Bonterra
Energy Corp.
Growth
Performance
Sustainability
ANNUAL REPORT 2011
The Value of Bonterra

Bonterra Energy Corp. is a high-yield, dividend paying oil and gas company headquartered in Calgary, Alberta, Canada with a proven history of creating growth and long-term value for shareholders on a per share basis. Bonterra has paid a monthly dividend (distribution) since inception and intends to pay approximately 50 to 65 percent of funds flow to investors. Bonterra's successful performance is due to its experienced management team, conservative capital structure and sustainable pace of development.

The company's asset base consists of concentrated, stable and underdeveloped properties located across western Canada with large amounts of remaining oil still in place, a long reserve life and low-risk drilling locations. Bonterra is the third largest operator in the Pembina Cardium, the largest reservoir in Canada and the company's operations are currently focused on creating value through the execution of its Cardium horizontal drill program and efficient operating practices.

Bonterra's shares trade on the Toronto Stock Exchange under the symbol BNE.

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Growth

Bonterra's track record of production, reserves and dividend growth on both a total and per share basis remains unparalleled in the Canadian energy industry. Bonterra's successful horizontal Cardium drill program is driving growth and the company will continue to pursue the development of its opportunities in both the main Pembina Cardium pool and in the halo area of the Pembina and Willesden Green fields. Bonterra will maintain its focus on providing superior growth to shareholders balanced by conservative financial management.

6,322 BOE PER DAY PRODUCED IN 2011

9% INCREASE IN PRODUCTION PER SHARE

41.2 MBOE OF P+P RESERVES

2% INCREASE IN P+P RESERVES PER SHARE

$3.04 PER SHARE PAID OUT IN 2011

22% INCREASE IN DIVIDENDS PER SHARE

Performance

Bonterra's business strategy is to provide income to shareholders on a monthly basis in the form of a monthly dividend and to generate above average returns for shareholders over time through the internal development and expansion of its high quality asset base. The company's conservative capital structure, large drilling inventory and above industry average results with its horizontal drilling program positions the company well to continue to provide superior value to its shareholders.

180% THREE YEAR RETURN TO SHAREHOLDERS

$1.04 BILLION MARKET CAP

$102 MILLION FUNDS FLOW

58% PAYOUT RATIO

$402 MILLION IN TAX POOLS

2016 TAX HORIZON

Sustainability

Bonterra's operations are characterized by a long reserve life index and low risk, predictable returns. The company focuses on the sustainable development of its asset base through a steady pace of development and efficient operating practices. Bonterra's implementation of new drilling and completion methods have decreased costs and improved well performance and reserve recovery. The company will continue to execute its disciplined approach to operations in 2012 to maximize shareholder returns on a long-term basis.

14 YEAR DRILLING INVENTORY

100% DRILLING SUCCESS RATE IN 2011

16.9 YEAR RLI (P+P)

74% OF P+P RESERVES WEIGHTED TO CRUDE OIL/LIQUIDS

$65 MILLION 2012 CAPITAL PROGRAM

33 GROSS HORIZONTAL WELLS PLANNED

Quarterly Highlights

2011	Q4	Q3	Q2	Q1
As at and for the periods ended ($000s, except $ per share)				
FINANCIAL				
Revenue – realized oil and gas sales	42,818	36,535	44,754	38,170
Funds flow [3]	26,001	20,815	27,906	27,266
Per share – basic	1.34	1.08	1.44	1.42
Per share – diluted	1.32	1.06	1.42	1.39
Payout ratio [4]	58%	72%	54%	51%
Cash flow from operations	26,180	21,730	25,465	24,034
Per share – basic	1.35	1.12	1.32	1.25
Per share – diluted	1.33	1.10	1.29	1.22
Cash dividends per share [4]	0.78	0.78	0.78	0.72
Payout ratio [4]	58%	69%	59%	58%
Net earnings	6,067	9,384	14,533	13,624
Per share – basic	0.31	0.49	0.75	0.71
Per share – diluted	0.31	0.48	0.74	0.69
Capital expenditures and acquisitions, net of disposals	20,529	15,941	5,872	20,344
Total assets	364,176	354,549	348,097	357,000
Working capital deficiency	51,576	43,362	30,823	39,777
Long-term debt	69,916	72,391	72,608	70,568
Shareholders' equity	181,640	185,908	192,297	192,054
OPERATIONS				
Oil (barrels per day)	4,096	3,789	4,164	4,258
NGLs (barrels per day)	493	340	372	338
Natural gas (MCF per day)	12,541	10,553	11,024	10,517
Total BOE per day [6]	6,679	5,887	6,373	6,350

(3) Funds flow is not a recognized measure under IFRS. For these purposes, the Company defines funds flow as funds provided by operations including proceeds from sale of investments and investment income received excluding the effects of changes in non-cash working capital items, restricted cash, investment tax credit receivable and decommissioning expenditures settled.
(4) Cash payments per share are based on payments made in respect of production months within the quarter.
(5) At December 31, 2010, long-term debt includes bank debt and subordinated promissory note.
(6) BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

RECORD CASH FLOW
in 2011 increased 47%
YEAR OVER YEAR.

Production increase of 13%
IN Q4 2011 OVER Q3 2011.

Report to Shareholders

Bonterra Energy Corp. (Bonterra) is pleased to announce its operational and financial results for the year ended December 31, 2011. During the year, Bonterra continued to focus on providing long-term returns to shareholders through the sustainable development of its Cardium horizontal drill program and a disciplined approach to financial management. The year 2011 was characterized by great success across the organization. Revenue, cash flow, dividends, net earnings, production and reserves all increased year over year and the Company continued to balance its business model with growth on both a total and per share basis and income through its monthly dividend to shareholders.

2011 BUILDING LONG-TERM SHAREHOLDER VALUE

Bonterra has been successful in offering above average results and returns to its investors.

It is a long-term focus that has defined Bonterra's ongoing strategy. The company has continued to focus on paying dividends to its investors, maintaining a strong balance sheet and exhibiting spending discipline across all business cycles while the efficient management of its high-quality, low-risk asset base provides sustainability to the company. With this approach, Bonterra has been successful in offering above average results and returns to its investors.

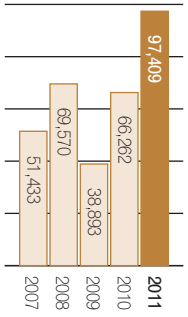
The Cardium horizontal drill program has provided a strong foundation for increased shareholder value and the company has continued to evolve as a top-tier growth and income investment in the Canadian oil and gas sector. In late 2008, Bonterra drilled the first horizontal Cardium well in the halo area of the Pembina field. It was a challenging time with lower commodity prices, the beginning of worldwide economic problems and the subsequent credit crisis. Bonterra was paying a dividend of $0.12 per share and the company had a market capitalization of approximately $318 million at the beginning of 2009.

Despite the difficult economic and business climate, Bonterra aggressively pursued the development of its large Cardium drilling inventory. To date, the company has drilled 54 gross (45.6 net) operated horizontal Cardium wells and 7 gross (1.61 net) non-operated horizontal Cardium wells with a 100 percent success rate and has recorded its best production results to date this year.

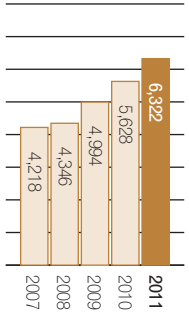
2011 operational highlights include:

- A capital program of $63 million comprised of 20 gross (16.3 net) operated Cardium horizontal wells drilled in the halo areas of the Pembina and Willesden Green fields, 4 gross (0.86 net) non-operated Cardium horizontal wells in the main Pembina pool and 1 gross (0.13 net) non-operated horizontal well in southeast Saskatchewan.

CASH FLOW FROM OPERATIONS
($ thousands)



AVERAGE DAILY PRODUCTION
(BOE per day)



- New production records set with average daily production of 6,322 barrels of oil equivalent (BOE) per day (approximately 71 percent oil and liquids) for full year 2011 and 6,679 BOE per day in the fourth quarter, an increase of 12.3 percent and 9.9 percent, respectively over the same periods in 2010.
- Production per share increased to 0.119 BOE per share, an increase of 9.2 percent over 2010.
- Proved plus Probable (P+P) reserves of 41.2 million BOE (approximately 74 percent oil and liquids), a 4.6 percent increase over December 2010 reserves of 39.4 million BOE.
- Added a total of 4.1 million BOE of P+P reserves which equates to 1.75 times 2011 production.
- Reserves per share (P+P) increased two percent to 2.13 BOE per share compared to the prior year.
- Conservative reserve booking with 50 percent of reserves assigned being Proved Developed Producing or Proved Developed Non-Producing and over 68 percent being Total Proved.
- Reserve life index of 16.9 years on a P+P basis and 12.9 years on a proved basis continues to remain above industry average.

The successful results of the ongoing Cardium development drilling coupled with improved oil pricing have led to strong shareholder returns since the horizontal program was implemented. Bonterra increased dividends to shareholders during 2011 to the current level of $0.26 per share per month. The company paid out a total of $3.04 per share in dividends during the year, a 22 percent increase over 2010. The market capitalization is over $1 billion and the company's three year return to shareholder's (2009 – 2011) was 179.9 percent, demonstrating Bonterra's commitment and success in providing investors with strong returns over time.

SUSTAINABLE DEVELOPMENT AND EVOLVED STRATEGY

The year 2011 saw a marked increase in industry activity within the main Pembina pool with expanded horizontal infill drilling programs by a number of Bonterra's peers. Positive results to date suggest that a significant recoverable resource remains.

Bonterra's strategy for exploiting the main Pembina Cardium pool by horizontal drilling has now replaced the company's previous exploitation strategy of drilling vertical infill wells. As such, Bonterra intends to focus the majority of its $65 million 2012 capital program on executing a targeted multi-well horizontal drilling program in the main Pembina Cardium pool. Current drilling plans include 33 gross (23.83 net) wells to be drilled with 21 gross (13.33 net) wells to be drilled in the main Pembina Cardium pool and 11 gross (9.5 net) wells to be drilled in the halo area of the Pembina Cardium and Willesden Green fields. The drilling program is expected to increase full year average daily production in 2012 to between 6,700 to 7,000 BOE per day.

Bonterra intends to focus the majority of its $65 million 2012 capital program on executing a targeted multi-well horizontal drilling program in the main Pembina Cardium pool.

Bonterra generated record cash flow from operations of $97.4 million ($5.04 per share) and record funds flow of $101.9 million, a 47 percent and 37 percent increase over 2010 levels, respectively.

To ensure sustainability, Bonterra continues to look at developing new long-term and low-risk opportunities. The Company plans to drill at least one new oil play using horizontal technology in 2012 and will continue to assess land, asset and corporate acquisitions. Bonterra will consider counter-cyclical natural gas acquisitions as its 14 year drilling inventory of mainly light oil targets will allow the company to inventory gas plays and drill them when natural gas prices recover.

FINANCIAL PERFORMANCE AND STRENGTH

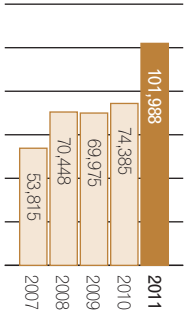
Financial results in 2011 were positively impacted by the company's record production levels and strong crude oil prices. Bonterra generated record cash flow from operations of $97.4 million ($5.04 per share) and record funds flow of $101.9 million, a 47 percent and 37 percent increase over 2010 levels, respectively.

The company's average oil price per barrel increased 24 percent over 2010 levels to $92.76 while natural gas liquids pricing increased to $60.89 per barrel, a 29 percent increase year over year. Natural gas prices continued to weaken and decreased seven percent in 2011 compared with 2010 and averaged $3.86 per MCF. The continued strength in crude oil pricing is positive for the company as 71 percent of production is comprised of light oil and liquids. This premium quality production results in higher netbacks and cash flow. In addition, tax pools of $402 million, investment tax credits of $27.7 million and $137.5 million of capital loss carry forwards (which can only be claimed against taxable capital gains) pushes the corporate tax horizon past 2016 which will allow Bonterra to continue paying out between 50 and 65 percent of cash flow to shareholders as a monthly dividend.

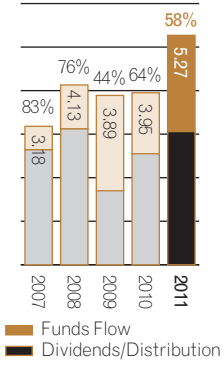
Bonterra does not have any commodity hedges in place and therefore fully benefits from the strong oil prices which are currently exceeding $100 per barrel. However, recently the differential between West Texas Intermediate (WTI) and the Edmonton Price (Edmonton Par) is in the $15 to $20 range and this results in reduced revenue. Normally the differential has been in the $5 range. As near-term development continues to focus on high-netback light oil opportunities, management and the Board will continue to assess the dividend levels in relation to anticipated production levels and commodity prices. The Board will consider increasing dividends during 2012 should crude oil pricing remain strong and should production continue to grow.

Bonterra conservatively manages its capital structure and has rarely accessed the equity markets to finance its growth objectives. Its ability to continue offering per share growth is unparalleled within its peer group in the junior and intermediate Canadian oil and gas sector. Bonterra ended 2011 with a net debt to 2011 cash flow from operations ratio of 1.25 times resulting in the company being well-funded to execute its 2012 capital program and fund potential acquisition opportunities.

FUNDS FLOW
($ thousands)



CASH DIVIDENDS/ DISTRIBUTIONS to INVESTORS
($ per unit/share)



OUTLOOK

Bonterra's focus on growing production, building reserves and creating shareholder value is unwavering. Its strong portfolio of conventional resource plays in the Cardium, technical expertise in horizontal drilling, multi-stage fracturing and operating experience provides the company with the ability to have success in the future.

The company will continue to focus on maximizing shareholder returns through the allocation of capital to its high return Pembina Cardium horizontal drilling program, the active pursuit of improved reserve recovery within the main Pembina Cardium pool and continued improvements in ongoing operations. Bonterra's proven management team and committed employees will execute its 2012 capital development program with discipline to meet its production guidance, manage its operations safely and efficiently and endeavor to maximize shareholder value.

Taking this approach will allow Bonterra to maintain its dividend policy that provides substantial income that is paid on a monthly basis while still retaining sufficient funds flow to ensure the long-term sustainability of its future growth.

Management would like to take this opportunity to thank the Board of Directors for its reliable counsel and investors for their continued support. Bonterra is well-positioned with the capacity to continue delivering strong returns to shareholders and looks forward to capitalizing on its many opportunities in 2012.

Submitted on behalf of the Board of Directors,

George F. Fink

Chief Executive Officer and
Chairman of the Board

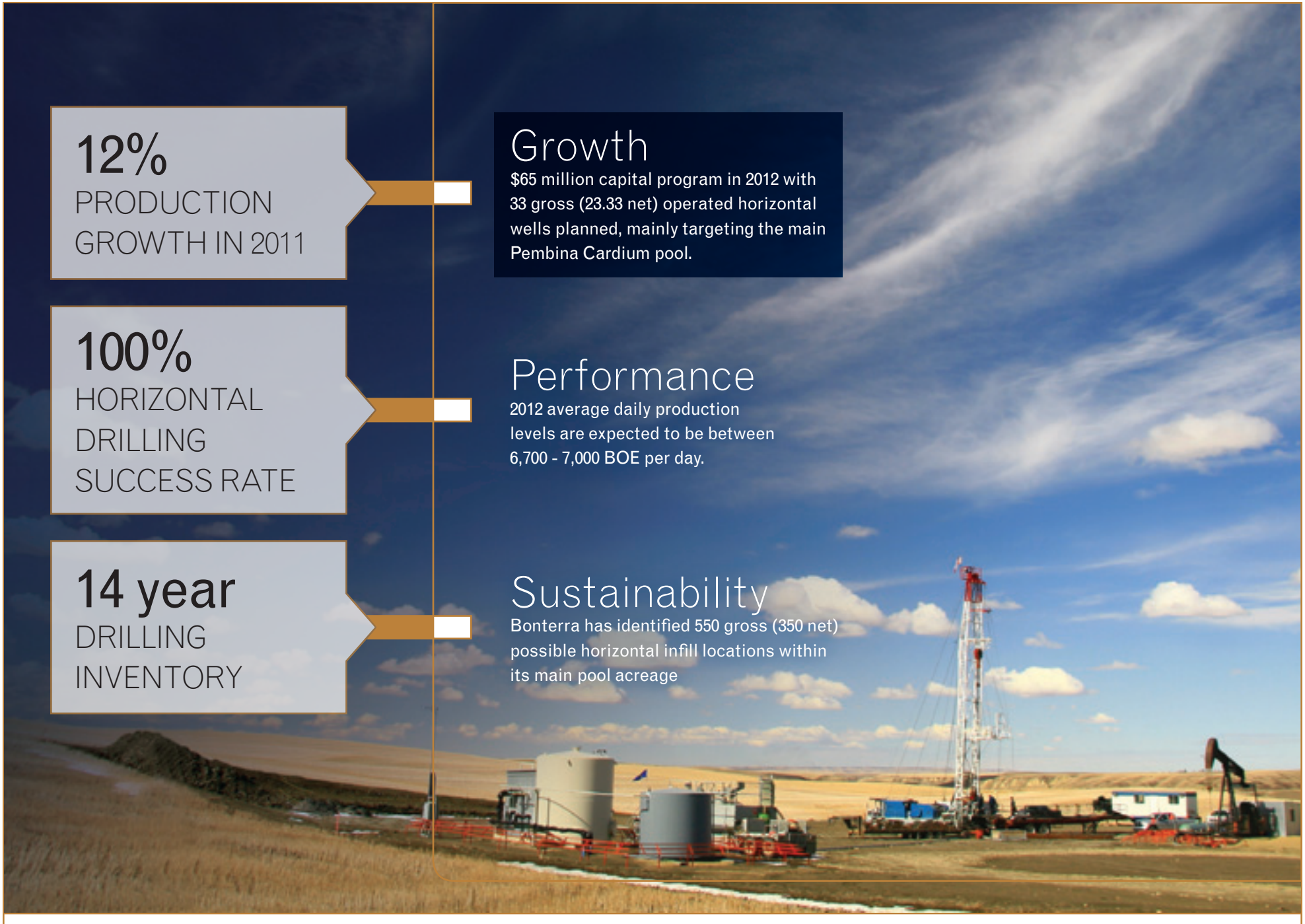
March 22, 2012

Randy Jarock

President and
Chief Operating Officer

March 22, 2012

Bonterra's proven management team and committed employees will execute its 2012 capital development program with discipline to meet its production guidance, manage its operations safely and efficiently and endeavor to maximize shareholder value.



