FOR IMMEDIATE RELEASE – CALGARY, ALBERTA – MARCH 14, 2012

BAYTEX ANNOUNCES 2011 RESULTS AND YEAR-END 2011 RESERVES

CALGARY, ALBERTA (March 14, 2012) - 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, 2011 (all amounts are in Canadian dollars unless otherwise noted).

Summary

- Produced record quarterly production of 53,054 boe/d in Q4/2011 (an increase of 18% over Q4/2010) and record annual production of 50,132 boe/d in 2011 (an increase of 13% over 2010);

- Generated record quarterly funds from operations ("FFO") of $163.0 million ($1.39 per basic share) in Q4/2011 (an increase of 32% over Q4/2010) and record annual FFO of $555.5 million ($4.79 per basic share) in 2011 (an increase of 24% over 2010);

- Increased total proved reserves by 12% to 157 million boe and total proved plus probable reserves by 10% to 252 million boe;

- As at December 31, 2011, contingent resource ranges from 560 million boe in the "Low Estimate" (a 6% increase over year-end 2010) to 1.2 billion boe in the "High Estimate" (an 19% increase over year-end 2010), with a "Best Estimate" of 783 million boe (a 17% increase over year-end 2010);

- Replaced 156% of 2011 production through exploration and development ("E&D") activities alone while re-investing only 66% of 2011 FFO into E&D. Including acquisitions (net of proceeds of disposition), our capital program replaced 227% of production while investing 93% of FFO;

- Recorded finding, development and acquisition ("FD&A") costs in 2011 of $18.57 per boe for proved plus probable reserves including changes in future development costs ("FDC") and $12.46 per boe excluding changes in FDC. Three year average (2009 – 2011) FD&A costs are $16.83 per boe for proved plus probable reserves including changes in FDC and $9.52 per boe excluding changes in FDC;

- Realized a recycle ratio (operating netback divided by FD&A costs) based on proved plus probable reserves (including changes in FDC) of 1.9x in 2011 and 1.9x for the three year average, and a recycle ratio based on proved plus probable reserves (excluding changes in FDC) of 2.8x in 2011 and 3.4x for the three year average;

- Maintained a cash payout ratio in Q4/2011 of 31% net of dividend reinvestment plan ("DRIP") participation;

- Closed a previously announced disposition of certain primarily undeveloped lands in Alberta and Saskatchewan for $47.4 million; and

- Generated total market return (including reinvestment of dividends) of 31.6% in Q4/2011 and 28.1% in 2011.

	Three Months Ended			Years Ended	
	December 31, 2011	September 30, 2011	December 31, 2010	**December 31, 2011**	December 31, 2010
FINANCIAL *(thousands of Canadian dollars, except per common share or unit amounts)*					
Petroleum and natural gas sales	**367,813**	313,787	263,497	**1,308,814**	1,005,136
Funds from operations (1)	**162,973**	144,825	123,162	**555,483**	447,657
Per share or unit – basic	**1.39**	1.24	1.09	**4.79**	4.02
Per share or unit – diluted	**1.36**	1.22	1.06	**4.67**	3.89
Cash dividends or distributions declared (2)	**50,925**	50,270	48,126	**205,960**	189,824
Cash dividends or distributions declared per share or unit	**0.62**	0.60	0.56	**2.42**	2.18
Net income	**57,780**	51,839	21,355	**217,432**	231,615
Per share or unit – basic	**0.49**	0.45	0.19	**1.88**	2.08
Per share or unit – diluted	**0.48**	0.44	0.18	**1.83**	2.01
Exploration and development	**72,013**	100,368	59,350	**367,848**	231,619
Property acquisitions	**10,329**	28,502	3,096	**76,164**	22,412
Corporate acquisition	**1,313**	22	-	**120,006**	40,314
Proceeds from divestitures	**(47,396)**	-	(896)	**(47,396)**	(19,033)
Total oil and natural gas capital expenditures	**36,259**	128,892	61,550	**516,622**	275,312
Bank loan	**311,960**	368,184	303,773	**311,960**	303,773
Long-term debt	**302,550**	305,835	150,000	**302,550**	150,000
Working capital deficiency	**36,071**	65,180	52,462	**36,071**	52,462
Total monetary debt (3)	**650,581**	739,199	506,235	**650,581**	506,235

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 year ended December 31, 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 long-term bank loans.

