FINANCIAL AND OPERATING SUMMARY
($000s except per share amounts)

	3 Months Ended March 31,		
	2011	2010	% Change
Financials highlights			
Oil and NGL sales	**21,650**	11,112	95%
Natural gas sales	**4,156**	2,750	51%
Other revenue	**66**	116	(43%)
Total oil, natural gas, and NGL revenue	**25,872**	13,978	85%
Funds from Operations[1]	**9,772**	6,039	62%
Per share basic ($)	**0.17**	0.33	(48%)
Per share diluted ($)	**0.17**	0.32	(47%)
Net income (loss)	**(502)**	2,749	nm
Per share basic ($)	**(0.01)**	0.15	nm
Per share diluted ($)	**(0.01)**	0.15	nm
Capital Expenditures - Petroleum & natural gas properties[2]	**35,538**	6,469	449%
Capital Expenditures - Exploration & evaluation assets[2]	**10,763**	-	nm
Capital Expenditures - Asset dispositions[2]	**(1,301)**	-	nm
Net debt at end of period[3]	**81,445**	44,355	84%
Operating highlights			
Production:			
Oil and NGL (bbls per day)	**3,090**	1,707	81%
Natural gas (mcf per day)	**11,915**	5,874	103%
Total (boe per day) (6:1)	**5,076**	2,686	89%
Average realized price (excluding commodity contracts):			
Oil and NGL ($per bbl)	**77.86**	72.35	8%
Natural gas ($ per mcf)	**3.88**	5.20	(25%)
Realized gain (loss) on commodity contracts ($ per boe)	**(1.62)**	0.96	nm
Net back (excluding commodity contracts) ($ per boe):			
Oil, natural gas and NGL sales	**56.64**	57.83	(2%)
Royalties	**(8.02)**	(7.80)	3%
Operating expenses	**(16.73)**	(16.11)	4%
Transporation expenses	**(2.54)**	(3.21)	(21%)
Operating netback	**29.35**	30.71	(4%)
G&A expenses	**(4.76)**	(4.55)	5%
Interest expense	**(0.98)**	(1.74)	(44%)
Corporate netback	**23.61**	24.42	(3%)
Common shares (000s)			
Common shares outstanding, end of period	**56,097**	18,842	198%
Weighted average basic shares outstanding	**56,095**	18,576	202%
Stock option dilution (treasury method)	**-**	457	nm
Weighted average diluted shares outstanding	**56,095**	19,033	195%

1 Management uses funds from operations (before changes in non-cash working capital and non-recurring recapitalization costs) to analyze operating performance and leverage. Funds from operations as presented does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures for other entities.
2 Please see capital expenditures note.
3 The Corporation defines net debt as outstanding bank debt plus or minus working capital excluding the fair value of financial contracts.

OVERVIEW AND HIGHLIGHTS

Surge is excited with the transformation it has achieved since recapitalizing Zapata Energy Corporation, beginning with approximately 2,000 boed of production in the second quarter of 2010. The Corporation has since positioned itself in three exciting light oil resource plays with considerable secondary recovery potential and continues to capture more light oil resource.

In the first quarter of 2011 Surge more than doubled its inventory of Spearfish locations with the announcement of two acquisitions in North Dakota. The first acquisition closed in the first quarter and the second acquisition closed in the second quarter. Surge now has a significant undeveloped land base of more than 500,000 net acres, internally estimated DPIIP[1] of more than 460 million barrels (gross) and more than 460 gross (350 net) oil drilling locations.

ACHIEVEMENTS AND FORECAST

- Began executing on its 2011 drilling program targeting light oil, which is projected to significantly increase Surge's operating netbacks[2] and increase Surge's light/medium oil weighting to greater than 70 percent by the fourth quarter of 2011.
- Achieved a 100 percent success rate drilling four gross (four net) wells in the first quarter of 2011.
- Increased production by 89 percent from an average of 2,686 boe per day in the first quarter of 2010 to 5,076 boe per day in the first quarter of 2011.
- Increased production by 27 percent from an average of 4,005 boe per day in the fourth quarter of 2010 to 5,076 boe per day in the first quarter of 2011.
- Increased oil and NGL production weighting from 58 percent in the fourth quarter of 2010 to 61 percent in the first quarter of 2011.
- Approximately 84 percent of Surge's revenue in the first quarter of 2011 resulted from oil and natural gas liquids production, up from 81 percent in the fourth quarter of 2010.
- Increased guidance and management is now forecasting to exit 2011 at 7,500 boe per day, with oil and NGL production weighting increasing from 58 percent in the fourth quarter of 2010 to more than 70 percent in the fourth quarter of 2011.
- Increased Surge's operating netback by six percent for the first quarter of 2011 as compared to the fourth quarter of 2010 from $27.65 per boe to $29.35 per boe. Surge's fourth quarter 2011 netback[2] is forecast to significantly increase per boe as a result of the Corporation's increasing light oil weighting in 2011 and decreasing combined operating and transportation costs, forecast to be $13.00 per boe in the fourth quarter 2011.
- Increased funds from operations by 62 percent to $9.8 million in the first quarter of 2011 from $6.0 million in the first quarter of 2010.

[1] Discovered Petroleum Initially In Place (DPIIP) is defined as quantity of hydrocarbons that are estimated to be in place within a known accumulation, plus those estimated quantities in accumulations yet to be discovered. There is no certainty that it will be economically viable or technically feasible to produce any portion of this DPIIP except for those identified as proved or probable reserves. There is no certainty that it will be commercially viable to produce any portion of the resources.

[2] Based on April 18, 2011 forward strip for the fourth quarter: CDN $103.95 Edmonton Par (US $111.17 WTI) and CDN $4.00/mcf AECO using a CAD/USD of $1.0346.

- Increased funds from operations by 24 percent to $9.8 million in the first quarter of 2011 from $7.9 million in the fourth quarter of 2010 with a forecast to grow funds from operations in 2011 to $75 million[3] and fourth quarter 2011 annualized funds from operations to $118 million[4].
- Established a non-core dispositions package which has successfully resulted in a total of more than $3.0 million of proceeds for Surge in the fourth quarter of 2010 and the first quarter of 2011, with an additional $4.9 million planned for the second quarter and further dispositions of approximately $2.0 million forecast for the second half of 2011.
- Subsequent to the first quarter of 2011, Surge increased its bank line to $120 million.

