Q2 REPORT | TWO THOUSAND FOURTEEN

SUMMARY

- Closed the $2.8 billion acquisition of Aurora Oil & Gas Limited ("Aurora") adding 22,350 net contiguous acres in the Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale;
- Generated production of 66,934 boe/d (87% oil and NGL) in Q2/2014, an increase of 12% over Q1/2014 and 15% over Q2/2013;
- Delivered funds from operations ("FFO") of $202.5 million ($1.49 per basic share) during Q2/2014 (excluding acquisition-related costs of $37 million), an increase of 19% over Q1/2014 and 30% over Q2/2013;
- Realized an operating netback (sales price less royalties, production and operating expenses, and transportation expenses) in Q2/2014 of $40.74/boe, an increase of 11% over Q1/2014 and 28% over Q2/2013;
- Maintained a conservative payout ratio, net of Dividend Reinvestment Plan ("DRIP") participation, of 37% (47% before DRIP) in Q2/2014;
- Issued US$800 million of senior unsecured notes in two equal tranches of US$400 million with maturities of seven and ten years bearing interest at 5.125% and 5.625%, respectively;
- Increased the monthly dividend on our common shares by 9% to $0.24 from $0.22 per share; and
- Subsequent to the quarter, announced the divestiture of our North Dakota assets for gross proceeds of approximately $357 million (US$330.5 million).

	Three Months Ended			Six Months Ended	
	June 30, 2014	March 31, 2014	June 30, 2013	**June 30, 2014**	June 30, 2013
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 476,404**	$ 385,809	$ 341,011	**$ 862,213**	$ 613,956
Funds from operations[(1)]	**165,503**	170,810	155,804	**336,312**	257,576
Per share – basic	**1.22**	1.36	1.26	**2.57**	2.09
Per share – diluted	**1.21**	1.34	1.25	**2.54**	2.07
Cash dividends declared[(2)]	**75,397**	63,441	60,326	**138,838**	116,775
Dividends declared per share	**0.68**	0.66	0.66	**1.34**	1.32
Net income	**36,799**	47,841	36,192	**84,640**	46,341
Per share – basic	**0.27**	0.38	0.29	**0.65**	0.37
Per share – diluted	**0.27**	0.38	0.29	**0.64**	0.37
Exploration and development	**148,916**	172,425	177,834	**321,341**	344,356
Acquisitions, net of divestitures	**2,920,845**	673	(1,796)	**2,921,518**	(23,227)
Total oil and natural gas capital expenditures	**$ 3,069,761**	$ 173,098	$ 176,038	**$ 3,242,859**	$ 321,129
Bank loan	**$ 952,402**	$ 300,564	$ 225,434	**$ 952,402**	$ 225,434
Long-term debt	**1,329,487**	465,795	457,680	**1,329,487**	457,680
Working capital deficiency	**178,517**	65,909	87,418	**178,517**	87,418
Total monetary debt[(3)]	**$ 2,460,406**	$ 832,268	$ 770,532	**$ 2,460,406**	$ 770,532

	Three Months Ended			Six Months Ended	
	June 30, 2014	March 31, 2014	June 30, 2013	**June 30, 2014**	June 30, 2013
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**12,340**	7,457	8,202	**9,912**	8,062
Heavy oil (bbl/d)	**45,986**	45,232	42,510	**45,611**	40,012
Total oil and NGL (bbl/d)	**58,326**	52,689	50,712	**55,523**	48,074
Natural gas (mcf/d)	**51,645**	40,886	45,148	**46,295**	42,243
Oil equivalent (boe/d @ 6:1)[(4)]	**66,934**	59,502	58,236	**63,239**	55,115
Average prices (before hedging)					
WTI oil (US$/bbl)	**102.99**	98.68	94.22	**100.84**	94.30
WCS heavy oil (US$/bbl)	**82.95**	75.55	75.07	**79.25**	68.75
Edmonton par oil ($/bbl)	**106.68**	100.18	92.94	**103.43**	90.77
LLS oil (US$/bbl)	**105.55**	104.38	104.81	**104.96**	109.37
Baytex heavy oil ($/bbl)[(5)]	**79.26**	71.13	63.92	**75.26**	59.07
Baytex light oil and NGL ($/bbl)	**91.03**	85.18	77.85	**88.84**	77.30
Baytex total oil and NGL ($/bbl)	**81.74**	73.12	66.17	**77.68**	62.12
Baytex natural gas ($/mcf)	**4.84**	5.22	3.59	**5.01**	3.53
Baytex oil equivalent ($/boe)	**75.06**	68.33	60.42	**71.92**	56.90
CAD/USD noon rate at period end	**1.0676**	1.1053	1.0512	**1.0676**	1.0512
CAD/USD average rate for period	**1.0894**	1.1035	1.0231	**1.0964**	1.0159
TSX					
Share price (Cdn$)					
High	**49.88**	45.65	43.05	**49.88**	47.60
Low	**44.30**	38.90	36.37	**38.90**	36.37
Close	**45.89**	45.52	37.90	**45.89**	37.90
Volume traded (thousands)	**45,952**	53,781	30,085	**99,733**	57,853
NYSE					
Share price (US$)					
High	**46.30**	41.28	42.50	**46.30**	47.47
Low	**40.70**	35.34	34.71	**35.34**	34.71
Close	**42.16**	41.13	36.04	**42.16**	36.04
Volume traded (thousands)	**3,552**	4,150	4,763	**7,702**	8,132
Common shares outstanding (thousands)	**165,421**	126,442	123,593	**165,421**	123,593

Notes:

(1) *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. We define funds from operations as cash flow 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 and six months ended June 30, 2014.*

(2) *Cash dividends 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 unrealized gains or losses on financial derivatives, assets held for sale and liabilities related to assets held for sale)), the principal amount of long-term debt and long-term bank loan.*

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

(5) *Heavy oil prices exclude condensate blending.*

Advisory Regarding Forward-Looking Statements

This report contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; the anticipated benefits from the acquisition of Aurora, including our beliefs that the acquisition will be an excellent fit with our business model and will provide shareholders with exposure to projects with attractive capital efficiencies; our expectations that the Aurora assets have infrastructure in place that support future annual production growth and that such assets will provide material production, long-term growth and high quality reserves with upside potential; our expectations regarding the effect of well downspacing, improving completion techniques and new development targets on the reserves potential of the Aurora assets; the timing of closing of the asset disposition; the estimated proceeds from the asset disposition; the intended use of the proceeds from the asset disposition; the results of our asset portfolio review, including the possibility of further asset divestitures; our average production rate for the second half of 2014 and full-year 2014; our exploration and development capital expenditures for the second half of 2014 and full-year 2014; our Cliffdale cyclic steam stimulation project, including our assessment of the modified injection and completion strategy; our Gemini steam-assisted gravity drainage project, including our assessment of the performance of the pilot project; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate light oil; 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 portion of our heavy oil volumes to be transported to market on railways in the third quarter of 2014; our liquidity and financial capacity; the sufficiency of our financial resources to fund our operations; and the target for our total monetary debt to FFO ratio. 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 funds from operations and capital expenditures and our prevailing financial circumstances at the time. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

Non-GAAP Financial Measures

Funds from operations is not a measurement based on 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 Baytex's 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.

Total monetary debt is not a measurement based on GAAP in Canada. Baytex defines total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loans. Baytex believes that this measure assists in providing a more complete understanding of its cash liabilities.

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 sales price less royalties, production and operating expenses and transportation expenses divided 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 by other entities. Baytex believes that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

MESSAGE TO SHAREHOLDERS

Acquisition of Aurora

On June 11, 2014, we completed the acquisition of Aurora for total consideration of approximately $2.8 billion. Aurora's primary asset consists of 22,350 net contiguous acres in the Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale. The Sugarkane Field has been largely delineated with infrastructure in place which is expected to facilitate future annual production growth. In addition, these assets have future reserves upside potential from well downspacing, improving completion techniques and new development targets in additional zones. Our second quarter results include twenty days of operations from the Eagle Ford assets representing the period from June 11 to June 30.

To finance the acquisition of Aurora, we completed the issuance of 38,433,000 subscription receipts at $38.90 each on February 24, 2014, raising gross proceeds of approximately $1.5 billion. These subscription receipts were subsequently exchanged for common shares upon closing of the acquisition. We also issued US$800 million of senior unsecured notes in two equal tranches of US$400 million with maturities of seven and ten years bearing interest at 5.125% and 5.625%, respectively. The proceeds from the issuance of the senior unsecured notes were used to retire existing debt of Aurora.

Update on Portfolio Review

In anticipation of the Eagle Ford transaction, we initiated a portfolio review of our assets late in the second quarter. During this review we identified assets representing 5% to 10% of our production that are not likely to command capital going forward given our plans to direct capital to the highest rate of return projects in our portfolio. Subsequent to the quarter, we have entered into an agreement to sell our North Dakota assets, effective July 1, 2014, for gross proceeds of approximately $357 million (US$330.5 million). The transaction is expected to close toward the end of the third quarter with after tax net proceeds from this sale, estimated at $275 million, to be applied against outstanding bank indebtedness. Production from our North Dakota assets averaged 3,200 boe/d in Q2/2014. We will continue to assess the market for any future divestitures.

Operations Review

Our operational execution remains on track with second quarter production volumes and capital spending consistent with our full-year plans. Production averaged 66,934 boe/d (87% oil and NGL) during Q2/2014, an increase of 12% from Q1/2014 and 15% from Q2/2013.

Our base business (excluding the Eagle Ford) contributed production of 60,828 boe/d (88% oil and NGL) during Q2/2014, an increase of 2% from Q1/2014 and 4% from Q2/2013. Production from the Eagle Ford averaged 27,783 boe/d (83% oil and NGL) for the 20-day period resulting in a contribution of 6,106 boe/d to our production volumes for Q2/2014.

Capital expenditures for exploration and development activities totaled $148.9 million in Q2/2014 and included the drilling of 51 (28.3 net) wells with a 100% success rate. Capital expenditures (excluding the Eagle Ford) for exploration and development activities totaled $122.9 million in Q2/2014 and included the drilling of 40 (25.4 net) wells. Capital expenditures for the Eagle Ford assets totaled $26.0 million and included the drilling of 11 (2.9 net) wells.

We are updating our 2014 guidance to reflect the expected closing date of the North Dakota asset sale. Our capital spending plans are unchanged as we had previously incorporated a reduction in spending in North Dakota in the second half of this year. For the second half of 2014, capital expenditures for exploration and development activities are forecast to be $440 to $465 million and we expect to generate an average production rate of 86,000 to 88,000 boe/d (previously 88,000 to 90,000 boe/d). Our full-year 2014 production guidance is 74,000 to 76,000 boe/d (previously 75,000 to 77,000 boe/d) with budgeted exploration and development expenditures of $765 to $790 million.

Wells Drilled – Three Months Ended June 30, 2014

	Crude Oil											
	Primary		Thermal		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster	21	9.2	2	2.0	–	–	–	–	–	–	23	11.2
Peace River	12	12.0	–	–	–	–	–	–	–	–	12	12.0
	33	**21.2**	**2**	**2.0**	**–**	**–**	**–**	**–**	**–**	**–**	**35**	**23.2**
Light oil, NGL and natural gas												
Eagle Ford	11	2.9	–	–	–	–	–	–	–	–	11	2.9
Western Canada	–	–	–	–	–	–	–	–	–	–	–	–
North Dakota	5	2.2	–	–	–	–	–	–	–	–	5	2.2
	16	**5.1**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**16**	**5.1**
Total	**49**	**26.3**	**2**	**2.0**	**–**	**–**	**–**	**–**	**–**	**–**	**51**	**28.3**

Wells Drilled – Six Months Ended June 30, 2014

	Crude Oil											
	Primary		Thermal		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster	113	71.1	2	2.0	–	–	13	13.0	2	2.0	130	88.1
Peace River	20	20.0	–	–	–	–	24	24.0	–	–	44	44.0
	133	**91.1**	**2**	**2.0**	**–**	**–**	**37**	**37.0**	**2**	**2.0**	**174**	**132.1**
Light oil, NGL and natural gas												
Eagle Ford	11	2.9	–	–	–	–	–	–	–	–	11	2.9
Western Canada	6	5.7	–	–	2	2.0	–	–	–	–	8	7.7
North Dakota	11	4.7	–	–	–	–	–	–	–	–	11	4.7
	28	**13.3**	**–**	**–**	**2**	**2.0**	**–**	**–**	**–**	**–**	**30**	**15.3**
Total	**161**	**104.4**	**2**	**2.0**	**2**	**2.0**	**37**	**37.0**	**2**	**2.0**	**204**	**147.4**

In Q2/2014, heavy oil production averaged 45,986 bbl/d, an increase of 2% from Q1/2014 and 8% from Q2/2013. During Q2/2014, we drilled 35 (23.2 net) oil wells on our heavy oil properties.

Production from our Peace River area properties averaged approximately 26,100 bbl/d in Q2/2014, an increase of 1% from Q1/2014 and 15% from Q2/2013. We drilled 12 (12.0 net) cold horizontal producers encompassing a total of 148 laterals in the Peace River area.

In our Lloydminster heavy oil area, Q2/2014 drilling included 19 (8.8 net) horizontal oil wells and two (0.4 net) vertical oil wells with a 100% success rate. We continue to expand the use of multi-lateral horizontal drilling techniques, drilling two horizontal wells at Lloydminster with two and four laterals, respectively.

