BAYTEX

ENERGY TRUST

Q3 2008

HIGHLIGHTS

- Generated record cash flow of $146.6 million in the quarter, 17% higher than the previous record set in Q2/08 and 96% higher than Q3/07;
- Achieved record quarterly production of 42,538 boe/d, an increase of 11% over Q2/08 and 12% over Q3/07;
- Generated record quarterly net income of $137.2 million, 299% higher than Q2/08 and 274% higher than Q3/07;
- Maintained conservative payout ratio of 50% in the quarter before DRIP (39% net of DRIP), and 47% year-to-date before DRIP (38% net of DRIP);
- Confirmed the commercial viability of heavy oil thermal development at Seal; and
- Acquired significant land positions in two light oil resource plays in North Dakota and Saskatchewan.

	Three Months Ended			Nine Months Ended	
	Sept. 30, 2008	June 30, 2008	Sept. 30, 2007	**Sept. 30, 2008**	Sept. 30, 2007
FINANCIAL *($ thousands, except per unit amounts)*					
Petroleum and natural gas sales	**363,044**	332,336	193,784	**959,828**	512,029
Cash flow from operations(1)	**146,586**	125,195	74,957	**373,351**	187,363
Per unit – basic	**1.53**	1.42	0.90	**4.16**	2.38
– diluted	**1.47**	1.33	0.84	**3.94**	2.23
Cash distributions	**57,233**	46,005	38,746	**141,712**	108,613
Per unit	**0.75**	0.65	0.54	**1.96**	1.62
Net income	**137,228**	34,417	36,674	**207,493**	91,507
Per unit – basic	**1.44**	0.39	0.44	**2.31**	1.16
– diluted	**1.39**	0.38	0.43	**2.28**	1.12
Exploration and development	**48,584**	41,827	43,533	**142,114**	114,370
Acquisitions – net of dispositions	**78,635**	178,409	752	**256,925**	240,363
Total capital expenditures	**127,219**	220,236	44,285	**399,039**	354,733
Long-term notes	**190,725**	179,900	179,280	**190,725**	179,280
Bank loan	**200,445**	180,000	259,328	**200,445**	259,328
Convertible debentures	**10,377**	11,654	16,531	**10,377**	16,531
Working capital deficiency	**56,446**	42,119	12,189	**56,446**	12,189
Total monetary debt(2)	**457,993**	413,673	467,328	**457,993**	467,328

	Three Months Ended			Nine Months Ended	
	Sept. 30, 2008	June 30, 2008	Sept. 30, 2007	**Sept. 30, 2008**	Sept. 30, 2007
OPERATING					
Daily production					
Light oil & NGL (bbl/d)	**8,377**	6,778	6,556	**7,498**	4,593
Heavy oil (bbl/d)	**24,078**	22,905	22,593	**23,159**	22,057
Total oil (bbl/d)	**32,455**	29,683	29,149	**30,657**	26,650
Natural gas (MMcf/d)	**60.5**	51.0	53.7	**53.9**	51.2
Oil equivalent (boe/d @ 6:1)	**42,538**	38,179	38,094	**39,635**	35,184
Average prices (before hedging)					
WTI oil (US$/bbl)	**118.36**	123.98	75.38	**113.43**	66.19
Edmonton par oil ($/bbl)	**122.77**	126.29	80.24	**115.97**	73.16
BTE light oil & NGL ($/bbl)	**107.41**	109.26	67.82	**100.66**	60.03
BTE heavy oil ($/bbl)(3)	**84.65**	78.92	45.89	**74.63**	42.13
BTE total oil ($/bbl)	**90.56**	85.82	50.85	**80.94**	45.23
BTE natural gas ($/Mcf)	**8.01**	9.29	5.80	**8.23**	6.72
BTE oil equivalent ($/boe)	**80.44**	79.15	47.06	**73.84**	44.04
TRUST UNIT INFORMATION					
TSX (C$)					
Unit Price					
High	**$ 35.01**	$ 35.37	$ 21.45	**$ 35.37**	**$ 22.92**
Low	**$ 23.15**	$ 22.60	$ 16.68	**$ 16.30**	**$ 16.68**
Close	**$ 25.73**	$ 34.79	$ 20.13	**$ 25.73**	**$ 20.13**
Volume traded (thousands)	**31,620**	34,782	26,365	**92,150**	68,759
NYSE (US$)					
Unit Price					
High	**$ 35.20**	$ 34.98	$ 21.03	**$ 35.20**	**$ 21.18**
Low	**$ 22.35**	$ 21.90	$ 15.51	**$ 15.88**	**$ 15.51**
Close	**$ 24.71**	$ 34.28	$ 20.33	**$ 24.71**	**$ 20.33**
Volume traded (thousands)	**10,240**	4,990	5,315	**20,016**	12,630
Units outstanding (thousands)(4)	**96,934**	96,017	86,478	**96,934**	86,478

(1) Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items (see reconciliation under MD&A). The Trust's cash flow from operations may not be comparable to other issuers. The Trust considers cash flow from operations a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) Total monetary debt is a non-GAAP term, and is defined in note 16 to the consolidated financial statements.

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

(4) Number of trust units outstanding includes the conversion of exchangeable shares at the respective exchange ratios in effect at the end of the reporting periods.

This report contains forward-looking information and statements relating to: the production and reserves potential of our light oil resources plays in North Dakota and Saskatchewan; the timing and amount of the deferred payments for the North Dakota acquisition; our assessment of the project economics of the North Dakota acquisition; our ability to improve well performance in North Dakota through the use of 3D seismic surveys and refinement of hydraulic fracturing designs; the development plans for the light oil resources plays in North Dakota and Saskatchewan, including the number of wells to be drilled and the number of wells per section; steam-oil ratios for our cyclic steam pilot project at our Seal heavy oil resource play; our production levels for the fourth quarter of 2008; our exploration and development capital program for 2008; royalty rates for future projects at our Seal heavy oil resource play; our liquidity and financial capacity; funding sources for our cash distributions and capital program; and the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business. 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.

MESSAGE TO UNITHOLDERS

Resource Play Land Acquisitions

During the third quarter, Baytex established substantial acreage positions in two light oil resource plays, located in northwest North Dakota and southwest Saskatchewan. The North Dakota acquisition significantly advances Baytex's U.S. growth strategy, and both acquisitions provide the opportunity for long-term light oil production and reserves growth to complement our heavy oil growth projects.

North Dakota – Bakken/Three Forks Light Oil

During the third quarter, Baytex reached agreement to acquire a significant land position in a Bakken/Three Forks light oil resource play in the Williston Basin in northwest North Dakota from a private company. Upon making all deferred payments associated with the transaction, Baytex will have acquired a 37.5% interest in 263,000 gross acres (approximately 98,600 net acres). At present, 94% of the lands are undeveloped. In addition, Baytex acquired approximately 300 boe/d (95% oil) of company interest production. This large contiguous land block is being acquired at a lower cost as compared to other recent Bakken/Three Forks transactions with proven productivity. The seller is retaining the remaining 62.5% interest in the project lands and production.

Initial transaction consideration of US$60.5 million (C$61.2 million at the time of the payment) was paid in the third quarter of 2008, with a series of deferred payments to follow over the next two to three year period, with the timing of the deferred payments dependent on the pace of development. The first deferred payment of US$3.0 million (C$3.2 million at the time of the payment) was also made in the third quarter of 2008. Baytex estimates that deferred acquisition payments of US$3.0 million will be made in the fourth quarter of 2008, US$15 million in 2009 and a total of US$25.5 million for the two-year period in 2010-2011. After all deferred payments have been made, total transaction consideration will be US$107 million over the period from 2008-2011.

The Bakken/Three Forks formation in the North Dakota project area has highly desirable characteristics for an oil resource play. The Bakken provides a high quality source rock and reservoir facies in the Bakken/Three Forks are equivalent to other successful Bakken projects. The project is being developed utilizing horizontal wells with multiple fracture stimulations, with well placement primarily in the Sanish member of the Bakken/Three Forks formation. Additional exploratory targets exist in multiple horizons both above and below the Bakken/Three Forks. A high-resolution 3D seismic survey will be shot this winter over much of the project area to optimize well placement in both the Bakken/Three Forks and the other exploratory targets. The project is economic using current well placement and stimulation techniques, and well performance is expected to further improve with use of the 3D survey and continued refinement of hydraulic fracturing designs. Initial development will occur at a pace of about 10 gross wells per year with expectations to accelerate development in the future. At the current spacing of one well per section, up to 400 gross wells may be drilled over the life of the project. We believe that sufficient resource-in-place may exist to accommodate down spacing development in the future. Baytex will be phased into operatorship of drilling and completion operations, and, after making the final deferred payment, will be assigned full operatorship of approximately three-eighths of the project area.

Saskatchewan – Viking Light Oil

This light oil resource play targets the Viking formation in southwest Saskatchewan. Through a combination of Crown and private mineral leasing, Baytex has acquired a 100% interest in approximately 20,800 net acres. At present, 99% of the lands are undeveloped. Land acquisition expenditures were $8.0 million, incurred primarily in the third quarter of 2008.

The Viking formation is a high quality reservoir rock by resource play standards and is oil-saturated throughout the acquired area. Productivity using horizontal wells with multiple fracture stimulations has been demonstrated by several wells in the area, including one drilled by Baytex. At current spacing of four wells per section, up to 125 wells may be drilled over the life of this project.

Operations Review

Exploration and development expenditures, excluding the aforementioned land acquisitions, totaled $48.6 million for the third quarter of 2008. During this quarter, Baytex participated in the drilling of 33 (28.5 net) wells, resulting in 28 (24.2 net) oil wells and five (4.3 net) gas wells for a 100% (100% net) success rate. Driven by particularly strong heavy oil prices, drilling in the third quarter was predominantly conducted in the Lloydminster area and at Seal, where Baytex successfully drilled 13 and seven oil wells, respectively. Drilling activities will continue to be focused in the Lloydminster area and at Seal in the fourth quarter.