Netback Comparison

	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Average production (boe per day)	**5,076**	4,005	3,138	2,258
Revenue	**$ 56.64**	$ 50.33	$ 49.41	$ 54.22
Royalties	**(8.02)**	(6.43)	(6.07)	(10.30)
Operating costs	**(16.73)**	(14.87)	(14.98)	(15.29)
Transportation costs	**(2.54)**	(1.72)	(1.86)	(2.33)
Operating netback	**$ 29.35**	$ 27.31	$ 26.50	$ 26.30

The Corporation's operating netback increased seven percent, from $27.31 in the last quarter of 2010 to $29.35 in the first quarter of 2011. The management team continues to focus on finding efficiencies within existing operations and expects operating netbacks to continue to grow through 2011.

Surge maintained approximately $38.6 million of borrowing capacity at quarter-end on the Corporation's $120 million bank line, with $81.4 million of net debt at quarter-end (defined as outstanding bank debt plus or minus working capital excluding the fair value of financial contracts).

OUTLOOK

Surge has had an excellent start to 2011 and continues to implement its business plan of targeting per share growth by positioning the Corporation in high impact oil resource plays with significant oil in place and applying its proven expertise and experience to build core areas. Surge continues to demonstrate this ability with its recent expansion into North Dakota, where the Corporation significantly strengthened its position in the Spearfish light oil resource play by adding 205 gross (120 net) light oil horizontal drilling locations on 6,000 net acres of highly prospective lands. Management estimates DPIIP to be approximately 125 million barrels (gross) within these lands.

Underlying the high impact, emerging light oil resource plays, the Corporation has built a low decline, oil-weighted production base with considerable secondary recovery potential. Surge has a significant undeveloped land base of more than 500,000 net acres, internally estimated DPIIP of more than 460 million barrels and more than 460 gross (350 net) oil drilling locations, comprised of 85 percent light oil, with the remainder of the inventory being medium gravity.

Surge is committed to delivering top quartile corporate performance and creating value for shareholders by growing reserves, cash flow and production on a per share basis. Surge looks forward to applying for listing on the TSX in the fourth quarter of 2011.

[3] Based on April 18, 2011 forward strip: CDN $99.06 Edmonton Par (US$106.12 WTI) and CDN $3.90/mcf AECO using a CAD/USD of $1.0307.

[4] Based on April 18, 2011 forward strip for the fourth quarter: CDN $103.95 Edmonton Par (US $111.17 WTI) and CDN $4.00/mcf AECO using a CAD/USD of $1.0346.

Surge has a syndicated bank facility of $120 million with a forecast for 2011 year end net debt of $91 million representing 0.8 times forecast annualized fourth quarter 2011 funds from operations of approximately $118 million[5].

Surge forecasts a 2011 capital program of $120 million with guidance to achieve 2011 exit production of 7,500 boe per day (greater than 70 percent light/medium oil & NGLs), a 67 percent increase over 2010, with 2011 annual production of 6,000 boe per day (greater than 65 percent light/medium oil and NGLs), a 98 percent increase over 2010. Based on this 2011 production guidance, Surge is forecasting an increase in funds from operations of approximately 189 percent as compared to 2010 to approximately $75 million[6] in 2011 and an increase in fourth quarter annualized funds from operations of approximately 269 percent as compared to 2010 to approximately $118 million[7] in 2011.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) of the consolidated financial position and results of operations of Surge Energy Inc. ("Surge" or the "Corporation"), which includes its subsidiaries and partnership arrangements, is for the three months ended March 31, 2011 and 2010. For a full understanding of the financial position and results of operations of the Corporation, the MD&A should be read in conjunction with the documents filed on SEDAR, including historical financial statements, press releases and the Annual Information Form (AIF). These documents are available at www.sedar.com.

Surge's MD&A, together with the first quarter financial statements now comply with International Financial Reporting Standards ("IFRS") as of January 1, 2011. Surge has provided IFRS accounting policies and prepared reconciliations between previous Canadian generally accepted accounting principles ("GAAP") and IFRS in the notes to its first quarter financial statements. Comparative numbers for 2010 have also been updated to reflect IFRS changes. These changes have not had an impact on the operating assets of Surge but have significantly modified Surge's financial statements and related notes.

Further information on the impact of the changeover to IFRS is provided in the "Accounting Policies" section of the MD&A.

FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements.

More particularly, this MD&A contains statements concerning anticipated: (i) production weighting for 2011, (ii) operating netbacks, (iii) exit and average production for 2011, (iv) operating costs, (v) funds from operations, (vi) dispositions, (vii) TSX listing application, (viii) year-end debt, (ix) capital expenditures for 2011, (x) the amount and timing of decommissioning liabilities, (xi) future liquidity and financial capacity, (xii) future oil and natural gas prices and interest rates in respect of Surge's commodity risk management program, (xiii) future interest rates and exchange rates, and (xiv) future tax rates. The forward-looking statements are based on certain key expectations and assumptions made by Surge, including expectations and assumptions concerning the performance of existing wells and success obtained in drilling new wells, anticipated expenses, the availability of labour and services, the availability of capital, prevailing commodity prices and economic conditions, anticipated expenses, cash flow and capital expenditures and the application of regulatory and royalty regimes.

Although Surge believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Surge can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated

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[5] Based on April 18, 2011 forward strip for the fourth quarter: CDN $103.95 Edmonton Par (US $111.17 WTI) and CDN $4.00/mcf AECO using a CAD/USD of $1.0346.

[6] Based on April 18, 2011 forward strip: CDN $99.06 Edmonton Par (US$106.12 WTI) and CDN $3.90/mcf AECO using a CAD/USD of $1.0307.

[7] Based on April 18, 2011 forward strip for the fourth quarter: CDN $103.95 Edmonton Par (US $111.17 WTI) and CDN $4.00/mcf AECO using a CAD/USD of $1.0346.

due to a number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity price and exchange rate fluctuations and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Certain of these risks are set out in more detail in this MD&A and in Surge's AIF which has been filed on SEDAR and can be accessed at www.sedar.com.