In the Cliffdale area of Peace River, thermal operations continued as planned with steam injection at Pad 2 commencing on schedule in early June. A modified injection and completion strategy to improve uniform horizontal well heat distribution is showing early positive results.

At the Gemini steam-assisted gravity drainage pilot project, oil production commenced in early April, 2014. The 600m horizontal well pair is currently producing approximately 1,000 bbl/d, which is in line with our expectations. We continue to analyze reservoir performance to confirm viability of a commercial development plan.

In the Eagle Ford, we participated in the drilling of 11 (2.9 net) wells. As at June 30, drilling operations were underway on 10 gross wells, 40 gross wells were awaiting fracture stimulation and 12 gross wells were being stimulated or prepared for production. Our average working interest for these wells is approximately 27%.

Financial Review

We generated FFO (excluding $37.0 million of acquisition-related costs) of $202.5 million ($1.49 per basic share) during Q2/2014, representing an increase of 19% from Q1/2014 and 30% from Q2/2013. The higher FFO is attributable to increased production (mainly due to the Aurora acquisition) and higher commodity prices. Inclusive of the acquisition-related costs, FFO totaled $165.5 million ($1.22 per basic share) during Q2/2014.

The average WTI price for Q2/2014 was US$102.99/bbl, representing an increase of 4% from Q1/2014 and 9% from Q2/2013. The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 19.0% in Q2/2014, as compared to 23.4% in Q1/2014 and 20.0% in Q2/2013. The strong market conditions for WCS reflect increased refinery demand in the U.S. Midwest, a continued increase in crude by rail volumes and normal seasonality.

Our realized total oil and NGL price of $81.74/bbl in Q2/2014 increased by 12% from $73.12/bbl in Q1/2014 and 24% from $66.17/bbl in Q2/2013. We continue to see strong price realizations for our heavy oil. Our realized heavy oil price of $79.26/bbl (88% of WCS) in Q2/2014 increased by 11% from $71.13/bbl (85% of WCS) in Q1/2014 and 24% from $63.92/bbl (83% of WCS) in Q2/2013. These improved price realizations reflect both strong benchmark prices and contributions from rail as we continue to increase our utilization of rail. In Q2/2014, approximately 55% of our heavy oil volumes were delivered to market by rail, as compared to 42% for full-year 2013. For Q3/2014, we expect to deliver approximately 60% of our total heavy oil volumes to market by rail.

We generated an operating netback (excluding financial derivatives) of $40.74/boe in Q2/2014, up 11% from $36.85/boe in Q1/2014 and up 28% from $31.71/boe in Q2/2013. Our Canadian operations generated an operating netback of $38.78/boe while the Eagle Ford generated an operating netback for the twenty-day period ending June 30 of $53.97/boe. The table below provides a summary of our Q2/2014 netback.

	Three Months Ended June 30, 2014			Three Months Ended June 30, 2013	
($ per boe)	Canada	Eagle Ford[(1)]	Total	Total	Change
Sales Price	$72.85	$85.47	$75.06	$60.42	24%
Less:					
Royalties	16.98	24.78	18.36	11.66	57%
Production and operating expenses	13.07	4.65	12.32	12.97	(5%)
Transportation expenses	4.02	2.07	3.64	4.08	(11%)
Operating netback	$38.78	$53.97	$40.74	$31.71	28%

(1) Eagle Ford netback reflects the 20-day period from June 11 to June 30, 2014.

As part of our hedging program, we are focusing on opportunities to further mitigate the volatility in WCS price differentials by transporting crude oil to higher value markets by rail. During the second quarter, we entered into our first Brent-based fixed differential physical heavy oil sale. This six-month term rail contract runs from October 1, 2014 to March 31, 2015 and is expected to represent approximately 25% of our crude by rail volumes.

For Q3/2014, we have entered into hedges on approximately 51% of our WTI exposure at a weighted average price of US$96.45/bbl. We have also reduced our exposure to WCS price differentials through a combination of long term physical supply contracts and rail delivery on approximately 45% of our heavy oil production. In addition, we have hedged approximately 54% of our natural gas price exposure and 29% of our exposure to currency movements between the U.S. and Canadian dollars.

Total monetary debt at the end of Q2/2014 is $2.46 billion. With $461 million in undrawn capacity on existing credit facilities, we have ample liquidity to allow us to execute our growth and income model. We continue to target a total monetary debt to FFO ratio under 2.0 times.

Conclusion

We are pleased to report our second quarter results which include twenty days of operations for our recently acquired Eagle Ford assets. The Eagle Ford is one of the premier oil resource plays in North America and will be an important growth engine for Baytex going forward. Our results reflect strong production volumes, increased funds from operations, and improved netbacks. For the second half of this year, we will continue to implement our capital program with over 90% of our spending directed to our three key oil resource plays which provide some of the highest rate of return projects in North America. We are pleased with our direction and are well positioned to deliver future growth and income.

We want to express our appreciation for your continued support as we move forward in executing our plan for long-term value creation.

On behalf of the Board of Directors,

James L. Bowzer
President and Chief Executive Officer
July 31, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and six months ended June 30, 2014. This information is provided as of July 30, 2014. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The second quarter results have been compared with the corresponding period in 2013. This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three and six months ended June 30, 2014, its audited comparative consolidated financial statements for the years ended December 31, 2013 and 2012, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2013. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

In this MD&A, 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, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as funds from operations, payout ratio, total monetary debt and operating netback) which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations, payout ratio and operating netback are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures by other issuers.

Funds from Operations

We define funds from operations as cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. However, funds from operations should not be construed as an alternative to traditional performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income. For a reconciliation of funds from operations to cash flow from operating activities, see "Funds from Operations, Payout Ratio and Dividends".

Payout Ratio

We define payout ratio as cash dividends (net of participation in our Dividend Reinvestment Plan ("DRIP")) divided by funds from operations. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments.

Total Monetary Debt

We define total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives, assets held for sale and liabilities related to assets held for sale)), the principal amount of long-term debt and long-term bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities. See "Liquidity and Capital Resources" for a description of Total Monetary Debt.

Operating Netback

We define operating netback as product revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. As sales volumes are not materially different than production volumes, we believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

SECOND QUARTER HIGHLIGHTS

The second quarter was a busy quarter for the Company as we set the stage for future growth. We closed the acquisition of Aurora Oil & Gas Limited ("Aurora") in June 2014 which resulted in an immediate increase in production. The new Eagle Ford assets added 6,106 boe/d of production and about $47.5 million of revenue in the period after closing. Production in our heavy oil properties increased by 8% for the second quarter of 2014 as compared to the same period in 2013, as we continued to have success in our drilling and development program, especially in the Peace River area. Oil prices were 24% higher this year compared to last year as the price for West Texas Intermediate crude oil ("WTI") increased, the discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, decreased and the Canadian dollar weakened against the U.S. dollar. We benefited from our rail transportation strategy which allowed us to access higher value markets for our heavy oil. We also completed a swap of assets, exiting mature properties in Saskatchewan and acquiring additional properties in the Peace River area. Funds from operations for the second quarter was $165.5 million ($202.5 million excluding acquisition-related costs of $37.0 million). We generated net income of $36.8 million in the second quarter which was similar to the net income in the same period last year, despite the acquisition-related costs.

BUSINESS COMBINATION

On June 11, 2014, we acquired all of the ordinary shares of Aurora for $4.20 (Australian dollars) per share by way of a scheme of arrangement under the Corporations Act 2001 (Australia) (the "Arrangement"). The total purchase price for Aurora was approximately $2.8 billion, including the assumption of $955 million of indebtedness and $54.6 million of cash. Aurora's primary asset consists of 22,200 net contiguous acres in the Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale. The Sugarkane Field has been largely delineated with infrastructure in place which is expected to facilitate future annual production growth. The acquisition adds an estimated 166.6 Mboe of proved and probable reserves. In addition, these assets have future reserves upside potential from well downspacing, improving completion techniques and new development targets in additional zones.

To finance the acquisition of Aurora, we completed the issuance of 38,433,000 subscription receipts at $38.90 each on February 24, 2014, raising gross proceeds of approximately $1.5 billion. The subscription receipts were converted to common shares on June 11, 2014. We also entered into an agreement with a Canadian chartered bank for the provision of new unsecured revolving credit facilities of approximately $1.2 billion (to replace the $850 million revolving credit facilities of Baytex Energy Ltd.), and a new two-year $200 million unsecured loan. The new facilities became available upon closing of the Arrangement and were used to finance a portion of the purchase price.

In anticipation of closing the Arrangement, we made tender offers for the US$665 million principal value of outstanding senior notes of Aurora USA Oil & Gas, Inc, a wholly-owned subsidiary of Aurora. Approximately 98% of the outstanding notes with a principal value totaling US$650.7 million were tendered in response to our offer resulting in US$745.6 million being paid to the former holders of the notes. In order to finance the tender offers, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 and US$400 million of 5.625% notes due June 1, 2024.

The Results of Operations include the results of Aurora from June 11, 2014. Total production from the date of acquisition to June 30, 2014 was 555,667 boe (27,783 boe/d), equivalent to 6,106 boe/d for the three months ended June 30, 2014 and 3,070 boe/d for the six months ended June 30, 2014. Revenue for the period, since June 11, was $47.5 million, or $85.47/boe, which generated a netback on the Aurora operations of $53.97/boe.

RESULTS OF OPERATIONS

Production

	Three Months Ended June 30			Six Months Ended June 30		
	2014	2013	Change	**2014**	2013	Change
Daily Production						
Light oil and NGL (bbl/d)	**12,340**	8,202	50%	**9,912**	8,062	23%
Heavy oil (bbl/d)[(1)]	**45,986**	42,510	8%	**45,611**	40,012	14%
Natural gas (mcf/d)	**51,645**	45,148	14%	**46,295**	42,243	10%
Total production (boe/d)	**66,934**	58,236	15%	**63,239**	55,115	15%
Production Mix						
Light oil and NGL	**18%**	14%		**16%**	14%	
Heavy oil	**69%**	73%		**72%**	73%	
Natural gas	**13%**	13%		**12%**	13%	

(1) *Heavy oil sales volumes may differ from reported production volumes due to changes in our heavy oil inventory. For the three months ended June 30, 2014, heavy oil sales volumes were 257 bbl/d higher than production volumes (three months ended June 30, 2013 – 204 bbl/d higher). For the six months ended June 30, 2014, heavy oil sales volumes were 101 bbl/d higher than production volumes (six months ended June 30, 2013 – 97 bbl/d higher).*

Production for the three months ended June 30, 2014 averaged 66,934 boe/d, an increase of 15% compared to 58,236 boe/d for the same period in 2013. Light oil and natural gas liquids ("NGL") production in the second quarter of 2014 increased by 50% to12,340 bbl/d, as compared to 8,202 bbl/d in the second quarter of 2013, primarily due to the Aurora acquisition which increased production by 5,032 bbl/d, partially offset by natural declines. Heavy oil production for the second quarter of 2014 increased by 8% to 45,986 bbl/d from 42,510 bbl/d in the second quarter of 2013, primarily due to successful development activities in the Peace River area. Natural gas production increased by 14% to 51.6 mmcf/d for the second quarter of 2014, as compared to 45.1 mmcf/d for the same period in 2013, mainly due to the addition of 6.4 mmcf/d from the acquisition of Aurora.

Production for the six months ended June 30, 2014 averaged 63,239 boe/d, an increase of 15% compared to 55,115 boe/d for the same period in 2013. Light oil and NGL production in the first six months of 2014 increased by 23% to 9,912 bbl/d, as compared to 8,062 bbl/d in the first six months of 2013, primarily due to the Aurora acquisition which increased production by 2,530 bbl/d, partially offset by natural declines. Heavy oil production for the six months ended June 30, 2014 increased by 14% to 45,611 bbl/d from 40,012 bbl/d for the same period in 2013, primarily due to successful development activities in the Peace River area. Natural gas production increased by 10% to 46.3 mmcf/d for the first six months of 2014, as compared to 42.2 mmcf/d for the same period in 2013, mainly due to the addition of 3.2 mmcf/d from the Aurora acquisition.

Commodity Prices

The prices received for our crude oil and natural gas production directly impact our earnings, funds from operations and our financial position. The following tables compare selected benchmark prices and our average realized selling prices for the current quarter and year to date against the same periods last year.

