



*Management's Discussion & Analysis*  
*("MD&A")*

*For Quarter*  
*Ended*  
*September 30,*  
*2011*

## MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") for Second Wave Petroleum Inc. ("Second Wave" or the "Company") should be read in conjunction with the unaudited financial statements and notes for the three and nine months ended September 30, 2011 and the audited financial statements and notes of the Company for the year ended December 31, 2010. This MD&A incorporates information up to and including November 11, 2011. All of the amounts reported in this MD&A are in Canadian dollars, unless otherwise indicated. Certain other information with respect to the Company is available on SEDAR at [www.sedar.com](http://www.sedar.com) and on the Company's website at [www.secondwavepetroleum.com](http://www.secondwavepetroleum.com). Information can also be obtained by contacting the Company at Second Wave Petroleum Inc, 1400, 202 – 6<sup>th</sup> Ave. S.W., Calgary, Alberta, T2P 2R9.

### BASIS OF PRESENTATION

The interim financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards (IFRS). The Company adopted IFRS on January 1, 2011 with a transition date of January 1, 2010. Previously, the Company prepared its financial statements in accordance with previous Canadian generally accepted account principles (Previous GAAP). The Company has provided IFRS accounting policies and prepared reconciliations between Previous GAAP and IFRS in Note 18 of its September 30, 2011 interim financial statements. Further information is provided in the Change in Accounting Policies section of the MD&A.

### NON-IFRS FINANCIAL MEASUREMENTS

The Company has used certain measures of financial reporting that are commonly used benchmarks within the oil and gas industry in this MD&A that are considered non-IFRS measures. The measures used in this document include "funds from operations", "funds from operations per share", "operating netback", and "operating netback per share". The term funds from operations contained within the MD&A should not be considered as an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS. The Company believes that funds from operations are a useful supplementary measure as investors may use this information to analyze operating performance, leverage and liquidity. Funds from operations, as disclosed within this MD&A, represents cash flow from operating activities before changes in non-cash working capital. The Company presents funds from operations per share, whereby per share amounts are calculated consistent with the calculation of net loss and comprehensive loss per share. The Company believes that the term operating netback contained within the MD&A is also a useful supplementary measure, as investors may use this information to analyze field level operating performance of the Company's oil and gas properties. Further supplemental indicators of performance common to the oil and gas industry are the measurement of costs and expenses on a per barrel of oil equivalent (boe). These non-IFRS measures may not necessarily be comparable to similarly titled measures used by other entities and readers of this MD&A are cautioned in attempting to make such comparisons.

### OTHER MEASUREMENTS

For the purposes of calculating unit costs, natural gas has been converted to a barrel of oil equivalent ("BOE") using 6,000 cubic feet (6 Mcf) of natural gas equal to one barrel of oil (6:1), unless otherwise stated. The BOE conversion ratio of 6 Mcf to 1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Therefore BOEs may be misleading if used in isolation. References to natural gas liquids ("NGLs") in

this MD&A include condensate, propane, butane and ethane and one barrel of NGLs is considered to be equivalent to one barrel of crude oil equivalent (BOE).

### **ADVISORY REGARDING FORWARD LOOKING STATEMENTS**

Certain statements included or incorporated by reference in the MD&A constitute forward-looking statements or forward-looking information under applicable securities legislation. Forward-looking statements or information typically include words such as “anticipate”, “expect”, “plan”, “intend”, “estimate”, “propose”, or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to reserves, crude oil and natural gas prices, well productivity, operating costs, general and administrative costs, taxation rates, interest rates, and capital expenditure plans for 2011 and beyond.

Existing or potential investors should not place undue reliance on forward-looking statements as there can be no assurance that the plans, intentions or expectations they are based on will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown, risks and uncertainties, both general and specific that contributes to the possibility that although the predictions, forecasts, projections and other forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in the presentation include general economics, business and market conditions, volatility of energy prices, fluctuations in interest rates, energy supply and demand; competition, access to future funding, timing and amount of capital expenditures, imprecision in estimated future productive capacity, well productivity, operating cost adjustments, cost overruns, and such other risks and uncertainties described from time to time. Existing or potential investors are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this report. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

Examples of forward-looking information in this document include, but are not limited to the following, each of which is subject to significant risks and uncertainties and is based on a number of assumptions which may prove to be incorrect:

- The expected increase in operating netbacks per boe in 2011 when compared with 2010 is a result of actual improved pricing for crude oil to date and current future strip pricing for crude oil for the rest of the year. Currently capital expenditures are being directed towards 40° API Beaverhill Lake formation crude oil at Judy Creek which is of a higher quality than the Company’s other production. The Beaverhill Lake light oil currently receives a price that is comparative to WTI. Further, lower operating costs per boe are expected to contribute to a higher operating netback. This is subject to the risk and uncertainty that oil pricing will remain strong during 2011 and not differ materially from what is currently anticipated. This is also subject to the risk and uncertainty of the continued drilling success in the Beaverhill Lake formation at Judy Creek.
- Due to the redeployment of capital from the sale of a 400 boe/d non-core asset on February 24, 2011 to the Judy Creek area, the Company expects to have a temporary reduction in sales volumes. This sale is also expected to significantly decrease freehold royalties on an aggregate and per boe basis. This is subject to the risk and uncertainty that sales volumes from Provost will be replaced by increased sales in Judy Creek, and that Judy Creek volumes will come on-stream when anticipated.

This MD&A is dated as at November 11, 2011.

#### Abbreviations

<b>Crude oil and natural gas liquids</b>		<b>Natural gas and natural gas liquids</b>	
bbl	barrel	mcf	thousand cubic feet
boe	barrel of oil equivalent	mcf/d	thousand cubic feet per day
bbl/d	barrels per day	gj	gigajoule
boe/d	barrels of oil equivalent per day	NGL	natural gas liquids
WTI	West Texas intermediate		

## Selected Financial Information

(\$000s, except share and per boe amounts)	Three months ended September 30,			Nine months ended September 30,			Three months ended June 30,	
	2011	2010	% Δ	2011	2010	% Δ	2011	% Δ *
Per boe								
Petroleum and natural gas sales	58.67	47.71	23	56.21	50.68	11	59.70	2
Royalties	(3.89)	(5.12)	(24)	(4.29)	(6.07)	(29)	(3.93)	1
Lease operating costs <sup>(1)</sup>	(26.03)	(19.19)	36	(23.59)	(19.50)	21	(20.25)	29
Transportation	(2.81)	(1.26)	122	(2.53)	(1.39)	82	(2.90)	3
<b>Operating netback<sup>(1)(2)</sup></b>	<b>25.94</b>	<b>22.14</b>	<b>17</b>	<b>25.80</b>	<b>23.72</b>	<b>9</b>	<b>32.62</b>	<b>20</b>
Net capital expenditures <sup>(1)</sup>	23,244	27,106	(14)	30,678	30,438	-	6,158	-
Net debt (excluding decommission provision and financial derivatives)	66,867	19,860	237	66,867	19,860	237	49,569	35
Funds from operating activities <sup>(2)</sup>	2,473	2,269	9	9,058	6,854	32	4,367	(43)
Funds from operating activities per share (basic and diluted) <sup>(2)</sup>	0.03	0.03	-	0.11	0.10	10	0.05	(40)
Cash flow from operating activities	5,253	2,768	90	7,767	6,014	29	2,418	117
Cash flow from operating activities per share (basic and diluted)	0.06	0.04	50	0.09	0.08	13	0.03	100
Net income (loss) <sup>(1)</sup>	899	(99)	-	139	2,258	(94)	1,734	(48)
Net income (loss) per share <sup>(1)</sup>	0.01	-	-	-	0.03	-	0.02	-
Production volumes								
Oil (bbl/d)	870	845	3	816	806	1	853	2
Natural gas liquids (bbl/d)	101	57	77	107	48	123	127	(20)
Natural gas (mcf/d)	2,992	3,351	(11)	3,547	3,051	16	4,015	(25)
<b>Combined (6:1)</b>	<b>1,470</b>	<b>1,460</b>	<b>1</b>	<b>1,514</b>	<b>1,362</b>	<b>11</b>	<b>1,650</b>	<b>(11)</b>
Crude oil and liquids weighting (%)	66	62	6	61	63	(3)	60	10

\* % Δ represents the change from the third quarter of 2011 as compared with the second quarter of 2011

<sup>(1)</sup> Prior period amounts restated to comply with the requirement of IFRS.

<sup>(2)</sup> Funds from operations, funds from operations per share and operating netback are not recognized measures under IFRS and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. Management considers them to be important measures as they demonstrate the Company's ability to generate the cash flow necessary to fund future growth through capital investment.

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**Judy Creek Drilling & Completions Program Update:**

- During the third quarter the Company successfully drilled and completed seven gross (3.4 net) Judy Creek Beaverhill Lake horizontal light oil wells and drilled an additional four gross (2.2 net) wells subsequent to the quarter-end.
- Irrespective that certain well completions were temporarily delayed due to unanticipated service company constraints during the third quarter, the Company increased its quarter-over-quarter Judy Creek Beaverhill Lake light oil production by 183% to an average rate of 494 boe/d (90% light oil) from 176 boe/d (100% light oil).
- During the month of October 2011, the Company's net estimated field Beaverhill Lake production increased to an average rate of 1,390 boe/d (96% oil and NGLs).
- In October 2011, the Company's average monthly production is estimated to be approximately 2,225 boe/d (79% oil and NGLs) irrespective that approximately 200 boe/d of net Pekisko production was shut-in during the month of October due to Maximum Rate Limitations (MRL's).
- Production rates going forward will be impacted by timing of completion activities and initial flow rates of the new Beaverhill Lake formation wells.
- The average 30-day gross light oil production rates for first nine fully tested Beaverhill Lake wells to date have exceeded 650 bbls/d.
- Based on drilling success, the Company recently increased its credit facilities to \$80 million from \$65 million.

Gross test rates on the Company's 2011 Beaverhill Lake wells are noted in the table below:

LSD	Working Interest	Status	Initial 30 Day Production Rate (bbls/d)	Initial Production Date	Current Gross Rate as of Nov. 1, 2011 (bbls/d)	Cumulative Production (bbls)
100/15-36-063-10W5	40%	Pumping	1,080	3/3/2011	260	63,000
100/08-14-063-09W5	40%	Pumping	30	7/3/2011	20	4,000
100/01-28-063-09W5	40%	Pumping	444	7/22/2011	120	22,000
100/16-13-063-10W5	40%	Pumping	400	8/3/2011	230	18,000
102/01-05-064-09W5	40%	Pumping	650	8/12/2011	260	30,000
100/04-06-064-09W5	40%	Pumpng	990	8/23/2011	225	34,000
100/12-16-063-09W5	40%	Pumping	350	9/9/2011	215	13,000
100/13-16-064-09W5	100%	Pumping	210	9/29/2011	150	8,000
100/13-25-063-10W5	40%	Flowing	1,800	10/7/2011	1,000	55,000
100/08-23-062-10W5	100%	Testing	na	10/30/2011	na	na
100/05-13-063-10W5	40%	Testing	na	11/12/2011	na	na
100/10-05-063-09W5	40%	Completing	na	Na	na	na
100/01-25-063-10W5	40%	Standing	na	est 26/11/2011	na	na
100/13-35-063-10W5	40%	Drilling	na	est 7/12/2011	na	na
100/16-24-063-10W5	40%	Drilling	na	est 19/12/2011	na	na
100/03-36-063-10W5	40%	Drilling	na	est 30/12/2011	na	na

\* Production data estimated as of November 1, 2011

Second Wave continues to utilize 3 rigs for drilling horizontal light oil wells in Judy Creek and expects to drill up to an additional 5 gross (2 net) wells in 2011.

### Funds from Operations and Net Income (Loss)

(\$000s)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Cash flow from operating activities	5,253	2,269	132	7,767	6,014	29
Change in non-cash working capital	(2,780)	499	-	1,291	840	54
<b>Funds from operations<sup>(1)</sup></b>	<b>2,473</b>	<b>2,768</b>	<b>(11)</b>	<b>9,058</b>	<b>6,854</b>	<b>32</b>

(1) Funds from operations is not a recognized measure under IFRS and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. Management considers them to be important measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment.

Funds from operations <i>(\$000s, except per share)</i>	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Funds from operations <sup>(1)</sup>	2,473	2,768	(11)	9,058	6,854	32
Per share:						
Basic (\$)	0.03	0.03	-	0.11	0.10	10
Diluted (\$)	0.03	0.03	-	0.11	0.10	10
Cash flow from operating activities	5,253	2,269	90	7,767	6,014	29
Per share						
Basic (\$)	0.06	0.04	50	0.09	0.08	13
Diluted (\$)	0.06	0.04	50	0.09	0.08	13

<sup>(1)</sup> Funds from operations and funds from operations per share are not recognized measures under IFRS and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. Management considers them to be important measures as they demonstrate the Company's ability to generate the cash flow necessary to fund future growth through capital investment.

Funds from operations for the three and nine months ended September 30, 2011 totalled \$2,473,000 and \$9,058,000, compared to \$2,269,000 and \$6,854,000 respectively for the comparative periods of 2010. The increase in funds from operations is primarily driven by an increase in production levels generated from capital activities net of the impact of 400 boe/d from asset sales, higher sales pricing received, realized gains on financial derivatives, lower royalty rates and partially offset by higher operating costs and transportation costs.

Cash flow from operating activities for the three months and nine months ended September 30, 2011 were \$5,253,000 and \$7,767,000 compared to \$2,269,000 and \$6,014,000, respectively for the comparative periods of 2010.

#### Net income (loss)

<i>(\$000s, except per share)</i>	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Net income (loss)	899	(99)	-	139	2,258	(94)
Basic (\$)	0.01	(0.00)	-	0.00	0.03	-
Diluted (\$)	0.01	(0.00)	-	0.00	0.03	-

Net income for the three month period ended September 30, 2011 was \$899,000 or \$0.01 per share compared to a net loss of \$(99,000) or \$Nil per share for the same period in 2010. The increase in net income is primarily a result of higher realized oil pricing and a hedging (realized and unrealized) gain of \$3.0 million recognized in the current quarter partially offset by higher depletion charges and operating expenses.

Net income for the nine month period ended September 30, 2011 was \$139,000 or \$Nil per share compared to a net income of \$2,258,000 or \$0.03 per share for the same period in 2010. The decrease in net income is primarily the result of higher depletion charges and operating expenses partially offset by

the increase in sales revenues from stronger oil pricing, gain on asset sales and increased production volumes in the comparative periods.

### Petroleum and Natural Gas Sales

Sales volumes		Three months ended September 30,			Nine months ended September 30,		
		2011	2010	% Δ	2011	2010	% Δ
Crude oil	<i>bbls/d</i>	870	845	3	816	806	1
Natural gas liquids	<i>bbls/d</i>	101	57	77	107	48	123
Natural gas	<i>mcf/d</i>	2,992	3,351	(11)	3,547	3,051	16
<b>Total (6:1)</b>	<i>boe/d</i>	<b>1,470</b>	<b>1,460</b>	<b>1</b>	<b>1,514</b>	<b>1,362</b>	<b>11</b>
Oil vs. natural gas weighting (%)							
Oil and natural gas liquids		66	62	6	61	63	(3)
Natural gas		34	38	(11)	39	37	5
<b>Total</b>		<b>100</b>	<b>100</b>	<b>-</b>	<b>100</b>	<b>100</b>	<b>-</b>

Sales volumes, on a boe basis, for the three and nine months ended September 30, 2011 averaged 1,470 and 1,514 boe/d, up 1% and 11% respectively, from the 1,460 and 1,362 boe/d average in the comparative quarters of 2010. Volumes have been impacted in the quarter by delays in the fracing schedule for new Beaverhill Lake wells and by curtailments in Pekisko volumes for recovery of MRL's. Volumes as compared with the previous period were partially offset by the sale of non-core assets (400 boe/d) in the first quarter of 2011.

The Company continues to overall have a greater percentage of its production derived from crude oil as opposed to natural gas. The Company possesses a large inventory of crude oil drilling projects and as such the Company expects to continue to target oil weighted prospects exclusively. With capital expenditures targeting oil prospects, the Company's production weighting towards oil and liquids has remained consistent when compared to last year's comparable quarter.

### Quarterly Sales Volume Summary

	2011			2010				2009
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
<i>Boe/d</i>	1,470	1,650	1,423	1,500	1,460	1,417	1,206	1,009

Second Wave's petroleum and natural gas ("P&NG") sales may vary significantly from period-to-period as a result of changes in commodity pricing and or sales volumes. The Company takes approximately 95% of its working interest production "in-kind" and it is marketed and sold through various commodity purchasers. Crude oil is marketed under various short term evergreen contracts with major North American Companies and/or marketers. Natural gas sales are also marketed under a short term contract and sold under both "spot" and monthly contracts with a major North American Company.

### Revenues

(\$000s)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Crude oil	6,171	5,017	23	17,355	14,546	19
Natural gas liquids	699	248	182	2,097	749	180
Natural gas	1,065	1,145	(7)	3,787	3,553	7
<b>Total</b>	<b>7,935</b>	<b>6,410</b>	<b>24</b>	<b>23,239</b>	<b>18,848</b>	<b>23</b>

Gross revenues from P&NG sales in the third quarter of 2011 totalled \$7,935,000, up 24% from the comparable period last year. The increase in revenues is a result of higher sales volumes from all products combined with a 16% increase in oil pricing realized and marginally higher realized gas pricing.

Gross revenues from P&NG sales in the nine months ended September 30, 2011 totalled \$23,239,000, up 23% from the comparable period last year. Revenues, as compared with the comparative period, were impacted by an increase in all product sales volumes and a 18% increase in oil pricing realized, partially offset by lower realized gas pricing.

### Derivatives

The Company does not enter into derivative contracts of a speculative nature. The Company will from time to time enter into derivative contracts to mitigate commodity price risk as a measure to protect its cash flow. Currently the Company has approximately 86% of its total sales volumes hedged under derivative contracts after the sale of its Provost property. The Company chose to maintain certain financial derivatives associated with its Provost property as to replace the volumes sold with incremental volumes generated from the Judy Creek capital program. Management's intention is to continue to hedge up to 50% of sales under short term financial derivative contracts.

As at September 30, 2011, the summary of certain fixed price crude oil contracts and their respective remaining fair market values based on third party estimates are as follows:

Daily quantity	Term of contract	Price	Fair value
Oil (bbls/d)		Fixed per bbl (WTI)	Fixed written call per bbl (WTI)
<b>250 bbls</b>	July 1, 2011 – March 31, 2012	Cdn \$98.55	\$ 678,600
<b>500 bbls</b>	July 1, 2011 – December 31, 2011		US \$90.00 (67,000)
<b>500 bbls</b>	January 1, 2012 – December 31, 2013		US \$107.40 (1,647,600)
<b>250 bbls</b>	January 1, 2012 – March 31, 2012	Cdn \$88.25	96,300
<b>700 bbls</b>	April 1, 2012 – June 30, 2012	Cdn \$88.80	248,700
<b>2,200 bbls</b>		<b>Total</b>	<b>\$ (691,000)</b>
Disclosure:			
	Unrealized derivative contracts – assets		\$ 1,023,600
	Unrealized derivative contracts – liabilities (current)		(684,850)
	Unrealized derivative contracts – liabilities (non-current)		(1,029,750)
		<b>Total</b>	<b>\$ (691,000)</b>

Subsequent to September 30, 2011, the Company entered into the following fixed price crude oil contract:

Daily quantity	Term of contract	Price
Oil (bbls/d)		Fixed per bbl (WTI)
<b>500 bbls</b>	July 1, 2012 – December 31, 2012	US \$88.90

Commodity pricing experienced since entering into the contracts has been volatile. Oil pricing has seen continued volatility in 2011 as a result of uncertainty regarding the pace of global economic recovery thus, moving the benchmark WTI to over US\$113.00 per barrel before retreating to close the third quarter at US\$85.61. During the third quarter of 2011, the Company recorded \$2,870,000 of unrealized gains (2010 - \$1,090,000 losses) and \$132,000 of realized gains (2010 - \$502,000) as a result of its derivative contracts.

During the nine month period of 2011, the Company recorded \$814,000 of unrealized gains (2010 - \$173,000 losses) and \$2,022,000 of realized gains (2010 - \$767,000) as a result of its derivative contracts.

Revenues are expected to increase for the remainder of 2011 as the result of continued success in the Judy Creek area with the capital program focusing on the Beaverhill Lake formation which produces high quality sweet, light (40° API) oil that currently is paid on a comparative value to WTI in the market.

**Average Sales Prices**<sup>(1)</sup>

		Three months ended September 30,			Nine months ended September 30,		
		2011	2010	% Δ	2011	2010	% Δ
Crude oil	<i>\$/bbl</i>	77.07	66.52	16	77.89	66.13	18
Natural gas liquids	<i>\$/bbl</i>	75.02	47.49	58	71.77	57.10	26
Natural gas	<i>\$/mcf</i>	3.87	3.72	4	3.91	4.27	(8)
<b>Total (6:1)</b>	<i>\$/boe</i>	<b>58.66</b>	<b>47.71</b>	<b>23</b>	<b>56.21</b>	<b>50.68</b>	<b>11</b>

<sup>(1)</sup> Average sales prices do not include the impact of hedging activities

Benchmark Pricing		Three months ended September 30,			Nine months ended September 30,		
		2011	2010	% Δ	2011	2010	% Δ
WTI crude oil	<i>(US\$/bbl)</i>	89.29	76.21	17	95.27	77.65	23
WTI crude oil	<i>(CDN\$/bbl)</i>	91.08	79.39	15	97.18	80.05	21
Western Canadian Select (WCS)	<i>(CDN\$/bbl)</i>	70.61	62.91	12	74.30	66.99	11
Average Price differential WTI-WCS	<i>(CDN\$/bbl)</i>	20.47	16.48	24	22.88	13.06	75
AECO natural gas <sup>(1)</sup>	<i>(CDN\$/mcf)</i>	3.47	3.54	(2)	3.57	4.12	(13)
Exchange rate	<i>(US\$/CDN\$)</i>	1.02	1.04	(2)	1.02	1.04	(2)

<sup>(1)</sup> The AECO natural gas price reported is the average daily spot price

The pricing that the Company receives from the sale of its commodities are set through open commodity markets and thus outside the control of the Company (see discussion of financial derivative contracts above). The average price received in the current quarter versus last year's comparative was up by 23%. Although WTI benchmark crude oil prices are 17% above last year's levels, natural gas pricing (AECO) has been lower with a decline of 2% in the comparative period.

The difference in the quality of oil produced by the Company as compared with the WTI benchmark 40° API oil will generate a price difference or differential. Generally, the lower the quality of the oil as compared with the WTI benchmark, the wider the price difference. The Company's production will trend toward the Western Canadian Select (20.5° API) benchmark pricing and as the differential between WTI and WCS changes, Second Wave's differentials will follow in relation to the ratio of its Pekisko to Beaverhill Lake (40° API) oil production.

The benchmark WTI crude oil price has increased over the comparative periods with an offsetting impact from the WTI-WCS differential increase. As a result Second Wave's crude oil differential for the three months ended September 30, 2011 was \$14.01/bbl as compared with \$12.87/bbl in the 2010 comparative period.

The benchmark WTI crude oil price has increased over the comparative periods with an offsetting impact from the WTI-WCS differential increase. As a result Second Wave's crude oil differential for the three months ended September 30, 2011 was \$14.01/bbl as compared with \$12.87/bbl in the 2010 comparative period.

Second Wave's crude oil differential for the nine months ended September 30, 2011 was \$19.29/bbl, as compared with \$13.92/bbl in the 2010 comparative period.

After the fracture stimulation process the initial high volume flow-back of the majority of the Beaverhill Lake wells is putting pressure on storage and processing requirements and as a result the Company has been hauling emulsion to various third party treating facilities in the area. Due to the increased demand for these processing services, the Company has seen treating fees and the associated trucking rates to those facilities increased to handle the significant volumes that are being delivered. During the third quarter, a portion of the flow-back oil was downgraded by certain third party processors and given "waste-oil" pricing, which dropped the Company's gross sales price on that oil by approximately \$25.00 - \$27.00/bbl. This quality cut is estimated to have lowered the Company quarterly average sales price in the range of \$5.00 - \$6.00/bbl. The Company sees this as a short term issue and is exploring various avenues to process its oil to become sales spec which may include the building of its own treating facilities, opening several other avenues for getting the product to market for sale. Treating facilities effectively take well emulsion and remove water and other impurities to provide a "pipeline spec" or "sales spec" oil.

As the Company's capital focus moves to the Beaverhill Lake formation, the Company expects oil differentials will improve as the production mix of Pekisko heavy sour and Beaverhill sweet light oil changes as new production is brought on stream.

## Royalties

(\$000s)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Crown royalties	461	401	15	1,382	1,277	8
Freehold	12	139	(91)	108	574	(81)
Gross overriding	53	148	(64)	283	406	(30)
<b>Total</b>	<b>526</b>	<b>688</b>	<b>(24)</b>	<b>1,773</b>	<b>2,257</b>	<b>(21)</b>
<b>Total royalties per boe</b>	<b>3.89</b>	<b>5.12</b>	<b>(24)</b>	<b>4.29</b>	<b>6.07</b>	<b>(29)</b>
Total as % of Revenues	7%	11%	(36)	8%	12%	(33)

Total royalties decreased by 24% in the third quarter of 2011, totalling \$526,000 versus \$688,000 in the same period of 2010. Royalties as a percentage of revenues amounted to 7% during the third quarter of 2011, compared to 11% during the same quarter last year.

Total royalties decreased by 21% in the nine month period of 2011, totalling \$1,773,000 versus \$2,257,000 in the same period of 2010. Royalties as a percentage of revenues amounted to 8% during the nine month period of 2011, compared to 12% during the same quarter last year.

Royalties as a percentage of revenues decreased as a result of the change in royalty mix away from higher rate freehold royalties due to the sale of the Provost area and further impacted by lower natural gas prices realized and the impact on the sliding scale royalty calculation.

The Company continues to see the benefit with the new well crown royalty rates at 5% however, as the initial reduced royalty period expires on new production there will be a movement towards higher crown payments. Wells drilled in 2010 will have normal crown royalty curves applied after their 12 month, 5% period has expired. New horizontal wells in the Beaverhill lake formation that have a 4,000 meter drilled total depth will benefit from an extended period of 5% incentive rates of 42 months or 90,000 boe of production.

The Alberta Government released the modifications to the province's Crown Royalty framework with the purpose to encourage new energy investment throughout Alberta. The following initiatives outlined are significant to Second Wave:

- The oil royalty curves were flattened and capped at 40%; previously the maximum was 50%. Changes are effective January 1, 2011.
- The gas royalty curves were flattened and capped at 36%; previously the maximum was 50%. Changes are effective January 1, 2011.
- The new well royalty rate of 5% for horizontal oil wells that have a depth of 2,500 meters to 3,000 meters is extended from twelve months to **twenty four months** of production or up to a maximum of 60,000 boe of production. For horizontal oil wells spud on or after May 1, 2010. This would pertain to our Pekisko program.
- The new well royalty rate of 5% for horizontal oil wells that have a depth of 2,500 meters to 4,000 meters is extended from twelve months to **forty two months** of production or up to a maximum of 90,000 boe of production. For horizontal oil wells spud on or after May 1, 2010. This would pertain to our Beaverhill Lake program.
- The new well royalty program with a maximum royalty of 5% on all new conventional oil and gas wells up to 50,000 boe of cumulative production has become a permanent program.
- Effective January 1, 2011, no Alberta drilled wells will be allowed to select the transitional royalty program.

### Lease Operating Costs

Lease operating costs include all costs relating to the operation of producing crude oil and natural gas properties. Typical costs include: contract labor, chemicals and supplies, repairs and maintenance, utilities, and gathering and processing fees. Work-overs performed on producing wells are also considered to be operating costs in situations where there are no enhancements to the equipment and related operations. Work-overs typically include bottom-hole pump replacement, down-hole sand clean-outs, and replacement or repair of other worn equipment. As the majority of Second Wave's wells are pumping oil wells, work-overs are a material component of operating costs. This is in contrast to certain of the Company's competitors that are mainly natural gas producers whose individual well work-over costs would be less costly and less frequent due to an absence of down-hole moving parts.

(\$000s, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Total operating costs <sup>(1)</sup>	3,521	2,579	37	9,754	7,250	35
Lease operating cost per boe	26.03	19.19	36	23.59	19.50	21

<sup>(1)</sup> Prior period amounts restated to comply with the requirement of IFRS.

Total lease operating costs increased 37% from \$2,579,000 in the third quarter last year to \$3,521,000 in the third quarter of 2011. On a per boe basis, lease operating costs increased by 36% from \$19.19/boe to \$26.03/boe during the same period. The increase in operating costs on a boe basis is related to work-over costs (\$3.20/boe) for the Pekisko and Ellerslie wells in the Judy Creek area, higher emulsion processing and trucking costs (\$2.11/boe) related to initial flow-back of the Beaverhill Lake wells, increase R&M costs for older Judy Creek area wells (\$1.00/boe) and additional labor costs due to the continued expansion of the Judy Creek field.

Total lease operating costs increased 35% from \$7,250,000 in the nine month period of last year to \$9,754,000 in the comparable period in 2011. On a per boe basis, lease operating costs increased by 21% from \$19.50/boe to \$23.59/boe during the same period. The increase in operating costs on a year-over-year boe basis is primarily driven by additional labor costs (\$2.00/boe) related to the continued development of the Judy Creek area, higher equipment rental and chemical costs (\$1.16/boe) and increased lease maintenance and emulsion trucking costs (\$1.08/boe).

When comparing the second quarter of 2011 to the third quarter of 2011, total operating costs per quarter have increased by \$480,000 or 16%. The increase in costs on an absolute dollar basis is primarily the result of higher repairs and maintenance costs expended in the current quarter. Operating costs increased by \$5.78/boe as a result of an increase in work-over costs (\$2.59/boe), higher trucking and processing fees related to the new well initial flow-back (\$1.82/boe) and higher repair and maintenance costs related to the older Peksiko producing wells in the Judy Creek area (\$1.20).

#### Quarterly Lease Operating Cost Summary

<i>(\$000's except per boe and per share amounts)</i>	2011			2010 <sup>(1)</sup>				2009 <sup>(2)</sup>
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Operating expenses	3,521	3,041	3,192	2,634	2,578	2,322	2,349	2,081
Per boe	26.03	20.25	24.94	19.09	19.19	18.00	21.64	22.41

<sup>(1)</sup> Prior period amounts restated to comply with the requirement of IFRS.

<sup>(2)</sup> The quarters in 2009 include previous GAAP results

## Transportation

The Company incurs transportation costs for the crude oil and natural gas it produces once the commodity enters a feeder or main pipeline to the title transfer point.

(\$000s, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Transportation	380	169	125	1,044	516	102
Per boe (\$)	2.81	1.26	123	2.53	1.39	82

On a boe basis, transportation costs increased 123% in the three months ended September 30, 2011 to \$2.81 per boe from \$1.26 per boe in the comparable period of 2010. The increase in absolute amount is primarily the result of higher trucking costs related to the Beaverhill Lake production, an overall increase in volumes in the Judy Creek area adding clean oil trucking costs and disposition of the pipeline connected volumes in the Provost area. The quarter has been further impacted by abnormally wet weather conditions in Western Canada, limiting ground access to the Company's south western Saskatchewan and south Judy Creek Ellerslie oil properties.

Due to the high volumes related to Beaverhill Lake wells, trucking costs incurred were higher than average as a result of the demand on the number of trucks utilized in the area, waiting times at loading and off-loading points at sales terminals and road conditions in the area due to abnormally wet weather. The Company will continue to look at various alternatives to lower the impact of trucking costs on future new drills brought onto production.

On a boe basis, transportation costs increased 82% in the nine months ended September 30, 2011 to \$2.53 per boe from \$1.39 per boe in the comparable period of 2010. The increase in absolute amount is a result of increased volumes in the Judy Creek area adding clean oil trucking costs and previously mentioned costs of trucking for high rate producing wells.

With the sale of the Provost area in February 2011, the Company expects that per boe transportation costs will increase corporately as the Provost pipeline was connected to the sales point generating the lowest transportation costs on an area level.

## Operating Netback

Operating netback is the amount of directly attributable net cash flow derived from field operations of the Company's crude oil and natural gas wells. The table below displays the operating netback on a per boe basis.

(\$/boe)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Petroleum and natural gas sales	58.67	47.71	23	56.21	50.68	11
Royalties	(3.89)	(5.12)	(24)	(4.29)	(6.07)	(28)
Net revenues	54.78	42.59		51.92	44.61	
Lease operating costs	(26.03)	(19.19)	36	(23.59)	(19.50)	21
Transportation	(2.81)	(1.26)	123	(2.53)	(1.39)	82
<b>Operating netback <sup>(1)</sup></b>	<b>25.94</b>	<b>22.14</b>	<b>17</b>	<b>25.80</b>	<b>23.72</b>	<b>9</b>

<sup>(1)</sup> Operating netback is not a recognized measure under IFRS and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. Management considers them to be important measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment.

Operating netback has increased during the third quarter of 2011 as compared with 2010, due mainly to higher realized sales and lower royalty rates, partially offset by higher operating and transportation costs in the current quarter.

Operating netback has seen a moderate increase of 9% during the nine month period of 2011 as compared with 2010, due mainly to higher realized sales and lower royalty rates, offset by higher operating and transportation costs in the current period.

On a quarter-over-quarter basis, operating netbacks have decreased from \$32.62/boe in the second quarter of 2011 to \$25.94/boe in the third quarter of 2011, mainly due to significant workover costs in the quarter.

Management expects 2011 corporate operating netbacks to continue to improve primarily due to higher expected netback from Judy Creek area production. With the progressing development of the Judy Creek field and the related improvements to operational efficiencies, management is expecting that lease operating expenses per boe will also continue to decrease in 2011.

**General and Administrative (“G&A”)**

(\$000s, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
G&A	558	901	(38)	2,420	2,821	(14)
Capitalized G&A	(79)	(162)	(51)	(298)	(523)	(43)
<b>Net G&amp;A expenses</b>	<b>479</b>	<b>739</b>	<b>(35)</b>	<b>2,122</b>	<b>2,298</b>	<b>(8)</b>
<b>Per boe (\$) <sup>(1)</sup></b>	<b>3.54</b>	<b>5.50</b>	<b>(36)</b>	<b>5.13</b>	<b>6.18</b>	<b>(17)</b>

<sup>(1)</sup> Prior period amounts restated to comply with the requirement of IFRS.

G&A expenses, net of capitalized G&A, decreased 35% in the current quarter to \$479,000 from \$739,000 in the same period last year. Aggregate G&A costs decreased 38% mainly due to the lower bonus program costs incurred in the 2011 compared to the 2010 program.

For the nine months of 2011, G&A expenses, net of capitalized G&A, decreased 8% in the current period to \$2,122,000 from \$2,298,000 in the same period last year. Aggregate G&A costs decreased 14% mainly due to lower bonus program costs in the comparative periods.

On a per boe basis, G&A expenses, net of capitalized G&A, decreased by 36% compared to the comparative quarter. The decrease in costs is due to higher production in the comparative periods and lower bonus program costs incurred in 2011.

**Share-Based Compensation**

Share-based compensation expense, net of capitalized share-based compensation, for the three months ended September 30, 2011 was \$596,000, as compared to \$379,000 in the comparative period of 2010. Share-based compensation expenses of \$83,000 were capitalized during the quarter, as compared with \$187,000 capitalized in the comparative 2010 quarter.

Share-based compensation expense, net of capitalized share-based compensation, for the nine months ended September 30, 2011 was \$1,064,000, as compared to \$991,000 in the comparative period of 2010. Share-based compensation expenses of \$295,000 were capitalized during the nine month period, as compared with \$574,000 capitalized in the comparative 2010 period.

## Finance Expense

(\$000s, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Interest on short term debt	607	(10)	-	1,589	153	9,386
Interest on debenture	-	319	-	-	478	-
Interest on flow-through (Part 12.6 tax)	-	2	-	-	45	-
	607	311	95	1,589	676	135
Non-cash						
Accretion of decommissioning provision	43	65	(31)	150	189	(21)
Amortization of bank fees	-	40	-	-	89	-
Accretion of debenture	-	70	-	-	105	-
Total non-cash	43	175	(75)	150	383	(61)
<b>Total</b>	<b>650</b>	<b>486</b>	<b>34</b>	<b>1,739</b>	<b>1,059</b>	<b>64</b>
<b>Per boe (\$)</b>	<b>4.81</b>	<b>3.62</b>	<b>33</b>	<b>4.21</b>	<b>2.85</b>	<b>48</b>

Finance expense increased by 34% from \$486,000 in 2010 to \$650,000 in the third quarter of 2011 mainly as a result of higher levels of debt during the current quarter as compared with the 2010 comparative.

Finance expense increased by 64% from \$1,059,000 in 2010 to \$1,739,000 in the nine month period of 2011 mainly as a result of higher levels of debt during the current quarter as compared with the 2010 comparative.

## Depletion and Depreciation

Depletion and depreciation rates are a useful measure for evaluating finding and development costs on proved and probable reserves as the rate generally considers all incurred acquisition, exploration and development capital costs in addition to future development costs associated with proved and probable non-producing reserves.

(\$000s, except per boe)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Depletion	3,847	2,287	68	12,087	6,579	84
Depreciation	11	11	-	32	28	14
<b>Total</b>	<b>3,858</b>	<b>2,298</b>	<b>68</b>	<b>12,119</b>	<b>6,607</b>	<b>83</b>
<b>Per boe (\$)</b>	<b>28.52</b>	<b>17.10</b>	<b>67</b>	<b>29.31</b>	<b>17.77</b>	<b>65</b>

Depletion and depreciation expense increased 68% in the third quarter of 2011 to \$3,858,000 from \$2,298,000 in the comparable period of 2010. This increase in depletion is a result of expenditures incurred from Second Wave's exploration and development program and related infrastructure costs incurred for the Judy Creek area including \$41 million transferred out of Exploration and Evaluation Assets. Depletion and depreciation on a per boe basis increased by 67% as compared with the prior year's quarter.

Depletion and depreciation expense increased 83% in the nine month period of 2011 to \$12,119,000 from \$6,607,000 in the comparable period of 2010. This increase in depletion is a result of expenditures incurred from Second Wave's exploration and development program and related infrastructure costs incurred for the Judy Creek area. Depletion and depreciation on a per boe basis increased by 65% as compared with the prior year.

### **Gain on Sale of Assets**

During the nine month period ended September 30, 2011, the Company recorded a gain on sale of assets of \$3,416,000 (2010 - \$1,834,000). The gains represent a higher disposition price than each of the respective carrying values of the disposed of properties. The Company's disposition of these properties in 2011 resulted in gross proceeds of approximately \$17,300,000, comprised of \$13,925,000 cash plus \$3,400,000 secured note receivable from the purchaser. The amount receivable is due in 18 months from closing and is non-interest bearing, therefore the face value was discounted to its fair value of \$3,115,000. Payment made by the purchaser in July 2011 has reduced the carrying amount outstanding of the note receivable to \$2,750,000.

### **Other Income (Expense)**

During the nine month period of 2011, the Company sold Alberta Drilling Credits for \$170,000 (2010 – Nil).

The Alberta Drill Credit program has expired and therefore the Company will not see any further benefits derived from the program.

### **Income Taxes**

The income tax recovery for the third quarter ended September 30, 2011 was \$Nil, compared to a recovery of \$1,075,000 in the comparative period of 2010. The income tax recovery for the nine month period ended September 30, 2011 was \$Nil, compared to a recovery of \$1,629,000 in the comparative period of 2010. The 2010 recovery was a result of the reversal of valuation allowance created by the tax impact of flow through shares issued.

Income taxes are comprised of two components: current and future income taxes. The expected 2011 income tax rate as a percentage of pre-tax income is approximately 26.6%.

## Capital Expenditures

During the three and nine months ended September 30, 2011, \$23,244,000 and \$30,678,000 respectively was expended on net capital additions as compared with \$27,106,000 and \$30,438,000 in the comparative periods in 2010 as summarized below:

Capital Expenditures (\$000s)	Three months ended September 30,			Nine months ended September 30,		
	2011	2010	% Δ	2011	2010	% Δ
Exploration and evaluation assets						
Exploration and evaluation asset additions	3,986	1,611	147	9,192	6,246	47
Oil and gas property and equipment						
Land	-	28	-	-	69	-
Geological and geophysical	19	(26)	-	98	1,331	(93)
Drilling, completion and workovers	13,412	16,452	(18)	25,403	20,654	23
Facilities and equipment	5,004	8,354	(40)	12,941	10,939	18
Office furniture and equipment	16	11	45	64	95	(33)
Capitalized G&A	79	162	(51)	298	361	(17)
	18,530	24,981	(26)	38,804	33,449	16
<b>Total Additions</b>	<b>22,516</b>	<b>26,592</b>	<b>(15)</b>	<b>47,996</b>	<b>39,695</b>	<b>21</b>
Dispositions						
Exploration and evaluation assets	-	-	-	-	(3,997)	-
Property and equipment	-	25	-	(13,950)	(1,474)	846
<b>Total Dispositions</b>	<b>-</b>	<b>25</b>	<b>-</b>	<b>(13,950)</b>	<b>(5,471)</b>	<b>155</b>
Net cash additions	<b>22,516</b>	<b>26,617</b>	<b>(15)</b>	<b>34,046</b>	<b>34,224</b>	<b>(1)</b>
Non-cash portion						
Capitalized share-based compensation	83	188	(56)	295	387	24
Asset retirement obligations incurred	645	301	114	2,401	570	321
Asset retirement obligation reduction from property sales	-	-	-	(1,814)	(1,254)	45
Non-cash adjustments of disposition of assets	-	-	-	(4,250)	(3,489)	22
Total Non-Cash	728	489	49	(3,368)	(3,786)	(11)
<b>Total Capital Expenditures</b>	<b>23,244</b>	<b>27,106</b>	<b>14</b>	<b>30,678</b>	<b>30,438</b>	<b>1</b>

In the third quarter of 2011, the Company drilled 7 gross (3.4 net) horizontal oil wells in the Judy Creek and Caribou areas, for total drilling and completion costs of \$11.7 million. A further \$5.0 million was incurred on surface related equipment, pipelining and facilities work in the Judy Creek area.

Drilling Results (2011)	Three months ended September 30, 2011			Nine months ended September 30, 2011		
	Gross	Net	Average working interest %	Gross	Net	Average working interest %
Crude oil	7	3.4	49	15	10.2	68
Natural gas	-	-	-	-	-	-
Dry and abandoned	-	-	-	-	-	-
<b>Total</b>	<b>7</b>	<b>3.4</b>	<b>49</b>	<b>15</b>	<b>10.2</b>	<b>68</b>

Drilling Results (2010)	Three months ended September 30, 2010			Nine months ended September 30, 2010		
	Gross	Net	Average working interest %	Gross	Net	Average working interest %
Crude oil	6	6.0	100	17	16.6	98
Natural gas	1	1.0	100	1	1.0	100
Dry and abandoned	2	1.25	62	2	1.25	63
Service (salt water disposal)	1	1.0	100	1	1.0	100
<b>Total</b>	<b>10</b>	<b>9.25</b>	<b>93</b>	<b>21</b>	<b>19.85</b>	<b>95</b>

### Liquidity and Capital Resources

The oil and gas business is inherently risky and capital intensive and can require significant capital and cash resources to expand through growing reserves, production and cash flow. As at September 30, 2011, the Company had a working capital deficiency (excluding current portion of Decommissioning provision) of \$66,428,000, had drawn \$45,304,000 of its then available \$65,000,000 debt facility, and for the quarter ended September 30, 2011 the Company had net income of \$899,000. Given the nature of the oil and gas business and the size of Second Wave, the Company must be able to continue to secure sufficient financial resources to achieve its growth objectives. As with the nature of junior oil and gas producers, the Company continues to monitor additional financing opportunities to fund future prospects and commitments. Based on its current forecasts of production volumes and commodity pricing, the Company expects that sufficient liquidity will be available to meet its obligations for the next twelve months.

On November 10, 2011, the Company increased its credit facilities to \$80,000,000 from its previous total of \$65,000,000.

On September 14, 2011, the Company increased its credit facilities to a total of \$65,000,000 (\$55,000,000 plus and additional \$10,000,000 development line) from its previous total of \$55,000,000.

On June 14, 2011, the Company increased its credit facilities to \$45,000,000 plus an additional \$10,000,000 development line from \$44,000,000. The next scheduled review is on or before November 1, 2011.

On March 1, 2011, the Company increased its credit facilities to \$44,000,000 from \$40,000,000.

On February 24, 2011, the Company disposed of its 400 boe/d operated non-core Provost property for approximately \$16,000,000, comprised of \$12,437,000 cash and \$3,400,000 in a secured loan receivable due 18 months from closing.

On January 19, 2011, the Company disposed of an 8 boe/d non-operated non-core interest property for approximately \$1,488,000.

**Quarterly Financial Summary**

(\$000's except per boe and per share amounts)	2011				2010 <sup>(1)</sup>			2009 <sup>(2)</sup>
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Average production (boe/d)	1,470	1,650	1,423	1,500	1,460	1,417	1,206	1,009
Petroleum and natural gas sales	7,935	8,962	6,342	6,656	6,410	6,423	6,015	4,522
Royalties	(526)	(590)	(657)	(715)	(688)	(829)	(740)	(662)
Operating expenses <sup>(1)</sup>	(3,521)	(3,041)	(3,192)	(2,634)	(2,579)	(2,322)	(2,349)	(2,081)
Transportation expenses	(380)	(435)	(228)	(211)	(169)	(191)	(156)	(86)
Operating netback <sup>(1)</sup>	3,508	4,896	2,265	3,096	2,974	3,081	2,770	1,693
Operating netback (per boe) <sup>(3)</sup>	25.94	32.62	17.68	22.44	22.13	23.89	25.52	18.24
Cash flow from (used in) operating activities	5,253	2,418	96	1,255	2,269	3,313	432	507
Per share - basic	0.06	0.03	-	0.02	0.03	0.05	0.01	0.01
Per share - diluted	0.06	0.03	-	0.02	0.03	0.05	0.01	0.01
Funds from operations <sup>(1)</sup>	2,473	4,367	2,218	1,456	2,768	2,347	1,739	802
Per share - basic	0.03	0.05	0.03	0.02	0.04	0.03	0.03	0.01
Per share - diluted	0.03	0.05	0.03	0.02	0.04	0.03	0.03	0.01
Net income (loss) <sup>(1)</sup>	899	1,734	(2,495)	(6,857)	(99)	(398)	2,754	1,329
Per share - basic	0.01	0.02	(0.03)	(0.08)	-	(0.01)	0.04	0.02
Per share - diluted	0.01	0.02	(0.03)	(0.08)	-	(0.01)	0.04	0.02
Total Assets	199,752	177,428	168,482	167,276	142,846	118,459	113,628	89,121
Net capital expenditures <sup>(1)</sup>								
Cash	22,516	8,929	2,602	27,315	26,617	15,388	18,836	13,373
Non-cash <sup>(1)</sup>	728	(2,771)	(1,327)	416	786	468	(4,254)	214
Total	23,244	6,158	1,275	27,731	27,403	15,856	14,582	13,587
Net debt (excludes decommission liabilities)	66,867	51,636	46,870	44,150	20,477	24,636	11,580	15,662
Long term financial liabilities	1,030	1,493	4,312	2,506	-	3,890	3,862	3,835

<sup>(1)</sup> Prior period amounts restated to comply with the requirement of IFRS.