12%
PRODUCTION GROWTH IN 2011

Growth

$65 million capital program in 2012 with 33 gross (23.33 net) operated horizontal wells planned, mainly targeting the main Pembina Cardium pool.

100%
HORIZONTAL DRILLING SUCCESS RATE

Performance

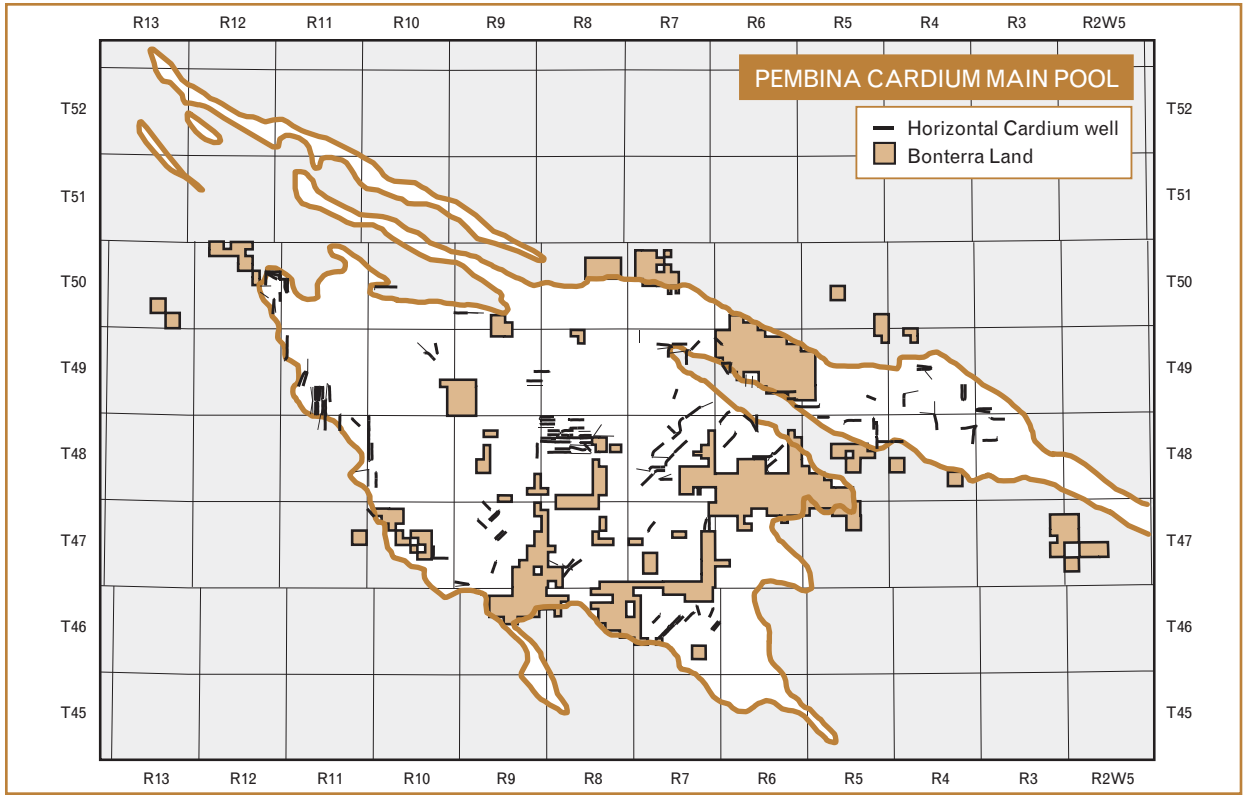
2012 average daily production levels are expected to be between 6,700 - 7,000 BOE per day.

14 year
DRILLING INVENTORY

Sustainability

Bonterra has identified 550 gross (350 net) possible horizontal infill locations within its main pool acreage

Pembina Cardium Horizontal Drilling – Main Pool Development



The Pembina Cardium Pool is the largest conventional oilfield in Canada with more than 9.3 billion barrels of original oil in place. Despite being on production since the early 1950's, only 13.7 percent of the original oil in place has been produced. The pool is characterized by long-term stable production, high quality oil and high netbacks. Bonterra is the third largest operator in the Pembina Cardium field and holds approximately 161 gross (118 net) sections of land.

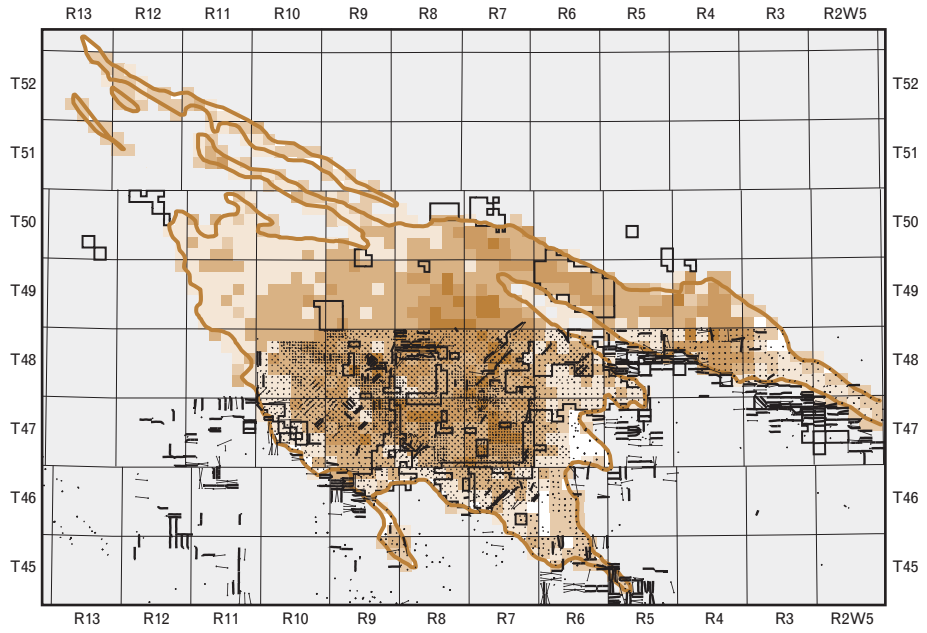
The enormous resource potential and strong economics of the Pembina Cardium pool provides Bonterra with a strong platform for future growth. Since 2009, over 160 horizontal wells have been drilled by Bonterra and its peers in the main producing field. Well performance to date within the main pool is very encouraging and signals that additional recovery can be realized. The application of multi-stage fractured horizontal well technology is revitalizing this 60 year old legacy asset.

The recent offset horizontal development by peer companies has helped to de-risk a large portion of Bonterra's acreage in the main Pembina pool. The table at left shows the average six-month production history on all main pool horizontal wells. Results to date are extremely positive for continued development. Additionally, there is a wealth of geologic and engineering data available in the legacy asset to facilitate the targeting of sweet spots and identify areas amenable to horizontal development.

Bonterra has drilled two 100 percent wells in Township 46 Range 9 W5M in the first quarter of 2012. These wells will be completed as soon as spring break-up ends.

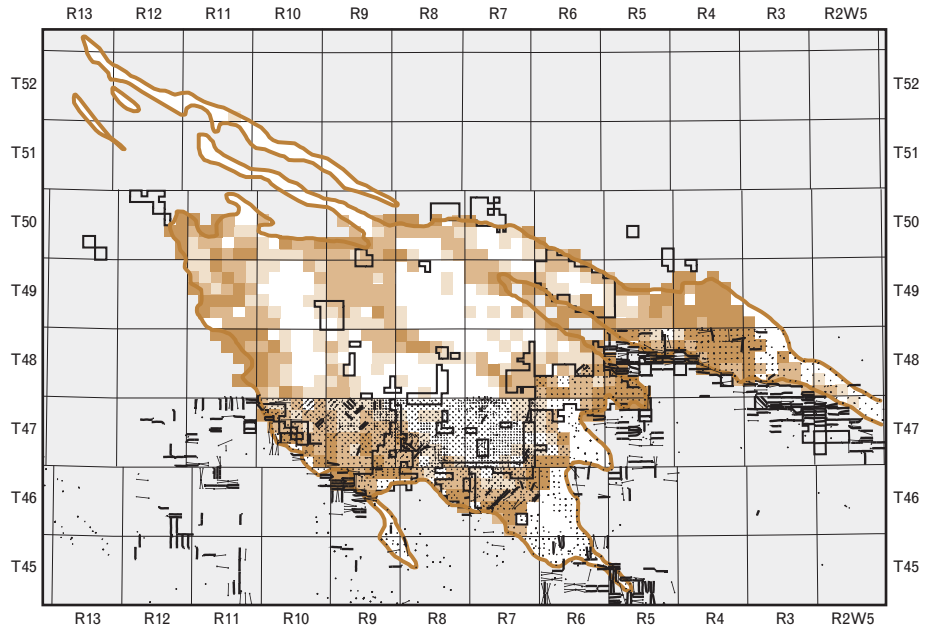
PRODUCTION RESULTS

Production Month	Number of wells	Calendar Day Average Oil (Bbl)	Calendar Day Average Gas (Mcf)	Calendar Day Average (BOE)	Producing Day Average Oil (Bbl)	Producing Day Average Gas (Mcf)	Producing Day Average (BOE)
1	138	68.9	65.0	79.7	175.2	147.5	199.8
2	131	123.0	135.9	145.6	144.7	154.3	170.4
3	123	107.4	155.6	133.3	116.8	162.7	143.9
4	113	95.0	141.7	118.6	104.0	150.8	129.2
5	108	82.9	128.6	104.3	87.8	136.4	110.6
6	103	75.4	123.5	96.0	79.2	131.3	101.1



As indicated in the map above left (Original Oil In Place), there is significant accumulations of oil present on Bonterra's main pool lands. Bonterra has identified 550 gross (350 net) possible horizontal infill locations within its acreage in the main pool and 77 gross (47.6 net) horizontal PUDS are reflected in Bonterra's 2011 reserve report constituting a three-year drilling program.

Recovery factors to date are varied across the pool as indicated by the map above right (Current Recovery Factor), however, they are generally lower on a majority of Bonterra owned lands. Recovery factors relate to reservoir quality, conglomerate occurrence, drilling density and secondary recovery schemes.



As shown in the above map (High Amounts of Original Oil In Place with Low Recovery Factor), much of Bonterra's land is under-developed (indicated by low recovery factor levels) and is amenable to multi-staged fractured horizontal well development. The company is targeting these areas with greater original oil in place coupled with lower recovery factors to capitalize on significant development upside leading to increased incremental value.

AVERAGE WELL ECONOMICS (1)

CapEx:	$2.7 million (avg.)	10% NPV BT:	$4.2 million
30 Day Initial Production:	250 BOE per day	Rate of Return	136 percent
First Year Ave. Production:	121 BOE per day	Payout:	9.6 months
Reserves	175 MBOE		

(1) Based on Sproule Jan. 31, 2012 price forecast: Oil - $96.87 per barrel; Natural gas - $3.16 per MCF and NGLs - $70.07 per barrel; based on all Bonterra horizontal Cardium wells drilled to date.

Bonterra's average well economics have led to high returns and quick payouts. Bonterra expects similar results in the main pool. Bonterra continues to look at additional methods to improve recovery. The company has

Statistical Review

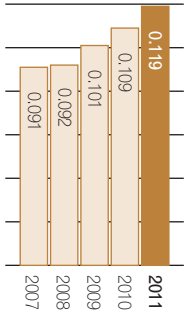
CORPORATE RESERVES INFORMATION:

Bonterra engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of December 31, 2011. The reserves are located in the provinces of Alberta, British Columbia and Saskatchewan. Bonterra's largest producing area is located in the Pembina and Willesden Green fields of Alberta which contains 93.6 percent of the Company's reserves on a Proved plus Probable basis. The gross reserve figures from the following tables represent Bonterra's ownership interest before royalties and before consideration of the Company's royalty interests. Tables may not add due to rounding.

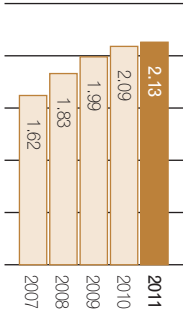
SUMMARY OF GROSS OIL AND GAS RESERVES AS OF DECEMBER 31, 2011

RESERVE CATEGORY:	Light and Medium Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	BOE[(1)] (MBOE)
PROVED				
Developed Producing	13,949.8	29,478	1,162.4	20,025.2
Developed Non-Producing	98.8	2,426	52.1	555.2
Undeveloped	5,484.0	9,918	413.1	7,550.1
TOTAL PROVED	19,532.5	41,822	1,627.6	28,130.4
PROBABLE	8,536.7	22,119	795.6	13,018.8
TOTAL PROVED PLUS PROBABLE	28,069.2	63,941	2,423.2	41,149.2

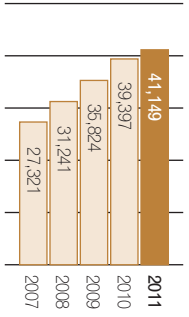
PRODUCTION PER SHARE/UNIT
(BOE)



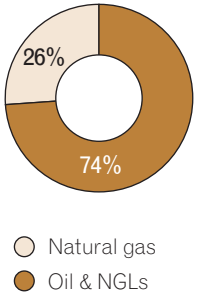
RESERVES PER SHARE/UNIT
(BOE)



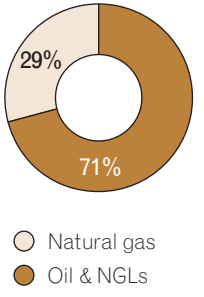
PROVED PLUS PROBABLE RESERVES
(MBOE)



2011 RESERVES by COMMODITY
*based on proved plus probable reserves



2011 PRODUCTION by COMMODITY



RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE AS OF DECEMBER 31, 2011

	Light and Medium Oil and Natural Gas Liquids		Natural Gas		BOE[1]	
	Proved (Mbbl)	Proved plus Probable (Mbbl)	Proved (MMcf)	Proved plus Probable (MMcf)	Proved (MBOE)	Proved plus Probable (MBOE)
December 31, 2010	22,158.5	30,448.4	38,500	53,692	28,575.2	39,397.1
Extension	4,356.0	7,547.9	7,507	12,418	5,607.2	9,617.6
Improved Recovery	0	0	0	0	0	0
Technical Revisions	(3,638.1)	(5,762.9)	556	2,712	(3,545.4)	(5,310.9)
Discoveries	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic factors	(56.7)	(81.4)	(665)	(805)	(167.5)	(215.6)
Production	(1,659.6)	(1659.6)	(4,076)	(4,076)	(2,338.9)	(2,338.9)
December 31, 2011	21,160.1	30,492.4	41,822	63,941	28,130.4	41,149.2

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2011

	NET PRESENT VALUE BEFORE INCOME TAXES DISCOUNTED AT (% PER YEAR)		
($ Millions)	0%	5%	10%
Reserve Category:			
PROVED			
Developed Producing	910,796	570,817	426,424
Developed Non-Producing	15,763	12,397	10,427
Undeveloped	264,113	170,975	116,405
TOTAL PROVED	1,190,672	754,190	553,256
PROBABLE	711,365	312,222	175,494
TOTAL PROVED PLUS PROBABLE	1,902,037	1,066,411	728,749

FINDING, DEVELOPMENT AND ACQUISITION (FD&A) COSTS

The Company has historically been active in its capital development program. Over three years, Bonterra has incurred the following FD&A [3] costs excluding Future Development Costs:

	2011 FD&A Costs per BOE[1][2][3]	2010 FD&A Costs per BOE[1][2][3]	2009 FD&A Costs per BOE[1][2][3]	Three Year Average[4]
Proved Reserve Net Additions	$33.22	$13.89	$7.32	$14.84
Proved plus Probable Reserve Net Additions	$15.38	$13.02	$3.94	$9.75

Over three years, Bonterra has incurred the following FD&A [3] costs including Future Development Costs:

	2011 FD&A Costs per BOE[1][2][3]	2010 FD&A Costs per BOE[1][2][3]	2009 FD&A Costs per BOE[1][2][3]	Three Year Average[5]
Proved Reserve Net Additions	$57.53	$21.98	$16.23	$18.54
Proved plus Probable Reserve Net Additions	$35.40	$19.19	$11.01	$13.03

(1) Barrels of Oil Equivalent may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.
(3) FD&A costs are net of proceeds of disposal and the FD&A costs per BOE are based on reserves acquired net of reserves disposed of.
(4) Three year average is calculated using three year total capital costs and reserve additions on both a Proved and Proved plus Probable basis.
(5) Three year average is calculated using three year total capital costs and reserves additions on both a Proved and Proved plus Probable basis plus the average change in future capital costs over the three year period.

Horizontal development of the main pool is an evolution of Bonterra's historic approach to exploiting its Cardium play that was previously achieved by drilling vertical infill wells. To reflect this approach, Bonterra cancelled 60 (48.31 net) vertical PUDs some of which were rescheduled as horizontal locations. As main pool horizontal infill drilling has less production history associated with it, the canceling of the vertical PUDs has had an overall negative impact on Proved reserves and therefore moderated growth in P+P reserves. Proved reserves decreased by less than two percent from 28.6 MBOE at December 31, 2010 to 28.1 MBOE at December 31, 2011 while P+P reserves increased approximately five percent to 41.2 million BOE over the previous year.

In 2011, Finding and Development and Acquisition (FD&A) costs were impacted by the negative revision discussed above. FD&A costs excluding future development costs increased to $33.22 per BOE on a proved basis and $15.38 per BOE on a P+P basis. FD&A costs on a three-year average remain competitive within industry with three year-average costs of $14.84 per BOE on a proved basis and $9.75 per BOE on a P+P basis.

Bonterra fully expects to see improvements in FD&A costs and reserves in the future as horizontal exploitation of the main Pembina pool matures.

Commodity prices used in the above calculations of reserves are as follows:

Year	Edmonton Par Price (Cdn $ per Bbl)	Natural Gas AECO-C Spot (Cdn $ per MMbtu)	Butanes Edmonton (Cdn $ per Bbl)	Pentanes Edmonton (Cdn $ per Bbl)	Inflation Rate (%/Yr)	Exchange Rate ($U.S./$Cdn)
2012	96.87	3.16	72.20	103.57	2.0	1.012
2013	93.75	3.78	69.87	100.23	2.0	1.012
2014	90.89	4.13	67.74	97.17	2.0	1.012
2015	96.23	5.53	71.73	102.89	2.0	1.012
2016	98.16	5.65	73.16	104.94	2.0	1.012
2017	100.12	5.77	74.63	107.04	2.0	1.012
2018	102.12	5.89	76.12	109.18	2.0	1.012
2019	104.17	6.01	77.64	111.37	2.0	1.012
2020	106.25	6.14	79.19	113.59	2.0	1.012
2021	108.38	6.27	80.78	115.87	2.0	1.012

Crude oil, natural gas and liquid prices escalate at 2.0 percent thereafter.