	Three Months Ended			Years Ended	
	December 31, 2011	September 30, 2011	December 31, 2010	**December 31, 2011**	December 31, 2010
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**7,232**	7,170	6,457	**6,769**	6,539
Heavy oil (bbl/d)	**38,006**	37,280	29,808	**35,252**	28,585
Total oil and NGL (bbl/d)	**45,238**	44,450	36,265	**42,021**	35,124
Natural gas (mmcf/d)	**46.9**	49.0	52.5	**48.7**	55.3
Oil equivalent (boe/d @ 6:1) (1)	**53,054**	52,625	45,015	**50,132**	44,341
Average prices (before hedging)					
WTI oil (US$/bbl)	**94.06**	89.76	85.17	**95.12**	79.53
Edmonton par oil ($/bbl)	**97.87**	92.45	80.73	**95.56**	77.81
BTE light oil and NGL ($/bbl)	**85.09**	80.48	68.07	**82.49**	65.90
BTE heavy oil ($/bbl) (2)	**70.85**	59.92	60.10	**65.53**	59.40
BTE total oil and NGL ($/bbl)	**73.13**	63.26	61.53	**68.26**	60.61
BTE natural gas ($/mcf)	**3.91**	4.20	3.84	**4.17**	4.32
BTE oil equivalent ($/boe)	**65.81**	57.31	53.99	**61.26**	53.39
USD/CAD noon rate at period end	**0.9833**	0.9626	1.0054	**0.9833**	1.0054
USD/CAD average rate for period	**0.9774**	1.0220	0.9873	**1.0114**	0.9708
COMMON SHARE OR TRUST UNIT INFORMATION					
TSX					
Share or Unit price (Cdn$)					
High	**$ 57.26**	$ 55.93	$ 48.15	**$ 58.76**	$ 48.15
Low	**$ 39.18**	$ 41.71	$ 37.12	**$ 39.18**	$ 27.72
Close	**$ 56.97**	$ 43.81	$ 46.61	**$ 56.97**	$ 46.61
Volume traded (thousands)	**26,471**	27,710	32,579	**111,236**	105,385
NYSE					
Share or Unit price (US$)					
High	**$ 56.33**	$ 59.04	$ 47.82	**$ 61.95**	$ 47.82
Low	**$ 36.39**	$ 40.31	$ 35.96	**$ 36.89**	$ 25.64
Close	**$ 55.89**	$ 41.67	$ 45.82	**$ 55.89**	$ 46.82
Volume traded (thousands)	**7,579**	11,771	5,231	**37,384**	21,489
Common shares or trust units outstanding (thousands)	**117,893**	116,755	113,712	**117,893**	113,712

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 53,054 boe/d during the fourth quarter of 2011, as compared to 45,015 boe/d in the fourth quarter of 2010 and 52,625 boe/d in the third quarter of 2011. Oil production in the fourth quarter increased 2% from the third quarter of 2011, while natural gas production decreased by 4%. Production for full-year 2011 averaged 50,132 boe/d, as compared to 44,341 boe/d for full-year 2010, with oil production 20% higher and natural gas production 12% lower.

Capital expenditures for exploration and development activities totaled $72.0 million for the fourth quarter of 2011 and $367.8 million for full-year 2011. During the fourth quarter, Baytex participated in the drilling of 32 (21.8 net) wells, resulting in 29 (18.8 net) oil wells and three (3.0 net) stratigraphic test and service wells for a 100% success rate. Fourth quarter drilling included 12 (11.3 net) oil wells and two (2.0 net) stratigraphic wells in our Lloydminster heavy oil area, four (4.0 net) horizontal cold production wells and one (1.0 net) service well in our Peace River heavy oil area, four (1.2 net) oil wells in our light oil and gas areas in western Canada, and nine (2.3 net) light oil wells in North Dakota. For full-year 2011, Baytex participated in the drilling of 198 (157.3 net) wells, resulting in 179 (138.3 net) oil wells, one (1.0 net) natural gas well, 16 (16.0 net) stratigraphic test and service wells, and two (2.0 net) dry and abandoned wells for a success rate of 99% (99% net).

Consistent with previous guidance, our exploration and development capital budget for 2012 is set at $400 million which is designed to generate an average annual production rate of 54,000 to 55,000 boe/d.

Heavy Oil

In the fourth quarter of 2011, heavy oil production averaged 38,006 bbl/d, an increase of 28% over the fourth quarter of 2010 and 2% over the third quarter of 2011. During the fourth quarter of 2011, we drilled 16 (15.3 net) oil wells and three (3.0 net) stratigraphic test and service wells on our heavy oil properties for a success rate of 100%.

For full-year 2011, heavy oil production averaged 35,252 bbl/d, an increase of 23% over the full-year 2010 average. During 2011, we drilled 129 (123.9 net) wells in our heavy oil areas, resulting in 112 (106.9 net) oil wells, 16 (16.0 net) stratigraphic test and service wells, and one (1.0 net) dry and abandoned well for a success rate of 99% (99% net).