The forward-looking statements contained in this MD&A are made as of the date hereof and Surge undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

All amounts are expressed in Canadian dollars unless otherwise noted. Oil, natural gas and natural gas liquids reserves and volumes are converted to a common unit of measure, referred to as a barrel of oil equivalent (boe), on the basis of 6,000 cubic feet of natural gas being equal to one barrel of oil. This conversion ratio is based on an energy equivalency conversion method, primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. It should be noted that the use of boe might be misleading, particularly if used in isolation.

The terms "funds from operations", "funds from operations per share", and “netback” used in this discussion are not recognized measures under International Financial Reporting Standards (IFRS). Management believes that in addition to net income, funds from operations and netback are useful supplemental measures as they provide an indication of the results generated by the Corporation's principal business activities before the consideration of how those activities are financed or how the results are taxed. Investors are cautioned, however, that these measures should not be construed as alternatives to net income determined in accordance with IFRS, as an indication of Surge's performance.

Surge's method of calculating funds from operations may differ from that of other companies, and, accordingly, may not be comparable to measures used by other companies. Surge determines funds from operations as cash flow from operating activities before changes in non-cash working capital and non-recurring recapitalization costs as follows:

($000s)	**Q1 2011**	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Cash flow from operating activities (per IFRS)	**9,007**	473	10,576	(324)	5,403
Change in non-cash working capital	**765**	7,313	(4,462)	(345)	636
Non-recurring recapitalization costs	**-**	-	-	5,409	-
Funds from operations	**9,772**	7,786	6,114	4,740	6,039

Funds from operations per share is calculated using the weighted average basic and diluted shares used in calculating income per share. Operating and corporate netbacks are also presented. Operating netbacks represent Surge’s revenue, excluding realized and unrealized gains or losses on commodity contracts, less royalties and operating and transportation expenses. Corporate netbacks represent Surge’s operating netback, less general and administrative and interest expenses, in order to determine the amount of funds generated by production. Operating and corporate netbacks have been presented on a per barrels of oil equivalent ("boe") basis.

Surge’s management is responsible for the integrity of the information contained in this report and for the consistency between the MD&A and financial statements. In the preparation of these statements, estimates are necessary to make a determination of future values for certain assets and liabilities. Management believes these estimates have been based on careful judgments and have been properly presented. The financial statements have been prepared using policies and procedures established by management and fairly reflect Surge’s financial position, results of operations and funds from operations.

Surge’s Board of Directors and Audit Committee have reviewed and approved the financial statements and MD&A. This MD&A is dated June 15, 2011.

OPERATIONS

Drilling

	Drilling		Success rate	Working
	Gross	Net	(%) gross	interest (%)
Q1 2011	4	4	100%	100%
Total	**4**	**4**	**100%**	**100%**

Surge achieved a 100 percent success rate in the three months ended March 31, 2011, drilling 4 gross (4 net) wells, resulting in 4 gross (4 net) oil wells. The four wells drilled in the first quarter include two wells at Valhalla South and two wells at Windfall.

Production

	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Oil and NGL (bbls per day)	**3,090**	2,308	1,841	1,621
Natural gas (mcf per day)	**11,915**	10,182	7,783	3,823
Total (boe per day) (6:1)	**5,076**	4,005	3,138	2,258
% Oil and NGL	**61%**	58%	59%	72%

Surge achieved production of 5,076 boe per day in the three months ended March 31, 2011, an 89 percent increase from the first quarter of 2010 production rate of 2,686 boe per day and a 27 percent increase from the fourth quarter of 2010 production rate of 4,005 boe per day. The increase in first quarter 2011 production volumes compared to the same period in 2010 was primarily due to increased production from acquisitions and new drills, partially offset by approximately 3,000 mcf per day of gas and 60 bbls per day for NGLs that were shut-in during the second quarter of 2010.

Surge realized a 61 percent oil and natural gas liquids production weighting in the three months ended March 31, 2011, up from 58 percent in the fourth quarter of 2010. The Corporation realized average oil and natural gas liquids production of 3,090 bbls per day for the first quarter of 2011.

Oil, Natural Gas and NGL, Commodity Contracts and Other Revenues

A two percent decrease in revenue per boe, combined with an 89 percent increase in production, resulted in revenues of $25.9 million in the three months ended March 31, 2011, up 85 percent from $14.0 million in the first quarter of 2010.

Surge had certain oil and gas commodity contracts in place as of March 31, 2011. The Corporation recognized an unrealized loss of $2.6 million and a realized loss of $0.7 million on its commodity contracts in the first quarter of 2011. This compares to an unrealized gain of $1.4 million and a realized gain of $0.2 million on its commodity contracts in the first quarter of 2010.

The realized commodity contract loss resulted in a decrease of $1.62 per boe to average revenue, including commodity contracts, for the three months ended March 31, 2011. The realized commodity contract gains resulted in an increase of $0.96 per boe to average revenue, including commodity contracts, for the three months ended March 31, 2010.

Please refer to the "Financial Instruments" section of this MD&A for further details on these oil and natural gas commodity contracts, and interest rate swaps.

Prices

In the three months ended March 31, 2011, Surge realized average revenue of $56.64 per boe, before realized commodity contract losses, a decrease of two percent from the $57.83 per boe recorded in the first quarter of 2010.

The Corporation realized an average of $77.86 per bbl of oil and natural gas liquids in the three months ended March 31, 2011, an increase of eight percent from the $72.35 per bbl realized in the three months ended March 31, 2010. This compares to an average Edmonton Light Sweet price of $87.77 per bbl in the three months ended March 31, 2011, which increased 10 percent per barrel from the $80.07 per bbl in the three months ended March 31, 2010. The increase in oil and natural gas liquids prices is consistent with the increase in benchmark prices.

The Corporation realized an average natural gas price of $3.88 per mcf in the three months ended March 31, 2011, a 25 percent decrease from the $5.20 per mcf averaged in the three months ended March 31, 2010. This compares to an average Alberta Plant Gate reference price of $3.56 per mcf in the first quarter of 2011 and $4.69 per mcf in the three months ended March 31, 2010 reflecting a 24 percent decrease. The decrease in natural gas prices is relatively consistent with the decrease in benchmark prices.