Production averaged a record 42,538 boe/d during the third quarter of 2008, as compared to 38,179 boe/d for the previous quarter. Production was strong in every segment of our business, with all three of our business units (Canadian light oil and gas, heavy oil, and United States) achieving record production levels. Heavy oil volumes were buoyed by development activities in both the Lloydminster area and at Seal. Canadian light oil and gas volumes benefited from the inclusion of a full quarter of production from the acquisition of Burmis Energy completed in June 2008. Production from the Burmis properties was in excess of 3,600 boe/d in the quarter, in line with our pre-acquisition expectation. U.S. production averaged 367 boe/d in the third quarter as a result of production acquired with our purchase of undeveloped Bakken/Three Forks land in North Dakota.

As previously announced on September 4, 2008, the results of our thermal pilot at Seal exceeded our expectations. Five months after steam injection, production from the pilot well is currently more than 100 bbl/d, which is double the well's projected rate on cold primary production. The project has achieved excellent thermal efficiencies, with incremental steam-oil-ratio currently at 1.7 (after deducting projected primary production). The incremental steam-oil-ratio is projected to decrease further as post-steam production continues to exceed primary rates. We are in the process of refining our geologic and numerical reservoir simulation models to design a commercial-scale cyclic steam project for Seal.

With the acquisition of the North Dakota project and continued strong performance from our Canadian operations, our production guidance for the fourth quarter of 2008 is increased to 42,000 boe/d (up from 41,000 boe/d previously). Reflecting development in the North Dakota properties, exploration and development expenditures guidance is increased to $180 million for full-year 2008 (up from $170 million previously).

Financial Review

Cash flow from operations for the third quarter of 2008 was a record $146.6 million, an increase of 17% over the previous record generated in the second quarter of 2008 and 96% higher than the same period one year ago. Net income was a record $137.2 million for the quarter, 299% higher than the second quarter of 2008 and a 274% increase over the third quarter of 2007. The key drivers of these results were increase in production from each of our business units, continued strength in heavy oil pricing, and unrealized gains associated with our WTI price collars reflected in net income.

The positive trend in Canadian heavy oil pricing continued with differentials averaging only 15% of WTI in the third quarter, compared to 18% in the second quarter of this year and 29% in the third quarter of 2007. The low differentials offset a modest decline in WTI, and resulted in Baytex realizing an average heavy oil wellhead price of $84.65 per barrel in the third quarter, an increase of 7% over pricing in the second quarter. The increase in heavy oil price offset a small decline in light oil and natural gas prices, resulting in an oil equivalent pricing of $80.44 per boe in the third quarter, as compared to $79.15 per boe in the second quarter of this year.

Cash flow for the current quarter was negatively affected by a $22.4 million realized loss from derivative contracts mainly associated with the WTI price collars. Net income in the third quarter was positively impacted by $89.0 million in unrealized gain related to our WTI price collars for the balance of 2008 and 2009.

Cash flow and net income in the current quarter were negatively impacted by an increase in heavy oil royalty rates. During the quarter, our first oil sands project at Seal (Township 84 – Range 18) reached payout, with the pre-payout royalty of 1% of gross revenue converting to a post-payout 25% net profit interest. The incremental royalty payable as a result of this change and the payout of a minor project at Cold Lake was approximately $4.1 million in the third quarter. Future cold primary development at Seal within this initial project area will be subject to the net profit interest, while development of new projects is expected to qualify for the pre-payout rates.

Total monetary debt, excluding notional mark-to-market assets and liabilities and future income taxes, was $458.0 million at the end of the third quarter. As at September 30, 2008, we have available borrowing capacity of approximately $226 million on our credit facilities, leaving us with a strong balance sheet to manage our business in this time of global economic uncertainty.

The current worldwide economic crisis has resulted in disruptions in the availability of credit on commercially acceptable terms. In light of this situation, we have undertaken a thorough review of our liquidity sources as well as our exposure to counterparties and have concluded that our capital resources are sufficient to meet our ongoing short, medium and long-term commitments. Specifically, we believe that our internally generated cash flow from operations, augmented by our hedging program and existing credit facilitates, 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 and where necessary, we have implemented enhanced credit protection with certain of these counterparties.

Subsequent to the end of the third quarter, prices for WTI have retreated to the US$60 to US$65 per barrel range. As a Canadian producer, the impact of declining world oil prices has been partially mitigated by a decline in the Canadian dollar relative to the U.S. dollar. Combined with improved differentials, current heavy oil wellhead prices of around $45 to $50 per barrel are still relatively robust in historical terms. Our strong balance sheet, low cost structure and prudent hedging programs will help us manage through these uncertain times. We will continue to monitor our levels of capital spending and distributions in relation to energy and capital market conditions, and plan to announce our 2009 operating plans in early December after approval by the Board of Directors.

Board of Directors and Management Appointments

The Board of Directors of Baytex is pleased to announce that Raymond T. Chan will be appointed Executive Chairman effective January 1, 2009. Mr. Chan joined Baytex in 1998 as Senior Vice-President, Chief Financial Officer and a director and has served as Chief Executive Officer since the inception of the Trust in 2003. Under his leadership, Baytex has developed into a top performer in our industry, with sector-leading capital investment efficiency and returns to unitholders. In his new role, Mr. Chan will focus on strategic issues and will work closely with Management in order to continue to deliver superior performance to all of our stakeholders.

Our Board is also pleased to announce that Anthony W. Marino will be promoted to the position of President, Chief Executive Officer and a director of Baytex effective January 1, 2009. Mr. Marino joined Baytex in November 2004 as Chief Operating Officer and was promoted to President and Chief Operating Officer in November 2007. His contributions have been instrumental to the success of Baytex and our development into a disciplined and profitable oil and gas entity with an enviable operating record and a high quality asset base with potential for generating excellent future income and growth.

Mr. Marino received a B.S. degree in Petroleum Engineering with Highest Distinction from the University of Kansas and an MBA from California State University at Bakersfield. He is a Chartered Financial Analyst and is a registered professional engineer. Mr. Marino is a member of the Board of Governors of the Canadian Association of Petroleum Producers.

Edward Chwyl, Chairman of the Board since the inception of the Trust, will continue to serve as a director of Baytex subsequent to the above appointments. Our Board and Management wish to express their gratitude for Mr. Chwyl's leadership of the Board over the past five years and look forward to his continued valuable counsel and guidance.

On behalf of the Board of Directors,

Raymond T. Chan, CA
Chief Executive Officer
November 13, 2008

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Trust ("Baytex" or the "Trust") for the three and nine months ended September 30, 2008. This information is provided as of November 11, 2008. The third quarter results have been compared with the corresponding period in 2007. This MD&A should be read in conjunction with the Trust's unaudited interim comparative consolidated financial statements for the three and nine months ended September 30, 2008 and 2007 and our audited consolidated comparative financial statements for the years ended December 31, 2007 and 2006, together with accompanying notes, and the Annual Information Form for the year ended December 31, 2007 (the "AIF"). These documents and additional information about the Trust are available on SEDAR at www.sedar.com.

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

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow from operations per unit are not measurements based on Generally Accepted Accounting Principles in Canada ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow from operations represents cash generated from operating activities before changes in non-cash working capital, site restoration and reclamation expenditures, deferred charges and other assets. The Trust's determination of cash flow from operations may not be comparable with the calculation of similar measures for other entities. The Trust considers cash flow from operations a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income. For a reconciliation of cash flow from operations to cash flow from operating activities, see "Cash Flow from Operations, Payout Ratio and Distributions".

Production

Canadian light oil and natural gas liquids ("NGL") production for the third quarter of 2008 increased by 22% to 8,010 bbl/d from 6,556 bbl/d a year earlier primarily due to the acquisition of Burmis Energy Inc. in June 2008. Heavy oil production increased 7% to 24,078 bbl/d for the third quarter of 2008 compared to 22,593 bbl/d for the same period last year due to development drilling at Seal and in the Lloydminster area. Natural gas production increased 13% from year-ago levels, averaging 60.5 MMcf/d for the third quarter of 2008 compared to 53.7 MMcf/d for the same period last year, primarily due to the Burmis acquisition. U.S. light oil and gas production was 367 boe/d in the third quarter of 2008 compared to no production in 2007, primarily due to production acquired with the purchase of the North Dakota lands.

For the first nine months of 2008, Canadian light oil and NGL production increased by 61% to 7,375 bbl/d from 4,593 bbl/d for the same period last year due to the Pembina acquisition in June 2007 and the Burmis acquisition in June 2008. Heavy oil production for the first nine months in 2008 increased by 5% to 23,159 bbl/d compared to 22,057 bbl/d for the same period in 2007, driven by both development activities and the Lindbergh acquisition in June 2007. Natural gas production increased by 5% to 53.9 MMcf/d for the first nine months in 2008 compared to 51.2 MMcf/d for the same period in 2007 due to the Pembina and Burmis acquisitions. U.S. light oil and gas production averaged 123 boe/d in the first nine months of 2008 compared to no production in 2007 primarily due to production acquired with the North Dakota lands.

Revenue

Petroleum and natural gas sales increased 87% to $363.0 million for the third quarter of 2008 from $193.8 million for the same period in 2007. Commencing with the first quarter of 2008, Baytex began reporting revenue from our heavy oil sales based on the price of the blend crude sold to the refineries. The cost of the blending diluent is reported as an expense. There is no impact to cash flow compared to the previous practice of reporting revenue based on heavy oil wellhead price net of blending charges.

For the per sales unit calculations, heavy oil sales for the three months ended September 30, 2008 were 204 bbl/d lower (three months ended September 30, 2007 – 162 bbl/d lower) than the production for the period due to changes in inventory. The corresponding number for the nine months ended September 30, 2008 was an increase of 284 bbl/d (nine months ended September 30, 2007 – a decrease of 124 bbl/d).