Production from our Peace River area properties averaged approximately 17,500 bbl/d in the fourth quarter, including volumes produced from the Reno area assets acquired in February 2011. In the fourth quarter of 2011, we drilled four (4.0 net) cold horizontal producers in the Peace River area, including three at Seal and one at Reno. Performance of our new Reno area wells improved over the two-week rates reported with our third quarter results. Including one well which was drilled in the third quarter, our two Reno area wells have now established average 30-day peak rates of 540 bbl/d. At Seal, three wells drilled in the fourth quarter and two wells drilled in the third quarter established average 30-day peak production rates of approximately 370 bbl/d per well. In the first quarter of 2012, we plan to drill approximately nine cold horizontal wells and 13 stratigraphic test wells in the Peace River area. For the full-year 2012, we plan to drill a total of approximately 40 cold horizontal wells in the Peace River area.

In the Cliffdale area of Seal, we began operation of our first commercial cyclic steam stimulation (“CSS”) project during the fourth quarter. We have now finished first-cycle steam and commenced flowback operations in two wells drilled earlier in 2011. Each of these wells accepted 40% more steam than our original Cliffdale CSS pilot well in its first cycle and we observed peak oil rates of approximately 300 bbl/d, 20% higher than first-cycle pilot well production performance. Subsequent to the end of the fourth quarter, we began fourth-cycle steaming of the pilot well, with significantly increased injectivity as compared to its third injection cycle. Based on steam injection rates thus far in the fourth-cycle for the pilot well, we project a steam slug size that is 70% higher than in the third injection cycle. During the fourth quarter, we drilled a horizontal water source well and commenced drilling operations on the final five CSS wells of the first 10-well thermal module, setting intermediate casing before year-end and drilling the horizontal laterals in January 2012. Subject to receipt of regulatory approvals, we plan to initiate development of a new 15-well thermal module during the fourth quarter of 2012.

Light Oil & Natural Gas

During the fourth quarter of 2011, light oil, NGL and natural gas production averaged 15,048 boe/d, which was comprised of 7,232 bbl/d of light oil and NGL and 46.9 mmcf/d of natural gas. Compared to the fourth quarter of 2010, light oil and NGL production increased by 12% and natural gas production declined by 11%. Compared to the third quarter of 2011, light oil and NGL production increased by 1% and natural gas production decreased by 4%.

During the fourth quarter of 2011, we completed the construction of a 33 kilometre wet gas pipeline in west central Alberta. This infrastructure expansion alleviated capacity restrictions that had adversely impacted our O'Chiese area natural gas and NGL production in 2011.

In the fourth quarter, we drilled one (1.0 net) Viking multi-lateral well in eastern Alberta, but it did not commence production before the end of the quarter. We plan to drill approximately ten Viking light oil horizontal wells in eastern Alberta in 2012, including two in the first quarter.

Two operated Cardium horizontal wells were fracture-stimulated and put on production in the fourth quarter and established average 30-day peak production rates of 180 boe/d.

During the fourth quarter, in our Bakken/Three Forks play in North Dakota, we participated in the drilling of nine (2.3 net) horizontal oil wells, six of which were Baytex-operated, and the fracture-stimulation of ten (2.6 net) wells. During the fourth quarter, ten Baytex-interest 1,280-acre spacing wells established average 30-day peak production rates of approximately 390 bbl/d and two Baytex-interest 640-acre spacing wells established average 30-day peak production rates of approximately 185 bbl/d.

Acquisition and Divestiture Activity

In the fourth quarter, we 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 was no production on the divested lands.

Also in the fourth quarter, we closed the sale of approximately 32,600 net acres of leasehold in the "halo" of the Dodsland field in southwest Saskatchewan for $36.3 million. Production from the lands at the time of sale was approximately 60 bbl/d. As at December 31, 2010, the properties had booked proved plus probable reserves of approximately 1.5 million boe (9% proved developed producing). We 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 fourth 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 $163 million ($1.39 per basic share) in the fourth quarter of 2011, an increase of 32% compared to the fourth quarter of 2010, and an increase of 13% compared to the third quarter of 2011. The increase in FFO relative to the third quarter of 2011 was the result of increased sales volumes combined with higher oil price realizations in the fourth quarter. Consistent with our practice prior to the adoption of IFRS, FFO is presented net of financing costs, which totaled $10.9 million in the fourth quarter.