In the first quarter of 2011, approximately 84 percent of Surge's revenue resulted from oil and natural gas liquids production, with approximately 16 percent derived from natural gas production.

Realized commodity contract losses resulted in a decrease of $1.62 per boe to the average revenue including commodity contracts during the three months ended March 31, 2011.

Revenue and Realized Prices

	March 31, 2011	March 31, 2010	% Change
Oil and NGL ($000s)	**21,650**	11,112	95%
Natural gas ($000s)	**4,156**	2,750	51%
Processing and other ($000s)	**66**	116	(43%)
Total oil, natural gas and NGL revenue ($000s)	**25,872**	13,978	85%
Oil and NGL ($ per bbl)	**77.86**	72.35	8%
Natural gas ($ per mcf)	**3.88**	5.20	(25%)
Total oil, natural gas and NGL revenue ($ per boe)	**56.64**	57.83	(2%)
Unrealized gain(loss) on commodity contracts ($ per boe)	**(5.71)**	5.74	nm
Realized gain(loss) on commodity contracts ($ per boe)	**(1.62)**	0.96	nm
Total oil, natural gas, and NGL revenue after commodity contracts ($ per boe)	**49.31**	64.53	(24%)
Reference Prices			
Edmonton Light Sweet ($ per bbl)	**87.77**	80.07	10%
Alberta Plant Gate ($ per mcf)	**3.56**	4.69	(24%)

Benchmark prices

	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010
($ per bbl)					
Benchmark - Edmonton Light Sweet	**87.77**	80.33	74.42	75.09	80.07
Surge realized prices	**77.86**	70.70	69.33	66.57	72.35
Difference	**(9.91)**	(9.63)	(5.09)	(8.52)	(7.72)
% Difference	**(11%)**	(12%)	(7%)	(11%)	(10%)
($ per mcf)					
Benchmark - Alberta Plant Gate	**3.56**	3.43	3.53	3.68	4.69
Surge realized prices	**3.88**	3.55	3.71	3.74	5.20
Difference	**0.32**	0.12	0.18	0.06	0.51
% Difference	**9%**	3%	5%	2%	11%

ROYALTIES

Surge realized a royalty expense of $3.7 million or 14 percent of revenue in the three months ended March 31, 2011, compared to $1.9 million or 13 percent of revenue in the first quarter of 2010. Royalties per boe increased due to Surge's movement to a higher oil production weighting.

On January 1, 2009 the Alberta government's Alberta Royalty Framework (ARF) took effect. Under the ARF, royalty rates on conventional and non-conventional oil and natural gas production in Alberta may increase to a maximum of 50 percent. The sliding scale royalty calculations are based on a broader range of commodity prices and production rates.

In response to the drop in commodity prices experienced during the second half of 2008, on November 19, 2008, the Government of Alberta announced the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program, companies drilling new natural gas or conventional oil wells (deeper than 1,000 metres and no deeper than 3,500 metres) will be given a one-time option, on a producing zone per well basis, to adopt either the new transitional royalty rates or those outlined in the ARF. In order to qualify for this program, wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the ARF.

On March 3, 2009, an incentive program designed to encourage the execution of new drilling projects in Alberta was announced in response to the global economic crisis and slowdown in drilling activity throughout the province of Alberta. The incentive program provides for a drilling royalty credit for new conventional oil and natural gas wells that initiate drilling on or after April 1, 2009 and that complete drilling by March 31, 2011. The incentive program also provides a reduced royalty rate of approximately five percent on new wells for the first year of production or up to an established total production volume of 50,000 boe (boe cap is calculated at 10:1).

In 2010, the Government of Alberta announced that the reduced royalty rate portion of the above incentive program will be permanently implemented. This incentive program is expected to positively impact the Corporation.

In April 2010, the Government of Alberta announced an additional royalty program relating to horizontal oil well drilling projects. Horizontal oil wells drilled on or after May 1, 2010 qualify for the Horizontal Oil New Well Royalty Rate program. This incentive program provides a reduced royalty rate on new horizontal oil wells for the first 18 to 48 months of production, based on drilling depth; up to an established total production volume of 50,000 to 100,000 boe (boe cap is calculated at 10:1).

During the three months ended March 31, 2011, Surge recorded $1.3 million of drilling royalty credits as a reduction to capital costs. The drilling royalty credit portion of the 2009 incentive program concluded on March 31, 2011.

In December 2008, the Manitoba government's drilling incentive program was announced. Under this program, any horizontal well (defined as a well that achieves an angle of at least 80 degrees from the vertical for a minimum distance of 100 m) that is drilled prior to January 1, 2014, earns a holiday oil volume of 10,000 m3 with a royalty rate of zero.

A horizontal leg drilled from a horizontal well on or after January 1, 2009 and prior to January 1, 2014 and more than one year after the finished drilling date of the well, earns a holiday oil volume of 3,000 m3. Unless otherwise approved by the Director, only the first horizontal leg drilled from a horizontal well is eligible for this holiday oil volume. These holiday oil volumes must be produced within 10 years of the finished drilling date of a newly drilled well.

As royalties under the ARF are sensitive to both commodity prices and production levels, the estimated ARF and corporate royalty rates will fluctuate with commodity prices, well production rates, production decline of existing wells, and performance and location of new wells drilled.

Royalties

	March 31, 2011	March 31, 2010	% Change
Royalties ($000s)	**3,665**	1,884	95%
% of Revenue	**14%**	13%	1%
$ per boe	**8.02**	7.79	3%

OPERATING EXPENSES

Operating expenses per boe increased four percent in the three months ended March 31, 2011 to $16.73 per boe as compared to $16.11 per boe in the same period of 2010. Total operating expenses in the three months ended March 31, 2011 were $7.6 million, up 96 percent from $3.9 million in the same period 2010.

The increase in operating expenses per boe in the three months ended March 31, 2011 compared to the same period in 2010 was mainly due to higher prior period equalizations and adjustments from third party partners, as well as start-up costs in the Waskada area.

The increase in operating expenses per boe to $16.73 in the three months ended March 31, 2011 compared to the fourth quarter of 2010 of $14.87 was mainly due to higher prior period equalizations and adjustments that combined to add approximately $0.80 per boe, as well as increased electrical costs of $0.62 per boe and start-up costs in the Waskada area of approximately $0.27 per boe.