	Three Months Ended June 30			Six Months Ended June 30		
	2014	2013	Change	2014	2013	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	$ 102.99	$ 94.22	9%	$ 100.84	$ 94.30	7%
WCS heavy oil (US$/bbl)[2]	$ 82.95	$ 75.07	10%	$ 79.25	$ 68.75	15%
Heavy oil differential[3]	19%	20%		22%	27%	
CAD/USD average exchange rate	1.0894	1.0231	6%	1.0964	1.0159	8%
Edmonton par oil ($/bbl)	$ 106.68	$ 92.94	15%	$ 103.43	$ 90.77	14%
LLS oil (US$/bbl)[4]	$ 105.55	$ 104.81	1%	$ 104.96	$ 109.37	(4%)
AECO natural gas price ($/mcf)[5]	$ 4.68	$ 3.46	35%	$ 4.72	$ 3.27	44%
Average Sales Prices						
Heavy oil ($/bbl)[6]	$ 79.17	$ 63.92	24%	$ 75.08	$ 57.82	30%
Physical forward sales contracts gain ($/bbl)	$ 0.09	$ –		$ 0.18	$ 1.25	
Heavy oil, net ($/bbl)	$ 79.26	$ 63.92	24%	$ 75.26	$ 59.07	27%
Light oil and NGL ($/bbl)[7]	$ 91.03	$ 77.85	17%	$ 88.84	$ 77.30	15%
Total oil and NGL, net ($/bbl)	$ 81.74	$ 66.17	24%	$ 77.68	$ 62.12	25%
Natural gas ($/mcf)	$ 4.84	$ 3.59	35%	$ 5.01	$ 3.53	42%
Summary						
Weighted average ($/boe)[7]	$ 75.00	$ 60.42	24%	$ 71.79	$ 55.99	28%
Physical forward sales contracts gain ($/boe)	0.06	–		0.13	0.91	
Weighted average, net ($/boe)	$ 75.06	$ 60.42	24%	$ 71.92	$ 56.90	26%

(1) WTI refers to the arithmetic average based on NYMEX prompt month WTI.
(2) WCS refers to the average posting price for the benchmark WCS heavy oil.
(3) Heavy oil differential refers to the WCS discount to WTI on a monthly weighted average basis.
(4) Louisiana Light Sweet ("LLS") refers to the monthly arithmetic average for Argus LLS front month.
(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter.
(6) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.
(7) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivatives.

Crude Oil

For the three months ended June 30, 2014, the WTI oil prompt price averaged US$102.99/bbl, a 9% increase from the average WTI price of US$94.22/bbl in the second quarter of 2013. In the three months ended June 30, 2014, prices benefited from a steady decline in crude oil inventories at Cushing, Oklahoma, heightened global geopolitical risk and bullish sentiment from speculative traders.

For the six months ended June 30, 2014, the WTI oil prompt price averaged US$100.84/bbl, a 7% increase from the average WTI price of US$94.30/bbl in the first half of 2013. In the first six months of 2014, prices benefited from increased pipeline connectivity between Cushing, Oklahoma and the U.S. Gulf Coast, resulting in a more narrow spread between WTI and globally priced crude oil.

The discount for Canadian heavy oil, as measured by the WCS price differential to WTI, averaged 19% for the three months ended June 30, 2014 compared to 20% for the same period in 2013. WCS differentials improved throughout the second quarter of 2014 compared to the first quarter of 2014, due to increased heavy oil demand stemming from the continued ramp up of BP Whiting's refinery modernization project and normal seasonality.

For the six months ended June 30, 2014, the WCS heavy oil differential averaged 22% compared to 27% in the first half of 2013. In the first six months of 2014, the differential narrowed due to an increase in crude caused by supply issues in the first quarter of 2014, low inventory levels and increasing take-away capacity out of Western Canada.

Natural Gas

For the three months ended June 30, 2014 the AECO natural gas price averaged $4.68/mcf, a 35% increase compared to $3.46/mcf in the same period of 2013. The increase in natural gas price for the three months ended June 30, 2014 compared to the same period in 2013 is a result of below average North American natural gas storage levels after a prolonged and colder than normal winter.

For the six months ended June, 30, 2014 the AECO natural gas price averaged $4.72/mcf, a 44% increase compared to $3.27/mcf in the same period of 2013. In the first six months of 2014, prices benefited from a weaker Canadian dollar and a colder than normal winter.

Average Sales Prices

Our realized heavy oil price during the second quarter of 2014 was $79.26/bbl, or 88% of WCS, compared to $63.92/bbl, or 83% of WCS in the second quarter of 2013. The realized price during the second quarter of 2014 increased due to the decline in the Canadian dollar compared to the second quarter of 2013, an increase in WTI coupled with a decrease in the WCS differential. We also increased our use of rail which helped to optimize our realized price. During the second quarter of 2014, our average sales price for light oil and NGL was $91.03/bbl, up 17% from $77.85/bbl in the second quarter of 2013, which is in line with the increase in the Edmonton par oil benchmark price over the same period. Our realized natural gas price for the three months ended June 30, 2014 was $4.84/mcf, up from $3.59/mcf in the second quarter of 2013. The increase is is in line with the increase in the AECO benchmark applicable to the Canadian production and in line with expected prices for the Aurora production over the same period.

Our realized heavy oil price for the six months ended June 30, 2014 was $75.26/bbl, or 87% of WCS, compared to $59.07/bbl, or 85% of WCS in the second quarter of 2013. The realized price during the first six months of 2014 increased due to the decline in the Canadian dollar compared to the same period in 2013, as well as an increase in the benchmark prices. During the first six months of 2014, our average sales price for light oil and NGL was $88.84/bbl, up 15% from $77.30/bbl in the first six months of 2013, in line with the increase in the Edmonton par oil benchmark price over the same period. Our realized natural gas price for the six months ended June 30, 2014 was $5.01/mcf, up from $3.53/mcf in the second quarter of 2013, largely in line with increase in the AECO benchmark and the US natural gas benchmarks.

Financial Derivatives

As part of normal operations in the upstream oil and gas industry, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize a series of financial derivative contracts which are intended to reduce some of the volatility in our operating cash flow. The following table summarizes the results of our financial derivative contracts for the three and six months ended June 30, 2014 and 2013.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2014**	2013	Change	**2014**	2013	Change
Realized (loss) gain on financial derivatives(1)						
Crude oil	**$ (12,054)**	$ 8,748	$ (20,802)	**$ (10,441)**	$ 15,609	$ (26,050)
Natural gas	**(629)**	(264)	(365)	**(1,816)**	79	(1,895)
Foreign currency	**(1,231)**	147	(1,378)	**(3,266)**	813	(4,079)
Interest	**117**	137	(20)	**(4,021)**	(3,605)	(416)
Total	**$ (13,797)**	$ 8,768	$ (22,565)	**$ (19,544)**	$ 12,896	$ (32,440)
Unrealized (loss) gain on financial derivatives(2)						
Crude oil	**$ (33,034)**	$ 5,226	$ (38,260)	**$ (42,346)**	$ (5,074)	$ (37,272)
Natural gas	**795**	3,037	(2,242)	**(2,241)**	650	(2,891)
Foreign currency	**(15,043)**	(8,539)	(6,504)	**6,118**	(11,476)	17,594
Interest(3)	**11,956**	(175)	12,131	**15,968**	3,554	12,414
Total	**$ (35,326)**	$ (451)	$ (34,875)	**$ (22,501)**	$ (12,346)	$ (10,155)
Total (loss) gain on financial derivatives						
Crude oil	**$ (45,088)**	$ 13,974	$ (59,062)	**$ (52,787)**	$ 10,535	$ (63,322)
Natural gas	**166**	2,773	(2,607)	**(4,057)**	729	(4,786)
Foreign currency	**(16,274)**	(8,392)	(7,882)	**2,852**	(10,663)	13,515
Interest(3)	**12,073**	(38)	12,111	**11,947**	(51)	11,998
Total	**$ (49,123)**	$ 8,317	$ (57,440)	**$ (42,045)**	$ 550	$ (42,595)

(1) Realized (loss) gain on financial derivatives represents actual cash settlement or receipts for the financial derivatives.

(2) Unrealized (loss) gain on financial derivatives represents the change in fair value of the financial derivatives during the period.

(3) Unrealized gain on interest rate derivatives includes the change in fair value of the call options embedded in our senior unsecured notes.

Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price on the date the contract matures. As the forward markets for commodities and currencies fluctuate and as new contracts are executed, changes in the fair value are reported as unrealized gains or losses in the period. Contracts in place at the beginning of the period which settle during the period will give rise to the reversal of the unrealized gain or loss recorded at the beginning of the period.

The realized loss of $13.8 million for the three months ended June 30, 2014 on derivative contracts is mainly due to crude oil prices exceeding our fixed price contracts during the quarter. The unrealized mark-to-market loss of $35.3 million for the three months ended June 30, 2014 mainly relates to higher forward crude oil prices at June 30, 2014 as compared to March 31, 2014, partially offset by the fair value gain of $12.1 million on the call options embedded within the senior unsecured notes and the strengthening Canadian dollar against the US dollar at June 30, 2014 as compared to March 31, 2014. The unrealized loss also includes the reversal of the unrealized gain of $31.6 million reported at March 31, 2014 on the Australian dollar contracts put in place to mitigate currency risk on the purchase price of Aurora.

The realized loss of $19.5 million for the six months ended June 30, 2014 on derivative contracts relates to crude oil rising to levels above our fixed price contracts and losses on the interest rate swaps as LIBOR remained low, as well as the weakening Canadian dollar against the U.S. dollar compared to December 31, 2013. The unrealized mark-to-market loss of $22.5 million for the six months ended June 30, 2014 is mainly due to higher forward commodity prices at June 30, 2014, as compared to December 31, 2013, partially offset by the fair value gain of $12.1 million on the call options embedded within the senior unsecured notes, addition of favourable foreign currency contracts and settlement of previously unrecorded unrealized losses on interest rate contracts.

A summary of the financial derivative contracts in place as at June 30, 2014 and the accounting treatment thereof are disclosed in note 18 to the consolidated financial statements.

Gross Revenues

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for %)	**2014**	2013	Change	**2014**	2013	Change
Oil revenue						
Light oil and NGL	**$ 102,226**	$ 58,106	76%	**$ 159,392**	$ 112,794	41%
Heavy oil	**333,518**	248,458	34%	**622,730**	428,818	45%
Total oil revenue	**435,744**	306,564	42%	**782,122**	541,612	44%
Natural gas revenue	**22,764**	14,730	55%	**41,959**	26,962	56%
Total oil and natural gas revenue	**458,508**	321,294	43%	**824,081**	568,574	45%
Other income	**415**	–	100%	**415**	–	100%
Heavy oil blending revenue	**17,481**	19,717	(11%)	**37,717**	45,382	(17%)
Total petroleum and natural gas revenues	**$ 476,404**	$ 341,011	40%	**$ 862,213**	$ 613,956	40%

Petroleum and natural gas revenues increased 40% to $476.4 million for the three months ended June 30, 2014 from $341.0 million for the same period in 2013. The growth in revenues for the three months ended June 30, 2014 is the result of both higher production volumes and higher commodity prices compared to the second quarter of 2013. Heavy oil blending revenue was down 11% for the three months ended June 30, 2014 due to the decrease in contracted volumes of heavy oil requiring blending diluent. Unlike transportation through oil pipelines, transportation of heavy oil by rail does not require blending diluent. The decrease in heavy oil blending revenue is offset by a corresponding decrease in heavy oil blending costs.

Petroleum and natural gas revenues increased 40% to $862.2 million for the six months ended June 30, 2014 from $614.0 million for the same period in 2013. The increase in revenues is a result of higher realized pricing on all product lines, combined with increased production. Blending revenue is 17% lower for the six months ended June 30, 2014 compared to the same period last year due to an increase in contracted volumes of heavy oil being transported by rail.

The assets acquired from Aurora contributed $47.5 million of petroleum and natural gas revenue for the three and six months ended June 30, 2014.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. Royalties are calculated based on gross revenues and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons including commodity produced, commodity price, royalty incentives, the producing formation and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three and six months ended June 30, 2014 and 2013:

($ thousands except for % and per boe)	Three Months Ended June 30 2014	2013	Change	Six Months Ended June 30 2014	2013	Change
Royalties	$ 112,282	$ 62,010	81%	$ 187,162	$ 107,288	74%
Royalty rates:						
Light oil, NGL and natural gas	23.9%	18.3%		22.3%	21.7%	
Heavy oil	24.7%	19.6%		22.8%	18.0%	
Average royalty rates(1)	24.5%	19.3%		22.7%	18.9%	
Royalty expenses per boe	$ 18.36	$ 11.66	57%	$ 16.33	$ 10.74	52%

(1) Average royalty rate excludes sales of heavy oil blending diluents and the effects of financial derivatives.

Royalty rates in the three months ended June 30, 2014 for light oil, NGL and natural gas were 23.9%, up from 18.3% in the three months ended June 30, 2013 as the Aurora assets have an expected royalty rate of 29%. Excluding the Aurora assets, the royalty rate for light oil, NGL and natural gas would have been 20.7%, largely in line with expectations. Royalty rates for heavy oil increased to 24.7% in the three months ended June 30, 2014 compared to 19.6% in the three months ended June 30, 2013, primarily due to higher royalty rates imposed by the Crown, a reduction in the royalty incentive volumes in Peace River and $2.8 million of adjustments applied by the Crown related to prior periods. Crown heavy oil royalty rates utilize a sliding scale based on commodity price and therefore have increased as WTI prices increased.

Royalty rates for light oil, NGL and natural gas increased from 21.7% in the six months ended June 30, 2013 to 22.3% in the six months ended June 30, 2014, primarily due to inclusion of the Aurora assets. Royalty rates for heavy oil increased from 18.0% in the six months ended June 30, 2013 to 22.8% in the six months ended June 30, 2014 primarily due to increased royalty rates imposed by the Crown based on higher commodity prices.