The average WTI price for the fourth quarter of 2011 was US$94.06/bbl, a 10% increase from the fourth quarter of 2010, and a 5% increase from the third quarter of 2011. We received an average oil and NGL price of $73.13/bbl in the fourth quarter of 2011 (inclusive of our physical hedging gains), up from $61.53/bbl for the fourth quarter of 2010 and $63.26/bbl for the third quarter of 2011. We received an average natural gas price of $3.91/mcf in the fourth quarter of 2011, up from $3.84/mcf for the fourth quarter of 2010 and down from $4.20/mcf for the third quarter of 2011.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 11.2% for the fourth quarter of 2011, as compared to 21.5% in the fourth quarter of 2010 and 19.6% in the third quarter of 2011. The reduced WCS differential was primarily due to increases in mid-continent refinery runs of heavy oil. In the first quarter of 2012, heavy oil differentials have widened as a result of both unplanned refinery outages and seasonal refinery turnarounds. This decreased refinery throughput exacerbated pipeline logistical difficulties as transport systems struggled to move increased oil production from several sources, including the Williston Basin in the United States. At the time of this writing, the prompt WCS differential to WTI was approximately 30%. As we look forward, incremental transportation capacity from the reversal of the Seaway pipeline near the end of the second quarter of 2012 may alleviate some pipeline constraints and crude oil backlogs, and completion of refinery turnarounds may support tighter heavy oil differentials. Nonetheless, in a closely balanced market, heavy oil differentials have the potential to remain volatile for the balance of 2012. Over the longer term, we continue to believe that transportation solutions to allow Canadian crudes to access additional markets will proceed, and that the prices for Canadian crudes will more closely match those of worldwide quality peers.

Baytex continues to actively hedge its exposure to commodity prices and foreign exchange rates. At the time of this writing, we have established forward contacts for 2012 on approximately 39% of our WTI price exposure, 24% of our heavy oil differential exposure, 18% of our natural gas price exposure (excluding covered call options that we have sold on natural gas), and 28% of our exposure to currency movements between the Canadian and US dollars. Details of all hedging contracts are contained in the notes to our interim condensed consolidated financial statements. We continue to monitor the markets for opportunities to add to our hedge positions.

Our WTI hedges include a series of ”extendable” swaps which are not included in the 39% WTI coverage cited above. The extendable swaps grant our counterparties the option to extend price swaps on up to 3,750 bbl/d at a weighted-average fixed price of $108.28/bbl for the second half of 2012. If our counterparties elect to extend those contracts, we will have 44% of our 2012 WTI exposure covered by swaps and collars.

Our WCS differential hedges are primarily contracts that provide a fixed dollar differential to WTI. Based on the forward strip for WTI, our WCS contracts for 2012 translate to approximately a 17% differential to WTI. We have additional contracts for smaller volumes in place for 2013 and 2014 at 19% differentials to WTI. In addition to our hedging program, we are also mitigating our exposure to WCS differentials by railing crude oil to higher value markets. We have contracted to deliver approximately 15% of our heavy volumes for March to market by rail and expect railed volumes to increase during the remainder of 2012. Furthermore, as part of our long-term transportation portfolio, we have submitted a nomination for a ten-year open-season pipeline commitment which, if accepted, would enable us to access the U.S. Gulf Coast markets for approximately 12% of our heavy oil production (based on current production rates) starting in mid-2014.

During the fourth quarter of 2011, we repaid $89 million of our monetary debt with the proceeds of asset dispositions and with FFO in excess of our spending requirements. We ended the year with total monetary debt of $651 million and undrawn credit facilities of $388 million. This level of debt represents a debt-to-FFO ratio of 1.2 times, based on FFO over the trailing twelve months. This level of debt and undrawn credit facilities are within our leverage and liquidity targets, and provide ample capacity to finance our operations.

Year-End 2011 Reserves

Baytex's year-end 2011 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, 2011, which will be filed later this month.

Highlights of the 2011 reserve report include:

- Total proved reserves increased 12% to 157 million boe, while total proved plus probable reserves increased 10% to 252 million boe;
- Inclusive of acquisitions, we replaced 227% of production, with FD&A costs of $18.57 per boe for proved plus probable reserves including changes in FDC. Three-year average (2009 – 2011) FD&A costs are $16.83 per boe for proved plus probable reserves including changes in FDC;
- FD&A costs of $12.46 per boe for proved plus probable reserves excluding changes in FDC. Three-year average (2009 - 2011) FD&A costs are $9.52 per boe for proved plus probable reserves excluding changes in FDC;
- Replaced 156% of production through E&D activities, while reinvesting only approximately 66% of FFO into E&D;
- Reserve life index is 13.0 years for proved plus probable reserves and 8.1 years for proved reserves, based on year-end reserves and Q4/2011 production of 53,054 boe/d;
- Year-end 2011 reserves are comprised of 92% oil and NGL on a proved plus probable basis, and 91% oil and NGL 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 1.9x in 2011 and 1.9x for the three-year average; and
- Generated a recycle ratio based on proved plus probable reserves (excluding changes in FDC) of 2.8x in 2011 and 3.4x for the three-year average.

Capital expenditures in 2011 totaled $517 million, with $368 million spent on exploration and development activities, and $149 million spent on property acquisitions (net of proceeds of disposition).

Heavy Oil

Year-end 2011 reserves reflect continued growth of our heavy oil reserves to 179 million barrels of proved plus probable reserves, an increase of 7% over 2010, and 108 million barrels of proved reserves, an increase of 3% over 2010.