The management team continues to focus on finding efficiencies within existing operations and expects operating expenses per boe to decline into 2011.

Operating Expenses

	March 31, 2011	March 31, 2010	% Change
Operating expenses ($000s)	**7,642**	3,895	96%
% of Revenue	**30%**	28%	2%
$ per boe	**16.73**	16.11	4%

TRANSPORTATION EXPENSES

Transportation expenses on per boe decreased 21 percent in the first quarter of 2011 to $2.54 per boe as compared to $3.21 recorded in the same period of 2010. The decrease in transportation costs per boe was primarily the result of a pipeline being constructed during August of 2010, connecting oil production from the Silver Battery, as well as increased tariffs relating to a three year transportation agreement that were recorded in the first quarter of 2010.

The management team continues to focus on finding efficiencies within existing operations and expects transportation expenses per boe to continue to decline throughout 2011. The management team is forecasting to reduce combined operating and transportation costs by 21 percent to $13.00 per boe in the fourth quarter of 2011.

Transportation Expenses

	March 31, 2011	March 31, 2010	% Change
Transportation expenses ($000s)	1,162	777	50%
% of Revenue	4%	6%	(2%)
$ per boe	2.54	3.21	(21%)

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

Net G&A expenses per boe for the three months ended March 31, 2011 increased five percent to $4.76 per boe as compared to $4.55 per boe in the same period of 2010. Net G&A expenses for the three months ended March 31, 2011, net of recoveries and capitalized amounts of $1.5 million, were $2.2 million, compared to $1.1 million in the same period of 2010, after recoveries and capitalized amounts of $0.5 million. The increase in net G&A expenses per boe in the first quarter of 2011 is due primarily to higher rent expense on additional office space, increased salaries and benefits due to higher staffing levels as compared to the first quarter of 2010, and increased consulting and legal expenditures. The first quarter net G&A expense per boe decreased by 20 percent to $4.76 compared to the fourth quarter of 2010 of $5.96.

The management team expects net G&A expenses per boe to decline moving forward in 2011.

The increase in recoveries was a result of the management group capitalizing more administrative costs directly attributable to capital activities, due to an increased focus on these types of activities.

G&A Expenses

($000s)	March 31, 2011	March 31, 2010	% Change
G&A expenses	3,653	1,552	135%
Recoveries and capitalized amounts	(1,478)	(451)	228%
Net G&A expenses	2,175	1,101	98%
Net G&A expenses $ per boe	4.76	4.55	5%

TRANSACTION COSTS

Transaction costs of $0.1 million or $0.19 per boe in March 31, 2011 relating to evaluation and review of business acquisitions.

Transaction Costs

($000s)	March 31, 2011	March 31, 2010	% Change
Transaction costs	87	-	nm
$ per boe	0.19	-	nm

FINANCE EXPENSES

Surge incurred an interest expense of $0.4 million or $0.98 per boe in the three months ended March 31, 2011 as compared to $0.4 million or $1.74 per boe in the first quarter of 2010, a decrease of 44 percent per boe. The decrease per boe is due to higher production levels during the current quarter as compared to the same period in 2010.

Accretion represents the change in the time value of the decommissioning liability. Accretion expense increased for the three months ended March 31, 2011 compared to the same period of 2010 due to new obligations from wells drilled and acquisition of assets. The underlying liability may increase over a period based on new obligations incurred from drilling wells, constructing facilities, acquiring operations or adjusting future estimates of timing or amounts. Similarly, this obligation can be reduced as a result of abandonment work undertaken and reducing future obligations.

Finance Expenses

	March 31, 2011	March 31, 2010	% Change
Interest expense	**448**	420	7%
$ per boe	**0.98**	1.74	(44%)
Accretion expense	**261**	91	187%
$ per boe	**0.57**	0.37	54%
Finance expenses	**709**	511	39%
$ per boe	**1.55**	2.11	(27%)

NETBACKS

During the three months ended March 31, 2011, the operating netback per boe (defined as revenue excluding realized and unrealized gains or losses on commodity contracts per boe less royalties, operating and transportation expenses on a per boe basis) of the Corporation was $29.35, a four percent decrease over the $30.71 recorded during the same period of 2010. The decrease in operating netback was largely due to a two percent decrease in revenue per boe, a three percent increase in royalty per boe and a four percent increase in operating expense per boe, partially offset by a 21 percent decrease in transportation expense per boe, as compared to the same period in 2010. The decrease in corporate netback was impacted by the increase in G&A expense per boe in 2011 and offset by a decrease in interest expense per boe, as compared to the same period in 2010.

The management team continues to focus on finding efficiencies within existing operations and expects both operating and corporate netbacks to improve throughout 2011.

Corporate Average Netbacks

($ per boe, except production)	March 31, 2011	March 31, 2010	% Change
Average production (boe per day)	**5,076**	2,686	89%
Revenue	**56.64**	57.83	(2%)
Royalties	**(8.02)**	(7.80)	3%
Operating costs	**(16.73)**	(16.11)	4%
Transportation costs	**(2.54)**	(3.21)	(21%)
Operating netback	**29.35**	30.71	(4%)
G&A expense	**(4.76)**	(4.55)	5%
Interest expense	**(0.98)**	(1.74)	(44%)
Corporate netback	**23.61**	24.42	(3%)

FUNDS FROM OPERATIONS AND CASH FLOW FROM OPERATIONS

During the three months ended March 31, 2011, funds from operations increased by 62 percent to $9.8 million compared to $6.0 million in the three months ended March 31, 2010. On a per share basis, funds from operations decreased by 48 percent to $0.17 per basic share in the first quarter of 2011 from $0.33 per basic share in the same period of 2010 due to equity issuances in the past year. Funds from operations decreased by 14 percent on a per boe basis to $21.39 in the three months ended March 31, 2011 from $24.98 in the three months ended March 31, 2010.

Cash flow from operations differs from funds from operations due to the inclusion of changes in non-cash working capital. Cash flow from operations for the three months ended March 31, 2011, was $9.0 million as compared to $5.4 million in the same period of 2010. Included in cash flow from operations is an increase in non-cash working capital of $0.8 million for the three months ended March 31, 2011 and an increase of $0.6 million for the same period of 2010.

Funds from Operations

	March 31, 2011	March 31, 2010	% Change
Funds from operatings ($000s)	**9,772**	6,039	62%
Per share - basic ($)	**0.17**	0.33	(48%)
Per share - diluted ($)	**0.17**	0.32	(47%)
$ per boe	**21.39**	24.98	(14%)
Cash flow from operations ($000s)	**9,007**	5,403	67%

STOCK-BASED COMPENSATION

Surge recorded net stock-based compensation expense of $0.7 million in the three months ended March 31, 2011 compared to $0.1 million for the same period of 2010, calculated using the Black-Scholes option-pricing model.

During the three months ended March 31, 2011, 443,000 options were issued at a weighted average exercise price of $7.82 per option and 43,000 options were forfeited at a weighted average price of $5.96 per option.

The following assumptions were used to calculate stock-based compensation during the three months ended March 31, 2011: zero dividend yield; expected volatility of 69 percent; risk free rate of two percent; and expected life of five years.

Stock-based compensation

($000s)	March 31, 2011	March 31, 2010	% Change
Stock-based compensation	**1,696**	190	793%
Capitalized stock-based compensation	**(973)**	(114)	754%
Net stock-based compensation	**723**	76	851%
Net stock-based compensation $ per boe	**1.58**	0.31	410%

DEPLETION AND DEPRECIATION

Depletion and depreciation are calculated based upon capital expenditures, production rates and proved plus probable reserves. Excluded from the Corporation’s depletion and depreciation calculation are costs associated with salvage values of $27.0 million. Future development costs for proved reserves of $79.4 million have been included in the depletion calculation.

Surge recorded $8.3 million or $18.17 per boe in depletion and depreciation expense in the three months ended March 31, 2011, a 22 percent increase per boe as compared to $14.88 per boe in DD&A expense in the same period of 2010.

The depletion and depreciation calculation is based on production volumes of 456,797 boe for the quarter. This increase in the depletion and depreciation rate per boe is due to the corporate acquisitions completed during the previous year, as well as an 89 percent increase in production.

Depletion and Depreciation Expense

	March 31, 2011	March 31, 2010	% Change
Depletion and depreciation expense ($000s)	**8,303**	3,597	131%
$ per boe	**18.17**	14.88	22%

NET INCOME (LOSS)

The Corporation recorded a net loss for the three months ended March 31, 2011 of $0.5 million or $0.01 per basic share, compared to net income of $2.7 million or $0.15 per basic share for the same period of 2010.

Net Income (Loss)

	March 31, 2011	March 31, 2010	% Change
Total ($000s)	**(502)**	2,749	nm
Per share - basic ($)	**(0.01)**	0.15	nm
Per share - diluted ($)	**(0.01)**	0.15	nm

CAPITAL EXPENDITURES

Cash-based capital expenditures, net of any applicable Alberta drilling royalty credits, for the three months ended March 31, 2011, were $45.0 million, a $38.5 million increase from the $6.5 million spent in the three months of 2010.

During the three months ended March 31, 2011, Surge invested $21.8 million ($20.5 million net of $1.3 million in Alberta drilling royalty credits) to drill 4 gross (4 net) wells. At Valhalla, Surge drilled 2 gross (2 net) wells, completed 2 wells and frac'd 4 existing vertical wells. At Windfall, Surged drilled 2 gross (2 net) wells and completed 3 wells.

In addition, Surge invested $8.4 million on facilities, pipeline, and equipment, $5.6 million on seismic and land acquisitions, $14.9 million on property acquisitions, and $1.5 million on other capital items. Surge disposed of certain oil and gas properties for proceeds of $1.3 million.

Non-cash costs consist primarily of the fair value of swapped lands, capitalized stock-based compensation and asset retirement obligations and the book value of swapped lands.

Capital Expenditure Summary

($000s)	March 31, 2011	March 31, 2010	% Change
Land and seismic	**269**	2,701	(90%)
Drilling and intangibles	**21,781**	2,680	713%
Alberta drilling royalty credits	**(1,287)**	-	nm
Facilities and equipment	**8,354**	584	1,330%
Other	**1,496**	504	197%
Total	**30,613**	6,469	373%
Corporate acquisitions	**-**	-	nm
Property acquisitions	**4,925**	-	nm
Property dispositions	**(1,301)**	-	nm
Total petroleum and natural gas properties	**34,237**	6,469	428%
Land and seismic	**5,284**	-	nm
Exploratory drilling and completion	**-**	-	nm
Property acquisitions	**5,479**	-	nm
Total exploration and evaluation	**10,763**	-	nm
Total cash based capital expenditures	**45,000**	6,469	596%
Non-cash based capital expenditures	**-**	-	nm
Property acquisitions	**4,683**	-	nm
Capitalized stock based compensation	**973**	-	nm
Decommissioning asset additions (reductions)	**(1,175)**	-	nm
Property Dispositions	**(2,781)**	-	nm
Total non-cash based capital expenditures	**1,700**	-	nm
Total capital expenditures	**46,700**	6,469	622%

Quarterly and Annual Financial Information

IFRS	Q1 2011	Year end 2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Oil, Natural gas & NGL sales	**25,872**	57,927	18,544	14,264	11,141	13,978
Unrealized gain(loss) on financial derivatives)	**(2,607)**	(2,349)	(2,648)	(1,110)	23	1,386
Provision for bad debt	**-**	506	391	-	-	115
Net earnings (loss)	**(502)**	(7,695)	(3,638)	(147)	(6,659)	2,749
Net earnings (loss) per share ($):						
Basic	**(0.01)**	(0.21)	(0.09)	-	(0.25)	0.15
Diluted	**(0.01)**	(0.21)	(0.09)	-	(0.25)	0.15
Total assets	**-**	378,544	-	-	-	-
Total long-term financial liabilities	**-**	30,000	-	-	-	-
Average daily sales						
Oil & NGL (bbls/d)	**3,090**	1,871	2,308	1,841	1,621	1,707
Natural gas (mcf/d)	**11,915**	6,930	10,182	7,783	3,823	5,874
Barrels of oil equivalent (boe per day) (6:1)	**5,076**	3,026	4,005	3,138	2,258	2,686
Average sales price						
Natural gas ($/mcf)	**3.88**	3.96	3.55	3.71	3.74	5.20
Oil & NGL ($/bbl)	**77.86**	69.83	70.70	69.33	66.57	72.35
Barrels of oil equivalent ($/boe)	**56.64**	52.45	50.33	49.41	54.22	57.83