Production and Operating Expenses

($ thousands except for % and per boe)	Three Months Ended June 30 2014	2013	Change	Six Months Ended June 30 2014	2013	Change
Production and operating expenses	$ 75,343	$ 68,999	9%	$ 144,178	$ 134,215	7%
Production and operating expenses per boe:						
Heavy oil	$ 12.28	$ 12.74	(4%)	$ 12.07	$ 13.30	(9%)
Light oil, NGL and natural gas	$ 12.42	$ 13.61	(9%)	$ 13.89	$ 13.78	1%
Total	$ 12.32	$ 12.97	(5%)	$ 12.58	$ 13.43	(6%)

Production and operating expenses for the three months ended June 30, 2014 increased to $75.3 million from $69.0 million for the same period in 2013. This increase is due to higher production volumes offset by lower costs per unit of production. Production and operating expenses decreased to $12.32/boe for the three months ended June 30, 2014 compared to $12.97/boe for the same period in 2013, primarily due to the inclusion of the Aurora assets which had production and operating expenses of $4.65/boe in the period since acquisition, lowering the total average cost by $0.77/boe. This was offset by higher fuel and electricity costs due to increasing prices for natural gas.

Production and operating expenses for the six months ended June 30, 2014 increased to $144.2 million from $134.2 million for the same period in 2013. This increase is due to higher production volumes offset by lower costs per unit of production. Production and operating expenses decreased to $12.58/boe for the six months ended June 30, 2014 compared to $13.43/boe for the same period in 2013, primarily due to the acquisition of Aurora which decreased overall production and operating expenses by $0.22/boe, as well as decreased repairs and maintenance and fluid hauling costs, partially offset by higher fuel and electricity costs. Repairs and maintenance costs and fluid hauling costs have decreased, in part, due to capital investments made in the U.S. and Peace River areas in 2013.

Transportation and Blending Expenses

Transportation expenses include the costs to move the production from the field to the sales point. The largest component of transportation expense relates to the movement of heavy oil to pipeline and rail delivery terminals. The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications and to facilitate its marketing. The cost of blending diluent is recovered in the sale price of the blended product. Product transported by rail does not require blending diluent.

The following table compares our blending and transportation expenses for the three and six months ended June 30, 2014 and 2013, expressed in dollars and per BOE:

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2014**	2013	Change	**2014**	2013	Change
Blending expenses	**$ 17,481**	$ 19,717	(11%)	**$ 37,717**	$ 45,382	(17%)
Transportation expenses	**22,256**	21,723	2%	**46,923**	42,194	11%
Total transportation and blending expenses	**$ 39,737**	$ 41,440	(4%)	**$ 84,640**	$ 87,576	(3%)
Transportation expenses per boe(1):						
Heavy oil	**$ 4.77**	$ 5.32	(10%)	**$ 5.30**	$ 5.56	(5%)
Light oil, NGL and natural gas	**$ 1.14**	$ 0.74	54%	**$ 0.96**	$ 0.68	41%
Total	**$ 3.64**	$ 4.08	(11%)	**$ 4.09**	$ 4.22	(3%)

(1) Transportation expenses per boe exclude the purchase of blending diluent.

Blending expenses for the three months ended June 30, 2014 decreased 11% from the same period in 2013 due to lower volumes of condensate being required due to increased rail volumes, partially offset by higher per barrel costs of condensate. In the second quarter of 2014, blending expenses were $17.5 million for the purchase of 1,679 bbl/d of condensate at $114.45/bbl, compared to $19.7 million for the purchase of 2,128 bbl/d at $101.82/bbl for the same period last year. In the first six months of 2014, blending expenses were $37.7 million for the purchase of 1,851 bbl/d of condensate at $112.58/bbl, compared to $45.4 million for the purchase of 2,403 bbl/d at $104.34/bbl for the same period last year. The decrease in blending expenses for the three and six months ended June 30, 2014, as compared to the same period in 2013, is due to higher volumes of heavy oil being transported by rail.

Transportation expenses increased by 2% and 11% for the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013, due to higher sales volumes offset by lower average per unit transportation expense. For the three and six months ended June 30, 2014, transportation expenses per boe decreased 11% and 3% to $3.64/boe and $4.09/boe, respectively, compared to $4.08/boe and $4.22/boe for the three and six month periods ended June 30, 2013, mainly due to shorter distance hauls and decreased wait times at the rail terminals.

Operating Netback

($ per boe except for % and volume)	Three Months Ended June 30 2014	2013	Change	Six Months Ended June 30 2014	2013	Change
Sales volume (boe/d)	**67,191**	58,440	15%	**63,340**	55,212	15%
Operating netback[1]:						
Sales price	**$ 75.06**	$ 60.42	24%	**$ 71.92**	$ 56.90	26%
Less:						
Royalties	**18.36**	11.66	57%	**16.33**	10.74	52%
Production and operating expenses	**12.32**	12.97	(5%)	**12.58**	13.43	(6%)
Transportation expenses	**3.64**	4.08	(11%)	**4.09**	4.22	(3%)
Operating netback before financial derivatives	**$ 40.74**	$ 31.71	28%	**$ 38.92**	$ 28.51	37%
Financial derivatives (loss) gain[2]	**(2.28)**	1.62		**(1.35)**	1.65	
Operating netback after financial derivatives (loss) gain	**$ 38.46**	$ 33.33	15%	**$ 37.57**	$ 30.16	25%

(1) Operating netback table includes revenues and costs associated with sulphur production.

(2) Financial derivatives reflect realized gains on commodity related contracts only and exclude the impact of interest rate swaps.

Evaluation and Exploration Expense

Evaluation and exploration expense includes the write off of undeveloped lands and assets.

Evaluation and exploration expense for the three months ended June 30, 2014 increased to $3.9 million from $2.0 million for the same period in 2013 due to an increase in the expiration of undeveloped land leases.

Evaluation and exploration expense for the six months ended June 30, 2014 increased to $14.5 million from $5.6 million for the same period in 2013 due to both an increase in the expiration of undeveloped land leases and the impairment of evaluation and exploration assets that will not be developed.

Depletion and Depreciation

Depletion and depreciation for the three and six months ended June 30, 2014 increased to $99.6 million and $188.2 million, respectively, from $86.5 million and $165.1 million for the same periods in 2013 due to overall higher production volumes. On a sales-unit basis, the provisions for the three and six months ended June 30, 2014 were $16.56/boe and $16.41/boe, respectively, compared to $16.29/boe and $16.52/boe for the same periods in 2013. The provision related to Aurora for the second quarter of 2014 was $26.23/boe reflecting the inclusion of the fair value of the acquired assets in the depletable pool. On a sales-unit basis, the provisions excluding Aurora, for the three and six months ended June 30, 2014 were $15.29/boe and $15.91/boe, respectively, compared to $16.29/boe and $16.52/boe for the same periods in 2013. The decrease for both the three month and six month periods ended June 30, 2014 was primarily due to properties with higher depletion rates being disposed of in the second quarter of 2014, as well as the increase in the 2014 opening reserves compared to 2013 opening reserves.

General and Administrative Expenses

($ thousands except for % and per boe)	Three Months Ended June 30 2014	2013	Change	Six Months Ended June 30 2014	2013	Change
General and administrative expenses	$ 14,309	$ 10,540	36%	$ 26,208	$ 22,090	19%
General and administrative expenses per boe	$ 2.34	$ 1.98	18%	$ 2.29	$ 2.21	4%

General and administrative expenses for the three months ended June 30, 2014 increased to $14.3 million, as compared to $10.5 million in the second quarter of 2013, due to higher salaries and increased head count, lower capital recoveries consistent with lower capital spending and the addition of Aurora's general and administrative expenses, which contributed $0.8 million subsequent to the acquisition date. General and administrative expenses per boe increased to $2.34/boe in the second quarter of 2014, from $1.98/boe in the second quarter of 2013.

General and administrative expenses for the six months ended June 30, 2014 increased to $26.2 million, as compared to $22.1 million in the first half of 2013, mainly due to higher salaries and increased head count and lower capital recoveries consistent with lower capital spending. General and administrative expenses per boe increased to $2.29/boe in the first half of 2014, from $2.21/boe in the first half of 2013.

Acquisition-related Costs

During the three and six months ended June 30, 2014, acquisition-related costs for the Aurora acquisition were $37.0 million, including legal, regulatory and advisory fees along with premiums paid on foreign currency hedges.

Share-based Compensation Expense

Compensation expense associated with the Share Award Incentive Plan and the Share Rights Plan is recognized in income over the vesting period of the share awards or share rights with a corresponding increase in contributed surplus. The issuance of common shares upon the conversion of share awards or exercise of share rights is recorded as an increase in shareholders' capital with a corresponding reduction in contributed surplus.

Compensation expense related to the Share Award Incentive Plan decreased to $8.2 million and $16.1 million for the three and six months ended June 30, 2013, respectively, from $9.8 million and $18.6 million in the three and six months ended June 30, 2013. This was mainly due to an increase in both actual forfeitures and the estimated future forfeiture rate on outstanding awards, as well as a decrease in the estimated payout multiplier.

Financing Costs

Financing costs include interest on bank loans and long-term debt, as well as non-cash charges related to accretion of asset retirement obligations and the amortization of financing expenses and debt issuance costs.

($ thousands except for %)	Three Months Ended June 30 2014	2013	Change	Six Months Ended June 30 2014	2013	Change
Bank loan and other	$ 4,509	$ 2,865	57%	$ 10,601	$ 4,480	137%
Long-term debt	11,252	7,732	46%	16,008	15,394	4%
Accretion on asset retirement obligations	1,779	1,690	5%	3,520	3,350	5%
Debt financing costs	57	2,117	(97%)	57	2,156	(97%)
Financing costs	$ 17,597	$ 14,404	22%	$ 30,186	$ 25,380	19%

Financing costs for the three months ended June 30, 2014 increased to $17.6 million from $14.4 million in the second quarter of 2013. Financing costs for the six months ended June 30, 2014 increased to $30.2 million from $25.4 million in the same period in 2013. The increases in financing costs for the three and six months ended June 30, 2014 were primarily due to higher outstanding debt levels compared to the same periods in 2013, partially offset by no amendment fees being incurred in 2014 on the credit facilities of Baytex Energy Ltd.

Foreign Exchange

Unrealized foreign exchange gains and losses are due to translation of the U.S. dollar denominated long-term debt and bank loans caused by the movement of the Canadian dollar against the U.S. dollar during the period. Realized foreign exchange gains and losses are due to our day-to-day U.S. dollar denominated transactions.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and exchange rates)	**2014**	2013	Change	**2014**	2013	Change
Unrealized foreign exchange (gain) loss	**$ (21,379)**	$ 4,919	(535%)	**$ (14,923)**	$ 8,736	(271%)
Realized foreign exchange loss (gain)	**2,924**	(1,565)	(287%)	**986**	(3,601)	(127%)
Foreign exchange (gain) loss	**$ (18,455)**	$ 3,354	(650%)	**$ (13,937)**	$ 5,135	(371%)
CAD/USD exchange rates:						
At beginning of period	**1.1053**	1.0156		**1.0636**	0.9949	
At end of period	**1.0676**	1.0512		**1.0676**	1.0512	

The unrealized foreign exchange gains of $21.4 and $14.9 million for the three and six months ended June 30, 2014, respectively, were mainly the result of the stronger Canadian dollar against the U.S. dollar at June 30, 2014 as compared to the issue date of the US$800 million notes.

Income Taxes

For the three and six months ended June 30, 2014, deferred income tax expense was $19.7 million and $40.1 million, respectively, as compared to $14.0 million and $17.8 million for the three and six months ended June 30, 2013.

When compared to the prior period, the increase in deferred income tax expense is primarily the result of an increase in the amount of tax pool claims required to shelter the increased taxable income in the six months ended June 30, 2014 compared to same period in 2013.

Net Income

Net income for the three months ended June 30, 2014 was $36.8 million, compared to net income of $36.2 million for the same period in 2013. The increase in net income was due to higher operating netbacks, higher foreign exchange gains, gains on dispositions in the current quarter and lower share-based compensation, partially offset by costs incurred related to the acquisition, higher depletion expense, financial derivative losses and higher income taxes.

Net income for the six months ended June 30, 2014 was $84.6 million, compared to net income of $46.3 million for the same period in 2013. The increase in net income was due to higher operating netbacks and lower share-based compensation, partially offset by costs incurred related to the acquisition of Aurora, the loss on financial derivative contracts and higher depletion and deferred income tax expenses.

Other Comprehensive Income

Other comprehensive income is comprised of the foreign currency translation adjustment on U.S. operations not recognized in profit or loss. The $45.6 million balance of accumulated other comprehensive income at June 30, 2014 relates to a $1.5 million foreign currency translation gain accumulated to December 31, 2013 combined with a $47.1 million foreign currency translation loss related to the six months ended June 30, 2014. The increased translation gain is primarily due to the strengthening of the Canadian dollar against the U.S. dollar at June 30, 2014, compared to closing date of the acquisition of Aurora on June 11, 2014.