At Peace River, excluding the Reno lands acquired in 2011, year-end 2011 proved reserves increased 8% to 48.5 million barrels (19% to 53.5 million barrels including Reno) and proved plus probable reserves increased 11% to 92.9 million barrels (22% to 102.1 million barrels including Reno). Proved reserves consist of 40.0 million barrels of primary (cold) reserves and 8.5 million barrels of reserves from thermally-enhanced oil recovery (“TEOR”). Proved plus probable reserves consist of 60.0 million barrels of primary (cold) reserves and 32.9 million barrels of reserves from TEOR. At year-end 2011, primary (cold) reserves were included on only 34 of our 263 sections of oil sands leasehold at Peace River, and thermal reserves were included on only 2 sections. The table below summarizes the reserve growth we have realized at Peace River since development began in 2005.

							Dec 31 2011	
	Dec 31 2005	**Dec 31 2006**	**Dec 31 2007**	**Dec 31 2008**	**Dec 31 2009**	**Dec 31 2010**	**Excluding Reno**	**Including Reno**
Reserves (MMbbl)								
Total Proved	2.2	8.5	20.2	27.0	31.2	45.0	48.5	53.5
Proved plus Probable	4.0	13.0	28.7	39.2	54.7	83.9	92.9	102.1
Land Assigned Reserves								
Sections (640 acres)	4	8	12	15	20	23	28	36

We will continue to focus on development of this potential at Peace River, and note that it will attract a larger percentage of our 2012 capital budget than any other project in our asset portfolio. In 2012, we expect to drill approximately 40 horizontal wells at Peace River, largely comprised of multi-lateral wells. Subject to receipt of regulatory approvals, we plan to initiate development of a second CSS module at Seal during the fourth quarter of 2012, with a planned module size of 15 wells, as compared to the 10-well CSS module that is currently in operation.

Light Oil and Natural Gas Liquids

In combination, our proved plus probable light oil and NGL reserves increased by approximately 11.5 million barrels, or 28%, to 52 million barrels at year-end 2011.

In our light oil resource plays, the year-end 2011 reserves report reflects a 47% increase in proved plus probable reserves to 32.4 million boe for our Bakken/Three Forks development in North Dakota and a 15% increase in proved plus probable reserves to 7.8 million boe for our Viking developments in southeast Alberta and southwest Saskatchewan, despite the divestiture of our Dodsland lands.

Natural Gas

Natural gas reserves declined year-over-year by one Bcf, or 1%, to 126 Bcf on a proved plus probable basis. During 2011, 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, 2011

	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	8,419	6,955	41,740	34,949	1,845	1,322
Developed Non-Producing	806	664	12,356	10,329	110	77
Undeveloped	18,999	16,092	53,998	46,471	3,811	3,132
Total Proved	28,224	23,711	108,094	91,749	5,766	4,531
Probable	15,010	12,656	71,150	59,169	2,857	2,226
Total Proved Plus Probable	43,234	36,367	179,244	150,918	8,623	6,757

	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	55.3	47.8	61,224	51,194
Developed Non-Producing	3.4	2.9	13,844	11,552
Undeveloped	28.2	22.8	81,494	69,500
Total Proved	86.9	73.5	156,562	132,246
Probable	39.5	32.8	95,613	79,508
Total Proved Plus Probable	126.4	106.3	252,175	211,754

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, 2010	18,416	17,943	36,359	104,978	62,435	167,413
Extensions	8,762	5,299	14,061	9,477	7,929	17,406
Discoveries	-	-	-	51	17	68
Improved Recoveries	-	-	-	3,191	3,409	6,600
Technical Revisions	3,498	(7,348)	(3,850)	(2,873)	(6,701)	(9,574)
Acquisitions	-	-	-	6,222	4,031	10,252
Dispositions	(548)	(864)	(1,412)	-	-	-
Economic Factors	(38)	(20)	(58)	(86)	30	(56)
Production	(1,866)	-	(1,866)	(12,867)	-	(12,867)
December 31, 2011	28,224	15,010	43,234	108,094	71,151	179,244

	Natural Gas Liquids			Natural Gas including solution gas		
	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)	Proved (mmcf)	Probable (mmcf)	Proved + Probable (mmcf)
December 31, 2010	2,825	1,215	4,040	83,825	43,453	127,278
Extensions	797	585	1,382	12,522	6,580	19,102
Discoveries	-	-	-	-	-	-
Improved Recoveries	-	-	-	21	5	26
Technical Revisions	2,367	902	3,269	4,461	(12,871)	(8,410)
Acquisitions	458	173	631	8,565	3,348	11,913
Dispositions	-	-	-	(240)	(13)	(253)
Economic Factors	(77)	(18)	(95)	(4,520)	(930)	(5,450)
Production	(604)	-	(604)	(17,764)	-	(17,764)
December 31, 2011	5,766	2,857	8,623	86,870	39,572	126,442