<sup>(2)</sup> The quarters in 2009 include previous GAAP results

<sup>(3)</sup> Funds from operations, funds from operations per share, operating netback and operating netback per boe are not recognized measures under IFRS and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. Management considers them to be important measures as they demonstrate the Company's ability to generate the cash flow necessary to fund future growth through capital investment.

## Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires Management to make certain judgments and estimates. Changes in these judgments and estimates could have a material impact on the Company's financial results and financial condition.

Management relies on the estimate of reserves as prepared by the Company's independent qualified reserves evaluator. The process of estimating reserves is critical as several accounting estimates are complex and require significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available and as economic conditions impact crude oil and natural gas prices, operating expenses, royalty burden changes, and future development costs. Reserve estimates impact net income through depletion and impairment of petroleum and natural gas properties. The reserve estimates are also used to assess the borrowing base for the Company's credit facilities. Revision or changes in the reserve estimates can either have a positive or a negative impact on net income and the borrowing base of the Company.

Management's process of determining the provision for deferred income taxes, the provision for decommissioning liability costs and related accretion expense, and the fair values assigned to any acquired assets and liabilities in a business combination, is based on estimates. These estimates are significant and can include proved and probable reserves, future production rates, future petroleum and natural gas prices, future costs, future interest rates, future tax rates and other relevant assumptions. Revisions or changes in any of these estimates can have either a positive or a negative impact on asset and liability values and net income.

In accordance with IFRS, derivative assets and liabilities are recorded at their fair values at the reporting date with gains and losses recognized directly in comprehensive income in the same period. The fair value of derivatives outstanding is an estimate based on pricing models, estimates, assumptions and market data available at that time. As such, the recognized amounts are non-cash items and the actual gains or losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices and foreign exchange rates as compared to the valuation assumptions.

The fair value of stock options is based on estimates using the Black-Scholes option pricing model and is recorded as share based payments expense in the financial statements

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## Change in Accounting Policies

### International Financial Reporting Standards

Canadian publicly accountable enterprises have implemented International Financial Reporting Standards (“IFRS”) for the fiscal years beginning on or after January 1, 2011. The transition date to IFRS was January 1, 2010 and comparative figures for 2010 and Second Wave’s financial position as at January 1, 2010 have been restated to IFRS from the previous Canadian generally accepted accounting principles (“Previous GAAP”). Reconciliations to IFRS from Previous GAAP financial statements, including the impact of the transition on the Company’s reported financial position and financial performance, and including the nature and effect of significant changes in accounting policies from those used in the Company’s financial statements for the year ended December 31, 2010, are summarized in note 18 to the unaudited interim financial statements. The following discussion explains the significant differences between IFRS and the Previous GAAP followed by the Company.

### Property and equipment

Under Previous GAAP, the Company, like many Canadian oil and gas reporting issuers, applied the “full cost” concept in accounting for its oil and gas assets. Under full cost, capital expenditures were maintained in a single cost centre for each country and the cost centre was subject to a single depletion and depreciation calculation and impairment test. Under IFRS, the Company makes a much more detailed assessment of its oil and gas assets that impact depletion and impairment calculations. Included in this assessment is an ongoing appraisal of exploration and evaluation expenditures (“E&E”). Under Previous GAAP, it was only necessary to track costs associated with unproved properties that would be excluded from depletion and depreciation calculations. Under IFRS, a company may choose to account for E&E under its Previous GAAP and capitalize such costs without recording depreciation expense until the technical feasibility and commercial viability of the project is determined, at which time the costs are moved to development properties or expensed accordingly. Second Wave capitalizes E&E costs except for costs incurred before the acquisition of rights to explore in a separate asset account, and will move the costs into property and equipment when proven technically feasible and commercially viable. As at transition on January 1, 2010, \$8.8 million was reclassified from property and equipment to exploration and evaluation assets. As at December 31, 2010, \$52.5 million was reclassified.

Under Previous GAAP the Company did not recognize gains or losses on the disposal of oil and gas properties unless such dispositions would change the depletion rate by 20% or more, under IFRS recognition is required, which results in a change to the carrying value and a gain or loss on sale of property and equipment (P&E).

### Depletion and depreciation

For Previous GAAP purposes, the full cost method of accounting for oil and gas properties required a single calculation of depletion and depreciation of the carrying value of P&E, based on proved reserves. However, IFRS requires an allocation of the amount recognized as P&E to each significant identified component and each component is depleted separately, utilizing an appropriate method of depletion. This component depletion of P&E results in an increased number of calculations of depletion expense and impacts the amount of depletion expense recognized. IFRS also permits the option of using either proved or proved and probable reserves in the depletion calculation. Second Wave has utilized proved and probable reserves to calculate depletion expense as we believe it represents a better approximation of useful life and depletion of reserves.

## Impairment of Assets

Under Previous GAAP, impairment calculations are prepared according to a two-step test generally conducted at a country level and are not subsequently reversed. Under IFRS, impairment testing is completed at an individual asset group or “Cash Generating Unit” level (“CGU”) when indicators suggest there may be impairment. A CGU is defined as the smallest group of assets that produce independent cash flows. Impairment of assets at a CGU level use a one-step approach for testing and measuring asset impairment by comparing asset carrying values with the higher of “Value in Use” and “Fair Value less Costs to Sell”. The IFRS methodology may result in the possibility of more frequent impairments in the carrying value of PP&E. However, under IFRS previous impairment losses must be reversed when circumstances change such that the previously recognized impairment has been reduced. The Company had impairment of \$2.2 million as at June 30, 2011 after the recovery of \$1.5 million through the sale of the Provost property in the first quarter of 2011. As at December 31, 2010 the Company had impairment of \$3.7 million.

## Decommissioning Liabilities

Both Previous GAAP and IFRS require a company to provide a liability related to decommissioning PP&E. Both methodologies are similar and we have determined there to be no significant difference for Second Wave other than a difference related to discount rates. Previous GAAP requires that the decommissioning liability be discounted at a credit-adjusted risk-free rate while IFRS requires that the decommissioning liability be discounted at an appropriate rate with either the cash flows or rate adjusted for risks. Second Wave has selected to use the risk-free rate for discounting purposes as we believe this accurately represents a market-based rate for such a liability. At transition date, January 1, 2010, the decommission liability was increased \$0.8 million.

## Share-based Payments

Under Previous GAAP, the Company accounted for share-based compensation with graded vesting on a similar basis as required by IFRS. Under Previous GAAP, forfeitures of awards were recognized as they occur. The calculation of share-based compensation under IFRS reflects an estimate of the number of awards expected to vest, which is revised if subsequent information indicates that actual forfeitures are likely to differ from the estimate. As a result, the Company adjusted its expense for share-based awards by \$0.3 million for the twelve months ending December 31, 2010 and recognized the corresponding adjustment in contributed surplus.

## Flow-through Shares

Flow-through shares are a Canadian income tax incentive which is the subject of specific guidance under Previous GAAP, however there is no specific guidance under IFRS. Under Previous GAAP, when flow-through shares were issued they were recorded at face value. The related future income tax liability was established for the tax effect of the difference between the tax basis and the book basis of the assets when renounced and was recorded as a reduction of share capital. The reduction to share capital under Previous GAAP was based on the corporate tax rates in effect at that time. There was no income statement effect associated with the issuance of these shares however upon renunciation to the flow-through subscriber, a deferred tax liability was recorded. In the Company’s case, since its tax basis was larger than its book basis, a deferred tax liability was reversed and taken into income as a deferred tax recovery.

The Company has adopted a policy under IFRS where the proceeds from the offering are to be allocated

between the sale of the shares and the sale of the income tax benefit. The allocation is made based on the difference between the quoted market price of the existing shares and the amount an investor pays for the flow-through shares. This flow-through premium is recorded as a liability that is reduced when qualifying flow-through expenditures are incurred. The reduction of the flow-through liability is offset by an increase in the deferred tax liability and due to the valuation allowance recognized, in the Company's case, it is treated as a deferred tax recovery. This has resulted in a re-classification between the deficit and share capital at January 1, 2010 of \$2,650,861.

### **First Time Adoption of International Financial Reporting Standards**

IFRS 1 provides the framework for the first time adoption of IFRS and specifies that an entity shall apply the principles under IFRS retrospectively. IFRS 1 also specifies that the adjustments that arise on retrospective conversion to IFRS from other previous GAAP should be directly recognized in retained earnings. Certain optional exemptions and mandatory exceptions to retrospective application are provided under IFRS 1. The Company has taken the following exemptions:

Companies using full-cost accounting are allowed to measure their oil and gas assets at the amount determined under the Previous GAAP at the date of transition. This amount is pro-rated to the underlying assets based upon the value of proved and probable reserve values at transition date, discounted at 12%.

Companies using the full cost book value, as deemed cost exemption, are allowed to measure the liabilities for decommissioning, restoration and similar liabilities at the date of transition and recognize directly in the deficit any difference between that amount and the carrying amount determined under Previous GAAP.

IFRS 3 Business Combinations has not been applied to acquisitions of subsidiaries or of interests in associates and joint ventures that occurred before January 1, 2010.

IFRS 2 Share-based Payments has not been applied to any stock options that were granted on or before November 7, 2002, nor has it been applied to stock options granted after November 7, 2002 that had vested before January 1, 2010.

### **New Standards and Interpretations Not Yet Adopted**

Standards issued but not yet effective up to the date of issuance of the Company's financial statements are listed below. This listing is of standards and interpretations issued which the Company reasonably expects to be applicable at a future date. The Company intends to adopt those standards when they become effective.

#### ***IFRS 11 Joint Arrangements***

IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures, and SIC-13, Jointly Controlled Entities—Non-monetary Contributions by Venturers. The Company has yet to assess the full impact of IFRS 11.

### ***IFRS 13 Fair Value Measurement***

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. The Company has yet to assess the full impact of IFRS 13.

### ***IFRS 9 Financial Instruments: Classification and Measurement***

IFRS 9 was issued in November 2009. This standard is the first step in the process to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 introduces new requirements for classifying and measuring financial assets and liabilities, which may affect the Company's accounting for its financial assets. The standard is not applicable until January 1, 2013 but is available for early adoption. The Company has yet to assess the full impact of IFRS 9.

### ***IAS 1 Presentation of Other Comprehensive Income***

In June 2011, the IASB issued an amendment to IAS 1, "Presentation of Financial Statements" requiring companies to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted.

### **Disclosure Controls and Procedures and Internal Control Over Financial Reporting**

Second Wave has established and maintains disclosure controls and procedures ("DC&P") that are designed to provide reasonable assurance that information required to be disclosed by the company in its annual filings, interim filings and other reports filed or submitted by it under Canadian securities laws is recorded, processed, summarized and reported within the time periods specified under such laws.

Second Wave has also established and maintains a process for internal control over financial reporting ("ICFR"), being a process designed by, or under the supervision of, the company's Chief Executive Officer and Chief Financial Officer, and effected by the board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework used to design the company's ICFR is *Internal Control – Integrated Framework* published by the Committee of Sponsoring Organizations of the Treadway Commission. No change in the company's ICFR occurred during the three months ended September 30, 2011 that has materially affected, or is reasonably likely to materially affect, its ICFR.

It should be noted that a control system, including the DC&P and ICFR of Second Wave, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met, and it should not be expected that such controls and procedures will prevent all errors or fraud.



*Interim Financial Statements Q3 (Unaudited)*

*For the Quarter  
Ended  
September 30,  
2011*

**Condensed Balance Sheet**

(Unaudited) (Cdn \$)

As at	Notes	September 30, 2011	December 31, 2010
<b>ASSETS</b>			
<b>Current assets:</b>			
Receivables	4	\$ 15,052,601	\$ 5,032,020
Secured note receivable		2,750,246	-
Prepaid expenses		310,263	195,386
Unrealized derivative contracts	11	1,023,600	3,022,637
		<b>\$ 19,136,710</b>	<b>\$ 8,250,043</b>
<b>Non-current assets:</b>			
Exploration and evaluation assets	5	20,485,124	52,470,367
Property and equipment	6	160,129,672	106,555,595
		<b>\$ 199,751,506</b>	<b>\$ 167,276,005</b>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>			
<b>Current liabilities:</b>			
Accounts payable and accrued liabilities	7	\$ 39,575,474	\$ 19,214,976
Bank indebtedness	8	45,304,451	31,163,776
Unrealized derivative contracts	11	684,850	2,021,558
Decommissioning provision	9	100,000	300,000
		<b>\$ 85,664,775</b>	<b>\$ 52,700,310</b>
<b>Non-current liabilities:</b>			
Derivative liabilities	11	1,029,750	2,506,302
Decommissioning provision	9	6,844,645	7,476,934
		<b>\$ 93,539,170</b>	<b>\$ 62,683,546</b>
<b>Shareholders' equity:</b>			
Share capital	10	\$ 112,409,070	\$ 112,186,599
Contributed surplus	10	12,315,037	11,056,212
Deficit		(18,511,771)	(18,650,352)
		<b>\$ 106,212,336</b>	<b>\$ 104,592,459</b>
		<b>\$ 199,751,506</b>	<b>\$ 167,276,005</b>

See accompanying notes to the condensed financial statements.

**Condensed Statements of Income (Loss)**

For the three and nine months ended September 30, 2011 and 2010  
(Unaudited) (Cdn \$)

	<i>Notes</i>	Three months ended September 30,		Nine months ended September 30,	
		2011	2010	2011	2010
<b>REVENUE</b>					
Crude oil, natural gas, and natural gas liquids sales		\$ 7,935,107	\$ 6,409,987	\$ 23,239,289	\$ 18,848,299
Royalties		(525,653)	(687,981)	(1,772,628)	(2,257,134)
		<b>\$ 7,409,454</b>	<b>\$ 5,722,006</b>	<b>\$ 21,466,661</b>	<b>\$ 16,591,165</b>
<b>EXPENSES</b>					
Operating		\$ 3,521,142	\$ 2,578,627	\$ 9,754,241	\$ 7,250,374
Transportation		380,385	169,091	1,043,564	516,392
General and administrative	13	478,611	738,882	2,122,317	2,298,139
Finance	14	649,527	485,924	1,738,600	1,058,885
Share-based compensation		596,384	378,981	1,063,730	990,884
Realized gain on derivatives		(132,190)	(502,101)	(2,022,119)	(767,052)
Unrealized (gain) loss on derivatives		(2,869,632)	1,089,707	(814,223)	172,890
Depletion and depreciation		3,858,480	2,297,700	12,118,825	6,607,300
Gain on sale of assets	6	-	-	(3,415,990)	(1,833,687)
Other (income) expense		27,419	(341,000)	(260,865)	(332,308)
		<b>\$ 6,510,126</b>	<b>\$ 6,895,811</b>	<b>\$ 21,328,080</b>	<b>\$ 15,961,817</b>
Income (loss) before income taxes		\$ 899,328	\$ (1,173,805)	\$ 138,581	\$ 629,348
Deferred income tax recovery		-	1,075,278	-	1,628,683
<b>Net income (loss)</b>		<b>\$ 899,328</b>	<b>\$ (98,527)</b>	<b>\$ 138,581</b>	<b>\$ 2,258,031</b>
<b>Net income (loss) per share</b>					
Basic	10	\$ 0.01	\$ (0.00)	\$ 0.00	\$ 0.03
Diluted	10	\$ 0.01	\$ (0.00)	\$ 0.00	\$ 0.03

See accompanying notes to the condensed financial statements.

## Condensed Statements of Cash Flows

For the three and nine months ended September 30, 2011 and 2010  
(Unaudited) (Cdn \$)

	Notes	Three months ended September 30,		Nine months ended September 30,	
		2011	2010	2011	2010
<b>Cash provided by (used in):</b>					
<b>OPERATIONS:</b>					
Net income (loss)		\$ 899,328	\$ (98,527)	\$ 138,581	\$ 2,258,031
Add (deduct) items not involving cash:					
Depletion and depreciation		3,858,480	2,297,700	12,118,825	6,607,300
Share-based compensation		596,384	378,981	1,063,730	990,884
Non-cash finance expense	14	42,552	175,856	150,039	383,088
Gain on sale of assets		-	-	(3,415,990)	(1,833,687)
Accretion on non-interest bearing receivable	4	(40,842)	-	(135,246)	-
Unrealized (gain) loss on derivatives		(2,869,632)	1,089,707	(814,223)	172,890
Deferred income tax recovery		-	(1,075,278)	-	(1,628,683)
Loss on sale of marketable securities		-	-	-	11,071
Expenditures on decommission liabilities		(13,747)	(250)	(47,748)	(106,584)
		<b>\$ 2,472,523</b>	<b>\$ 2,768,189</b>	<b>\$ 9,057,968</b>	<b>\$ 6,854,310</b>
Changes in non-cash working capital	17	\$ 2,780,209	\$ (499,184)	\$ (1,290,588)	\$ (840,437)
		<b>\$ 5,252,732</b>	<b>\$ 2,269,005</b>	<b>\$ 7,767,380</b>	<b>\$ 6,013,873</b>
<b>FINANCING:</b>					
Issue of common shares		\$ -	\$ 27,110,000	\$ -	\$ 47,110,000
Share issue costs		-	(1,904,927)	-	(2,972,730)
Changes in bank indebtedness		1,611,876	(7,337,528)	14,140,675	366,741
Issue of shares on exercise of warrants		-	-	-	886,040
Exercise of stock options	10	95,500	28,501	122,501	115,435
Changes in non-cash working capital	17	-	-	-	(55,000)
		<b>\$ 1,707,376</b>	<b>\$ 17,896,046</b>	<b>\$ 14,263,176</b>	<b>\$ 45,450,486</b>
<b>INVESTING:</b>					
Property and equipment expenditures		\$ (18,529,974)	\$ (24,981,494)	\$ (38,804,076)	\$ (58,430,513)
Additions to exploration and evaluation assets		(3,986,077)	(1,611,268)	(9,191,923)	(7,857,365)
Disposition of property and equipment		-	(24,587)	13,949,815	1,449,231
Disposition of exploration and evaluation assets		-	-	-	3,997,213
Proceeds from sale of marketable securities		-	-	-	3,477,427
Changes in non-cash working capital	17	15,555,943	6,402,298	12,015,628	5,899,648
		<b>\$ (6,960,108)</b>	<b>\$ (20,215,051)</b>	<b>\$ (22,030,556)</b>	<b>\$ (51,464,359)</b>
Increase in cash and cash equivalents		\$ -	\$ (50,000)	\$ -	\$ -
Cash and cash equivalents, beginning of period		-	50,000	-	-
<b>Cash and cash equivalents, as at period end</b>		<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>

See accompanying notes to the condensed financial statements.

**Condensed Statements of Changes in Shareholders' Equity**

For the nine months ended September 30, 2011 and 2010  
(Unaudited) (Cdn \$)

	Notes	Nine months ended September 30,	
		2011	2010
<b>SHARE CAPITAL</b>			
Balance, beginning of period	10	\$ 112,186,599	\$ 63,757,543
Common shares issued		-	50,010,000
Share issue costs		-	(2,972,730)
Stock options exercised		122,501	115,435
Warrants exercised		-	886,040
Share-based compensation		99,970	50,049
Warrant compensation		-	190,144
Transfer of equity portion of convertible debenture on conversion		-	140,729
<b>Balance, as at period end</b>		<b>\$ 112,409,070</b>	<b>\$ 112,177,210</b>
<b>WARRANTS</b>			
Balance, beginning of period	10	\$ -	\$ 2,931,553
Warrants exercised		-	(190,144)
Warrants expired		-	(2,741,409)
<b>Balance, as at period end</b>		<b>\$ -</b>	<b>\$ -</b>
<b>CONTRIBUTED SURPLUS</b>			
Balance, beginning of period	10	\$ 11,056,212	\$ 6,325,267
Share-based compensation		1,358,795	1,565,325
Stock options exercised		(99,970)	(50,049)
Warrants expired		-	2,741,409
<b>Balance, as at period end</b>		<b>\$ 12,315,037</b>	<b>\$ 10,581,952</b>
<b>EQUITY COMPONENT OF CONVERTIBLE DEBENTURE</b>			
<b>Balance as at beginning and period end</b>	10	<b>\$ -</b>	<b>\$ -</b>
<b>DEFICIT</b>			
Balance, beginning of period		\$ (18,650,352)	\$ (14,051,293)
Net income		138,581	2,258,031
<b>Balance, as at period end</b>		<b>\$ (18,511,771)</b>	<b>\$ (11,793,262)</b>
		<b>\$ 106,212,336</b>	<b>\$ 110,965,900</b>

See accompanying notes to the condensed financial statements.

## ***Notes to Condensed Financial Statements***

For the three and nine months ended September 30, 2011 and 2010  
(Unaudited) (Cdn \$)

### **1. Nature of business**

Second Wave Petroleum Inc. (“Second Wave” or “the Company”) is the continuing corporation following the amalgamation of Second Wave and its wholly owned subsidiary, Milagro Energy Inc., under the *Business Corporations Act* (Alberta, Canada) on January 1, 2009. Second Wave’s head office is located at 1400, 202 - 6<sup>th</sup> Avenue SW, Calgary, Alberta Canada. Second Wave is a publicly listed company whose common shares began trading on the Toronto Stock Exchange on December 1, 2010 under the trading symbol “SCS”. Brookfield Asset Management (“BAM”) holds approximately 48% of Second Wave’s outstanding common shares at September 30, 2011.

The Company’s principal activity is the exploration for and the acquisition, development and production of petroleum and natural gas in Western Canada.

These condensed interim financial statements were approved and authorized for issuance by the Board of Directors on November 11, 2011.

### **2. Basis of presentation**

#### (a) Statement of Compliance

These condensed interim financial statements are unaudited and have been prepared in accordance with IAS 34 ‘Interim Financial Reporting’ (“IAS 34”) and the accounting policies the Company expects to adopt in its financial statements as at and for the year ending December 31, 2011. The Company’s financial statement policies are consistent with International Financial Reporting Standards (“IFRS”) and its interpretations including International Accounting Standards (“IAS”) and interpretations of the International Financial Reporting Interpretations Committee (“IFRIC”) as issued by the International Accounting Standards Board (“IASB”).

The Company’s financial statements are prepared in accordance with IFRS and IFRS 1 - First-time Adoption of International Financial Reporting Standards has been applied. The Company’s financial statements were previously prepared in accordance with Canadian Generally Accepted Accounting Principles (“Canadian GAAP”), which differs in some areas from IFRS. In preparing these condensed interim financial statements, management has amended certain accounting and valuation methods previously applied in the Canadian GAAP financial statements to comply with IFRS as disclosed in note 18. The comparative amounts for 2010 were restated to reflect these adjustments.

As these interim financial statements are the Company’s first financial statements prepared using IFRS, certain information and disclosures that are required to be included in annual financial statements prepared in accordance with IFRS, and which are considered material to the understanding of the Company’s interim financial statements, have been provided. These interim financial statements should be read in conjunction with the Company’s 2010 annual financial statements which have been prepared in accordance with Canadian GAAP.

#### (b) Basis of measurement

The financial statements have been prepared on a going concern basis and using the historical cost basis except for derivative financial instruments which are measured at fair value. The methods used to measure fair values are discussed further in note 12.

(c) Use of estimates and assumptions

The preparation of financial information in accordance with IFRS requires management to make estimates and assumptions. It also requires management to exercise its judgment in the process of applying the Company's accounting policies. In particular, critical accounting policies and estimates utilized in the normal course of preparing the Company's financial statements require the determination of future cash flows utilized in assessing net recoverable amounts and net realizable values, useful lives and residual value of the Company's property, plant and equipment, determination of valuation allowances against future income tax assets and expected realization of those assets, estimation of effective income tax rates used, and fair values for recognition, measurement and disclosure purposes. Such critical accounting estimates could change from period to period and have a material impact on the Company's results of operations, financial positions and cash flows. Critical accounting estimates could also involve estimates where management may have used a different estimate in the current account period. Future events vary and estimates routinely require adjustment.

In particular, information about significant areas of estimation uncertainty considered by management in preparing the financial statements is described in the following notes:

- Note 6 – Property and equipment
- Note 9 – Decommissioning provision
- Note 15 – Contingencies and commitments
- Income tax valuation allowance

(i) *Key sources of estimation uncertainty*

The following are the key assumptions concerning the key sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities within the next financial year.

- Estimates of recoverable quantities of proved and probable reserves include judgmental assumptions and the economic, geological and technical factors used to estimate reserves may change from period to period
- Forward price estimates of the oil and natural gas prices are used in the impairment model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, weather, economic and geopolitical factors.
- The impairment model uses discount rate to calculate the net present value of cash flows based on weighted average cost of capital estimates. Changes in the general economic environment could result in significant changes in this estimate.
- Amounts recorded from joint venture partners are based on the Company's interpretation of underlying agreements and may be subject to joint approval. The Company has recorded balances due from its joint venture partners based on costs incurred and its interpretation of allowable expenditures. Any adjustment required as a result of joint venture audits are recorded in the period of settlement with joint venture partners.

- The decommissioning provision is based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices and discovery and analysis of site conditions and changes in clean-up technology.
- The Company has significant income tax loss carry-forwards expiring between 2011 and 2029, which have not been recorded as deferred income tax assets. These loss carry-forwards have yet to be recorded as assets due to a valuation allowance. The Company reviews the valuation allowance on a periodic basis.
- The above judgments, estimates and assumptions relate primarily to unsettled transactions and events as of the date of the condensed financial statements. Actual results could differ from these estimates and the differences could be material.

(d) Functional Currency

These financial statements are presented in Canadian dollars, which is the Company's functional currency.

### 3. Significant accounting policies

The accounting policies the Company follows are described in Note 3 of the Unaudited Condensed Financial Statements for the three months ended March 31, 2011.

#### **New standards and interpretations not yet adopted**

Standards issued, but not yet effective, up to the date of issuance of the Company's financial statements are listed below. This listing is of standards and interpretations issued which the Company reasonably expects to be applicable at a future date. The Company intends to adopt those standards when they become effective.

##### ***IFRS 11 Joint Arrangements***

IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures, and SIC-13, Jointly Controlled Entities—Non-monetary Contributions by Venturers. The Company has yet to assess the full impact of IFRS 11.

##### ***IFRS 13 Fair Value Measurement***

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair

value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. The Company has yet to assess the full impact of IFRS 13.

#### ***IFRS 9 Financial Instruments: Classification and Measurement***

IFRS 9 was issued in November 2009. This standard is the first step in the process to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 introduces new requirements for classifying and measuring financial assets and liabilities, which may affect the Company's accounting for its financial assets. The standard is not applicable until January 1, 2015 but is available for early adoption. The Company has yet to assess the full impact of IFRS 9.

#### ***IAS 1 Presentation of Other Comprehensive Income***

In June 2011, the IASB issued an amendment to IAS 1, "Presentation of Financial Statements" requiring companies to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 will full retrospective application. Early adoption is permitted.

#### **4. Receivables**

<b>As at</b>	<b>September 30, 2011</b>		<b>December 31, 2010</b>	
Trade receivable	\$	7,358,927	\$	4,755,145
Joint operations receivable		7,726,674		309,875
Allowance for doubtful accounts		(33,000)		(33,000)
	\$	<b>15,052,601</b>	\$	<b>5,032,020</b>
Secured note receivable	\$	2,750,246	\$	-
	\$	<b>17,802,847</b>	\$	<b>5,032,020</b>
Current	\$	17,802,847	\$	5,032,020
Non-current		-		-
<b>Total</b>	\$	<b>17,802,847</b>	\$	<b>5,032,020</b>

Trade receivables relate to the sale of oil and natural gas products. They are non-interest bearing, unsecured and are generally collected on 30 to 45 day terms. Subsequent to the quarter, the Company has collected \$5,100,000 of the outstanding joint operations receivables balance.

The Company's exposure to credit and currency risks and impairment losses related to trade and other receivables are disclosed in note 11.

In connection with the disposition of an asset during the first quarter of 2011, the Company issued a secured 18 month non-interest bearing note to the purchaser for \$3,400,000. The Company's security is comprised of all assets of the purchaser, and is subordinate to the purchaser's senior creditor. The face value of the amount receivable was discounted at 6% and was recorded at a carrying value of \$3,115,000. During the period ended September 30, 2011, the carrying value was reduced by \$500,000 that was paid by the purchaser in July 2011, and increased by \$135,246 of accretion.

**5. Exploration and evaluation assets**

As at	September 30, 2011	December 31, 2010
Cost, as at January 1	\$ 52,470,367	\$ 8,797,591
Additions	9,191,923	48,272,134
Transfer to property and equipment	(41,177,166)	(602,145)
Dispositions	-	(3,997,213)
<b>Cost, as at end of period</b>	<b>\$ 20,485,124</b>	<b>\$ 52,470,367</b>

E&E assets consist of the Company's intangible exploration and development projects which are pending the determination of proved or probable reserves. The Company assesses the recoverability of E&E assets at the cash-generating unit level at least annually.

**6. Property and equipment**

## (a) Cost

	Oil and gas property	Corporate assets	Total
Cost, as at January 1, 2010	\$ 77,422,241	\$ 42,531	\$ 77,464,772
Additions	45,166,033	114,483	45,280,516
Dispositions	(2,511,838)	-	(2,511,838)
Transferred from exploration and evaluation assets	602,145	-	602,145
Cost, as at December 31, 2010	\$ 120,678,581	\$ 157,014	\$ 120,835,595
Additions	39,914,082	64,282	39,978,364
Dispositions	(20,014,624)	-	(20,014,624)
Transferred from exploration and evaluation assets	41,177,162	-	41,177,162
<b>Cost, as at September 30, 2011</b>	<b>\$ 181,755,201</b>	<b>\$ 221,296</b>	<b>\$ 181,976,497</b>

## (b) Accumulated depletion, depreciation and impairment

	Oil and gas property	Corporate assets	Total
Balance, as at January 1, 2010	\$ -	\$ -	\$ -
Depletion and depreciation	(10,504,000)	(40,000)	(10,544,000)
Impairment loss	(3,736,000)	-	(3,736,000)
Balance, as at December 31, 2010	\$ (14,240,000)	\$ (40,000)	\$ (14,280,000)
Depletion and depreciation	(12,087,000)	(31,825)	(12,118,825)
Dispositions	4,552,000	-	4,552,000
<b>Balance, as at September 30, 2011</b>	<b>\$ (21,775,000)</b>	<b>\$ (71,825)</b>	<b>\$ (21,846,825)</b>

## (c) Net book value

	Oil and gas property	Corporate assets	Total
Balance, as at January 1, 2010	\$ 77,422,241	\$ 42,531	\$ 77,464,772
Balance, as at December 31, 2010	\$ 106,438,581	\$ 117,014	\$ 106,555,595
<b>Balance, as at September 30, 2011</b>	<b>\$ 159,980,201</b>	<b>\$ 149,471</b>	<b>\$ 160,129,672</b>

The Company has capitalized \$79,000 and \$298,000 (2010 - \$162,000 and \$523,000) of general and administration expenses, and \$83,000 and \$295,000 (2010 - \$187,000 and \$574,000) of share-based compensation expenses that were directly related to exploration and development activities for the respective three and nine month period ended September 30, 2011.

Future development costs on proved plus probable undeveloped reserves of \$75.3 million as at September 30, 2011 are included in the calculation of depletion (December 2010 - \$24.1 million).

During the nine month period ended September 30, 2011, the Company completed the sale of certain non-core properties for gross proceeds of \$17,300,000, including a receivable of \$3,400,000 from the purchaser. A \$3,400,000 gain (2010 - \$1,800,000) was recognized on these transactions.

During the year ended December 31, 2010, the Company tested oil and natural gas properties for impairment and booked an impairment loss of \$3.7 million as a result of the net book value being greater than the estimated fair value of the year end reserves assigned at a CGU level. An adjustment to the gain on sale of \$1,500,000 was recorded as a result of the sale of a property in the first quarter of 2011 resulting in an impairment balance of \$2,200,000 related to the Company's remaining properties. There were no indicators of impairment at September 30, 2011.

**7. Accounts payable and accrued liabilities**

As at	September 30, 2011	December 31, 2010
Accounts payable	\$ 29,449,357	\$ 14,213,104
Accrued liabilities	10,091,345	4,892,487
Payables to joint operations partners	34,772	109,385
<b>Balance, as at period end</b>	<b>\$ 39,575,474</b>	<b>\$ 19,214,976</b>

Accounts payable are non-interest bearing and are normally settled on 30 to 75 day terms. Payables and accruals to joint operations partners represent the partners share of the joint operations' operating results. Included in accrued liabilities is \$640,000 (December 31, 2010 - \$790,000) related to the CRA's audit of previous years flow-through expenditures (see note 15).

**8. Bank indebtedness**

As at	September 30, 2011	December 31, 2010
Current:		
Bank overdraft	\$ 26,900,000	\$ 4,363,776
Revolving operating credit facility	8,500,778	26,800,000
Development facility	9,903,673	-
<b>Balance, as at period end</b>	<b>\$ 45,304,451</b>	<b>\$ 31,163,776</b>

As at September 30, 2011, the Company had a \$55,000,000 demand revolving operating credit facility and up to a \$10,000,000 development facility with a Canadian chartered bank. The revolving facility provides that advances may be made by way of direct advances, bankers' acceptances, or standby letters of credit/guarantees. Direct advances bear interest at the bank's prime lending rate plus an applicable margin. The development facility is to be utilized for the development of certain of the Company's properties. Access to the development facility is subject to the bank's pre-approval on a project by project basis. The development facility is reduced by \$250,000 per month commencing on November 1, 2011. The applicable margin charged by the bank is dependent upon the Company's net debt to trailing cash flow ratio. The bankers' acceptances bear interest at the applicable banker's acceptance rate plus an explicit stamping fee based upon the Company's net debt to trailing cash flow ratio. The credit facilities are secured by a first fixed and floating charge debenture on the assets of the Company.

The bank has recently reviewed the credit facilities and on November 10, 2011, increased the Company's credit facilities to \$80,000,000.

The next bank review of the credit facilities is scheduled on or before May 31, 2012.

Second Wave is required to meet certain covenants including providing certain financial information on a timely basis. The Company is also required to maintain a working capital ratio of not less than 1:1 as defined in the agreement, which includes the undrawn portion of the facility. As at September 30, 2011, the Company was not in compliance with its working capital ratio debt covenant. The lender has waived compliance of this covenant as at September 30, 2011.

**9. Decommissioning provision**

	For the period ended September 30, 2011	Year ended December 31, 2010
Balance, as at January 1	\$ 7,776,933	\$ 7,891,228
New obligations	433,226	1,094,691
Accretion	150,039	255,913
Spending on existing obligations	(47,748)	(144,506)
Revision in estimates	445,994	(65,945)
Disposals	(1,813,799)	(1,254,447)
<b>Balance, as at period end</b>	<b>\$ 6,944,645</b>	<b>\$ 7,776,934</b>
Current	\$ 100,000	\$ 300,000
Non-current	6,844,645	7,476,934
<b>Balance, as at period end</b>	<b>\$ 6,944,645</b>	<b>\$ 7,776,934</b>

The Company's decommissioning provision results from its net ownership interest in petroleum and natural gas properties. The timing and amounts settled in respect to these provisions are uncertain and dependent on various factors that are not always within management's control. These discounted estimates have been created based on the Company's internal estimates and are expected to be utilized in the future ranging from 2011 to 2026. The discount factor, being the risk-adjusted rate related to the liability, is 2.5% (2010: 3.5%). Assumptions have been based on the current economic environment, technology and legal requirements. Reviews of estimated decommissioning and restoration costs are carried out annually to take into account any material changes to the assumptions.

## 10. Shareholders' equity

### (a) Share capital authorized

The authorized share capital consists of an unlimited number of no par value common shares, and an unlimited number of no par value preferred shares. There are no issued or outstanding preferred shares.

### (b) Share capital outstanding

	Number of Common Shares	Period ended September 30, 2011	Number of Common Shares	Year ended December 31, 2010
Balance, as at January 1	82,899,295	\$ 112,186,599	60,287,940	\$ 63,757,543
Issued for cash (i)	113,334	122,501	19,278,022	47,011,475
Transfer of carrying value on exercise of warrants (c)	-	-	-	190,144
Transfer from contributed surplus related to stock options exercised (e)	-	99,970	-	50,049
Issued on conversion of convertible debenture (f)	-	-	3,333,333	4,000,000
Transfer of equity portion of convertible debenture on conversion (g)	-	-	-	140,729
Share issue costs	-	-	-	(2,963,341)
<b>Balance, as at period end</b>	<b>83,012,629</b>	<b>\$ 112,409,070</b>	<b>82,899,295</b>	<b>\$ 112,186,599</b>

#### (i) Issued for cash

During the nine month period ended September 30, 2011, 113,334 stock options were exercised at an average price of \$1.08 for gross proceeds of \$122,501.

On January 15, 2010, 443,020 warrants were exercised for gross proceeds of \$886,040.

On February 12, 2010, the Company closed a private placement equity financing of 5,000,000 common shares at \$2.00 per share with a major shareholder for aggregate gross proceeds of \$10,000,000 and through a public offering by prospectus, the Company raised an additional \$10,000,000 through the issuance of 5,000,000 common shares at \$2.00 per share.

On July 20, 2010, the Company closed an equity financing of 6,670,000 common shares at \$3.00 per share and 2,000,000 flow-through common shares at \$3.55 per share for gross proceeds of \$27,110,000.

As at December 31, 2010, all of these expenditures have been incurred and were renounced to subscribers.

During the year ended December 31, 2010, 165,002 stock options were exercised at an average price of \$0.70 for gross proceeds of \$115,435.

## (c) Warrants

	Period ended		Year ended	
	Number of	September	Number of	December 31, 2010
	warrants	30, 2011	warrants	
Balance, as at January 1	-	\$ -	3,000,489	\$ 2,931,553
Warrants exercised	-	-	(443,020)	(190,144)
Warrants expired	-	-	(2,557,469)	(2,741,409)
<b>Balance, as at period end</b>	<b>-</b>	<b>\$ -</b>	<b>-</b>	<b>\$ -</b>

## (d) Stock option plan

	September 30, 2011		December 31, 2010	
	Number of	Weighted average	Number of	Weighted average
	options	exercise price	options	exercise price
Balance, as at January 1	5,825,832	\$ 1.85	5,051,500	\$ 2.68
Granted	2,712,000	2.60	986,000	2.98
Exercised	(113,334)	1.08	(165,002)	0.70
Forfeited	(281,666)	2.94	(46,666)	1.16
Expired	(40,000)	10.00	-	-
<b>Balance, as at period end</b>	<b>8,102,832</b>	<b>\$ 1.95</b>	<b>5,825,832</b>	<b>\$ 1.85</b>
<b>Exercisable, as at period end</b>	<b>3,525,856</b>	<b>\$ 1.82</b>	<b>2,318,849</b>	<b>\$ 1.85</b>

The Company has a stock option plan for directors, officers, employees and consultants. The Company may grant up to 10% of the aggregate number of common shares outstanding and no one optionee is permitted to hold more than 5% of the total options granted. Options vest as to one third each of the first, second and third anniversary dates. All options expire five years from the date of grant.

September 30, 2011	Options Outstanding		Options exercisable	
Exercise price	Number	Weighted average remaining life (years)	Number	Weighted average remaining life (years)
<b>\$0.46 - \$0.90</b>	2,107,998	2.53	1,328,672	2.53
<b>\$1.30 - \$2.00</b>	1,578,500	2.23	949,505	1.62
<b>\$2.11 - \$2.60</b>	2,876,000	4.07	508,334	1.55
<b>\$2.61 - \$3.35</b>	1,540,334	3.39	739,345	2.23
	<b>8,102,832</b>	<b>3.18</b>	<b>3,525,856</b>	<b>2.08</b>

The weighted average price per option granted in the nine months ended September 30, 2011 was \$2.60 (year ended December 31, 2010 - \$2.98).

The fair value of each option granted is estimated on the date of grant using Black-Scholes option pricing model with assumptions as follows:

	<b>Period ended September 30, 2011</b>	<b>Year ended December 31, 2010</b>
Exercise price	\$ 2.60	\$ 2.77
Volatility	75%	75%
Option life	5 years	5 years
Dividends	0.0%	0.0%
Expected forfeiture rate	1.0%	1.0%
Risk-free interest rate	1.41% - 2.75%	2.56%

In 2011, share-based compensation cost of \$596,384 and \$1,063,730 (2010 - \$378,981 and \$990,884) was expensed during the three and nine month periods respectively. In addition, share-based compensation expense of \$83,463 and \$295,065 (2010 - \$187,615 and \$574,441) was capitalized. Volatility was estimated based on historical and peer analysis.

(e) Contributed surplus

	<b>Period ended September 30, 2011</b>	<b>Year ended December 31, 2010</b>
Balance, as at January 1	\$ 11,056,212	\$ 6,325,267
Share-based compensation	1,358,795	2,039,585
Expiry of warrants	-	2,741,409
Transfer of common shares related to stock options exercised	(99,970)	(50,049)
<b>Balance, as at period end</b>	<b>\$ 12,315,037</b>	<b>\$ 11,056,212</b>

(f) Convertible debenture

Concurrently, with an equity offering that closed on June 30, 2009, the Company issued a \$4,000,000 convertible debenture (the "Debenture") to a major shareholder to repay \$4,000,000 of a \$7,500,000 term loan that was due May 8, 2010. The Debenture bore interest at a fixed rate of 7% per annum with scheduled maturity on June 30, 2011, and was convertible at the holder's option at any time into common shares of the Company at a conversion price of \$1.20 per share. The Company did not have the right to repay the Debenture prior to its maturity, however it could force the early conversion after June 30, 2010 into 3,333,333 common shares if the share price exceeded \$1.80 per share for a thirty day period with a minimum share trading volume. Upon early conversion, the Company would be required to pay interest to the maturity date of the Debenture. The Debenture was subordinate to the Company's senior lender and is secured by assets of the Company.

On August 26, 2010, the Company exercised its right to require early conversion of the \$4,000,000 convertible debenture. As a result of the conversion, the Company issued 3,333,333 common shares to settle the debenture and in connection with the conversion paid, "make-whole interest" of \$255,000 to the debenture holder.

(g) Equity portion of convertible debenture

Upon conversion of the debenture, the equity portion was reclassified into share capital. The equity portion of the debenture was calculated using the residual valuation approach, where the liability component was valued and the difference between the proceeds of the debenture and the fair value of the liability is assigned to the equity component.

(h) Capital management

The Company's objective when managing capital is to maintain a flexible capital structure, allowing it to execute its capital expenditure program, which includes expenditures in oil and gas activities which may or may not be successful. Therefore, the Company works to balance the proportion of debt and equity in its capital structure to take into account the level of risk being incurred in its capital expenditures.

The Company considers its capital structure to include shareholders' equity, bank indebtedness, convertible debentures, and working capital deficiency (excluding current portion of decommissioning provision) which at September 30, 2011 totaled \$172,640,401 (December 31, 2010 – \$148,742,726).

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions including: the current economic conditions, the risk characteristics of the underlying assets, the depth of its investment opportunities, forecasted investment levels, the past efficiencies of investments, the efficiencies of forecasted investments and the desired pace of investment, current and forecasted debt levels, current and forecasted energy commodity prices and other factors that influence commodity prices and funds generated from operations, such as foreign exchange and quality basis differential.

In order to maintain or adjust the capital structure, the Company will consider the following; its forecasted net debt to forecasted funds generated by operations ratio while attempting to finance an acceptable capital spending program including incremental capital spending and acquisition opportunities, the current level of bank credit available from the commercial bank, the level of bank credit that may be attainable from its commercial bank as a result of oil and gas reserve growth, the availability of other sources of debt with different characteristics than the existing bank debt, the sale of assets, limiting the size of capital spending programs and new common equity if available on favorable terms.

The Company's share capital is not subject to external restrictions, however the bank debt facility is based on petroleum and natural gas reserves and certain financial covenants as described in Note 8. The Company has not paid or declared any dividends since the date of incorporation, nor are any contemplated in the foreseeable future.

(i) Per share data

The basic weighted average number of shares outstanding during the three and nine month periods ended September 30, 2011 was 82,967,629 and 82,936,341 respectively (2010 – 79,056,324 and 72,006,386).

Diluted weighted average number of shares outstanding during the three and nine month periods ended September 30, 2011 was 85,204,892 and 84,942,336 (2010 – 79,056,324 and 72,006,386) respectively.

During the nine month period ended September 30, 2011 and the three month period ended September 30, 2010 all options would have an anti-dilutive effect on the loss per share as the Company was in a loss position. The dilutive effect of outstanding warrants and options for the three and nine month periods ended September 30, 2011, is calculated using the treasury stock method.

## 11. Financial risk management

The Company has exposure to the following risks from its use of financial instruments:

- Credit risk
- Liquidity risk
- Market risk

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with risk management policies.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

### *Credit risk:*

Credit risk is the risk of financial loss to the Company if a customer to a financial instrument fails to meet its contractual obligations, and principally arises from the Company's receivables from petroleum and natural gas marketers and joint venture partners.

Substantially, all of the Company's petroleum and natural gas production is marketed under standard industry terms. The industry has a pre-arranged monthly settlement day for payment of revenues from all buyers of crude oil and natural gas. This occurs on the 25<sup>th</sup> day of the following month in which the production is sold. The Company's policy to mitigate capital risk associated with these balances is to establish marketing arrangements with large purchasers. The Company has historically not experienced any collection issues with its petroleum and natural gas marketers. Where Second Wave has activities with joint venture partners it collects the Company share of net revenues and share of capital expenditures. Collection of joint venture receivables are typically received one to three months subsequent to the date of billing to partners. These amounts are typically subject to normal industry risk. Second Wave attempts to mitigate risk from joint venture receivables by partnering with and obtaining partner approval prior to expenditure, collecting in advance for significant amounts related to partners' share of capital expenditures in accordance with normal operating procedures. Collection of outstanding balances from joint venture partners is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venture partners as disagreements occasionally arise that increases the potential for non-collection.

The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners, however the Company does have the ability to withhold production from joint venture partners in the event of non-payment.

The Company's credit risk is limited to the carrying value of its accounts receivables, which are primarily due from entities involved in the oil and gas industry. At September 30, 2011, the Company had \$33,000 (2010 - \$33,000) of allowance for doubtful accounts for accounts receivable deemed uncollectible after \$58,000 of receivables previously written off were collected during 2010. The aging of accounts receivable, after taking into account the allowance for doubtful accounts, is as follows:

	Less than 60 days	Greater than 60 days	Total
<b>Accounts receivable</b>	\$ 12,763,688	\$ 2,288,913	\$ 15,052,601

*Liquidity risk:*

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. 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 stressed conditions without incurring unacceptable losses or risking harm to the Company's reputation.

The Company prepares an annual budget for operations and capital which is monitored and updated as considered necessary.

The financial liabilities on its balance sheet consist of accounts payable and loans payable. Accounts payable consists of invoices to trade suppliers relating to the Company's capital expenditure program, field operations and office expenses.

As at September 30, 2011, the timing of cash outflows related to financial liabilities are outlined in the table below:

	<b>Less than 1 year</b>	<b>Greater than 1 year</b>
Accounts payable and accrued liabilities	\$ 39,575,474	\$ -
Bank indebtedness	45,304,451	-
Unrealized derivative contracts	684,850	1,029,750
Decommissioning provision	100,000	6,289,497
<b>Total</b>	<b>\$ 85,664,775</b>	<b>\$ 7,319,247</b>

*Market risk:*

Market risk is the risk that changes in market prices such as changes in foreign exchange rates, commodity prices and interest rates, will affect the Company's net loss or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

Second Wave uses financial derivatives to manage market risk. All such transactions are conducted in accordance with the risk management policy that has been approved by the Board of Directors.

(i) *Commodity price risk*

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted not only by the relationship between the Canadian and United States dollar, as outlined below, but also global economic events that dictate the levels of supply and demand. The Company has attempted to mitigate commodity price risk through the use of financial derivative contracts as indicated below. If commodity prices were \$1.00 per barrel and \$0.10 per mcf higher, with all other variables held constant, net loss for the three and nine months ended September 30, 2011 would have been \$117,000 and \$349,000 respectively (2010 - \$111,000 and \$314,000) lower.

The Company had the following fixed price crude oil contracts outstanding as at September 30, 2011:

Daily quantity	Term of contract	Price		Fair value
		Fixed per bbl (WTI)	Fixed written call per bbl (WTI)	
Oil (bbls/d)				
250 bbls	July 1, 2011 – March 31, 2011	Cdn \$98.55	\$	678,600
500 bbls	July 1, 2011 – December 31, 2011		US \$90.00	(67,000)
500 bbls	January 1, 2012 – December 31, 2013		US \$107.40	(1,647,600)
250 bbls	January 1, 2012 – March 31, 2012	Cdn \$88.25		96,300
700 bbls	April 1, 2012 – June 30, 2012	Cdn \$88.80		248,700
<b>2,200 bbls</b>			<b>Total \$</b>	<b>(691,000)</b>
Disclosure:				
	Unrealized derivative contracts – assets		\$	1,023,600
	Unrealized derivative contracts – liabilities (current)			(684,850)
	Unrealized derivative contracts – liabilities (non-current)			(1,029,750)
			<b>Total \$</b>	<b>(691,000)</b>

(ii) *Foreign currency exchange rate risk*

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. The Company does not sell or transact in any foreign currency, however the United States dollar influences the price of petroleum and natural gas sold in Canada. The Company's financial assets and liabilities are not affected by a change in currency rates. The Company had no foreign exchange contracts in place as at or during the three and nine month periods ended September 30, 2011 and 2010.

(iii) *Interest rate risk*

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's debts that have a floating interest rate. The Company had no interest rate swaps or contracts in place as at or during the three and nine months ended September 30, 2011 and 2010. If interest rates rise by 100 basis points, with all other variables held constant, using the September 30, 2011 and 2010 balance of variable rate debt, interest expense would increase by \$340,000 (2010 - \$35,000) for the nine month period.

## 12. Financial instruments

The Company's financial instruments recognized in the balance sheet include accounts receivable, accounts payable, accrued liabilities, bank indebtedness, and financial derivative contracts.

Loans payable bear interest at floating market rates, are revolving and are due on demand. Accordingly, their fair value approximates the carrying value.

Financial derivatives contracts are held for trading and are carried at fair value.

The fair values of the remaining instruments approximate their carrying value due to their short term to maturity.

The Company categorizes its financial instruments carried at fair value into one of three different levels, depending on the observability of the inputs employed in the measurement.

Level 1:

Level 1 includes assets and liabilities measured at fair value based on unadjusted quoted prices for identical assets or liabilities in active markets that are accessible at the measurement date. An active market for an asset or liability is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. At September 30, 2011, the Company did not have any assets or liabilities which it valued using Level 1 inputs.

Level 2:

Level 2 includes assets and liabilities measured at fair value using directly or indirectly observable inputs other than quoted prices included in Level 1. Level 2 valuations are based on inputs including quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative instrument. At September 30, 2011, the Company valued all derivative financial instruments using Level 2 inputs.

Level 3:

Level 3 includes all assets and liabilities measured at fair value based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the instrument's fair value. At September 30, 2011, the Company did not have any assets or liabilities which it valued using Level 3.

Second Wave entered into various financial derivative contracts to economically hedge a portion of its revenues and resulting cash flows against volatility in commodity prices. During the three and nine months ended September 30, 2011, the Company recorded realized and unrealized financial derivative gains of \$3,001,822 and \$2,836,342, respectively. The portion of Company revenues that are not protected by financial derivative contracts are exposed to fluctuations in commodity prices.

### 13. General and administrative (G&A)

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Salaries and wages	\$ 572,663	\$ 484,655	\$ 1,804,015	\$ 1,847,804
Rent and insurance	68,844	105,059	280,209	301,923
Office and other costs	357,418	327,217	948,470	750,793
Capitalized G&A and overhead recoveries	(520,314)	(178,049)	(910,377)	(602,381)
<b>Total G&amp;A</b>	<b>\$ 478,611</b>	<b>\$ 738,882</b>	<b>\$ 2,122,317</b>	<b>\$ 2,298,139</b>

Personnel expenses directly attributed to exploration activities or oil and gas development activities have been capitalized in exploration assets or oil and gas properties.

**14. Finance expense**

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Cash				
Interest on bank overdrafts and loans	\$ 606,975	\$ (10,853)	\$ 1,588,561	\$ 152,616
Interest on convertible debenture	-	319,233	-	477,918
Interest on flow-through obligations (Part 12.6 tax)	-	1,688	-	45,263
	\$ 606,975	\$ 310,068	\$ 1,588,561	\$ 675,797
Non-cash				
Accretion of decommissioning provision	\$ 42,552	\$ 65,493	\$ 150,039	\$ 188,840
Accretion of convertible debenture	-	70,363	-	105,257
Loan fee amortization	-	40,000	-	88,991
	\$ 42,552	\$ 175,856	\$ 150,039	\$ 383,088
<b>Total finance expense</b>	<b>\$ 649,527</b>	<b>\$ 485,924</b>	<b>\$ 1,738,600</b>	<b>\$ 1,058,885</b>

**15. Contingencies and commitments**

- (a) The Company has the following corporate office, field office and field vehicle rental commitments:

<b>2011</b>	<b>\$ 92,400</b>
<b>2012</b>	<b>\$ 415,600</b>
<b>2013</b>	<b>\$ 319,000</b>
<b>2014</b>	<b>\$ 44,900</b>

- (b) The Canada Revenue Agency (“CRA”) has audited the Company’s eligible capital expenditures for flow through expenditure purposes for the 2004 to 2006 periods. Based upon the CRA’s findings their position is that:

- (i) *Certain well or wells previously drilled by the Company, and thought to qualify as eligible CEE were reviewed by the CRA and were determined to not be eligible for renouncement to flow-through subscribers; and*
- (ii) *Certain expenditures incurred subsequent to December 31, 2007 related to a 2006 flow-through equity offering did not qualify as valid flow-through expenditures for purposes of the Act.*

Related to matters (i) and (ii) above, the CRA’s position is that \$2,800,000 of required expenditures under the March 6, 2006 flow-through equity financing were not spent in accordance with the provisions of the Act. Second Wave is vigorously defending its position that all of the flow-through expenditures have been appropriately expended and has appealed the CRA’s decision. However, should the Company be unsuccessful in its position and the full \$2,800,000 is deemed to be non-eligible, Second Wave would have an indemnity liability for approximately \$1,200,000 of tax reassessments to its flow-through subscribers.

Management believes that on appeal, it has a very strong position relating to \$1,300,000 of this amount to be classified as qualifying expenditures, however there is uncertainty relating to the remaining \$1,500,000 of expenditures.

As a result, the Company has accrued for \$640,000 in these financial statements as a liability pertaining to this portion of the expenditures under review. An amount of \$560,000 representing potential indemnity on the remaining \$1,300,000 of expenditures is considered to be a contingent liability, and no amount has been recorded in the financial statements.

#### 16. Related party disclosures

During the three and nine months ended September 30, 2011, the Company incurred \$3,002,000 and \$7,231,000 respectively (2010 – \$2,522,000 and \$3,507,000) for drilling and well services from companies who are under significant influence by a major shareholder in the Company. As at September 30, 2011, amounts payable for related party drilling and well servicing were \$1,227,000 and (2010 - \$1,069,000).

All transactions have been completed on the basis of market terms and conditions and have been recorded at exchange amounts.

#### 17. Changes in non-cash working capital

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
<b>Decrease (increase) in non-cash working capital</b>				
Accounts receivable	\$ (2,197,419)	\$ (181,101)	\$ (9,520,580)	\$ (954,907)
Prepaid expenses	47,098	81,379	(114,877)	320
Accounts payable and accrued liabilities	20,486,473	6,004,836	20,360,497	5,958,798
<b>Net change in non-cash working capital</b>	<b>\$ 18,336,152</b>	<b>\$ 5,903,114</b>	<b>\$ 10,725,040</b>	<b>\$ 5,004,211</b>
<b>Relating to:</b>				
Operating	\$ 2,780,209	\$ (499,184)	\$ (1,290,588)	\$ (840,437)
Financing	-	-	-	(55,000)
Investing	15,555,943	6,402,298	12,015,628	5,899,648
<b>Net change in non-cash working capital</b>	<b>\$ 18,336,152</b>	<b>\$ 5,903,114</b>	<b>\$ 10,725,040</b>	<b>\$ 5,004,211</b>

#### 18. Explanation of transition to IFRS

As stated in note 2 (a), these are the Company's first financial statements prepared in accordance with IFRS. The Company has adopted IFRS effective January 1, 2011. The Company's financial statements for the year ending December 31, 2011 will be the first annual financial statements that comply with IFRS. Accordingly, the Company will make an unreserved statement of compliance with IFRS beginning with its 2011 annual financial statements. The Company's transition date is January 1, 2010 (the "transition date") and the Company has prepared its opening IFRS balance sheet at that date.

The accounting policies set out in note 3 have been applied in preparing the financial statements for the period ended June 30, 2011, the comparative information presented in these financial statements for the period ended June 30, 2010 and the preparation of an opening IFRS statement of financial position at January 1, 2010 (the Company's date of transition). The Company will ultimately prepare its opening balance sheet and financial statements for 2010 and 2011 by applying existing IFRS with an effective date

of December 31, 2011 or prior. Accordingly, the opening balance sheet and financial statements for 2010 and 2011 may differ from these financial statements.

In preparing its opening IFRS statement of financial position, the Company has adjusted amounts reported previously in financial statements prepared in accordance with previous Canadian GAAP. An explanation of how the transition from previous Canadian GAAP to IFRS has affected the Company's financial position, financial performance and cash flows, is set out in the following tables and the notes that accompany the tables.

(a) Elected exemptions from full retrospective application

In preparing these financial statements in accordance with IFRS 1 *First-time Adoption of International Financial Reporting Standards* ("*IFRS 1*"), the Company has applied certain of the optional exemptions from full retrospective application of IFRS. The optional exemptions are described below:

(i) *Business combinations*

The Company has applied the business combinations exemption in IFRS 1 to not apply IFRS 3 retrospectively to past business combinations. Accordingly, the Company has not restated business combinations that took place prior to January 1, 2010.

(ii) *Share-based payment transactions*

IFRS 2 *Share-Based Payments* has not been applied to any stock options that were granted on or before November 7, 2002, nor has it been applied to stock options granted after November 7, 2002 that had vested before January 1, 2010.

(iii) *Decommissioning provisions*

The Company has elected to apply the exemption from full retrospective application of decommissioning provisions as allowed under IFRS 1. As such the Company has re-measured the provisions as at January 1, 2010 under IAS 37, estimated the amount to be included in the cost of the related asset by discounting the liability to the date at which the liability arose using best estimates of the historical risk-free discount rates, and recalculated the accumulated depreciation, depletion and amortization under IFRS. Upon transition to IFRS this resulted in a \$786,223 increase in decommissioning obligations with a corresponding decrease in retained earnings.

(iv) *Oil and gas property cost basis*

The Company followed the 'full cost' approach under previous Canadian GAAP, which is a policy no longer permitted upon transition to IFRS. The Company has elected to apply the first-time adoption exemption for full cost oil and gas entities, where the carrying value of oil and gas assets at the date of transition to IFRS is measured on a deemed cost basis as follows:

Exploration and evaluation assets are reclassified from previous Canadian GAAP full cost pool to intangible exploration assets at the amount that was recorded under Canadian GAAP.

The remaining full cost pool has been allocated to producing and development oil and gas properties using reserve values.

This resulted in \$8,797,591 of recognition of exploration and evaluation assets with a corresponding decrease in oil and gas properties.

(b) Mandatory exceptions to retrospective application

In preparing these financial statements in accordance with IFRS 1, the Company has applied certain mandatory exceptions from full retrospective application of IFRS. The mandatory exceptions applied from full retrospective application of IFRS are described below:

(i) *Estimates*

Hindsight was not used to create or revise estimates and accordingly the estimates previously made by the Company under previous Canadian GAAP are consistent with their application under IFRS.

## (c) Reconciliation of equity from Previous Canadian GAAP to IFRS

(i) As at September 30, 2010:

(In Cdn \$)	Previous Canadian GAAP	Effect of transition to IFRS						IFRS	
		E&E <i>note iv( a)</i>	ARO <i>note iv( b)</i>	Compensation <i>note iv( c)</i>	Flow-through <i>note iv( d)</i>	DD&A <i>note iv( e)</i>	Dispositions <i>note iv( f)</i>		Lease Rental <i>note iv( g)</i>
<b>Assets:</b>									
<b>Current assets:</b>									
Accounts receivable	3,588,058	-	-	-	-	-	-	3,588,058	
Prepaid	224,933	-	-	-	-	-	-	224,933	
	<b>3,812,991</b>							<b>3,812,991</b>	
<b>Non-current assets:</b>									
Exploration and evaluation assets	-	12,360,783	-	-	-	-	-	12,360,783	
Property and equipment	133,713,580	(12,360,783)	471,340	(386,279)	-	3,669,000	1,689,709	(124,306)	126,672,261
<b>Total assets</b>	<b>137,526,571</b>							<b>142,846,035</b>	
<b>Liabilities:</b>									
<b>Current liabilities:</b>									
Accounts payable and accrued liabilities	18,480,568	-	-	-	-	-	-	18,480,568	
Bank indebtedness	4,634,346	-	-	-	-	-	-	4,634,346	
Derivative liabilities	617,072	-	-	-	-	-	-	617,072	
Flow-through obligations	-	-	-	557,746	-	-	-	557,746	
Decommissioning provision	300,000	-	-	-	-	-	-	300,000	
	<b>24,031,986</b>							<b>24,589,732</b>	
<b>Non-current liabilities:</b>									
Decommissioning provision	6,350,588	-	1,083,793	-	-	-	(143,979)	-	7,290,402
	<b>30,382,574</b>							<b>31,880,134</b>	
<b>Shareholders' equity:</b>									
Share capital	108,107,349	-	-	-	4,069,861	-	-	-	112,177,210
Contributed surplus	10,611,257	-	-	(29,305)	-	-	-	-	10,581,952
Deficit	(11,574,609)	-	(612,453)	(356,974)	(4,627,607)	3,669,000	1,833,688	(124,306)	(11,793,261)
<b>Shareholders' equity</b>	<b>107,143,997</b>								<b>110,965,901</b>
<b>Total liabilities and shareholders' equity</b>	<b>137,526,571</b>								<b>142,846,035</b>

## (ii) As at December 31, 2010

(In Cdn \$)	Previous Canadian GAAP	Effect of transition to IFRS						IFRS	
		E&E	ARO	Compensation	Flow- through	DD&A	Dispositions		Mineral lease
		<i>note iv (a)</i>	<i>note iv (b)</i>	<i>note iv (c)</i>	<i>note iv (d)</i>	<i>note iv (e)</i>	<i>note iv (f)</i>		<i>note iv (g)</i>
<b>Assets:</b>									
<b>Current assets:</b>									
Accounts receivable	5,032,021	-	-	-	-	-	-	-	5,032,021
Derivatives assets	3,022,637	-	-	-	-	-	-	-	3,022,637
Prepaid	195,386	-	-	-	-	-	-	-	195,386
Deferred tax assets	1,881,500	-	-	-	(1,881,500)	-	-	-	-
	<b>10,131,544</b>								<b>8,250,044</b>
<b>Non-current assets:</b>									
Exploration and evaluation assets	-	52,470,367	-	-	-	-	-	-	52,470,367
Property and equipment	157,220,328	(52,470,367)	732,650	(498,169)	-	26,000	1,689,709	(144,556)	106,555,595
	<b>167,351,872</b>								<b>167,276,006</b>
<b>Liabilities:</b>									
<b>Current liabilities:</b>									
Accounts payables and accrued liabilities	19,214,976	-	-	-	-	-	-	-	19,214,976
Bank indebtedness	31,163,776	-	-	-	-	-	-	-	31,163,776
Derivative liabilities	2,021,558	-	-	-	-	-	-	-	2,021,558
Decommissioning provision	300,000	-	-	-	-	-	-	-	300,000
	<b>52,700,310</b>								<b>52,700,310</b>
<b>Non-current liabilities:</b>									
Derivative liabilities	2,506,302	-	-	-	-	-	-	-	2,506,302
Decommissioning provision	6,334,179	-	1,286,734	-	-	-	(143,979)	-	7,476,934
	<b>61,540,791</b>								<b>62,683,546</b>
<b>Shareholders' equity:</b>									
Share capital	108,116,738	-	-	-	4,069,861	-	-	-	112,186,599
Contributed surplus	11,381,621	-	-	(325,409)	-	-	-	-	11,056,212
Deficit	(13,687,278)	-	(554,084)	(172,760)	(5,951,361)	26,000	1,833,688	(144,556)	(18,650,351)
	<b>105,811,081</b>								<b>104,592,460</b>
<b>Total liabilities and shareholders' equity</b>	<b>167,351,872</b>								<b>167,276,006</b>

(iv) *Notes to reconciliations*

(a) Exploration and evaluation (“E&E”)

Upon transition to IFRS, Second Wave reclassified all E&E expenditures that were included in the property and equipment asset balance on the balance sheet under previous Canadian GAAP. This consisted of the carrying amount for the Company’s undeveloped land which did not have proved or probable reserves attributed directly to related exploration properties. Additions to E&E assets include expenditures on properties where proved and probable reserves have yet to be determined. E&E assets will not be depleted and will be assessed for impairment when indicators of impairment exist. When reserves have been determined, E&E assets will be transferred into property and equipment. Management identified and reclassified the following amounts from property and equipment assets to E&E in the balance sheet prepared under IFRS as at September 30, 2010 (\$12,360,783), and December 31, 2010 (\$52,470,367).

(b) Decommissioning provision (“ARO”)

Under IFRS, the Company re-measured its previous Canadian GAAP liability for decommissioning provision using the risk-free rate of interest. IFRS requires that asset decommissioning provisions be re-measured each reporting period for changes in the discount rate, with a corresponding adjustment to the cost of property and equipment. At January 1, 2010, the Company’s total of its decommissioning provision increased by \$786,223 to \$7,691,228 as the liability was revalued to reflect the estimated risk free rate of interest of 3.5% as compared to the credit adjusted risk-free rate of 9% used under previous GAAP. As at September 30 and December 31, 2010 the decommissioning provision as compared with previous GAAP increased by \$1,083,793 and \$1,286,734 respectively.

In addition, under previous Canadian GAAP the unwinding of the discount was included with depletion and depreciation expense. As required under IFRS, accretion expense of \$65,493 and \$188,840 for the three and nine months ended September 30, 2010 respectively and by \$255,913 for the year ended December 31, 2010, has been reclassified to finance expense.

(c) Compensation

(i) *Share-based compensation*

Under previous Canadian GAAP, the Company accounted for share-based compensation with graded vesting on a similar basis as required by IFRS. Under Canadian GAAP, forfeitures of awards were recognized as they occurred. The calculation of share-based compensation under IFRS reflects an estimate of the number of awards expected to vest, which is revised if subsequent information indicates that actual forfeitures are likely to differ from the estimate.

Under IFRS, the Company has elected to apply IFRS 2 share based payments to equity instruments granted after November 7, 2002 that has not yet vested by the transition date.

Share-based compensation (net of capitalized share-based compensation) decreased by \$45,160 and \$76,512 for the three and nine months ended September 30, 2010 respectively, and by \$322,681 for the year ended December 31, 2010.

(ii) *Capitalized G&A and share-based compensation*

Under previous Canadian GAAP, a portion of G&A and share-based compensation was capitalized to property and equipment to account for overhead on capital projects. Under IFRS, only directly attributable costs can be capitalized. As a result, both capitalized G&A and capitalized share-based

compensation were lower under IFRS than under Canadian GAAP by \$67,162 and \$47,415 for the three months ended September 30, 2010 respectively, \$252,771 and \$133,508 for the nine months ended September 30, 2010, and \$324,726 and \$173,443 for the year ended December 31, 2010 respectively.

(d) Flow-through shares

The Company raises equity through the issuance of flow-through shares.

Flow-through shares are a Canadian income tax incentive which was subject to specific guidance under previous Canadian GAAP, however there is no specific guidance under IFRS. Under previous Canadian GAAP, when flow-through shares were issued they were recorded at face value. The related future income tax liability was established for the tax effect of the difference between the tax basis and the book basis of the assets when renounced and was recorded as a reduction of share capital. The reduction to share capital under Canadian GAAP was based on the corporate tax rates in effect at that time. There was no income statement effect associated with the issuance of these shares, however upon renunciation to the flow-through subscriber, a deferred tax liability was recorded. In the Company's case, since its tax basis was larger than its book basis, a deferred tax liability was reversed and taken into income as a deferred tax recovery.

The Company has adopted a policy under IFRS where the proceeds from the offering are to be allocated between the sale of the shares and the sale of the income tax benefit. The allocation is made based on the difference between the quoted market price of the existing shares and the amount an investor pays for the flow-through shares. This flow-through premium is recorded as a liability that is reduced when qualifying flow-through expenditures are incurred. The reduction of the flow-through liability is offset by an increase in the deferred tax liability and due to the valuation allowance recognized in the Company's case, it is treated as a deferred income tax recovery. This has resulted in a re-classification between deficit and share capital at September 30, 2010 of \$4,069,861, net of the deferred tax expense impact.

The amount of the flow-through obligation liability was \$1,086,429 at transition and the amount was reduced over the period as flow-through obligations were made.

(e) Depletion, depreciation and impairment

Under previous Canadian GAAP, depletion and depreciation was calculated on a unit-of-production ("UOP") basis for the full cost pool of all oil and gas properties based on proved reserves. Under IFRS, the Company continues to deplete under the UOP method but has chosen to include both proved and probable reserves in its calculation. IFRS also requires the Company to deplete its assets at a lower CGU level. The Company will deplete costs incurred to date, plus an estimation of future development costs, to recover proved and probable reserves.

As a result, the depletion and depreciation expense decreased as compared to its previous Canadian GAAP calculations. For the period ended September 30, 2010 depletion decreased by \$3,699,000 and decreased by \$3,762,000 for the year ended December 31, 2010.

For the year ended December 31, 2010 the Company incurred an impairment of \$3,736,000. The impairment was a result of the carrying value of certain CGUs being less than the fair market value.

(f) Dispositions

Under previous Canadian GAAP, proceeds from the sale of assets were applied in full against property and equipment, with no gain or loss recognized, unless the sale would result in a change in the depletion rate by 20% or more. Under IFRS, a gain or loss is recorded when property and equipment are sold. This

difference in methodology resulted in a gain on sale of \$1,833,688 during the periods ended September 30, 2010 and December 31, 2010.

(g) Mineral lease rentals

Under previous Canadian GAAP, non-producing lease rentals were capitalized in property and equipment, however under IFRS, these lease rentals are expensed as operating expenses. For the period ended September 30, 2010 and December 31, 2010, additional lease operating expenses of \$124,306 and \$144,556 were recognized respectively, with equal reductions to property and equipment.

(h) Reconciliation of profit and loss

**For the three month period ended September 30, 2010**

(In Cdn \$)	Previous Canadian GAAP	Effect of transition to IFRS						IFRS	
		reclass	ARO <i>note iv (b)</i>	Compensati on <i>note iv (c)</i>	Flow- through <i>note iv (d)</i>	DD&A <i>note iv (e)</i>	Dispositions <i>note iv (f)</i>		Lease Rental <i>note iv (g)</i>
<b>Revenues:</b>									
Crude oil, natural gas and natural gas liquids	6,409,987	-	-	-	-	-	-	-	6,409,987
Royalties	(687,981)	-	-	-	-	-	-	-	(687,981)
	<b>5,722,006</b>	-	-	-	-	-	-	-	<b>5,722,006</b>
<b>Expenses:</b>									
Operating	2,538,085	-	-	-	-	-	-	40,542	2,578,627
Transportation	169,091	-	-	-	-	-	-	-	169,091
General and administrative	671,720	-	-	67,162	-	-	-	-	738,882
Finance expenses	350,068	196,477	(60,621)	-	-	-	-	-	485,924
Share-based comp	333,821	-	-	45,160	-	-	-	-	378,981
Realized (gain) on derivatives	(502,101)	-	-	-	-	-	-	-	(502,101)
Unrealized loss on derivatives	1,089,707	-	-	-	-	-	-	-	1,089,707
Depletion and depreciation	4,087,814	(126,114)	-	-	-	(1,664,000)	-	-	2,297,700
Accretion of convertible debenture	70,363	(70,363)	-	-	-	-	-	-	-
Other (income) expense	(340,999)	-	-	-	-	-	-	-	340,999
	<b>8,467,569</b>	-	-	-	-	-	-	-	<b>6,895,811</b>
Income (loss)	(2,745,563)	-	-	-	-	-	-	-	(1,173,805)
<b>Income taxes</b>									
Deferred tax recovery	-	-	-	-	1,075,278	-	-	-	1,075,278
<b>Net income (loss)</b>	<b>(2,745,563)</b>	-	<b>(60,621)</b>	<b>112,322</b>	<b>1,075,278</b>	<b>(1,664,000)</b>	-	<b>40,542</b>	<b>(98,527)</b>

## For the nine month period ended September 30, 2010

(In Cdn \$)	Previous Canadian GAAP	Effect of transition to IFRS						IFRS	
		reclass	ARO <i>note iv (b)</i>	Compensation <i>note iv (c)</i>	Flow-through <i>note iv (d)</i>	DD&A <i>note iv (e)</i>	Dispositions <i>note iv (f)</i>	Lease Rental <i>note iv (g)</i>	
<b>Revenues:</b>									
Crude oil, natural gas and natural gas liquids	18,848,299	-	-	-	-	-	-	18,848,299	
Royalties	(2,257,134)	-	-	-	-	-	-	(2,257,134)	
	<b>16,591,165</b>	-	-	-	-	-	-	<b>16,591,165</b>	
<b>Expenses:</b>									
Operating	7,126,068	-	-	-	-	-	124,306	7,250,374	
Transportation	516,392	-	-	-	-	-	-	516,392	
General and administrative	2,045,368	-	-	252,771	-	-	-	2,298,139	
Finance expenses	764,788	467,867	(173,770)	-	-	-	-	1,058,885	
Share-based comp	1,067,396	-	-	(76,512)	-	-	-	990,884	
Realized loss on derivatives	(767,052)	-	-	-	-	-	-	(767,052)	
Unrealized gain on derivatives	172,890	-	-	-	-	-	-	172,890	
Depletion and depreciation	10,638,910	(362,610)	-	-	-	(3,669,000)	-	6,607,300	
Accretion of convertible debenture	105,257	(105,257)	-	-	-	-	-	-	
Gain on disposition	-	-	-	-	-	-	(1,833,688)	(1,833,688)	
Other (income) expense	(332,308)	-	-	-	-	-	-	(332,308)	
	<b>21,337,709</b>							<b>15,961,817</b>	
Income (loss)	(4,746,544)	-	-	-	-	-	-	629,348	
<b>Income taxes</b>									
Deferred tax recovery	-	-	-	-	1,628,683	-	-	1,628,683	
<b>Net income (loss)</b>	<b>(4,746,544)</b>	-	<b>(173,770)</b>	<b>176,259</b>	<b>1,628,683</b>	<b>(3,669,000)</b>	<b>(1,833,688)</b>	<b>124,306</b>	<b>2,258,031</b>

## For the period ended December 31, 2010

(In Cdn \$)	Previous Canadian GAAP	Effect of transition to IFRS							IFRS
		reclass	ARO <i>note iv (b)</i>	Compensation <i>note iv (c)</i>	Flow- through <i>note iv (d)</i>	DD&A <i>note iv (e)</i>	Dispositions <i>note iv (f)</i>	Lease Rental <i>note iv (g)</i>	
<b>Revenues:</b>									
Crude oil, natural gas and natural gas liquids	25,504,417	-	-	-	-	-	-	-	25,504,417
Royalties	(2,971,800)	-	-	-	-	-	-	-	(2,971,800)
	<b>22,532,617</b>								<b>22,532,617</b>
<b>Expenses</b>									
Operating	9,739,718	-	-	-	-	-	-	144,556	9,884,274
Transportation	727,128	-	-	-	-	-	-	-	727,128
General and administrative	2,940,231	-	-	324,726	-	-	-	-	3,264,957
Finance expense	1,151,730	593,309	(232,139)	-	-	-	-	-	1,512,900
Share-based comp	1,604,855	-	-	(322,681)	-	-	-	-	1,272,174
Realized gain on derivatives	(576,974)	-	-	-	-	-	-	-	(576,974)
Unrealized loss on derivatives	1,061,041	-	-	-	-	-	-	-	1,061,041
Depletion and depreciation	14,794,052	(488,052)	-	-	-	(3,762,000)	-	-	10,544,000
Asset impairment	-	-	-	-	-	3,736,000	-	-	3,736,000
Accretion of convertible debenture	105,257	(105,257)	-	-	-	-	-	-	-
Gain on disposition	-	-	-	-	-	-	(1,833,688)	-	(1,833,688)
Other (income) expense	(273,708)	-	-	-	-	-	-	-	(273,708)
	<b>31,273,330</b>								<b>29,318,104</b>
Loss before income taxes	(8,740,713)	-	-	-	-	-	-	-	(6,785,487)
<b>Income taxes</b>									
Deferred tax recovery	1,881,500	-	-	-	304,929	-	-	-	2,186,429
<b>Net income (loss)</b>	<b>(6,859,213)</b>	<b>-</b>	<b>232,139</b>	<b>7,955</b>	<b>304,929</b>	<b>26,000</b>	<b>1,833,688</b>	<b>(144,556)</b>	<b>(4,599,058)</b>

## (i) Reconciliation of cash flow statement for the periods ended:

The transition from previous Canadian GAAP to IFRS had had no significant effect upon the reported cash flows generated by the Company.

The reconciling items between previous Canadian GAAP presentation and IFRS presentation have no significant net impact on the cash flows generated.

**19. Subsequent events**

- i) On October 24, 2011, the Company entered into the following fixed price crude oil contract:

<b>Daily quantity</b>	<b>Term of contract</b>	<b>Price</b>
Oil (bbls/d)		Fixed per bbl (WTI)
<b>500 bbls</b>	July 1, 2012 – December 31, 2012	US \$88.90

- ii) On November 10, 2011, the bank, increased the Company's credit facility to \$80,000,000 from \$65,000,000.