Capital Expenditures

Capital expenditures for the three and six months ended June 30, 2014 and 2013 are summarized as follows:

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	2014	2013	2014	2013
Land	$ 1,822	$ 2,415	$ 3,212	$ 5,400
Seismic	774	208	1,166	766
Drilling and completion	90,559	122,425	224,017	241,170
Equipment	55,761	52,786	92,946	96,992
Other	–	–	–	28
Total exploration and development	$ 148,916	$ 177,834	$ 321,341	$ 344,356
Total acquisitions, net of divestitures	2,920,845	(1,796)	2,921,518	(23,227)
Total oil and natural gas expenditures	3,069,761	176,038	3,242,859	321,129
Other plant and equipment, net	5,313	1,350	6,070	4,720
Total capital expenditures	$ 3,075,074	$ 177,388	$ 3,248,929	$ 325,849

During the three months ended June 30, 2014, we drilled 28.3 net wells, compared to 25.8 net wells in the three months ended June 30, 2013. During the six months ended June 30, 2014, we drilled 147.4 net wells, compared to 135.6 net wells in the six months ended June 30, 2013. In 2014, capital investment activity has progressed as planned in our key development areas. 90% of the wells drilled were heavy oil focused.

In the second quarter, we completed the swap of assets on a non-cash basis by disposing of assets in the Saskatchewan heavy oil area in exchange for acquired assets in the Peace River area. The assets exchanged were comparable in terms of value and current production volumes. A gain of $18.7 million was recognized in the three and six months ended June 30, 2014 in respect of the disposed assets.

Total acquisitions, net of divestitures of $2.9 million for the three months ended June 30, 2014 include the acquisition of Aurora for approximately $2.8 billion which closed in the quarter. See "Business Combination" for further details on the acquisition. The acquisition is reported at estimated fair value of the assets acquired.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DIVIDENDS

Funds from operations and payout ratio are non-GAAP measures. Funds from operations represents cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Payout ratio is calculated as cash dividends (net of participation in the DRIP) divided by funds from operations. Baytex considers these to be key measures of performance as they demonstrate our ability to generate the cash flow necessary to fund dividends and capital investments.

The following table reconciles cash flow from our operating activities (a GAAP measure) to funds from operations (a non-GAAP measure):

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands except for %)	2014	2013	2014	2013
Cash flow from operating activities	$ 152,087	$ 160,306	$ 273,696	$ 255,480
Change in non-cash working capital	25,960	6,776	81,938	19,558
Asset retirement expenditures	2,992	1,273	6,888	4,246
Financing costs	(17,597)	(14,404)	(30,186)	(25,380)
Accretion on asset retirement obligations	1,779	1,690	3,520	3,350
Accretion on notes and long-term debt	281	163	456	322
Funds from operations	$ 165,502	$ 155,804	$ 336,312	$ 257,576
Dividends declared	$ 95,467	$ 81,432	$ 178,724	$ 162,391
Reinvested dividends	(20,070)	(21,106)	(39,886)	(45,616)
Cash dividends declared (net of DRIP)	$ 75,397	$ 60,326	$ 138,838	$ 116,775
Payout ratio(1)	58%	52%	53%	63%
Payout ratio (net of DRIP)(1)	46%	39%	41%	45%

(1) Payout ratio, excluding acquisition related costs was 47% (37% net of DRIP) for the three months ended June 30, 2014 and 48% (37% net of DRIP) for the six months ended June 30, 2014.

Baytex does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of petroleum and natural gas assets, certain levels of capital expenditures are required to maintain production. Due to the nature of reserve reporting, natural production declines and the risks involved in capital investment, we are unable to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire petroleum and natural gas assets increase significantly, it is possible that we would be required to reduce or eliminate dividends on our common shares in order to fund capital expenditures. There can be no certainty that we will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of $75.4 million and $138.8 million for the three and six months ended June 30, 2014 were funded by funds from operations of $165.5 million and $336.3 million respectively.

LIQUIDITY AND CAPITAL RESOURCES

We regularly review our liquidity sources as well as our exposure to counterparties and have concluded that our capital resources are sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations, augmented by our hedging program and existing credit facilities, will provide sufficient liquidity to sustain our operations in the short, medium and long-term. Further, we believe that our counterparties currently have the financial capacities to honor outstanding obligations to us in the normal course of business. We periodically review the financial capacity of our counterparties and, in certain circumstances, we will seek enhanced credit protection.

($ thousands)	June 30, 2014	December 31, 2013
Bank loan	$ 952,402	$ 223,371
Long-term debt(1)	1,329,487	459,540
Working capital deficiency(2)	178,517	79,151
Total monetary debt	$ 2,460,406	$ 762,062

(1) Principal amount of instruments.

(2) Working capital is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives, assets held for sale, and liabilities related to assets held for sale).

At June 30, 2014, total monetary debt was $2,460.4 million, as compared to $762.1 million at December 31, 2013. The increase in monetary debt at June 30, 2014 as compared to December 31, 2013 was primarily due to the acquisition of Aurora and exploration and development expenditures exceeding cash flow from operations during the first six months of the year.

Effective June 4, 2014 Baytex reached agreement with its bank lending syndicate to establish credit facilities for approximately $1.4 billion consisting of the following: (i) revolving extendible unsecured credit facilities consisting of a $50 million operating loan and a $950 million syndicated loan for Baytex and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex USA Oil & Gas, Inc., both of which have a four-year term (collectively, the "Revolving Facilities"); and (ii) a $200 million non-revolving unsecured syndicated loan with a two-year term (the "Non-Revolving Facility" and, together with the Revolving Facilities, the "Unsecured Facilities"). The Unsecured Facilities contain standard commercial covenants for facilities of this nature and the Revolving Facilities do not require any mandatory principal payments prior to maturity. At June 30, 2014, $952.4 million has been drawn on these Unsecured Facilities with $461.1 million remaining available. A copy of the credit agreement is accessible on the SEDAR website at www.sedar.com (filed under the category "Material Document" on June 11, 2014).

The following table lists the financial covenants under the Unsecured Facilities and the senior unsecured notes, and the compliance therewith as at June 30, 2014.

Covenant Description	Maximum Ratio	Position at June 30, 2014
Bank loan		
Senior debt to capitalization(1)(2)	0.50:1.00	0.46:1.00
Senior debt to Adjusted income(1)(5)(6)	3.00:1.00	1.96:1.00
Debt to Adjusted income(3)(5)(6)	4.00:1.00	1.98:1.00
Long-term debt		
Fixed charge coverage(4)(5)(6)	2:00:1.00	0.10:1.00

(1) "Senior debt" is defined as the sum of our bank loan and principal amount of long-term debt.
(2) "Capitalization" is defined as the sum of our bank loan, principal amount of long-term debt and shareholders' equity.
(3) "Debt" is defined as the sum of our bank loan, the principal amount of long-term debt, and certain other liabilities identified in the credit agreement.
(4) Fixed charge coverage is computed as the ratio of financing cost to trailing twelve month Adjusted income.
(5) For purposes of the covenant calculations, Aurora's Adjusted income for the trailing twelve months has been included, in accordance with the terms of the credit agreements.
(6) "Adjusted income" is calculated based on terms and definitions set out in the banking agreements which adjusts net income for financing costs, certain specific unrealized and non-cash transactions, acquisition and disposition activity and is calculated based on a trailing twelve month basis.

Adjusted income for the trailing twelve months ended June 30, 2014 was $1.16 billion.

In the event of a material acquisition, certain of the financial covenants are relaxed for up to two quarter ends following the closing of such material acquisition, provided that in each quarter: (i) the senior debt to capitalization ratio shall not exceed 0.55:1.00; (ii) the senior debt to Adjusted Income ratio shall not exceed 3.50:1.00; and (iii) the sole cause of such ratios exceeding the levels set forth above is due to the material acquisition. If we exceed any of the covenants under the Unsecured Facilities, we would be required to repay, refinance or renegotiate the loan terms and conditions which may restrict our ability to pay dividends to our shareholders.

The weighted average interest rate on the bank loan for the three and six months ended June 30, 2014 was 3.73% and 3.92%, respectively (three and six months ended June 30, 2013 – 5.09% and 5.31%, respectively).

On July 19, 2012, we issued $300 million principal amount of senior unsecured notes bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. On February 17, 2011, we issued US$150 million principal amount of senior unsecured notes bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021.

Pursuant to the acquisition of Aurora, Baytex assumed US$365 million of 9.875% senior unsecured notes due February 15, 2017 (the "2017 Notes") and US$300 million of 7.500% senior unsecured notes due April 1, 2020 (the "2020 Notes" and, together with the 2017 Notes, the "Notes").

On April 22, 2014, Baytex commenced a cash tender offer and consent solicitation for the Notes at a price (per $1,000 of principal amount) of US$1,107.34 for the 2017 Notes and US$1,138.97 for the 2020 Notes. Upon closing of the tender offers on June 11, 2014, Baytex purchased US$357.1 million (97.8% of total outstanding) of the 2017 Notes and US$293.6 million (97.9% of total outstanding) of the 2020 Notes, which have been cancelled. The remaining Notes are redeemable at the Company's option, in whole or in part, commencing on February 15, 2015 (in the case of the 2017 Notes) and April 1, 2016 (in the case of the 2020 Notes) at specified redemption prices.

On June 6, 2014, Baytex issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "2021 Notes") and US$400 million of 5.625% notes due June 1, 2024 (the "2024 Notes"). The 2021 Notes and the 2024 Notes pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on June 1, 2017 (in the case of the 2021 Notes) and June 1, 2019 (in the case of the 2024 Notes) at specified redemption prices.

Pursuant to various agreements with our lenders, we are restricted from paying dividends to shareholders where the dividend would or could have a material adverse effect on us or our subsidiaries' ability to fulfill our respective obligations under our senior unsecured notes and credit facilities.

We believe that our funds from operations, together with the existing credit facilities, will be sufficient to finance current operations, dividends to the shareholders and planned capital expenditures in the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of dividend is also discretionary, and the Company has the ability to modify dividend levels should funds from operations be negatively impacted by factors such as reductions in commodity prices or production volumes.

Subsequent Event

On July 29, 2014, the Company signed an agreement with an oil and gas company to sell the North Dakota assets for approximately$357 million, effective July 1, 2014. We expect the net after-tax proceeds of approximately $275 million to be applied first to the Non-Revolving Facility in accordance with certain banking agreements and then to outstanding bank indebtedness. Production for the six months ended June 30, 2014 was 3,200 boe/d and proved and probable reserves at December 31, 2013 were estimated to be 53.5 million boe. The transaction is subject to standard terms and conditions and is expected to close near the end of the third quarter of 2014.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. The rights and terms of preferred shares are determined upon issuance. As at July 28, 2014, we had 166,068,926 common shares and no preferred shares issued and outstanding. During the second quarter of 2014, we converted 38,433,000 subscription receipts issued in February 2014 into 38,433,000 common shares upon closing of the acquisition of Aurora.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's funds from operations in an ongoing manner. A significant portion of these obligations will be funded by funds from operations. These obligations as of June 30, 2014 and the expected timing for funding these obligations is noted in the table below.

Operating leases	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	$ 446,543	$ 446,543	$ –	$ –	$ –
Dividends payable to shareholders	39,701	39,701	–	–	–
Bank loan[(1)]	952,402	–	200,000	752,402	–
Long-term debt[(2)]	1,329,487	–	8,434	–	1,321,053
Operating leases	46,318	8,061	16,160	15,845	6,252
Processing agreements	92,259	10,663	21,808	13,795	45,993
Transportation agreements	73,116	11,233	19,858	18,005	24,020
Total	$ 2,979,826	$ 516,201	$ 266,260	$ 800,047	$ 1,397,318

(1) The bank loan is a covenant-based loan with a revolving portion that is extendible annually for up to a four year period and a non-revolving portion which matures on June 3, 2016. Unless extended, the revolving period will end on June 3, 2018, with all amounts to be re-paid on such date.

(2) Principal amount of instruments.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. Programs to abandon and reclaim them are undertaken regularly in accordance with applicable legislative requirements.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Our normal operations expose us to a number of financial risks, including liquidity risk, credit risk and market risk. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. We manage liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default resulting in the Company incurring a loss. Credit risk is managed by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of foreign currency risk, interest rate risk and commodity price risk. Market risk is partially mitigated through a series of derivative contracts intended to reduce some of the volatility of our operating cash flow.

A summary of the risk management contracts in place as at June 30, 2014 and the accounting treatment thereof is disclosed in note 18 to the consolidated financial statements.

QUARTERLY FINANCIAL INFORMATION

	2014		2013				2012	
($ thousands, except per common share amounts)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Gross revenues	476,404	385,809	330,712	422,791	341,011	272,945	292,095	299,786
Net income	36,799	47,841	31,173	87,331	36,192	10,149	31,620	26,773
Per common share – basic	0.27	0.38	0.26	0.70	0.29	0.08	0.26	0.22
Per common share – diluted	0.27	0.38	0.25	0.70	0.29	0.08	0.26	0.22

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: the anticipated benefits from the acquisition of Aurora; our expectations that the Aurora assets have infrastructure in place that support future annual production growth; our expectations regarding the effect of well downspacing, improving completion techniques and new development targets on the reserves potential of the Aurora assets; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; the royalty rate for the Aurora assets; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; our business strategies, plans and objectives; our ability to fund our capital expenditures and dividends on our common shares from funds from operations; funding sources for our cash dividends and capital program; the timing of closing of the asset disposition; the estimated proceeds from the asset disposition; the intended use of proceeds from the asset disposition; the timing of funding our financial obligations; and the existence, operation and strategy of our risk management program. 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 funds from operations 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: our ability to execute and realize on the anticipated benefits of the acquisition of Aurora; 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 for our operating activities; 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; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: failure to realize the anticipated benefits of the acquisition of Aurora; declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; access to external sources of capital; third party credit risk; a downgrade of our credit ratings; risks associated with the exploitation of our properties and our ability to acquire reserves; increases in operating costs; changes in government regulations that affect the oil and gas industry; changes to royalty or mineral/severance tax regimes; risks relating to hydraulic fracturing; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with properties *operated by third parties; risks associated with delays in business operations; risks associated with the marketing of our petroleum and natural gas production; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; expansion of our operations; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in environmental, health and safety regulations; the implementation of strategies for reducing greenhouse gases; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the activities of our operating entities and their key personnel and information systems; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonal weather patterns; our permitted investments; access to technological advances; changes in the demand for oil and natural gas products; involvement in legal, regulatory and tax proceedings; the failure of third parties to comply with confidentiality agreements; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond the control of Baytex. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2013, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.*

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements 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.