	Oil Equivalent (3)		
	Proved (mboe)	Probable (mboe)	Proved + Probable (mboe)
December 31, 2010	140,190	88,835	229,025
Extensions	21,123	14,910	36,033
Discoveries	51	17	68
Improved Recoveries	3,194	3,410	6,604
Technical Revisions	3,736	(15,291)	(11,555)
Acquisitions	8,107	4,762	12,869
Dispositions	(588)	(866)	(1,454)
Economic Factors	(953)	(164)	(1,117)
Production	(18,298)	-	(18,298)
December 31, 2011	156,562	95,613	252,174

Notes:
(1) Gross Company interest reserves include solution gas but do not include royalty interests.
(2) Reserve information as at December 31, 2011 and 2010 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 actual Q4/2011 production level of 53,054 boe/d.

	Q4/2011 Production	Reserve Life Index (years) Total Proved	Proved Plus Probable
Oil and NGL (bbl/d)	45,238	8.6	14.0
Natural Gas (mmcf/d)	46.8	5.1	7.4
Oil Equivalent (boe/d)	53,054	8.1	13.0

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:

	2011	2010	2009	Three Year Average 2009 - 2011
Excluding Future Development Costs				
FD&A costs – Proved ($/boe)				
Exploration and development[1]	**$ 13.85**	$ 9.54	$ 12.54	**$ 11.92**
Acquisitions (net of dispositions)	**18.35**	21.84	21.27	**19.91**
Total	**$ 14.90**	$ 10.52	$ 15.45	**$ 13.56**
FD&A costs – Proved plus probable ($/boe)				
Exploration and development[1]	**$ 12.87**	$ 5.41	$ 9.25	**$ 8.52**
Acquisitions (net of dispositions)	**11.56**	10.96	16.70	**13.09**
Total	**$ 12.46**	$ 5.90	$ 11.63	**$ 9.52**
Operating netback per boe[2]	**$ 34.68**	$ 32.27	$ 27.64	**$ 31.95**
Recycle ratio[2]				
Proved plus probable	**2.8**	5.5	2.4	**3.4**
Including Future Development Costs				
FD&A costs – Proved ($/boe)				
Exploration and development[1]	**$ 24.18**	$ 15.22	$ 22.96	**$ 20.46**
Acquisitions (net of dispositions)	**23.39**	32.71	28.28	**26.45**
Total	**$ 24.00**	$ 16.61	$ 24.73	**$ 21.69**
FD&A costs – Proved plus probable ($/boe)				
Exploration and development[1]	**$ 19.99**	$ 12.44	$ 20.01	**$ 16.29**
Acquisitions (net of dispositions)	**15.43**	20.68	23.12	**18.76**
Total	**$ 18.57**	$ 13.17	$ 21.00	**$ 16.83**
Recycle ratio[2]				
Proved plus probable	**1.9**	2.5	1.3	**1.9**

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). Operating netback is calculated as revenue (including realized hedging gains and losses) minus royalties, production and operating expenses and transportation expenses.

Net Present Value of Reserves (Using Forecast Prices and Costs and Before Income Taxes)

Reserve Category	Summary of Net Present Value of Future Net Revenue As at December 31, 2011 Before Income Taxes and Discounted at (%/year)				
	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	2,245,149	1,886,065	1,646,807	1,474,966	1,344,829
Developed Non-Producing	511,190	388,377	304,848	245,749	202,561
Undeveloped	2,706,576	1,804,291	1,274,225	939,406	714,592
Total Proved	5,462,915	4,078,732	3,225,881	2,660,121	2,261,982
Probable	3,884,906	2,343,263	1,590,382	1,158,294	885,369
Total Proved Plus Probable	9,347,822	6,421,995	4,816,263	3,818,415	3,147,351

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, 2011 Forecast Prices

Year	WTI Cushing US$/bbl	Edmonton Par Price C$/bbl	Hardisty Lloydblend 20.5^{o} API C$/bbl	AECO C-Spot C$/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2011 act.	95.00	95.16	77.09	3.72	1.5	1.01
2012	98.07	96.87	82.34	3.16	2.0	1.01
2013	94.90	93.75	79.69	3.78	2.0	1.01
2014	92.00	90.89	77.25	4.13	2.0	1.01
2015	97.42	96.23	81.80	5.53	2.0	1.01
2016	99.37	98.16	83.44	5.65	2.0	1.01
2017	101.35	100.12	85.10	5.77	2.0	1.01
2018	103.38	102.12	86.81	5.89	2.0	1.01
2019	105.45	104.17	88.54	6.01	2.0	1.01
2020	107.56	106.25	90.31	6.14	2.0	1.01
2021	109.71	108.38	92.12	6.27	2.0	1.01

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)
2012	219,874	287,245
2013	265,695	352,796
2014	215,271	289,184
2015	154,327	238,187
2016	127,843	171,979
Remaining	112,273	134,167
Total (Undiscounted)	1,095,283	1,473,558

Contingent Resource Assessment

We commissioned Sproule to conduct an assessment of contingent resource effective December 31, 2011 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 the Redwater area of Alberta and the Kerrobert and Whiteside areas of Saskatchewan. We also commissioned McDaniel & Associates Consultants Ltd. ("McDaniel") to conduct an assessment of contingent resource effective December 31, 2011 on certain heavy oil properties in Northeast Alberta.

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 four plays, Sproule and McDaniel's estimate of contingent resource as of December 31, 2011 ranges from 560 million boe in the "low estimate" (C1) to 1.2 billion boe in the "high estimate" (C3), with a "best estimate" (C2) of 783 million boe. Contingent resources are in addition to currently booked reserves. During 2011, 26 million boe of C1 contingent resources were converted into proved reserves and 32 million barrels of C2 contingent resources were converted into proved plus probable reserves.

The tables below summarize Sproule and McDaniel's estimates of gross reserves and contingent resources for the four plays by geographic area and the net present value before tax of the future net revenue attributable to the contingent resource using forecast prices and costs and before income taxes.

Summary of Contingent Resources[1]
As of December 31, 2011

(millions of barrels of oil equivalent and bitumen)[3]	Proved plus Probable Gross Reserves[4] As at Dec. 31, 2011	Contingent Resources (gross)[5] As at Dec. 31, 2011		
		Low[6]	Best[7]	High[8]
Bluesky – Seal, Alberta	92.9	438.8	531.0	776.9
Mannville Group – Northeast Alberta	4.0	69.6	130.1	201.8
Bakken/Three Forks – North Dakota, USA	32.4	47.3	110.5	204.9
Viking – Redwater, Alberta	3.6	4.2	9.3	18.0
Viking – Kerrobert/Whiteside, Saskatchewan	4.2	0.6	1.9	10.1
Total	137.1	560.4	782.9	1,211.7
Percent oil and bitumen		99%	99%	98%

	Summary of Net Present Values of Future Net Revenues from Contingent Resources As of December 31, 2011 Forecast Prices and Costs(2)			
	Before income taxes discounted at (%/year) (9)			
	0%	5%	8%	10%
	($ millions)			
Low estimate (C1)(6)				
Bluesky – Seal, Alberta	13,596.8	6,021.3	3,855.0	2,905.8
Mannville Group – Northeast Alberta	1,365.9	640.3	430.0	333.6
Bakken/Three Forks – North Dakota, USA	1,150.9	370.5	189.3	119.8
Viking – Redwater, Alberta	26.6	(0.1)	(9.1)	(13.2)
Viking – Kerrobert/Whiteside, Saskatchewan	(26.2)	(19.7)	(16.7)	(15.0)
Total	16,113.9	7,012.2	4,448.5	3,331.0
Best estimate (C2)(7)				
Bluesky – Seal, Alberta	17,810.2	7,757.3	4,927.1	3,697.2
Mannville Group – Northeast Alberta	3,365.4	1,348.7	856.8	648.8
Bakken/Three Forks – North Dakota, USA	5,650.3	1,821.3	1,014.6	708.6
Viking – Redwater, Alberta	421.5	260.5	200.0	169.1
Viking – Kerrobert/Whiteside, Saskatchewan	31.3	16.3	10.7	7.9
Total	27,278.8	11,240.1	7,009.2	5,231.6
High estimate (C3)(8)				
Bluesky – Seal, Alberta	29,738.4	12,092.3	7,434.6	5,476.0
Mannville Group – Northeast Alberta	6,088.5	2,265.1	1,404.7	1,053.9
Bakken/Three Forks – North Dakota, USA	13,540.2	3,874.9	2,093.7	1,450.7
Viking – Redwater, Alberta	1,083.3	666.5	518.4	444.2
Viking – Kerrobert/Whiteside, Saskatchewan	464.9	264.4	191.4	155.4
Total	50,915.4	19,163.2	11,642.8	8,580.2

Notes:

(1) The contingent resource assessments were prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook and NI 51-101. Contingent resource is defined in the Canadian Oil and Gas Evaluation Handbook as those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets.

(2) The forecast price and cost assumptions utilized in the year-end 2011 reserves report were also utilized by Sproule and McDaniel in preparing the contingent resource assessments. See "Sproule December 31, 2011 Forecast Prices" in this press release.

(3) 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.

(4) Proved plus probable gross reserve volumes are based on the year-end 2011 reserves report.

(5) Sproule and McDaniel 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. Gross means the company's working interest share in the contingent resource before deducting royalties.

