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 for the year ended December 31, 2008. This information is provided as of March 16, 2009. In this MD&A, references to "Baytex", the "Trust", "we", "us" and "our" and similar terms refer to Baytex Energy Trust and its subsidiaries on a consolidated basis, except where the context requires otherwise. This MD&A should be read in conjunction with the Trust's audited consolidated comparative financial statements for the years ended December 31, 2008 and 2007, together with accompanying notes, and Annual Information Form for the year ended December 31, 2008. 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, asset retirement expenditures, and decrease in deferred obligations. 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".

2008 OVERVIEW

Baytex Energy Trust is an open-ended, unincorporated investment trust created under the laws of the Province of Alberta pursuant to a trust indenture. Baytex was established on September 2, 2003 in connection with a Plan of Arrangement of our subsidiary, Baytex Energy Ltd. (the "Company"). Through our subsidiaries, we are actively engaged in the exploration, development and production of oil, natural gas and natural gas liquids in Canada in the provinces of British Columbia, Alberta and Saskatchewan and in the United States in North Dakota and Wyoming.

Our business objective has been to maintain production levels through investing approximately half of our internally generated cash flow while distributing the balance of our cash flow to holders of our trust units. Over our life, we have grown our reserve base and added to production levels through exploration and development activities complimented by strategic acquisitions.

During 2008, the Trust executed a successful capital program (excluding acquisitions) resulting in the replacement of 119% of production (on a proved plus probable basis) by spending 43% of cash flow from operations. When acquisitions are included, the Trust replaced 233% of production by spending 63% of cash flow.

As at December 31 2008, we had a reserve base of 187 million (gross) boe on a proved plus probable basis. During the year ended December 31, 2008, our production averaged 40,239 boe/d primarily in Canada, with minor amounts of production contributed from our U.S. operations.

On June 4, 2008, we acquired all of the issued and outstanding shares of Burmis Energy Inc. ("Burmis") on the basis of 0.1525 of a Baytex trust unit for each Burmis common share. Approximately 6.38 million Baytex trust units were issued to acquire Burmis. Pursuant to this transaction, we acquired multi-zone, liquids-rich natural gas and light oil properties located in west central Alberta and approximately 110,300 net acres of undeveloped land. Production from the Burmis properties averaged 3,791 boe/d during the first quarter of 2008.

During the third quarter of 2008, we reached agreement to acquire a significant land position in a Bakken/Three Forks light oil resource play in the Williston Basin in North Dakota from a private company. Upon making all deferred payments associated with the transaction, we will have acquired a 37.5% interest in 263,000 gross acres (approximately 98,625 net acres). At the time of the acquisition, 94% of the lands were undeveloped. In addition, we acquired approximately 300 boe/d (95% oil) of company interest production. The seller retained the remaining 62.5% interest in the project lands and production.

PROPERTY REVIEW

Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2008. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2008. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2008, except where otherwise indicated.

Our crude oil and natural gas operations are organized into Canadian Heavy Oil, Canadian Conventional Oil and Gas and U.S. business units. Each business unit has an extensive portfolio of operated properties and development prospects with considerable upside potential. Within these business units, Baytex has established a total of eight geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of those opportunities.

Baytex invested approximately $82 million in land over the past two years targeting three light oil resource plays. These plays include the Bakken/Three Forks in the Williston Basin of North Dakota, the Viking in southwestern Saskatchewan and eastern Alberta and a Mowry Shale exploratory play in the Powder River Basin of eastern Wyoming. These light oil resources plays provide the opportunity for long term light oil production and reserve growth to complement our heavy oil growth projects. These resource plays are described in more detail in the business unit descriptions below.

Heavy Oil Business Unit

The Heavy Oil business unit accounts for more than 55% of current production and more than 65% of oil-equivalent reserves. Baytex's heavy oil operations consist predominantly of cold primary production, without the assistance of steam injection. In some cases, Baytex's heavy oil reservoirs are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 250 bbl/d of crude with gravities ranging from 11 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. Heavy crude is usually blended with light-hydrocarbon diluents (such as condensate) prior to being introduced into a sales pipeline. The blended crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers. All production rates reported are for heavy crude only, before the addition of diluents.

In 2008, production in the Heavy Oil business unit averaged approximately 23,530 bbl/d of heavy oil and 6,654 Mcf/d of natural gas (24,639 Boe/d). Baytex drilled 111 (103.8 net) wells in the Heavy Oil business unit resulting in 105 (97.8 net) oil wells, 4 (4.0 net) stratigraphic test wells, and 2 (2.0 net) dry and abandoned wells, for a success rate of 98%.

The Heavy Oil business unit possesses a large inventory of development projects within the operating areas of west-central Saskatchewan and Cold Lake/Ardmore and Peace River in Alberta. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to maintaining our overall production rate. Because of our large inventory of heavy oil projects, we are able to select from a wide range of investment opportunities to maintain heavy oil production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area and Baytex's historical area of emphasis around Lloydminster. Our net undeveloped lands in the Heavy Oil business unit totalled approximately 348,000 acres at year-end 2008.

Listed below is a brief description of the principal properties within the Heavy Oil Business Unit:

Ardmore, Alberta: Acquired in 2002, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2008 was approximately 1,395 bbl/d of oil and 455 Mcf/d of natural gas (1,471 boe/d). Seven successful oil wells and no dry holes were drilled in the area during 2008. Baytex anticipates drilling four wells in this area in 2009. Due to extensive Baytex infrastructure in this area, operating expenses in 2008 remained relatively low at approximately $8.20 per boe. Net undeveloped lands were 39,000 acres at year-end 2008.

Carruthers, Saskatchewan: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. No new wells were drilled in 2008, but 4 re-completions were conducted. Despite the absence of new well drilling, year-over-year production decline was only about 8% due mostly to strong performance of the ongoing waterflood. Average production in 2008 was approximately 2,115 bbl/d of heavy oil and 650 Mcf/d of natural gas (2,224 boe/d). Net undeveloped lands were 9,900 acres at year-end 2008.

Celtic, Saskatchewan: This producing property was acquired in October 2005, in a transaction where Baytex purchased cold heavy oil production of 1,600 bbl/d and natural gas production of 900 Mcf/d. As a result of Baytex's well re-completion and drilling activities, production averaged 4,670 bbl/d of heavy oil and 1,118 Mcf/d of natural gas (4,856 boe/d) during 2008. (This production number includes very minor production in the area held prior to the Celtic acquisition). Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base with multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. The heavy oil at Celtic is relatively highly gas-saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2009, Baytex expects to drill 10 new wells and re-complete approximately 45 existing wells. Net undeveloped lands were 8,800 acres at year-end 2008.

Cold Lake, Alberta: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily from the Colony formation. Average oil production during 2008 was approximately 507 bbl/d. Baytex drilled two successful oil wells in the Cold Lake area in 2008, and we plan to drill three new wells in the area in 2009. Net undeveloped lands were 13,600 acres at year-end 2008.

Dodsland, Saskatchewan: During 2008, Baytex developed a new resource play in the Viking sand in southwest Saskatchewan. The zone is regionally charged with light (34 API) oil, and in its more permeable areas, has been a prolific oil horizon since the 1960s. Baytex targeted the less permeable but undeveloped areas of the play and drilled a 1,400 metre horizontal well in 2008. The horizontal well was completed with 7 fracture stimulations, applying the same multi-zone fracture technology that is used to stimulate horizontal wells in the Bakken oil play in southeast Saskatchewan and North Dakota. At year-end 2008, Baytex had leased 34,600 net acres in the play. Ultimately, up to 150 wells may be drilled on these lands.

Marsden/Epping/Macklin/Silverdale, Saskatchewan: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18 API. Initial per well production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30% of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average production in this area during 2008 was approximately 3,380 bbl/d of oil and 831 Mcf/d of natural gas (3,518 boe/d). Twenty-three successful oil wells were drilled in this region in 2008. In addition, a significant facility expansion involving water flow-lining and conservation of the solution gas was completed. This project has reduced operating costs in the area and tied-in approximately 300 mcf/d of solution gas into the local sales network. For 2009, a further 14 wells are planned. Net undeveloped lands were 26,300 acres at year-end 2008.

Seal, Alberta: Seal is a highly prospective property located in the Peace River oil sands area of northern Alberta. Baytex holds a 100% working interest in 105 sections of long-term oil sands leases. In certain parts of this land base, heavy oil can be produced using horizontal wells at initial rates of 150 to 250 bbl/d per well, without employing more cost-intensive methods such as steam injection. In 2008, Baytex drilled four stratigraphic test wells, designed to identify extensions to our current development areas. Baytex also drilled 19 horizontal production wells in 2008, bringing the total number of producing wells to 44. The average production rate during 2008 was 3,707 bbl/d of heavy oil. Detailed reservoir simulations of the Seal property have indicated that both waterflood and cyclic steam recovery methods have the potential to greatly increase economic oil reserves beyond what is achievable with cold primary recovery. A cyclic steam pilot project was carried out on an existing horizontal producer during 2008 to validate the numerical reservoir simulation models. Due to the positive results from our steam pilot, the year-end 2008 reserve report included an assignment for thermal reserves at Seal for the first time. This reserve assignment supports our assessment that commercial cyclic steam development at Seal is economically viable. Seal area facilities were expanded in 2008 by constructing a water disposal plant and a fuel gas supply pipeline. Operating costs for primary production are forecasted to remain very low at $4 to $5/bbl and the gas pipeline ensures an adequate fuel supply for future thermal development of the property. As the region continues to develop, the Seal property will take an increasingly more prominent role in our production profile. During 2009, Baytex plans to drill two additional stratigraphic test wells and 14 additional cold horizontal production wells. Net undeveloped lands were 65,000 acres at year-end 2008.

