	1,194,590	850,602	643,448
Total Proved Plus Probable	8,197,417	5,571,931	4,174,947	3,326,987	2,763,315

The net present values noted in the table above do not include any value for future net revenue which may ultimately be generated from the contingent resources discussed later in this press release.

Sproule December 31, 2010 Forecast Prices

Year	WTI Cushing US$/bbl	Edmonton Par Price C$/bbl	Hardisty Heavy 12 API C$/bbl	AECO C-Spot C$/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2010 act.	79.43	77.81	62.29	4.16	1.5%	0.97
2011	88.40	93.08	74.46	4.04	1.5%	0.93
2012	89.14	93.85	75.08	4.66	1.5%	0.93
2013	88.77	93.43	72.87	4.99	1.5%	0.93
2014	88.88	93.54	71.09	6.58	1.5%	0.93
2015	90.22	94.95	72.16	6.69	1.5%	0.93
2016	91.57	96.38	73.25	6.80	1.5%	0.93
2017	92.94	97.84	74.36	6.91	1.5%	0.93
2018	94.34	99.32	75.48	7.02	1.5%	0.93
2019	95.75	100.81	76.62	7.14	1.5%	0.93
2020	97.19	102.34	77.78	7.26	1.5%	0.93

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below (using forecast prices and costs).

YEAR	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2011	255,592	327,459
2012	194,056	282,761
2013	103,985	200,014
2014	75,809	150,146
2015	54,939	152,561
Remaining	95,550	107,349
Total (Undiscounted)	779,931	1,220,290

Year-End Reserves and Reserve Life Index Pro Forma 2011 Heavy Oil Acquisition

On February 3, 2011, Baytex completed an acquisition of heavy oil assets located in the Seal area of northern Alberta and the Lloydminster area of western Saskatchewan. The assets were acquired through a combination of a corporate acquisition of a private company and an asset acquisition. The reserves attributed to the 2011 Heavy Oil Acquisition have been evaluated by Sproule effective January 1, 2011. The following tables highlight Baytex's reserves pro forma the 2011 Heavy Oil acquisition.

	Baytex Reserves Pro forma 2011 Heavy Acquisition Forecast Prices and Costs		
Reserve Category	Baytex	Acquisition	Pro forma
Heavy Oil (mbbl)			
Proved	104,978	6,201	111,179
Proved Plus Probable	167,414	10,501	177,915
Light Oil and Natural Gas Liquids (mbbl)			
Proved	21,241	-	21,241
Proved Plus Probable	40,399	-	40,339
Natural Gas (mmcf)			
Proved	83,865	-	83,825
Proved Plus Probable	127,278	-	127,278
Oil Equivalent (mboe)			
Proved	140,189	6,201	146,390
Proved Plus Probable	229,025	10,501	239,506

The following table sets forth our reserve life index based on pro forma total proved and pro forma proved plus probable reserves and the mid-point of our 2011 production guidance of 49,500 boe/d, as it was updated following the 2011 Heavy Oil Acquisition.

	2011 Production Target	Reserve Life Index (years) Total Proved	Proved Plus Probable
Oil and NGL (bbl/d)	41,500	8.7	14.4
Natural Gas (mmcf/d)	48.0	4.8	7.3
Oil Equivalent (boe/d)	49,500	8.1	13.3

Contingent Resource Assessment

We commissioned Sproule to conduct an assessment of contingent resource effective November 30, 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. This contingent resource assessment has now been updated by Sproule with an effective date of December 31, 2010. This update largely consisted of recognizing the conversion of 17 million barrels of oil and bitumen into proved reserves and 42 million barrels of oil and bitumen into proved plus probable reserves from contingent resource during 2010. Contingent resource represents the quantity 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.

For the total of these three plays, Sproule's estimate of contingent resource ranges from 528 million barrels of oil and bitumen in the "Low Estimate" (C1) to 1.02 billion barrels of oil and bitumen in the "High Estimate" (C3), with a "Best Estimate" (C2) of 668 million barrels of oil and bitumen. Contingent resources are in addition to currently booked reserves. The table below summarizes Sproule's estimates of working interest reserves and contingent resource for the three plays by geographic area.