(6) 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.

(7) 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.

(8) 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.

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

There is no certainty that it will be commercially viable to produce any portion of the contingent resource or that we will produce any portion of the volumes currently classified as contingent resource. The recovery and resource estimates provided herein are estimates. Actual contingent resource (and any volumes that may be reclassified as reserves) and future production from such contingent resource may be greater than or less than the estimates provided herein.

Management Appointments

We are pleased to announce the following appointments to our management team and reorganization of our business unit structure.

Michael Kaluza, formerly our Vice President of Planning, has been promoted to Vice President of Corporate Development and Planning. In his new role, Mr. Kaluza will continue to discharge his planning responsibilities while also assuming leadership of our acquisition and divestiture program.

Kendall Arthur has been named Vice President of our newly-created Saskatchewan Business Unit. This business unit has been formed to operate and develop our Lloydminster-area heavy oil assets, which had previously been managed in combination with our Peace River heavy oil assets. The Saskatchewan Business Unit is charged with maintaining high capital efficiencies while developing a growth trajectory for our Lloydminster assets. Mr. Arthur has a Bachelor of Science degree in Mechanical Engineering from the University of Saskatchewan and was formerly Team Leader for our Tangleflags-area integrated team.

Rick Ramsay, formerly Vice President of our Heavy Oil Business Unit, has assumed leadership of our light oil and gas assets in western Canada as well as continuing his management of our Peace River assets. Mr. Ramsay's new title is Vice President, Alberta/British Columbia Business Unit.

These management appointments and the reorganization of our business units further strengthen Baytex as we execute our growth-and-income business model.

Additional Information

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

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to: our exploration and development capital expenditures for 2012; our average production rate for 2012; development plans for our properties, including the number of wells to be drilled in the first quarter and full-year 2012; initial production rates from wells drilled; our Cliffdale cyclic steam stimulation project at Seal, including our assessment of the steam injection cycle and initial production rates for two additional wells, the steam slug size for the third steam cycle of the original pilot well and our plan for a second commercial module of CSS; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate; the alleviation of pipeline constraints through the addition of incremental transportation capacity; the completion of refinery turnarounds; the demand for Canadian heavy oil by U.S. refiners; the existence, operation and strategy of our risk management program for commodity prices, heavy oil differentials and interest and foreign exchange rates; our ability to mitigate our exposure to heavy oil price differentials by transporting our crude oil to market by railways; the volume of heavy oil to be transported to market on railways in 2012; the amount of our undrawn credit facilities at December 31, 2011; our debt-to-FFO ratio; our liquidity and financial capacity; the sufficiency of our financial resources to fund our operations; the long-term growth potential of our Peace River area properties;

our reserve life index; forecast prices for oil and natural gas; forecast interest and exchange rates; and future development costs. 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. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of FFO and capital expenditures 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 receipt, in a timely manner, of regulatory and other required approvals; 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; failure to obtain the necessary regulatory and other approvals on the planned timelines; 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.

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 adjusted for financing costs, changes in non-cash operating working capital and other operating items. 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.

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to product revenue less royalties, operating expenses and transportation expenses dividend by barrels of oil equivalent sales volume for the applicable period. Baytex's determination of operating netback may not be comparable with the calculation of similar measures for other entities. Baytex believes that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

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, 2011, which will be filed later in March 2012. 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), Kerrobert/Whiteside (Viking) and Northeast Alberta (Mannville) 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 as of December 31, 2011 of the volumes of, and the net present value of the future net revenue from, the "contingent resource" for four of our oil resource plays: the Bluesky in the Seal area of Alberta; the Bakken/Three Forks in North Dakota; the Viking in southeast Alberta and southwest Saskatchewan; and the Mannville in northeast Alberta. These estimates were prepared by independent qualified reserves evaluators.

"Contingent resource" is not, and should not be confused with, petroleum and natural gas reserves. "Contingent resource" is defined in the Canadian Oil and Gas Evaluation Handbook as: "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

The primary contingencies which currently prevent the classification of the contingent resource as reserves consist of: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; access to capital markets; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices; demonstration of economic viability; future drilling program and testing results; further reservoir delineation and studies; facility design work; limitations to development based on adverse topography or other surface restrictions; and the uncertainty regarding marketing and transportation of petroleum from development areas.

There is no certainty that it will be commercially viable to produce any portion of the contingent resource or that we will produce any portion of the volumes currently classified as contingent resource. The estimates of contingent resource involve implied assessment, based on certain estimates and assumptions, that the resource described exists in the quantities predicted or estimated and that the resource can be profitably produced in the future. The net present value of the future net revenue from the contingent resource does not necessarily represent the fair market value of the contingent resource.

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

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 resource. Contingent resource represents 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 resource in reports filed with it by United States companies.

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