PRODUCTION

	2011		
	Oils and NGLs (Bbls per day)	Natural Gas (MCF per day)	Total (BOE per day)
Pembina and Willesden Green, Alberta	4,170	8,499	5,586
Saskatchewan	182	73	194
British Columbia	17	2,358	410
Other Alberta	92	233	132
	4,461	11,163	6,322

LAND HOLDINGS

	2011		2010	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	169,862	107,645	172,749	109,944
Saskatchewan	6,881	5,630	6,881	5,640
British Columbia	62,045	22,639	61,330	21,217
	238,788	135,914	240,960	136,801

PETROLEUM AND NATURAL GAS EXPENDITURES

The following table summarizes petroleum and natural gas capital expenditures incurred by Bonterra on acquisitions, land, seismic, exploration and development drilling and production facilities for the years ended December 31:

($ 000s)	2011	2010
Land	309	-
Acquisitions	-	-
Disposals	(238)	(6,234)
Exploration and development costs	62,615	76,914
Net petroleum and natural gas capital expenditures	62,686	70,680

DRILLING HISTORY

The following tables summarize Bonterra's gross and net drilling activity and success:

	2011					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	25	17.29	-	-	25	17.29
Natural gas	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	25	17.29	-	-	25	17.29
Success rate	100%	100%	-	-	100%	100%

	2010					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	30	22.09	-	-	30	22.09
Natural gas	1	0.11	-	-	1	0.11
Dry	-	-	-	-	-	-
Total	31	22.20	-	-	31	22.20
Success rate	100%	100%	-	-	100%	100%

Management's Discussion and Analysis

This report dated March 22, 2012 is a review of the operations and current financial position for the year ended December 31, 2011 for Bonterra Energy Corp. (Bonterra or the Company) and should be read in conjunction with the audited financial statements presented under International Financial Reporting Standards (IFRS), including the notes related thereto.

A reconciliation of the new and revised standards and interpretations for comparative purposes are outlined in Note 21 of the December 31, 2011 audited financial statements.

TRANSITION TO IFRS FROM CANADIAN GAAP

The Company prepares its financial statements in accordance with Canadian generally accepted accounting principles (GAAP) as set out in the Handbook of the Canadian Institute of Chartered Accountants (CICA Handbook). In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and requires publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Accordingly, the Company has commenced reporting on this basis in their financial statements after applying the requirements of International Financial Reporting Standards 1 – First-time Adoption of International Financial Reporting Standards (IFRS 1). In the Management's Discussion and Analysis (MD&A), the term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS. The Company's financial statements for the year ending December 31, 2011 will be the first annual financial statements that comply with IFRS.

IFRS are premised on a conceptual framework similar to Canadian GAAP, however, significant differences exist in certain matters of recognition, measurement and disclosure. On adoption, the Company utilized certain first-time adoption exemptions available resulting in significant changes to the statement of financial position and statement of comprehensive income. In particular, the Company's opening statement of financial position reflects the revaluation of certain capital assets to their fair values as at January 1, 2010. The revaluation is primarily the result of applying the fair value of assets received versus the carrying cost of assets disposed of on a non-cash asset exchange, net of depletion for our transition to IFRS or as a result of the policies we adopted under IFRS requiring certain assets to be measured at fair value.

Additionally, these changes to the opening statement of financial position required that a corresponding tax asset or liability be established based on the resultant differences between the carrying amount of these capital assets under IFRS and their associated tax bases. In aggregate, these increases and the application of various policies under IFRS that differ from Canadian GAAP increased shareholders' equity by $61,670,000 as at January 1, 2010. Note 21 of our financial statements provides detailed reconciliations between Canadian GAAP and IFRS of shareholders' equity as at January 1 and December 31, 2010 and of comprehensive income for the year ended December 31, 2010. These reconciliations provide explanations of each major difference.

The following discussion highlights the significant new standards that the Company has adopted under IFRS and the effect on the comparative period results of operations and financial position as previously reported under Canadian GAAP as well as the possible effects going forward.

IAS 16 *Property, Plant and Equipment* (IAS 16) requires an entity to record a non-cash transaction at fair value for the consideration or capital assets received and record a gain or loss on disposal for the consideration paid or capital assets transferred to other party. Under Canadian GAAP an entity is required to record a non-cash transaction at book value for the consideration transferred to the other party and therefore no gain or loss on disposal is recorded.

The Company has revalued its non-cash transactions using the fair value of the consideration received for certain oil and gas property, plant and equipment assets exchanged previously in 2007 (Asset Exchange). Revaluing the Asset Exchange increased shareholders' equity by $8,309,000 on an after-tax basis as at January 1, 2010. It also increased Property, Plant and Equipment (PP&E) by $11,755,000 after the effects of depletion and depreciation as at January 1, 2010.

IFRS 6 *Exploration for and Evaluation of Mineral Resources* (IFRS 6) allows for a policy decision to be made with regard to costs incurred between the date the Company acquires the legal right to explore a particular area and the date when the technical feasibility and the commercial viability of reserves are demonstrable. Costs incurred during this period may include lease acquisition rights, technical studies and services, seismic costs, geologic and geophysical costs, exploratory drilling and testing and directly attributable costs. Upon adoption of IFRS, the Company reclassified $7,992,000 from PP&E to Exploration and Evaluation (E&E) assets as at January 1, 2010.

IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* (IAS 37), similar to Canadian GAAP requires the Company to recognize a decommissioning liability for statutory, contractual, constructive or legal obligations, including those associated with the reclamation of oil and gas properties and equipment, when those obligations result from the acquisition, construction, development or normal operation of the assets. Initially, a liability for the decommissioning of an asset is recognized as its fair value in the period in which it is incurred. Upon initial recognition of the liability, the corresponding decommissioning liability is added to the carrying amount of the related asset and the cost is amortized as an expense over the economic life of the asset using the unit of production method. Following the initial recognition of the decommissioning liability, the carrying amount of the liability is increased for the passage of time and adjusted for changes to the discount rate used, amount or timing of the underlying cash flows needed to settle the liability. Under Canadian GAAP the discount rate used is the credit adjusted risk free rate, which is higher than the risk free rate used under IFRS. Revaluing the decommissioning liabilities under IFRS increased the decommissioning liabilities by $3,492,000, PP&E by $1,736,000 and shareholders' equity by $1,314,000 on an after-tax basis as at January 1, 2010.

The adoption of IFRS impacts the Company's assets, liabilities, shareholders' equity and net earnings for the comparative periods. A summary of the significant IFRS changes to the 2010 financial information are as follows:

SUMMARY NET EARNINGS RECONCILIATION

		2010			
($ 000s except $ per share)	Annual	Q4	Q3	Q2	Q1
Net earnings - Canadian GAAP	**49,864**	**14,213**	**12,724**	**10,887**	**12,040**
Other income - gain on sale of property	73	-	-	-	73
Unwinding of the fair value of decommissioning liabilities	17	(18)	16	232	(213)
Depletion and depreciation	(1,040)	(273)	(250)	(482)	(35)
Other	(1)	-	(3)	5	(3)
Deferred taxes	(8,959)	(2,084)	(2,357)	(254)	(4,264)
Net earnings - IFRS	**39,954**	**11,838**	**10,130**	**10,388**	**7,598**
Basic net earnings per share – Canadian GAAP	**2.65**	**0.75**	**0.68**	**0.58**	**0.64**
Effects of adjustments to net earnings	(0.53)	(0.13)	(0.14)	(0.03)	(0.23)
Basic net earnings per share – IFRS	**2.12**	**0.62**	**0.54**	**0.55**	**0.41**
Diluted net earnings per share – Canadian GAAP	2.58	0.73	0.66	0.56	0.63
Effects of adjustments to net earnings	(0.52)	(0.12)	(0.14)	(0.02)	(0.23)
Diluted net earnings per share – IFRS	**2.06**	**0.61**	**0.52**	**0.54**	**0.40**

SUMMARY TOTAL ASSETS, TOTAL LIABILITIES, SHAREHOLDERS' EQUITY AND WORKING CAPITAL DEFICIENCY RECONCILIATION

	2010			
($ 000s)	Q4	Q3	Q2	Q1
Total Assets - Canadian GAAP	335,144	318,493	307,934	305,440
Current				
Deferred tax asset	(22,889)	(18,082)	(10,735)	(11,342)
Non-current				
Exploration and evaluation assets and property, plant and equipment	14,795	12,114	12,364	12,623
Deferred tax asset	20,775	16,096	8,688	9,297
Total Assets - IFRS	347,825	328,621	318,251	316,018
Total Liabilities - Canadian GAAP	196,731	190,001	181,889	180,048
Current				
Deferred credit	(19,586)	(15,320)	(8,996)	(8,370)
Non-current				
Deferred credit	(25,850)	(32,072)	(40,814)	(41,692)
Decommissioning liabilities	6,357	3,385	3,398	3,412
Total Liabilities - IFRS	157,652	145,994	135,477	133,398
Shareholders' Equity - Canadian GAAP	138,413	128,492	126,045	125,392
Retained earnings	51,760	54,135	56,729	57,228
Shareholders' Equity - IFRS	190,173	182,627	182,774	182,620
Total Liabilities and Shareholders' Equity - IFRS	347,825	328,621	318,251	316,018
Working Capital (Deficiency) - Canadian GAAP	14,602	17,891	2,281	13,178
Current assets	22,889	18,082	10,735	11,342
Current liabilities	(19,586)	(15,320)	(8,996)	(8,370)
Working Capital (Deficiency) - IFRS	17,905	20,653	4,020	16,150

USE OF NON-IFRS FINANCIAL MEASURES

Throughout this Management's Discussion and Analysis (MD&A) the Company uses the terms "payout ratio" and "cash netback" to analyze operating performance, which are not standardized measures recognized under IFRS and do not have a standardized meaning prescribed by IFRS. These measures are commonly utilized in the oil and gas industry and are considered informative by management, shareholders and analysts. These measures may differ from those made by other companies and accordingly may not be comparable to such measures as reported by other companies.

The Company calculates payout ratio by dividing cash dividends to shareholders by cash flow from operating activities both of which are measures prescribed by IFRS which appear on our statements of cash flows. The Company calculates cash netback by dividing various income statement items as determined by IFRS by total production on a barrel of oil equivalent basis.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A include statements which contain words such as "anticipate", "could", "should", "expect", "seek", "may", "intend", "likely", "will", "believe" and similar expressions, relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions. Forward-looking information in this MD&A includes, but is not limited to: expected cash provided by continuing operations; cash dividends; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas companies to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; opportunities available to or pursued by us; and other factors, many of which are beyond our control.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do, what benefits will be derived there from. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

The forward-looking information contained herein is expressly qualified by this cautionary statement.

FINANCIAL AND OPERATIONAL DISCUSSION

Annual Comparisons

As at and for the year ended ($ 000s except $ per share)	December 31, 2011 IFRS	December 31, 2010 IFRS	December 31, 2009 Canadian GAAP
Financial			
Revenue – realized oil and gas sales	162,277	118,980	85,712
Cash flow from operations	97,409	66,238	38,893
Per share – basic	5.04	3.52	2.16
Per share – diluted	4.98	3.42	2.15
Payout ratio (1)	61%	72%	79%
Cash dividends per share (1)	3.06	2.55	1.70
Net earnings	43,608	39,954	68,563
Per share – basic	2.25	2.12	3.81
Per share – diluted	2.23	2.06	3.78
Capital expenditures and acquisitions net of dispositions	62,686	70,680	5,640
Total assets	364,176	347,825	293,987
Working capital deficiency	51,576	17,905	10,162
Long-term debt	69,916	85,386	59,823
Shareholders' equity	181,640	190,173	118,874
Operations			
Oil (barrels per day)	4,075	3,585	2,881
NGLs (barrels per day)	386	290	259
Natural gas (MCF per day)	11,163	10,521	11,120
Total barrels of oil equivalent per day (BOE) (2)	6,322	5,628	4,994

(1) Cash dividends per share are based on payments made in respect of production months within the quarter.

(2) Barrels of oil equivalent (BOE) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Quarterly Comparisons

	2011			
As at and for the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Financial				
Revenue – realized oil and gas sales	42,818	36,535	44,754	38,170
Cash flow from operations	26,180	21,730	25,465	24,034
Per share – basic	1.35	1.12	1.32	1.25
Per share – diluted	1.33	1.10	1.29	1.22
Cash dividends per share [1]	0.78	0.78	0.78	0.72
Payout ratio [1]	58%	69%	59%	58%
Net earnings	6,067	9,384	14,533	13,624
Per share – basic	0.31	0.49	0.75	0.71
Per share – diluted	0.31	0.48	0.74	0.69
Capital expenditures and acquisitions, net of disposals	20,529	15,941	5,872	20,344
Total assets	364,176	354,549	348,097	357,000
Working capital deficiency	51,576	43,362	30,823	39,777
Long-term debt	69,916	72,391	72,608	70,568
Shareholders' equity	181,640	185,908	192,297	192,054
Operations				
Oil (barrels per day)	4,096	3,789	4,164	4,258
NGLs (barrels per day)	493	340	372	338
Natural gas (MCF per day)	12,541	10,553	11,024	10,517
Total BOE per day [2]	6,679	5,887	6,373	6,350

(1) Cash dividends per share are based on payments made in respect of production months within the quarter.

(2) Barrels of oil equivalent (BOE) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

	2010			
As at and for the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Financial				
Revenue – realized oil and gas sales	34,208	28,332	29,191	27,248
Cash flow from operations	16,989	17,544	16,644	15,061
Per share – basic	0.90	0.93	0.89	0.81
Per share – diluted	0.88	0.91	0.87	0.78
Cash dividends per share [1]	0.68	0.66	0.64	0.57
Payout ratio [1]	76%	71%	72%	70%
Net earnings	11,837	10,130	10,388	7,598
Per share – basic	0.62	0.54	0.55	0.41
Per share – diluted	0.61	0.52	0.54	0.40
Capital expenditures and acquisitions, net of disposals	25,318	19,227	10,994	15,141
Total assets	347,825	328,621	318,251	316,018
Working capital deficiency	17,905	20,653	4,020	16,150
Long-term debt	85,386	73,901	78,434	63,097
Shareholders' equity	190,173	182,627	182,774	182,620
Operations				
Oil (barrels per day)	4,062	3,579	3,607	3,080
NGLs (barrels per day)	316	311	267	265
Natural gas (MCF per day)	10,214	10,674	11,157	10,038
Total BOE per day [2]	6,080	5,669	5,733	5,018

(1) Cash dividends per share are based on payments made in respect of production months within the quarter.

(2) Barrels of oil equivalent (BOE) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

PRODUCTION

	Three months ended			Year ended	
	December 31, 2011	September 30, 2011	December 31, 2010	December 31, 2011	December 31, 2010
Oil (barrels per day)	4,096	3,789	4,062	4,075	3,585
NGLs (barrels per day)	493	340	316	386	290
Natural gas (MCF per day)	12,541	10,553	10,214	11,163	10,521
Average BOE per day	6,679	5,887	6,080	6,322	5,628

Barrels of oil equivalent (BOE) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Production volumes for 2011 increased 12.3 percent to 6,322 BOE per day compared to 5,628 BOE per day for 2010. The increase in production volumes is due to Bonterra's continued success from its Cardium horizontal oil drilling program, partially offset by shut-in production along with normal production declines.

Shut-in production was due to several events throughout the year. The Company experienced 21 days of shut-in production for compressor upgrades by the operator of a major plant. It is estimated that approximately 1,500 BOE per day (1,210 barrels of crude oil and liquids per day and 1,715 MCF per day of natural gas) was shut-in during the months of July and August. The Company also experienced shut-in production when additional wells were drilled in the Company's multi well pad drilling program and existing wells on that surface lease had to be shut in during the drilling and completion of the new well, workovers in the Willesden Green area and the shut in of approximately 130 BOE per day of annualized production from 21 shallow natural gas wells due to low natural gas prices for the majority of 2011. Higher than normal precipitation in the month of July caused additional production issues.

The majority of the operating issues experienced at the Willesden Green property have now been resolved. High operating line pressures throughout most of 2011 were alleviated when the Company constructed a permanent tie-in to a low pressure gas gathering system in which it has an ownership interest. The project was completed in December.

Production volumes for Q4 2011 increased by 13.5 percent to 6,679 BOE per day compared to Q3 2011. The production increase was due to continued success from its Cardium development program partially offset by pipeline apportionments that resulted in the Company having higher than usual oil inventory at the end of the fourth quarter. Factoring in the effects of the oil inventory, the Company's actual production was 6,359 BOE per day for 2011 and 6,839 BOE per day for the fourth quarter of 2011. Despite these production reductions, the Company's exit production for 2011 was approximately 6,900 BOE per day.

Apportionments have continued in the first quarter of 2012. The Company has been seeking other possible solutions to handle the continued increase in oil production volumes.

The Company drilled 20 gross (16.3 net) Pembina and Willesden Green Cardium horizontal wells during 2011, of which six gross (5.2 net) wells were drilled in the fourth quarter of 2011. All but two of the 20 wells was placed on production by the end of 2011.

OIL AND GAS SALES, NET OF ROYALTIES

	Three months ended			Year ended	
($ 000s)	December 31, 2011	September 30, 2011	December 31, 2010	December 31, 2011	December 31, 2010
Revenue – oil and gas sales	42,818	36,535	34,209	162,277	118,980
Less:					
Crown royalties	2,993	3,428	2,092	12,316	7,562
Freehold, gross overriding and other royalties	1,277	1,725	794	5,261	4,016
Total royalties	4,270	5,153	2,886	17,577	11,578
Oil and gas sales, net of royalties	38,548	31,382	31,323	144,700	107,402
Average Realized Prices ($):					
Crude oil (per barrel)	96.25	88.21	78.01	92.76	74.76
NGLs (per barrel)	59.46	63.80	48.82	60.89	47.11
Natural gas (per MCF)	3.34	3.91	3.82	3.86	4.14
Royalties – percentage of revenue	10.0	14.1	8.4	10.8	9.7
Royalties $ per BOE	6.95	9.51	5.16	7.62	5.64

Revenue from petroleum and natural gas sales increased by $43,297,000 in 2011, a 36 percent improvement over the corresponding 2010 year, due to a 12 percent increase in production and a 26 percent increase in crude oil and NGL prices which was partially offset by a seven percent reduction in natural gas pricing. Quarter over quarter saw an increase in revenues of $6,283,000 or 17 percent due to increasing production volumes and commodity prices for crude oil, which was partially offset by declining commodity prices for natural gas and NGLs.