	Proved plus Probable Reserves As at Dec. 31, 2010(2)	Contingent Resource(3) As at December 31, 2010		
(millions of barrels of oil and bitumen)(1)		Low(4)	Best(5)	High(6)
Bluesky – Seal, Alberta	*83.7*	*486.6*	*570.7*	*840.8*
Bakken/Three Forks – North Dakota, USA	*19.5*	*31.2*	*77.9*	*145.4*
Viking – Redwater, Alberta	*3.9*	*4.6*	*9.7*	*18.3*
Viking – Dodsland/Kerrobert, Saskatchewan	*2.9*	*5.8*	*10.0*	*16.8*
Total	*110.1*	*528.2*	*668.3*	*1,021.3*

Notes:

(1) 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.

(2) Proved plus probable reserve volumes are based on the report prepared by Sproule dated March 7, 2011 entitled "Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2010)", which was prepared in accordance with NI 51-101.

(3) 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.

(4) Low Estimate (C1) is considered to be a conservative estimate of the quantity of resources 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 resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources 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 resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources 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.

We did not commission Sproule to evaluate the contingent resources of our other oil resource plays, including the Viking and Cardium in central Alberta and the Slave Point in northern Alberta, or of our conventional oil and gas properties.

Additional Information

Our unaudited consolidated financial statements for the three months and years ended December 31, 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.

Our audited consolidated financial statements for the years ended December 31, 2010 and 2009 and related Management's Discussion and Analysis and our Annual Information Form for the year ended December 31, 2010 will be posted on our website and filed on SEDAR and EDGAR later this month.

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 and the allocation thereof; our average production rate for 2011; initial production rates from wells drilled, development plans for our properties, including the number of wells to be drilled in 2011; production for the remainder of 2011 from the 2011 Heavy Oil Acquisition; the pricing differential between Western Canadian Select and West Texas Intermediate crude oils; our ability to fund our capital expenditures and dividends from funds from operations in 2011; our liquidity and financial capacity; 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 December 31, 2010 (before and after giving effect to the 2011 Heavy Oil Acquisition); our debt to FFO ratio, our heavy oil resource play at Seal, including its growth potential, the number of wells to be drilled in 2011, our ability to increase recoveries from existing wells by drilling additional horizontal legs at closer inter-well spacing and the timing of completing a 10-well module of CSS development; the value of our undeveloped land holdings; the amount of future asset retirement obligations; the volumes and estimated value of our petroleum and natural gas reserves; the volume and product mix of our 2011 oil and gas production; the productive life of our reserves; future petroleum and natural gas prices; future results from operations and operating metrics; future costs, expenses and royalty rates; future exploration, development and acquisition activities (including drilling plans) and related capital expenditures; and contingent resource estimates and the assumptions relating thereto. 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, 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.

Non-GAAP Financial Measures

Funds from operations is not a measurement based on Generally Accepted Accounting Principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. Funds from operations represents cash generated from operating activities before changes in non-cash working capital, site restoration and reclamation expenditures, deferred charges and other assets. Baytex's determination of funds from operations may not be comparable with the calculation of similar measures for other entities. 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 to shareholders and capital investments. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

Advisory Regarding Oil and Gas Information

The reserves information contained in this press release has been prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"). Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2010, which will be filed in late March 2011. Listed below are cautionary statements that are specifically required by NI 51-101:

- *Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs 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.*

- *This press release contains reserves estimates for our Seal (Bluesky), North Dakota (Bakken/Three Forks), Redwater (Viking) and Dodsland/Kerrobert (Viking) properties. Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation.*

- *With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.*

- *This press release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.*

This press release contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage." There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Baytex will produce any portion of the volumes currently classified as contingent resources. A "best estimate" of contingent resources 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 resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

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

Notice to United States Readers

The petroleum and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (both as defined in SEC rules). Canadian securities laws require oil and gas issuers, in their filings with Canadian securities regulatory authorities, to disclose not only "proved reserves" but also "probable reserves" (both as defined in NI 51-101), both of which are defined differently from the SEC rules. Accordingly, proved, probable and proved plus probable reserves disclosed in this press release may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this press release may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

We also included in this press release estimates of contingent resources. Contingent resources represent the quantity of petroleum and natural gas 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. The SEC does not permit the inclusion of estimates of resources in reports filed with it by United States companies.

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