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(thousands of Canadian dollars) (unaudited)*	June 30, 2014	December 31, 2013
ASSETS		
Current assets		
Cash	$ 18,152	$ 18,368
Trade and other receivables	288,809	141,651
Crude oil inventory	766	1,507
Financial derivatives	3,732	10,087
Assets held for sale (note 5)	–	73,634
	311,459	245,247
Non-current assets		
Financial derivatives	18,261	–
Exploration and evaluation assets (note 6)	544,212	162,987
Oil and gas properties (note 7)	4,933,062	2,222,786
Other plant and equipment	34,092	29,559
Other assets (note 4)	4,085	–
Goodwill	642,278	37,755
TOTAL ASSETS	$ 6,487,449	$ 2,698,334
LIABILITIES		
Current liabilities		
Trade and other payables	$ 446,543	$ 213,091
Dividends payable to shareholders	39,701	27,586
Financial derivatives	67,416	18,632
Liabilities related to assets held for sale (note 5)	–	10,241
	553,660	269,550
Non-current liabilities		
Bank loan (note 8)	952,402	223,371
Long-term debt (note 9)	1,310,283	452,030
Asset retirement obligations (note 10)	237,499	221,628
Deferred income tax liability	815,536	248,401
Financial derivatives	438	869
	3,869,818	1,415,849
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 11)	3,487,029	2,004,203
Contributed surplus	46,610	53,081
Accumulated other comprehensive income	(45,641)	1,484
Deficit	(870,367)	(776,283)
	2,617,631	1,282,485
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,487,449	$ 2,698,334

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(thousands of Canadian dollars, except per common share amounts) (unaudited)	Three Months Ended June 30 2014	Three Months Ended June 30 2013	Six Months Ended June 30 2014	Six Months Ended June 30 2013
Revenues, net of royalties (note 15)	$ 364,122	$ 279,001	$ 675,051	$ 506,668
Expenses				
Production and operating	75,343	68,999	144,178	134,215
Transportation and blending	39,737	41,440	84,640	87,576
Exploration and evaluation (note 6)	3,898	1,995	14,508	5,577
Depletion and depreciation	99,591	86,529	188,184	165,110
General and administrative	14,309	10,540	26,208	22,090
Acquisition-related costs (note 3)	36,973	–	36,973	–
Share-based compensation (note 12)	8,232	9,894	16,087	18,938
Financing costs (note 16)	17,597	14,404	30,186	25,380
Loss (gain) on financial derivatives (note 18)	49,123	(8,317)	42,045	(550)
Foreign exchange (gain) loss (note 17)	(18,455)	3,354	(13,937)	5,135
Gain on divestiture of oil and gas properties (note 5)	(18,741)	–	(18,741)	(20,951)
	307,607	228,838	550,331	442,520
Net income before income taxes	56,515	50,163	124,720	64,148
Deferred income tax expense (note 14)	19,716	13,971	40,080	17,807
Net income attributable to shareholders	$ 36,799	$ 36,192	$ 84,640	$ 46,341
Other comprehensive income				
Foreign currency translation adjustment	(57,332)	7,457	(47,125)	11,343
Comprehensive (loss) income	$ (20,533)	$ 43,649	$ 37,515	$ 57,684
Net income per common share (note 13)				
Basic	$ 0.27	$ 0.29	$ 0.65	$ 0.37
Diluted	$ 0.27	$ 0.29	$ 0.64	$ 0.37
Weighted average common shares (note 13)				
Basic	135,620	123,271	130,806	122,883
Diluted	137,158	124,362	132,332	124,138

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) *(unaudited)*	Shareholders' capital	Contributed surplus[1]	Accumulated other comprehensive income (loss)	Deficit	Total equity
Balance at December 31, 2012	$ 1,860,358	$ 65,615	$ (12,462)	$ (614,099)	**$ 1,299,412**
Dividends to shareholders	–	–	–	(162,391)	**(162,391)**
Exercise of share rights	13,495	(8,194)	–	–	**5,301**
Vesting of share awards	11,839	(11,839)	–	–	**–**
Share-based compensation	–	18,938	–	–	**18,938**
Issued pursuant to dividend reinvestment plan	46,333	–	–	–	**46,333**
Comprehensive income for the period	–	–	11,343	46,341	**57,684**
Balance at June 30, 2013	$ 1,932,025	$ 64,520	$ (1,119)	$ (730,149)	**$ 1,265,277**
Balance at December 31, 2013	$ 2,004,203	$ 53,081	$ 1,484	$ (776,283)	**$ 1,282,485**
Dividends	–	–	–	(178,724)	**(178,724)**
Exercise of share rights	10,348	(5,626)	–	–	**4,722**
Vesting of share awards	16,932	(16,932)	–	–	**–**
Share-based compensation	–	16,087	–	–	**16,087**
Issued for cash	1,495,044	–	–	–	**1,495,044**
Issuance costs, net of tax	(78,468)	–	–	–	**(78,468)**
Issued pursuant to dividend reinvestment plan	38,970	–	–	–	**38,970**
Comprehensive income for the period	–	–	(47,125)	84,640	**37,515**
Balance at June 30, 2014	$ 3,487,029	$ 46,610	$ (45,641)	$ (870,367)	**$ 2,617,631**

(1) Share-based compensation is accumulated in contributed surplus.

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended June 30		Six Months Ended June 30	
(thousands of Canadian dollars) (unaudited)	**2014**	2013	**2014**	2013
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income for the period	**$ 36,799**	$ 36,192	**$ 84,640**	$ 46,341
Adjustments for:				
Share-based compensation (note 12)	**8,232**	9,894	**16,087**	18,938
Unrealized foreign exchange (gain) loss (note 17)	**(21,379)**	4,919	**(14,923)**	8,736
Exploration and evaluation	**3,898**	1,995	**14,508**	5,577
Depletion and depreciation	**99,591**	86,529	**188,184**	165,110
Unrealized loss on financial derivatives (note 18)	**35,326**	451	**22,501**	12,346
Gain on divestitures of oil and gas properties (note 5)	**(18,741)**	–	**(18,741)**	(20,951)
Deferred income tax expense	**19,716**	13,971	**40,080**	17,807
Financing costs (note 16)	**17,597**	14,404	**30,186**	25,380
Change in non-cash working capital	**(25,960)**	(6,776)	**(81,938)**	(19,558)
Asset retirement obligations settled (note 10)	**(2,992)**	(1,273)	**(6,888)**	(4,246)
	152,087	160,306	**273,696**	255,480
Financing activities				
Payments of dividends	**(67,251)**	(58,436)	**(127,637)**	(115,680)
(Decrease) increase in secured bank loan (note 8)	**(300,564)**	69,592	**(223,371)**	109,040
Increase in unsecured bank loan (note 8)	**809,343**	–	**809,343**	–
Net proceeds from issuance of long-term debt (note 9)	**849,944**	–	**849,944**	–
Tender of long-term debt (note 9)	**(793,099)**	–	**(793,099)**	–
Issuance of common shares on share rights (note 11)	**2,388**	1,583	**4,722**	5,301
Issuance of common shares, net of issue costs (note 11)	**1,401,317**	–	**1,401,317**	–
Other assets (note 4)	**(4,085)**	–	**(4,085)**	–
Interest paid	**(12,149)**	(5,461)	**(29,460)**	(21,999)
	1,885,844	7,278	**1,887,674**	(23,338)
Investing activities				
Additions to exploration and evaluation assets (note 6)	**(1,828)**	(913)	**(9,148)**	(5,063)
Additions to oil and gas properties (note 7)	**(147,088)**	(176,921)	**(312,193)**	(339,293)
Property acquisitions	**(9,920)**	(54)	**(10,593)**	(54)
Corporate acquisition (note 3)	**(1,866,307)**	–	**(1,866,307)**	–
Proceeds from divestiture of oil and gas properties	**814**	1,850	**814**	44,232
Additions to other plant and equipment, net of disposals	**(4,104)**	(1,350)	**(4,861)**	(4,720)
Change in non-cash working capital	**6,677**	13,104	**40,208**	74,935
	(2,021,756)	(164,284)	**(2,162,080)**	(229,963)
Impact of foreign currency translation on cash balances	**(363)**	(1,177)	**494**	(1,662)
Change in cash	**15,812**	2,123	**(216)**	517
Cash, beginning of period	**2,340**	231	**18,368**	1,837
Cash, end of period	**$ 18,152**	$ 2,354	**$ 18,152**	$ 2,354

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at June 30, 2014 and December 31, 2013 and for the three and six months ended June 30, 2014 and 2013
(all tabular amounts in thousands of Canadian dollars, except per common share amounts) (unaudited)

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the United States. The Company's common shares are traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange under the symbol BTE. The Company's head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PRESENTATION

The condensed interim unaudited consolidated financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards ("IAS") 34, Interim Financial Reporting, as issued by the International Accounting Standards Board. These consolidated financial statements do not include all the necessary annual disclosures as prescribed by International Financial Reporting Standards ("IFRS") and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2013. The Company's accounting policies are unchanged compared to December 31, 2013 except as listed in note 3 "Changes in Accounting Policies" of the consolidated financial statements of March 31, 2014. The use of estimates and judgments is also consistent with the December 31, 2013 financial statements.

The consolidated financial statements were approved by the Board of Directors of Baytex on July 30, 2014.

The consolidated financial statements have been prepared on the historical cost basis, except for derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is rounded to the nearest thousand, except per share amounts and when otherwise indicated.

3. BUSINESS COMBINATION

On June 11, 2014, Baytex acquired all of the issued and outstanding shares of Aurora Oil & Gas Limited ("Aurora"), a public oil and natural gas company listed on the Australian Stock Exchange and TSX with properties in Texas, USA. The acquisition expands our asset base and diversifies our portfolio. The total consideration for the acquisition was $2.8 billion (including the assumption of approximately $0.9 billion of indebtedness).

The acquisition has been accounted for as a business combination with the fair value of the assets acquired and liabilities assumed at the date of acquisition summarized below:

Consideration for the acquisition:	
Cash paid	$1,920,928
Cash acquired	(54,621)
Bank loan assumed	145,618
Long-term debt assumed	810,061
Total consideration	**$2,821,986**
Allocation of purchase price:	
Trade and other receivables	$ 108,965
Exploration and evaluation assets	391,127
Oil and gas properties	2,520,612
Other plant and equipment	1,209
Goodwill	615,338
Trade and other payables	(242,045)
Financial derivative contracts	(20,083)
Asset retirement obligations	(1,217)
Deferred income tax liabilities	(551,920)
Total net assets acquired	**$2,821,986**

Acquisition-related costs totaling $37.0 million have been excluded from the consideration paid and have been recognized as an expense in the three and six months ended June 30, 2014, within the "Acquisition-related costs" line item in the consolidated statements of income and comprehensive income. Goodwill arising on this acquisition of $615.3 million relates to incremental well locations and undeveloped zones and areas, and is attributable to the excess of consideration paid over the fair value of assets acquired of which $551.9 million relates to the recognition of deferred income tax liabilities. Goodwill is not deductible for tax purposes.

From the period June 11, 2014 to June 30, 2014, the acquired properties contributed revenues, net of royalties, of $33.7 million and operating income of $30.0 million to Baytex's operations. If the acquisition had occurred on January 1, 2014, management estimates for the three and six months ended June 30, 2014, that its incremental pro forma revenues, net of royalties, would have been approximately $143.7 million and $285.6 million, respectively, and incremental operating income would have been approximately $125.4 million and $249.3 million for the three and six months ended June 30, 2014.

The fair values of assets and liabilities recognized are estimates due to the uncertainty of provisional amounts recognized. Amendments may be made to the purchase price equation as the cost estimates and balances are finalized.

4. OTHER ASSETS

Other assets include debt issuance costs related to the restructuring of the credit facilities (note 8) and will be amortized over the four-year term of the credit facilities.

5. ASSETS HELD FOR SALE

At June 30, 2014, there were no assets or related liabilities classified as held for sale. In December 2013, the Board of Directors of Baytex approved a transaction with an oil and natural gas company to exchange certain heavy oil assets in Saskatchewan and in return, receive certain heavy oil assets in the Peace River region of Alberta. Assets held for sale at December 31, 2013 included $0.3 million of exploration and evaluation assets and $73.3 million of oil and natural gas properties. Liabilities related to assets held for sale included $10.2 million of asset retirement obligations. The disposition was completed during the second quarter of 2014, resulting in a gain on disposition of $18.7 million for the three and six months ended June 30, 2014.