Revenue from light oil and NGL for the third quarter of 2008 increased 102% from the same period a year ago due to a 28% increase in production and a 58% increase in wellhead prices. Revenue from heavy oil increased 95% as a result of an 83% increase in wellhead prices and a 7% increase in production. Revenue from natural gas increased 56% due to a 13% increase in production and a 38% increase in wellhead prices.

	Three Months ended September 30			
	2008		2007	
	$000s	$/Unit(1)	$000s	$/Unit(1)
Oil revenue				
Light oil & NGL	82,786	107.41	40,904	67.82
Heavy oil(2)	185,914	84.65	95,302	46.18
Total oil revenue	268,700	90.56	136,206	51.08
Natural gas revenue	44,578	8.01	28,622	5.80
Total oil and gas revenue	313,278	80.44	164,828	47.23
Sulphur revenue	3,306		–	
Sales of heavy oil blending diluent	46,460		28,956	
Total petroleum and natural gas sales	363,044		193,784	

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/Mcf; and per-unit total revenue is in $/boe.
(2) Heavy oil wellhead prices are net of blending costs.

For the first nine months of 2008, light oil and NGL revenue increased 175% from the same period last year due to a 68% increase in wellhead prices and a 63% increase in production. Revenue from heavy oil increased 89% due to a 76% increase in wellhead prices and a 5% increase in production. Revenue from natural gas increased 29% due to a 5% increase in production combined with a 22% increase in wellhead prices.

	Nine Months ended September 30			
	2008		2007	
	$000s	$/Unit(1)	$000s	$/Unit(1)
Oil revenue				
Light oil & NGL	206,813	100.66	75,271	60.03
Heavy oil(2)	479,377	74.63	253,792	42.39
Total oil revenue	686,190	80.94	329,063	45.44
Natural gas revenue	121,503	8.23	93,950	6.72
Total oil and gas revenue	807,693	73.84	423,013	44.20
Sulphur revenue	5,960		–	
Other income	2,000		–	
Sales of heavy oil blending diluent	144,175		89,016	
Total petroleum and natural gas sales	959,828		512,029	

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/Mcf; and per-unit total revenue is in $/boe.
(2) Heavy oil wellhead prices are net of blending costs.

During the current quarter, sulphur production averaged 53.5 tonnes per day with an average price of $672 per tonne. For the nine months ended September 30, 2008, sulphur production averaged 40.6 tonnes per day with an average price of $536 per tonne. In prior years, sulphur revenue was not material for reporting purposes.

During the first quarter of 2008, Baytex received a $2.0 million payment from a partner as compensation for non-performance of a drilling obligation which was reported as other income under petroleum and natural gas sales.

Financial Derivatives

The gain on financial derivatives for the third quarter was $66.7 million compared to $1.2 million in the third quarter of 2007. This is comprised of $22.3 million in realized loss and $89.0 million in unrealized gain for the third quarter of 2008 compared to $0.6 million in realized gain and $0.6 million in unrealized gain in the same period one year ago.

The loss on financial derivatives for the nine months ended September 30, 2008 was $24.5 million compared to $2.9 million for the same period in 2007. This is comprised of $57.9 million in realized loss and $33.4 million in unrealized gain for the first nine months of 2008 compared to $1.2 million in realized gain and $4.1 million in unrealized loss in the same period one year ago.

Royalties

Total royalties increased to $72.8 million for the third quarter of 2008 from $28.7 million in the same period last year. Total royalties for the third quarter of 2008 were 23.0% of oil and gas revenue excluding sales of heavy oil diluent compared to 17.5% for the same period in 2007. For the third quarter of 2008, royalties were 23.0% of revenue for light oil, NGL and natural gas and 23.0% for heavy oil excluding sales of heavy oil diluent. These rates compared to 20.1% and 15.5%, respectively, for the same period last year. Royalties are generally based on well productivity and market index prices in the period, with rates increasing as price and volume escalate. Heavy oil royalties as a percentage of revenue were higher in the current quarter as market prices were higher than the prices realized by Baytex under fixed differential supply agreements. Heavy oil royalties also increased in the third quarter of 2008 as certain oilsands projects at Seal and Cold Lake reached payout, with the pre-payout royalty of 1% of gross revenue converting to a post-payout 25% net profit interest.

For the nine months ended September 30, 2008, royalties increased to $175.8 million from $70.3 million for the same period last year. Total royalties for the first nine months of 2008 were 21.6% of oil and gas revenue excluding sales of diluent, compared to 16.7% for the corresponding period a year ago. For the first nine months of 2008, royalties were 23.2% of revenue for light oil, NGL and natural gas and 20.6% for heavy oil excluding sales of diluent. These rates compared to 18.2% and 15.7%, respectively, for the same period in 2007.

Operating Expenses

Operating expenses for the third quarter of 2008 increased to $46.4 million from $37.8 million in the corresponding quarter last year. Included in operating expenses for the current quarter is $0.1 million of costs related to the production of sulphur. Operating expenses were $11.91 per boe for the third quarter of 2008 compared to $10.84 per boe for the third quarter of 2007. For the third quarter of 2008, operating expenses were $10.93 per boe of light oil, NGL and natural gas and $12.63 per barrel of heavy oil. Operating expenses on a per boe basis for the same period a year ago were $10.09 and $11.36, respectively. The primary driver of the increase in operating expense per unit was a 23% increase in fluid hauling, fuel and electricity costs. These energy-complex related cost categories constitute our largest cost items, and are related to WTI oil price, which increased 57% from the third quarter of 2007 to the third quarter of 2008. Property taxes and other municipal fees continued to rise at a rapid pace, up approximately 15% in the quarter-to-quarter comparison.

Operating expenses for the first nine months of 2008 increased to $125.1 million from $96.0 million for the first nine months of 2007. Operating expenses were $11.44 per boe for the first nine months of 2008 compared to $10.03 per boe for the corresponding period of the prior year. For the first nine months of 2008, operating expenses were $11.25 per boe of light oil, NGL and natural gas and $11.53 per barrel of heavy oil compared to $9.57 and $10.30, respectively, for the same period a year earlier. The primary driver of the increase in operating expense per unit was a 15% increase in fluid hauling, fuel and electricity costs due to higher oil prices. Property taxes and other municipal fees also increased approximately 15% in the nine-month period comparison. Furthermore, the nine-month comparison was also negatively impacted by the acquisition of higher operating cost assets at Pembina and Lindbergh in June 2007.

Transportation and Blending Expenses

Transportation and blending expenses for the third quarter of 2008 were $57.1 million compared to $36.0 million for the third quarter of 2007. Transportation expenses for the current quarter include $0.3 million related to the transportation of sulphur. Transportation expenses were $2.65 per boe for the third quarter of 2008 compared to $2.03 per boe for the same period in 2007. Transportation expenses were $0.70 per boe of light oil, NGL and natural gas, and $4.16 per barrel of heavy oil. The corresponding amounts for 2007 were $0.67 and $2.97, respectively. The increase in transportation cost per unit is related to a 57% increase in WTI oil price and the related increase in fuel cost. In addition, increasing volumes from Seal, which are hauled longer distance than our Lloydminster-area production, contributed to the increased transportation cost.

Transportation and blending expenses for the nine months ended September 30, 2008 were $173.0 million compared to $111.9 million for the first nine months of 2007. Transportation expenses were $2.55 per boe in 2008 compared to $2.39 per boe in 2007. Transportation expenses were $0.70 per boe of light oil, NGL and natural gas and $3.85 per barrel of heavy oil in the 2008 period, compared to $0.86 and $3.30, respectively, for the same period in 2007. The increase in transportation cost per unit is related to a 71% increase in WTI oil price and the related increase in fuel cost and increased volumes from Seal.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. Baytex purchases primarily condensate as the blending diluent from industry producers to facilitate the marketing of our heavy oil. In the third quarter of 2008, the blending cost was $46.5 million for the purchase of 3,909 bbl/d of condensate at $129.18 per barrel as compared to 3,673 bbl/d at $85.68 per barrel in the same period last year. The cost of diluent is effectively recovered through the sale price of a blended product. For the nine months ended September 30, 2008, the blending cost was $144.2 million for the purchase of 4,228 bbl/d of condensate at $124.45 per barrel as compared to 4,149 bbl/d at $78.60 per barrel in the same period last year.

General and Administrative Expenses

General and administrative expenses for the third quarter of 2008 increased to $7.1 million from $5.6 million in 2007. On a per sales unit basis, these expenses were $1.82 per boe for the third quarter of 2008 compared to $1.61 per boe for the same period in 2007.

General and administrative expenses for the first nine months of 2008 were $22.0 million, compared to $16.8 million for the prior period. On a per sales unit basis, these expenses were $2.01 per boe in 2008 and $1.75 per boe in 2007. In accordance with our full cost accounting policy, no expenses were capitalized in either 2008 or 2007.

Unit-based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $2.0 million for the third quarter of 2008 compared to $2.4 million for the third quarter of 2007. For the nine months ended September 30, 2008 and 2007, compensation expenses were unchanged at $6.2 million.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the rights with a corresponding increase in contributed surplus. The exercise of rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Interest Expenses

Interest expenses decreased to $8.2 million for the third quarter of 2008 from $9.7 million for the same quarter last year, primarily due to the decrease in prime lending rates on the bank loan plus the lower foreign exchange rates on payment of interest on the U.S. dollar denominated debt.

Interest expense decreased to $25.1 million for the first nine months of 2008 from $26.6 million for the first nine months of 2007 for the same reasons noted above.