Tangleflags, Saskatchewan: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. Accordingly, this property supplies long-term development potential through a considerable number of re-completion opportunities. In 2008, the company drilled 3 wells and a further 15 wells were either re-started or re-completed to a new zone. Average production during 2008 was approximately 1,626 bbl/d of heavy oil and 915 Mcf/d of natural gas (1,779 boe/d). In 2009, Baytex plans to re-work or re-complete about 15 existing wells. Net undeveloped lands were 7,100 acres at year-end 2008.

Lindbergh, Alberta: Lindbergh is a primarily non-operated heavy oil property that was purchased in June of 2007. Oil production at Lindbergh is operated by a senior Canadian producer. Baytex has a 21.25% working interest. Company-interest production is approximately 800 bbl/d of heavy oil. Like Tangleflags and Celtic, Lindbergh is a multi-zone property that is expected to provide future development projects for many years. Thus far, economic production has been obtained from the Dina, Cummings, General Petroleum, Sparky and Colony formations. Nine (1.9 net) wells were drilled in this area in 2008. Baytex expects the field operator to maintain a level of activity that would result in an approximately flat production rate. Net undeveloped lands were 11,000 acres at year-end 2008.

Conventional Oil and Gas Business Unit

Although Baytex is best known as a “heavy oil” energy trust, we also possess a growing array of light oil and natural gas properties. In addition to Baytex’s historical light oil and natural gas properties in northern and south-eastern Alberta, the geographic scope of our conventional oil and gas operations has expanded to central Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Conventional Oil and Gas business unit produces light and medium gravity crude oil, natural gas and natural gas liquids (“NGL”) from various fields in Alberta and British Columbia. During 2008, production from this business unit averaged 48,066 Mcf/d of natural gas sales and 7,401 bbl/d of light oil and NGL (15,412 boe/d). During 2008, the Conventional business unit drilled 31 (21.4 net) wells resulting in 18 (11.9 net) gas wells, 7 (4.1 net) oil wells, 2 (1.4 net) service wells, and 4 (4.0 net) dry holes for a success rate of 87.1% (81.3% net). Our net undeveloped lands in this business unit were approximately 329,000 acres at year-end 2008.

Listed below is a brief description of the principal properties within the Conventional Oil and Gas Business Unit:

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production is obtained from the Belly River, Viking and Mannville formations. During 2008, production for the area averaged approximately 2,524 Mcf/d of gas and 264 bbl/d of light oil (685 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. During 2008, Baytex drilled two (1.75 net) oil wells in this area. At year-end 2008, Baytex had 11,500 net undeveloped acres in this area.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Baytex-operated gas plants. Production during 2008 averaged approximately 2,209 Mcf/d of gas (368 boe/d). At year-end 2008, Baytex had 18,100 net undeveloped acres in this area.

Leahurst, Alberta: Production averaged approximately 4,109 Mcf/d of gas and 11 bbl/d of NGL (696 boe/d) during 2008 from this multi-zone, year-round access area. Natural gas production from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Baytex-operated. During 2008, Baytex participated in the drilling of 4 operated and 1 non-operated locations, resulting in 4 (2.9 net) producing gas wells and 1 (1.0 net) dry hole. At year-end 2008, Baytex had 11,700 net undeveloped acres in this area.

Pembina, Alberta: Baytex acquired its initial position in Pembina in June 2007 and further expanded its presence in the area through the acquisition of Burmis in June 2008. Production is primarily from the Nisku formation and to a lesser extent from Cretaceous and Jurassic age formations including the Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg. The majority of Baytex's production in this area is treated at a Baytex-operated oil battery with the remaining production treated at two third-party oil batteries. Gas production is delivered to a combination of four mid-stream gas processing facilities and two producer-operated gas processing facilities. Baytex owns a working interest in one of the producer-operated gas processing facilities and a minor working interest in one of the mid-stream gas processing facilities. During 2008, Pembina production averaged 4,062 bbl/d of light oil and NGL and 13,272 Mcf/d of gas (6,274 boe/d). Baytex participated in drilling 6 (5.0 net) operated and 2 (0.6 net) non-operated locations in 2008. Four wells (2.3 net) were drilled to test Nisku prospects, resulting in 1 (0.6 net) oil well, 1 (0.4 net) gas well and 2 (1.4 net) service wells. Four (3.3 net) wells were drilled for development of multi-zone potential in the Cretaceous in 2008, resulting in 3 (3.0 net) gas wells and 1 (0.25 net) dry hole. The 2009 drilling program for Pembina will include up to three wells to evaluate Nisku prospects and four wells for multi-zone Cretaceous potential. During the first quarter of 2009, Baytex will be constructing a pipeline in the Pembina O'Chiese area to increase gas volumes delivered to market and improve netback prices for our Pembina production. At year-end 2008, Baytex had 32,600 net undeveloped acres in this area.

Richdale/Sedalia, Alberta: Baytex acquired its initial position in this area in 2001, and significantly increased its presence with a 2004 acquisition of a private company. During 2008, production averaged approximately 5,971 Mcf/d of sales gas and 11 bbl/d of NGL (1,006 boe/d). This area has advantages of year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the gas produced from this area is processed at two Baytex-operated gas plants. During 2008, Baytex drilled 5 (1.7 net) wells in this area, resulting in 3 (1.5 net) gas wells and 2 (0.2 net) oil wells. At year-end 2008, Baytex had 29,200 net undeveloped acres in this area.

Red Earth/Goodfish/Lafond, Alberta: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Baytex-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Baytex-operated. Production from this area during 2008 averaged approximately 4,058 Mcf/d of gas and 770 bbl/d of light oil and NGL (1,446 boe/d). During 2008, Baytex drilled 4 (3.1 net) wells in this area, resulting in 1 (0.5 net) oil well, 1 (0.6 net) gas well, and 2 (2.0 net) dry holes. At year-end 2008, Baytex had 28,600 net undeveloped acres in this area.

Stoddart, British Columbia: The Stoddart asset acquisition was completed in December 2004. Oil and liquids-rich gas production in this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production from this area during 2008 averaged approximately 8,375 Mcf/d of gas and 1,392 bbl/d of oil and NGL (2,788 boe/d). Baytex drilled 3 (2.4 net) wells in 2008 resulting in 1 (1.0 net) oil well, 1 (0.4 net) gas well, and 1 (1.0 net) dry hole. During 2009, Baytex plans to drill two wells in the area. At year-end 2008, Baytex had 32,000 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. Production during 2008 averaged approximately 519 bbl/d of oil and NGL and 1,383 Mcf/d of gas (750 boe/d). Production is from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Baytex-operated batteries and gas is processed at two outside-operated gas plants. During 2008, Baytex drilled one (0.1 net) gas well in this area. At year-end 2008, Baytex had 9,600 net undeveloped acres in this area.

United States Business Unit

Through our wholly-owned subsidiary, Baytex Energy USA Ltd. ("Baytex USA"), we acquired significant land positions in the Williston and Powder River Basins in 2007 and 2008. During 2008, Baytex USA drilled and/or acquired an interest in 34 (12 net) wells and increased its acreage position to over 120,000 net acres. Net production from the United States properties averaged 188 boe/d in 2008, and 339 boe/d in December 2008.

Listed below is a brief description of the principal properties within the United States Business Unit:

Williston Basin – Bakken/Three Forks Project: This light oil resource play is located in the Divide and Burke Counties of North Dakota. Production is primarily from horizontal wells using multi-zone hydraulic fracturing in the Bakken and Three Forks formations. Both zones are accessed through a single horizontal lateral. Baytex USA has invested in approximately 251,000 (94,000 net) acres of land. In 2008, Baytex USA participated in 8 gross (3 net) wells. Baytex USA also participated in the acquisition of a new 3D seismic survey covering 188,000 acres. This survey was 73% complete at the end of 2008. Net production from the project was approximately 341 boe/d in the fourth quarter of 2008. In 2009, Baytex USA plans to drill 6 gross (2.25 net) horizontal wells. Ultimately, the project has the potential to include 150 to 300 wells with average initial rates expected to be 190 boe/d or more per well and average recoveries expected to be 280 mboe/well or more.

Powder River Basin – Mowry Shale Play (Wild West): In September 2007, Baytex USA acquired its initial leasehold interest in this Mowry shale play covering approximately 15,300 (9,200 net) acres. A vertical well (Baytex USA 60% working interest) was drilled in 2008 to acquire core and ultimately serve as a microseismic monitoring well for subsequent horizontal-well fracturing. Completion of the vertical well, including hydraulic fracturing, is scheduled for the first quarter of 2009. Baytex USA views horizontal, multi-zone hydraulically-fractured wells as the most promising method to ultimately develop the Mowry, although there have been no horizontal wells drilled in the project area to-date. A horizontal well is planned to further evaluate the prospect in 2009. Ultimately, the project may include up to 60 horizontal wells.

MARKETING

Crude Oil

The year 2008 was marked by the unprecedented volatility in world oil prices. Early in the year strong worldwide oil demand growth coupled with limited spare production capacity pushed prices to all time highs. During the fourth quarter demand for oil collapsed on the back of plunging economic conditions which were exacerbated by high energy prices. Inventories swelled reflecting demand destruction and naturally prices fell steeply. The ongoing sub-prime mortgage and credit crisis created much uncertainty in the financial and commodity markets, adding to price weakness and volatility. For the most part, these financial considerations overshadowed geopolitical events in spite of the protracted conflicts in Iraq and Afghanistan and the fear of Iran's potential entry into the world's nuclear club.

Prices for New York Mercantile exchange traded West Texas Intermediate ("WTI"), the benchmark for Canadian crude oil sales, peaked at US$147.27 per barrel on July 11th and plunged to a low for the year on December 19th of US$33.87 per barrel – a staggering 77% decline from the peak. This represents the largest crude oil price drop in history. World demand for oil and products decreased to 85.8 million barrels per day (according to the International Energy Agency) from 86.0 million barrels a day in 2007. United States demand alone dropped by 0.5 million barrels a day over the year. Weather was not a significant factor in 2008 despite some refinery shut downs in the U.S. Gulf Coast which caused local refined product shortages in September due to hurricanes. Hurricane activity did not significantly affect critical U.S. Gulf Coast crude oil or natural gas production facilities.

Benchmark WTI prices averaged US$99.59 per barrel during 2008 which obscures the drastic monthly changes in the market during the fourth quarter. The price in 2008 was on average 38% higher than 2007 when the price averaged US$72.31 per barrel. The 5-year WTI average is US$67.22 per barrel.

Canadian Par crude at Edmonton averaged $102.86 per barrel in 2008 versus $76.35 per barrel in 2007, up 33% for the year. The 5-year Canadian Par average price is $74.55 per barrel.

Canadian heavy sour crude price differentials were generally much tighter this year at 23% of WTI than the previous five-year average of 33%. Again the extremes were severe in 2008 between the highs at 46% in December and the low of 14% during the summer. We believe that the December differential was anomalous due to the lag between negotiated fixed differentials in the market and the month of delivery drop in benchmark WTI prices. The December fixed differentials were negotiated in mid-November when they would have provided a 24% differential, but WTI dropped precipitously (by over US$15.00 per barrel) into the delivery month of December. We believe that Canadian heavy sour crude price differentials will remain low through 2010.

Baytex's conventional light crude oil and NGL prices averaged $88.92 before hedging, 36% higher than the $65.53 per barrel we received in 2007. For portions of 2008, the Canadian light sweet crude oil prices were depressed due to logistical challenges and competitive market pressures from new U.S. Bakken production.

Our heavy oil wellhead prices averaged $65.22 per barrel in 2008, 47% higher than the $44.28 per barrel we received in 2007 due to fundamental changes in the supply/demand balance for Canadian heavy crude oil. Several refineries completed heavy crude oil conversion projects in the markets served by Canadian heavy crude and supply growth out of the Western Canadian Sedimentary Basin was muted due to high costs and poor project delivery performance. This combination along with improved pipeline access and capacity meant that Canadian heavy crude was in good demand. Diluent premiums also decreased over the period which contributed to improved netbacks for Canadian heavy crude. As mentioned above, the market was disappointed by marginal increases in heavy crude supply at the same time much rail receipt capacity was added to bring in U.S. sourced diluent (condensate and naphtha). Further, the price of U.S. naphthas and natural gasoline was depressed due to a worldwide oversupply of waterborne naphtha-like material due to new NGL liquefaction projects. The net result was a significant decrease in Canadian diluent prices, which is a significant cost input to production of Canadian heavy crude oil blends.

In October and November of 2007, Baytex entered into physical heavy sour crude oil sales agreements with four parties. The contracts required Baytex to deliver 15,340 bbl/d of Lloydminster Blend or Western Canadian Select ("WCS") heavy crude oil blend for 2008, and 10,340 bbl/d for 2009. Prices received from these agreements average 68% of WTI in 2008 and 67% in 2009. In January 2009, we added two physical heavy sour crude oil sales agreements to contribute to the management our heavy oil pricing volatility exposure by selling 775 bbl/d of WCS heavy crude oil to counterparty at WTI minus a fixed US$10.00 per barrel and 775 bbl/d at 80% of delivery month WTI. These agreements commence April 1, 2009 and terminate August 31, 2009. The cumulative affect of these agreements significantly reduces the volatility of Baytex's cash flows from heavy crude oil sales.

WTI costless collars have been put in place for 2009 on 4,000 barrels per day at a weighted average price from US$100.00 per barrel to US$154.55 per barrel. No collars or any other hedging instruments have yet been implemented for 2010.

The market and infrastructure solutions for our Seal area remain a work-in-progress. Long-term logistical solutions are being developed for the area. Pembina Pipeline announced on August 12, 2008 that they are installing two pipelines to serve the area by mid-2011. The first pipeline will provide 100,000 bbl/d of blended heavy crude oil capacity to the Edmonton market. The second pipeline will provide 22,000 bbl/d of condensate/diluent supply to the Nipisi/Seal region for use in blending bitumen to pipeline viscosity specifications. Both lines can be expanded by 50%. This new capacity should open up existing capacity on the Rainbow Pipeline operated by Plains Marketing which also serves the region. Plains Marketing is also considering providing condensate/diluent service to the area. Baytex does not have term transportation obligations in place with either party.

Natural Gas

Natural gas prices in North America weakened in 2008 due to a significant growth in U.S. domestic natural gas supply and, later in the year, reduced demand due to a slumping economy. In 2007, natural gas prices were negatively affected in the latter half of the year as some three Bcf/d of liquefied natural gas ("LNG") was imported during the summer months into the U.S. from foreign sources. During 2008, LNG did not enter the market in significant quantities, but this was completely offset by growth of 6% or 3.3 Bcf/d in domestic U.S. gas production. The new production came from the Rockies basin and the new shale basins in Texas and Louisiana. It is expected that demand will be lost in the coming year due to low industrial and commercial demand due to a weak economy.

During the first half of 2008, high oil prices sustained natural gas prices at levels that might have been much lower in a lower alternative energy price environment. Second half gas prices were negatively impacted as the general economic environment deteriorated, and industrial demand collapsed. U.S. gas prices peaked at US$12.96 per MMBtu in July and dipped to close the year at US$6.47 per MMBtu. U.S. natural gas inventories continue to stay within the five year average. In addition to the new supply from U.S. sources, there was little in the way of any weather related disruptions as suffered during the 2005 hurricane season. U.S. gas prices represented by the NYMEX futures contract, averaged US$9.03 per MMbtu in 2008, an increase of 32% from US$6.86 per MMbtu in 2007 – all on the back of higher crude oil prices. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $8.15 per Mcf in 2008, up 27% from $6.44 per Mcf in 2007. The five-year averages are US$7.57 per MMBtu for the NYMEX contract, and $7.27 per Mcf for Alberta daily prices. We expect gas drilling to drop off throughout North America which, along with general improvement in the continental economy, will bring the supply/demand picture into better balance by 2010.

For 2008, Baytex had entered into several physical forward sales contracts with price collars. Baytex received an average of $7.92 per Mcf for 2008 natural gas sales compared to $6.61 per Mcf in 2007, a 7% increase. Baytex entered into one natural gas collar for calendar 2009 for a volume of 4,739 Mcf/d with a floor (put price) of $7.39 per Mcf and a ceiling (call price) of $8.39 per Mcf.

OPERATIONS

Production

The Trust's average production for fiscal 2008 was 40,239 boe/d compared to 36,222 boe/d for fiscal 2007.

For the year ended December 31, 2008, light oil and NGL production increased by 39% to 7,575 bbl/d from 5,483 bbl/d for last year. The increase primarily resulted from the inclusion of full-year results from the Pembina assets acquired in June 2007 and from the acquisition of Burmis Energy Inc. in June 2008. Heavy oil production for 2008 increased by 7% to 23,530 bbl/d, as compared to 22,092 bbl/d for 2007. The increase in heavy oil production stemmed from development activities and the inclusion of full-year production from the Lindbergh assets acquired in June 2007. Natural gas production increased by 6% to average 54.8 MMcf/d for 2008 compared to 51.9 MMcf/d for 2007 due largely to the Pembina and Burmis acquisitions in June 2007 and 2008, respectively.

	Light Oil and NGL *(bbl/d)*	Heavy Oil *(bbl/d)*	Natural Gas *(MMcf/d)*	Oil Equivalent *(boe/d)*
2008				
Heavy Oil Business Unit	**–**	**23,530**	**6.7**	**24,639**
Conventional Oil and Gas Business Unit	**7,575**	**–**	**48.1**	**15,600**
Total Production[(1)]	**7,575**	**23,530**	**54.8**	**40,239**
2007				
Heavy Oil Business Unit	–	22,092	7.3	23,315
Conventional Oil and Gas Business Unit	5,483	–	44.6	12,907
Total Production	5,483	22,092	51.9	36,222

(1) Per unit calculations throughout the MD&A are based on sales volumes, which differ from production volumes due to changes in inventory balances related to heavy oil, as discussed below.

Revenue

Petroleum and natural gas sales for 2008 increased by 55% to $1,159.7 million from $745.9 million for fiscal 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 2008 were 300 bbl/d higher (2007 – 340 bbl/d higher) than the production for the period due to changes in inventory.

Benchmark WTI crude oil averaged US$99.59 per barrel for 2008, representing a 38% increase over the US$72.31 per barrel for 2007. The Trust's light oil and NGL price averaged $88.92 per barrel for 2008, representing a 36% increase over the 2007 price of $65.53 per barrel. The heavy oil price increased 46% to $65.22 per barrel in 2008 from $44.53 per barrel in 2007. Natural gas prices were 20% higher in 2008, averaging $7.92 per Mcf compared to $6.61 per Mcf during the previous year.

For 2008, light oil and NGL revenue increased 88% from the same period last year due to a 36% increase in wellhead prices and a 38% increase in sales volume. Revenue from heavy oil increased 56% due to a 46% increase in wellhead prices and a 7% increase in sales volume. Revenue from natural gas production increased 27% compared to 2007, as production increased 6% combined with a price increase of 20%.

During 2008, sulphur production averaged 48.9 tonnes per day with an average price of $381 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 company as compensation for non-performance of a drilling obligation which was reported as other income under petroleum and natural gas sales.

	2008		2007	
	$ thousands	$/Unit(1)	$ thousands	$/Unit(1)
Oil revenue				
Light oil & NGL	246,516	88.92	131,143	65.53
Heavy oil(2)	568,841	65.22	364,581	44.53
Total oil revenue	815,357	70.94	495,724	48.65
Natural gas revenue	158,845	7.92	125,235	6.61
Total oil and gas revenue	974,202	65.66	620,959	46.53
Sulphur revenue	6,820		–	
Other income	2,000		–	
Sales of heavy oil blending diluent	176,696	110.30	124,926	82.94
Total petroleum and natural gas sales	1,159,718		745,885	

(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.

Financial Instruments

The gain on financial instruments for the year ended December 31, 2008 was $59.8 million, as compared to a loss of $34.5 million in 2007. For 2008, this is comprised of $60.1 million in realized loss and $119.9 million in unrealized gain, as compared to $3.2 million in realized loss and $31.3 million in unrealized loss in 2007.

Royalties

For the year ended December 31, 2008, royalties increased to $207.5 million from $102.8 million for last year. Royalties for 2008 include $0.9 million related to the production of sulphur. Total royalties in 2008 were 21% of oil and gas revenue (excluding sales of heavy oil diluent), as compared to 17% of sales for 2007. For 2008, royalties were 23% of sales for light oil, NGL and natural gas and 20% for heavy oil (excluding sales of heavy oil diluent), as compared to 19% and 15%, respectively, for the same period in 2007. 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 year as market prices, on average, were higher than the prices realized by Baytex under fixed differential supply agreements. Heavy oil royalties also increased in 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.

Operating Expenses

Operating expenses for the year ended December 31, 2008 increased to $172.5 million from $134.7 million in 2007. Operating expenses for 2008 include $0.3 million related to the production of sulphur. Operating expenses were $11.62 per boe for 2008 as compared to $10.09 per boe for the prior year. In 2008, operating expenses were $11.68 per boe of light oil, NGL and natural gas and $11.55 per barrel of heavy oil as compared to $9.61 and $10.40, respectively, in 2007. In the case of light oil, NGL and natural gas, increased operating expense was driven primarily by increases in costs for third-party processing (including prior-period adjustments), fuel, power and labor. In the case of heavy oil, increased operating expense was due primarily to increased fluid hauling charges, and higher property taxes. Heavy oil operating expense was also negatively impacted by inclusion of higher-cost production at Lindbergh for the full year.

Transportation and Blending Expenses

Transportation and blending expenses for the year ended December 31, 2008 were $218.7 million compared to $155.8 million for 2007. Transportation expense for 2008 included $1.3 million related to the transportation of sulphur. Transportation expenses were $2.83 per boe in 2008 compared to $2.31 per boe in 2007. Transportation expenses were $0.64 per boe of light oil, NGL and natural gas and $4.22 per barrel of heavy oil in 2008, compared to $0.80 and $3.26, respectively, in 2007. The increase in transportation cost per unit was driven by increased long-haul trucking from Seal and fuel costs which increased by over 25% from 2007 to 2008. In 2008, the blending cost was $176.7 million for the purchase of 4,377 bbl/d of condensate at $110.30 per barrel, as compared to $124.9 million for the purchase of 4,127 bbl/d at $82.94 per barrel in 2007.

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 its heavy oil. The cost of diluent is effectively recovered in the sale price of a blended product.

Net Revenue

	Light Oil & NGL (*$/bbl*)		Heavy Oil (*$/bbl*)		Total Oil & NGL (*$/bbl*)		Natural Gas (*$/Mcf*)		BOE (*$/boe*)	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Sales price[(1)]	**88.92**	65.53	**65.22**	44.53	**70.94**	48.65	**7.92**	6.61	**65.66**	46.53
Royalties	**(22.97)**	(12.99)	**(12.93)**	(6.68)	**(15.35)**	(7.91)	**(1.50)**	(1.17)	**(13.92)**	(7.70)
Operating costs	**(12.38)**	(10.79)	**(11.55)**	(10.40)	**(11.75)**	(10.48)	**(1.85)**	(1.48)	**(11.60)**	(10.09)
Transportation	**(0.47)**	(0.66)	**(4.22)**	(3.26)	**(3.31)**	(2.75)	**(0.13)**	(0.15)	**(2.74)**	(2.31)
Net revenue	**53.10**	41.09	**36.52**	24.19	**40.53**	27.51	**4.44**	3.81	**37.40**	26.43

(1) Sales price is before realized loss/gain recognized on financial derivative contracts and sulphur production and is net of blending costs for heavy oil.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2008 were $29.6 million, compared to $23.6 million for the prior year. On a per sales unit basis, these expenses were $2.00 per boe in 2008 and $1.77 per boe in 2007. The increase is attributable to escalating costs in the labor market and additional expenses associated with a new office in Denver to manage the U.S. operations. In accordance with our full cost accounting policy, no expenses were capitalized in either 2008 or 2007.

($ thousands)	**2008**	2007
Gross corporate expense	**37,554**	32,132
Operator's recoveries	**(7,950)**	(8,567)
Net expenses	**29,604**	23,565

Unit-based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $7.8 million for the year ended December 31, 2008 compared to $8.0 million for 2007.

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

Interest Expense

For the year ended December 31, 2008, interest expense was $33.0 million compared to $35.2 million for last year. Interest expense was affected by a more favorable exchange rate on the U.S. dollar denominated interest expense and through lower interest on reduced bank borrowings. These factors were partially offset by accretion of the discontinued fair value hedge.

Foreign Exchange

The foreign exchange loss for the year ended December 31, 2008 was $37.7 million compared to a gain of $32.4 million in the prior year. The 2008 loss is comprised of an unrealized foreign exchange loss of $41.7 million and a realized foreign exchange gain of $4.0 million. The 2007 gain was substantially unrealized. The 2008 unrealized loss stemmed from the translation of the U.S. dollar denominated debt at 0.8166 CAD/USD at December 31, 2008 compared to 1.0120 CAD/USD at December 31, 2007. The 2007 unrealized gain was based on translation at 1.0120 CAD/USD at December 31, 2007 compared to 0.8581 CAD/USD at December 31, 2006.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion increased to $223.9 million for the year ended December 31, 2008 compared to $189.5 million for 2007. On a sales-unit basis, the provision for the current year was $15.09 per boe compared to $14.20 per boe for 2007. The higher rate is primarily due to the acquisition of Burmis in June 2008.

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. See "– Federal Government's Trust Tax Legislation." As a result, we recognized a future income tax recovery of $0.5 million in the second quarter of 2007 relating to unutilized tax pools which will be deductible to us after 2010. The majority of our temporary differences reside in a consolidated subsidiary which is not subject to the distribution tax, and is therefore not impacted by this legislative change.

Current tax expense for the year ended December 31, 2008 is comprised of $10.2 million of Saskatchewan capital tax and resource surcharge. The 2007 current tax expense included $7.2 million of Saskatchewan capital tax and resource surcharge, and a recovery of $0.5 million relating to a prior period.

The fiscal 2008 provision for future taxes was an expense of $15.4 million compared to a recovery of $49.4 million for the prior year. As at December 31, 2008, total future tax liability of $217.8 million (December 31, 2007 – $142.4 million) consisted of a $25.4 million current future tax liability (December 31, 2007 – $11.5 million current future tax asset) and a $192.4 million long-term future tax liability (December 31, 2007 – $153.9 million). The increase from the prior year is due to future tax liability recognized on the Burmis acquisition of $37.9 million and current year provision of $25.4 million attributable to the unrecognized gain on financial instruments of $119.9 million.

As a result of the Pembina/Lindbergh acquisition in 2007, Baytex recognized a future tax liability of $74.5 million arising from the difference between the $64.0 million in tax pools acquired and the value assigned to the assets.

Federal Tax Pools

($ thousands)	2008	2007
Cumulative Canadian Exploration Expense	53,047	36,872
Cumulative Canadian Development Expense	193,319	183,910
Cumulative Canadian Oil and Gas Property Expense	217,260	187,899
Undepreciated Capital Cost	249,306	217,939
Other	27,741	19,827
Total Canadian tax pools	740,673	646,447
U.S. tax pools	116,785	2,132

Net Income

Net income for the year ended December 31, 2008 was $259.9 million compared to $132.9 million for 2007. The increase is the result of increased production, increased sales prices and unrealized gain on financial instruments, partially offset by increased royalties, and increased loss on foreign exchange and depletion.

Cash Flow from Operations

Cash flow from operations in 2008 increased 52% to $433.8 million from $286.0 million for the previous year. The increase is primarily due to higher production volumes and a 38% increase in average WTI oil price in 2008 compared to 2007. On a barrel of oil equivalent basis, cash flow from operations was $29.46 per boe for 2008 compared to $21.63 per boe for 2007.

Cash Distributions

During 2008, total cash distributions of $2.64 per unit were declared. The monthly cash distribution in 2008 was increased from $0.18 per unit to $0.20 per unit in March and then to $0.25 per unit in June. Distributions were decreased in December 2008 to $0.18 per unit and in February 2009 to $0.12 per unit.

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, asset retirement expenditures, and deferred obligations. 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):

($ thousands)	2008	2007
Cash flow from operating activities	$ 471,237	$ 286,450
Change in non-cash working capital	(38,896)	(5,140)
Asset retirement expenditures	1,443	2,442
Decrease in deferred obligations	39	2,278
Cash flow from operations	$ 433,823	$ 286,030
Cash distributions	$ 197,026	$ 145,927
Payout ratio	45%	51%

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 declared, net of DRIP participation, of $197.0 million during the year 2008 were funded through cash flow from operations of $433.8 million.

The following table compares cash distributions to cash flow from operating activities and net income:

($ thousands)	2008	2007
Cash flow from operating activities	$ 471,237	$ 286,450
Cash distributions declared	197,026	145,927
Excess of cash flow from operating activities over cash distributions declared	$ 274,211	$ 140,523
Net income	$ 259,894	$ 132,860
Cash distributions declared	197,026	145,927
Excess (shortfall) of net income over cash distributions declared	$ 62,868	$ (13,067)

It is Baytex's long-term operating objective to substantially fund cash distributions and capital expenditures for exploration and development activities through cash flow from operating activities. Future production levels are highly dependant 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 December 31, 2008, Baytex had approximately $183 million in available undrawn credit facilities to fund 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 year ended December 31, 2008, the Trust's net income exceeded distributions declared by $62.9 million with net income reduced by $211.3 million of non-cash items and asset retirement expenditures. Non-cash items 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 facilities, will provide sufficient liquidity to sustain our operations in the short, medium, and long-term. Further, we believe that our counterparties currently have the financial capacities to honor outstanding obligations to us in the normal course of business and, where necessary, we have implemented enhanced credit protection with certain of these counterparties.

At December 31, 2008, total monetary debt was $533.0 million compared to $444.1 million at the end of 2007. Included in this increase is a $42.6 million unrealized foreign exchange loss related to the translation of our U.S. dollar denominated notes 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. Bank borrowings and working capital deficiency at the end of 2008 were $302.5 million compared to total credit facilities of $485.0 million.

Baytex has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The syndicated credit facilities were increased from $370.0 million to $485.0 million in June 2008. The facilities are subject to semi-annual review and are secured by a floating charge over all of Baytex's assets. The credit facilities mature on July 1, 2009, and are eligible for extension.

Baytex's credit facilities are available pursuant to an agreement with a syndicate of nine financial institutions. Of the nine syndicate members in our facilities, five are major Canadian banks which represent $275 million or 57% of the commitments under the $485 million facilities. We have had preliminary discussions with members of our lending syndicate, and have no reason to believe that the facilities will not be extended upon maturity; however, the amount of the facilities available upon extension has not yet been determined. Under the terms of our credit agreement, we may make a formal request for extension as early as April 1, 2009. A copy of our credit agreement and the first amendment agreement is accessible on the SEDAR website at www.sedar.com (filed on March 28, 2008 and September 15, 2008).

Baytex has US$179.7 million of 9.625% senior subordinated notes due July 15, 2010. These notes are unsecured and are subordinate to Baytex's bank credit facilities.

Pursuant to various agreements with Baytex's creditors, we are restricted from making distributions to Unitholders if the distribution would or could have a material adverse effect on the Trust or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities or the U.S. dollar senior subordinated notes.

The Trust believes that cash flow generated from operations, together with the existing bank facilities, will be sufficient to substantially finance current operations, distributions to the unitholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of distribution is also discretionary and the Trust has the ability to modify distribution levels should cash flow from operations be negatively impacted by a reduction in commodity prices.

Capital Expenditures

Capital expenditures during 2008 totaled $450.2 million, with $185.1 million spent on exploration and development activities, $180.5 million on corporate acquisitions and $84.6 million spent on property acquisitions (net of dispositions). For the year ended December 31, 2008, in Canada the Trust participated in the drilling of 142 (125.8 net) wells, resulting in 113 (102.1 net) oil wells, 17 (12.3 net) gas wells, 6 (5.4 net) stratigraphic test and service wells and 6 (6.0 net) dry holes compared to prior year activities of 136 (127.9 net) wells, including 103 (98.3 net) oil wells, 20 (16.8 net) gas wells, 7 (6.8 net) stratigraphic test wells and 6 (6.0 net) dry holes. In the U.S., the Trust participated in the drilling of 10 (4.5 net) wells, resulting in 9 (3.6 net) oil wells and 1 (0.9 net) dry hole.

($ thousands)	2008	2007
Land	**9,534**	7,253
Seismic	**4,947**	1,994
Drilling and completion	**132,296**	108,106
Equipment	**34,720**	26,624
Other	**3,586**	4,742
Total exploration and development	**185,083**	148,719
Corporate acquisition (net of working capital)	**180,467**	243,273
Property acquisitions	**84,826**	2,877
Property dispositions	**(194)**	(723)
Total capital expenditures	**450,182**	394,146

Off Balance Sheet Arrangements and Contractual Obligations

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 December 31, 2008, and the expected timing of funding of these obligations are noted in the table below.

($ thousands)	Total	1 year	2-3 years	4-5 years	Beyond 5 years
Accounts payable and accrued liabilities	164,279	164,279	–	–	–
Distributions payable to unitholders	17,583	17,583	–	–	–
Bank loan(1)	208,482	208,482	–	–	–
Long-term debt(2)	220,362	–	220,362	–	–
Convertible debentures(2)	10,398	–	10,398	–	–
Deferred obligations	74	46	23	5	–
Operating leases	42,732	2,776	7,112	7,887	24,957
Processing and transportation agreements	22,350	8,478	13,631	241	–
Total	686,260	401,644	251,526	8,133	24,957

(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; however, the amount of the facilities available upon extension has not yet been determined.

(2) Principal amount of instruments.

Future interest payments related to our bank loan have not been included since future debt levels and interest rates are not known at this time.

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

Unitholders' Equity

The Trust is authorized to issue an unlimited number of units. On October 18, 2004, the Trust implemented a DRIP under which Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units may be issued from treasury at 95% of the "weighted average closing price" or acquired on the market at prevailing market prices. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days.

Non-controlling Interest

Baytex 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 Baytex 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.

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 was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008 of 1.79560. As at December 31, 2008, there were no exchangeable shares outstanding.

Financial Instruments and Risk Management

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of qualified members of the Board of Directors of the Company (the "Board"), assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserves estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, the Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar senior subordinated notes. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as the Company's banking facilities are based on the lenders' prime lending rate and short-term bankers' acceptance rates.

Details of the risk management contracts in place as at December 31, 2008, and the accounting for the Trust's financial instruments are disclosed in note 16 to the consolidated financial statements. A summary of certain risk factors relating to our business is included in our Annual Information Form for the year ended December 31, 2008 under the Risk Factors section.