The acquired assets and related liabilities were measured at fair value. The fair value of these acquired assets as at June 30, 2014 included $0.4 million of exploration and evaluation assets and $82.4 million of oil and natural gas properties. Liabilities acquired in this exchange include $1.6 million of asset retirement obligations.

6. EXPLORATION AND EVALUATION ASSETS

Cost	
As at December 31, 2012	**$ 240,015**
Capital expenditures	11,846
Property acquisition	3,060
Exploration and evaluation expense	(10,286)
Transfer to oil and gas properties	(82,886)
Divestitures	(1,109)
Assets held for sale (note 5)	(305)
Foreign currency translation	2,652
As at December 31, 2013	**$ 162,987**
Capital expenditures	9,148
Corporate acquisition	391,127
Property acquisition	10,053
Exploration and evaluation expense	(14,508)
Transfer to oil and gas properties	(8,024)
Divestitures	(9)
Foreign currency translation	(6,562)
As at June 30, 2014	**$ 544,212**

7. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2012	**$ 2,758,309**
Capital expenditures	539,054
Corporate acquisition	100
Property acquisitions	108
Transferred from exploration and evaluation assets	82,886
Assets held for sale (note 5)	(110,386)
Change in asset retirement obligations	(28,734)
Divestitures	(33,907)
Foreign currency translation	16,338
As at December 31, 2013	**$ 3,223,768**
Capital expenditures	312,193
Corporate acquisition	2,520,612
Property acquisitions	83,295
Transferred from exploration and evaluation assets	8,024
Change in asset retirement obligations	18,145
Divestitures	(690)
Foreign currency translation	(45,395)
As at June 30, 2014	**$ 6,119,952**

Accumulated depletion	
As at December 31, 2012	**$ 720,733**
Depletion for the period	325,793
Divestitures	(10,191)
Assets held for sale (note 5)	(37,057)
Foreign currency translation	1,704
As at December 31, 2013	**$ 1,000,982**
Depletion for the period	186,661
Divestitures	(293)
Foreign currency translation	(460)
As at June 30, 2014	**$ 1,186,890**

Carrying value	
As at December 31, 2013	**$ 2,222,786**
As at June 30, 2014	**$ 4,933,062**

8. BANK LOAN

	June 30, 2014	December 31, 2013
Bank loan	$ 952,402	$ 223,371

Effective June 4, 2014, Baytex reached agreement with its bank lending syndicate to establish credit facilities for approximately $1.4 billion consisting of the following: (i) revolving extendible unsecured credit facilities consisting of a $50 million operating loan and a $950 million syndicated loan for Baytex and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex USA Oil & Gas, Inc., both of which have a four-year term (collectively, the "Revolving Facilities"); and (ii) a $200 million non-revolving unsecured syndicated loan with a two-year term (the "Non-Revolving Facility") and together with the Revolving Facilities, the "Unsecured Facilities".

The Unsecured Facilities replaced the revolving extendible secured credit facilities ($40 million operating loan and $810 million syndicated loan) of the Company's wholly-owned subsidiary, Baytex Energy Ltd.

Unless extended, the revolving period under the Revolving Facilities will end on June 3, 2018 with all amounts to be re-paid on such date. Baytex may, once in each calendar year, request that the lenders under the Revolving Facilities extend the revolving period for up to four years (subject to a maximum four-year term at any time). The Revolving Facilities do not require any mandatory principal payments prior to maturity and do not include a term-out feature or a borrowing base restriction. The Revolving Facilities include an option allowing such facilities to be increased by up to $250 million, subject to existing or new lender(s) providing commitments for any such increase.

The Non-Revolving Facility is a single drawdown facility available solely to finance the acquisition of Aurora. The Non-Revolving Facility provides for mandatory reductions and repayments for specified equity and debt issuances and asset dispositions with all amounts to be re-paid by June 3, 2016.

The Unsecured Facilities contain standard commercial covenants for facilities of this nature and are guaranteed by Baytex and its material subsidiaries. Advances (including letters of credit) under the Unsecured Facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. In the event that Baytex does not comply with the covenants under the Unsecured Facilities, its ability to pay dividends to its shareholders may be restricted.

The weighted average interest rate on the bank loan for the three and six months ended June 30, 2014 was 3.73% and 3.92% respectively, and 5.09% and 5.31% for the three and six months ended June 30, 2013, respectively.

9. LONG-TERM DEBT

	June 30, 2014	December 31, 2013
9.875% notes (US$7,900 – principal) due February 15, 2017	$ 9,074	$ –
7.500% notes (US$6,400 – principal) due April 1, 2020	7,572	–
6.750% notes (US$150,000 – principal) due February 17, 2021	158,369	157,673
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	294,604	294,357
5.125% notes (US$400,000 – principal) due June 1, 2021	421,721	–
5.625% notes (US$400,000 – principal) due June 1, 2024	418,943	–
	$ 1,310,283	$ 452,030

Pursuant to the acquisition of Aurora (note 3), Baytex assumed US$365 million of 9.875% senior unsecured notes due February 15, 2017 (the "2017 Notes") and US$300 million of 7.500% senior unsecured notes due April 1, 2020 (the "2020 Notes" and, together with the 2017 Notes, the "Notes").

On April 22, 2014 Baytex commenced a cash tender offer and consent solicitation for the Notes at a price (per $1,000 of principal amount) of US$1,107.34 for the 2017 Notes and US$1,138.97 for the 2020 Notes. Upon closing of the tender offers, on June 11, 2014, Baytex purchased US$357.1 million (97.8% of total outstanding) of the 2017 Notes and US$293.6 million (97.9% of total outstanding) of the 2020 Notes, which have been canceled. The remaining Notes are recorded at fair value by applying the tender premium on the Notes on the date of acquisition and the premium will be amortized using the effective interest rate of 6.8% for the 2017 Notes and 5.3% for the 2020 Notes. The Notes are redeemable at the Company's option, in whole or in part, commencing on February 15, 2015 (in the case of the 2017 Notes) and April 1, 2016 (in the case of the 2020 Notes) at specified redemption prices.

On June 6, 2014, Baytex issued US$800 million of senior unsecured notes comprised of US$400 million of 5.125% notes due June 1, 2021 (the "2021 Notes") and US$400 million of 5.625% notes due June 1, 2024 (the "2024 Notes"). The 2021 notes and the 2024 notes pay interest semi-annually and are redeemable at the Company's option in whole or in part, commencing on June 1, 2017 (in the case of the 2021 Notes) and June 1, 2019 (in the case of the 2024 Notes) at specified redemption prices. These notes are carried at amortized cost, net of debt issuance costs of US$7.4 million (in the case of the 2021 Notes) and US$10.5 million (in the case of the 2024 Notes), which accrete to the principal balance at maturity using the effective interest rate of 5.3% for the 2021 Notes and 5.9% for the 2024 Notes.

Each of the outstanding notes are redeemable at the Company's option in accordance with the redemption provisions contained in the indenture governing such notes. Baytex has recognized the fair value of this redemption feature as a derivative financial asset. The fair value has been estimated using a valuation model that considers current bond prices and the spreads associated with the outstanding notes compared to the fixed redemption rates. A fair value gain of $12.1 million for the three and six months ended June 30, 2014 (three and six months ended June 30, 2013 – $ nil) has been recorded as financial derivatives loss (gain). As at June 30, 2014, $17.6 million has been included in Financial derivatives (December 31, 2013 – $nil) representing the fair value of the redemption feature on all notes.

Accretion expense on the outstanding notes and debentures of $0.3 million has been recorded in financing costs for the three months ended June 30, 2014 (three months ended June 30, 2013 – $0.2 million) and $0.5 million for the six months ended June 30, 2014 (six months ended June 30, 2013 – $0.3 million).

10. ASSET RETIREMENT OBLIGATIONS

	June 30, 2014	December 31, 2013
Balance, beginning of period	$ 221,628	$ 265,520
Liabilities incurred	5,044	14,901
Liabilities settled	(6,888)	(12,076)
Liabilities acquired	2,192	–
Liabilities divested	(1,976)	(1,409)
Corporate acquisition	1,217	–
Accretion	3,520	7,011
Change in estimate[(1)]	12,885	(42,226)
Liabilities related to assets held for sale (note 5)	–	(10,241)
Foreign currency translation	(123)	148
Balance, end of period	$ 237,499	$ 221,628

(1) Changes in the status of wells, discount rates and the estimated costs of abandonment and reclamation are factors resulting in a change in estimate.

11. SHAREHOLDERS' CAPITAL

Shareholders' Capital

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at June 30, 2014, no preferred shares have been issued by the Company and all common shares issued were fully paid.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2012	**121,868**	**$ 1,860,358**
Issued on exercise of share rights	802	10,586
Transfer from contributed surplus on exercise of share rights	–	20,333
Transfer from contributed surplus on vesting and conversion of share awards	555	24,542
Issued pursuant to dividend reinvestment plan	2,167	88,384
Balance, December 31, 2013	**125,392**	**$ 2,004,203**
Issued on exercise of share rights	267	4,722
Transfer from contributed surplus on exercise of share rights	–	5,626
Transfer from contributed surplus on vesting and conversion of share awards	395	16,932
Issued for cash	38,433	1,495,044
Issuance costs, net of tax	–	(78,468)
Issued pursuant to dividend reinvestment plan	934	38,970
Balance, June 30, 2014	**165,421**	**$ 3,487,029**

On February 24, 2014, Baytex issued 38.4 million subscription receipts at $38.90 each to partially finance the acquisition of Aurora (note 3). The gross proceeds from the sale of the subscription receipts ($1,495.0 million) were placed in escrow (the "escrowed funds") pending the completion of the acquisition. Concurrent with the closing of the acquisition on June 11, 2014, the escrowed funds were released to Baytex and each subscription receipt was exchanged for one common share and a dividend equivalent payment of $0.88 (representing the four dividends declared from the date of issuance of the subscription receipts to the date of closing of the acquisition). Issuance costs of $93.7 million ($78.5 million, after tax), including the aggregate dividend equivalent payment of $33.8 million, were incurred.

Monthly dividends of $0.24 per common share in June 2014 and $0.22 per common share for each of the previous five months were declared by the Company. During the three and six months ended June 30, 2014, total dividends declared of $95.5 million ($75.4 million net of dividend reinvestment) and $178.7 million ($138.8 million net of dividend reinvestment), respectively, were declared.

12. EQUITY BASED PLANS

Share Award Incentive Plan

The Company recorded compensation expense related to the share awards of $8.2 million for the three months ended June 30, 2014 (three months ended June 30, 2013 – $9.8 million) and $16.1 million for the six months ended June 30, 2014 (six months ended June 30, 2013 – $18.6 million)

The estimated weighted average fair value for share awards at the measurement date is $40.36 per restricted award and performance award granted during the six months ended June 30, 2014 (six months ended June 30, 2013 – $43.37 per restricted award and performance award).

The number of share awards outstanding is detailed below:

	Number of restricted awards *(000s)*	Number of performance awards *(000s)*	Number of share awards *(000s)*
Balance, December 31, 2012	**566**	**388**	**954**
Granted	437	374	811
Vested and converted to common shares	(215)	(142)	(357)
Forfeited	(65)	(40)	(105)
Balance, December 31, 2013	**723**	**580**	**1,303**
Granted	350	273	623
Vested and converted to common shares	(155)	(119)	(274)
Forfeited	(50)	(29)	(79)
Balance, June 30, 2014	**868**	**705**	**1,573**

Share Rights Plan

No new grants have been made under the Share Rights Plan since December 31, 2010. All outstanding share rights have been fully expensed and are exercisable.

The number of share rights outstanding and exercise prices are detailed below:

	Number of share rights *(000s)*	Weighted average exercise price
Balance, December 31, 2012(1)	**1,525**	**$ 16.79**
Exercised(2)	(802)	13.53
Forfeited(1)	(6)	27.77
Balance, December 31, 2013(1)	**717**	**$ 17.69**
Exercised(2)	(267)	17.54
Forfeited(1)	–	–
Balance, June 30, 2014(1)	**450**	**$ 16.80**

(1) Weighted average exercise price reflects the grant price less the reduction in exercise price for dividends and distributions.

(2) Weighted average exercise price includes rights exercised at both original grant prices and original grant prices reduced for dividends and distributions subsequent to grant date.

13. NET INCOME PER SHARE

	Three Months Ended June 30					
	2014			2013		
	Net income	Common shares (000s)	Net income per share	Net income	Common shares (000s)	Net income per share
Net income – basic	**$ 36,799**	**135,620**	**$ 0.27**	$ 36,192	123,271	$ 0.29
Dilutive effect of share awards	**–**	**1,284**	**–**	–	462	–
Dilutive effect of share rights	**–**	**254**	**–**	–	629	–
Net income – diluted	**$ 36,799**	**137,158**	**$ 0.27**	$ 36,192	124,362	$ 0.29

	Six Months Ended June 30					
	2014			2013		
	Net income	Common shares (000s)	Net income per share	Net income	Common shares (000s)	Net income per share
Net income – basic	$ 84,640	130,806	$ 0.65	$ 46,341	122,883	$ 0.37
Dilutive effect of share awards	–	1,266	–	–	543	–
Dilutive effect of share rights	–	260	–	–	712	–
Net income – diluted	$ 84,640	132,332	$ 0.64	$ 46,341	124,138	$ 0.37

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six Months Ended June 30	
	2014	2013
Net income before income taxes	$ 124,720	$ 64,148
Expected income taxes at the statutory rate of 25.47% (2013 – 25.51%)(1)	31,766	16,364
Increase (decrease) in income taxes resulting from:		
Share-based compensation	4,097	4,830
Effect of rate adjustments for foreign jurisdictions	952	(3,595)
Other	3,265	208
Income tax expense	$ 40,080	$ 17,807

(1) The change in statutory rate is mainly related to changes in the provincial apportionment of income.