The Company's product split on a revenue basis for the 2011 year is approximately 90 percent weighted towards crude oil and NGLs. This ratio will likely increase as the Company continues to develop its Pembina and Willesden Green Cardium (mainly oil) properties and also the likely pricing scenario where oil prices will continue to remain high relative to natural gas prices.

Royalties paid by the Company consist primarily of Crown royalties paid to the Provinces of Alberta, Saskatchewan and British Columbia. Approximately half of the Company's production is from low productivity wells and therefore has low Crown royalty rates with a significant amount of the remaining production coming from horizontal wells that are paying five percent Crown royalty rates. The Company's average Crown royalty rate is approximately 7.6 percent for the year ended December 31, 2011 compared to 6.4 percent for the previous year. Quarter over quarter saw Crown royalties decrease to 7.0 percent in Q4 2011 compared to 9.4 percent for Q3 2011. Crown royalty increases for the 2011 year compared to the same period in 2010 were due to increased volumes, higher commodity prices and some of the previously drilled horizontal Cardium wells no longer being eligible for the initial five percent royalty rate because accumulated production thresholds were reached. The quarter over quarter decrease in crown royalties was mainly due to NGL crown royalties relating to previous periods, partially offset by increased production and commodity prices for crude oil.

The Company's non-crown royalty rate averaged 3.2 percent of oil and gas sales for the year ended December 31, 2011 compared to 3.4 percent in 2010. However, the gross amount of non-crown royalties increased by $1,245,000 in 2011 compared to 2010 primarily due to increased production and commodity prices. Quarter over quarter saw a decrease to 3.0 percent for Q4 2011 compared to 4.7 percent for Q3 2011. The decrease in non-crown royalties is primarily due to a gross overriding royalty adjustment in the third quarter, which was partially offset by higher commodity prices and production volumes for wells that are subject to gross overriding royalties.

OTHER INCOME

	Three months ended			Year ended	
($ 000s)	December 31, 2011	September 30, 2011	December 31, 2010	December 31, 2011	December 31, 2010
Gain on sale of property	-	158	-	162	6,558
Gain on sale of investments	-	272	782	2,126	4,335
Investment income	5	8	10	27	24
Administrative income	79	83	90	327	418
	84	521	882	2,642	11,335

During 2011, the Company disposed of a portion of its investments. Gross proceeds from these sales were $3,991,000 resulting in an accounting gain of $2,126,000, most of which occurred in the first quarter of 2011. During 2010, the Company disposed of a portion of its investments for gross proceeds of $5,603,000 resulting in an accounting gain of $4,335,000, most of which occurred in the third quarter of 2010. The market value of the investments held by the Company is in excess of $6,800,000 at December 31, 2011.

In February 2010, the Company disposed of its Southeast Saskatchewan Pinto property for cash proceeds of $5,534,000 resulting in an accounting gain of $5,858,000. In the third quarter of 2010, the Company disposed of non-producing land for proceeds of $700,000. The Company had no capital costs associated with this non-producing land.

The Company receives administrative income by way of management fees from related parties (see related party transactions).

PRODUCTION COSTS

	Three months ended			Year ended	
($ 000s except $ per BOE)	December 31, 2011	September 30, 2011	December 31, 2010	December 31, 2011	December 31, 2010
Production costs	9,824	9,159	8,698	36,787	30,451
$ per BOE	15.99	16.91	15.55	15.94	14.82

Total production costs for 2011 increased by $6,336,000 compared to 2010 mainly due to higher production, weather and regulatory delays in tie-in of oil and gas pipelines which resulted in higher facility start-up costs, trucking costs, road maintenance costs and higher gas compression and processing fees at third party facilities. The pipeline tie-in of the Warburg facility was completed in September and the tie-in of the oil and gas pipelines at the Willesden Green facility were completed in December which should result in reduced operating costs in the future. In addition, during 2011 the Company experienced higher electrical costs and a general increase in other services costs compared to 2010. On a per BOE basis, production costs have increased by approximately eight percent year over year.

Quarter over quarter saw an increase in production costs primarily due to increased production. This was partially offset by a decrease in electrical rates, service rig work and road and lease maintenance. On a per BOE basis, production costs have decreased by approximately five percent in the fourth quarter primarily due to increased production, tie-in of the Warburg and Willesden Green facilities and less weather related issues.

Approximately half of the Company's production comes primarily from low productivity wells. These wells generally have higher productions costs on a unit-of-production basis as costs such as municipal taxes, surface leases, power and personnel costs are not variable with production volumes. In the future, the Company's horizontal drilling program, improved tie-ins and upgraded facilities should lower production costs on a unit-of-production basis.

The Company continues to monitor capital and operating costs in order to realize greater efficiency in its spending. Access to quality equipment, services and contractors will be a primary concern as industry activity increases in the future leading to an overall increase in service costs.

GENERAL AND ADMINISTRATION (G&A) EXPENSE

	Three months ended			Year ended	
($ 000s except $ per BOE)	December 31, 2011	September 30, 2011	December 31, 2010	December 31, 2011	December 31, 2010
Employee compensation expense	896	1,027	1,099	4,456	4,274
Office and administration expense	1,059	252	460	2,332	1,539
	1,955	1,279	1,559	6,788	5,813
$ per BOE	3.18	2.36	2.79	2.94	2.83

Total G&A expense increased 17 percent to $6,788,000 for the year ended December 31, 2011 from $5,813,000 in 2010. On a BOE basis, total G&A expense increased by 3.9 percent year over year.

The increase in employee compensation expense of $182,000 for the 2011 year compared to a year ago was primarily due to annual salary adjustments and an increase in accrued bonuses due to higher net earnings before income taxes. The Company has a bonus plan in which the bonus pool consists of three percent of earnings before income taxes. The bonus pool is determined entirely by this three percent of earnings as the Company firmly believes that tying employee compensation (including the use of stock options) to the performance of the Company clearly aligns the interest of the employees to that of the shareholders.

Office and administration costs consist primarily of professional services such as office rent, legal, engineering, accounting, computer services, consulting fees and bank charges. The increase in office and administration expense for 2011 related primarily to increased engineering and accounting consulting fees, regulatory filing and printing fees and legal fees, compared to 2010.

Quarter over quarter office and administration expense saw an increase of $807,000 related to increased legal fees, engineering and accounting consulting fees and an increase in the provision in the allowance for doubtful accounts. This was partially offset by a decrease in employee compensation expense.

FINANCE COSTS

($ 000s except $ per BOE)	Three months ended December 31, 2011	Three months ended September 30, 2011	Three months ended December 31, 2010	Year ended December 31, 2011	Year ended December 31, 2010
Interest on long-term debt	547	502	653	2,272	2,243
Other interest	305	305	192	1,210	555
Interest expense	852	807	845	3,482	2,798
$ per BOE	1.39	1.49	1.51	1.51	1.36
Unwinding of the discounted value of decommissioning liabilities	339	205	216	954	858
Total finance costs	1,191	1,012	1,061	4,436	3,656

Interest on long-term debt increased in 2011 compared to 2010 primarily due to an increase in the Company's overall average outstanding debt balance. The debt increase results mainly from higher capital expenditures (net of disposals) in the last half of 2010.

Other interest relates to amounts paid to related parties (see related party transactions) and the $15,000,000 subordinated promissory note from a private investor which the Company entered into on October 4, 2010.

The terms of the subordinated promissory note are that it bears interest at three percent, is not callable by the investor prior to January 4, 2012 at which time it will be a demand note until its maturity of April 4, 2012, and can be repaid at the option of the Company at any time. Security consists of a floating demand debenture totaling $15,000,000 over all of the Company's assets and is subordinated to any and all claims in favor of the syndicate of senior lenders providing credit facilities to the Company. The loan was not called by the investor on January 4, 2012. On February 10, 2012, the Company and the investor entered into an amending agreement whereby the subordinated promissory note would be repaid by the Company after thirty days written notice by either party on or after April 4, 2012.

As of December 31, 2011 and December 31, 2010, the Company has a bank facility consisting of $100,000,000 syndicated revolving credit facility and a $20,000,000 non-syndicated revolving credit facility. Amounts drawn under the facility at December 31, 2011 were $69,916,000 (December 31, 2010 – $70,386,000). Amounts borrowed under the credit facility at December 31, 2011 bear interest at a floating rate based on the applicable Canadian prime rate or Banker's Acceptance rate, plus between 0.75 percent and 3.50 percent, depending on the type of borrowing and the Company's consolidated total funded debt to consolidated cash flow. The terms of the revolving credit facility provided that the loan is revolving to April 26, 2012 and with a maturity date of April 25, 2013 and is subject to annual review. The revolving credit facility has no fixed terms of repayment.

The amount available for borrowing under the credit facilities is reduced by outstanding letters of credit. Letters of credit totaling $400,000 were issued December 31, 2011 (December 31, 2010 – $285,000). Security for credit facilities consists of various and floating demand debentures totaling $200,000,000 over all of the Company's assets and general security agreement with first ranking over all personal and real property.

The following is a list of the material covenants on the banking facility:

- The Company is required to not exceed $120,000,000 in consolidated debt (includes working capital but excludes related party amounts and subordinated promissory note).
- Dividends paid in the current quarter and the three previous quarters shall not exceed 80 percent of the previous four quarters' cash flow as defined under IFRS excluding adjustments for non-cash working capital items.

At December 31, 2011, the Company is in compliance with all covenants.

Provisions are made for decommissioning liabilities through the recognition of the fair value of obligations associated with the retirement of tangible long-life assets being recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual, constructive or legal obligations. The liability is adjusted over time for changes in the value of the liability through the unwinding of the fair value of decommissioning liabilities which is included in finance costs. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

At December 31, 2011, the estimated total undiscounted amount required to settle the decommissioning liabilities was $73,475,000 (2010 – $62,579,000).

These obligations will be settled based on the useful lives of the underlying assets, which extend up to 50 years into the future. This amount has been discounted using a risk-free interest rate of two and a half percent. The discount rate is reviewed each reporting period and adjusted if considered necessary. A change in the rate would have a significant impact on the amount recorded for decommissioning liabilities. Based on the current provision, a one percent increase in the risk free rate would decrease the decommissioning liabilities by $7,617,000, while a one percent decrease in the risk free rate would increase the decommissioning liabilities by $11,067,000.

SHARE-BASED PAYMENTS

	Three months ended			Year ended	
($ 000s)	December 31, 2011	September 30, 2011	December 31, 2010	December 31, 2011	December 31, 2010
	822	815	57	2,554	483

Share-based payments are a statistically calculated value representing the estimated expense of issuing employee stock options. The Company records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. Share-based payments increased in 2011 over 2010 primarily due to 599,000 stock options issued in the first quarter of 2011. In 2010 the share-based payment expense relates primarily to 1,390,500 stock options issued in 2008, with most of the share-based expense being recorded in the first year after issuance. Based on currently outstanding options, the Company anticipates that an expense of approximately $4,184,000 will be recorded for 2012; $1,624,000 for 2013 and $45,000 for 2014.

The Company granted 1,142,000 stock options in 2011 (2010 – 36,000) with an estimated fair value of $8,394,000 or $7.35 per option (2010 – $204,000 or $5.67 per option) using the Black-Scholes option pricing model with the following key assumptions:

($ 000s)	December 31, 2011	December 31, 2010
Weighted-average risk free interest rate (%) [1]	1.40	1.87
Expected life (years)	2.03	2.80
Weighted-average volatility (%) [2]	32.41	33.10
Forfeiture rate (%)	0.00	0.00
Dividend yield 2011 and 2010	Based on the expected dividend yield over the expected life of the options for each grant	

(1) Risk-free interest rate is based on the weighted average Government of Canada benchmark bond yields for two, three and five year terms to match corresponding vesting periods.

(2) The expected volatility is measured as the standard deviation of expected share price returns based on statistical analysis of historical weekly share prices for a representative period.

The weighted average share price of the options exercised in 2011 was $53.38 (2010 – $41.26).

DEPLETION, DEPRECIATION AND IMPAIRMENT

	Three months ended			Year ended	
($ 000s)	December 31, 2011	September 30, 2011	December 31, 2010	December 31, 2011	December 31, 2010
Depletion and depreciation	13,467	6,209	6,089	32,699	22,444
Impairment of natural gas assets	2,585	-	-	2,585	-

Capital costs for oil and gas properties that result in the addition of reserves are depleted using the unit-of-production basis by field over their proved developed reserve life. For production, facility and equipment expenditures such as well and production processing equipment, the Company uses a 10 percent declining basis for depreciation calculation.

Provision for depletion and depreciation increased 46 percent in 2011 over 2010. The increase in the depletion amount was due to increased average cost of reserves, increased production volumes and from a lower percentage of proved developed reserves currently assigned to the Company's new horizontal wells. Increased production over lower proved developed reserves increased depletion for the fourth quarter compared to the third quarter. The increase in depletion was also impacted by a large decommissioning liability adjustment of $11,354,000 due to a decrease in the risk free discount rate, which increased property, plant and equipment costs subject to depletion.

Total proved reserves assigned by a Canadian-based, independent reserve evaluator's report (or Reserve Report) for December 31, 2011 decreased by two percent compared to the December 31, 2010 report and total proved plus probable reserves increased 4.6 percent to 41.2 million BOE. Horizontal drilling of the main pool has replaced the Company's previous approach to exploiting the Cardium play by drilling vertical infill wells. To reflect this new approach, the Company cancelled 60 (48.3 net) vertical proved undeveloped wells (PUDs) some of which were rescheduled as horizontal locations. As the main pool horizontal infill drilling has less production history associated with it, the canceling of the vertical PUDs has had an overall negative impact on proved reserves. The proved reserves assigned may be modified in the future when longer term production history is available from the horizontal wells.

The Company currently has an estimated reserve life for its proved developed producing reserves of 8.2 (2010 – 10.1) years calculated using the Company's gross reserves (prior to allowance for royalties) based on the Reserve Report dated December 31, 2011 and fourth quarter 2011 average production rates of 6,679 BOE per day (2010 – 6,080 BOE per day). Based on total proved reserves, the Company has an 11.5 (2010 – 12.9) year reserve life and on a proved plus probable basis the reserve life is to 16.9 (2010 – 17.8) years.

There were significant changes in the future commodity price forecasts for natural gas used in the Company's December 31, 2011 Reserve Report when compared to December 31, 2010. Expected future cash flows from the sale of forecasted production volumes are calculated based on the Company's best estimate of future oil and gas prices. Prices for oil and gas used for future cash flow projections are based on quality and the Edmonton par price for crude oil and heat content and the AECO price for natural gas. The Company determined lower natural gas prices caused an impairment of the Company's minor natural gas assets in British Columbia, as the carrying amount was greater than the discounted amount calculated in the Reserve Report. Based on this assessment, the Company determined that $2,585,000 comprised of $914,000 of Exploration and Evaluation assets and $1,671,000 of Property, Plant and Equipment assets within the British Columbia area were impaired. Should the forward prices for natural gas increase, the Company will reverse the impairment expense up to the original carrying value less depletion and depreciation.

TAXES

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

($ 000s)	Rate of Utilization (%)	Amount
Undepreciated capital costs	20-100	32,482
Eligible capital expenditures	7	6,370
Canadian oil and gas property expenditures	10	17,444
Canadian development expenditures	30	98,957
Canadian exploration expenditures	100	11,174
SR&ED expenditures	100	12,004
Income tax losses carried forward [(1)]	100	223,665
		402,096

(1) Federal income tax losses carried forward expire in the following years; 2013 - $1,069,000, 2024 - $3,347,000, 2025 - $7,532,000, 2026 - $46,671,000, 2027 - $117,189,000, 2028 - $34,726,000, 2029 - $13,131,000.

The Company also has $27,670,000 (December 31, 2010 – $27,670,000) remaining of investment tax credits that expire in the following years; 2019 - $3,469,000, 2020 - $3,059,000, 2021 - $4,667,000, 2022 - $3,909,000, 2023 - $3,155,000, 2024 - $1,995,000, 2025 - $2,257,000, 2026 - $2,405,000, 2027 - $2,009,000, 2028 - $745,000.

In addition to the above, the Company has $137,514,000 (December 31, 2010 – $139,773,000) of capital loss carry forwards which can only be claimed against taxable capital gains.

The amount and timing of reversals of temporary differences will also depend on the Company's future operating results and its future acquisitions and dispositions of assets and liabilities. A significant change in these assumptions could materially affect the Company's estimate of the deferred income tax asset.

The Company recorded a deferred tax expense of $17,940,000 for 2011 (2010 – $15,936,000). The deferred tax expense increased in 2011 over 2010 primarily due to an increase in earnings before income taxes in 2011.

NET EARNINGS

($ 000s except $ per share)	Three months ended December 31, 2011	Three months ended September 30, 2011	Three months ended December 31, 2010	Year ended December 31, 2011	Year ended December 31, 2010
Net earnings	6,067	9,384	11,837	43,608	39,954
$ per share – basic	0.31	0.49	0.62	2.25	2.12
$ per share – diluted	0.31	0.48	0.61	2.23	2.06

Net earnings increased in 2011 by $3,654,000 or nine percent from the prior year. Increased net earnings resulted primarily from higher crude oil and NGL prices and increased production volumes. This increase was partially offset by lower natural gas prices, higher crown royalties, production costs, depletion and depreciation expense, an impairment provision on the British Columbia natural gas assets and a gain on disposal in the prior period relating to the sale of the Pinto producing property. The Company returned in excess of 27 percent of its gross realized revenues in net earnings in 2011. The Company's low capital costs combined with the Company's lower production decline rates should allow for continued positive earnings even in a low commodity price environment. The net earnings for Q4 2011 compared to Q3 2011 decreased by $3,317,000. This was the result of higher depletion and depreciation expense and an impairment provision recorded in the fourth quarter of 2011, mainly offset by lower natural gas prices, increased production volumes and increased commodity pricing for crude oil.

OTHER COMPREHENSIVE INCOME

Other comprehensive income for the year ended 2011 consists of an unrealized loss before tax on investments (including investments in a related party) of $1,462,000 relating to a decrease in the investments' fair value (December 31, 2010 – unrealized gain of $8,602,000 relating to an increase in the investments' fair value). The Company also disposed of a portion of these investments which are comprised of marketable securities in 2011 for a realized gain before tax of $2,126,000 (December 31, 2010 – $4,335,000). Realized gains decrease other comprehensive income as the gains are transferred to net earnings. Other comprehensive income varies from net earnings by unrealized changes in the fair value of Bonterra's holdings of investments including the investment in related party, net of tax.

CASH FLOW FROM OPERATIONS

($ 000s except $ per share)	Three months ended December 31, 2011	Three months ended September 30, 2011	Three months ended December 31, 2010	Year ended December 31, 2011	Year ended December 31, 2010
Cash flow from operations	26,180	21,730	16,976	97,409	66,238
$ per share – basic	1.35	1.12	0.90	5.04	3.52
$ per share – diluted	1.33	1.10	0.88	4.98	3.42

The 2011 cash flow from operations increased $31,171,000 or 47 percent compared to 2010 primarily due to higher crude oil and NGL prices, increased production and a positive change in non-cash working capital. The increase is partially offset by increased production costs and crown royalties. The quarter over quarter increase of $4,450,000 or 20 percent was due primarily to increased production volumes and crude oil prices partially offset by increased office and administration costs and a decrease in the change in non-cash working capital.

CASH NETBACK

The following table illustrates the calculation of the Company's cash netback from operations for the periods ended:

$ per BOE	Three months ended December 31, 2011	Three months ended September 30, 2011	Three months ended December 31, 2010	Year ended December 31, 2011	Year ended December 31, 2010
Production volumes (BOE)	614,482	541,595	559,400	2,307,465	2,054,375
Gross production revenue	$ 69.68	$ 67.46	$ 61.15	$ 70.33	$ 57.92
Royalties	(6.95)	(9.51)	(5.16)	(7.62)	(5.64)
Field operating costs	(15.99)	(16.91)	(15.55)	(15.94)	(14.82)
Field netback	46.74	41.04	40.44	46.77	37.46
General and administrative	(3.18)	(2.36)	(2.79)	(2.94)	(2.85)
Interest and other	(1.25)	(1.33)	(1.35)	(1.36)	(1.16)
Cash netback	$ 42.31	$ 37.35	$ 36.30	$ 42.47	$ 33.45

RELATED PARTY TRANSACTIONS

The Company holds 689,682 (December 31, 2010 – 689,682) common shares in Geomark Exploration Ltd. (Geomark) which have a fair market value as of December 31, 2011 of $566,000 (December 31, 2010 – $814,000). Geomark is a publically traded minerals exploration company listed on the TSX Venture Exchange under the symbol GME. The Company has common directors and some common management with Geomark. In addition, Geomark owns 204,633 (December 31, 2010 – 204,633) common shares in Bonterra.

Effective July 6, 2010, Comaplex Minerals Corp. (Comaplex) (a company with some common management and common directors) was acquired by Agnico-Eagle Mines Limited (Agnico-Eagle). In exchange for Bonterra's 689,682 common shares in Comaplex, the Company received 689,682 shares in Geomark and 108,693 common shares in Agnico-Eagle (value of the remaining shares are included in Investments on the balance sheet). The common shares of Agnico-Eagle trade on the Toronto Stock Exchange under the symbol AEM and the common shares of Geomark trade on the TSX Venture Exchange under the symbol GME. The investment in Geomark represents 1.3 percent ownership in the outstanding common shares of Geomark.

Geomark paid a management fee to the Company of $270,000 (December 31, 2010 – $316,500 paid by Geomark and Comaplex). Geomark also shares office rental costs and reimburses the Company for costs related to employee benefits and office materials. Services provided by the Company include executive services (chief executive officer and chief financial officer duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. At December 31, 2011, Geomark owed the Company $74,000 (December 31, 2010 – $35,000).

As a result of the acquisition by Agnico-Eagle of Comaplex on July 6, 2010, the $12,000,000 loan previously held by Comaplex was transferred to Geomark and is repayable by the Company under the same terms. In the third quarter of 2010, Geomark loaned Bonterra an additional $8,000,000. As of December 31, 2011, Geomark has loaned the Company a total of $20,000,000 (December 31, 2010 – $20,000,000). At December 31, 2011, the loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. The loan cannot be repaid, or demanded to be paid by Geomark, unless the Company has sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan during 2011 was $475,000 (December 31, 2010 – $313,000 paid to Geomark and Comaplex). This loan results in a substantial benefit to Bonterra and to Geomark. The interest paid to Geomark by Bonterra is substantially lower than bank interest and for Geomark, the interest earned is substantially higher than Geomark would receive by investing in bank instruments such as BAs or GICs.

As of December 31, 2011, the Company's Chief Executive Officer (CEO), Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2010 – $12,000,000). At December 31, 2011, the loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. The loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan during 2011 was $285,000 (2010 – $242,000). This loan results in a substantial benefit to Bonterra as the interest paid to the CEO by Bonterra is lower than bank interest.

As at December 31, 2011, the Company had sufficient room to repay both the Geomark and CEO loans.

The Company also has a management agreement with Pine Cliff Energy Ltd. (Pine Cliff). Pine Cliff has some common directors and some common management with the Company. Pine Cliff trades on the TSX Venture Exchange. Pine Cliff paid a management fee to the Company of $60,000 (December 31, 2010 – $90,000). Services provided by the Company include executive services (chief executive officer, president and chief financial officer duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. The Company has no share ownership in Pine Cliff. As at December 31, 2011, the Company had an account receivable from Pine Cliff of $4,000 (December 31, 2010 – $1,000).

LIQUIDITY AND CAPITAL RESOURCES

During 2011, the Company incurred capital costs of $62,924,000 (2010 – $76,914,000) net of drilling credits. The costs relate primarily to the drilling, completing, tieing-in and equipping of 20 (16.3 net) Pembina Cardium and Willesden Green horizontal wells.

The Company currently has plans to spend an estimated $65,000,000 on its 2012 Pembina Cardium horizontal well program and non-operated capital programs. Drilling in the fourth quarter resulted in six wells (5.2 net) drilled and all but two (2.0 net) tied-in and on production by the end of the year. Bonterra anticipates funding the 2012 capital program out of cash flow, proceeds from the exercise of stock options, sale of investments and, if necessary, the Company's unused line of credit.

As of December 31, 2011 and December 31, 2010, the Company has a bank facility consisting of a $100,000,000 syndicated revolving credit facility and a $20,000,000 non-syndicated revolving credit facility. Amounts drawn under these facilities at December 31, 2011 were $69,916,000 (December 31, 2010 – $70,386,000). The interest rates on the outstanding debt as of December 31, 2011 were approximately 3.8 percent and 3.0 percent on the Company's Canadian prime rate loan and Banker's Acceptances, respectively. For information related to interest rate levels and material covenants please refer to the discussion under Interest Expense. Going forward, Bonterra remains committed to maintaining conservative financial management, whereby, capital expenditure ranges and dividend payments annually will not result in the bank loan to cash flow ratio exceeding 1.5 to 1.

SHAREHOLDERS' EQUITY

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

Issued	Number	Amount ($ 000s)
Common Shares		
Balance, January 1, 2011	19,219,541	135,030
Issued pursuant to Company share option plan	351,775	7,150
Transfer of contributed surplus to share capital		387
Balance, December 31, 2011	19,571,316	142,567

The Company is authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

The Company provides an equity settled stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,957,131 (December 31, 2010 – 1,921,954) common shares. The exercise price of each option granted will not be lower than the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2011 and December 31, 2010, and changes during the years ended on those dates is presented below:

	December 31, 2011		December 31, 2010	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	747,000	$ 20.56	1,330,900	$ 20.36
Options granted	1,142,000	54.54	36,000	36.98
Options exercised	(351,775)	20.32	(599,900)	20.63
Options cancelled	(11,000)	14.90	(20,000)	34.66
Options forfeited	(58,000)	32.14	-	-
Outstanding at end of year	1,468,225	$ 46.63	747,000	$ 20.56
Options exercisable at end of year	333,225	$ 20.75	255,500	$ 20.50

The following table summarizes information about options outstanding at December 31, 2011:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number outstanding at December 31, 2011	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable at December 31, 2011	Weighted-average exercise price
$ 20.50	338,225	0.9 years	$ 20.50	330,225	$ 20.50
48.00 – 52.00	508,500	2.9 years	50.12	3,000	48.60
54.00 – 59.00	621,500	2.1 years	57.99	-	-
$ 20.50 – $ 59.00	1,468,225	2.1 years	$ 46.63	333,225	$ 20.75

DIVIDEND POLICY

For the year ended December 31, 2011, Bonterra declared and paid dividends of $58,805,000 ($3.04 per share) compared to $46,867,000 ($2.49 per share) for the year ended December 31, 2010. Bonterra's dividend policy is continually monitored and is dependent upon production, commodity prices, funds from operations, debt levels and capital expenditures. As a dividend paying corporation, Bonterra is well positioned to provide its shareholders a combination of sustainable growth and meaningful income.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure the information required to be disclosed by the Company is accumulated and communicated to the Company's Management, as appropriate, to allow timely decisions regarding required disclosures. The Company's Chief Executive Officer (CEO) and Chief Financial Officer (CFO), together with management, have concluded, based on their evaluation as of the end of the period covered by the interim and year end filings that the Company's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Company. It should be noted that while the Company's CEO and CFO believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting 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 objective of the control system is met.

INTERNAL CONTROL UPDATE

The Company's CEO and CFO are responsible for establishing and maintaining Disclosure Controls and Procedures (DC&P) and adequate Internal Control over Financial Reporting (ICFR) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements at the financial year end for external purposes in accordance with Canadian GAAP. The control framework the Company used to design its ICFR was in accordance with the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal control over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company for the foregoing purpose.

As reported in the Company's September 30, 2011 third quarter MD&A, the Company identified a material weakness related to segregation of duties caused by the limited number of finance staff at the Company. The Company believes this weakness is mitigated by active involvement of senior management and the Board of Directors; the open lines of communication within the Company; the present level of activities and transactions within the Company being readily transparent; the thorough review of the financial statements by management and the Board of Directors; a whistle blowing program and appropriate segregation in key areas due to the hiring of additional staff.

All internal control systems, no matter how well designed, have inherent limitations. These systems, therefore, provide reasonable but not absolute assurance that financial information is accurate and complete.

FINANCIAL REPORTING UPDATE

Recent Accounting Pronouncements

As of January 1, 2013, Bonterra will be required to adopt amendments to IAS 1 "Presentation of Financial Statements" which will require companies to group together items within other comprehensive income that may be reclassified to the net earnings section of the comprehensive income statement. Bonterra does not expect a material impact as a result of the amendments.

Each of the additional new standards outlined below is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted, except for IFRS 9 "Financial Instruments" which is effective for annual periods beginning on or after January 1, 2015. The Company has not yet assessed the impact, if any, that the new amended standards will have on its financial statements or whether to early adopt any of the new requirements.

IFRS 9 "Financial Instruments"

The result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

IFRS 10 "Consolidated Financial Statements"

Replaces Standing Interpretations Committee 12, "Consolidation - Special Purpose Entities" and the consolidation requirements of IAS 27 "Consolidated and Separate Financial Statements". The new standard replaces the existing risk and rewards based approaches and establish control as the determining factor when determining whether an interest in another entity should be included in the consolidated financial statements.

IFRS 11 "Joint Arrangements"

Replaces IAS 31 "Interests in Joint Ventures" along with amending IAS 28 "Investment in Associates". The new standard focuses on the rights and obligations of an arrangement, rather than its legal form. The standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted.

IFRS 12 "Disclosure of Interests in Other Entities"

Provides comprehensive disclosure requirements on interests in other entities, including joint arrangements, associates, and special purpose vehicles. The new disclosure requires information that will assist financial statement users in evaluating the nature, risks and financial effects of an entity's interest in subsidiaries and joint arrangements.

IFRS 13 "Fair Value Measurement"

Provides a common definition of fair value within IFRS. The new standard provides measurement and disclosure guidance and applies when IFRS requires or permits the item to be measured at fair value, with limited exceptions. This standard does not determine when an item is measured at fair value and as such does not require new fair value measurements.

Additional information relating to the Company may be found on www.sedar.com or visit our website at www.bonterraenergy.com.

Management's Responsibility for Financial Statements

The information provided in this report, including the financial statements, is the responsibility of management. The timely preparation of the financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte & Touche LLP has been appointed by the Shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditor's report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

George F. Fink

Chief Executive Officer and
Chairman of the Board

March 22, 2012

Robb D. Thompson

Chief Financial Officer

March 22, 2012

Independent Auditor's Report

TO THE SHAREHOLDERS OF BONTERRA ENERGY CORP.

We have audited the accompanying financial statements of Bonterra Energy Corp., which comprise the statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010, and the statements of comprehensive income, statements of changes in equity, and statements of cash flows for the years ended December 31, 2011 and December 31, 2010, and the notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Bonterra Energy Corp. as at December 31, 2011, December 31, 2010 and January 1, 2010 and its financial performance and its cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

Chartered Accountants
Calgary, Alberta
March 22, 2012

Financial Statements

STATEMENTS OF FINANCIAL POSITION

As at ($ 000s)	Note	December 31, 2011	December 31, 2010 (Note 21)	January 1, 2010 (Note 21)
Assets				
Current				
Accounts receivable	4	17,094	17,345	14,713
Crude oil inventory		1,092	487	431
Prepaid expenses		1,688	1,631	3,247
Investments		6,266	11,471	4,462
Investment in related party	6	-	-	4,827
		26,140	30,934	27,680
Restricted cash		-	-	812
Investment in related party	6	566	814	-
Exploration and evaluation assets	7	1,989	4,595	7,992
Property, plant and equipment	8	274,361	233,026	172,559
Investment tax credit receivable	9	27,670	27,670	27,670
Deferred tax asset	9	33,450	50,786	67,304
		364,176	347,825	304,017
Liabilities				
Current				
Accounts payable and accrued liabilities	10	30,716	16,839	18,868
Due to related parties	11	32,000	32,000	23,500
Subordinated promissory note	12	15,000	-	-
		77,716	48,839	42,368
Subordinated promissory note	12	-	15,000	-
Bank debt	13	69,916	70,386	59,823
Decommissioning liabilities	14	34,904	23,427	21,282
		182,536	157,652	123,473
Commitments	19			
Shareholders' Equity				
Share capital	15	142,567	135,030	121,955
Contributed surplus	15	5,302	3,135	3,350
Accumulated other comprehensive income		2,662	5,702	2,020
Retained earnings		31,109	46,306	53,219
		181,640	190,173	180,544
		364,176	347,825	304,017

See accompanying notes to these financial statements.

On behalf of the Board:

George F. Fink
Director

Bill Woodward
Director

STATEMENTS OF COMPREHENSIVE INCOME

For the year ended December 31 ($ 000s, except $ per share)	Note	2011	2010 (Note 21)
Revenue			
Oil and gas sales, net of royalties	16	144,700	107,402
Other income	17	2,642	11,335
		147,342	118,737
Expenses			
Production costs		36,787	30,451
Office and administration		2,332	1,539
Employee compensation		4,456	4,274
Finance costs	5	4,436	3,656
Share-based payments	15	2,554	483
Depletion and depreciation	8	32,699	22,444
Impairment of natural gas assets	7,8	2,585	-
		85,849	62,847
Earnings before income taxes		61,493	55,890
Deferred income taxes	9	17,885	15,936
Net earnings for the year		43,608	39,954
Other comprehensive income (loss)			
Unrealized gains (losses) on investments		(1,462)	8,602
Deferred taxes on unrealized losses (gains) on investments		266	(1,192)
Realized gains on investments transferred to net earnings		(2,126)	(4,335)
Deferred taxes on realized gains on investments transferred to net earnings		282	607
Other comprehensive income (loss) for the year		(3,040)	3,682
Total comprehensive income for the year		40,568	43,636
Net earnings per share – basic	15	2.25	2.12
Net earnings per share – diluted	15	2.23	2.06
Comprehensive income per share – basic	15	2.10	2.32
Comprehensive income per share – diluted	15	2.07	2.26

See accompanying notes to these financial statements.

STATEMENTS OF CASH FLOWS

For the year ended December 31 ($ 000s)	2011	2010
Operating Activities		
Earnings before income taxes	61,493	55,890
Items not affecting cash		
Share-based payments	2,554	483
Depletion and depreciation	32,699	22,444
Impairment of natural gas assets	2,585	-
Unwinding of the fair value of decommissioning liabilities	954	858
Gain on sale of property	(162)	(6,558)
Gain on sale of investments	(2,126)	(4,335)
Interest income	(27)	(24)
Interest expense	3,482	2,798
Change in non-cash working capital		
Change in accounts receivable	(2,313)	(2,590)
Change in crude oil inventory	(417)	(39)
Change in prepaid expenses	(57)	1,616
Change in accounts payable and accrued liabilities	3,057	(1,313)
Restricted cash	-	812
Decommissioning expenditures	(831)	(1,006)
Interest paid	(3,482)	(2,798)
Cash Provided by Operating Activities	97,409	66,238
Financing Activities		
Increase (decrease) in bank debt	(470)	10,563
Due to related parties	-	8,500
Subordinated promissory note	-	15,000
Stock option proceeds	7,150	12,377
Dividends	(58,805)	(46,867)
Cash Used in Financing Activities	(52,125)	(427)
Investing Activities		
Interest received	27	24
Exploration and evaluation expenditures	(309)	-
Property, plant and equipment expenditures	(62,615)	(76,914)
Proceeds on sale of property	238	6,234
Proceeds on sale of investments	3,991	5,603
Change in non-cash working capital		
Change in accounts payable and accrued liabilities	10,820	(716)
Change in accounts receivable	2,564	(42)
Cash Used in Investing Activities	(45,284)	(65,811)
Net cash Inflow	-	-
Cash, beginning of year	-	-
Cash, end of year	-	-

STATEMENTS OF CHANGES IN EQUITY

For the year ended
($000s, except for number of shares outstanding)

	Number of shares outstanding (Note 15)	Share Capital (Note 15)	Contributed Surplus [1]	Accumulated other comprehensive income [2]	Retained Earnings	Total Shareholders' Equity
January 1, 2010	18,619,641	121,955	3,350	2,020	53,219	180,544
Share-based payments			483			483
Exercise of options	599,900	12,377				12,377
Transfer to share capital on exercise of options		698	(698)			-
Comprehensive income				3,682	39,954	43,636
Dividends (Note 15)					(46,867)	(46,867)
December 31, 2010	19,219,541	135,030	3,135	5,702	46,306	190,173
Share-based payments			2,554			2,554
Exercise of options	351,775	7,150				7,150
Transfer to share capital on exercise of options		387	(387)			-
Comprehensive income				(3,040)	43,608	40,568
Dividends (Note 15)					(58,805)	(58,805)
December 31, 2011	**19,571,316**	**142,567**	**5,302**	**2,662**	**31,109**	**181,640**

(1) Contributed surplus comprises of share-based payments.

(2) Accumulated other comprehensive income comprises of unrealized gains and losses on available-for-sale investments.

See accompanying notes to these financial statements

Notes to the Financial Statements

As at and for the years ended December 31, 2011 and December 31, 2010 and as at January 1, 2010.

1. NATURE OF BUSINESS AND SEGMENT INFORMATION

Bonterra Energy Corp. (Bonterra or the Company) is a public company listed on the Toronto Stock Exchange and incorporated under the Business Corporations Act (Alberta). The address of the Company's executive office is Suite 901, 1015 4th Street SW, Calgary, Alberta, Canada, T2R 1J4.

Bonterra operates in one industry and has only one reportable segment being the development and production of oil and natural gas in the Western Canadian Sedimentary Basin.

The financial statements were authorized for issue by the Company's Board of Directors on March 22, 2012.

2. BASIS OF PREPARATION

a) Statement of Compliance

These financial statements are prepared in accordance with International Financial Reporting Standards (IFRS). In 2010, the Canadian Institute of Chartered Accountants Handbook (CICA Handbook) was revised to incorporate IFRS as issued by the International Accounting Standards Board (IASB) and requires publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Accordingly, the Company has commenced reporting on this basis in these financial statements after applying the requirements of International Financial Reporting Standards 1 – First-time Adoption of International Financial Reporting Standards (IFRS 1). In the financial statements, the term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS.

The December 31, 2011 annual financial statements are the Company's first annual financial statements prepared in compliance with IFRS using the policies as presented in these statements, having an adoption date of January 1, 2011 and a transition date of January 1, 2010. Consequently, the comparative figures for 2010 and the Company's statement of financial position as at January 1, 2010 have been restated from accounting principles generally accepted under Canadian GAAP to comply with IFRS.

The reconciliations to IFRS from the previously published Canadian GAAP financial statements are summarized in Note 21. In addition, IFRS 1 requires certain exceptions and allows certain exemptions from retrospective application of IFRS in the opening statement of financial position. Where these have been applied they are explained in Note 21.

b) Basis of Measurement

These financial statements have been prepared on a historical cost basis, except for certain financial instruments and share-based payment transactions which are measured at fair value.

c) Use of Judgments and Estimates

The timely preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the statement of financial position as well as the reported amounts of revenues, expenses and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the financial statements. Actual results could differ materially from estimated amounts.

Exploration and evaluation assets and property, plant and equipment, are aggregated into cash generating units (CGU's) based on their potential ability to generate largely independent cash flows and are used for impairment assessment. The determination of the Company's CGU's is subject to management's judgment.

Amounts recorded for depletion and depreciation are based on estimates of crude oil and natural gas reserves. Amounts used for impairment calculations are also based on estimates of crude oil and natural gas reserves and future costs required to develop those reserves. Share-based payments are based upon expected volatility and option life estimates. Provisions for decommissioning liabilities are based on estimates of abandonment costs, timing of abandonment, inflation and interest rates. The provision for income taxes is based on judgments in applying income tax law and estimates on the timing, likelihood and reversal of temporary differences between the accounting and tax basis of assets and liabilities. These estimates are subject to measurement uncertainty and changes in these estimates could materially impact the financial statements of future periods. Further details regarding judgments are discussed in Note 3.

d) Presentation Currency

The Company's functional and presentation currency is the Canadian dollar.

Monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the reporting date. Non-monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the transaction dates. Exchange gains and losses are recorded as income or expense in the period in which they occur.

e) Recent Accounting Pronouncements

As of January 1, 2013, Bonterra will be required to adopt amendments to IAS 1 "Presentation of Financial Statements" which will require companies to group together items within other comprehensive income that may be reclassified to the net earnings section of the comprehensive income statement. Bonterra does not expect a material impact as a result of the amendments.

Each of the additional new standards outlined below is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted, except for IFRS 9 "Financial Instruments" which is effective for annual periods beginning on or after January 1, 2015. The Company has not yet assessed the impact, if any, that the new amended standards will have on its financial statements or whether to early adopt any of the new requirements.

IFRS 9 "Financial Instruments"

The result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

IFRS 10 "Consolidated Financial Statements"

Replaces Standing Interpretations Committee 12, "Consolidation - Special Purpose Entities" and the consolidation requirements of IAS 27 "Consolidated and Separate Financial Statements". The new standard replaces the existing risk and rewards based approaches and establish control as the determining factor when determining whether an interest in another entity should be included in the consolidated financial statements.

IFRS 11 "Joint Arrangements"

Replaces IAS 31 "Interests in Joint Ventures" along with amending IAS 28 "Investment in Associates". The new standard focuses on the rights and obligations of an arrangement, rather than its legal form. The standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted.

IFRS 12 "Disclosure of Interests in Other Entities"

Provides comprehensive disclosure requirements on interests in other entities, including joint arrangements, associates, and special purpose vehicles. The new disclosure requires information that will assist financial statement users in evaluating the nature, risks and financial effects of an entity's interest in subsidiaries and joint arrangements.

IFRS 13 "Fair Value Measurement"

Provides a common definition of fair value within IFRS. The new standard provides measurement and disclosure guidance and applies when IFRS requires or permits the item to be measured at fair value, with limited exceptions. This standard does not determine when an item is measured at fair value and as such does not require new fair value measurements.

3. SIGNIFICANT ACCOUNTING POLICIES

a) Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when the significant risks and rewards of ownership have been transferred to the customer. This generally occurs when the product is physically transferred into a third-party pipeline or when the delivery truck arrives at a customer's receiving location. Items such as royalties from crown, freehold, gross overriding (GORR) and Saskatchewan surcharge are netted against revenue. These items are netted to reflect the deduction for other parties' proportionate share of the revenue.

Administration fee income is recorded when management services and office administration are provided (see related parties disclosure Note 11 and Note 17).

b) Jointly Controlled Assets

Significant portions of the Company's oil and gas assets are owned and operated jointly with other parties and accordingly the financial statements reflect only the Company's proportionate share of assets, liabilities, revenues, expenses and cash flows from these activities.

c) Inventories

Inventories consist of crude oil. Crude oil stored in the Company's tanks is valued on a first in first out basis at the lower of cost or net realizable value. Inventory cost for crude oil is determined based on combined average per barrel operating costs, depletion and depreciation for the period and net realizable value is determined based on estimated sales price less transportation costs.

d) Investments and Investment in Related Party

Investments and investments in related party consist of equity securities classified on initial recognition as available-for-sale and are carried at fair value. Fair value is determined by multiplying the period end trading price of the investments by the number of common shares held as at period end. Unrealized holding gains and losses are recognized in other comprehensive income. Net gains and losses arising on disposal are recognized in net earnings.

e) Exploration and Evaluation Assets

General exploration or evaluation (E&E) expenditures incurred prior to acquiring the legal right to explore are charged to expense as incurred.

E&E expenditures represent undeveloped land costs, licenses and exploration well costs.

Undeveloped land costs, licenses and exploration well costs are initially capitalized and, if subsequently determined to have not found sufficient reserves to justify commercial production, are charged to expense. E&E assets continue to be capitalized as long as sufficient progress is being made to assess the reserves and economic viability of the well and/or related project. Once technical feasibility and commercial viability has been established, E&E assets are transferred to property, plant and equipment (PP&E). E&E assets are assessed for impairment either annually, upon transfer to PP&E assets or whenever indications of impairment exist to ensure they are not carried above their recoverable amounts.

f) Property, Plant and Equipment

PP&E assets include transferred-in E&E costs, development drilling and other subsurface expenditures. PP&E assets are carried at cost less depletion and depreciation of all development expenditures and include all other expenditures associated with PP&E assets.

When commercial production in an area has commenced, PP&E properties, excluding surface costs are depleted using the unit-of-production method over their proved developed reserve life. Proved developed reserves are determined annually by qualified independent reserve engineers. Changes in factors such as estimates of proved developed reserves that affect unit-of-production calculations are accounted for on a prospective basis. Surface costs such as production facilities and furniture, fixtures and other equipment are depreciated over their estimated useful lives.

Oil and Gas Properties

The initial cost of an asset is comprised of its purchase price or construction cost, including expenditures such as drilling costs, the present value of the initial and changes in the estimate of any decommissioning obligation associated with the asset and finance charges on qualifying assets, that are directly attributable to bringing the asset into operation and to its present location.

Production Facilities

Production facilities are comprised of costs related to petroleum and natural gas plant and production equipment.

Depletion and Depreciation

Depletion and depreciation is recognized in the statement of comprehensive income. Production facilities, furniture, fixtures and other equipment are depreciated over the individual assets' estimated economic lives. These assets are depreciated on a declining balance method as follows:

Production facilities	10 percent per year
Furniture, fixtures and other equipment	10 percent to 20 percent per year

g) Impairment of Assets

Impairment of Financial Assets

A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. An impairment loss in respect of an available-for-sale financial asset is calculated by reference to its current fair value.

All impairment losses are recognized in net earnings. An impairment loss is reversed if there is an indicator that the impairment reversal can be related objectively to an event occurring after the impairment loss was recognized. Any subsequent recovery of an impairment loss in respect of an investment in an equity instrument classified as available-for-sale is reversed through other comprehensive income instead of net earnings. For financial assets measured at amortized cost, the reversal is recognized in net earnings.

Impairment of Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment. If such indication exists, then the assets' carrying amounts are assessed for impairment.

For the purpose of impairment testing, assets (which include E&E and PP&E assets) are grouped together into the smallest group of assets that generates cash flows from continuing use that are largely independent of the cash flows of other assets or groups of assets (the cash-generating unit or CGU). The recoverable amount of an asset or a CGU is the greater of its value-in-use (VIU) and its fair value less costs to sell (FVLCS).

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. Impairment losses are recognized in the statement of comprehensive income. Impairment losses recognized in respect of a CGU are allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amount of the other assets of the CGU on a pro-rata basis.

An impairment loss in respect of goodwill cannot be reversed. In respect of other assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If the amount of the impairment loss decreases in a subsequent period and the decrease can be objectively related to an event occurring after the impairment was recognized, the impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

h) Decommissioning Liabilities

The fair value of the statutory, contractual, constructive or legal liabilities associated with the retirement and reclamation of oil and gas properties is recorded when incurred, with a corresponding increase to the carrying amount of the related PP&E. The amount recognized is the estimated cost of decommissioning, discounted to its present value using the Company's risk free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates and changes to the risk free rates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment. The unwinding of the discount on the decommissioning provision is charged to net earnings as a finance cost.

The Company recognizes a decommissioning liability in the period in which it is incurred when a reasonable estimate of the fair value can be made. On a periodic basis, management will review these estimates and changes, if there are any, will be applied prospectively. The fair value of the estimated provision is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the proved developed reserves. The liability amount is increased each reporting period due to the passage of time and this amount is charged to earnings in the period. Actual costs incurred upon settlement of the obligations are charged against the provision to the extent of the liability recorded and the remaining balance of the actual costs is recorded in the statement of comprehensive income.

i) Income Taxes

Tax expense comprises current and deferred taxes. Tax is recognized in the statement of comprehensive income or directly in equity.

Current tax expense is based on the results for the period as adjusted for items that are not taxable or not deductible. Current tax is calculated using tax rates and laws that are substantively enacted at the end of the reporting period. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. Provisions are established where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred tax is recognized using the liability method, providing for unused tax losses, unused tax credits and temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for the following temporary differences: the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit, and differences relating to

investments in subsidiaries to the extent that they are unlikely to be reversed in the foreseeable future. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which unused tax losses, unused tax credits and temporary differences can be utilized. Deferred tax assets are reviewed at each balance date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

j) Share-Based Payments

The Company accounts for share-based payments using the fair-value method of accounting for stock options granted to directors, officers, employees and other service providers using the Black-Scholes option pricing model. Share-based payments are recognized through the statement of comprehensive income over the vesting period with a corresponding amount reflected in contributed surplus in equity. For awards issued in tranches that vest at different times, the fair value of each tranche is recognized over its respective vesting period.

At the grant date and at the end of each reporting period, the Company assesses and re-assesses for subsequent periods its estimates of the number of awards that are expected to vest and recognizes the impact of the revisions in the statement of comprehensive income. Upon exercise of share-based options, the proceeds received net of any transaction costs and the fair value of the exercised share-based options is credited to share capital.

k) Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument and are classified into one of the following five categories: fair-value through profit or loss, loans and receivables, held-to-maturity investments, available-for-sale financial assets and financial liabilities at amortized cost.

Subsequent measurement of financial instruments is based on their initial classification. Fair-value through profit or loss financial instruments are measured at fair value and changes in fair value are recognized in the statement of comprehensive income. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

Cash and restricted cash are classified as fair-value through profit and loss. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Investments are classified as available-for-sale which is measured at fair value and any gains or losses are recognized in other comprehensive income in the period they occur. Accounts payable and accrued liabilities, bank debt, subordinated promissory note and amounts due to related parties are classified as financial liabilities at amortized cost.

Bank debt, subordinated promissory note and due to related parties are classified as current liabilities unless the Company has an unconditional right to defer settlement of the liability for at least 12 months after the reporting date.

l) Risk Management Contracts

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign currency exchange rates and interest rates in the normal course of its business. The Company may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, the Company accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party quotes or valuations provided by independent third parties. Any realized gains or losses on risk management contracts are recognized in net earnings in the period they occur.

The Company may elect to use hedge accounting when there is a high degree of correlation between the price movements in the financial instruments and the items designated as being hedged and the Company has documented the relationship between the instruments and the hedged item as well as its risk management objective and strategy for undertaking hedge transactions. During the years ended December 31, 2011 and December 31, 2010, the Company did not designate any of its financial instruments as hedges. There were no risk management contracts outstanding as at December 31, 2011, December 31, 2010 and January 1, 2010.

m) Net Earnings and Comprehensive Income per Share

Per share amounts are calculated by dividing the net earnings or comprehensive income attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the reporting period.

Diluted per share amounts are calculated similar to basic per share amounts except that the weighted average common shares outstanding are increased to include additional common shares from the assumed exercise of dilutive share options. The number of additional outstanding common shares is calculated by assuming that the outstanding in-the-money share options were exercised and that the proceeds from such exercises were used to acquire common shares at the average market price during the reporting period.

4. ACCOUNTS RECEIVABLE

Accounts receivable are non-interest-bearing financial assets and are generally due on monthly terms. Impairment allowances are recognized based on the Company's inability to collect impaired receivables for more than 12 months and there is no clear evidence that particular receipts are reasonably collectable. The Company's allowance for doubtful account balance is $42,000 (December 31, 2010 – $100,000, January 1, 2010 – $160,000).

5. FINANCE COSTS

A breakdown of finance costs for the current and previous year is:

($ 000s)	December 31, 2011	December 31, 2010
Interest expense on bank debt	2,272	2,134
Interest expense on subordinated promissory note	450	109
Interest expense on amounts owing to related parties	760	555
Unwinding of the fair value of decommissioning liabilities	954	858
	4,436	3,656

6. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 (December 31, 2010 – 689,682) common shares in Geomark Exploration Ltd. (Geomark), a company with common directors and some common management with the Company. The investment is recorded at fair market value.

Effective July 6, 2010, Comaplex Minerals Corp. (Comaplex) (a company with some common management and common directors) was acquired by Agnico-Eagle Mines Limited (Agnico-Eagle). In exchange for Bonterra's 689,682 common shares in Comaplex, the Company received 689,682 shares in Geomark and 108,693 common shares in Agnico-Eagle (value included in Investments on the balance sheet). The common shares of Agnico-Eagle trade on the Toronto Stock Exchange under the symbol AEM and the common shares of Geomark trade on the TSX Venture Exchange under the symbol GME. The investment in Geomark represents 1.3 percent ownership in the outstanding common shares of Geomark.

7. EXPLORATION AND EVALUATION ASSETS

($ 000s)	E&E assets
Cost and carrying amount	
Balance at January 1, 2010	7,992
Additions	-
Transfers to property, plant and equipment	(3,397)
Balance at December 31, 2010	**4,595**
Additions	309
Transfers to property, plant and equipment	(2,001)
Impairment (Note 8)	(914)
Balance at December 31, 2011	**1,989**

8. PROPERTY, PLANT AND EQUIPMENT

Cost ($ 000s)	Oil and gas properties	Production facilities	Furniture, fixtures & other equipment	Total property, plant & equipment
Balance at January 1, 2010	211,020	52,552	1,461	265,033
Additions	69,449	10,386	13	79,848
Transfers from exploration and evaluation assets	3,397	-	-	3,397
Disposals	(382)	(210)	-	(592)
Balance at December 31, 2010	**283,484**	**62,728**	**1,474**	**347,686**
Additions	58,874	15,019	77	73,970
Transfers from exploration and evaluation assets	2,001	-	-	2,001
Disposals	(166)	(136)	(41)	(343)
Balance at December 31, 2011	**344,193**	**77,611**	**1,510**	**423,314**

Accumulated Depletion and Depreciation ($ 000s)	Oil and gas properties	Production facilities	Furniture, fixtures & other equipment	Total property, plant & equipment
Balance at January 1, 2010	(70,030)	(21,428)	(1,016)	(92,474)
Depletion and depreciation	(18,412)	(3,950)	(82)	(22,444)
Disposals and other	145	113	-	258
Balance at December 31, 2010	**(88,297)**	**(25,265)**	**(1,098)**	**(114,660)**
Depletion and depreciation	(27,435)	(5,181)	(83)	(32,699)
Disposals and other	(5)	44	38	77
Impairment	(784)	(887)	-	(1,671)
Balance at December 31, 2011	**(116,521)**	**(31,289)**	**(1,143)**	**(148,953)**

Carrying amounts as at: ($ 000s)				
January 1, 2010	140,990	31,124	445	172,559
December 31, 2010	195,187	37,463	376	233,026
December 31, 2011	**227,672**	**46,322**	**367**	**274,361**

Impairment

Management has determined there are four cash generating units for the Company, which are comprised of one core cash-generating unit (CGU) for the Pembina Cardium and Willesden Green assets in Alberta, Canada and three other CGUs.

These CGUs are the Company's producing fields. As part of its annual impairment analysis, the Company assessed its PP&E assets, production facilities, furniture and other equipment by CGU for possible impairment.

The assessment for impairment has been determined based on the value-in-use (VIU) method. VIU was determined on the basis of the discounted expected future cash flows based on the Company's plans to continue to produce total proved and probable reserves.

Projected estimates of cash flows from the CGUs have been determined based on the economic life of the reserves using an inflation rate of 2.0 percent. The pre-tax discount rate applied to the cash flows for the Company's total proved and probable developed assets is 10 percent and 15 percent for probable undeveloped assets.

At December 31, 2011, there were significant changes in the future commodity price forecasts for natural gas used by the Company's Canadian-based, independent reserves evaluator when compared to December 31, 2010. Expected future cash flows from the sale of these volumes are calculated based on the Company's best estimate of future oil and gas prices. Prices for oil and gas used for future cash flow projections are based on quality and Edmonton PAR for oil and AECO for natural gas forward prices. The Company considered the downward price adjustments of natural gas to be an indicator of impairment for the Company's minor natural gas assets in British Columbia, as the VIU was lower than the carrying amount. Based on this assessment, the Company determined that $2,585,000 comprising of $914,000 of E&E assets and $1,671,000 of PP&E assets within the British Columbia CGU were impaired. No impairment provisions were taken as at December 31, 2010 and January 1, 2010.

9. INCOME TAXES

The Company has recorded a deferred tax asset related to:

($ 000s)	December 31, 2011	December 31, 2010	January 1, 2010
Deferred tax asset (liability) related to:			
Investments	(308)	(832)	(824)
Exploration and evaluation assets and property, plant and equipment	(27,354)	(16,053)	(9,583)
Decommissioning liabilities	8,737	5,866	5,352
Share issue costs	-	367	802
Corporate tax losses and SR&ED claims	52,067	60,606	71,557
Corporate capital tax loss	17,212	17,705	17,883
Unrecorded benefit of capital tax losses	(16,904)	(16,873)	(17,883)
Deferred tax asset	33,450	50,786	67,304

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

($ 000s)	December 31, 2011	December 31, 2010
Earnings before taxes	61,493	55,890
Combined federal and provincial income tax rates	26.53%	28.06%
Income tax provision calculated using statutory tax rates	16,314	15,683
Increase (decrease) in taxes resulting from:		
Share-based payments	677	136
Non-taxable portion of capital gains	(300)	(596)
Unrecorded benefit of capital tax losses	31	(1,010)
Change in effective tax rate	1,055	1,592
Others	108	131
Income tax expense	17,885	15,936

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

($ 000s)	Rate of Utilization (%)	Amount
Undepreciated capital costs	20-100	32,482
Eligible capital expenditures	7	6,370
Canadian oil and gas property expenditures	10	17,444
Canadian development expenditures	30	98,957
Canadian exploration expenditures	100	11,174
SR&ED expenditures	100	12,004
Income tax losses carried forward [1]	100	223,665
		402,096

(1) Federal income tax losses carried forward expire in the following years; 2013 – $1,069,000, 2024 – $3,347,000, 2025 – $7,532,000, 2026 – $46,671,000, 2027 – $117,189,000, 2028 – $34,726,000, 2029 – $13,131,000.

The Company has $27,670,000 (December 31, 2010 – $27,670,000) remaining of investment tax credits that expire in the following years; 2019 – $3,469,000, 2020 – $3,059,000, 2021 – $4,667,000, 2022 – $3,909,000, 2023 – $3,155,000, 2024 – $1,995,000, 2025 – $2,257,000, 2026 – $ 2,405,000, 2027 – $2,009,000, 2028 – $745,000.

The Company also has $137,514,000 (December 31, 2010 – $139,773,000) of capital loss carry forwards which can only be claimed against taxable capital gains.

The amount and timing of reversals of temporary differences will also depend on the Company's future operating results, and acquisitions and dispositions of assets and liabilities. A significant change in any of the preceding assumptions could materially affect the Company's estimate of the deferred income tax asset.

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Total accounts payable and accrued liabilities comprise the following categories:

($ 000s)	December 31, 2011	December 31, 2010	January 1, 2010
Accounts payable	25,890	13,120	15,657
Accrued liabilities	4,826	3,719	3,211
	30,716	16,839	18,868

11. TRANSACTIONS WITH RELATED PARTIES

As of December 31, 2011, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2010 – $12,000,000, January 1, 2010 – $11,500,000). The loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms. but is payable on demand. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. Interest paid on this loan during the year was $285,000 (December 31, 2010 – $242,000).

As a result of the acquisition by Agnico-Eagle of Comaplex on July 6, 2010, the $12,000,000 loan previously held by Comaplex was transferred to Geomark and is repayable by the Company under the same terms. In the third quarter of 2010, Geomark loaned Bonterra an additional $8,000,000. As of December 31, 2011, Geomark has loaned the Company a total of $20,000,000 (December 31, 2010 – $20,000,000, Comaplex January 1, 2010 – $12,000,000). At December 31, 2011 the loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms but is payable on demand. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. Interest paid on this loan during 2011 was $475,000 (December 31, 2010 – $313,000 paid to Geomark and Comaplex).

The Company's bank agreement requires that the above loans can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. As at December 31, 2011, the Company had sufficient room to repay all balances.

The Company received a management fee from Geomark of $270,000 for the year ended December 31, 2011 (2010 – $316,500 received from Geomark and Comaplex) for management services and office administration. This fee has been included in other income. As at December 31, 2011, the Company had an account receivable from Geomark of $74,000 (December 31, 2010 – $35,000, Comaplex January 1, 2010 – $105,000).

The Company received a management fee of $60,000 for the year ended December 31, 2011 (2010 – $90,000) for management services and office administration from Pine Cliff Energy Ltd. (Pine Cliff), a company with some common directors and some common management with Bonterra. This fee has been included in other income. As at December 31, 2011, the Company had an account receivable from Pine Cliff of $4,000 (December 31, 2010 – $1,000, January 1, 2010 – $1,000).

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Compensation for key management personnel

($ 000s)	December 31, 2011	December 31, 2010
Compensation	1,352	1,291
Share-based payments	1,289	176
Total compensation	2,641	1,467

Key management personnel are those persons, including all directors, having authority and responsibility for planning, directing and controlling the activities of the Company.

12. SUBORDINATED PROMISSORY NOTE

On October 4, 2010 the Company borrowed $15,000,000 from a private investor. In exchange, Bonterra has issued a subordinated promissory note for $15,000,000. The terms of the Subordinated Promissory Note are that it bears interest at three percent, is not callable by the investor prior to January 4, 2012 at which time it will be a demand note until its maturity of April 4, 2012, and can be repaid at the option of the Company at any time. Security consists of a floating demand debenture totaling $15,000,000 over all of the Company's assets and is subordinated to any and all claims in favor of the syndicate of senior lenders providing credit facilities to the Company. Interest paid on the subordinated promissory note for the year ended December 31, 2011 was $450,000 (December 31, 2010 – $109,000).

The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. As of December 31, 2011 the Company has sufficient room to repay the subordinated promissory note.

The loan was not called by the investor on January 4, 2012. On February 10, 2012, the Company and the investor entered into an amending agreement whereby the subordinated promissory note would be repaid by the Company after thirty days written notice by either party beginning at any time on or after April 4, 2012.

13. BANK DEBT

As of December 31, 2011 and December 31, 2010, the Company has a bank facility consisting of $100,000,000 syndicated revolving credit facility and a $20,000,000 non-syndicated revolving credit facility. Amounts drawn under the facility at December 31, 2011 were $69,916,000 (December 31, 2010 – $70,386,000). Amounts borrowed under the credit facility at December 31, 2011 bear interest at a floating rate based on the applicable Canadian prime rate or Banker's Acceptance rate, plus between 0.75 percent and 3.50 percent, depending on the type of borrowing and the Company's consolidated total funded debt to consolidated cash flow. The terms of the revolving credit facility provided that the loan is revolving to April 26, 2012 and with a maturity date of April 25, 2013 and is subject to annual review. The revolving credit facility has no fixed terms of repayment.

The amount available for borrowing under the credit facilities is reduced by outstanding letters of credit. Letters of credit totaling $400,000 were issued December 31, 2011 (December 31, 2010 – $285,000). Security for credit facilities consists of various and floating demand debentures totaling $200,000,000 over all of the Company's assets, and general security agreement with first ranking over all personal and real property.

The following is a list of the material covenants on the banking facility:

- The Company is required to not exceed $120,000,000 in consolidated debt (includes working capital but excludes related party amounts and subordinated promissory note).
- Dividends paid in the current quarter and the three previous quarters shall not exceed 80 percent of the previous four quarters' cash flow as defined under IFRS excluding adjustments for non-cash working capital items.

At December 31, 2011, the Company is in compliance with all covenants.

14. DECOMMISSIONING LIABILITIES

At December 31, 2011, the estimated total undiscounted amount required to settle the decommissioning liabilities was $73,475,000 (December 31, 2010 – $62,579,000, January 1, 2010 – $64,482,000). The provision has been calculated assuming a 2.0 percent inflation rate (December 31, 2010 – 1.5 percent inflation rate, January 1, 2010 – 2.0 percent inflation rate). These obligations will be settled based on the useful lives of the underlying assets, which extend up to 50 years into the future. This amount has been discounted using a risk-free interest rate of 2.5 percent (December 31, 2010 and January 1, 2010 – 4.1 percent).

Changes to decommissioning liabilities were as follows:

($ 000s)	December 31, 2011	December 31, 2010
Decommissioning liabilities, January 1	23,427	21,282
Adjustment to decommissioning liabilities	11,354	2,736
Adjustment related to asset disposals	-	(443)
Liabilities settled during the year	(831)	(1,006)
Unwinding of the fair value of decommissioning liabilities	954	858
Decommissioning liabilities, end of year	34,904	23,427

15. SHAREHOLDERS' EQUITY

Authorized

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

	December 31, 2011		December 31, 2010	
Issued and fully paid – Common Shares	Number	Amount ($ 000s)	Number	Amount ($ 000s)
Balance, January 1	19,219,541	135,030	18,619,641	121,955
Issued pursuant to Company share option plan	351,775	7,150	599,900	12,377
Transfer of contributed surplus to share capital		387		698
Balance, end of year	19,571,316	142,567	19,219,541	135,030

The Company is authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

The weighted average common shares used to calculate basic and diluted net earnings per share for the years ended December 31 is as follows:

	2011	2010
Basic shares outstanding	19,341,514	18,810,355
Dilutive effect of share options [(1)]	212,643	538,636
Diluted shares outstanding	19,554,157	19,348,991

(1) The Company did not include 599,000 share options (December 31, 2010 – 6,000) in the dilutive effect of share options calculation as these share options were anti-dilutive.

For the year ended December 31, 2011, the Company declared and paid dividends of $58,805,000 ($3.04 per share) (December 31, 2010 – $46,867,000 ($2.49 per share)).

The Company provides an equity settled option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,957,131 (December 31, 2010 – 1,921,954) common shares. The exercise price of each option granted cannot be lower than the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2011 and December 31, 2010, and changes during the years ended on those dates is presented below:

	Number of options	Weighted average exercise price
At January 1, 2010	1,330,900	$ 20.36
Options granted	36,000	36.98
Options exercised	(599,900)	20.63
Options cancelled	(20,000)	34.66
At December 31, 2010	747,000	$ 20.56
Options granted	1,142,000	54.54
Options exercised	(351,775)	20.32
Options cancelled	(11,000)	14.90
Options forfeited	(58,000)	32.14
At December 31, 2011	1,468,225	$ 46.63

The following table summarizes information about options outstanding at December 31, 2011:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number outstanding at December 31, 2011	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable at December 31, 2011	Weighted-average exercise price
$ 20.50	338,225	0.9 years	$ 20.50	330,225	$ 20.50
48.00 – 52.00	508,500	2.9 years	50.12	3,000	48.60
54.00 – 59.00	621,500	2.1 years	57.99	-	-
$ 20.50 – $ 59.00	1,468,225	2.1 years	$ 46.63	333,225	$ 20.75

The Company records compensation expense over the vesting period, which ranges between one to three years, based on the fair value of options granted to employees, directors and consultants. In 2011, the Company granted 1,142,000 stock options (December 31, 2010 – 36,000) with an estimated fair value of $8,394,000 or $7.35 per option (December 31, 2010 – $204,000 or $5.67 per option) using the Black-Scholes option pricing model with the following key assumptions:

($ 000s)	December 31, 2011	December 31, 2010
Weighted-average risk free interest rate (%) [1]	1.40	1.87
Expected life (years)	2.03	2.80
Weighted-average volatility (%) [2]	32.41	33.10
Forfeiture rate (%)	0.00	0.00
Dividend yield 2011 and 2010	Based on the expected dividend yield over the expected life of the options	

(1) Risk-free interest rate is based on the weighted average Government of Canada benchmark bond yields for two, three and five year terms to match corresponding vesting periods.

(2) The expected volatility is measured as the standard deviation of expected share price returns based on statistical analysis of historical weekly share prices for a representative period.

The weighted average share price of the options exercised in 2011 was $53.38 (2010 – $41.26).

16. OIL AND GAS SALES, NET OF ROYALTIES

($ 000s)	December 31, 2011	December 31, 2010
Oil and gas sales	162,277	118,980
Less:		
Crown royalties	(12,316)	(7,562)
Freehold, gross overriding royalties and other	(5,261)	(4,016)
Oil and gas sales, net of royalties	144,700	107,402

17. OTHER INCOME

($ 000s)	December 31, 2011	December 31, 2010
Investment income	27	24
Administrative income	327	418
Gain on sale of property	162	6,558
Gain on sale of investments	2,126	4,335
Other income	2,642	11,335

18. FINANCIAL AND CAPITAL RISK MANAGEMENT

Financial Risk Factors

The Company undertakes transactions in a range of financial instruments including:

- Accounts receivable
- Accounts payable and accrued liabilities
- Common share investments
- Due to related parties
- Bank debt
- Subordinated promissory note

The Company's activities result in exposure to a number of financial risks including market risk (commodity price risk, interest rate risk, and foreign exchange risk), credit risk, liquidity risk and equity price risk.

The Company's overall risk management program seeks to mitigate these risks and reduce the volatility on the Company's financial performance. Financial risk is managed by senior management under the direction of the Board of Directors.

The Company may enter into various risk management contracts to manage the Company's exposure to commodity price fluctuations. Currently no risk management agreements are in place. The Company does not speculatively trade in risk management contracts. The Company's risk management contracts are entered into to manage the risks relating to commodity prices from its business activities.

Capital Risk Management

The Company's objectives when managing capital, which the Company defines to include shareholders' equity, debt and working capital balances, are to safeguard the Company's ability to continue as a going concern, so that it can continue to provide returns to its shareholders and benefits for other stakeholders and to maintain a capital structure that provides a low cost of capital. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends, debt facilities or issue new shares.

The Company monitors capital on the basis of the ratio of debt to cash flow. This ratio is calculated using each quarter end net debt (total debt adjusted for working capital) and divided by the preceding twelve months cash flow. The Company believes that a debt level of approximately one and a half year's cash flow is an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its undeveloped resources by horizontal or vertical drill programs.

The following section (a) of this note provides a summary of the Company's underlying economic positions as represented by the carrying values, fair values and contractual face values of the Company's financial assets and financial liabilities. The Company's debt to cash flow from operations is also provided.

The following section (b) addresses in more detail the key financial risk factors that arise from the Company's activities including its policies for managing these risks.

The following section (c) provides details of the Company's risk management contracts that are used for financial risk management.

a) Financial assets, financial liabilities and debt ratio

The carrying amounts, fair value and face values of the Company's financial assets and liabilities are shown in Table 1.

Table 1

	As at December 31, 2011			As at December 31, 2010		
($ 000s)	Carrying Value	Fair Value	Face Value	Carrying Value	Fair Value	Face Value
Financial assets						
Accounts receivable	17,094	17,094	17,136	17,345	17,345	17,445
Investments	6,266	6,266	N/A	11,471	11,471	N/A
Investments in related party	566	566	N/A	814	814	N/A
Financial liabilities						
Accounts payable and accrued liabilities	30,716	30,716	30,716	16,839	16,839	16,839
Due to related parties	32,000	32,000	32,000	32,000	32,000	32,000
Subordinated promissory note	15,000	15,000	15,000	15,000	15,000	15,000
Bank debt	69,916	69,916	69,916	70,386	70,386	70,386

	As at January 1, 2010		
($ 000s)	Carrying Value	Fair Value	Face Value
Financial assets			
Accounts receivable	14,713	14,713	14,873
Investments	4,462	4,462	N/A
Investments in related party	4,827	4,827	N/A
Restricted cash	812	812	812
Financial liabilities			
Accounts payable and accrued liabilities	18,868	18,868	18,868
Due to related parties	23,500	23,500	23,500
Bank debt	59,823	59,823	59,823

Financial instruments consisting of accounts receivable, accounts payable and accrued liabilities, due to related parties, subordinated promissory note and bank debt on the statement of financial position are carried at amortized cost. Investments and investments in related party are carried at fair value. All of the fair value items are transacted in active markets. Bonterra classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Bonterra's investments and investments in related party have been assessed on the fair value hierarchy described above and are all considered Level 1.

The net debt and cash flow figures as of December 31, 2011 are presented in Table 2.

Table 2

($ 000s)	December 31, 2011
Bank debt	69,916
Accounts payable and accrued liabilities	30,716
Due to related parties	32,000
Subordinated promissory note	15,000
Current assets	(26,140)
Net debt	121,492
Cash flow from operations	97,409
Net debt to annualized cash flow from operations	1.25

b) Risks and mitigations

Market risk is the risk that the fair value or future cash flow of the Company's financial instruments will fluctuate because of changes in market prices. Components of market risk to which the Company is exposed are discussed below.

Commodity price risk

The Company's principal operation is the production and sale of crude oil, natural gas and natural gas liquids. Fluctuations in prices of these commodities directly impact the Company's performance and ability to continue with its dividends.

The Company has used various risk management contracts to set price parameters for a portion of its production. Management, in agreement with the Board of Directors, decided that at least in the near term it will discontinue the use of commodity price agreements. The Company will assume full risk in respect of commodity prices.

Interest rate risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. Interest rate risk arises from interest bearing financial assets and liabilities that the Company uses. The principal exposure of the Company is on its borrowings which have a variable interest rate which gives rise to a cash flow interest rate risk.

The Company's debt facilities consist of a $100,000,000 revolving operating line, $20,000,000 demand operating line, $32,000,000 due to related parties and a $15,000,000 subordinated promissory note. The borrowings under these facilities, except for the subordinated promissory note, are at bank prime plus or minus various percentages as well as by means of banker's acceptances (BAs) within the Company's credit facility. The subordinated promissory note is at a fixed interest rate of three percent. The Company manages its exposure to interest rate risk on its floating interest rate debt through entering into various term lengths on its BAs but in no circumstances do the terms exceed six months.

Sensitivity Analysis

Based on historic movements and volatilities in the interest rate markets and management's current assessment of the financial markets, the Company believes that a one percent variation in the Canadian prime interest rate is reasonably possible over a 12-month period.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by $764,000.

Equity price risk

Equity price risk refers to the risk that the fair value of the investments and investment in related party will fluctuate due to changes in equity markets. Equity price risk arises from the realizable value of the investments that the Company holds which are subject to variable equity market prices which on disposition gives rise to a cash flow equity price risk. The Company will assume full risk in respect of equity price fluctuations.

Foreign exchange risk

The Company has no foreign operations and currently sells all of its product sales in Canadian currency. The Company however is exposed to currency risk in that crude oil is priced in U.S. currency, then converted to Canadian currency. The Company currently has no outstanding risk management agreements. Management, in agreement with the Board of Directors, decided that at least in the near term it will not use commodity price agreements. The Company will assume full risk in respect of foreign exchange fluctuations.

Credit risk

Credit risk is the risk that a contracting party will not complete its obligations under a financial instrument and cause the Company to incur a financial loss. The Company is exposed to credit risk on all financial assets included on the statement of financial position. To help mitigate this risk:

- The Company only enters into material agreements with credit worthy counterparties. These include major oil and gas companies or major Canadian chartered banks; and
- Agreements for product sales are primarily on 30 day renewal terms.

Of the $17,094,000 accounts receivable balance at December 31, 2011 (December 31, 2010 – $17,345,000) over 70 percent (2010 – 88 percent) relates to product sales with international oil and gas companies and drilling credits receivable from the province of Alberta.

The Company assesses quarterly if there has been any impairment of the financial assets of the Company. During the year ended December 31, 2011, there was no material impairment provision required on any of the financial assets of the Company due to historical success of realizing financial assets. The Company does have a credit risk exposure as the majority of the Company's accounts receivables are with counterparties having similar characteristics. However, payments from the Company's largest accounts receivable counterparties have consistently been received within 30 days and the sales agreements with these parties are cancellable with 30 days notice if payments are not received.

At December 31, 2011, approximately $626,000 or 3.7 percent of the Company's total accounts receivable are aged over 90 days and considered past due. The majority of these accounts are due from various joint venture partners. The Company actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or netting payables when the accounts are with joint venture partners. Should the Company determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If the Company subsequently determines an account is uncollectable, the account is written off with a corresponding charge to the allowance account. The Company's allowance for doubtful accounts balance at December 31, 2011 is $42,000 (December 31, 2010 – $100,000) with the difference being included in general and administrative expenses. There were no material accounts written off during the period.

The maximum exposure to credit risk is represented by the carrying amounts of accounts receivable, accounts payable and accrued liabilities and the continuing availability of subordinated promissory note, due to related parties and bank debt on the statement of financial position. There are no material financial assets that the Company considers past due.

Liquidity risk

Liquidity risk includes the risk that, as a result of the Company's operational liquidity requirements:

- The Company will not have sufficient funds to settle a transaction on the due date;
- The Company will not have sufficient funds to continue with its dividends;
- The Company will be forced to sell assets at a value which is less than what they are worth; or
- The Company may be unable to settle or recover a financial asset at all.

To help reduce these risks the Company:

- Maintains a portfolio of high-quality, long reserve life oil and gas assets.

The Company has the following maturity schedule for its financial liabilities:

($ 000s)	Recognized on Financial Statements	Less than 1 year	Over 1 year to 3 years	4 to 5 years
Accounts payable and accrued liabilities	Yes - Liability	30,716	-	-
Due to related parties	Yes - Liability	32,000	-	-
Subordinated promissory note	Yes - Liability	15,000	-	-
Bank debt	Yes - Liability	-	69,916	-
Office leases	No	817	761	-
Total		78,533	70,677	-

c) Risk management contracts

The Company has no outstanding risk management contracts.

19. COMMITMENTS

Operating leases

The Company has entered into leases for buildings and office equipment. These leases have an average life of 1.9 years. There are no restrictions placed upon the lessee by entering into these leases. Future minimum lease payments under non-cancellable operating leases as at December 31, 2011 are as follows:

($ 000s)	2011
Within one year	817
After one year but not more than five years	761
Total	1,578

20. SUBSEQUENT EVENT – DIVIDENDS

Subsequent to December 31, 2011, the Company has declared the following dividends:

Date declared	Record date	$ per share	Date payable
January 4, 2012	January 16, 2012	0.26	January 31, 2012
February 2, 2012	February 15, 2012	0.26	February 29, 2012
March 2, 2012	March 15, 2012	0.26	March 30, 2012

21. TRANSITION TO IFRS

As stated in Note 2, these financial statements are prepared in accordance with IFRS. For all accounting periods prior to January 1, 2011, the Company prepared its financial statements under Canadian GAAP. An explanation of how the transition from previous GAAP to IFRS has affected the Company's statement of financial position and comprehensive income is set out in this note.

The accounting policies set out in Note 3 have been applied in preparing the financial statements for the year ended December 31, 2011, the comparative information presented in these financial statements for the year ended December 31, 2010 and as at December 31, 2010 and in the preparation of an opening IFRS statement of financial position at January 1, 2010 (the Company's date of transition).

IFRS 1 "First-time Adoption of International Financial Reporting Standards" (IFRS 1)

IFRS 1 generally requires that first-time adopters retrospectively apply all effective IFRS standards and interpretations in effect as at the reporting date. IFRS 1 also provides for certain optional exemptions and certain mandatory exceptions to this general principle.

Initial elections upon adoption

Set forth below are the IFRS 1 applicable exemptions and exceptions applied in the conversion from Canadian GAAP to IFRS.

- Business combinations (IFRS 3) – provides the option to apply IFRS 3, Business Combinations, retrospectively or prospectively from the Transition Date or an earlier date chosen by management. The retrospective basis would require restatement of all business combinations that occurred prior to the Transition Date. The Company elected not to retrospectively apply IFRS 3 to business combinations that occurred prior to its Transition Date and such business combinations have not been restated.
- Share-based payment (IFRS 2) – encourages the application of its provisions to equity instruments granted on or before November 7, 2002, but permits the application only to equity instruments granted after November 7, 2002 that had not vested by the Transition Date. The Company elected to avail itself of the exemption provided under IFRS 1 and applied IFRS 2 for all equity instruments granted after November 7, 2002 that had not vested by its Transition Date. Further, the Company applied IFRS 2 for all liabilities arising from share-based payment transactions that existed at its Transition Date. This election has no material effect on the Company's financial statements.
- Borrowing Costs (IAS 23) – requires an entity to capitalize the borrowing costs related to all qualifying assets for which the commencement date for capitalization is on or after January 1, 2010 or earlier if elected by management. Due to the short time frame to drill a well and place it on production this election has no material effect on the Company.
- Leases (IAS 17) – requires an entity to assess arrangements outstanding at the Transition Date. It also requires a determination of the appropriate lease classification in accordance with IAS 17, should an arrangement containing a lease be identified as part of the application of the International Financial Reporting Interpretations Committee (IFRIC) 4, Determining Whether an Arrangement Contains a Lease. This election has no effect on the Company.

21.1 RECONCILIATION OF THE STATEMENT OF FINANCIAL POSITION

		As at January 1, 2010			As at December 31, 2010		
($ 000s)	Notes	Canadian GAAP	IFRS Adjustments	IFRS	Canadian GAAP	IFRS Adjustments	IFRS
ASSETS							
Current							
Accounts receivable		14,713	-	14,713	17,345	-	17,345
Crude oil inventory		431		431	487		487
Prepaid expenses		3,247		3,247	1,631		1,631
Deferred tax asset	(b)	11,889	(11,889)	-	22,889	(22,889)	-
Investments		4,462		4,462	11,471		11,471
Investment in related party		4,827		4,827	-		-
		39,569	(11,889)	27,680	53,823	(22,889)	30,934
Restricted cash		812	-	812	-	-	-
Investment in related party		-	-	-	814	-	814
Exploration and evaluation assets	(a)	-	7,992	7,992	-	4,595	4,595
Property, plant and equipment	(a)	167,671	4,888	172,559	222,826	10,200	233,026
Investment tax credit receivable		27,670	-	27,670	27,670	-	27,670
Deferred tax asset	(b)	58,265	9,039	67,304	30,011	20,775	50,786
		254,418	21,919	276,337	281,321	35,570	316,891
		293,987	10,030	304,017	335,144	12,681	347,825
LIABILITIES							
Current							
Accounts payable and accrued liabilities		18,868	-	18,868	16,839	-	16,839
Due to related parties		23,500	-	23,500	32,000	-	32,000
Deferred credit	(c)	7,363	(7,363)	-	19,586	(19,586)	-
		49,731	(7,363)	42,368	68,425	(19,586)	48,839
Subordinate promissory note		-	-	-	15,000	-	15,000
Bank debt		59,823	-	59,823	70,386	-	70,386
Deferred credit	(c)	47,769	(47,769)	-	25,850	(25,850)	-
Decommissioning liabilities	(d)	17,790	3,492	21,282	17,070	6,357	23,427
		175,113	(51,640)	123,473	196,731	(39,079)	157,652
Shareholders' Equity							
Share capital		121,955	-	121,955	135,030	-	135,030
Contributed surplus		3,350	-	3,350	3,135	-	3,135
Accumulated other comprehensive income		2,020	-	2,020	5,702	-	5,702
Retained earnings (deficit)	(e)	(8,451)	61,670	53,219	(5,454)	51,760	46,306
Total equity		118,874	61,670	180,544	138,413	51,760	190,173
		293,987	10,030	304,017	335,144	12,681	347,825

IFRS has many similarities with Canadian GAAP as it is based on a similar conceptual framework. However, there are important differences with regard to recognition, measurement and disclosure. While adoption of IFRS did not change Bonterra's actual cash flows significantly, it resulted in changes to Bonterra's statement of financial position, statement of comprehensive income and statement of changes in equity as set out below:

a) Property, plant and equipment

	January 1, 2010 ($ 000s)
The Company exchanged certain oil and gas assets (Asset Exchange) in Alberta for oil and gas assets in Saskatchewan. The assets received were recorded at book value of the assets disposed of under Canadian GAAP. In accordance with IFRS, the values of the assets received are to be recorded at fair value, net of depletion	11,755
Increase related to change in discount rate used to present value future oil and gas well reclamation and abandonment costs, net of depletion	1,736
The Company is required to retroactively restate its capitalized overhead relating to oil and gas assets previously reported under Canadian GAAP. Under IFRS, only directly attributable costs can be capitalized	(611)
Under Canadian GAAP, capitalized exploration and evaluation assets was included with the Company's property, plant and equipment assets. Under IFRS, exploration and evaluation assets are separately disclosed within the statement of financial position	(7,992)
Net effect – increase in PP&E assets	4,888

	December 31, 2010 ($ 000s)
Increase related to using fair value instead of book value for the assets received in the Asset Exchange, net of depletion	10,884
Increase related to change in discount rate used to present value future oil and gas well reclamation and abandonment costs, net of depletion	4,480
Restatement of capitalized overhead from Canadian GAAP	(569)
Reclassification of E&E assets grouped with PP&E assets under Canadian GAAP	(4,595)
Net effect – increase in PP&E assets	10,200

b) Deferred tax assets

	January 1, 2010 ($ 000s)
Increase related to using fair value instead of book value for the assets received in the Asset Exchange	(3,446)
In accordance with IFRS, a decrease in deferred taxes has resulted from the increase of the decommissioning liabilities provision (see (d) below)	442
Restatement of capitalized overhead from Canadian GAAP	154
Reclassification of deferred tax assets classified as current under Canadian GAAP to non-current	11,889
Net effect – increase in deferred tax asset	**9,039**

	December 31, 2010 ($ 000s)
Increase related to using fair value instead of book value for the assets received in the Asset Exchange	(2,726)
In accordance with IFRS, a decrease in deferred taxes has resulted from the increase of the decommissioning liabilities provision (see (d) below)	470
Restatement of capitalized overhead from Canadian GAAP	142
Reclassification deferred tax assets classified as current under Canadian GAAP to non-current	22,889
Net effect – increase in deferred tax asset	**20,775**

c) Deferred credit

On November 12, 2008, Bonterra Energy Income Trust (the Trust) was acquired by Bonterra Oil & Gas Ltd. through a reverse takeover by the Trust of SRX Post Holdings Inc. (SRX). This transaction gave the Company additional tax pools in excess of the purchase price. Under Canadian GAAP, this purchase was considered an acquisition of an asset and not a business combination and therefore the resulting gain on acquisition had to be deferred and charged to net earnings on the same basis as the acquired assets. Under IFRS, the deferred gain does not meet the definition of a liability and was credited to retained earnings upon transition to IFRS.

d) Decommissioning liabilities

The discounted value of the decommissioning liabilities has increased due to a change in the discount rate used to calculate the present value of future oil and gas well reclamation and abandonments. Under Canadian GAAP, a credit risk adjusted discount rate was used; under IFRS, a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the obligation has been used. In accordance with IFRS 1, the Company has elected to recognize the $3,492,000 increase in the decommissioning obligation along with an increase to the related property, plant and equipment net of depletion, deferred tax assets and retained earnings (see (a) and (b) above and (e) below) at the transition date.

Similar adjustments were made for the year ended December 31, 2010 for $6,357,000 to decommissioning liabilities.

e) Retained earnings

The following tables represent the cumulative effect on the above transitional adjustments on retained earnings for the respective periods covered under this reconciliation:

	January 1, 2010 ($ 000s)
Using fair value instead of book value for assets received in the Asset Exchange (see (a) and (b) above)	8,309
Restatement of capitalized overhead from Canadian GAAP (see (a) and (b) above)	(457)
Deferred credit (see (c) above)	55,132
Decommissioning liabilities (see (a), (b) and (d) above)	(1,314)
Net effect – increase in retained earnings	61,670

	December 31, 2010 ($ 000s)
Using fair value instead of book value for assets received in the Asset Exchange (see (a) and (b) above)	8,158
Restatement of capitalized overhead from Canadian GAAP (see (a) and (b) above)	(427)
Deferred credit (see (c) above)	45,436
Decommissioning liabilities (see (a), (b) and (d) above)	(1,407)
Net effect – increase in retained earnings	51,760

21.2 RECONCILIATION OF THE STATEMENT OF COMPREHENSIVE INCOME

		Year ended December 31, 2010		
($ 000s)	Notes	Canadian GAAP	IFRS Adjustments	IFRS
Revenues				
Oil and gas sales, net of royalties	(a)	107,543	(141)	107,402
Other income	(b)	10,856	479	11,335
		118,399	338	118,737
Expenses				
Production costs		30,451	-	30,451
Office and administration	(c)	5,406	(3,867)	1,539
Employee compensation	(c)	-	4,274	4,274
Finance costs	(d)	2,799	857	3,656
Share-based payments expense		483	-	483
Depletion and depreciation	(e)	22,278	166	22,444
		61,417	1,430	62,847
Earnings before income taxes		56,982	(1,092)	55,890
Income taxes				
Current	(a)	141	(141)	-
Deferred	(f)	6,977	8,959	15,936
		7,118	8,818	15,936
Net earnings for the year		49,864	(9,910)	39,954
Other comprehensive income				
Unrealized gains on investments		8,602	-	8,602
Deferred taxes on unrealized gains on investments		(1,192)	-	(1,192)
Realized gains on investments transferred to net earnings		(4,335)	-	(4,335)
Deferred taxes on realized gains on investments transferred to net earnings		607	-	607
Other comprehensive income for the year		3,682	-	3,682
Comprehensive income for the year		53,546	(9,910)	43,636
Net earnings per share – basic		2.65	(0.53)	2.12
Net earnings per share – diluted		2.58	(0.52)	2.06
Comprehensive income per share – basic		2.85	(0.53)	2.32
Comprehensive income per share – diluted		2.77	(0.51)	2.26

The nature of the adjustments is explained as follows:

a) Oil and gas sales, net of royalties

($ 000s)	Year ended December 31, 2010
Reclassification of the Saskatchewan surcharge from taxes to royalties which are netted against revenue. This item is netted off of revenue to reflect the deduction for the other party's proportionate share of the revenue	(141)

b) Other income

($ 000s)	Year ended December 31, 2010
Increase on the gain from the sale of property which relates to an increase in the decommissioning liabilities prior to sale (see note 21.1 (d))	73
Reclassification of management fee income previously netted off of office and administration expense under Canadian GAAP	406
	479

c) Office and administration

($ 000s)	Year ended December 31, 2010
Reclassification of employee compensation grouped with office administration under Canadian GAAP	(4,274)
Reclassification of management fee income previously netted off of office and administration expense under Canadian GAAP	406
Other	1
	(3,867)

d) Finance costs

($ 000s)	Year ended December 31, 2010
Decrease in the unwinding of the fair value of decommissioning liabilities due to the transition adjustment (see note 21.1 (d))	(17)
Reclassification of the unwinding of the fair value of decommissioning liabilities previously grouped with depletion and depreciation under Canadian GAAP	874
	857

e) Depletion and depreciation

($ 000s)	Year ended December 31, 2010
Increase in depletion due to the increase in PP&E (see note 21.1 (a))	1,040
Reclassification of the unwinding of the fair value of decommissioning liabilities previously grouped with depletion and depreciation under Canadian GAAP	(874)
	166

f) Deferred taxes

($ 000s)	Year ended December 31, 2010
Increase in deferred taxes due to the removal of the deferred credit (see note 21.1 (c))	9,695
Decrease in deferred taxes due to the increase in PP&E (see note 21.1 (a)) and a decrease in deferred taxes due to the increase in the decommissioning liabilities (see note 21.1 (d))	(736)
	8,959

Corporate Information

BOARD OF DIRECTORS

G.J. Drummond, Nassau, Bahamas

G.F. Fink, Calgary, Alberta

C.R. Jonsson, Vancouver, British Columbia

F.W. Woodward, Calgary, Alberta

OFFICERS

B.A. Curtis – Vice President, Business Development

G.F. Fink – Chairman of the Board and Chief Executive Officer

R.M. Jarock – President and Chief Operating Officer

R.D. Thompson – Chief Financial Officer and Secretary

REGISTRAR & TRANSFER AGENT

Olympia Trust Company, Calgary, Alberta

AUDITORS

Deloitte & Touche LLP, Calgary, Alberta

SOLICITORS

Borden Ladner Gervais LLP, Calgary, Alberta

BANKERS

CIBC, Calgary, Alberta

Alberta Treasury Branch, Calgary, Alberta

STOCK LISTING

The Toronto Stock Exchange

Trading Symbol: BNE

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