Foreign Exchange

Foreign exchange loss in the third quarter of 2008 was $7.1 million compared to a $12.6 million gain in the prior period. This loss is based on the translation of the U.S. dollar denominated long-term debt at 0.9435 at September 30, 2008 compared to 0.9817 at June 30, 2008. The 2007 gain is based on translation at 1.0037 at September 30, 2007 compared to 0.9404 at June 30, 2007.

Foreign exchange loss for the first nine months of 2008 was $12.9 million compared to a gain of $31.2 million in the prior period. The 2008 loss is based on the translation of the U.S. dollar denominated long-term debt at 0.9435 at September 30, 2008 compared to 1.0120 at December 31, 2007. The 2007 gain is based on translation at 1.0037 at September 30, 2007 compared to 0.8581 at December 31, 2006.

Depletion, Depreciation and Accretion

The provision for depletion, depreciation and accretion at $61.3 million for the third quarter of 2008 represents an increase of 19% from $51.5 million for the same quarter in 2007 primarily due to a 12% increase in production. On a per sales unit basis, the provision for the current quarter was $15.73 per boe compared to $14.76 per boe for the same quarter in 2007. The higher rate is primarily due to the costs of the acquisitions completed in June 2008 and June 2007.

Depletion, depreciation and accretion increased to $162.6 million for the first nine months of 2008 compared to $135.4 million for the same period last year. On a sales-unit basis, the provision for the current period was $14.87 per boe compared to $14.15 per boe for the same period a year earlier. The increase is attributable to the same factors influencing the third quarter calculations.

Taxes

On June 22, 2007, the federal government's bill regarding the taxation of distributions of publicly traded income trusts beginning January 1, 2011 received Royal Assent. As a result, a future income tax recovery of $0.5 million was recognized in the third quarter of 2007 relating to unutilized tax pools in the Trust which will be deductible to the Trust after 2010. The majority of the Trust's temporary differences reside in a consolidated subsidiary which is not subject to the distribution tax, and is therefore not impacted by this legislative change.

The government's bill provides that the new tax regime for income trusts will not apply until January 1, 2011 so long as the Trust experiences only "normal growth" and no "undue expansion". As part of the government's bill, a "safe harbour" limit was established for existing income trusts by limiting future equity issues to 40% of each trust's October 31, 2006 market capitalization for the period November 1, 2006 to December 31, 2007, and an additional 20% of this market capitalization for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730.0 million for 2006/2007 and $365.0 million for each of the subsequent three years. Issuance of equity or convertible debt beyond these limits will result in the new regime applying to the Trust before 2011. As of September 30, 2008, Baytex has issued $412.2 million of equity since November 2006.

On July 14, 2008, the Department of Finance released proposed amendments (the "Conversion Rules") to the Income Tax Act (Canada) to facilitate the conversion of existing income trusts into corporations. In general, the proposed amendments will permit a conversion to be tax deferred for both the unitholders and the trust. However, the Conversion Rules provide alternative approaches to completing a tax deferred conversion. The Department of Finance requested comments on the Conversion Rules by September 15, 2008 and it is anticipated that there will be further amendments to the Conversion Rules. Management and the Board of Directors continue to review the impact of the future taxation of distributions on our business strategy but at this time have made no decision as to the ultimate legal form under which Baytex will operate post 2010.

The provision for future income taxes for the current quarter was an expense of $26.0 million compared to a recovery of $3.9 million in the same period in 2007.

Current tax of $3.2 million for the third quarter of 2008 is comprised of Saskatchewan capital tax and resource surcharge. Current tax for the same period a year ago was $1.9 million, also comprised entirely of this Saskatchewan levy. Current tax expenses were $8.4 million for the first nine months of 2008 compared to

$4.6 million for the same period last year. Current tax expenses were comprised entirely of Saskatchewan capital tax and resource surcharge.

Net Income

Net income for the third quarter of 2008 was $137.2 million compared to $36.7 million for the third quarter in 2007. The variance is the result of increased production, increased sales prices and unrealized gain on financial derivatives, partially offset by increased royalties, increased loss on foreign exchange and depletion.

Net income for the first nine months of 2008 was $207.5 million compared to $91.5 million for the same period in 2007. The variance is due to higher sales prices partially offset by higher operating and transportation costs, higher depletion and foreign exchange loss and lower future tax recovery.

Cash Flow from Operations, Payout Ratio and Distributions

Cash flow from operations and payout ratio are non-GAAP terms. Cash flow from operations represents cash flow from operating activities before changes in non-cash working capital, deferred charges and other assets and asset retirement expenditures. The Trust's payout ratio is calculated as cash distributions (net of participation in our Distribution Reinvestment Plan ("DRIP")) divided by cash flow from operations. The Trust considers these to be key measures of performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

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

	Three Months Ended			Nine Months Ended		Year Ended	
($000's)	**September 30, 2008**	June 30, 2008	September 30, 2007	**September 30, 2008**	September 30, 2007	December 31, 2007	December 31, 2006
Cash flow from operating activities	**150,815**	101,070	73,722	**372,830**	186,319	286,450	261,982
Change in non-cash working capital	**(4,591)**	24,141	308	**(229)**	(1,995)	(5,140)	9,058
Asset retirement expenditures	**351**	(27)	351	**718**	1,311	2,442	1,747
Increase in deferred charges and other assets	**11**	11	576	**32**	1,728	2,278	1,875
Cash flow from operations	**146,586**	125,195	74,957	**373,351**	187,363	286,030	274,662
Cash Distributions	**57,233**	46,005	38,746	**141,712**	108,613	145,927	143,072
Payout ratio	**39%**	37%	52%	**38%**	58%	51%	52%

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and gas assets, certain levels of capital expenditures are required to minimize production declines. In the oil and gas industry, due to the nature of reserves reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire oil and natural gas assets increase significantly, it is possible that the Trust would be required to reduce or eliminate its distributions in order to fund capital expenditures. There can be no certainty that the Trust will be able to maintain current production levels in future periods.

Cash distributions, net of DRIP participation, of $57.2 million for the third quarter of 2008 were funded through cash flow from operations of $146.6 million.

The following tables compare cash distributions to cash flow from operating activities and net income:

	Three Months Ended			Nine Months Ended		Year Ended	
($000's)	**September 30, 2008**	June 30, 2008	September 30, 2007	**September 30, 2008**	September 30, 2007	December 31, 2007	December 31, 2006
Cash flow from operating activities	**150,815**	101,070	73,722	**372,830**	186,319	286,450	261,982
Actual cash distributions	**57,233**	46,005	38,746	**141,712**	108,613	145,927	143,072
Excess of cash flow from operating activities over cash distributions	**93,582**	55,065	34,976	**231,118**	77,706	140,523	118,910
Net Income	**137,228**	34,417	36,674	**207,493**	91,507	132,860	147,069
Actual cash distributions	**57,233**	46,005	38,746	**141,712**	108,613	145,927	143,072
Excess (shortfall) of net income over cash distributions	**79,995**	(11,588)	(2,072)	**65,781**	(17,106)	(13,067)	3,997

It is Baytex's long-term operating objective to substantially fund cash distributions and capital expenditures required to maintain production and reserves through cash flow from operating activities. Future production levels are highly dependent upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized are the main factors influencing the sustainability of our cash distributions. During periods of lower commodity prices, or periods of higher capital spending for acquisitions, it is possible that internally generated cash flow will not be sufficient to fund both cash distributions and capital spending. In these instances, the cash shortfall may be funded through a combination of equity and debt financing. As at September 30, 2008, Baytex had approximately $226 million in available undrawn credit facilities to fund any such shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital.

For the three months ended September 30, 2008, the Trust's net income exceeded cash distributions by $80.0 million, with net income reduced by $13.6 million of non-cash items. For the nine months ended September 30, 2008, the Trust's net income exceeded cash distributions by $65.8 million, with net income reduced by $165.3 million of non-cash items. Non-cash charges such as depletion, depreciation and accretion are not fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions. Other non-cash charges, such as unrealized losses on financial instruments and unrealized foreign exchange losses, reduce the net income of a current period, but may not have the same impact on future periods' cash flow. Accordingly, net income is not a fair representation of the Trust's ability to fund our distributions and capital programs.

Liquidity and Capital Resources

The current worldwide economic crisis has resulted in disruptions in the availability of credit on commercially acceptable terms. In light of this situation, we have undertaken a thorough review of our liquidity sources as well as our exposure to counterparties and have concluded that our capital resources are sufficient to meet our ongoing short, medium and long-term commitments. Specifically, we believe that our internally generated cash flow from operations, augmented by our hedging program and existing credit facilitates, 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 and where necessary, we have implemented enhanced credit protection with certain of these counterparties.

At September 30, 2008, net monetary debt was $458.0 million compared to $467.3 million at September 30, 2007, with the decrease mainly attributable to the surplus in cash flow after the funding of distributions and capital expenditures. Bank borrowings and working capital deficiency at the end of third quarter 2008 was $256.9 million compared to total credit facilities of $485 million. Effective June 4, 2008, total credit facilities were increased to $485 million from $370 million. The credit facilities mature on July 1, 2009, and are eligible for extension. We have had discussions with members of our lending syndicate, and we have no reason to believe that the facilities will not be extended upon maturity.

The Trust has a number of financial obligations in the ordinary course of business. These obligations are of a recurring and consistent nature and impact the Trust's cash flows in an ongoing manner. A significant portion of these obligations will be funded through operating cash flow. These obligations as of September 30, 2008, and the expected timing of funding of these obligations are noted in the table below.

($000's)	Total	1 year	2-3 years	4-5 years	Beyond 5 years
Accounts payable and accrued liabilities	156,577	156,577	–	–	–
Distributions payable to unitholders	24,233	24,233	–	–	–
Bank loan(1)	200,445	200,445	–	–	–
Derivative contracts(2)	12,323	12,323	–	–	–
Long-term debt(3)	190,725	–	190,725	–	–
Convertible debentures(3)	10,607	–	10,607	–	–
Deferred obligations	82	44	38	–	–
Operating leases	5,297	3,007	1,710	580	–
Processing and transportation agreements	18,418	6,403	10,674	1,341	–
Total	618,707	403,032	213,754	1,921	–

(1) The bank loan is a 364-day revolving loan with the ability to extend the term. The Trust has no reason to believe that it will be unable to extend the credit facility when it matures on July 1, 2009.

(2) Current liability component of financial derivative contracts.

(3) Principal amount of instruments.

The Trust is authorized to issue an unlimited number of trust units. As at November 5, 2008, the Trust had 97,157,252 trust units issued and outstanding, and $10.6 million in convertible debentures outstanding which are convertible into 719,118 trust units.

Effective August 29, 2008, all of the outstanding exchangeable shares were purchased by Baytex ExchangeCo Ltd. for consideration of 1.79560 trust units for each exchangeable share.

Capital Expenditures

Capital expenditures for the three and nine months ended September 30, 2008 and 2007 are summarized as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
($000's)	**2008**	2007	**2008**	2007
Land	**450**	2,997	**4,636**	6,056
Seismic	**531**	155	**1,439**	1,524
Drilling and completion	**34,827**	31,888	**104,503**	85,065
Equipment	**11,712**	7,339	**28,968**	18,476
Other	**1,064**	1,154	**2,568**	3,249
Total exploration and development	**48,584**	43,533	**142,114**	114,370
Corporate acquisition	**–**	–	**178,351**	239,884
Property acquisitions	**78,701**	804	**78,702**	839
Property dispositions	**(66)**	(52)	**(128)**	(360)
Total capital expenditures	**127,219**	44,285	**399,039**	354,733

Financial Instruments and Risk Management

The Trust is exposed to a number of financial risks, including market risk, credit risk and liquidity risk. 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 currency risk, interest rate risk and commodity price risk. Market risk is managed by the Trust through a series of derivative contracts intended to manage the volatility of our operating cash flow. Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust manages its liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default resulting in the Trust incurring a loss. The Trust manages this credit risk by entering into sales contracts only with credit worthy entities and reviewing its exposure to individual entities on a regular basis.

Details of the risk management contracts in place as at September 30 2008, and the accounting for the Trust's financial instruments are disclosed in note 14 to the consolidated financial statements, which are incorporated herein by reference.

Selected Quarterly Financial Information

	2008			2007				2006
($000's, except per unit data)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**363,044**	332,336	264,448	233,856	193,784	156,670	161,575	164,103
Net income	**137,228**	34,417	35,848	41,353	36,674	31,050	23,783	19,988
Net income per trust unit								
Basic	**1.44**	0.39	0.42	0.49	0.44	0.41	0.32	0.27
Diluted	**1.39**	0.38	0.41	0.46	0.43	0.39	0.30	0.26

Changes in Accounting Policies

Effective January 1, 2008, the Trust adopted the following accounting standards of the Canadian Institute of Chartered Accountants ("CICA"): Section 3862 "Financial Instruments – Disclosures"; Section 3863 "Financial Instruments – Presentation"; and Section 1535 "Capital Disclosures". The adoption of the new standards resulted in additional disclosures with regard to financial instruments (note 14) and the Trust's objectives, policies and process for managing capital (note 16).

The Trust also adopted Section 3031 "Inventories". This new standard replaces the previous inventories standard and requires inventory to be valued on a first-in, first-out or weighted average basis. The adoption of Section 3031 did not have an impact on the consolidated financial statements of the Trust.

Future Accounting Changes

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public issuers are expected to converge with International Financial Reporting Standards ("IFRS"). In March 2007, the AcSB released an *"Implementation Plan for Incorporating IFRS into Canadian GAAP"*, which assumes a convergence date of January 1, 2011. Following a progress review on February 13, 2008, the AcSB has confirmed this changeover date. The Trust is assessing the impact of adoption of IFRS and is developing its plan for transition.

In February 2008, the CICA issued Section 3064 "Goodwill and Intangible Assets", which replaces Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets by profit-oriented enterprises subsequent to their initial measurement. The new standard will be effective on January 1, 2009. The Trust does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

Controls and Procedures

Disclosure Controls and Procedures

Raymond Chan, the Chief Executive Officer, and Derek Aylesworth, the Chief Financial Officer, of Baytex Energy Ltd. (together the "Disclosure Officers") are responsible for establishing and maintaining disclosure controls and procedures for Baytex. They have designed such disclosure controls and procedures, or caused them to be designed under their supervision, to provide reasonable assurance that all material or potentially material information about the activities of Baytex is made known to them by others within Baytex.

It should be noted that while our Disclosure Officers believe that Baytex's disclosure controls and procedures provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

Internal Controls over Financial Reporting

Under the supervision and with participation of Raymond Chan, the Chief Executive Officer, and Derek Aylesworth, the Chief Financial Officer of Baytex Energy Ltd., we conducted an evaluation of the design and effectiveness of our internal control over financial reporting as of December 31, 2007 based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that as of December 31, 2007, Baytex did maintain effective internal control over financial reporting.

There were no changes in our internal control over financial reporting during the nine months ended September 30, 2008 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Advisory Regarding Forward-Looking Statements

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

Specifically, this document contains forward-looking statements relating to: our liquidity and financial capacity; funding sources for our cash distributions and capital program; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; the extension of our credit facilities upon maturity; and the impact of the adoption of new accounting standards on our financial results.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash distributions that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; fluctuations in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; changes in income tax laws, royalty rates and incentive programs relating to the oil and gas industry and income trusts; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2007, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

CONSOLIDATED BALANCE SHEETS

(thousands) (unaudited)	September 30, 2008	December 31, 2007
ASSETS		
Current assets		
Accounts receivable	$ 122,372	$ 105,176
Crude oil inventory	1,992	5,997
Financial derivative contracts (note 14)	8,958	–
Future income taxes	1,030	11,525
	134,352	122,698
Financial derivative contracts (note 14)	2,532	–
Petroleum and natural gas properties	1,609,087	1,246,697
Goodwill	37,755	37,755
	$ 1,783,726	$ 1,407,150
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 156,577	$ 104,318
Distributions payable to unitholders	24,233	15,217
Bank loan	200,445	241,748
Financial derivative contracts (note 14)	12,323	34,239
	393,578	395,522
Long-term debt (note 4)	187,617	173,854
Convertible debentures (note 5)	10,377	16,150
Asset retirement obligations (note 6)	48,839	45,113
Deferred obligations	82	113
Future income taxes	215,873	153,943
	856,366	784,695
Non-controlling interest (note 8)	–	21,235
UNITHOLDERS' EQUITY		
Unitholders' capital (note 7)	1,117,544	821,624
Conversion feature of debentures (note 5)	509	796
Contributed surplus (note 9)	19,801	18,527
Deficit	(210,494)	(239,727)
	927,360	601,220
	$ 1,783,726	$ 1,407,150

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENT OF INCOME AND COMPREHENSIVE INCOME

(thousands, except per unit data) (unaudited)	Three Months Ended September 30 2008	Three Months Ended September 30 2007	Nine Months Ended September 30 2008	Nine Months Ended September 30 2007
Revenue				
Petroleum and natural gas sales	$ 363,044	$ 193,784	$ 959,828	$ 512,029
Royalties	(72,833)	(28,680)	(175,832)	(70,281)
Gain (loss) on financial derivatives (note 14)	66,654	1,182	(24,525)	(2,853)
	356,865	166,286	759,471	438,895
Expenses				
Operating	46,399	37,839	125,116	96,010
Transportation and blending	57,077	36,045	172,988	111,866
General and administrative	7,071	5,619	21,968	16,750
Unit-based compensation (note 9)	2,038	2,370	6,249	6,176
Interest (note 12)	8,227	9,666	25,102	26,592
Foreign exchange loss (gain) (note 13)	7,064	(12,601)	12,937	(31,177)
Depletion, depreciation and accretion	61,250	51,525	162,649	135,426
	189,126	130,463	527,009	361,643
Income before taxes and non-controlling interest	167,739	35,823	232,462	77,252
Taxes (note 11)				
Current expense	3,176	1,934	8,445	4,604
Future expense (recovery)	25,962	(3,895)	13,166	(21,710)
	29,138	(1,961)	21,611	(17,106)
Income before non-controlling interest	138,601	37,784	210,851	94,358
Non-controlling interest (note 8)	(1,373)	(1,110)	(3,358)	(2,851)
Net income/Comprehensive income	$ 137,228	$ 36,674	$ 207,493	$ 91,507

CONSOLIDATED STATEMENT OF DEFICIT

(thousands, except per unit data) (unaudited)	Three Months Ended September 30 2008	Three Months Ended September 30 2007	Nine Months Ended September 30 2008	Nine Months Ended September 30 2007
Deficit, beginning of period	$ (275,590)	$ (230,916)	$ (239,727)	$ (202,471)
Net income	137,228	36,674	207,493	91,507
Distributions to unitholders	(72,132)	(45,231)	(178,260)	(128,509)
Deficit, end of period	$ (210,494)	$ (239,473)	$ (210,494)	$ (239,473)
Net income per trust unit (note 10)				
Basic	$ 1.44	$ 0.44	$ 2.31	$ 1.16
Diluted	$ 1.39	$ 0.43	$ 2.23	$ 1.12
Weighted average trust units (note 10)				
Basic	95,597	83,669	89,796	78,601
Diluted	99,976	89,272	94,943	84,454

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended September 30		Nine Months Ended September 30	
(thousands) (unaudited)	2008	2007	2008	2007
CASH PROVIDED BY (USED IN):				
Operating Activities				
Net income	$ 137,228	$ 36,674	$ 207,493	$ 91,507
Items not affecting cash:				
Unit-based compensation (note 9)	2,038	2,370	6,249	6,176
Unrealized foreign exchange loss (gain) (note 13)	7,306	(12,263)	12,680	(31,048)
Depletion, depreciation and accretion	61,250	51,525	162,649	135,426
Accretion on debentures and long term debt (note 4 & note 5)	439	35	1,162	105
Unrealized loss (gain) on financial derivatives (note 14)	(89,010)	(599)	(33,406)	4,056
Future income tax expense (recovery)	25,962	(3,895)	13,166	(21,710)
Non-controlling interest (note 8)	1,373	1,110	3,358	2,851
	146,586	74,957	373,351	187,363
Change in non-cash working capital	4,591	(308)	229	1,995
Asset retirement expenditures	(351)	(351)	(718)	(1,311)
Decrease in deferred obligations	(11)	(576)	(32)	(1,728)
	150,815	73,722	372,830	186,319
Financing Activities				
Increase (decrease) in bank loan	20,445	1,351	(41,303)	131,833
Payments of distributions	(54,817)	(38,959)	(133,501)	(107,194)
Issue of trust units, net of issuance costs (note 7)	1,629	559	10,125	145,858
	(32,743)	(37,049)	(164,679)	170,497
Investing Activities				
Petroleum and natural gas property expenditures	(48,584)	(43,533)	(142,114)	(114,370)
Acquisition (net of disposal) of petroleum and natural gas properties	(78,635)	(752)	(80,392)	(253,592)
Change in non-cash working capital	9,147	7,612	14,355	11,146
	(118,072)	(36,673)	(208,151)	(356,816)
Change in cash and cash equivalents	–	–	–	–
Cash and cash equivalents, beginning of period	–	–	–	–
Cash and cash equivalents, end of period	$ –	$ –	$ –	$ –

See accompanying notes to the consolidated financial statements.

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust and Baytex Energy Ltd. (the "Company"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Pursuant to the Plan of Arrangement, the Company became a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles.

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Trust as at December 31, 2007, except as noted below. The interim consolidated financial statements contain disclosures, which are supplemental to the Trust's annual consolidated financial statements. Certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. The interim consolidated financial statements should be read in conjunction with the Trust's consolidated financial statements and notes thereto for the year ended December 31, 2007.

Certain comparative figures have been reclassified to conform to the presentation adopted in the current period.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008, the Trust adopted the following accounting standards of the Canadian Institute of Chartered Accountants ("CICA"): Section 3862 "Financial Instruments – Disclosures"; Section 3863 "Financial Instruments – Presentation"; and Section 1535 "Capital Disclosures". The adoption of the new standards resulted in additional disclosures with regard to financial instruments (note 14) and the Trust's objectives, policies and process for managing capital (note 16).

The Trust also adopted Section 3031 "Inventories". This new standard replaces the previous inventories standard and requires inventory to be valued on a first-in, first-out or weighted average basis. The adoption of Section 3031 did not have an impact on the consolidated financial statements of the Trust.

Future Accounting Changes

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS"). In March 2007, the AcSB released an *"Implementation Plan for Incorporating IFRS into Canadian GAAP"*, which assumes a convergence date of January 1, 2011. Following a progress review on February 13, 2008, the AcSB has confirmed this changeover date. The Trust is assessing the impact of adoption of IFRS and is developing its plan for transition.

In February 2008, the CICA issued Section 3064 "Goodwill and Intangible Assets", which replaces Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets by profit-oriented enterprises subsequent to their initial measurement. The new standard will be effective on January 1, 2009. The Trust does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

3. CORPORATE ACQUISITIONS

On June 4, 2008, Baytex acquired all the issued and outstanding shares of Burmis Energy Inc., a public company which had interests in certain natural gas and light oil properties located primarily in west central Alberta. The results of operations from these properties have been included in the consolidated financial statements since the closing of the acquisition on June 4, 2008. In conjunction with the acquisition, Burmis Energy Inc. was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:	
Trust units issued	$ 152,053
Net debt assumed	24,480
Costs associated with acquisition	1,818
Total purchase price	$ 178,351
Allocation of purchase price:	
Property, plant and equipment	$ 217,087
Future income taxes	(37,200)
Asset retirement obligations	(1,536)
Total net assets acquired	$ 178,351

All of the issued and outstanding shares of Burmis were acquired on the basis of 0.1525 of a Baytex trust unit for each Burmis share, resulting in the issuance of 6,383,416 Baytex trust units valued at $23.82 per unit, which was the average closing price of Baytex trust units for the ten trading days bordering the initial public announcement of the transaction. Amendments may be made to the purchase equation as the cost estimates and balance are finalized.

On June 26, 2007, Baytex acquired all the issued and outstanding shares of a private company which had interests in certain petroleum and natural gas properties and related assets located primarily in the Pembina and Lindbergh areas of Alberta. The results of operations from these properties have been included in the consolidated financial statements since the closing of the acquisition on June 26, 2007. Subsequent to the acquisition, the private company was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:	
Cash paid for property, plant and equipment	$ 241,092
Costs associated with acquisition	2,181
Cash paid for working capital	13,229
Total purchase price	$ 256,502
Allocation of purchase price:	
Working capital	$ 13,229
Property, plant and equipment	320,036
Future income taxes	(74,524)
Asset retirement obligations	(2,239)
Total net assets acquired	$ 256,502

4. LONG-TERM DEBT

	September 30, 2008	December 31, 2007
10.5% senior subordinated notes (US$247)	$ 262	$ 244
9.625% senior subordinated notes (US$179,699)	190,463	177,561
	190,725	177,805
Discontinued fair value hedge	(3,108)	(3,951)
	$ 187,617	$ 173,854

The Company has US$0.2 million senior subordinated notes bearing interest at 10.5% payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

The Company also has US$179.7 million senior subordinated notes bearing interest at 9.625% payable semi-annually with principal repayable on July 15, 2010. These notes are unsecured and are subordinate to the Company's bank credit facilities. After July 15 in each of the following years, these notes are redeemable at the Company's option, in whole or in part with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as percentage of the principal amount of the notes): 2007 at 104.813%, 2008 at 102.406%, 2009 and thereafter at 100%. These notes are carried at amortized cost net of a discontinued fair value hedge of $6.0 million recorded on adoption of CICA Handbook Section 3865 "Hedges". The notes will accrete up to the principal balance at maturity using the effective interest method. Accretion expense of $1.1 million had been recorded for the nine months ended September 30, 2008. The effective interest rate is 10.6%. The Company had an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three-month LIBOR rate plus 5.2% until the maturity of these notes. In November 2007, the Company terminated the interest rate swap contract. A gain on termination of $2.0 million was recorded as a reduction to interest expense in 2007.

5. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

In June 2005, the Trust issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010, at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. The debt portion will accrete up to the principal balance at maturity, using the effective interest rate of 7.6%. The accretion and the interest paid are expensed as interest expense in the consolidated statement of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

	Number of Debentures	Amount of Debentures	Conversion Feature of Debentures
Balance, December 31, 2006	19,619	$ 18,906	$ 940
Conversion	(2,999)	(2,895)	(144)
Accretion	–	139	–
Balance, December 31, 2007	16,620	16,150	796
Conversion	(6,013)	(5,848)	(287)
Accretion	–	75	–
Balance, September 30, 2008	10,607	$ 10,377	$ 509

6. ASSET RETIREMENT OBLIGATIONS

	Nine Months Ended September 30, 2008	Year Ended December 31, 2007
Balance, beginning of period	$ 45,113	$ 39,855
Liabilities incurred	1,027	2,180
Liabilities settled	(718)	(2,442)
Acquisition of liabilities	1,536	2,239
Disposition of liabilities	(157)	(585)
Accretion	2,794	3,404
Change in estimate[(1)]	(756)	462
Balance, end of period	$ 48,839	$ 45,113

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

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years. The undiscounted amount of estimated cash flow required to settle the retirement obligations at September 30, 2008 was $278.7 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0% and an estimated annual inflation rate of 2.0%.

7. UNITHOLDERS' CAPITAL

Trust Units

The Trust is authorized to issue an unlimited number of trust units.

	Number of Units	Amount
Balance, December 31, 2006	75,122	$ 637,156
Issued from treasury for cash	7,000	142,135
Issued on conversion of debentures	203	3,037
Issued on conversion of exchangeable shares	12	230
Issued on exercise of trust unit rights	739	5,482
Transfer from contributed surplus on exercise of trust unit rights	–	2,816
Issued pursuant to distribution reinvestment plan	1,464	27,763
Cumulative effect of change in accounting policy	–	3,005
Balance, December 31, 2007	84,540	821,624
Issued on conversion of debentures	408	6,135
Issued on conversion of exchangeable shares	2,787	86,888
Issued on exercise of trust unit rights	1,354	10,277
Transfer from contributed surplus on exercise of trust unit rights	–	4,975
Issued on acquisition of Burmis Energy Inc. net of issuance costs	6,383	151,903
Issued pursuant to distribution reinvestment plan	1,462	35,742
Balance, September 30, 2008	**96,934**	**$ 1,117,544**

8. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either a cash payment or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly to account for distributions paid on the trust units by dividing the cash distribution paid by the weighted average trust unit price for the five-day trading period ending on the record date. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

	Number of Exchangeable Shares	Amount
Balance, December 31, 2006	1,573	$ 17,187
Exchanged for trust units	(7)	(83)
Non-controlling interest in net income	–	4,131
Balance, December 31, 2007	1,566	21,235
Exchanged for trust units	(1,566)	(24,593)
Non-controlling interest in net income	–	3,358
Balance, September 30, 2008	**–**	**$ –**

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share had been exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008. As at September 30, 2008, there were no exchangeable shares outstanding.

9. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the Plan is a "rolling" maximum equal to 10.0% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units will result in an increase in the number of trust units available for issuance under the Plan, and any exercises of rights will make new grants available under the Plan, effectively resulting in a re-loading of the number of rights available to grant under the Plan. Trust unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a term of five years. The Plan provides for the exercise price of the rights to be reduced in future periods by a portion of the future distributions, subject to certain performance criteria.

The Trust recorded compensation expense of $2.0 million for the three months ended September 30, 2008 ($2.4 million in 2007) and $6.2 million for the first nine months in 2008 ($6.2 million in 2007) pursuant to rights granted under the Plan.

The Trust uses the binomial-lattice model to calculate the estimated fair value of $5.10 per right for rights issued during the nine months ended September 30, 2008 ($3.98 per right in 2007). The following assumptions were used to arrive at the estimate of fair values:

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Expected annual exercise price reduction	**$2.71**	$2.16
Expected volatility	**28%**	28%
Risk-free interest rate	**2.98% – 4.17%**	3.77% – 4.50%
Expected life of right (years)	**Various(1)**	Various(1)

(1) The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Plan.

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

	Number of Rights	Weighted Average Exercise Price[1]
Balance, December 31, 2006	6,313	$ 14.00
Granted	2,642	$ 19.85
Exercised	(739)	$ 7.42
Cancelled	(554)	$ 16.91
Balance, December 31, 2007	7,662	$ 14.67
Granted	406	$ 27.09
Exercised	(1,354)	$ 7.59
Cancelled	(212)	$ 17.77
Balance, September 30, 2008	**6,502**	**$ 14.79**

(1) Exercise price reflects grant price less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at September 30, 2008:

Range of Exercise Prices	Number Outstanding at September 30, 2008	Weighted Average Remaining Term	Weighted Average Exercise Price	Number Exercisable at September 30, 2008	Weighted Average Exercise Price
		(years)			
$1.00 to $6.00	591	1.1	$ 3.96	591	$ 3.96
$6.01 to $11.00	1,288	2.0	$ 8.42	802	$ 8.22
$11.01 to $16.00	529	2.9	$ 14.00	209	$ 13.59
$16.01 to $21.00	3,723	3.6	$ 17.60	604	$ 17.89
$21.01 to $26.00	132	4.5	$ 22.59	–	–
$26.01 to $32.96	239	4.8	$ 29.49	–	–
$1.00 to $32.96	6,502	3.1	$ 14.79	2,206	$ 10.24

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2006	$ 13,357
Compensation expense	7,986
Transfer from contributed surplus on exercise of trust unit rights[1]	(2,816)
Balance, December 31, 2007	18,527
Compensation expense	6,249
Transfer from contributed surplus on exercise of trust unit rights[1]	(4,975)
Balance, September 30, 2008	**$ 19,801**

(1) Upon exercise of rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.

10. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the period, converted at the applicable exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

	September 30, 2008			September 30, 2007		
Three Months Ended	Net Income	Trust Units	Net Income per Unit	Net Income	Trust Units	Net Income per Unit
Net income per basic unit	$137,228	95,597	$ 1.44	$ 36,674	83,669	$ 0.44
Dilutive effect of trust unit rights	–	3,117		–	1,874	
Conversion of convertible debentures	142	755		199	1,172	
Exchange of exchangeable shares	1,373	507		1,110	2,557	
Net income per diluted unit	$138,743	99,976	$ 1.39	$ 37,983	89,272	$ 0.43

	September 30, 2008			September 30, 2007		
Nine Months Ended	Net Income	Trust Units	Net Income per Unit	Net Income	Trust Units	Net Income per Unit
Net income per basic unit	$207,493	89,796	$ 2.31	$ 91,507	78,601	$ 1.16
Dilutive effect of trust unit rights	–	3,044		–	2,068	
Conversion of convertible debentures	521	940		622	1,226	
Exchange of exchangeable shares	3,358	1,163		2,851	2,559	
Net income per diluted unit	$211,372	94,943	$ 2.23	$ 94,980	84,454	$ 1.12

The dilutive effect of trust unit rights for the nine months ended September 30, 2008 did not include 0.3 million trust unit rights (2007 – 2.6 million) because the respective proceeds of exercise plus the amount of compensation expense attributed to future services not yet recognized exceeded the average market price of the trust units during the period.

11. INCOME TAXES EXPENSE (RECOVERY)

The provision for expense (recovery of) income taxes has been computed as follows:

	Nine Months Ended September 30	
	2008	2007
Income before income taxes and non-controlling interest	$ 232,462	$ 77,252
Expected income taxes at the statutory rate of 30.22% (2007 – 34.02%)	70,250	26,282
Increase (decrease) in taxes resulting from:		
Net income of the Trust	(57,008)	(46,090)
Non-taxable portion of foreign exchange loss (gain)	1,881	(5,173)
Effect of change in tax rate	(5,930)	1,962
Effect of change in opening tax pool balances	1,755	(1,017)
Unit based compensation	1,888	2,101
Other	330	225
Future tax	13,166	(21,710)
Current tax	8,445	4,604
Total tax expense (recovery)	$ 21,611	$ (17,106)

On June 22, 2007, Bill C-52 Budget Implementation Act, which contains legislative provisions to tax publicly traded income trusts in Canada, received Royal Assent in the Canadian House of Commons. The new tax is not expected to apply to the Trust until 2011. As a result of the tax legislation becoming enacted, an additional future tax recovery of $0.5 million was recorded in 2007.

12. INTEREST EXPENSE

The Trust incurred interest expense on its outstanding debt as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	2007	2008	2007
Bank loan and miscellaneous financing	$ 3,095	$ 4,311	$ 10,029	$ 9,638
Convertible debentures	205	316	752	987
Long-term debt	4,927	5,039	14,321	15,967
Total interest	$ 8,227	$ 9,666	$ 25,102	$ 26,592

13. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	2007	2008	2007
Interest paid	$11,642	$ 14,232	$ 28,122	$ 29,981
Income taxes paid	$ 1,781	$ 2,208	$ 4,150	$ 7,194

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Unrealized foreign exchange loss (gain)	$ 7,306	$ (12,263)	$ 12,680	$ (31,048)
Realized foreign exchange loss (gain)	(242)	(338)	257	(129)
Total foreign exchange loss (gain)	$ 7,064	$ (12,601)	$ 12,937	$ (31,177)

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Trust's financial assets and liabilities are comprised of accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, financial derivative contracts, long-term debt, convertible debentures and deferred obligations.

Categories of Financial Instruments

Under Canadian generally accepted accounting principles, financial instruments are classified into one of the following 5 categories: held-for-trading, held to maturity, loans and receivables, available-for-sale and other financial liabilities. The carrying value and fair value of the Trust's financial instruments on the consolidated balance sheet are classified into the following categories:

	September 30, 2008		December 31, 2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Loans and receivables				
Accounts receivable	$ 122,372	$ 122,372	$ 105,176	$ 105,176
Total loans and receivables	$ 122,372	$ 122,372	$ 105,176	$ 105,176
Held for trading				
Derivatives designated as held for trading	$ 11,490	$ 11,490	–	–
Total held for trading	$ 11,490	$ 11,490	–	–
Financial Liabilities				
Held for trading				
Derivatives designated as held for trading	$ (12,323)	$ (12,323)	$ (34,239)	$ (34,239)
Total held for trading	$ (12,323)	$ (12,323)	$ (34,239)	$ (34,239)
Other financial liabilities				
Accounts payable and accrued liabilities	$ (156,577)	$ (156,577)	$ (104,318)	$ (104,318)
Distributions payable to unitholders	(24,233)	(24,233)	(15,217)	(15,217)
Bank loan	(200,445)	(200,445)	(241,748)	(241,748)
Long-term debt	(187,617)	(191,201)	(173,854)	(182,132)
Convertible debentures	(10,377)	(12,008)	(16,150)	(19,481)
Deferred obligations	(82)	(82)	(113)	(113)
Total other financial liabilities	$ (579,331)	$ (584,546)	$ (551,400)	$ (563,009)

The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than bank loan, and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its book value as it is at a market rate of interest. The fair value of the long term debt is based on the trading value of the instrument. The fair value of the convertible debentures has been calculated as the present value of future cash flows associated with the debentures.

Financial Risk

The Trust is exposed to a variety of financial risk, including market risk, credit risk and liquidity risk. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign currency risk

The Trust is exposed to fluctuations in foreign currency as a result of its U.S. dollar denominated notes, crude oil sales based on U.S. dollar indices and commodity contracts that are settled in U.S. dollars. The Trust's net income and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

In order to manage these risks, the Trust may enter into agreements to fix the exchange rate of Canadian to U.S. dollar in order to lessen the impact of currency rate fluctuations.

At September 30, 2008, the Trust had in place the following currency swap:

	Period	Amount	Swap Price
Swap	July 1, 2008 to December 31, 2008	US$10.0 million per month	CAD/US$0.9935

The following table demonstrates the effect of exchange rate movement on net income before taxes and non-controlling interest due to changes in the fair value of its currency swap as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at September 30, 2008.

	$0.10 Increase/Decrease in CAD/US$ Exchange Rate
Gain/loss on currency swap	$ 193
Gain/loss on other monetary assets/liabilities	15,174
Impact on income before taxes and non-controlling interest	$15,367

The carrying amounts of the Trust's foreign currency denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	September 30, 2008	December 31, 2007	**September 30, 2008**	December 31, 2007
U.S. dollar denominated	**US$ 32,944**	US$ 54,674	**US$ 186,619**	US$ 226,528

Interest rate risk

The Trust's interest rate risk arises from its floating rate bank loan. As at September 30, 2008, $200.0 million of the Trust's total debt is subject to movements in floating interest rates. An increase or decrease of 1.0% in interest rates would impact cash flow for the nine months ended September 30, 2008 by approximately $1.7 million.

Commodity Price Risk

The Trust monitors and, when appropriate, utilizes financial derivative agreements or fixed price 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 the Company. Under the Trust's risk management policy, financial instruments are not used for speculative purposes.

When assessing the potential impact of commodity price changes, a 10% increase in commodity prices could have resulted in a reduction to the unrealized gain in the third quarter of 2008 of $14.5 million relating to the financial derivative instruments outstanding as at September 30, 2008, while a 10% decrease could have resulted in a $14.6 million additional gain.

At September 30, 2008, the Trust had the following commodity derivative contracts:

Oil	Period	Volume	Price	Index
Price collar	Calendar 2008	2,000 bbl/d	US$60.00 – $80.25	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$65.00 – $77.05	WTI
Price collar	Calendar 2008	2,000 bbl/d	US$65.00 – $80.10	WTI
Price collar	Calendar 2009	2,000 bbl/d	US$90.00 – $136.40	WTI
Price collar	Calendar 2009	2,000 bbl/d	US$110.00 – $172.70	WTI

Derivative contracts are marked to market at the end of each reporting period, with the following reflected in the income statement:

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	2007	2008	2007
Realized gain (loss) on financial derivatives	$ (22,356)	$ 583	$ (57,931)	$ 1,203
Unrealized gain (loss) on financial derivatives	89,010	599	33,406	(4,056)
	$ 66,654	$ 1,182	$ (24,525)	$ (2,853)

Liquidity risk

Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust manages its liquidity risk through cash and debt management. As at September 30, 2008, the Trust had available unused bank credit facilities in the amount of $226 million. The Trust believes it has sufficient funding capacity through its credit facilities to meet foreseeable borrowing requirements.

The timing of cash outflows relating to financial liabilities are outlined in the table below:

	Total	1 year	2-3 years	4-5 years	Beyond 5 years
	$	$	$	$	$
Accounts payable and accrued liabilities	156,577	156,577	–	–	–
Distributions payable to unitholders	24,233	24,233	–	–	–
Bank loan[(1)]	200,445	200,445	–	–	–
Derivative contracts[(2)]	12,323	12,323	–	–	–
Long-term debt[(3)]	190,725	–	190,275	–	–
Convertible debentures[(3)]	10,607	–	10,607	–	–
Deferred obligations	82	44	38	–	–

(1) The bank loan is a 364-day revolving loan with the ability to extend the term. The Trust has no reason to believe that it will be unable to extend the credit facility when it matures on July 1, 2009.

(2) Current liability component of financial derivative contracts.

(3) Principal amount of instruments.

Credit risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in the Trust incurring a loss. Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets.

The carrying amount of accounts receivable are reduced through the use of an allowance for doubtful accounts and the amount of the loss is recognized in net income.

As at September 30, 2008, the Trust has no material amount of accounts receivable that are past due and no material allowance for doubtful accounts.

15. COMMITMENTS AND CONTINGENCIES

At September 30, 2008, the Trust had the following crude oil supply contracts:

Heavy Oil

	Period	Volume	Price
Price Swap – WCS Blend	Calendar 2008	13,340 bbl/d	WTI × 67.1% (weighted average)
Price Swap – LLB Blend	Calendar 2008	2,000 bbl/d	WTI less US$24.55
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI × 67.0% (weighted average)

At September 30, 2008, the Trust had the following natural gas physical sales contracts:

Gas

	Period	Volume	Price/GJ
Price collar	Calendar 2008	5,000 GJ/d	$6.15 – $7.00
Price collar	Calendar 2008	5,000 GJ/d	$6.15 – $7.46
Price collar	April 1, 2008 to October 31, 2008	5,000 GJ/d	$6.15 – $7.50
Price collar	April 1, 2008 to October 31, 2008	2,500 GJ/d	$6.15 – $9.35
Price Swap	June 4, 2008 to December 31, 2008	7,000 GJ/d	$7.67 (weighted average)
Price Collar	Calendar 2009	5,000 GJ/d	$7.00 – $7.95

At September 30, 2008, the Trust had the following power contracts:

Power

	Period	Volume	Price/MWh
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$78.61
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$79.92

At September 30, 2008, the Trust had operating lease and transportation obligations as summarized below:

	Payments Due Within					
	Total	1 year	2 years	3 years	4 years	5 years
Operating leases	$ 5,297	$ 3,007	$ 1,459	$ 251	$ 384	$ 196
Processing and transportation agreements	18,418	6,403	5,662	5,012	1,308	33
Total	$ 23,715	$ 9,410	$ 7,121	$ 5,263	$ 1,692	$ 229

OTHER

At September 30, 2008, there were outstanding letters of credit aggregating $2.2 million (September 30, 2007 – $7.4 million) issued as security for performance under certain contracts.

The Company has future contractual processing obligations with respect to assets acquired. The fair value of $7.8 million of the original obligation is being drawn down over the life of the obligations, which continue until October 2008. The fair value of the remaining obligation at September 30, 2008 was $0.2 million, all of which has been included in current liabilities.

In connection with a purchase of properties in 2005, Baytex became liable for contingent consideration whereby an additional amount would be payable by Baytex if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase, therefore such consideration should be recognized only when the contingency is resolved. As at September 30, 2008, additional payments totaling $5.3 million have been paid under the agreement and have been recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement, therefore no accrual has been made.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

16. CAPITAL STRUCTURE

The Trust's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of the business through maintenance of investor, creditor and market confidence.

The Trust considers its capital structure to include total monetary debt and unitholders' equity. Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital, which is current assets less current liabilities excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative gains or losses, the principal amount of long-term debt and the balance sheet value of the convertible debentures.

The Trust's financial strategy is designed to maintain a flexible capital structure consistent with the objectives above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to maintain the capital structure, the Trust may adjust the amount of its distributions, adjust its level of capital spending, issue new units, issue new debt or sell assets to reduce debt.

The Trust monitors capital based on current and projected ratios of total monetary debt to cash flow, and the current and projected level of its undrawn bank credit facilities. The Trust's objectives are to maintain a total monetary debt to cash flow from operations ratio of less than two times and to have access to undrawn bank credit facilities of not less than $100 million. The total monetary debt to cash flow from operations ratio may increase beyond two times, and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors, including acquisitions, changes to commodity prices and changes in the credit market. To facilitate management of the total monetary debt to cash flow from operations ratio and the level of undrawn bank credit facilities, the Trust continuously monitors its cash flow from operations and evaluates its distribution policy and capital spending plans.

The Trust's financial objectives and strategy as described above have remained substantially unchanged over the last two completed fiscal years. These objectives and strategy are reviewed on an annual basis. The Trust believes its financial metrics are within acceptable limits pursuant to its capital management objectives.

The Trust is subject to financial covenants relating to its bank loan, senior subordinated notes and convertible debentures. The Trust is in compliance with all financial covenants.

On June 22, 2007, new tax legislation modifying the taxation of specified investment flow-through entities, including income trusts such as the Trust, was enacted (the "New Tax Legislation"). The New Tax Legislation will apply a tax at the trust level on distributions of certain income from trusts. The New Tax Legislation permits "normal growth" for income trusts through the transitional period ending December 31, 2010. However, "undue expansion" could cause the transitional relief to be revisited, and the New Tax Legislation to be effective at a date earlier than January 1, 2011. On December 15, 2006, the Department of Finance released guidelines on normal growth for income trusts and other flow-through entities (the "Guidelines"). Under the Guidelines, trusts will be able to increase their equity capital each year during the transitional period by an amount equal to a safe harbour amount. The safe harbour amount is measured by reference to a trust's market capitalization as of the end of trading on October 31, 2006. The safe harbour amounts are 40% for the period from November 2006 to the end of 2007, and 20% per year for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730 million for 2006/2007 and $365 million for each of the subsequent three years. The safe harbour amounts are cumulative allowing amounts not used in one year to be carried forward to a future year. Two trusts can merge without being impacted by the growth limitations. Limits are not impacted by non-convertible debt-financed growth, but rather focus solely on the issuance of equity to facilitate growth. At September 30, 2008, the Trust had not exceeded its "normal growth" limits.

ABBREVIATIONS

bbl	barrel	*Mcf*	thousand cubic feet
bbl/d	barrel per day	*Mcf/d*	thousand cubic feet per day
Bcf	billion cubic feet	*MMbbl*	million barrels
boe	barrels of oil equivalent	*MMboe*	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day	*MMcf*	million cubic feet
Mbbl	thousand barrels	*MMcf/d*	million cubic feet per day
Mboe	thousand barrels of oil equivalent	*NGL*	natural gas liquids

CORPORATE INFORMATION

BOARD OF DIRECTORS

Edward Chwyl (2)(3)(4)
Chairman of the Board
Independent Businessman

John A. Brussa (2)(3)(4)
Partner
Burnet, Duckworth & Palmer LLP

Raymond T. Chan
Chief Executive Officer
Baytex Energy Trust

Naveen Dargan (1)(2)(4)
Independent Businessman

R. E. T. (Rusty) Goepel (1)
Senior Vice President
Raymond James Ltd.

Gregory K. Melchin (1)
Independent Businessman

Dale O. Shwed (3)
President and CEO
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 Governance Committee

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The Toronto-Dominion Bank
Bank of Nova Scotia
BNP Paribas (Canada)
Canadian Imperial Bank of Commerce
Fortis Capital (Canada) Ltd.
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of California

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

OFFICERS

Raymond T. Chan
Chief Executive Officer

Anthony W. Marino
President & Chief Operating Officer

W. Derek Aylesworth
Chief Financial Officer

Randal J. Best
Senior Vice President,
Corporate Development

Stephen Brownridge
Vice President, Heavy Oil

Brett J. McDonald
Vice President, Land

Timothy R. Morris
Vice President, US Business Development

R. Shaun Paterson
Vice President, Marketing

Mark F. Smith
Vice President, Conventional Oil & Gas

Shannon M. Gangl
Corporate Secretary
Partner, Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE.UN

New York Stock Exchange
Symbol: BTE