15. REVENUES

	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Petroleum and natural gas revenues	$ 474,901	$ 340,070	$ 859,323	$ 611,859
Royalty charges	(112,282)	(62,010)	(187,162)	(107,288)
Royalty income	1,088	941	2,475	2,097
Other income	415	–	415	–
Revenues, net of royalties	$ 364,122	$ 279,001	$ 675,051	$ 506,668

16. FINANCING COSTS

	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Bank loan and other	$ 4,509	$ 2,865	$ 10,601	$ 4,480
Long-term debt	11,252	7,732	16,008	15,394
Accretion on asset retirement obligations	1,779	1,690	3,520	3,350
Debt financing costs	57	2,117	57	2,156
Financing costs	$ 17,597	$ 14,404	$ 30,186	$ 25,380

17. SUPPLEMENTAL INFORMATION

Foreign Exchange

	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Unrealized foreign exchange (gain) loss	$ (21,379)	$ 4,919	$ (14,923)	$ 8,736
Realized foreign exchange loss (gain)	2,924	(1,565)	986	(3,601)
Foreign exchange (gain) loss	$ (18,455)	$ 3,354	$ (13,937)	$ 5,135

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Foreign Currency Risk

At June 30, 2014, the Company had in place the following currency derivative contracts relating to operations:

Type	Period	Amount per month	Sales Price	Reference
Monthly average rate forward	July to December 2014	US$3.50 million	1.0671	(2)
Monthly forward spot sale	July to December 2014	US$9.50 million	1.0517	(2)
Monthly average collar	July to December 2014	US$1.00 million	1.0300-1.0600	(2)(5)
Monthly average collar	July to December 2014	US$7.00 million	1.0469-1.1100	(2)(3)
Monthly average range forward	July to December 2014	US$2.00 million	1.0800-1.1400	(1)(5)
Contingent average rate forward	July to December 2014	US$1.00 million	1.1400	(1)(6)
Monthly range forward spot sale	July to December 2014	US$1.00 million	1.0550-1.1303	(1)(5)
Contingent monthly forward spot sale	July to December 2014	US$0.50 million	1.1303	(1)(6)
Monthly average rate forward	July 2014 to December 2015	US$1.50 million	1.0933	(1)
Monthly forward spot sale	July 2014 to December 2015	US$2.00 million	1.1100	(2)
Monthly average collar	January 2015	US$6.50 million	1.0675-1.1200	(1)(3)
Monthly average range forward	January 2015	US$0.50 million	1.0950-1.1200	(1)(5)
Contingent average rate forward	January 2015	US$0.50 million	1.1200	(1)(6)
Monthly forward spot sale	January 2015 to December 2015	US$1.00 million	1.1000	(1)
Monthly average range forward	February 2015 to March 2015	US$0.50 million	1.1050-1.1350	(1)(5)
Contingent average rate forward	February 2015 to March 2015	US$0.50 million	1.1350	(1)(6)
Sold call option	January 2015 to December 2015	US$3.00 million	1.1040	(1)(4)
Sold call option	January 2015 to December 2015	US$3.00 million	1.0990	(1)(4)
Sold call option	January 2015 to December 2015	US$4.00 million	1.0925	(1)(4)

(1) Actual contract rate (CAD/USD).
(2) Based on the weighted average contract rates (CAD/USD).
(3) Settlement price above the upper end of the price collar will result in settlement at the lower end of the price collar.
(4) Counterparty has the option to enter into a monthly average rate forward for the periods, amounts per month and sales prices noted.
(5) Settlement at or below the lower strike price results in settlement at the lower strike price. Settlement above the lower strike price results in settlement at the higher strike price.
(6) Settlement required if settlement price is above the strike price, contract entered into simultaneously with monthly average range forward contract or monthly range forward spot sale.

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	June 30, 2014	December 31, 2013	June 30, 2014	December 31, 2013
U.S. dollar denominated	US$198,828	US$102,367	US$1,331,367	US$194,924

Interest Rate Risk

As at June 30, 2014, Baytex had the following interest rate swap financial derivative contracts:

Type	Period	Notional Principal Amount	Fixed interest rate	Floating rate index
Swap – pay fixed, receive floating	July to September 2014	US$90.0 million	4.06%	3-month LIBOR
Swap – pay fixed, receive floating	July to September 2014	US$90.0 million	4.39%	3-month LIBOR

Commodity Price Risk

Baytex monitors and, when appropriate, utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of Baytex. Under the Company's risk management policy, financial derivatives are not to be used for speculative purposes.

Financial Derivative Contracts

At June 30, 2014, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	July to August 2014	2,065 bbl/d	US$97.47	WTI
Fixed – Sell	July to September 2014	8,500 bbl/d	US 99.50	WTI
Fixed – Sell	July to December 2014	9,660 bbl/d	US$94.34	WTI
Fixed – Buy	August to December 2014	380 bbl/d	US$101.06	WTI
Fixed – Sell	October to December 2014	8,000 bbl/d	US$97.20	WTI
Fixed – Sell	July 2014 to February 2015	2,497 bbl/d	US$91.79	WTI
Fixed – Sell	September 2014 to February 2015	1,613 bbl/d	US$93.97	WTI
Fixed – Sell	July 2014 to March 2015	6,000 bbl/d	US$96.62	WTI
Fixed – Sell	January 2015 to March 2015	1,000 bbl/d	US$95.90	WTI
Fixed – Sell	March 2015 to May 2015	5,187 bbl/d	US$90.52	WTI
Fixed – Sell	January 2015 to June 2015	2,304 bbl/d	US$95.33	WTI
Fixed – Sell	July 2015 to August 2015	4,968 bbl/d	US$90.00	WTI
Fixed – Sell	January 2015 to December 2015	4,000 bbl/d	US$95.98	WTI
Price collar	July to December 2014	491 bbl/d	US$80.00-US$95.50	WTI
Sold call option(2)	January 2015 to December 2015	500 bbl/d	US$99.00	WTI
Sold call option(2)	January 2015 to December 2015	4,000 bbl/d	US$98.00	WTI
Sold call option(2)	January 2015 to March 2015	1,000 bbl/d	US$97.70	WTI
Basis swap	July to December 2014	3,000 bbl/d	WTI less US$21.70	WCS

(1) Based on the weighted average price/unit for the remainder of the contract.

(2) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted.

Natural Gas	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	July to October 2014	5,750 mmBtu/d	US$4.19	NYMEX
Fixed – Sell	July to December 2014	2,000 mmBtu/d	US$4.45	NYMEX
Fixed – Sell	July 2014 to March 2015	10,000 mmBtu/d	US$4.08	NYMEX
Fixed – Sell	November 2014 to March 2015	10,000 mmBtu/d	US$4.31	NYMEX
Price collar	July to October 2014	5,000 mmBtu/d	US$3.90-US$4.50	NYMEX
Sold call option(2)	November 2014 to March 2015	5,000 mmBtu/d	US$4.65	NYMEX
Sold call option(2)	April 2015 to October 2015	5,000 mmBtu/d	US$4.00	NYMEX
Basis swap	July to October 2014	5,000 mmBtu/d	NYMEX less US$0.3150	AECO
Basis swap	July 2014 to March 2015	17,750 mmBtu/d	NYMEX less US$0.2225	AECO
Basis swap	November 2014 to March 2015	5,000 mmBtu/d	NYMEX less US$0.2700	AECO

(1) Based on the weighted average price/unit for the remainder of the contract.

(2) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted.

Financial derivatives are marked-to-market at the end of each reporting period, with the following reflected in the condensed consolidated statements of income and comprehensive income:

	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Realized loss (gain) on financial derivatives	$ 13,797	$ (8,768)	$ 19,544	$ (12,896)
Unrealized loss on financial derivatives	35,326	451	22,501	12,346
Loss (gain) on financial derivatives	$ 49,123	$ (8,317)	$ 42,045	$ (550)

Included in unrealized loss on financial derivatives for the three and six months ended June 30, 2014 is a gain of $12.1 million related to the redemption feature on outstanding notes included in long-term debt (note 9) (three and six months ended June 30, 2013 – $nil).

Physical Delivery Contracts

As at June 30, 2014, the following physical delivery contracts were held for the purpose of delivery of non-financial items in accordance with the Company's expected sale requirements. Physical delivery contracts are not considered financial instruments; therefore, no asset or liability has been recognized in the consolidated financial statements.

Heavy Oil	Period	Volume	Price/Unit(1)
WCS Blend	July to December 2014	2,000 bbl/d	WTI × 81.00%
WCS Blend	July to December 2014	3,000 bbl/d	WTI less US$19.07

(1) Based on the weighted average price/unit for the remainder of the contract. At June 30, 2014, Baytex had committed to deliver the volumes of raw bitumen noted below to market on rail:

Heavy Oil	Period	Term Volume
Raw bitumen	July to September 2014	14,000 bbl/d
Raw bitumen	October to December 2014	15,000 bbl/d
Raw bitumen	January to March 2015	14,500 bbl/d
Raw bitumen	April to December 2015	7,000 bbl/d
Raw bitumen	January to December 2016	5,000 bbl/d

19. SUBSEQUENT EVENT

On July 29, 2014, the Company signed an agreement with an oil and gas company to sell the North Dakota assets for gross proceeds of $357 million, effective July 1, 2014. Net proceeds, after tax, of approximately $275 million will be applied to the Non-Revolving Facility in accordance with certain banking agreements. The transaction is subject to standard terms and conditions and is expected to close near the end of the third quarter of 2014.

20. CONSOLIDATING FINANCIAL INFORMATION – BASE SHELF PROSPECTUS

Baytex filed a Short Form Base Shelf Prospectus on October 25, 2013, with the securities regulatory authorities in each of the provinces of Canada (other than Québec) and a Registration Statement with the United States Securities and Exchange Commission (collectively, the "Shelf Prospectus"). The Shelf Prospectus allows Baytex to offer and issue common shares, subscription receipts, warrants, options and debt securities by way of one or more prospectus supplements at any time during the 25-month period that the Shelf Prospectus remains in place. The securities may be issued from time to time, at the discretion of Baytex, with an aggregate offering amount not to exceed $750 million.

Any debt securities issued by Baytex pursuant to the Shelf Prospectus will be guaranteed by all of its direct and indirect wholly-owned material subsidiaries (the "Guarantor Subsidiaries"). The guarantees of the Guarantor Subsidiaries are full and unconditional and joint and several. These guarantees may in turn be guaranteed by Baytex. Other than investments in its subsidiaries, Baytex has no independent assets or operations. As at June 30, 2014, all non-minor subsidiaries of Baytex provide guarantees for its indebtedness. There are no significant restrictions on the ability of Baytex to obtain funds from its subsidiaries. In accordance with Rule 3-10(f), Regulation S-X, condensed consolidating financial information is not required.

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DRIP	Dividend Reinvestment Plan
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *Oil equivalent amounts may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

Raymond T. Chan
Chairman of the Board
Baytex Energy Corp.

James L. Bowzer
President and Chief Executive Officer
Baytex Energy Corp.

John A. Brussa(3)(4)
Vice Chairman
Burnet, Duckworth & Palmer LLP

Edward Chwyl(2)(3)(4)
Lead Independent Director
Independent Businessman

Naveen Dargan(1)(2)
Independent Businessman

R. E. T. (Rusty) Goepel(4)
Senior Vice President
Raymond James Ltd.

Gregory K. Melchin(1)
Independent Businessman

Mary Ellen Peters(1)(2)
Independent Businesswoman

Dale O. Shwed(3)
President and Chief Executive Officer
Crew Energy Inc.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Nominating and Governance Committee

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Bank of Montreal
Barclays Bank PLC
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
Credit Suisse AG
National Bank of Canada
Royal Bank of Canada
Société Générale
The Toronto-Dominion Bank
Union Bank
Wells Fargo Bank

OFFICERS

James L. Bowzer
President and Chief Executive Officer

Rodney D. Gray
Chief Financial Officer

Richard P. Ramsay
Chief Operating Officer

Geoffrey J. Darcy
Senior Vice President, Marketing

Brian G. Ector
Senior Vice President, Capital Markets
and Public Affairs

Daniel G. Anderson
Vice President, U.S. Business Unit

Kendall D. Arthur
Vice President,
Saskatchewan Business Unit

Murray J. Desrosiers
Vice President, General Counsel
and Corporate Secretary

Neal E. Halstead
Vice President, Finance and Controller

Cameron A. Hercus
Vice President, Corporate Development

Ryan M. Johnson
Vice President, Alberta/B.C. Business Unit

Mark A. Montemurro
Vice President, Thermal Projects

Timothy R. Morris
Vice President, U.S. Business Development

Gregory A. Sawchenko
Vice President, Land

Michael L. Verm
Vice President, Eagle Ford Operations

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Deloitte LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE