PETROBAKKEN

A PETROBANK COMPANY

Third Quarter 2011 Report

PETROBAKKEN ANNOUNCES THIRD QUARTER 2011 RESULTS, CURRENT PRODUCTION IN EXCESS OF 47,500 BOEPD, AND REVISION TO EXIT GUIDANCE

Calgary, Alberta – November 8, 2011 – PetroBakken Energy Ltd. ("PetroBakken" or the "Company") (TSX:PBN), a 59% owned subsidiary of Petrobank Energy and Resources Ltd. (TSX:PBG), is pleased to announce third quarter 2011 financial and operating results and current production in excess of 47,500 boepd (based on field estimates). PetroBakken third quarter 2011 financial and operating results were highlighted by funds flow from operations of $152.4 million ($0.81 per basic share and $0.76 per diluted share), a top decile operating netback of $50.04 per barrel of oil equivalent ("boe") and average production of 39,074 barrels of oil equivalent per day ("boepd") (85% light oil and NGLs). Third quarter production was significantly impacted by shut-in wells and wet weather which delayed field operations. Since the end of July, production has consistently increased and October production averaged more than 46,000 boepd. Improved weather conditions have allowed us to accelerate our drilling schedule and, with 11 drilling rigs now operating, it is anticipated that an additional 25 net wells will be drilled in the remainder of 2011. With an additional 52 net wells expected to be brought on stream by year-end, we now forecast 2011 exit production rates in excess of 49,000 boepd.

FINANCIAL & OPERATING RESULTS

The following table provides a summary of PetroBakken's financial and operating results for the three and nine months ended September 30, 2011 and 2010. Interim consolidated financial statements with Management's Discussion and Analysis ("MD&A") are available on the Company's website at www.petrobakken.com and will also be available on the SEDAR website at www.sedar.com.

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% change	**2011**	2010	% change
Financial ($000s, except where noted)						
Oil and natural gas sales	**272,346**	228,537	19	**828,595**	750,197	10
Funds flow from operations [(1)]	**152,357**	140,761	8	**478,734**	485,499	(1)
Per share - basic ($)	**0.81**	0.75	8	**2.56**	2.65	(3)
- diluted ($)[(2)]	**0.76**	0.71	7	**2.36**	2.47	(4)
Adjusted Net income [(1) (3)]	**29,671**	36,063	(18)	**138,938**	110,222	26
Per share - basic ($)	**0.16**	0.19	(16)	**0.74**	0.60	23
- diluted ($)[(2)]	**0.16**	0.19	(16)	**0.73**	0.60	22
Net capital expenditures[(1)]	**271,786**	233,003	17	**669,688**	419,052	60
Total assets	**6,346,447**	5,677,921	12	**6,346,447**	5,677,921	12
Net debt [(1)]	**1,338,425**	858,375	56	**1,338,425**	858,375	56
Dividends	**44,880**	45,177	(1)	**134,692**	132,129	2
Per Share ($)	**0.24**	0.24	-	**0.72**	0.72	-
Common shares, end of period (000)						
Basic	**187,237**	187,675	-	**187,237**	187,675	-
Diluted [(2)]	**220,261**	215,137	2	**220,261**	215,137	2

	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% change	**2011**	2010	% change
Operations						
Operating netback ($/boe except where noted) (1) (4)						
Oil and NGL revenue ($/bbl) (5)	**84.61**	68.43	24	**87.17**	71.97	21
Natural gas revenue ($/Mcf) (5)	**4.01**	3.82	5	**4.11**	4.31	(5)
Oil, NGL and natural gas revenue(5)	**75.37**	60.63	24	**77.98**	64.71	21
Royalties	**12.20**	8.64	41	**12.36**	9.17	35
Production expenses	**13.13**	8.38	57	**12.73**	7.92	61
Operating netback (6)	**50.04**	43.61	15	**52.89**	47.62	11
Average daily production (4)						
Oil and NGL (bbls)	**33,112**	33,230	-	**32,965**	35,229	(6)
Natural gas (Mcf)	**35,776**	41,193	(13)	**34,030**	39,473	(14)
Total (boe)	**39,074**	40,095	(3)	**38,636**	41,808	(8)

(1) Non-GAAP measure. See "*Non-GAAP Measures*" section within this press release.

(2) Consists of common shares, stock options, deferred common shares, incentive shares and convertible debentures as at the period end date.

(3) Net income has been adjusted for the IFRS accounting effects of the gain/loss on derivative financial liability. For the three months ended September 30, 2011, adjusted net income includes a $10.6 million reduction (2010 - $24.9 million increase) for this gain. For the nine months ended September 30, 2011, adjusted net income includes a $71.7 million reduction (2010 - $69.3 million reduction). Management considers adjusted net income a better measure of the Company's economic performance period over period.

(4) Six Mcf of natural gas is equivalent to one barrel of oil equivalent ("boe").

(5) Net of transportation expenses.

(6) Excludes hedging activities.

HIGHLIGHTS

(In this report, quarterly comparisons are third quarter 2011 to third quarter 2010 unless otherwise noted.)

- PetroBakken's production averaged 39,074 boepd in the third quarter of 2011, representing an 11% increase compared to the second quarter of 2011, and a 3% decrease from the prior year period. The increase in production over the second quarter was the result of a combination of restoring production that was shut-in due to the extended spring break-up and production additions from new wells that were put on production in the latter part of the third quarter.

- Our operating netback (excluding hedging activities) of $50.04/boe decreased 12% compared to the second quarter of 2011, and increased 15% over the prior year period. The decrease over the second quarter was primarily as a result of lower pricing that more than offset decreased royalty and production expenses.

- Our production and strong operating netback resulted in funds flow from operations of $152.4 million ($0.81 per basic share and $0.76 per diluted share), a 1% decrease from the second quarter of 2011, and an 8% increase from the prior year. The decrease from the second quarter was primarily due to lower operating netbacks partially offset by higher production.

- Net capital expenditures were $271.8 million in the third quarter, up 196% from the second quarter of 2011, and up 17% from a year ago. The increase from the prior quarter was due to the seasonal nature of expenditures in our core operating areas, and we remain on budget for 2011.

- PetroBakken drilled 96 (70.1 net) wells with a 100% success rate in the third quarter: 44 (31.5 net) wells were drilled in the Cardium, 33 (25.4 net) in the Bakken, 18 (12.2 net) in Saskatchewan Conventional, and 1 (1.0 net) in Alberta/BC.

- We brought 60 (47.3 net) wells on production in the quarter: 23 (18.7 net) wells in the Cardium, 27 (20.6 net) wells in the Bakken, with the remaining wells in our Saskatchewan Conventional Business Unit.

OPERATIONAL UPDATE

Average Daily Production

	Three months ended September 30, 2011			Three months ended June 30, 2011			Three months ended March 31, 2011		
Business Unit	Oil &NGL (bbl/d)	Gas (Mcf/d)	**Total (boe/d)**	Oil &NGL (bbl/d)	Gas (Mcf/d)	**Total (boe/d)**	Oil &NGL (bbl/d)	Gas (Mcf/d)	**Total (boe/d)**
Bakken	17,701	5,973	**18,697**	16,385	5,641	**17,325**	22,327	6,392	**23,392**
Conventional (SE SK)	5,274	1,362	**5,501**	5,093	1,304	**5,310**	6,046	1,531	**6,301**
Cardium (central AB)	9,004	13,628	**11,275**	7,040	13,715	**9,326**	6,718	12,148	**8,743**
Alberta/BC	1,133	14,811	**3,601**	1,158	13,086	**3,339**	1,049	12,463	**3,126**
	33,112	35,774	**39,074**	29,676	33,746	**35,300**	36,140	32,534	**41,562**

Field operations in Q3 got off to a slow start as weather related challenges that existed in Q2 persisted into July. However, drilling activity commenced where possible and production that had been shut-in due to wet lease conditions was gradually restored. Our field activities were heavily weighted towards the latter part of the quarter, resulting in low average production volumes for the period and rapid growth in production through the end of Q3 and into Q4. Average production in October of more than 46,000 boepd exceeded the low end of our original exit guidance, and production in early November is in excess of 47,500 boepd (based on field estimates).

Production for the third quarter averaged 39,074 boepd, comprised of 33,112 bopd of light oil and natural gas liquids and 35,774 Mcf/d of natural gas. Liquids production increased 12% in the third quarter 2011 as compared to the second quarter of 2011, due primarily to the restoration of production that was shut-in for weather conditions. Gas production increased 6% over the second quarter, due primarily to well optimizations in the Alberta/BC Business Unit.

Drilling and completion activity commenced later than expected during the quarter because of the unusually long spring break-up and although our drilling program was accelerated, we completed fewer wells than expected. The following table summarizes third quarter 2011 activity and the inventory of wells to be completed and/or brought on production for each business unit.

Q3 2011 Activity

	Drilled		Completed		On Production		Inventory(1)	
Business Unit	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Bakken	33.0	25.4	34.0	28.0	27.0	20.6	18.0	12.6
Conventional (SE SK)	18.0	12.2	16.0	10.1	10.0	8.0	16.0	6.8
Cardium (central AB)	44.0	31.5	22.0	14.4	23.0	18.7	37.0	23.5
Alberta/BC	1.0	1.0	-	-	-	-	2.0	2.0
Total	**96.0**	**70.1**	**72.0**	**52.5**	**60.0**	**47.3**	**73.0**	**44.8**

(1) Inventory refers to the number of wells pending completion and/or tie-in.

Since the end of the third quarter we have drilled an additional 39 (26.6 net) wells, completed 33 (24.5 net) wells, and brought 46 (31.2 net) wells on production. Drilling activity continues, and currently we have 11 rigs operating – five in southeast Saskatchewan, five in the Cardium, and one in central Alberta. We expect drilling activity to slow down over the next two months as the consistent weather has allowed us to accelerate our schedule. Completion and tie-in activity will continue as we reduce the number of wells in inventory, resulting in continued production growth through the fourth quarter.

Bakken Business Unit Update

Bakken production was 8% higher in the third quarter of 2011 compared to the second quarter of 2011, as shut-in production was restored after an unusually long spring break-up (in a typical year, field activity resumes in mid-May). Despite the drilling program commencing later than expected, shorter cycle times and additional rigs allowed us to accelerate our drilling. In addition, we reduced our inventory of wells that were on production but unfrac'd to 8 (6.5 net) from 14 (13.7 net) at the end of the second quarter. Since the end of the third quarter, we have drilled 13 (8.9 net) wells, completed 18 (13.9 net) wells, and brought 13 (9.1 net) wells on production. This activity has resulted in production of more than 21,500 boepd (based on field estimates) at the beginning of November.

We continue to see evidence that the new CleanTech™ completion technique that we adopted in certain areas of the Bakken play has improved initial oil rates and lowered water cuts. This has provided us with the opportunity to extend the economic limits of the Bakken drilling fairway.

We are re-completing our injector well in our first natural gas Enhanced Oil Recovery ("EOR") pilot, providing for more uniform natural gas injection along the length of the horizontal wellbore. We expect to begin natural gas flooding in our next pilot prior to year-end. This pilot is designed to test an injection configuration applicable to both single leg and bilateral horizontal wells. Our third injector well is currently on primary production, and we expect to drill two additional wells in 2012. As previously indicated, it is our intention to place all injector wells on primary production prior to commencing injection.

Cardium Business Unit Update

Production for the Cardium Business Unit averaged 11,275 boepd in the third quarter, representing an increase of 21% over the second quarter of 2011, due to shut-in production being restored and an active capital program throughout the quarter. Spring break-up for this business unit is typically longer than the Bakken, and the program completed during the quarter was in-line with our original plans. Since the end of the third quarter we have drilled an additional 16 (10.7 net) wells, completed 8 (6.4 net) wells and brought 25 (17.7 net) wells on production, resulting in production of over 15,750 boepd (based on field estimates) in early November.

Results from the Cardium play continue to meet or exceed our expectations. All of our Cardium areas are generating strong economic returns, and recent wells in West Pembina, Garrington and Lochend (where we have approximately 75% of our acreage) are typically exceeding our type curve. Although we have seen increases in the cost of certain drilling and completion services, the impact has been attenuated through improved execution efficiencies and reduced cycle times.

We have now drilled 176 (132.1 net) horizontal wells since the summer of 2010 and have an inventory of over 650 net remaining locations as we continue to prove up and add to our acreage.

OTHER ACTIVITY

Our activity in the southeast Saskatchewan conventional Mississippian plays increased significantly from the second quarter. One of the two planned facility upgrades to handle increased water production has been completed, providing for an additional 425 boepd of production from existing wells and also an opportunity for increased drilling activity in both our Bakken and conventional Mississippian plays. The second facility upgrade is expected to be completed in 2012.

In our Alberta/BC Business Unit, we continue to evaluate our lands in northeast British Columbia and Alberta. Earlier this year we drilled two Montney wells at Monias in northeast British Columbia to retain our mineral rights and further develop this acreage. The first of these Montney wells has been producing since the beginning of the second quarter while the second well came on-stream in October. We also control 120,000 net acres in emerging oil resource plays in Alberta, and have now drilled three wells to begin evaluating these lands, with a fourth well to commence drilling prior to year-end.

FINANCIAL UPDATE

PetroBakken's financial performance continued to be strong in the third quarter of 2011 with high operating netbacks due to our light oil focus, resulting in funds flow from operations of $152.4 million ($0.81 per basic and $0.76 per diluted share). Our operating netback of $50.04 decreased 12% compared to the second quarter of 2011, driven primarily by lower WTI prices, which more than offset decreases in operating and royalty expenses.

Adjusted net income of $29.7 million ($0.16 per basic and diluted share) decreased 65% compared to the second quarter of 2011, primarily due to an unrealized foreign exchange loss on the convertible debenture, a lower gain on asset dispositions and higher depletion expense, partially offset by an unrealized gain on risk management contracts due to lower WTI prices at the end of the quarter.

Net capital expenditures for the quarter were $271.8 million, related to drilling, completions, recompletions, and facilities. Net debt increased from the second quarter by $162.9 million, primarily due to higher activity levels, while drawn credit facility debt remained essentially unchanged at $1.13 billion. At September 30, 2011, our net debt to third quarter annualized funds flow from operations ratio was 2.2 to 1, slightly higher than our target, but with growing production and strong oil prices we expect this ratio to come back below our 2 to 1 target. Debt levels were well within all our credit facility covenants and available bank credit at the end of the quarter was $218 million.

OUTLOOK AND SUMMARY

Operational challenges that began in the second quarter and persisted into the third quarter are largely behind us now, and execution of our field operations has delivered early November production of over 47,500 boepd (based on field estimates). We now anticipate exit production in excess of 49,000 boepd while maintaining our capital expenditures for the year at approximately $900 million. Assuming a go-forward production rate of approximately 49,000 boepd (87% oil weighted), the estimated cash flow would be approximately $905 million in 2012, assuming US$90 WTI, foreign exchange of 0.975, AECO CDN$3.50 and a 5% differential.

During September and October, uncertainties in the global economic climate and market rumours around our Company caused a precipitous decline in our share price. Investors and market participants have been focused on the perceived strength of our balance sheet, due in part to the existence of the convertible debenture we have outstanding, and away from the high quality, light oil assets that underpin PetroBakken. As communicated previously, our management and Board of Directors are very dedicated to managing balance sheet flexibility. In addition to our growing production base and the potential for increased cash flow over time, we have a number of options to provide increased liquidity in the next 15 months to manage the one-time put option that exists with the convertible securities in February 2013. These options include (in no specific order): modifying our capital program and/or altering our cash dividend to provide additional free cash flow, issuing additional debt instruments or equity, instituting a dividend reinvestment program, renegotiating the terms of the existing convertible debentures, or realizing on asset sales.

Our team continues to focus on generating long term growth and yield for our shareholders through the continued exploration and exploitation of our existing land holdings, which currently exceed 1 million acres. We have established a long-life base of producing assets in our Bakken and Conventional Business Units, currently generating free cash flow in excess of all sustaining investments. We expect this cash flow to increase over time as decline rates flatten and less capital investment is required to maintain production. Following the same model, we have grown the Cardium Business Unit production from zero to over 15,750 boepd in less than two years and, within the next two years, we expect this business unit to mature and also generate significant free cash flow. In addition to these Business Units, we have prospective natural gas assets in northeast British Columbia, resulting in a total inventory of over 2,150 net drilling locations. Finally, we expect to generate further growth from our expanding inventory of new plays, including some of the prospects currently being tested on oil-focused resource plays in Alberta, where we have accumulated a material land position.

The following Management's Discussion and Analysis ("MD&A") is dated November 8, 2011 and should be read in conjunction with the unaudited condensed interim consolidated financial statements and accompanying notes of PetroBakken Energy Ltd. ("PetroBakken", "we" or "our" or the "Company") as at and for the three and nine months ended September 30, 2011, MD&A and the condensed interim consolidated financial statements for the three months ended March 31, 2011 and MD&A and the consolidated annual financial statements as at and for the year ended December 31, 2010. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except share amounts or as otherwise noted. Natural gas volumes have been converted to barrels of oil equivalent ("boe"). Six thousand cubic feet ("Mcf") of natural gas is equal to one barrel of oil equivalent based on an energy equivalency conversion method primarily attributable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, especially if used in isolation.

Forward-Looking Statements

This MD&A and the accompanying summary of results contain forward-looking statements. More particularly, they contain forward-looking statements concerning potential exploration and development activities, the potential for enhanced recovery and production, the reduction of operating costs from the application of completion and recompletion activities and the construction of facilities, expected production growth, the timing for bringing shut-in production back on stream, future dividend payments and anticipated sources of funding for capital and operating activities. The forward-looking statements are based on certain key expectations and assumptions, including expectations and assumptions concerning the availability of capital, the success of future drilling, completion, recompletion and development activities, the performance of existing wells, the performance of new wells, prevailing commodity prices and economic conditions, the availability of labour and services, weather and access to drilling locations, the geological nature of the formations targeted and prevailing accounting standards.

Although we believe that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because we can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; uncertainties associated with new technologies and methodologies; reliance on industry partners; availability of equipment and personnel; uncertainty surrounding timing for drilling and completion activities resulting from weather and other factors; changes in applicable regulatory regimes and health, safety and environmental risks; commodity price and exchange rate fluctuations and general economic conditions). Certain of these risks are set out in more detail in this MD&A and our Annual Information Form which has been filed on SEDAR and can be accessed at www.sedar.com.

Conversion to IFRS

Effective January 1, 2010 PetroBakken transitioned from Canadian Generally Accepted Accounting Principles ("GAAP") to International Financial Reporting Standards ("IFRS"). Note 20 to the condensed interim financial statements for the three and nine months ended September 30, 2011 discloses the impact of adopting IFRS on shareholders' equity, cash flows, net income and comprehensive income for these periods. Our 2010 comparative financial information has been restated to be in accordance with our IFRS accounting policies.

Non-GAAP Measures

This report contains financial terms that are not considered measures under IFRS, such as funds flow from operations, adjusted net income, funds flow per share, adjusted net income per share, net debt and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for management and stakeholders. Specifically, funds flow from operations reflects cash generated from operating activities before changes in non-cash working capital. Adjusted net income is determined by adding back any losses or deducting any gains on the derivative liabilities. Management considers funds flow from operations, funds flow per share, adjusted net income and adjusted net income per share important as it helps evaluate performance and demonstrate the ability to generate sufficient cash to fund future growth opportunities, pay dividends and repay debt. Net debt includes bank debt outstanding plus accounts payable less accounts receivable and prepaid expense and is used to evaluate PetroBakken's financial leverage. Profitability relative to commodity prices per unit of production is demonstrated by an operating netback. Operating netback reflects revenues less royalties, transportation costs, and production expenses divided by production for the period. Funds flow from operations, funds flow per share, adjusted net income, adjusted net income per share, net debt and operating netbacks may not be comparable to those reported by other companies nor should they be viewed as an alternative to cash flow from operations or other measures of financial performance calculated in accordance with IFRS.

FINANCIAL AND OPERATING REVIEW

(Comparisons presented in this MD&A are third quarter of 2011 compared to the third quarter of 2010 and the first nine months of 2011 compared to the first nine months of 2010 unless otherwise noted.)

Average Daily Production

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Oil and NGL (bbls)	**33,112**	33,230	-	**32,965**	35,229	(6%)
Natural gas (Mcf)	**35,776**	41,193	(13%)	**34,030**	39,473	(14%)
Total (boe)	**39,074**	40,095	(3%)	**38,636**	41,808	(8%)

Production decreased by 3 and 8 percent respectively for the three and nine months ended September 30, 2011 and increased 11 percent from the second quarter. The decrease in gas production for the three and nine months was primarily the result of non-core property dispositions in 2010 and natural declines, as our drilling program remains focused on light oil. Oil production decreased as a result of an extensive spring break-up due to extreme weather conditions, particularly in southeast Saskatchewan, which adversely impacted our ability to service existing wells and transport oil from our single well batteries resulting in shut-in production throughout the second quarter and into July of the third quarter. By the end of the third quarter shut-in production had been restored back to normal operating levels. Poor conditions at the beginning of the third quarter also caused delays in executing our new well program. While we were able to catch-up on our drilling activity; completions and equipping were delayed into the latter part of the third quarter and the beginning of the fourth quarter. During the quarter we drilled 70.1 net wells compared to 75.0 net wells a year ago and brought on production 47.3 net wells compared to 49.8 net wells a year ago.

In southeast Saskatchewan, as conditions improved throughout the quarter, we were able to restore most shut-in production and return to normal operating conditions and begin the execution of our summer drilling program. We were able to frac 10.2 net wells from our inventory of unfrac'd Bakken wells, which decreased to 6.5 net wells at September 30, 2011. Production for the quarter increased by 7 percent to an average of 24,200 boepd and reached 26,500 by the end of September.

In Alberta during the third quarter, we continued to execute and grow production in the Cardium Business Unit, which has increased 117 percent quarter over quarter and 21 percent from Q2 2011. Weather related to poor lease conditions at the beginning of the quarter resulted in temporarily shut-in production, all of which was fully restored by the end of the quarter. Poor conditions at the beginning of the quarter also resulted in delays completing and bringing wells on production until later in the quarter and into October. However, we were able to place 18.7 net Cardium wells on production by September 30, with an additional 17.7 net wells brought on production in October.

Since quarter-end, our staff has been busy drilling and completing new wells. Field estimates for October average production was in excess of 46,000 boepd, with estimated current production in excess of 47,500 boepd.

Average Benchmark and Realized Prices

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
WTI (US$/bbl)	**89.76**	76.15	18%	**95.47**	77.67	23%
WTI ($/bbl)	**87.86**	79.17	11%	**93.28**	80.42	16%
Edmonton Par	**91.74**	74.43	23%	**94.26**	76.56	23%
AECO natural gas ($/Mcf)	**3.66**	3.53	4%	**3.76**	4.13	(9%)
US$ per C$1	**0.98**	0.96	2%	**0.98**	0.97	1%
Oil and NGL						
Realized price per bbl ($/bbl)	**85.08**	70.02	22%	**87.83**	73.18	20%
Discount % of Edm. Par	**7%**	6%	-	**7%**	4%	-
Natural gas						
Realized price per Mcf ($/Mcf)	**4.01**	3.82	5%	**4.11**	4.31	(5%)

In the third quarter and first nine months of 2011, realized oil and NGL prices increased due to higher oil prices. Contributing to this increase was a strengthening of Edmonton par prices relative to WTI due to increased demand for Canadian sourced crude.

Revenue

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Oil and natural gas sales	**272,346**	228,537	19%	**828,595**	750,197	10%
Royalties	**(43,871)**	(31,886)	38%	**(130,409)**	(104,685)	25%
Revenue	**228,475**	196,651	16%	**698,186**	645,512	8%

The change in third quarter and first nine months of 2011 sales is primarily due to higher oil and NGL prices, which more than offset lower production. The table below summarizes these changes:

Reconciliation of Changes in Sales

Three months ended September 30, 2010	228,537
Sales volumes	(7,117)
Realized prices	50,926
Three months ended September 30, 2011	**272,346**
$ change in sales	43,809
% change in sales	19%

Reconciliation of Changes in Sales

Nine months ended September 30, 2010	750,197
Sales volumes	(71,750)
Realized prices	150,148
Nine months ended September 30, 2011	**828,595**
$ change in sales	78,398
% change in sales	10%

Net Realized Prices

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Oil and natural gas sales	**272,346**	228,537	19%	**828,595**	750,197	10%
Transportation expense	**1,416**	4,873	(71%)	**5,991**	11,677	(49%)
Total sales, net of transportation expense	**270,930**	223,664	21%	**822,604**	738,520	11%
Gross sales ($/boe)	**75.76**	61.95	22%	**78.55**	65.73	20%
Transportation costs ($/boe)	**0.39**	1.32	(70%)	**0.57**	1.02	(44%)
Realized price, net of transportation expense ($/boe)	**75.37**	60.63	24%	**77.98**	64.71	21%

Net realized price for the third quarter and first nine months of 2011 improved mainly due to higher oil prices. On a unit of production and total basis, transportation expense decreased due to infrastructure added in southeast Saskatchewan which resulted in tied-in production and reduced trucking costs.

Royalties

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Royalties (1)	**43,871**	31,886	38%	**130,409**	104,685	25%
$ per boe	**12.20**	8.64	41%	**12.36**	9.17	35%
Royalties as a % of realized price, net of transportation costs	**16%**	14%	14%	**16%**	14%	14%

(1) Royalties include the Saskatchewan Resource Surcharge determined as a percentage of sales from our Saskatchewan Crown lands.

Royalties increased in the third quarter and first nine months of 2011 on a total and unit of production basis and as a percentage of revenue, due to higher oil prices. On Crown lands in Saskatchewan, the first 37,740 boe of production from horizontal wells receive a royalty incentive but incur the Saskatchewan Resource Surcharge of 1.7%. On Crown lands in Alberta, horizontal oil wells are subject to a maximum 5% royalty rate for 18 to 48 months or 50,000 to 100,000 boe of production, whichever comes first, depending on well length.

Gain (Loss) on Risk Management Contracts

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Realized gain (loss):						
Crude oil derivative contracts	**(190)**	(769)	75%	**(4,864)**	(1,908)	(155%)
Natural gas derivative contracts	**471**	2,654	(82%)	**1,647**	3,907	(58%)
Interest rate swap contracts	**(222)**	(494)	55%	**(668)**	(2,087)	68%
	59	1,391	(96%)	**(3,885)**	(88)	(4,315%)
Unrealized gain (loss):						
Crude oil derivative contracts	**55,837**	(7,041)	-	**56,520**	7,897	616%
Natural gas derivative contracts	**(387)**	(321)	(21%)	**(1,560)**	929	-
Interest rate swap contracts	**(130)**	(1,538)	92%	**(315)**	(68)	(363%)
	55,320	(8,900)	-	**54,645**	8,758	524%
Gain (loss) on risk management contracts	**55,379**	(7,509)	-	**50,760**	8,670	485%

PetroBakken enters into commodity price derivative contracts to limit exposure to declining commodity prices, thereby protecting project economics and providing increased stability of cash flows, dividends and capital expenditure programs. Commodity prices fluctuate for a number of reasons; including changes in economic conditions, political events, weather conditions, disruptions in supply, and changes in demand. The Company's risk management activities are conducted pursuant to the Company's risk management policies that have been approved by the Board of Directors.

The majority of our financial commodity derivative contracts are option-based contracts and as such their fair value at a particular point in time is affected by underlying commodity prices, expected commodity price volatility and the duration of the contract. The fair value of fixed price derivative contracts at a particular point in time is determined by the expected future settlements of the underlying commodity or interest rate. At September 30, 2011, the fair value of financial derivative contracts was an asset of $41.6 million. The fair value of this asset represents the estimated amount that would be received for settling PetroBakken's outstanding contracts at September 30, 2011 and will be different than what will eventually be realized.

The gain or loss on risk management contracts is made up of two components; the realized component reflects actual settlements that occurred during the period, and the unrealized component represents the change in the fair value of contracts during the period. The unrealized gain on risk management contracts in the third quarter and first nine months of 2011 was primarily the result of the fluctuations in expected future WTI prices.

The following table summarizes the change in and the fair value of derivative contracts:

	Crude Oil	Natural Gas	Interest	Total
Risk management asset (liability), December 31, 2010	(14,835)	2,022	(235)	(13,048)
Unrealized gain (loss)	56,520	(1,560)	(315)	54,645
Risk management asset (liability), September 30, 2011	41,685	462	(550)	41,597

At September 30, 2011, PetroBakken recorded a $41.7 million asset related to crude oil price risk management contracts. The following is a summary of crude oil derivative contracts in place as at September 30, 2011:

Crude Oil Price Risk Management Contracts – WTI [(1)]

Term	Volume (bopd)	Average Price ($/bbl)	Benchmark
Oct. 1, 2011 – Dec. 31, 2011	2,500	$78.00 floor/$95.40 ceiling	C$WTI
Oct. 1, 2011 – Dec. 31, 2011	4,500	$76.11 floor/$101.43 ceiling	US$WTI
Oct. 1, 2011 – Jun. 30, 2012	2,000	$75.00 floor/$99.59 ceiling	US$WTI
Oct. 1, 2011 – Dec. 31, 2012	1,000	$75.00 floor/$98.25 ceiling	US$WTI
Jan. 1, 2012 – Jun. 30, 2013	3,750	$75.00 floor/$122.01 ceiling	US$WTI
Jan. 1, 2012 – Dec. 31, 2013	1,750	$80.00 floor/$134.12 ceiling	US$WTI
Jul. 1, 2012 – Jun. 30, 2013	1,000	$75.00 floor/$117.45 ceiling	US$WTI
Jul. 1, 2013 – Dec. 31, 2013	2,000	$75.00 floor/$127.37 ceiling	US$WTI
Jul. 1, 2013 – Jun. 30, 2014	500	$80.00 floor/$127.65 ceiling	US$WTI

(1) Prices are the volume weighted average prices for the period.

The following is a summary of crude oil derivative contracts entered into subsequent to Sept. 30, 2011:

Term	**Volume (bopd)**	**Average Price ($/bbl)**	**Benchmark**
Jan. 1, 2013 – Dec. 31, 2013	500	$75.00 floor/$104.50 ceiling	US$WTI
Jul. 1, 2013 – Jun. 30, 2014	500	$75.00 floor/$102.00 ceiling	US$WTI

The average of the above volumes is as follows:

Term	**Volume (bopd)**	**Average Price ($/bbl) [(1)]**	**Benchmark**
2011	10,000	$77.01 floor/$100.48 ceiling	US$WTI
2012	8,000	$76.09 floor/$118.60 ceiling	US$WTI
2013	6,125	$76.63 floor/$123.96 ceiling	US$WTI
2014	500	$77.50 floor/$114.83 ceiling	US$WTI

(1) Canadian dollar contracts are converted at an exchange rate of $1.0389.

At September 30, 2011 PetroBakken recorded a $0.5 million asset related to the following natural gas price risk management contract:

Natural Gas Price Risk Management Contracts – AECO

Term	Volume (GJ/d)	Price ($/GJ)	Type
Oct. 1, 2011 – Dec. 31, 2011	2,000	$6.00	Fixed Price Swap

At September 30, 2011, PetroBakken recorded a $0.6 million liability related to the following interest rate swap contracts:

Term	**Notional Principal / Month**	**Fixed Annual Rate (%)**
Oct. 1, 2011 – Jan. 31, 2012	C$50 million	1.620%
Oct. 1, 2011 – Jan. 31, 2012	C$50 million	1.653%
Oct. 1, 2011 – Feb. 28, 2012	C$25 million	1.540%
Oct. 1, 2011 – Feb. 28, 2012	C$25 million	1.510%
Oct. 1, 2011 – Apr. 30, 2012	C$50 million	1.300%
Oct. 1, 2011 – Jun. 30, 2012	C$25 million	2.094%

Production Expenses

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Production expenses	**47,207**	30,924	53%	**134,291**	90,355	49%
$ per boe	**13.13**	8.38	57%	**12.73**	7.92	61%

Production expenses increased in the third quarter and first nine months of 2011 on a total dollar and per boe basis as poor surface lease conditions during an extended spring-break-up in southeast Saskatchewan and central Alberta continued into the beginning of the third quarter. This resulted in higher seasonal costs, increased road and lease maintenance and trucking partial loads of produced fluid. These costs decreased throughout the third quarter as conditions improved and were $11.80/boe in September. Increased industry activity has led to increased demand for services resulting in cost inflation. Overall costs improved by $2.11/boe from $15.24/boe in the second quarter, and are expected to continue to improve into the fourth quarter as we return to operating under normal conditions with higher production levels.

Netbacks

Three months ended September 30,	**2011**			2010	
	Oil and NGL's ($/bbl)	**Natural Gas ($/Mcf)**	**Total ($/boe)**	Total ($/boe)	Change
Sales price [(1)]	**84.61**	**4.01**	**75.37**	60.63	24%
Royalties	**13.82**	**0.54**	**12.20**	8.64	41%
Production expenses	**12.97**	**2.34**	**13.13**	8.38	57%
Operating netback [(2) (3)]	**57.82**	**1.13**	**50.04**	43.61	15%

(1) Net of transportation expenses.

(2) Non-GAAP measure. See "Non-GAAP Measures" section within the MD&A.

(3) Excludes hedging activities.

Netbacks

Nine months ended September 30,	2011			2010	
	Oil and NGL's ($/bbl)	**Natural Gas ($/Mcf)**	**Total ($/boe)**	Total ($/boe)	Change
Sales price [1]	**87.17**	**4.11**	**77.98**	64.71	21%
Royalties	**13.90**	**0.57**	**12.36**	9.17	35%
Production expenses	**12.53**	**2.32**	**12.73**	7.92	61%
Operating netback [2] [3]	**60.74**	**1.22**	**52.89**	47.62	11%

(1) Net of transportation expenses.

(2) Non-GAAP measure. See "Non-GAAP Measures" section within the MD&A.

(3) Excludes hedging activities.

The increase in the Company's netbacks for the three and nine months ended September 30, 2011 is primarily due to the increase in oil prices. This is partially offset by increased production expenses and the increase in royalties as a result of the increased pricing.

General and Administrative Expenses

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
General and administrative expenses	**10,654**	9,006	18%	**29,058**	25,947	12%
$ per boe	**2.96**	2.44	22%	**2.75**	2.27	21%

General and administrative costs increased in the third quarter and first nine months of 2011 on an absolute and per boe basis due primarily to additional personnel and office costs as a result of expanding operations and consolidation of office space. The increase in absolute costs from Q2 2011 was in part due to a delay in overhead recovery from partners as a result of a large portion of capital spending being incurred in the latter part of the quarter. We expect overhead recoveries to increase in the fourth quarter.

Share-based Compensation

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Share-based compensation	**6,083**	9,107	(33%)	**15,231**	26,948	(43%)

Share-based compensation expenses relate to stock options, deferred common shares and incentive shares granted. The calculation of this non-cash expense is based on the fair value of stock options, deferred common shares and incentive shares granted, amortized over the vesting period of the option and incentive share or immediately upon grant of the deferred common share. The decrease in share-based compensation is primarily due to a lower fair value of new grants and forfeitures of stock options and incentives shares.

Gain (Loss) on Dispositions

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Gain (loss) on dispositions	**(122)**	9,685	-	**15,070**	11,048	36%

The gain (loss) on dispositions for the third quarter and first nine months of 2011 relates to the disposal of non-core properties for net proceeds of $0.1 million in the third quarter of 2011 and $22.7 million in the first nine months of 2011. The gain in the third quarter of 2010 relates to the disposal of a non-core property in Alberta for net proceeds of $8.3 million, and the gain in the first nine months of 2010 primarily relates to this disposal and the disposal of four divestiture packages in Alberta representing approximately 3,000 boepd (55% natural gas) for total net proceeds of $130.1 million.

Gain (Loss) on Derivative Financial Liability

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Gain (loss) on derivative financial liability	**10,606**	(24,937)	-	**71,654**	69,258	3%

The gain (loss) on the derivative liability represents the change in the fair value of derivative financial liability on the convertible debentures between the beginning and the end of the period. The fair value is determined using a valuation model, refer to note 9 in the interim financial statements at September 30, 2011 for further details. The gain is primarily due to a lower share price at September 30, 2011 compared to June 30, 2011 for the third quarter and compared to December 31, 2010 for the nine months ended.

Interest and Other Expenses

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Interest on credit facility and other	**10,781**	5,973	80%	**28,291**	15,958	77%
Amortization of deferred financing costs	**466**	1,308	(64%)	**2,868**	3,520	(19%)
Accretion of the convertible debentures	**6,040**	5,927	2%	**17,545**	15,665	12%
Interest expense on convertible debenture	**5,884**	6,184	(5%)	**17,268**	16,536	4%
Accretion on decommissioning liability	**1,388**	1,284	8%	**4,078**	3,765	8%
Finance expense	**24,559**	20,676	19%	**70,050**	55,444	26%

Cash interest expense includes interest on bank debt, fees on letters of credit, and interest on the convertible debentures. Cash interest expense increased in the third quarter of 2011 and first nine months of the year primarily due to higher bank debt outstanding in these periods. Bank debt was repaid at the end of January 2010 when the convertible debentures were issued, and increased throughout 2010 into 2011 to fund the 2010 corporate acquisitions and capital expenditures. On average, bank debt outstanding for the third quarter was $1,128 million as compared to $607 million in 2010, and $1,023 million in the first nine months of 2011 as compared to $458 million in the first nine months of 2010.

Foreign Exchange Gain (loss)

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Foreign exchange gain (loss)	**(46,176)**	18,419	-	**(27,417)**	680	-

The Company recognizes foreign exchange gains/losses primarily due to the appreciation/depreciation of the Canadian dollar relative to the U.S. dollar. Our convertible debentures are denominated in U.S. dollars and, as a result, the vast majority of unrealized foreign exchange gains and losses relate to the change in the foreign exchange rate compared to the rate at the end of the previous period. A weaker Canadian dollar at September 30, 2011 compared to June 30, 2011 and December 31, 2010 resulted in a foreign exchange loss for the three and nine months ended September 30, 2011.

Depletion and Depreciation ("D&D")

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Depletion and depreciation	**94,472**	92,094	3%	**277,840**	287,384	(3%)
$ per boe	**26.28**	24.97	5%	**26.34**	25.18	5%

On a unit of production and absolute basis D&D expense increased in the third quarter due to positive reserve additions being offset by the inclusion of land transferred to the Bakken cash generating unit. This also resulted in the increase in the nine month cost per boe. On an absolute basis D&D expense decreased in the nine month period due to lower production.

Income Tax Expense

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Income tax expense	**23,494**	14,503	62%	**65,200**	57,933	13%

The Company's deferred tax expense for the third quarter and first nine months of 2011 is consistent with income earned adjusted for non-deductible tax items.

Net Income

As summarized in the table below, the increase in third quarter 2011 net income is primarily due to higher prices, an increased unrealized gain on risk management contracts, gain on the derivative financial liability and lower share based compensation, partially offset by lower sales volumes, higher royalties, production expenses, interest expenses, income taxes and depletion and depreciation, lower gains on dispositions, and a foreign exchange loss related to the convertible debentures.

The increase in net income for the first nine months of 2011 is primarily due to higher prices, unrealized gains on risk management contracts, higher gains on dispositions, a higher gain on the derivative financial liability, and lower share based compensation and depletion and depreciation, partially offset by lower sales volumes, higher royalties, production, interest, and income tax expense, and a foreign exchange loss related to the convertible debentures.

Reconciliation of Changes in Net Income

	Three months ended September 30,	Nine months ended September 30,
Net income: September 30, 2010	11,126	179,480
Increase (decrease) due to:		
Sales volumes	(7,117)	(71,750)
Realized prices	50,926	150,148
Royalties	(11,985)	(25,724)
Unrealized gain (loss) on risk management contracts	64,220	45,887
Production expenses	(16,283)	(43,936)
Share-based compensation	3,024	11,717
Gain on disposal of assets	(9,807)	4,022
Gain on derivative financial liability	35,543	2,396
Interest and other	(3,883)	(14,606)
Foreign exchange loss	(64,595)	(28,097)
Depletion and depreciation	(2,378)	9,544
Income taxes	(8,991)	(7,267)
Other (1)	477	(1,222)
Net income: September 30, 2011	**40,277**	**210,592**

(1) Includes realized gain (loss) on risk management contracts, transportation expense, and general and administrative.

Funds Flow from Operations

The increase in funds flow from operations in the third quarter is primarily due to higher realized prices partially offset by lower sales volumes and higher royalties, production and interest expenses.

The decrease in funds flow from operations for the first nine months of 2011 is primarily due to lower sales volumes and higher royalties, production and interest expenses, partially offset by higher prices.

Reconciliation of Changes in Funds Flow From Operations

	Three months ended September 30,	Nine months ended September 30,
Funds flow from operations: September 30, 2010	140,761	485,499
Increase (decrease) due to:		
Sales volumes	(7,117)	(71,750)
Realized prices	50,926	150,148
Royalties	(11,985)	(25,724)
Production expenses	(16,283)	(43,936)
Cash interest expense	(4,508)	(13,065)
Other (1)	563	(2,438)
Funds flow from operations: September 30, 2011	**152,357**	**478,734**

(1) Includes transportation expenses, general and administrative, realized gain (loss) on risk management contracts, realized FX gain and decommissioning liabilities settled.

The following table shows the reconciliation of funds flow from operations to cash flow from operating activities for the periods noted:

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Funds flow from operations:						
Non-IFRS	**152,357**	140,761	8%	**478,734**	485,499	(1%)
Changes in non-cash working capital	**9,202**	(14,605)	-	**11,938**	(59,533)	-
Cash flow from operating activities:						
IFRS	**161,559**	126,156	28%	**490,672**	425,966	15%

Capital Expenditures

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2011	2010	Change	**2011**	2010	Change
Capital expenditures (1)	**271,861**	241,309	13%	**692,352**	549,113	26%

(1) Includes exploration and evaluation expenditures for the three and nine months ended September 30, 2011 of $2.1 million (2010 - $58.8 million) and $31.4 million (2010 - $118.2 million) respectively.

Capital Expenditures by Type

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
Drilling, completions and recompletions	**224,768**	145,580	**511,154**	361,268
Land	**3,270**	38,820	**29,908**	87,556
Facilities	**30,870**	32,617	**112,914**	51,602
Seismic	**2,036**	949	**3,842**	6,057
Other (1)	**9,205**	3,730	**29,367**	12,654
Capital expenditures before acquisitions	**270,149**	221,696	**687,185**	519,137
Asset acquisitions	**1,712**	19,613	**5,167**	29,976
Total capital expenditures(2)	**271,861**	241,309	**692,352**	549,113
Proceeds from dispositions	**(75)**	(8,306)	**(22,664)**	(130,061)
Net capital expenditures	**271,786**	233,003	**669,688**	419,052

(1) Includes health, safety and environmental expenditures, capitalized salaries, and office furniture and fixtures.
(2) Includes exploration and evaluation expenditures.

Drilling Activity (Net), for the three months ended September 30, 2011

Business Unit	Net wells drilled 2011	Net wells drilled 2010	Net wells pending completion and/or tie-in 2011	Net wells pending completion and/or tie-in 2010	Dry and abandoned wells 2011	Dry and abandoned wells 2010	Success Rate 2011	Success Rate 2010
Bakken	**25.4** (1)	42.9	**12.6** (2)	4.2	**-**	-	**100%**	100%
Conventional	**12.2**	12.5	**6.8**	5.2	**-**	1.0	**100%**	92%
Cardium	**31.5**	19.6	**23.5**	15.0	**-**	-	**100%**	100%
BC/Other AB	**1.0**	-	**2.0**	1.0	**-**	-	**100%**	-
Total	**70.1**	**75.0**	**44.9**	**25.4**	**-**	**1.0**	**100%**	**99%**

(1) Includes 15.8 net bilateral wells.
(2) Does not include 6.5 wells where fracs have been delayed.

Drilling Activity (Net), for the nine months ended September 30, 2011

Business Unit	Net wells drilled 2011	Net wells drilled 2010	Net wells pending completion and/or tie-in 2011	Net wells pending completion and/or tie-in 2010	Dry and abandoned wells 2011	Dry and abandoned wells 2010	Success Rate 2011	Success Rate 2010
Bakken	**58.5** (1)	104.5	**12.6** (2)	4.2	**-**	1.0	**100%**	99%
Conventional	**16.8**	34.0	**6.8**	5.2	**-**	1.0	**100%**	97%
Cardium	**73.2**	22.4	**23.5**	15.0	**1.0**	-	**99%**	100%
BC/Other AB	**3.0**	1.0	**2.0**	1.0	**-**	-	**100%**	100%
Total	**151.5**	**161.9**	**44.9**	**25.4**	**1.0**	**2.0**	**99%**	**99%**

(1) Includes 37.0 net bilateral wells.
(2) Does not include 6.5 wells where fracs have been delayed.

The majority of capital expenditures in the third quarter and first nine months of 2011 were focused on drilling, completions, recompletions, facilities, and land acquisitions. The increase in capital in the third quarter and first nine months was due to increased activity in the Cardium in central Alberta, where drilling and completion costs per well are higher than southeast Saskatchewan. This was partially offset by fewer wells drilled in Saskatchewan. The increase in wells waiting to be brought on production is the result of the delay in the program caused by poor weather conditions in the second and early third quarter. While we were able to catch up on drilling activity, completions and bringing wells on production was delayed until early in the fourth quarter. Subsequent to the end of the third quarter the majority of these wells have been completed and brought on production and we have returned to a normal operating cycle. As of early November we had 18.2 net wells in the Cardium and 12.4 net wells in the Bakken pending completion and/or tie-in. Facilities expenditures decreased in the third quarter due to the delays in equipping wells discussed above. Facilities costs increased in the first nine months of 2011 due to costs to equip and tie-in drilled wells, completion of two Bakken oil batteries in southeast Saskatchewan, expansion of gathering systems to our five major facilities in southeast Saskatchewan, and expansion of gathering systems to our facility in the Cardium. Activity in Saskatchewan and new play areas in Alberta resulted in the majority of land, property, and seismic acquisitions in 2011.

Goodwill

There were no changes to goodwill in the third quarter and first nine months of 2011. Goodwill as at September 30, 2011 was $1,496.0 million.

Decommissioning Liability

The decommissioning liability increased $32.5 million in the third quarter of 2011 and $38.5 million in the first nine months primarily as a result of a change in the risk free rate, new wells drilled and accretion expense. The decommissioning liability as at September 30, 2011 was $170.9 million.

SUMMARY OF QUARTERLY RESULTS

	2011			2010				2009 – CDN GAAP [1]
	Q3	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
Financial ($000s except where noted)								
Total assets	**6,346,447**	**6,093,444**	**6,112,769**	5,865,005	5,677,921	5,530,641	5,077,282	4,480,604
Net debt [2]	**1,338,425**	**1,175,511**	**1,190,268**	1,015,774	858,375	702,832	562,591	910,791
Capital expenditures [3]	**271,861**	**113,010**	**307,481**	262,758	241,309	122,688	185,116	177,278
Proceeds from dispositions	**75**	**21,305**	**1,284**	3,571	8,306	15,723	106,032	178,849
Dividends	**44,880**	**44,947**	**44,865**	45,076	45,177	45,265	41,687	41,246
Per share	**0.24**	**0.24**	**0.24**	0.24	0.24	0.24	0.24	0.24
Oil and natural gas sales	**272,346**	**274,952**	**281,297**	258,359	228,537	245,954	275,706	276,334
Adjusted net income [2] [4]	**29,671**	**84,162**	**25,105**	40,401	36,063	3,062	71,097	33,385
Per share – basic	**0.16**	**0.45**	**0.13**	0.21	0.19	0.02	0.41	0.19
Per share – diluted	**0.16**	**0.45**	**0.13**	0.21	0.19	0.02	0.41	0.19
Funds flow from operations [2]	**152,357**	**153,353**	**173,024**	160,817	140,761	155,687	189,051	173,566
Per share – basic	**0.81**	**0.82**	**0.92**	0.85	0.75	0.83	1.09	1.01
Per share – diluted [9]	**0.76**	**0.76**	**0.86**	0.80	0.71	0.78	1.00	1.01
Operations								
Operating netbacks by product								
Crude oil and NGL sales price ($/bbl) [5] [6]	**84.61**	**96.37**	**81.92**	75.19	68.43	70.98	76.08	71.63
Royalties	**13.82**	**15.04**	**13.03**	10.94	9.67	10.36	10.56	11.26
Production expenses [7]	**12.97**	**15.32**	**9.81**	8.65	7.92	7.05	7.29	7.99
Operating netback [2] [6]	**57.82**	**66.01**	**59.08**	55.60	50.84	53.57	58.23	52.38
Natural gas sales price ($/Mcf) [6]	**4.01**	**4.19**	**4.13**	3.96	3.82	4.11	5.20	4.61
Royalties	**0.54**	**0.53**	**0.65**	0.66	0.62	0.60	0.60	0.63
Production expenses [7]	**2.34**	**2.47**	**2.13**	1.78	1.77	1.68	1.88	1.60
Operating netback [2] [6]	**1.13**	**1.19**	**1.35**	1.52	1.43	1.83	2.72	2.38
Oil equivalent sales price ($/boe) [5] [6] [8]	**75.37**	**85.02**	**74.46**	67.00	60.63	62.86	70.41	65.05
Royalties	**12.20**	**13.15**	**11.84**	9.84	8.64	9.17	9.68	10.14
Production expenses	**13.13**	**15.24**	**10.20**	8.97	8.38	7.59	7.80	8.23
Operating netback [2] [6] [8]	**50.04**	**56.63**	**52.42**	48.19	43.61	46.10	52.93	46.68
Average daily production [8]								
Crude oil and NGL's (bbls)	**33,112**	**29,676**	**36,140**	34,754	33,230	34,852	37,654	38,796
Natural gas (Mcf)	**35,776**	**33,746**	**32,534**	39,474	41,193	44,469	32,662	40,951
Total (boe)	**39,074**	**35,300**	**41,562**	41,333	40,095	42,263	43,098	45,621

(1) As PetroBakken's transition date was January 1, 2010, 2009 comparative information has not been restated.
(2) Non-GAAP measure. See "Non-GAAP Measures" section within the MD&A.
(3) Includes exploration and evaluation expenditures.
(4) Net income has been adjusted for the effects of the gain (loss) on the derivative financial liability.
(5) Net of transportation expenses.
(6) Excludes hedging activities.
(7) Determined based on production volumes where as previously determined using production values.
(8) Six Mcf of natural gas is equivalent to one barrel of oil equivalent.
(9) Consists of common shares, stock options, deferred common shares, and incentive shares on the same basis as net income. Convertible debentures have been included as at the period end date based on the conversion price as of that date. Assumes 109,800,001 common shares were outstanding in the first nine months of 2009.

Significant factors influencing quarterly results were:

- Production began to increase from the third quarter of 2010 following the completion of our planned disposition program and as we began to reduce the backlog of wells waiting to be brought on production. Poor weather conditions in the second quarter of 2011, particularly in southeast Saskatchewan, led to wells being shut-in and delays in the drilling program, resulting in a production decrease in excess of normal declines. The shut-in production was mostly restored throughout the third quarter. This recovery, combined with new well activity, has resulted in higher production in the third quarter with increases expected to continue into the fourth quarter.

- Crude oil benchmark prices have generally improved throughout 2010 and into the first half of 2011, contributing to improving operating netbacks, revenue, and funds flow from operations. In the third quarter, prices declined over the second quarter but were still higher than 2010 levels. Natural gas prices have remained low and oscillated more over this time period, however they haven't had a significant impact on results due to the Company's relatively low gas production weighting. Third quarter 2011 netbacks decreased over the second quarter primarily due to lower WTI prices, partially offset by lower royalty and production expenses.

- Third quarter 2011 capital expenditures followed the typical seasonal pattern and increased following reduced expenditures in the second quarter due to spring break-up.

- Production expenses per boe declined in the first and second quarters of 2010 due to non-core property dispositions and field optimization. In 2011, production expenses per boe have increased, primarily due to lower production volumes in southeast Saskatchewan, but relatively flat fixed costs, temporary cost increases caused by the poor weather in the second quarter, and cost inflation in the third quarter as a result of increased industry activity. With shut-in production mostly restored during the third quarter, per boe production expenses improved from second quarter levels.

Commitments

The following is a summary of the estimated costs required to fulfill the Company's remaining contractual commitments at September 30, 2011:

Type of commitment	< 1 Year	1-3 Years	Thereafter	Total
Office leases [1]	$ 4,795	$ 12,848	$ 44,120	$ 61,763
Drilling and completion rigs	9,388	16,125	1,725	27,238
Other	1,885	1,858	385	4,128
Total	**$ 16,068**	**$ 30,831**	**$ 46,230**	**$ 93,129**

(1) Includes sublease recoveries of $26.1 million.

Liquidity and Capital Resources

PetroBakken's strategy is to provide a reasonable dividend yield to shareholders combined with an accretive long-term growth-oriented business plan. We are focused on securing appropriate levels of capitalization to support this business strategy. As commodity prices fluctuate, we have the ability to alter our capital program and/or dividend payments in order to maintain acceptable debt levels. We will continue to monitor our plans and forecasts and make adjustments required to maintain acceptable levels of capitalization.

As at September 30, 2011, PetroBakken had $1.13 billion of bank debt drawn on our $1.35 billion credit facility. Our credit facility is with a syndicate of banks and has a maturity date of June 2, 2014. The amount of the facility is based on, among other things, reserves, results from operations, current and forecasted commodity prices and the current economic environment. The credit facility provides that advances may be made by way of direct advances, banker's acceptances, or standby letters of credit/guarantees. Direct advances bear interest at the bank's prime lending rate plus an applicable margin for Canadian dollar advances, and at the bank's US base rate plus an applicable margin for US dollar advances. The applicable margin charged by the bank is based on a sliding scale ratio of PetroBakken's debt to earnings before interest, taxes, depletion, depreciation and amortization ("EBITDA"). The facility is secured by a $2.0 billion demand debenture and a securities pledge on the Company's assets. The credit facility has financial covenants that limit the ratio of secured debt to EBITDA to 3:1, limit the ratio of total debt (total debt defined as facility debt plus the value of outstanding debentures in Canadian dollars) to EBITDA to 4:1, and limit secured debt to 50% of total liabilities plus total equity. The Company is in compliance with all of these covenants.

As at September 30, 2011, PetroBakken had convertible debentures outstanding of US$750 million with an annual coupon of 3.125%. The convertible debenture has a financial covenant that limits the amount of security and encumbrances to 35% of our total assets. The Company is in compliance with this covenant. The debentures have a one-time, one-day early put option on February 8, 2013 that allows those holders that elect to exercise the option to request payment in full for their debentures. In the event that holders request payment, PetroBakken has the option to repay in cash or through the issuance of PetroBakken shares based on the then current share price. We have been, and will continue to be, pursuing various options to provide additional flexibility in order to repay any bonds that may be put back to us with either cash or shares.

In addition to the financial resources noted above, other possible sources of funds available to PetroBakken to fund operations and create liquidity for the February 8, 2013 put date include the following:

- Funds flow from operations;
- Increases under our existing credit facility;
- Issuance of common shares of PetroBakken;
- Commencement of a dividend reinvestment program or a dividend reduction;

- Issuance of subordinated or convertible debt;
- Renegotiating the terms of the existing convertible debenture;
- Adjustments to capital program as commodity prices fluctuate;
- Sale of producing or non-producing assets. Cash generated from a sale may be reduced by any required debt payments; and
- Monetization of risk management assets.

We expect to satisfy ongoing working capital requirements with funds flow from operations, cash and available credit. Early in the second quarter of 2011, we engaged TD Securities Inc. as financial advisor, to assist us in our assessment and pursuit of certain options to provide increased liquidity, and we continue to actively evaluate alternatives going forward.

Capital Plan

The capital plan is focused on the development of our Cardium light oil properties in central Alberta, development of our Bakken and conventional Mississippian light oil properties in southeast Saskatchewan, exploration and development of our Alberta and northeast British Columbia properties, and leveraging our significant undeveloped land base into new resource opportunities. The capital plan is expected to be financed through funds flow from operations and available financial resources.

Dividends

The Company currently pays a monthly dividend of $0.08 per share or the equivalent of $0.96 per share per annum. The dividend represented 29% of the funds flow from operations for the third quarter of 2011 and 28% for the first nine months of 2011. The dividend is expected to remain the same for the remainder of 2011 and to be funded from operations.

Transactions with Related Parties

The Company is party to a management services agreement with Petrobank providing for certain executive functions as well as other services to be shared between the two companies, including administration, financial, treasury, tax, accounting, information technology and human resources support. The fee is based on a negotiated value for services provided. In May 2011, the management services agreement was amended to include a sub-lease office space cancellation payment of $3.0 million, which is to be paid out by PetroBakken to Petrobank over a nine year period, for office space no longer required. Amounts paid to Petrobank under this agreement totalled $0.2 million for the three months ended September 30, 2011 (2010 - $0.6 million) and $1.2 million for the nine months then ended (2010 - $1.9 million), and were recorded as general and administrative expense.

Outstanding Share Data

As at the date of this MD&A there are 187,293,129 PetroBakken common shares outstanding, an increase of 56,445 from September 30, 2011 due to the exercise of incentive shares. At the date of this MD&A there are 9,574,828 stock options, 2,700,462 incentive shares, and 89,644 deferred common shares outstanding.

Risks and Uncertainties

There have been no significant changes in the three and nine months ended September 30, 2011 to the risks and uncertainties identified in the MD&A for the year ended December 31, 2010.

Sensitivities

PetroBakken's earnings and funds flow from operations are sensitive to changes in crude oil and natural gas prices, exchange rates and interest rates.

The following factors demonstrate the expected impact on annualized before tax funds flow from operations excluding the effect of hedging for 2011:

Change of:		**(millions)**
Crude oil	US$1.00/bbl WTI reference price (assuming 33,000 bopd)	**$9.7**
	1,000 bopd of production @ US$90.00/bbl WTI	**$25.3**
Natural gas	$1.00/Mcf AECO reference price (assuming 35 MMcf /d)	**$10.9**
	10.0 MMcf per day of production @ $4.00/Mcf AECO	**$12.1**
Currency	US$0.01 in exchange rate	**$9.0**
Interest rate	1% change in interest rate	**$10.2**

Critical Accounting Policies and Estimates

A summary of PetroBakken's significant accounting policies can be found in Note 2 to PetroBakken's March 31, 2011 unaudited condensed interim consolidated financial statements. There have been no significant changes to the Company's critical accounting policies in the three months ended September 30, 2011.

Changes in Accounting Policies

Adoption of International Financial Reporting Standards

Effective January 1, 2010 PetroBakken transitioned from Canadian Generally Accepted Accounting Principles ("GAAP") to International Financial Reporting Standards ("IFRS"). The interim consolidated financial statements at March 31, 2011 were the first statements prepared under IFRS in accordance with IFRS 1, *First-time Adoption of International Financial Reporting Standards,* and with International Accounting Standards ("IAS") 34, *Interim Financial Reporting.* Refer to Note 26 of interim consolidated financial statements at March 31, 2011 for IFRS comparatives for 2010 and an opening balance sheet at January 1, 2010 showing the changes from Canadian GAAP to IFRS. There have been no significant changes to the IFRS policies in the three months ended September 30, 2011. Note 20 of the interim financial statements at September 30, 2011 provides reconciliations between the Canadian GAAP figures and the IFRS results as at and for the three and nine months ended September 30, 2011.

Regulatory Policies

Certification of Disclosures in Interim Filings

In accordance with National Instrument (NI) 52-109 of the CSA, the Company quarterly issues a Certification of Interim Filings ("Certification"). The Certification requires certifying officers to state that they are responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR").

The Certification requires certifying officers to state that they designed DC&P, or caused it to be designed under their supervision, to provide reasonable assurance that: (i) material information relating to PetroBakken is made known to the certifying officers by others; (ii) information required to be disclosed by PetroBakken in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian securities legislation. In addition, the Certification requires certifying officers to state that they have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes.

During the three and nine months ended September 30, 2011, there has been no change to the Company's ICFR that has materially affected, or is reasonably likely to materially affect, the Company's ICFR. The Company has procedures in place relating to DC&P and ICFR and will continue to monitor such procedures as the Company's business evolves.

Additional Information

Further information regarding PetroBakken Energy Ltd., including its Annual Information Form, can be accessed under the Company's public filings found at http://www.sedar.com and on the Company's website at www.petrobakken.com.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited, thousands of Canadian dollars)

	Note	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Oil and natural gas sales		**$ 272,346**	$ 228,537	**$ 828,595**	$ 750,197
Royalties		**(43,871)**	(31,886)	**(130,409)**	(104,685)
Oil and natural gas revenues		**228,475**	196,651	**698,186**	645,512
Gain (loss) on risk management contracts	15	**55,379**	(7,509)	**50,760**	8,670
		283,854	189,142	**748,946**	654,182
Production		**47,207**	30,924	**134,291**	90,355
Transportation		**1,416**	4,873	**5,991**	11,677
General and administrative		**10,654**	9,006	**29,058**	25,947
Share-based compensation	12	**6,083**	9,107	**15,231**	26,948
Loss (gain) on disposition	8	**122**	(9,685)	**(15,070)**	(11,048)
Loss (gain) on derivative financial liability	9	**(10,606)**	24,937	**(71,654)**	(69,258)
Interest and other	3	**24,559**	20,676	**70,050**	55,444
Foreign exchange loss (gain)		**46,176**	(18,419)	**27,417**	(680)
Depletion and depreciation expense	6	**94,472**	92,094	**277,840**	287,384
Income before taxes		**63,771**	25,629	**275,792**	237,413
Income tax expense	11	**23,494**	14,503	**65,200**	57,933
Net income and comprehensive income		**$ 40,277**	$ 11,126	**$ 210,592**	$ 179,480
Basic earnings per share	13	**$ 0.22**	$ 0.06	**$ 1.12**	$ 0.98
Diluted earnings per share	13	**$ 0.21**	$ 0.06	**$ 1.11**	$ 0.97

See accompanying notes to these condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED BALANCE SHEETS

(Unaudited, thousands of Canadian dollars)

As at,	Note	Sept. 30, 2011	Dec. 31, 2010
Assets			
Current assets			
Accounts receivable		**$ 144,130**	$ 147,339
Prepaid expenses		**13,483**	11,151
Risk management assets	15	**19,225**	2,231
		176,838	160,721
Risk management assets	15	**22,926**	-
Exploration and evaluation	5	**887,770**	1,045,805
Property, plant and equipment	6	**3,762,908**	3,162,474
Goodwill	7	**1,496,005**	1,496,005
Total assets		**$ 6,346,447**	$ 5,865,005
Liabilities and Equity			
Current liabilities			
Accounts payable and accrued liabilities		**$ 363,394**	$ 344,476
Risk management liabilities	15	**554**	12,682
		363,948	357,158
Bank debt	4	**1,127,719**	824,845
Convertible debentures	9	**646,246**	600,844
Derivative financial liability	9	**4,487**	76,141
Other long-term liabilities		**11,010**	5,170
Decommissioning liability	10	**170,946**	132,495
Risk management liabilities	15	**-**	2,597
Deferred tax liabilities		**562,425**	497,225
		2,886,781	2,496,475
Shareholders’ equity			
Common shares	12	**3,149,184**	3,147,238
Contributed surplus	12	**49,752**	36,462
Retained earnings		**260,730**	184,830
		3,459,666	3,368,530
Total liabilities and equity		**$ 6,346,447**	$ 5,865,005

Commitments and contingencies (Note 18)

See accompanying notes to these condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited, thousands of Canadian dollars)

	Note	Common Shares	Contributed Surplus	Retained Earnings	Total
January 1, 2011		$ 3,147,238	$ 36,462	$ 184,830	$ 3,368,530
Net earnings		-	-	210,592	210,592
Common shares issued under employee incentive plan	12	5	-	-	5
Share-based compensation	12	-	15,231	-	15,231
Transfer from contributed surplus related to shares issued under employee incentive plan	12	1,941	(1,941)	-	-
Dividends on common shares		-	-	(134,692)	(134,692)
September 30, 2011		**$ 3,149,184**	**$ 49,752**	**$ 260,730**	**$ 3,459,666**
January 1, 2010		$ 2,717,098	$ 7,125	$ 143,196	$ 2,867,419
Net earnings		-	-	179,480	179,480
Shares issued for acquisitions	12	453,554	-	-	453,554
Common shares issued under employee incentive plan	12	2	-	-	2
Share-based compensation	12	-	26,948	-	26,948
Transfer from contributed surplus related to shares issued under employee incentive plan	12	397	(397)	-	-
Repurchase of common shares	12	(16,329)	-	(4,685)	(21,014)
Dividends on common shares		-	-	(132,129)	(132,129)
September 30, 2010		**$ 3,154,722**	**$ 33,676**	**$ 185,862**	**$ 3,374,260**

See accompanying notes to these condensed interim consolidated financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOW

(Unaudited, thousands of Canadian dollars)

	Note	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Operating Activities					
Net income		**$ 40,277**	$ 11,126	**$ 210,592**	$ 179,480
Adjusted for:					
Depletion and depreciation	6	**94,472**	92,094	**277,840**	287,384
Income tax expense	11	**23,494**	14,503	**65,200**	57,933
Unrealized loss (gain) on risk management contracts	15	**(55,320)**	8,900	**(54,645)**	(8,758)
Unrealized foreign exchange (gain) loss		**46,307**	(18,304)	**27,857**	(16,648)
Share-based compensation	12	**6,083**	9,107	**15,231**	26,948
Loss (gain) on disposition	8	**122**	(9,685)	**(15,070)**	(11,048)
Loss (gain) on derivative financial liability	9	**(10,606)**	24,937	**(71,654)**	(69,258)
Accretion on convertible debentures		**6,040**	5,927	**17,545**	15,665
Accretion on decommissioning liability		**1,388**	1,284	**4,078**	3,765
Realized foreign exchange loss related to financing		**-**	-	**-**	18,184
Amortization of deferred financing costs		**466**	1,308	**2,868**	3,520
Decommissioning liabilities settled		**(366)**	(436)	**(1,108)**	(1,668)
		152,357	140,761	**478,734**	485,499
Changes in non-cash working capital	17	**9,202**	(14,605)	**11,938**	(59,533)
		161,559	126,156	**490,672**	425,966
Investing Activities					
Expenditures on property, plant, and equipment		**(269,759)**	(182,531)	**(660,986)**	(430,947)
Exploration and evaluation expenditures		**(2,102)**	(58,778)	**(31,366)**	(118,166)
Acquisitions		**-**	-	**-**	(482,749)
Proceeds from dispositions	8	**75**	8,306	**22,664**	130,061
Changes in non-cash working capital	17	**165,437**	36,862	**14,819**	5,359
		(106,349)	(196,141)	**(654,869)**	(896,442)
Financing Activities					
Issuance of shares	12	**1**	(17,872)	**5**	(21,012)
Issuance (repayment) of bank debt		**(10,124)**	133,091	**302,856**	(149,336)
Issuance of convertible debentures – net of costs	9	**-**	-	**-**	769,651
Realized loss on foreign exchange contract	9	**-**	-	**-**	(18,184)
Financing costs related to bank debt		**-**	-	**(2,850)**	(1,750)
Amortization of obligations under gas sale contract		**(208)**	(208)	**(618)**	(618)
Dividends		**(44,880)**	(45,177)	**(134,692)**	(132,129)
Changes in non-cash working capital	17	**1**	151	**(504)**	(715)
		(55,210)	69,985	**164,197**	445,907
Net change in cash and cash equivalents		**-**	-	**-**	(24,569)
Cash and cash equivalents, beginning of period		**-**	-	**-**	24,569
Cash and cash equivalents, end of period		**$ -**	$ -	**$ -**	$ -
Other cash flow information:					
Cash interest paid		**$ 16,658**	$ 12,167	**$ 45,539**	$ 32,391

Note 1 – Corporate Information and Basis of Presentation

Corporate Information

PetroBakken Energy Ltd. ("PetroBakken" or the "Company") is a Canadian corporation with shares listed on the Toronto Stock Exchange ("TSX"). The principal address is located at 2800, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

The Company is principally engaged in the exploration and development of oil and natural gas in western Canada. The Company's parent is Petrobank Energy and Resources Ltd. The condensed interim consolidated financial statements ("financial statements") of the Company as at and for the three and nine months ended September 30, 2011 comprise the Company and its subsidiaries; refer to Note 19 for details.

Basis of Presentation

The financial statements are stated in Canadian dollars and have been prepared in accordance with International Financial Reporting Standards ("IFRS") applicable to the preparation of interim financial statements, including IAS 34 *Interim Financial Reporting*. Prior to 2011, the consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). Note 20 contains the reconciliations between Canadian GAAP and IFRS. The accounting policies followed in these financial statements are the same as those applied to the Company's interim financial statements for the period ended March 31, 2011. The financial statements should be read in conjunction with the Company's Canadian GAAP annual financial statements for the year ended December 31, 2010, and the Company's first IFRS interim financial statements for the quarter ended March 31, 2011.

The financial statements were approved by the Company's Board of Directors on November 8, 2011.

Use of Estimates and Judgments

The preparation of financial statements in conformity with IFRS requires management to make estimates, assumptions, and judgments that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the balance sheets 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.

Amounts recorded for depletion and depreciation costs and amounts used for property, plant and equipment and goodwill impairment calculations are based on a number of factors including estimates of oil and natural gas reserves and future costs required to develop those reserves. To test impairment costs are allocated into cash generating units ("CGU's") based on their ability to generate largely independent cash flows. The determination of CGU's is subject to judgment. The transfer of exploration and evaluation assets to property, plant and equipment is based on management's judgment of technical feasibility and commercial viability. Share-based compensation is based upon expected volatility and option life estimates. Decommissioning liabilities and accretion on decommissioning liabilities are based on estimates of abandonment costs, timing of abandonment, inflation and interest rates. The derivative financial liability related to the convertible debenture and the gain or loss on derivative financial liability is based on estimated fair value using the Black-Scholes model. The fair value of derivative instruments resulting in risk management assets and liabilities is subject to measurement uncertainty. 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 bases 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.

Note 2 – Changes in Accounting Policies

Accounting standards effective for periods beginning on or after January 1, 2011 have been adopted as part of the transition to IFRS.

Pending Accounting Pronouncements

The International Accounting Standards Board ("IASB") and International Financial Reporting Interpretations Committee ("IFRIC") have issued the following new accounting standards or amendments to existing standards which are applicable beginning after October 1, 2011 or later periods. We are currently evaluating the impact these changes may have on the Company.

IFRS 9 – Financial Instruments

As of January 1, 2013, PetroBakken will be required to adopt IFRS 9, "Financial Instruments" which is the first stage in a project to replace IAS 39. The new standard replaces the current multiple classification and measurements models for financial assets and liabilities with a single model that will only have two classification categories: amortized cost and fair value.

IFRS 10 – Consolidated Financial Statements

As of January 1, 2013, PetroBakken will be required to adopt IFRS 10, "Consolidated Financial Statements" which provides guidance as to whether an investee, including a special purpose entity, should be consolidated.

IFRS 11 – Joint Arrangements

As of January 1, 2013, PetroBakken will be required to adopt IFRS 11, "Joint Arrangements" which provides a revised method for determining how a company should account for joint arrangements. Based on the terms of the joint arrangement a company will account for joint arrangements using either proportionate consolidation or the equity method.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

IFRS 12 – Disclosure of Interests in Other Entities

As of January 1, 2013, PetroBakken will be required to adopt IFRS 12, "Disclosure of Interest in Other Entities" which provides disclosure requirements for interests held in subsidiaries and joint arrangements.

IFRS 13 – Fair Value Measurements

As of January 1, 2013, PetroBakken will be required to adopt IFRS 13, "Fair Value Measurement" which provides guidance on determination of fair value and disclosure requirements for instances where IFRS requires fair value to be used.

IAS 1 – Presentation of Financial Statements

As of July 1, 2012, the Company will be required to adopt the amendments issued to IAS 1 issued in January 2011. The amendments require items of other comprehensive income, "OCI" to be differentiated between those that will eventually be included in income and those that will not. Since the Company does not have any items of OCI this amendment is not expected to have any impact on the Company.

IAS 27 – Separate Financial Statements

As of January 1, 2013, the Company will be required to adopt the amendments to IAS 27. The amendments conform to the changes made in IFRS 10 but retain current guidance for separate financial statements.

IAS 28 – Investments in Associates and Joint Ventures

As of January 1, 2013, the Company will be required to adopt the amendments to IAS 28. These amendments conform to changes made in IFRS 10 and IFRS 11.

Note 3 – Interest and Other

The interest and other costs for the Company are broken down as follows:

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
	2011	2010	**2011**	2010
Interest on credit facility and other	**$ 10,781**	$ 5,973	**$ 28,291**	$ 15,958
Amortization of deferred financing costs	**466**	1,308	**2,868**	3,520
Accretion on convertible debenture	**6,040**	5,927	**17,545**	15,665
Interest expense on convertible debenture	**5,884**	6,184	**17,268**	16,536
Accretion on decommissioning liability	**1,388**	1,284	**4,078**	3,765
Interest and Other	**$ 24,559**	$ 20,676	**$ 70,050**	$ 55,444

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Note 4 – Bank Debt

The Company maintains a covenant based revolving credit facility with a syndicate of banks. The facility has a lending capacity of $1.35 billion and a maturity date of June 2, 2014. The credit facility bears interest at the prime rate plus a margin based on a sliding scale ratio of PetroBakken's debt to earnings before interest, depletion, depreciation and amortization ("EBITDA"). The facility is secured by a $2.0 billion demand debenture and a securities pledge of Company's assets.

As at,	**Sept. 30, 2011**	Dec. 31, 2010
Bank debt outstanding	**$ 1,132,644**	$ 829,788
Deferred financing costs	**(4,925)**	(4,943)
Bank debt	**$ 1,127,719**	$ 824,845

Note 5 – Exploration and Evaluation Assets

Exploration and evaluation assets comprise the Company's exploration and evaluation projects which are pending determination of proved and probable reserves.

	Sept. 30, 2011	Dec. 31, 2010
Exploration and evaluation assets, beginning of period	**$ 1,045,805**	$ 682,090
Additions	**31,366**	122,580
Acquisitions	**-**	352,002
Dispositions	**(4,444)**	(5,089)
Transfers to property, plant, and equipment	**(184,957)**	(105,778)
Exploration and evaluation assets, end of period	**$ 887,770**	$ 1,045,805

Note 6 – Property, Plant, and Equipment

	Oil and Natural Gas Assets	**Other**	**Total**
Cost			
As at January 1, 2011	$ 4,117,803	$ 22,819	$ 4,140,622
Additions	681,836	14,631	696,467
Dispositions	(3,150)	-	(3,150)
Transfers from E&E assets	184,957	-	184,957
As at September 30, 2011	$ 4,981,446	$ 37,450	$ 5,018,896
Depletion, Depreciation, and Impairment			
As at January 1, 2011	$ 966,403	$ 11,745	$ 978,148
Charge for the period	273,844	3,996	277,840
As at September 30, 2011	$ 1,240,247	$ 15,741	$1,255,988
Carrying amount as at September 30, 2011	**$ 3,741,199**	**$ 21,709**	**$3,762,908**

Depletion and depreciation expense was $94.5 million for the three months ended September 30, 2011 (2010 - $92.1 million) and $277.8 million for the nine months ended September 30, 2011 (2010 – $287.4 million).

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

	Oil and Natural Gas Assets	Other	Total
Cost			
As at January 1, 2010	$ 2,984,001	$ 16,787	$ 3,000,788
Additions	695,331	6,032	701,363
Dispositions	(97)	-	(97)
Acquisitions	332,790	-	332,790
Transfers from E&E assets	105,778	-	105,778
As at December 31, 2010	$ 4,117,803	$ 22,819	$ 4,140,622
Depletion, Depreciation, and Impairment			
As at January 1, 2010	$ 584,012	$ 8,264	$ 592,276
Charge for the period	382,391	3,481	385,872
As at December 31, 2010	$ 966,403	$ 11,745	$ 978,148
Carrying amount as at December 31, 2010	**$ 3 ,151,400**	**$ 11,074**	**$ 3,162,474**

Other fixed assets are mainly comprised of office furniture and fixtures, and computer equipment.

Note 7 – Goodwill

	Sept. 30, 2011	Dec. 31, 2010
Goodwill, beginning of period	**$ 1,496,005**	$ 1,032,862
Acquisitions	**-**	463,143
Goodwill, end of period	**$ 1,496,005**	$ 1,496,005

Goodwill acquired through business combinations has been allocated to the Cash Generating Unit ("CGU") or groups of CGU's that are expected to benefit from the synergies of the acquisition. For purposes of impairment testing, goodwill is allocated to the following CGU's or groups of CGU's which represents the lowest level for which goodwill is monitored for internal purposes:

Cash generating unit(s)	Sept. 30, 2011	Dec. 31, 2010
Bakken and Conventional (Saskatchewan)	**$ 1,024,551**	$ 1,024,551
BC	**8,311**	8,311
Cardium (Alberta)	**463,143**	463,143
Goodwill as at September 30, 2011	**$ 1,496,005**	$ 1,496,005

In assessing goodwill for impairment, the carrying amount of the CGU's are compared to the recoverable amount of the CGU, which is the higher of the fair value less costs to sell and the value in use. For impairment testing of goodwill the recoverable amount is based on the value in use. The value in use is calculated using the discounted value of proved plus probable reserves.

The key assumptions used in determining value in use were the discount rate, commodity prices, volumes, and inventory of undrilled locations. The values assigned to the key assumptions represent management's assessment of the future trends in the oil and natural gas industry and are based on both external and internal sources. A discount rate of 10% (2010 – 10%) was used in the assessment for impairment for all CGU's.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Note 8 – Acquisitions and Dispositions

Asset Divestitures

During the three month period ended September 30, 2011, PetroBakken closed non-core asset divestitures for net proceeds of $0.1 million (2010 - $8.3 million) resulting in a loss on asset disposal of $0.1 million (2010 - $9.7 million gain).

During the nine month period ended September 30, 2011, PetroBakken closed non-core asset divestitures for net proceeds of $22.7 million (2010 - $130.1 million) resulting in a gain on asset disposal of $15.1 million (2010 - $11.0 million gain).

Note 9 – Convertible Debentures

On January 25, 2010, PetroBakken issued US$750 million of convertible debentures maturing in February 2016. The debentures are convertible into common shares of PetroBakken and have an annual coupon rate of 3.125% and an initial conversion price of US$39.61 per debenture. The conversion price is subject to change in certain circumstances including for dividends paid by the Company. Due to dividends paid to shareholders of PetroBakken from February 2010 to September 2011, the conversion price has been adjusted to US$36.27 per debenture. Upon conversion, based on the current conversion price, a total of 20,678,246 common shares may be issued, however the Company has an option to repay the debentures in cash. If the repayment is to be in cash, the cash amount to be paid is variable and is equal to the total shares to be issued multiplied by the 20 day weighted average market price at the date of conversion. In addition, individual bondholders have a one-time put option right of prepayment of the debentures for 100 per cent of the par value plus accrued interest on February 8, 2013. A bondholder has a 10 day period between December 10 and December 20, 2012 to exercise their put option.

The debentures have been classified as a liability net of the fair value of the conversion feature which has been classified as a derivative financial liability. The US$750 million issuance, including transaction costs, resulted in $617.1 million being classified as a liability and $152.6 million being classified as a derivative financial liability. At inception, the fair value of the derivative financial liability was determined using the Black-Scholes valuation model. The following assumptions were used:

At January 25, 2010	
Risk free interest rate	**2.65%**
Annual dividend per share (1)	**$0.00**
Expected life (years)	**6**
Expected volatility (2)	**31%**
CDN/US $ FX rate	**1.06**
Market price	**CDN$31.70**
Conversion price	**US $39.61**

(1) Dividend per share is nil because the share conversion price is adjusted for dividends paid.
(2) Expected volatility includes a premium for the difference between US$/CDN$ exchange rates.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

The liability portion is measured at amortized cost and will be accreted up to the principal balance at maturity using the effective interest rate method. The accretion and the interest paid are expensed as interest expense in the consolidated statement of operations and comprehensive income. The derivative financial liability is measured at fair value through profit and loss, with changes to the fair value being recorded as a gain or loss on derivative financial liability.

If the debentures are converted to common shares, the relative portion of the value of the conversion feature under derivative financial liability will be reclassified to common share capital along with the principal amounts converted.

The US dollar denominated convertible debentures are translated for accounting purposes based on the Canadian dollar exchange rate on the date of issue and at the end of the applicable reporting period. The Company entered into currency swap agreements prior to the date of issue and the actual Canadian dollar proceeds received by the Company resulted in an $18.2 million realized foreign exchange loss in the first quarter of 2010.

The following table summarizes the liability component of the convertible debentures:

	Sept. 30, 2011	Dec. 31, 2010
Liability component of debenture, beginning of period	$ 600,844	$ -
Issuance of convertible debenture	-	617,101
Accretion	17,545	21,557
Changes in exchange rate	27,857	(37,814)
Liability component, end of period	**$ 646,246**	$ 600,844

The following assumptions were used in determining the fair value of the derivative financial liability:

	Sept. 30, 2011	Dec. 31, 2010
Risk free interest rate	1.21%	2.55%
Annual dividend per share (1)	-	-
Expected life (years)	4.25	5.00
Expected volatility (2)	46%	36%
US/CDN $ FX rate	1.04	0.99
Market price	CDN$6.75	CDN$21.71
Conversion price	US $36.27	US $38.19

(1) Dividend per share is nil because the share conversion price is adjusted for dividends paid.
(2) Expected volatility includes a premium for the difference between US$/CDN$ exchange rates.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

The following table summarizes the derivative financial liability:

	Sept. 30, 2011	Dec. 31, 2010
Derivative financial liability, beginning of period	**$ 76,141**	$ -
Issuance of convertible debenture	**-**	152,550
Gain	**(71,654)**	(76,409)
Derivative financial liability, end of period	**$ 4,487**	$ 76,141

The gain on derivative financial liability was $10.6 million for the three months ended September 30, 2011 (2010 - $24.9 million loss) and $71.7 million for the nine months ended September 30, 2011 (2010 – $69.3 million gain).

Note 10 – Decommissioning Liability

The total future decommissioning liability was estimated by management based on the Company's net ownership interest in all wells, gathering lines and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods.

Changes to decommissioning liability were as follows:

	Sept. 30, 2011	Dec. 31, 2010
Decommissioning liability, beginning of period	**$ 132,495**	$ 107,572
Change in estimate(1)	**27,765**	-
Obligations incurred	**7,347**	7,941
Obligations acquired	**422**	16,484
Obligations disposed	**(53)**	(1,930)
Obligations settled	**(1,108)**	(2,634)
Accretion	**4,078**	5,062
Decommissioning liability, end of period	**$ 170,946**	$ 132,495

(1) This amount relates to the change in the discount rate used.

The decommissioning liability has been calculated using an inflation rate of two percent and discounted using a risk free rate of three percent per annum. Most of these obligations are not expected to be paid for several years extending up to 45 years in the future and are expected to be funded from the general resources of the Company at the settlement date. The total undiscounted amount of estimated cash flows required to settle the liabilities at September 30, 2011 is $214.2 million (December 31, 2010 – $204.8 million).

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Note 11 – Income Taxes

Income tax expense is comprised of the following amounts:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
Deferred income tax	**$ 23,494**	$ 14,503	**$ 65,200**	$ 57,933
Current income tax	**-**	-	**-**	-
Income tax expense	**$ 23,494**	$ 14,503	**$ 65,200**	$ 57,933

Income tax expense differs from the amount that would have been expected by applying the statutory tax rate to income before taxes. The principal reasons for this difference are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
Income before tax expense	**$ 63,771**	$ 25,629	**$ 275,792**	$ 237,413
Statutory tax rate	**27.54%**	29.04%	**27.54%**	29.04%
Expected tax expense	**17,562**	7,443	**75,953**	68,945
Increase (decrease) in tax expense resulting from:				
Non-deductible loss (non-taxable gain) on derivative financial liability	**(2,921)**	7,243	**(19,734)**	(20,115)
Non-deductible (non-taxable) foreign exchange losses (gains)	**6,377**	(2,658)	**3,836**	223
Share-based compensation	**1,676**	2,645	**4,195**	7,827
Accretion on convertible debentures	**1,663**	1,722	**4,832**	4,550
Valuation of temporary differences at deferred tax rates	**(1,315)**	(1,717)	**(3,289)**	(4,203)
Other	**452**	(175)	**(593)**	706
Income tax expense	**$ 23,494**	$ 14,503	**$ 65,200**	$ 57,933

Note 12 – Share Capital

Authorized

The authorized capital of PetroBakken consists of an unlimited number of PetroBakken Class A Shares without nominal or par value, an unlimited number of Class B Shares without nominal or par value and an unlimited number of Preferred Shares without nominal or par value. Class B Shares hold equal voting rights as Class A Shares and are convertible into Class A shares on a one for one basis at no extra cost.

Normal Course Issuer Bid

During the three months ended September 30, 2010, the Company purchased and cancelled 834,400 shares. The shares repurchased had an average cost of $21.42 per share. Of the amount paid, $14.0

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million reduced the book value of the common shares and the remaining $3.9 million was recorded as a reduction to retained earnings.

During the nine months ended September 30, 2010, the Company repurchased and cancelled 971,500 shares. The shares had an average cost of $21.63 per share. Of the amount paid, $16.3 million reduced the book value of the common shares and the remaining $4.7 million was recorded as a reduction to retained earnings.

Common Shares

Class A Share Continuity	**Number**		**Amount**
Balance at January 1, 2010	156,891,940	$	2,306,151
Issued upon acquisition of Rondo	5,524,471		150,266
Issued upon acquisition of Result	11,232,904		303,288
Exercise of incentive shares and deferred common shares	207,146		10
Repurchase of common shares	(1,680,400)		(28,241)
Transfer from contributed surplus related to incentive shares and deferred common shares exercised	-		4,817
Balance at December 31, 2010	172,176,061	$	2,736,291
Exercise of incentive shares and deferred common shares	96,265		5
Transfer from contributed surplus related to incentive shares and deferred common shares exercised	-		1,941
Balance at September 30, 2011	**172,272,326**	**$**	**2,738,237**

Class B Share Continuity	**Number**		**Amount**
Balance at Jan 1, 2010 and Dec 31, 2010 and Sept. 30, 2011	**14,964,358**	**$**	**410,947**

Total of Class A and Class B Common Shares	**Number**		**Amount**
Balance at September 30, 2011	**187,236,684**	**$**	**3,149,184**

Contributed Surplus

Changes in Contributed Surplus		**Amount**
Balance at January 1, 2010	$	7,125
Share-based compensation		34,154
Transfer from contributed surplus related to incentive shares and deferred common shares exercised		(4,817)
Balance at December 31, 2010	$	36,462
Share-based compensation		15,231
Transfer from contributed surplus related to incentive shares and deferred common shares exercised		(1,941)
Balance at September 30, 2011	**$**	**49,752**

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Dividends

Dividends paid were $0.24 per share for the three months ended September 30, 2011 (2010 – $0.24 per share) resulting in total dividends paid of $44.9 million (2010 - $45.2 million). For the nine months ended September 30, 2011 dividends paid were $0.72 per share (2010 - $0.72 per share) or $134.7 million in total (2010 - $132.1 million).

Stock Options

Options granted under the stock option plan have an exercise price that is no less than the five day weighted average trading price of the Company's common shares on the Toronto Stock Exchange prior to the date of the grant. Stock options terms are determined by the Company's Board of Directors but typically, options vest evenly over a period of three to four years from the date of grant and expire between five and 10 years after the date of grant.

The following is a continuity of stock options outstanding:

	September 30, 2011		December 31, 2010	
	Stock Options	**Weighted-Average Exercise Price**	Stock Options	Weighted-Average Exercise Price
Opening	**6,030,283**	**$ 25.15**	4,161,500	$ 34.15
Granted	**4,649,164**	**14.22**	3,495,495	23.66
Forfeited	**(1,171,001)**	**21.70**	(1,626,712)	32.24
Closing	**9,508,446**	**$ 20.23**	6,030,283	$ 25.15

The following summarizes information about stock options outstanding at September 30, 2011:

Stock Options Outstanding

Range of exercise prices	Number	Weighted – Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price
10.40 - 13.44	3,180,813	5.3	$ 12.90
13.45 – 23.11	2,105,950	4.4	18.75
23.12 – 34.54	4,221,683	5.4	26.48
	9,508,446	**5.2**	**$ 20.23**

As at September 30, 2011, there were 1,000,762 stock options vested and exercisable into common shares with a weighted average exercise price of $27.22.

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Incentive Shares

The incentive plan allows holders to receive one common share upon payment of $0.05 per share. Incentive share terms are determined by the Company's Board of Directors but typically, incentive shares vest over a period of three to four years from the date of grant and expire between five and 10 years from the date of grant. Up to 4.0 million incentive shares have been approved for issuance under this plan.

The following is a continuity of incentive shares outstanding:

	Sept. 30, 2011	Dec. 31, 2010
Opening	**2,159,210**	1,971,384
Granted	**1,108,082**	784,291
Exercised	**(95,647)**	(206,419)
Forfeited	**(423,751)**	(390,046)
Closing	**2,747,894**	**2,159,210**

As at September 30, 2011, there were 405,942 incentive shares vested and exercisable into common shares at $0.05 per share.

Deferred Common Shares

The holders of deferred common shares are entitled to receive one common share upon payment of $0.05 per share. The deferred common shares vest after three years or immediately upon resignation or retirement, and expire 10 years from the date of the grant. Up to 1.0 million deferred common shares have been approved for issuance under this plan.

The following is a continuity of deferred common shares outstanding:

	Sept. 30, 2011	Dec. 31, 2010
Opening	**42,136**	1,751
Granted	**48,126**	41,112
Exercised	**(618)**	(727)
Closing	**89,644**	**42,136**

As at September 30, 2011, there were no deferred common shares exercisable into common shares.

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Share-Based Compensation

The fair value of PetroBakken incentive shares, stock options and deferred common shares granted have been estimated on their respective grant dates using the Black-Scholes option-pricing model using the following assumptions:

Nine months ended September 30,	**2011**	2010
Risk free interest rate	**1.15-2.51%**	2.25%
Annual dividend per share	**$0.96**	$0.96
Expected life – incentive shares (years)	**3.00 - 3.75**	0.75 – 3.75
Expected life – stock options (years)	**3.00 - 3.75**	3.75
Expected life – deferred common shares (years)	**8.0**	8.0
Estimated forfeiture rate	**7%**	7%
Average fair value at grant date – incentive shares	**$20.07**	$23.18
Average fair value at grant date – options	**$4.11**	$4.11
Average fair value at grant date – deferred common shares	**$15.69**	$19.59
Expected volatility	**25-30%**	25-28%

Share-based compensation expense was $6.1 million for the three months ended September 30, 2011 (2010 - $9.1 million) and $15.2 million for the nine months ended September 30, 2011 (2010 - $26.9 million).

Note 13 – Earnings per Share

Basic earnings per share is calculated by dividing net income by the weighted average number of common share outstanding during the period. Diluted earnings per share reflects the potential dilution of stock options, incentive shares, deferred common shares, and convertible debentures.

Net income used in determining earning per share is presented below:

	Three months ended September 30,		Nine months ended Septembers 30,	
	2011	2010	**2011**	2010
Net income	**$ 40,277**	$ 11,126	**$ 210,592**	$ 179,480

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The following table summarize the basic and diluted weighted average number of Class A and Class B common shares:

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
	2011	2010	**2011**	2010
Weighted average common shares outstanding, basic	**187,233,848**	188,302,302	**187,206,660**	183,343,536
Effect of:				
Stock options	**-**	-	**435,385**	115,371
Incentive shares	**1,242,428**	421,503	**1,658,711**	695,514
Deferred common shares	**89,263**	42,038	**89,368**	42,053
Weighted average common shares outstanding, diluted	**188,565,539**	188,765,843	**189,390,124**	184,196,474

In determining the weighted average number of diluted common shares outstanding for the three months ended September 30, 2011, 9,508,446 stock options are excluded because the effect would be anti-dilutive (2010 – 5,729,483 stock options). For the nine months ended September 30, 2011, 5,863,333 stock options are excluded because the effect would be anti-dilutive (2010 - 1,443,250 stock options). The 20,678,246 common shares that could be issued on the conversion of the debenture (2010 – 19,419,990) were also considered anti-dilutive and were excluded from the weighted average number of diluted shares.

Note 14 – Capital Management

The Company's policy is to maintain a strong capital base in order to provide flexibility in the future development of the business.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Company considers its capital structure to include common share capital, bank debt outstanding, convertible debentures and working capital. In order to maintain or adjust the capital structure, from time to time the Company may issue common shares, debt or other securities, sell assets, adjust capital spending or its dividend to manage current and projected debt levels.

As at	**Sept. 30, 2011**	Dec. 31, 2010
Working capital deficit (1)	**$ 205,781**	$ 185,986
Bank debt – principal	**1,132,644**	829,788
Convertible debentures – principal amount (US$)	**750,000**	750,000
Common share capital	**3,149,184**	3,147,238
Credit facility – borrowing base	**$ 1,350,000**	$ 1,200,000
Available credit capacity	**217,356**	370,212

(1) Working capital deficit is calculated as current liabilities less current assets, excluding risk management assets and liabilities.

The Company monitors leverage and adjusts its capital structure based on the ratio of bank debt to annualized earnings before interest, taxes and non-cash items. At September 30, 2011, the ratio of bank debt to annualized third quarter 2011 earnings before interest, taxes and non-cash items was 1.7 to 1, which is within a range acceptable to management. PetroBakken uses the ratio of bank debt to annualized earnings before interest, taxes and non-cash items as a key indicator of the Company's leverage and to monitor the strength of the balance sheet. In order to facilitate the management of this ratio, the Company prepares annual budgets, which are updated as necessary depending on varying factors including current and forecast commodity prices, changes in capital structure, execution of the Company's business plan and general industry conditions. The annual budget is approved by the PetroBakken Board of Directors and updates are prepared and reviewed as required.

The Company is in compliance with all covenants on its credit facility agreement. The credit facility has financial covenants that limit the ratio of secured debt (defined as total drawn on credit facility) to earnings before interest, taxes, depreciation and amortization ("EBITDA") to 3:1, limit the ratio of total debt (defined as total drawn on credit facility plus value of outstanding convertible debenture in Canadian dollars) to EBITDA on a trailing 12 month basis to 4:1, and limit secured debt to 50% of total liabilities plus total equity.

PetroBakken's convertible debentures are considered to be equity as opposed to debt for capital management purposes. The Company has the option to repay the principal and interest amount in common shares or cash at the put or maturity date.

PetroBakken is in compliance with the covenants on its convertible debentures. The convertible debenture agreement stipulates that the ratio of secured debt to total assets is not to exceed 35%.

The Company had positive cash flow from operations for the three and nine months ended September 30, 2011 and a credit facility with $217.4 million of available capacity as at September 30, 2011.

Note 15 – Financial Instruments and Financial Risk Management

The Company has exposure to the following risks from its use of financial instruments: credit risk, liquidity risk and market risk. This note presents information about the Company's exposure to each of these risks and the objectives, policies and processes for measuring and managing risk. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors of PetroBakken have overall responsibility for the establishment and oversight of the Company's financial risk management framework and monitors risk management activities. The Company identifies and analyzes the risks it faces and may utilize financial instruments to mitigate these risks.

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Credit Risk

A substantial portion of our accounts receivable is with customers and joint-venture participants in the oil and natural gas industry and is subject to normal industry credit risks. The carrying amount of accounts receivable reflects management's assessment of the credit risk associated with these customers and participants. At September 30, 2011 accounts receivable consisted of $126.4 million (December 31, 2010 - $139.7 million) from oil and natural gas customers and $17.7 million (December 31, 2010 - $7.7 million) of other trade receivables. At September 30, 2011, oil, natural gas and NGL production is being sold to a number of oil and gas marketers. Accounts receivable from oil and natural gas marketers are normally collected 25 days after the month of production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers and, where practical, obtain support in the form of guarantees or letters of credit. Receivables from joint-venture partners related to capital and operating expenses are generally collected between 45 and 90 days after the month of billing. The Company historically has not experienced any collection issues with its oil and natural gas marketers or joint interest partners.

The carrying amount of accounts receivable and cash and cash equivalents represent the Company's maximum credit exposure. PetroBakken had a $2.0 million allowance for doubtful accounts as at September 30, 2011 (December 31, 2010 – $1.9 million). The allowance for doubtful accounts substantially relates to items that are past due.

PetroBakken's accounts receivables are aged as follows:

As at	**Sept. 30, 2011**	Dec. 31, 2010
Not past due	**$ 141,065**	$ 140,698
Past due	**3,065**	6,641
Total	**$ 144,130**	$ 147,339

Liquidity Risk

The Company's approach to managing liquidity is to ensure that it will have sufficient liquidity to meet its liabilities when due, under both normal and unusual conditions without incurring unacceptable losses or jeopardizing the Company's business objectives.

The Company prepares annual capital expenditure budgets, which are monitored and updated as considered necessary. Production is monitored regularly to provide current cash flow estimates and the Company utilizes authorizations for expenditures on projects to manage capital expenditures. To facilitate the capital expenditure program, the Company has a revolving credit facility, as outlined in Note 4, which has a maturity date of June 2, 2014.

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The following are the contractual maturities of financial liabilities at September 30, 2011:

Financial Liability	< 1 Year	1-3 Years	Thereafter	Total
Accounts payable and accrued liabilities	$ 363,394	$ -	$ -	$ 363,394
Risk management liabilities	554	-	-	554
Bank debt – principal	-	1,132,644	-	1,132,644
Convertible debentures – principal (US$)	-	-	750,000 (1)	750,000
Total (2)	**$ 363,948**	**$ 1,132,644**	**$ 779,175**	**$ 2,275,767**

(1) Bondholders have a one-time put option right for prepayment of the debentures on February 8, 2013, payable in common shares or cash at the Company's option.
(2) US$ amounts have been converted using a period end exchange rate of $1.0389.

Market Risk

Market risk is the risk that changes in market factors, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's cash flows, net income, liquidity or the value of financial instruments. The objective of market risk management is to mitigate market risk exposures where considered appropriate and maximize returns.

The Company uses derivative instruments to manage market risk. The Board of Directors of PetroBakken has approved a hedging policy and periodically reviews the results of all risk management activities and all outstanding positions.

Foreign Currency Risk

The Company is exposed to fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil, and to a certain extent, natural gas prices are based upon reference prices denominated in US dollars, while the majority of the Company's expenses are denominated in Canadian dollars. The Company also has a convertible debenture with semi-annual interest payments based in US dollars. When appropriate, the Company may enter into agreements to fix the exchange rate of Canadian dollars to US dollars in order to manage exchange rate risks. The Company had no forward exchange rate contracts in place as at September 30, 2011.

At September 30, 2011, if the Canadian dollar had depreciated five percent against the United States dollar with all other variables held constant, net income would have been $26.1 million lower for the three and nine months ended September 30, 2011 (2010 – $24.7 million lower), due to the period end valuation of US dollar denominated risk management contracts outstanding and convertible debentures.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Commodity Price Risk

Changes in commodity prices may significantly impact the results of the Company's operations and cash generated from operating activities, and can also impact the Company's lending value under its secured credit facility. Lower commodity prices can also reduce the Company's ability to raise capital. Crude oil prices are impacted by world economic and political events that dictate the levels of supply and demand. Natural gas prices in Canada are influenced primarily by North American supply and demand. From time to time the Company may attempt to mitigate commodity price risk through the use of financial derivatives. It has been PetroBakken's policy to only enter into commodity contracts considered appropriate to a maximum of 50% of forecasted production.

The following is a summary of crude oil derivative contracts in place as at September 30, 2011:

Crude Oil Price Risk Management Contracts – WTI [(1)]

Term	Volume (bopd)	Average Price ($/bbl)	Benchmark
Oct. 1, 2011 – Dec. 31, 2011	2,500	$78.00 floor/$95.40 ceiling	C$WTI
Oct. 1, 2011 – Dec. 31, 2011	4,500	$76.11 floor/$101.43 ceiling	US$WTI
Oct. 1, 2011 – Jun. 30, 2012	2,000	$75.00 floor/$99.59 ceiling	US$WTI
Oct. 1, 2011 – Dec. 31, 2012	1,000	$75.00 floor/$98.25 ceiling	US$WTI
Jan. 1, 2012 – Jun. 30, 2013	3,750	$75.00 floor/$122.01 ceiling	US$WTI
Jan. 1, 2012 – Dec. 31, 2013	1,750	$80.00 floor/$134.12 ceiling	US$WTI
Jul. 1, 2012 – Jun. 30, 2013	1,000	$75.00 floor/$117.45 ceiling	US$WTI
Jul. 1, 2013 – Dec. 31, 2013	2,000	$75.00 floor/$127.37 ceiling	US$WTI
Jul. 1, 2013 – Jun. 30, 2014	500	$80.00 floor/$127.65 ceiling	US$WTI

(1) Prices are the volume weighted average prices for the period

The following crude oil contracts were entered into subsequent to September 30, 2011:

Term	Volume (bopd)	Average Price ($/bbl)	Benchmark
Jan. 1, 2013 – Dec. 31, 2013	500	$75.00 floor/$104.50 ceiling	US$WTI
Jul. 1, 2013 – Jun. 30, 2014	500	$75.00 floor/$102.00 ceiling	US$WTI

The average of the above volumes is as follows:

Term	Volume (bopd)	Average Price ($/bbl) [(1)]	Benchmark
2011	10,000	$77.01 floor/$100.48 ceiling	US$WTI
2012	8,000	$76.09 floor/$118.60 ceiling	US$WTI
2013	6,125	$76.63 floor/$123.96 ceiling	US$WTI
2014	500	$77.50 floor/$114.83 ceiling	US$WTI

(1) Canadian dollar contracts are converted at an exchange rate of $1.0389

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

The following natural gas price risk management contracts were outstanding as at September 30, 2011:

Natural Gas Price Risk Management Contracts – AECO

Term	Volume (GJ/d)	Price ($/GJ)	Type
Oct. 1, 2011 – Dec. 31, 2011	2,000	$6.00	Fixed Price Swap

The fair value of the commodity risk management contract asset as at September 30, 2011 is $42.1 million (December 31, 2010 – $12.8 million liability). If crude oil prices had been 10% lower on September 30, 2011, with all other variables held constant, the change in the fair value of the risk management contracts would have resulted in net income that was $38.4 million higher for the three and nine months then ended (2010 – $26.2 million higher). If natural gas prices had been 10% lower on September 30, 2011, with all other variables held constant, the change in the fair value of the risk management contracts would have resulted in net income that was $0.1 million higher for the three and nine months then ended (2010 – $0.7 million).

Long-Term Physical Gas Sale Contract

The Company is committed to deliver 2,209 GJ per day of natural gas under an escalating price contract which expires October 31, 2012. The wellhead price under this contract for the nine months ended September 30, 2011 was $5.57 per GJ. The Company applies the expected purchase and sale exemption to this contract and accordingly does not apply hedge accounting principles to this contract. The obligation under gas sales contract is included on other long-term liabilities on the balance sheet.

Interest Rate Risk

The Company is exposed to interest rate cash flow risk on floating interest rate bank debt due to fluctuations in market interest rates. The remainder of the Company's financial assets and liabilities are not exposed to interest rate risk.

PetroBakken had the following interest rate swap contracts in place as at September 30, 2011:

Term	Notional Principal / Month	Fixed Annual Rate (%)
Oct. 1 2011 – Jan 31. 2012	C$50 million	1.620%
Oct. 1 2011 – Jan 31. 2012	C$50 million	1.653%
Oct. 1 2011 – Feb 28. 2012	C$25 million	1.540%
Oct. 1 2011 – Feb 28. 2012	C$25 million	1.510%
Oct. 1 2011 – Apr 30. 2012	C$50 million	1.300%
Oct. 1 2011 – Jun 30. 2012	C$25 million	2.094%

The fair value of the interest rate swap contracts as at September 30, 2011 was a liability of $0.5 million (December 31, 2010 - $0.2 million liability). If interest rates had been 1% higher at September 30, 2011, net income would have increased by $0.9 million (2010 – $3.4 million higher) for the three and nine months then ended due to the change in fair value of the interest rate swaps.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Fair Value of Financial Derivative Contracts

The following table summarizes the change in the fair value of derivative contracts:

	Crude Oil	Natural Gas	Interest	**Total**
Risk management asset (liability),				
December 31, 2010	(14,835)	2,022	(235)	**(13,048)**
Unrealized gain (loss)	56,520	(1,560)	(315)	**54,645**
Risk management asset (liability),				
September 30, 2011	41,685	462	(550)	**41,597**

The net risk management asset/liability consists of current and non-current assets and liabilities. The tables below summarize the components of the net risk management asset/liability as at September 30, 2011:

	Crude Oil	Natural Gas	Interest	**September 30, 2011**
Current				
Risk management asset	18,763	462	-	**19,225**
Risk management liability	(4)	-	(550)	**(554)**
Non-current				
Risk management asset	22,926	-	-	**22,926**
Risk management liability	-	-	-	**-**
Net risk management asset (liability)	41,685	462	(550)	**41,597**

	Crude Oil	Natural Gas	Interest	December 31, 2010
Current				
Risk management asset	-	2,022	209	2,231
Risk management liability	(12,318)	-	(364)	(12,682)
Non-current				
Risk management asset	-	-	-	-
Risk management liability	(2,517)	-	(80)	(2,597)
Net risk management asset (liability)	(14,835)	2,022	(235)	(13,048)

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

The unrealized gain (loss) represents the change in fair value of the underlying risk management contracts to be settled in the future. The realized gain (loss) represents the risk management contracts settled during the period. The table below summarizes the components of the realized and unrealized risk management gains and losses:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	**2011**	2010
Realized gain (loss) on risk management contracts:				
Crude oil derivative contracts	**$ (190)**	$ (769)	**$ (4,864)**	$ (1,908)
Natural gas derivative contracts	**471**	2,654	**1,647**	3,907
Interest rate swap contracts	**(222)**	(494)	**(668)**	(2,087)
	59	1,391	**(3,885)**	(88)
Unrealized gain (loss) on risk management contracts:				
Crude oil derivative contracts	**55,837**	(7,041)	**56,520**	7,897
Natural gas derivative contracts	**(387)**	(321)	**(1,560)**	929
Interest rate swap contracts	**(130)**	(1,538)	**(315)**	(68)
	55,320	(8,900)	**54,645**	8,758
Gain (loss) on risk management contracts	**$ 55,379**	$ (7,509)	**$ 50,760**	$ 8,670

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Fair Value of Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, risk management liabilities, bank debt, convertible debentures, derivative financial liability, and obligations under the gas sale contract on the balance sheet. The carrying value and fair value of these financial instruments at September 30, 2011 is disclosed below by financial instrument classification, as well as any related gain, loss, expense or revenue for the nine months ended September 30, 2011:

Financial Instrument	Carrying Value	Fair Value	Gain/ (Loss)	Interest Expense	Revenue
Accounts receivable	144,130	144,130	-	-	-
Accounts payable and accrued liabilities	363,394	363,394	-	-	-
Risk management asset (net)	41,597	41,597	50,760 (1)	-	-
Bank debt	1,127,719	1,132,644	-	31,139 (2)	-
Convertible debentures	646,246	623,340 (3)	(27,857) (4)	34,813 (5)	-
Derivative financial liability	4,487	4,487	71,654 (6)	-	-
Obligations under gas sale Contract	898	(1,796) (7)	-	-	618 (8)

(1) Included in gain (loss) on risk management contracts on the statement of operations and comprehensive income. Of this amount, the unrealized gain of $54.6 million is included on the statement of cash flow.
(2) Included in interest expense on the statement of operations and comprehensive income. The effective yield on bank debt at September 30, 2011 was 3.6% (December 31, 2010 – 3.5%).
(3) The Company estimated the fair value of the convertible debenture based on the market transactions closed on September 30, 2011.
(4) Included in foreign exchange gain on the statement of operations and comprehensive income and statement of cash flow.
(5) Included in interest expense on the statement of operations and comprehensive income and statement of cash flow. The effective yield on the convertible debenture is 7.8%.
(6) Included in loss (gain) on derivative financial liability on the statement of operations and comprehensive income and statement of cash flow.
(7) The estimated fair value of the long-term physical gas sale contract is based on AECO forward strip pricing and is in an asset position at September 30, 2011.
(8) Included in oil and natural gas revenues on the statement of operations and comprehensive income. The amortization of obligations under gas sale contract is included on the statement of cash flow.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

The Company classifies the fair value of these financial instruments 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.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level.

The risk management contracts (level 2) are recorded at their fair value based on quoted market prices in the futures market on the balance sheet date; accordingly, there is no difference between fair value and carrying value. The derivative financial liability (level 2) is recorded at fair value based on the valuation determined through using inputs from quoted market prices on the balance sheet date; accordingly there is no difference between the carrying value and the fair value. Due to the short-term nature of cash and cash equivalents, accounts receivable, and accounts payable and accrued liabilities, their carrying values approximate their fair values.

Bank debt bears interest at a floating rate and accordingly fair value approximates carrying value.

Note 16 – Operating Leases

Operating lease payments represent monthly rent payables. The table below shows the expense recorded in the period:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2011	2010	**2011**	2010
Minimum lease payments	**$ 2,652**	$ 1,267	**$ 6,110**	$ 4,053
Sub-lease rentals	**(584)**	(249)	**(1,062)**	(835)
Net Lease payments	**$ 2,068**	$ 1,018	**$ 5,048**	$ 3,218

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Note 17 – Changes in Non-Cash Working Capital

	Three months ended Sept. 30,		Nine months ended Sept. 30	
	2011	2010	**2011**	2010
Change in:				
Accounts receivable	**$ (7,238)**	$ 284	**$ 3,209**	$ 12,116
Prepaid expenses	**1,079**	(3,010)	**(2,332)**	3,952
Accounts payable and accrued liabilities	**179,197**	25,178	**18,918**	(34,623)
Other	**1,602**	(44)	**6,458**	(132)
	174,640	22,408	**26,253**	(18,687)
Working capital deficiencies acquired	**-**	-	**-**	(36,202)
	$ 174,640	$ 22,408	**$ 26,253**	$ (54,889)
Changes relating to:				
Attributable to operating activities	**$ 9,202**	$ (14,605)	**$ 11,938**	$ (59,533)
Attributable to financing activities	**$ 1**	$ 151	**$ (504)**	$ (715)
Attributable to investing activities	**$ 165,437**	$ 36,862	**$ 14,819**	$ 5,359

Note 18 – Commitments and Contingencies

The following is a summary of the estimated costs required to fulfill the Company's remaining contractual commitments at September 30, 2011:

Type of commitment	< 1 Year	1-3 Years	Thereafter	Total
Office leases [1]	$ 4,795	$ 12,848	$ 44,120	$ 61,763
Drilling and completion rigs	9,388	16,125	1,725	27,238
Other	1,885	1,858	385	4,128
Total	**$ 16,068**	**$ 30,831**	**$ 46,230**	**$ 93,129**

(1) Includes sublease recoveries of $26.1 million.

Note 19 – Related Party Transactions

Significant Subsidiaries

Subsidiary	Country of Incorporation	Ownership interest 2011	Ownership interest 2010
PetroBakken Capital Ltd.	Canada	100%	100%
Southside Petroleum Ltd.	US	100%	100%
Southside Oil & Gas Ltd.	US	100%	100%

The Company either directly or through its subsidiaries owns a 100% interest in PBN Partnership.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Transactions with Petrobank Energy and Resources Ltd. ("Petrobank")

As at September 30, 2011, Petrobank owned 59% of the Company's shares.

The Company is party to a management services agreement with Petrobank providing for certain executive functions as well as other services to be shared between the two companies, including administration, financial, treasury, tax, accounting, information technology and human resources support. The fee is based on a negotiated value for services provided. In May 2011, the management services agreement was amended to include a sub-lease office space cancellation payment of $3.0 million, which is to be paid out by PetroBakken to Petrobank over a nine year period, for office space no longer required. Amounts paid to Petrobank under this agreement totalled $0.2 million for the three months ended September 30, 2011 (2010 - $0.6 million) and $1.2 million for the nine months then ended (2010 - $1.9 million), and were recorded as general and administrative expense.

Note 20 – Transition to IFRS

Transition Elections

The Company has applied the following exceptions and exemptions to full retrospective application of IFRS:

Exemption/Election	Impact
Estimates	Estimates made under Canadian GAAP are consistent with estimates made under IFRS after adjustments for changes in accounting policies.
Business Combinations	The Company elected not to retrospectively apply IFRS 3, *Business Combinations* to business combinations that occurred prior to the transition date and such business combinations have not been restated. Goodwill from business combinations that took place prior to transition date were tested for impairment on transition and were determined not to be impaired.
Deemed cost of property, plant and equipment	As described in Note 20 a.
Decommissioning liabilities included in the cost of property, plant, and equipment	As described in Note 20 c.
Share-based payment transactions	As described in Note 20 d.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Reconciliation of Canadian GAAP to IFRS

IFRS 1 requires the Company to reconcile equity, comprehensive income, and cash flows for prior periods. The Company's first time adoption of IFRS did not have any impact on total operating, investing, or financing cash flows. The following represents the reconciliations from Canadian GAAP to IFRS for the respective periods for equity, and comprehensive income.

Reconciliation of Equity	Note	Dec. 31, 2010	Sept. 30, 2010
Shareholders' equity Canadian GAAP		$ 3,456,734	$ 3,496,694
Assets held for sale	b	(48,656)	(48,656)
Gain on disposal of assets	b	9,259	11,048
Depletion and depreciation	f	134,935	100,481
Convertible debentures	g	(194,113)	(194,113)
Accretion on convertible debentures	g	3,976	2,861
Foreign exchange on convertible debentures	g	2,268	1,056
Derivative financial liability	g	76,409	69,258
Accretion on decommissioning liability	c	(466)	(340)
Decommissioning liability	c	(65,711)	(65,711)
Deferred tax	e	(6,105)	1,682
Shareholders' equity IFRS		$ 3,368,530	$ 3,374,260

Reconciliation of net income and comprehensive income	Note	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2010
Net income and comprehensive income, Canadian GAAP		$ 9,194	$ 32,907
Share-based compensation	d	(4,200)	(9,510)
Gain on disposition	b	9,685	11,048
Gain (loss) on derivative financial liability	g	(24,937)	69,258
Gain on unrealized foreign exchange on convertible debentures	g	1,100	1,056
Depletion and depreciation	f	28,855	100,481
Accretion on convertible debentures	g	1,101	2,861
Accretion on decommissioning liability	c	(123)	(340)
Deferred tax expense	e	(9,549)	(28,281)
Net income and comprehensive income, IFRS		$ 11,126	$ 179,480

Notes to the Reconciliation

a. IFRS 1 election for full cost oil and gas entities

The Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

(i) pre-development assets were reclassified from the full cost pool to exploration and evaluation assets at the amount that was recorded under Canadian GAAP; and

(ii) the remaining full cost pool was allocated to the oil and natural gas assets components pro rata using reserve values.

During the nine months ended September 30, 2010 the balance in exploration and evaluation assets increased by $411.4 million due to land and seismic acquired in the quarter partially offset by transfers to property, plant and equipment. The increase for the year ended December 31, 2010 as a result of this was $363.7 million.

b. Assets held for sale

In the fall of 2009 the Company made the decision to dispose of certain oil and gas properties. Under Canadian GAAP, these properties were not considered assets held for sale due to AcG-16 – *Oil and Gas Accounting Full Cost*. The assets sold in 2010 met the criteria of assets held for sale under IFRS 5.

The final non-core property disposition was completed during the second quarter of 2010, which resulted in both the assets held for sale balance and liabilities held for sale balance being $nil as at September 30, 2010. During the three months ended September 30, 2010, there was a minor disposition that took place resulted in a gain of $9.7 million for the period as the proceeds received were in excess of the carrying value.

During the nine months ended September 30, 2010 the disposition of the four non-core property dispositions and other dispositions resulted in a gain of $11.0 million as the proceeds received were higher than the carrying value. This resulted in an increase of the same amount to property, plant and equipment.

c. Decommissioning liability

Under Canadian GAAP asset retirement obligations were discounted at a credit adjusted risk free rate of 8% for the Company. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been discounted at a risk free rate of 4% percent.

For the three months ended September 30, 2010, the impact on the decommissioning liability as a result of the change in discount rate was an increase of $2.7 million caused by:

i. Increase of $2.6 million with a corresponding increase to property, plant, and equipment due to obligations incurred/disposed of in the quarter.

ii. Increase of $0.1 million due to increased accretion expense.

For the nine months ended September 30, 2010, the impact on the decommissioning liability as a result of the change in discount rate was an increase of $4.8 million caused by:

i. Decrease of $2.9 million with a corresponding decrease to property, plant, and equipment due to obligations incurred/disposed of in the quarter.

ii. Increase of $7.4 million related to the Berens, Rondo and Result acquisitions, with an increase in goodwill of $5.5 million and a decrease in the deferred tax liability of $1.9 million.

iii. Increase of $0.3 million due to increased accretion expense.

Under Canadian GAAP, accretion was included in depletion and depreciation. Under IFRS, accretion is included within interest and other expenses.

d. Share based payments

Under Canadian GAAP, the Company recognized an expense related to their share-based payments on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiple. Under IFRS, the Company is required to recognize the expense using graded vesting and estimate a forfeiture rate.

The Company elected an IFRS 1 exemption for all options issued whereby the share-based compensation expense and contributed surplus for options that vested prior to January 1, 2010 were not required to be restated.

For the three months ended September 30, 2010 the impact of using graded vesting resulted in an increase in share-based compensation and contributed surplus of $4.2 million. The impact of this change for the nine months ended September 30, 2010 was $9.5 million.

e. Income taxes:

Many of the Company's IFRS transitional adjustments have related effects on deferred taxes primarily due to adjustments affecting the carrying value of property, plant, and equipment, exploration and evaluation assets, non-current assets and liabilities held for sale, and decommissioning liabilities.

For the three months ended September 30, 2010, the Company recorded additional deferred tax expense of $9.5 million upon the transition to IFRS. For the nine months ended September 30, 2010, the Company recorded additional deferred tax expense of $28.3 million. These adjustments were recorded as decreases to net income.

In accordance with Canadian GAAP, the Company presented certain future income tax assets and future income tax liabilities as current assets or current liabilities. Under IFRS, all deferred tax assets and liabilities are disclosed as long-term.

f. Depletion policy:

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The Company chose to deplete over proved plus probable reserves as this reserve category better matches the economic valuation parameters of the Company's asset base. The depletion policy under Canadian GAAP was based on units of production over proved reserves. In addition, depletion was done on the Canadian cost centre under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual components (i.e. fields or combinations thereof).

For the three months ended September 30, 2010 the change to the basis for depletion resulted in a decrease to depletion of $28.9 million with a corresponding increase to property, plant and equipment. For the nine months ended September 30, 2010 the impact was $100.5 million.

g. Convertible debenture

As the convertible debenture has a cash settlement option, it was determined that the conversion option would be accounted for as a financial derivative liability under IFRS. Under Canadian GAAP the conversion option was accounted for as a component of equity. On issuance of the debenture, the financial derivative liability had a value of $152.6 million and the liability portion had value of $617.1 million, a decrease of $39.9 million in the liability portion from Canadian GAAP. In addition the equity portion of the convertible debentures of $194.1 million was eliminated, and deferred taxes were increased by $1.6 million. For the three months ended September 30, 2010, as a result of the change in the liability portion, accretion on convertible debenture decreased by $1.1 million and there was an unrealized foreign exchange gain on the debentures of $1.1 million. In the third quarter of 2010 there was a loss on the derivative financial liability of $24.9 million, as the liability is fair valued at each reporting date. For the nine months ended September 30, 2010 there was a decrease in accretion of $2.9 million, a foreign exchange gain of $1.1 million and a gain on the derivative financial liability of $69.3 million.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Consolidated Balance Sheet at September 30, 2010.

As at,	Note	Canadian GAAP	Transition Adjustments	2010 IFRS adjustments	IFRS
Assets					
Current assets					
Cash and cash equivalents		$ -	$ -	$ -	$ -
Accounts receivable		114,783	-	-	114,783
Prepaid expenses		12,770	-	-	12,770
Risk management assets		4,174	-	-	4,174
Deferred tax asset	e	748	(782)	34	-
		132,475	(782)	34	131,727
Non-current assets held for sale	b	-	139,512	(139,512)	-
Exploration and evaluation assets	a,b	-	682,090	411,442	1,093,532
Property, plant and equipment	a,b,c,f	3,986,893	(870,258)	(163,428)	2,953,207
Risk management assets		3,450	-	-	3,450
Goodwill	c	1,490,514	-	5,491	1,496,005
Total assets		$ 5,613,332	$ (49,438)	$ 114,027	$ 5,677,921
Liabilities and Equity					
Current liabilities			-		
Accounts payable and accrued liabilities		$ 288,631	$ -	$ -	$ 288,631
Risk management liabilities		2,715	-	-	2,715
Future income tax liabilities	e	1,150	-	(1,150)	-
		292,496	-	(1,150)	291,346
Bank debt		691,525	-	-	691,525
Convertible debentures	g	580,087	-	36,031	616,118
Derivative financial liability	g	-	-	83,292	83,292
Other long-term liabilities		3,211	-	-	3,211
Non-current liabilities held for sale	b	-	15,387	(15,387)	-
Decommissioning liability	b,c	59,086	50,324	20,124	129,534
Risk management liabilities		995	-	-	995
Deferred tax liabilities	b,e,g	489,238	(30,745)	29,147	487,640
		2,116,638	34,966	152,057	2,303,661
Shareholders' equity					
Common shares		3,154,722	-	-	3,154,722
Convertible debentures	g	194,113	-	(194,113)	-
Contributed surplus	d	23,232	934	9,510	33,676
Retained earnings		124,627	(85,338)	146,573	185,862
		3,496,694	(84,404)	(38,030)	3,374,260
Total liabilities and equity		$ 5,613,332	$ (49,438)	$ 114,027	$ 5,677,921

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Reconciliation of Consolidated Statement of Operations, Comprehensive Income, and Retained Earnings for the three months ended September 30, 2010.

Three months ended September 30, 2010	**Note**	Canadian GAAP	Effect of Transition to IFRS	IFRS
Oil and natural gas sales		$ 228,537	$ -	$ 228,537
Royalties		(31,886)	-	(31,886)
Oil and natural gas revenues		196,651	-	$ 196,651
Gain on risk management contracts		(7,509)	-	(7,509)
		189,142	-	189,142
Production expenses		30,924	-	30,924
Transportation expenses		4,873	-	4,873
General and administrative expenses		9,006	-	9,006
Share-based compensation expenses	d	4,907	4,200	9,107
Gain on disposition	b	-	(9,685)	(9,685)
Loss on derivative financial liability	g	-	24,937	24,937
Interest and other	c,g	20,493	183	20,676
Foreign exchange gain	g	(17,319)	(1,100)	(18,419)
Depletion and depreciation expense(1)	c,f	122,110	(30,016)	92,094
Income before taxes		14,148	11,481	25,629
Income tax expense	e	4,954	9,549	14,503
Net income and comprehensive income		$ 9,194	$ 1,932	$ 11,126
Retained earnings, beginning of period		$ 164,458	$ 59,303	$ 223,761
Cash dividends paid or declared		(45,177)	-	(45,177)
Repurchase of common shares		(3,848)	-	(3,848)
Retained earnings, end of period		$ 124,627	$ 61,235	$ 185,862
Basic earnings per share		$ 0.05	$ 0.01	$ 0.06
Diluted earnings per share		$ 0.05	$ 0.01	$ 0.06

(1) Canadian GAAP amount includes accretion expense. IFRS adjustment includes reclassification of accretion of $1.2M to financing expense

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Reconciliation of Consolidated Statement of Operations, Comprehensive Income, and Retained Earnings for the nine months ended September 30, 2010.

Nine months ended September 30, 2010	**Note**	Canadian GAAP	Effect of Transition to IFRS	IFRS
Oil and natural gas sales		$ 750,197	$ -	$ 750,197
Royalties		(104,685)	-	(104,685)
Oil and natural gas revenues		645,512	-	$ 645,512
Gain on risk management contracts		8,670	-	8,670
		654,182	-	654,182
Production expenses		90,355	-	90,355
Transportation expenses		11,677	-	11,677
General and administrative expenses		25,947	-	25,947
Share-based compensation expenses	d	17,438	9,510	26,948
Gain on disposition	b	-	(11,048)	(11,048)
Gain on derivative financial liability	g	-	(69,258)	(69,258)
Interest and other	c,g	54,540	904	55,444
Foreign exchange loss	g	376	(1,056)	(680)
Depletion and depreciation expense(1)	c,f	391,290	(103,906)	287,384
Income before taxes		62,559	174,854	237,413
Income tax expense	e	29,652	28,281	57,933
Net income and comprehensive income		$ 32,907	$ 146,573	$ 179,480
Retained earnings, beginning of period		$ 228,534	$ (85,338)	$ 143,196
Cash dividends paid or declared		(132,129)	-	(132,129)
Repurchase of common shares		(4,685)	-	(4,685)
Retained earnings, end of period		$ 124,627	$ 61,235	$ 185,862
Basic earnings per share		$ 0.18	$ 0.80	$ 0.98
Diluted earnings per share		$ 0.18	$ 0.79	$ 0.97

(1) Canadian GAAP amount includes accretion expense. IFRS adjustment includes reclassification of accretion of $3.7M to financing expense

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Consolidated Balance Sheet at December 31, 2010.

As at,	Note	Canadian GAAP	Transition Adjustments	2010 IFRS adjustments	IFRS
Assets					
Current assets					
Cash and cash equivalents		$ -	$ -	$ -	$ -
Accounts receivable		147,339	-	-	147,339
Prepaid expenses		11,151	-	-	11,151
Risk management assets		2,231	-	-	2,231
Deferred tax asset	e	3,455	(782)	(2,673)	-
		164,176	(782)	(2,673)	160,721
Non-current assets held for sale	b	-	139,512	(139,512)	-
Exploration and evaluation assets	a,b	-	682,090	363,715	1,045,805
Property, plant and equipment	a,b,c,f	4,114,105	(870,258)	(81,373)	3,162,474
Risk management assets		-	-		-
Goodwill	c	1,490,514	-	5,491	1,496,005
Total assets		$ 5,768,795	$ (49,438)	$ 145,648	5,865,005
Liabilities and Equity					
Current liabilities			-		
Accounts payable and accrued liabilities		$ 344,476	$ -	$ -	$ 344,476
Risk management liabilities		12,682	-	-	12,682
Future income tax liabilities	e	608	-	(608)	-
		357,766	-	(608)	357,158
Bank debt		824,845	-	-	824,845
Convertible debentures	g	567,140	-	33,704	600,844
Derivative financial liability	g	-	-	76,141	76,141
Other long-term liabilities		5,170	-	-	5,170
Non-current liabilities held for sale	b	-	15,387	(15,387)	-
Decommissioning liability	b,c	60,258	50,324	21,913	132,495
Risk management liabilities		2,597	-	-	2,597
Deferred tax liabilities	b,e,g	494,285	(30,745)	33,685	497,225
		2,312,061	34,966	149,448	2,496,475
Shareholders' equity					
Common shares		3,147,238	-	-	3,147,238
Convertible debentures	g	194,113	-	(194,113)	-
Contributed surplus	d	24,262	934	11,266	36,462
Retained earnings		91,121	(85,338)	179,047	184,830
		3,456,734	(84,404)	(3,800)	3,368,530
Total liabilities and equity		$ 5,768,795	$ (49,438)	$ 145,648	$ 5,865,005

CORPORATE INFORMATION

DIRECTORS

Ian Brown (1) (4)
Calgary, Alberta

Martin Hislop (1) (4)
Calgary, Alberta

Craig Lothian (2) (3)
Regina, Saskatchewan

Kenneth McKinnon (1) (3) (5)
Calgary, Alberta

Corey C. Ruttan
Calgary, Alberta

Dan Themig (2) (4)
Calgary, Alberta

John D. Wright (2)
Calgary, Alberta

(1) Member of the Audit Committee
(2) Member of the Reserves Committee
(3) Member of the Compensation Committee
(4) Member of the Nominating Committee
(5) Chairman of the Board of Directors

OFFICERS

John D. Wright
President and Chief Executive Officer

R. Gregg Smith
Senior Vice President and Chief Operating Officer

Mary Bulmer
Vice President, Corporate Services

Lawrence Fisher
Vice President, Land and A&D

Andrea Hatzinikolas
Corporate Secretary

Peter Hawkes
Vice President, Exploration

William A. Kanters
Vice President, Capital Markets

Rene LaPrade
Senior Vice President, Operations

Doreen Scheidt
Corporate Controller

Peter D. Scott
Senior Vice President and Chief Financial Officer

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RESERVE ENGINEERS

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Calgary, Alberta, Canada.

EXCHANGE LISTING

The Toronto Stock Exchange
SYMBOL: PBN

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www.sedar.com

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