CRITICAL ACCOUNTING ESTIMATES

A summary of Baytex's significant accounting policies can be found in notes 1 and 2 to the consolidated financial statements. The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. The financial and operating results of the Trust incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Trust expects to recover in the future;
- estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
- estimated value of asset retirement obligations that are dependant upon estimates of future costs and timing of expenditures; and
- estimated future recoverable value of petroleum and natural gas properties and goodwill.

The Trust has hired individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008, the Trust adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 1535 "Capital Disclosures", Section 3862 "Financial

Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation". These standards were adopted prospectively.

Capital Disclosures

Effective January 1, 2008, the Trust prospectively adopted Section 1535, "Capital Disclosures" which establishes standards for disclosing information about the Trust's capital and how it is managed. It requires disclosures of the Trust's objectives, policies and processes for managing capital, the quantitative data about what the Trust regards as capital, whether the Trust has complied with any capital requirements and if it has not complied, the consequences of such non-compliance. The only effect of adopting this standard are disclosures on the Trust's capital and how it is managed and are included in note 18 to the consolidated financial statements.

Financial Instruments – Disclosures, Financial Instruments – Presentation

Effective January 1, 2008, the Trust prospectively adopted Section 3862, "Financial Instruments Disclosures" and Section 3863, "Financial Instruments Presentations." These new accounting standards replaced Section 3861, "Financial Instruments – Disclosure and Presentation." Section 3862 requires additional information regarding the significance of financial instruments for the entity's financial position and performance, and the nature, extent and management of risks arising from financial instruments to which the entity is exposed. The additional disclosures required under these standards are included in note 16 to the consolidated financial statements.

FUTURE ACCOUNTING CHANGES

In February 2008, the CICA issued Section 3064 "Goodwill and Intangible Assets", replacing Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". The new Section will be effective on January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section, however does not expect a material impact on its consolidated financial statements.

In April 2008, the CICA published the exposure draft "Adopting IFRS in Canada". The exposure draft proposes to incorporate International Financial Reporting Standards ("IFRS") into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The Trust is currently reviewing the standards to determine the potential impact on its consolidated financial statements. The Trust has appointed internal staff to lead the conversion project along with sponsorship from the senior leadership team. In addition, an external advisor has been retained to assist the Trust in scoping its conversion project. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRS. At this time, the Trust is evaluating the impact of these differences and assessing the need for amendments to existing accounting policies in order to comply with IFRS.

In January 2009, the CICA issued Section 1582 "Business Combinations", which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2009 and does not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In January 2009, the CICA issued Section 1601 "Consolidated Financial Statements" and Section 1602 "Non-controlling Interests", which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination.

These standards are effective on the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt these standards effective January 1, 2009 and does not expect the adoption will have a material impact on the results of operations or financial position.

FOURTH QUARTER 2008

The following discussion reviews the Trust's results of operations for the fourth quarter of 2008.

Production

Light oil and NGL production for the fourth quarter of 2008 decreased by 4% to 7,803 bbl/d from 8,123 bbl/d a year earlier. Heavy oil production for the fourth quarter of 2008 increased by 11% to 24,635 bbl/d from 22,196 bbl/day a year ago due to development drilling in the Seal and Lloydminster area. Natural gas production increased by 7% to 57.6 MMcf/d for the fourth quarter of 2008 as compared to 53.9 MMcf/d for the same period last year primarily due to the acquisition of Burmis in June 2008.

Revenue

Petroleum and natural gas sales decreased 15% to $199.9 million for the fourth quarter of 2008 from $233.9 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 December 31, 2008 were 345 bbl/d higher (three months ended December 31, 2007 – 1,717 bbl/d higher) than the production for the period due to changes in inventory.

Revenue from light oil and NGL for the fourth quarter of 2008 decreased 29% from the same period a year ago due to a 4% decrease in sales volume and a 26% decrease in wellhead prices. Revenue from heavy oil decreased 19% as the result of a 23% decrease in wellhead prices slightly offset by a 4% increase in sales volume. Revenue from natural gas increased 19% as the result of a 7% increase in volume and a 12% increase in wellhead prices.

During the current quarter, sulphur production averaged 69.4 tonnes per day with an average price of $131 per tonne. Sulphur revenue for the same period a year ago was not material for reporting purposes.

Royalties

Total royalties decreased to $31.7 million for the fourth quarter of 2008 from $32.5 million in 2007. Royalties for the current quarter include $0.2 million related to the production of sulphur. Total royalties for the fourth quarter of 2008 were 19% of oil and gas revenue (excluding sales of heavy oil diluent), as compared to 17% for the same period in 2007. For the fourth quarter of 2008, royalties were 23% of sales for light oil, NGL and natural gas, and 16% of sales for heavy oil (excluding sales of heavy oil diluent), as compared to 20% and 14%, 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 increase. Heavy oil royalties increased in 2008 as certain oil sands projects at Seal and Cold Lake reached payout in the third quarter, with the pre-payout royalty of 1% of gross revenue converting to a post-payout 25% net profit interest.

Operating Expenses

Operating expenses for the fourth quarter of 2008 increased to $47.4 million from $38.7 million in the corresponding quarter last year. Operating expenses for the current quarter include $0.1 million related to the production of sulphur. Operating expenses were $12.15 per boe for the fourth quarter of 2008 compared to $10.25 per boe for the fourth quarter of 2007. For the fourth quarter of 2008, operating expenses were $12.88 per boe of light oil, NGL and natural gas, and $11.59 per barrel of heavy oil as compared to $9.67 and $10.66, respectively, for the same period in 2007. In the case of light oil, NGL and natural gas, the largest single driver of the increase in unit operating expense was prior-period adjustments to third-party processing costs, which were responsible for a majority of the quarter-over-quarter increase. Other drivers of the increase were increases in labor costs, fuel, power and property taxes. In the case of heavy oil, the increase in quarter-over-quarter operating expense was due primarily to increased fluid hauling charges.

Transportation and Blending Expenses

Transportation and blending expenses for the fourth quarter of 2008 were $45.7 million compared to $43.9 million for the fourth quarter of 2007. Transportation expenses for the current quarter include $0.4 million related to the transportation of sulphur. Transportation expenses were $3.38 per boe for the fourth quarter of 2008 compared to $2.11 for the same period in 2007. Transportation expenses were $0.48 per boe of light oil, NGL and natural gas and $5.24 per barrel of heavy oil in the fourth quarter of 2008, as compared to $0.67 and $3.15, respectively, for the same period of 2007. The increase in transportation cost per unit was driven by increased long-haul trucking from Seal and higher fuel costs which, as of the fourth quarter of 2008, had yet to fully respond to the decline in benchmark prices.

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 fourth quarter of 2008, the blending cost was $32.5 million for the purchase of 4,820 bbl/d of condensate at $73.34 per barrel, as compared to 4,062 bbl/d at $96.10 per barrel for the same period last year. The cost of diluent is effectively recovered in the sale price of a blended product.

General and Administrative Expenses

General and administrative expenses for the fourth quarter of 2008 increased to $7.6 million from $6.8 million a year earlier. On a per sales unit basis, these expenses were $1.96 per boe for the fourth quarter of 2008 compared to $1.81 per boe for the same period in 2007. In accordance with our full cost accounting policy, no expenses were capitalized in either period.

Unit-based Compensation Expense

Compensation expense related to our trust unit rights incentive plan was $1.6 million for the fourth quarter of 2008 compared to $1.8 million for the fourth quarter of 2007.

Interest Expense

Interest expense for the fourth quarter of 2008 decreased to $7.9 million compared to $8.6 million in the same quarter last year. The decrease is primarily due to the decrease in prime lending rates and a reduction in the bank loan, partially offset by higher foreign exchange rates on payment of interest on the U.S. dollar denominated debt.

Foreign Exchange

Foreign exchange loss in the fourth quarter of 2008 was $24.8 million compared to a gain of $1.2 million in the fourth quarter of 2007. The 2008 amount is comprised of an unrealized foreign exchange loss of $29.0 million and a realized foreign exchange gain of $4.2 million. The gain in the 2007 period was comprised of an unrealized foreign exchange gain of $1.5 million and a realized foreign exchange loss of $0.3 million. The current quarter's unrealized loss is based on the translation of the U.S. dollar denominated debt at 0.8166 CAD/USD at December 31, 2008 compared to 0.9435 CAD/USD at September 30, 2008. The prior period gain is based on translation at 1.0120 CAD/USD at December 31, 2007 compared to 1.0037 CAD/USD at September 30, 2007.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion for the fourth quarter of 2008 increased to $61.3 million from $54.1 million for the same quarter in 2007. On a per sales unit basis, the provision for the current quarter was $15.71 per boe compared to $14.33 per boe for the same quarter in 2007. The higher rate is primarily due to the acquisition of Burmis completed in June 2008.

Taxes

Current tax of $1.7 million for the fourth quarter of 2008 is comprised primarily of Saskatchewan capital tax and resource surcharge.

For the fourth quarter of 2008, future tax expense totaled $2.2 million compared to a recovery of $27.7 million in the same period in 2007. As at December 31, 2008, total future tax liability of $217.8 million (December 31, 2007 – $142.4 million) consisted of a $25.4 million current future tax liability (December 31, 2007 – $11.5 million current future tax asset) and a $192.4 million long-term future tax liability (December 31, 2007 – $153.9 million).

Net Income

Net income for the fourth quarter of 2008 was $52.4 million compared to $41.4 million for the fourth quarter in 2007. The increase was the result of the unrealized gain on financial instruments offset by reduced petroleum and natural gas revenue, higher depletion, foreign exchange losses and future tax expense.

Trust Unit Information

As at February 28, 2009, the Trust had 98,212,328 units outstanding.

As at February 28, 2009, the Trust had $10.4 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit.

Selected Annual Information

($ thousands, except per unit amounts)	2008	2007	2006
Financial			
Petroleum and natural gas sales	**1,159,718**	745,885	687,016
Net income(1)	**259,894**	132,860	147,069
Per unit basic(1)	**2.83**	1.66	2.02
Per unit diluted(1)	**2.74**	1.60	1.91
Total assets	**1,812,333**	1,407,150	1,079,629
Total long-term financial liabilities	**227,468**	190,004	228,597
Cash distributions declared per unit	**2.64**	2.16	2.16

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

Overall production for 2008 was 40,239 boe per day which represented a 11% increase from 36,222 boe per day in 2007. Production in 2006 was 34,292 boe per day. Average wellhead prices net of blending costs received were $65.66 per boe during 2008, $46.53 per boe during 2007 and $44.48 per boe during 2006.

Quarterly Information

	2008					2007				
	TOTAL 2008	Q4	Q3	Q2	Q1	TOTAL 2007	Q4	Q3	Q2	Q1
Production										
Light oil and NGLs *(bbl/d)*	7,575	7,803	8,377	6,778	7,330	5,483	8,123	6,556	3,705	3,484
Heavy oil *(bbl/d)*	23,530	24,635	24,078	22,905	22,484	22,092	22,196	22,593	21,444	22,129
Total oil and NGLs *(bbl/d)*	31,105	32,438	32,455	29,683	29,814	27,575	30,319	29,149	25,149	25,613
Natural gas *(MMcf/d)*	54.8	57.6	60.5	51.0	50.1	51.9	53.9	53.7	49.3	50.6
Oil equivalent *(boe/d)*	40,239	42,035	42,538	38,179	38,157	36,222	39,304	38,094	33,372	34,041

	2008					2007				
	TOTAL 2008	Q4	Q3	Q2	Q1	TOTAL 2007	Q4	Q3	Q2	Q1
Average Prices										
WTI oil *(US$/bbl)*	99.59	58.35	118.36	123.98	97.90	72.31	90.68	75.38	65.03	58.27
Edmonton par oil *($/bbl)*	102.86	63.94	122.77	126.29	97.50	76.35	86.41	80.24	72.15	67.09
BTE light oil *($/bbl)*	88.92	55.31	107.41	109.26	84.91	65.53	74.77	67.82	54.42	51.08
BTE heavy oil *($/bbl)*	65.22	38.93	84.65	78.92	59.65	44.53	50.36	46.18	40.42	40.36
BTE total oil *($/bbl)*	70.94	42.83	90.56	85.82	65.66	48.65	56.55	51.08	42.50	41.82
BTE natural gas *($Mcf)*	7.92	7.05	8.01	9.29	7.42	6.61	6.31	5.80	7.02	7.43
BTE oil equivalent *($/boe)*	65.66	42.71	80.44	79.15	61.16	46.53	52.45	47.23	42.40	42.51

	2008					2007				
($ thousands, except per unit amounts)	TOTAL 2008	Q4	Q3	Q2	Q1	TOTAL 2007	Q4	Q3	Q2	Q1
Financial										
Petroleum and natural gas sales	1,159,718	199,890	363,044	332,336	264,448	745,885	233,856	193,784	156,670	161,575
Cash distributions declared per unit	2.64	0.68	0.75	0.65	0.56	2.16	0.54	0.54	0.54	0.54

Reconciliation of Net Income to Cash Flow from Operations

	2008					2007				
($ thousands, except per unit amounts)	TOTAL 2008	Q4	Q3	Q2	Q1	TOTAL 2007	Q4	Q3	Q2	Q1
Net income[1]	259,894	52,401	137,228	34,417	35,848	132,860	41,353	36,674	31,050	23,783
Items not affecting cash:										
Unit-based compensation	7,812	1,563	2,038	2,129	2,082	7,986	1,810	2,370	1,946	1,860
Unrealized foreign exchange loss (gain)	41,712	29,032	7,306	(1,636)	7,010	(32,574)	(1,526)	(12,263)	(16,495)	(2,290)
Depletion, depreciation and accretion	223,900	61,251	61,250	50,941	50,458	189,512	54,086	51,525	42,541	41,360
Accretion on debentures & notes	1,681	519	439	359	364	2,164	2,059	35	34	36
Unrealized (gain) loss on financial instruments	(119,917)	(86,511)	(89,010)	48,433	7,171	31,320	27,264	(599)	4,005	650
Future tax expense (recovery)	15,383	2,217	25,962	(10,318)	(2,478)	(49,369)	(27,659)	(3,895)	(11,307)	(6,508)
Non-controlling interest	3,358	0	1,373	870	1,115	4,131	1,280	1,110	981	760
Cash flow from operations[2]	433,823	60,472	146,586	125,195	101,570	286,030	98,667	74,957	52,755	59,651
Change in non-cash working capital	38,896	38,667	4,591	(24,141)	19,779	5,140	3,145	(308)	956	1,347
Asset retirement expenditures	(1,443)	(725)	(351)	27	(394)	(2,442)	(1,131)	(351)	(257)	(703)
Decrease in deferred obligations	(39)	(7)	(11)	(11)	(10)	(2,278)	(550)	(576)	(576)	(576)
Cash flow from operating activities	471,237	98,407	150,815	101,070	120,945	286,450	100,131	73,722	52,878	59,719
Net income per unit[1]										
Basic	2.83	0.54	1.44	0.39	0.42	1.66	0.49	0.44	0.41	0.32
Diluted	2.74	0.53	1.39	0.38	0.41	1.60	0.48	0.43	0.39	0.30
Cash flow from operations per unit[2]										
Basic	4.73	0.62	1.53	1.42	1.19	3.57	1.17	0.90	0.69	0.79
Diluted	4.51	0.61	1.47	1.33	1.12	3.54	1.10	0.84	0.65	0.74
Cash flow from operating activities per unit										
Basic	5.14	1.01	1.58	1.14	1.42	3.58	1.19	0.88	0.69	0.79
Diluted	4.89	0.99	1.51	1.07	1.33	3.33	1.11	0.83	0.64	0.74

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

(2) 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 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, asset retirement expenditures and decrease in deferred obligations. 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 it 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.

2009 Guidance

Baytex has set a 2009 exploration and development capital budget of $150 million designed to generate production levels at an annual average of 40,000 boe/d. Sixty percent of this budget has been allocated to our heavy oil operations, with the planned drilling of 60 gross wells, including 10 primary horizontal producers in our Seal area in the Peace River oil sands region. The remainder of this budget has been allocated to our conventional oil and gas operations, including the drilling of 18 gross wells. Our 2009 production mix is forecast to be approximately 60% heavy oil, 18% light oil and NGL and 22% natural gas. In addition to the exploration and development capital budget, we expect to incur an additional $10 million for deferred acquisition payments on our North Dakota light oil resource play.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Baytex has entered into the following contracts to provide downside protection to 2009 cash flow while allowing for participation in a high commodity price environment. Baytex will continue to monitor market developments and may enter into additional similar contracts if deemed desirable.

Financial Derivative Contracts

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2009	2,000 bbl/d	USD 90.00 – $136.40	WTI
Price collar	Calendar 2009	2,000 bbl/d	USD 110.00 – $172.70	WTI

GAS

	Period	Volume	Price	Index
Price collar	April 1, 2009 to December 31, 2010	5,000 GJ/d	CAD 5.00 – CAD 6.30	AECO 7A

Foreign Currency

	Period	Amount	Rate
Swap	January 1, 2009 to December 31, 2009	USD 8.3 million per month	CAD/USD 1.2394 (weighted average)
Swap	January 1, 2009 to December 31, 2009	USD 1.7 million per month	CAD/USD 1.2345

Physical Sale Contracts

HEAVY OIL

	Period	Volume	Price
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI x 67.0% (weighted average)
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI × 80.0%
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI less US$10.00

GAS

	Period	Volume	Price
Price Collar	Calendar 2009	5,000 GJ/d	CAD 7.00 – CAD 7.95

POWER

	Period	Volume	Price
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
Fixed	March 1, 2009 to June 30, 2010	0.6 mw/hr	$76.89

Gain or loss on financial derivative contracts comprise realized and unrealized gains or losses on financial instruments that do not meet the accounting definition requirements of an effective hedge, even though the Trust considers all financial derivative contracts to be effective economic hedges. Accordingly, gains and losses on such contracts are shown as a separate category in the statement of income.

Strong commodity prices throughout most of 2008 had a significant impact on the Trust's revenue; however, these strong prices resulted in realized cash losses of $51.4 million for the Trust's oil and natural gas financial derivative contracts. During 2008, the Trust recorded a $8.7 million realized loss on foreign exchange financial derivative contracts due to the strengthening of the U.S. dollar during the year.

The 2008 results of the Trust include an unrealized mark-to-market gain of $119.9 million with a net unrealized mark-to-market asset gain position of $85.7 million. The mark-to-market values represent the market price to buy-out the Trust's contracts as of December 31, 2008 and may be different from what will eventually be realized.

The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. See note 16 to the consolidated financial statements for a more detailed description of accounting treatment of these derivative contracts.

Environmental Regulation and Risk

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of Baytex.

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION and which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects the Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance of the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

The Federal Government and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on Baytex and our operations and financial condition.

Further information regarding environmental regulation is contained in our Annual Information Form for the year ended December 31, 2008 under the Industry Conditions Section.

The New Royalty Framework

On October 25, 2007, the Alberta government announced the "New Royalty Framework" ("NRF"), which introduced the following changes to Alberta's royalty regime effective January 1, 2009:

- Conventional oil – overall royalty rates increased from the pre-NRF maximum of 30% and 35% for old and new tiers. The NRF rates vary on a sliding scale basis up to 50%, and rate caps have been raised to $120 per barrel for West Texas Intermediate (WTI) crude.
- Natural gas – the Government eliminated "old" and "new" tiers. Royalty rates, pre-NRF at 5% to 35% increased to 5% to 50%, based on a sliding rate formula sensitive to price and production volume, with rate caps at $16.59/GJ.
- Oil Sands – before NRF, the pre-payout royalty rate was 1%. Under the NRF, this rate increased for prices above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher. Under the previous regime, once an oil sands project reached payout, the 1% royalty converted to a 25% net profits interest. Under the NRF, the net profits interest applies at the rate of 25% when oil is less than $55 per bbl of WTI, and increases for every dollar oil is priced above $55 per barrel to a maximum of 40% when oil is priced at $120 or higher.

On November 19, 2008, the Alberta Government announced transitional amendments to the NRF for certain types of drilling. In general terms, operators will have a one-time option of selecting either the transitional royalty regime or the NRF when drilling a new natural gas or conventional oil well 1,000 to 3,500 metres in depth. The transitional regime effectively caps royalty rates at 30% for those wells which qualify, and reduces the commodity prices and production rates at which the top 50% royalty rate kicks in for oil wells. All wells drilled between 2009 and 2013 that adopt the transitional rates will be required to shift to the NRF on January 1, 2014. The transitional regime is not applicable to oil sands projects or to wells producing before January 1, 2009.

On March 3, 2009, the Alberta Government announced a new well incentive program intended to stimulate conventional drilling activity. The incentive program offers a one-year royalty credit for conventional oil and gas wells of $200 per metre drilled with the maximum benefit of the incentive accruing to smaller companies. The program also provides for a maximum 5% royalty for all new wells that begin producing conventional oil and gas between April 1, 2009 and March 31, 2010.

Further information regarding NRF is contained in our Annual Information Form for the year ended December 31, 2008 under the Industry Conditions Section.

Broad-based Federal Tax Reductions

On October 30, 2007 the Federal Government presented the fall economic statement that proposed significant reductions in corporate income tax rates from 22.1% to 15%. The reductions will be phased in between 2008 and 2012. In addition, the Government announced that it plans to collaborate with the provinces and territories to reach a 25% combined federal-provincial-territorial statutory corporate income tax rate. The reduction in the federal rate will also reduce the SIFT tax rate to 28% as compared to the rate of 31.5% previously announced subject to comments below concerning the provincial SIFT tax proposal.

Federal Government's Trust Tax Legislation

In 2007, the Federal Government introduced and passed into law amendments to the Income Tax Act (Canada) that will result in the taxation of distributions by certain specified investment flow-through trust entities (a "SIFT"), such as Baytex, commencing January 1, 2011 (provided the SIFT only experiences "normal growth" and no "undue expansion" before then) (the "**SIFT Rules**"). Subject to the Provincial SIFT Tax Proposal described below, the SIFT Rules currently provide that the tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011 and 15% in 2012) plus the provincial SIFT tax factor (which is set at a fixed rate of 13%), for a combined tax rate of 29.5% in 2011 and 28% in 2012.

Generally, there will be a transition period for an existing SIFT and the tax under the SIFT Rules will not apply until January 1, 2011. However, the SIFT Rules provide that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the “normal growth” of a trust existing on October 31, 2006 is exceeded. “Normal growth” includes equity growth within certain “safe harbour” limits, measured by reference to a specified investment flow-through trust’s market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of its issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007 and 20 percent each for calendar 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. For us, the growth limits are approximately $730 million for 2006/2007 and an additional approximately $365 million for each of 2008, 2009 and 2010 with any unused amount carrying forward to the next year. We did not issue equity in excess of the safe harbour limits during 2006/2007 or 2008. As at December 31, 2008, we had unused safe harbour limit of $596.6 million that was carried forward, resulting in a safe harbour limit of $961.6 million for 2009.

On December 20, 2007, the Minister of Finance announced technical amendments to provide some clarification to the SIFT Rules. As part of the announcement, the Minister of Finance indicated that the Federal Government intends to provide legislation in 2008 to permit income trusts to convert to taxable Canadian corporations without any undue tax consequence to investors or the trusts.

On February 26, 2008, the Minister of Finance announced (the “**Provincial SIFT Tax Proposal**”) that instead of basing the provincial component of the SIFT tax on a flat rate of 13%, the provincial component will be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, our taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of our taxable distributions for the year that our wages and salaries in the province are of our total wages and salaries in Canada; and
- that proportion of our taxable distributions for the year that our gross revenues in the province are of our total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal, we would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%, which will result in an effective tax rate of 26.5% in 2011 and 25% in 2012. Taxable distributions that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

In 2008, the Federal Government also introduced draft tax legislation to facilitate the conversion of existing income trusts into corporations on a tax deferred basis and to accelerate the recognition of the “safe harbor” limit. Neither this draft tax legislation nor the Provincial SIFT Tax Proposal was enacted prior to prorogation of parliament in December 31, 2008. Therefore, all bills containing the draft legislation had lapsed as of that date.

Subsequent to the year end, the Federal Government introduced draft tax legislation which included the above mentioned measures as part of Canada’s Economic Action Plan. This legislation received Royal assent on March 12, 2009, and was therefore was passed into law. We 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 we will operate post 2010.

Notwithstanding the SIFT Rules, cash flow earned by a trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

Disclosure Controls and Procedures

As of December 31, 2008, an internal evaluation was conducted of the effectiveness of the Trust’s “disclosure controls and procedures” (as defined in the United States by Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”) and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”)). Based on that evaluation, the President and Chief

Executive Officer and the Chief Financial Officer concluded that the Trust's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust files or submits under the Exchange Act or under Canadian securities legislation is recorded, processed, summarized and reported, within the time periods specified in the rules and forms therein and accumulated and communicated to the Trust's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Trust's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Internal Control over Financial Reporting

"Internal control over financial reporting" (as defined in the United states by Rule 13a-15(f) and 15d-15(f) under the Exchange Act and in Canada by NI 52-109) is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely financial information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. Management has assessed the effectiveness of the Trust's internal control over financial reporting. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Trust's internal control over financial reporting was effective as of December 31, 2008. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2008 has been audited by Deloitte & Touche LLP, as reflected in their report for 2008.

No changes were made to our internal control over financial reporting during the year ended December 31, 2008, that have 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 ability to maintain production levels by investing approximately half of our internally generated cash flow; our ability to grow our reserve base and add to production levels through exploration and development activities complimented by strategic acquisitions; development plans for our properties; our heavy oil resource play at Seal, including our assessment of the viability and economics of a commercial-scale cyclic steam injection project, the timing for completion of a commercial-scale cyclic steam injection project, the ability to recover incremental reserves using waterflood and cyclic steam recovery methods, operating costs and the resource potential of our undeveloped land; our light oil resource play in North Dakota, including our assessment of the number of wells to be drilled, initial production rates and average recoveries per well; oil and gas prices and differentials between light, medium and heavy oil prices; the demand for and supply of crude oil and natural gas; the level of natural gas drilling activity in North America; the sufficiency of our capital resources to meet our ongoing short, medium and long-term commitments; 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; funding sources for our cash distributions and capital program; the timing of funding our financial obligations; the impact of the adoption of new accounting standards on our financial results; our production levels for 2009, including our product mix; our exploration and development capital program for 2009; the timing and allocation of our exploration and development expenditures; the timing and amount of deferred acquisition payments for the North Dakota acquisition; the impact of new environmental regulation; potential changes to our business form; and the taxation of income trusts. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.*

These forward-looking statements are based on certain key assumptions regarding, among other things: 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, 2008, 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.

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.