Quarterly and Annual Financial Information

Previous GAAP	Year end 2009	Q4 2009	Q3 2009	Q2 2009
Oil, Natural gas & NGL sales	42,853	12,932	10,788	9,829
Unrealized gain(loss) on financial derivatives)	(1,222)	(1,116)	1,026	(22)
Provision for bad debt	840	-	-	840
Net earnings (loss)	(2,112)	(21)	844	(1,294)
Net earnings (loss) per share ($):				
Basic	(0.13)	-	0.05	(0.08)
Diluted	(0.13)	-	0.05	(0.08)
Total assets	132,360	-	-	-
Total long-term financial liabilities	41,650	-	-	-
Average daily sales				
Oil & NGL (bbls/d)	1,477	1,614	1,428	1,374
Natural gas (mcf/d)	6,995	6,887	6,295	7,586
Barrels of oil equivalent (boe per day) (6:1)	2,643	2,762	2,478	2,638
Average sales price				
Natural gas ($/mcf)	4.85	4.63	4.28	3.59
Oil & NGL ($/bbl)	58.84	69.52	62.39	58.48
Barrels of oil equivalent ($/boe)	45.32	51.44	47.34	39.88

Share Capital and Option Activity

	IFRS	IFRS	IFRS	IFRS	IFRS	Previous GAAP	Previous GAAP	Previous GAAP
	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009
Weighted Common Shares	**56,094,747**	53,065,155	30,874,642	27,589,374	18,576,487	16,669,721	16,666,811	16,668,503
Stock option dilution (treasury method)[1]	**-**	-	-	-	457,033	-	69,353	-
Weighted average dilution shares oustanding[1]	**56,094,747**	53,065,155	30,874,642	27,589,374	19,033,520	16,669,721	16,736,164	16,668,503

[1] In computing the net loss per diluted share, nil shares were added to the weighted average number of shares outstanding because they were anti-dilutive.

On June 15, 2011 Surge had 56,096,547 common shares, 2,076,136 performance warrants and 3,316,332 options outstanding.

LIQUIDITY AND CAPITAL RESOURCES

On March 31, 2011, Surge had net debt of $81.4 million and a net working capital deficit of $86.6 million including unrealized hedging losses of $5.2 million, as well as bank debt of $62.4 million.

Surge anticipates that future capital requirements will be funded through a combination of internal cash flow, divestitures, debt and/or equity financing. Furthermore, Surge's flexible capital program, significant unused bank line further add to Surge's ability to fund future capital requirements. There is no assurance that debt and equity financing will be available on terms acceptable to the Corporation to meet its capital requirements.

The Corporation defines net debt as outstanding bank debt plus or minus cash-based working capital excluding the fair value of financial contracts as follows:

Net Debt

($000s)	
Bank debt	(62,368)
Accounts receivable	16,056
Prepaid expenses and deposits	2,979
Accounts payable and accrued liabilities	(38,112)
Total	**(81,445)**

The facility is secured by a general assignment of book debts, debentures of $200.0 million with a floating charge over all assets of the Corporation with a negative pledge and undertaking to provide fixed charges on the major producing petroleum and natural gas properties at the request of the bank.

RELATED-PARTY AND OFF-BALANCE-SHEET TRANSACTIONS

Surge was not involved in any off-balance-sheet transactions or related party transactions during the three months ended March 31, 2011.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Corporation has entered into farm-in agreements in the normal course of its business. The Corporation is also contractually obligated under its debt agreements as outlined under liquidity and capital resources.

Surge has future minimum payments relating to its operating leases and firm transportation agreements totalling $10.7 million, as summarized below:

Commitments

($000s)	
2011	1,395
2012	2,492
2013	1,804
2014	1,465
2015	1,404
2016+	2,129
Total	**10,689**

In 2010, the Corporation issued a total of 681,819 flow-through common shares at $4.40 per share as part of a flow-through unit for gross proceeds of $3.0 million. The Corporation renounced these qualifying petroleum and natural gas expenditures effective December 31, 2010. As at March 31, 2011 Corporation had incurred $0.8 million towards this flow-through share obligation and has until December 31, 2011 to incur the $2.2 million of remaining expenditures.

Financial instruments

Derivative contracts are recorded at fair value based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices and other relevant factors. The actual amounts received or paid to settle these instruments at maturity could differ significantly from those estimated.

The following table outlines the realized and unrealized gains (losses) on oil and gas commodity contracts for the three months ended March 31, 2011:

Term	Type (floating to fixed)	Volume	Swap Price (Surge receives) (C$)	Index (Surge pays)	Unrealized gains (losses) ($000s CDN)	Realized gains (losses) ($000s CDN)
Jan 1 to Dec 31, 2011	Swap		$ 80.00	WTI - NYMEX		(290)
Jan 1 to Dec 31, 2011	Call		$ 96.55	WTI - NYMEX		31
Jan 1 to Dec 31, 2011	Call		$ 78.40	WTI - NYMEX		(163)
Jan 1 to Dec 31, 2011	Swap		$ 85.50	WTI - NYMEX		(166)
Jan 1 to Dec 31, 2011	Swap		$ 80.00	WTI - NYMEX		(290)
Jan 1 to Dec 31, 2011	Call		$ 91.00	WTI - NYMEX		74
Jan 1 to Dec 31, 2011	Call	500 GJs/d	$ 6.55	AECO Monthly Average	1	-
Jan 1 to Dec 31, 2011	Put	500 GJs/d	$ 5.00	AECO Monthly Average	(51)	64
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$ 80.00	WTI - NYMEX	(468)	-
Jan 1 to Dec 31, 2011	Call	250 bbls/d	$ 96.55	WTI - NYMEX	425	-
Jan 1 to Dec 31, 2011	Call	125 bbls/d	$ 78.40	WTI - NYMEX	(183)	-
Jan 1 to Dec 31, 2011	Put	250 bbls/d	$ 78.40	WTI - NYMEX	(67)	-
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$ 85.50	WTI - NYMEX	(590)	-
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	$ 80.00	WTI - NYMEX	(467)	-
Jan 1 to Dec 31, 2011	Call	250 bbls/d	$ 91.00	WTI - NYMEX	465	-
Jan 1 to Dec 31, 2012	Swap	250 bbls/d	$ 97.00	WTI - NYMEX	(673)	-
Jan 1 to Dec 31, 2012	Call	63 bbls/d	$ 80.00	WTI - NYMEX	(636)	-
Jan 1 to Dec 31, 2012	Put	250 bbls/d	$ 90.00	WTI - NYMEX	351	-
Jan 1 to Dec 31, 2012	Call	250 bbls/d	$ 89.95	WTI - NYMEX	1,881	-
Apr 1 to Dec 31, 2011	Call	250 bbls/d	$ 84.35	WTI - NYMEX	1,510	-
Apr 1 to Dec 31, 2011	Swap	250 bbls/d	$ 80.00	WTI - NYMEX	(1,714)	-
Jan 1 to Dec 31, 2012	Swap	250 bbls/d	$ 80.00	WTI - NYMEX	(2,194)	-
Jul 1 to Dec 31, 2011	Put	250 bbls/d	$ 90.00	WTI - NYMEX	140	-
Jan 1 to Dec 31, 2012	Put	250 bbls/d	$ 90.00	WTI - NYMEX	578	-
Jan 1 to Dec 31, 2012	Call	93 bbls/d	$ 90.00	WTI - NYMEX	(695)	-
Jul 1 to Dec 31, 2011	Call	65 bbls/d	$ 90.00	WTI - NYMEX	(220)	-
Total					**(2,607)**	**(740)**

SUBSEQUENT EVENTS

Subsequent to March 31, 2011, the Corporation entered into a three year interest rate hedge with the following terms:

Term	Type (floating to fixed)	Amount (C$)	Company Fixed Interest Rate (%)[1]	Counterparty Floating Rate Index
Jan 1, 2012 to Dec 31, 2014	Swap	$50,000,000	2.74%	CAD-BA-CDOR
Total				

(1) The interest rate hedge is comprised of a range, beginning at 1.439% and escalating quarterly to a maximum of 3.952%.

On May 12, 2011, the Corporation acquired certain oil and gas properties for cash of approximately $13.5 million.

CHANGE IN ACCOUNTING POLICIES

Adoption of International Financial Reporting Standards

The interim consolidated financial statements and comparative information has been prepared in accordance with International Financial Reporting Standards (IFRS). The Corporation adopted IFRS on January 1, 2011. Previously, Surge prepared its interim consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles (Canadian GAAP). The Corporation has provided IFRS accounting policies and reconciliations between Canadian GAAP and IFRS in note 3 and note 17 in its March 31, 2011 Interim Consolidated Financial Statements.

IFRS 1 Exemptions

On transition to IFRS on January 1, 2010, Surge used certain exemptions allowed under IFRS 1 – *First Time Adoption of International Reporting Standards*.

Impact of Transition to IFRS

Exploration and Evaluation (E&E) assets – On transition to IFRS, Surge reclassified $0.3 million, at January 1, 2010, of E&E assets previously included in the petroleum and natural gas properties balance on the interim consolidated statement of financial position. E&E assets are not depleted and must be assessed for impairment at the transition date and when indicators of impairment exist. There was no transitional impairment of the E&E assets. The cost of undeveloped land that expires or any impairment recognized during a period is charged as additional depletion and depreciation expense.

Petroleum and Natural gas Properties – This includes oil and gas assets in the development and production phases. The Corporation has allocated the amount recognized under the previous GAAP as at January 1, 2010 to CGUs using reserve values.

Decommissioning Obligations – Under the previous GAAP, a credit adjusted risk free rate was used to measure the obligation. Under IFRS, Surge has used a risk free rate given the expected cash flows are risked. The result of using a lower discount rate was an increase to the obligation on transition of $5.8 million at January 1, 2010.

Depletion and depreciation expense – Under IFRS, Surge has chosen to base the depletion calculation using proved plus probable reserves. This has resulted in a decrease to the depletion and depreciation expense for the year ended December 31, 2010 of $4.7 million as compared to GAAP.

Business Combinations – Accounting for business combinations also differs under IFRS. Surge elected not to restate business combinations recorded prior to January 1, 2010 in accordance with IFRS standards. Transaction costs of $1.0 million incurred subsequent to January 1, 2010, which are included in the cost of the acquisition under previous GAAP, have been expensed under IFRS.

Flow-through shares – The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. On issuance the premium received on the flow-through shares, being the difference in price over a common share with no tax attributes is recognized on the statement of financial position. As expenditures are incurred the deferred tax liability associated with the renounced tax deductions are recognized through profit and loss along with a pro-rata portion of the deferred premium.

ACCOUNTING POLICIES

(a) Basis of consolidation

Subsidiaries

Subsidiaries are entities controlled by the Corporation. Control exists when the Corporation has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the statement of income.

Jointly controlled operations and jointly controlled assets

Many of the Corporation's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Corporation's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Foreign currency

Transactions in foreign currencies are translated to the functional currencies of each entity at exchange rates prevailing on the date of each transaction. Monetary assets and liabilities denominated in foreign currencies are translated to each entity's functional currency at the period-end exchange rate. Non-monetary assets and liabilities that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of transaction. Foreign currency differences arising on translation are recognized in profit or loss. Foreign currency gains and losses are reported on a net basis.

The assets and liabilities of foreign operations are translated to Canadian dollars, the reporting currency, at the reporting date. The income and expense transactions of foreign operations are translated to Canadian dollars at exchange rates at the date of each transaction. Foreign currency differences on translation to the reporting currency are recognized directly in equity.

(c) Cash and cash equivalents

Cash and cash equivalents are comprised of cash and all investments that are highly liquid in nature and have a maturity date of three months or less.

(d) Petroleum and natural gas properties

Exploration and evaluation expenditures

Pre-license costs are recognized in the statement of income as incurred.

Exploration and evaluation costs, including the costs of acquiring licenses and directly attributable general and administrative costs, initially are capitalized as either tangible or intangible exploration and evaluation assets according to the nature of the assets acquired. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven and/or probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proven and/or probable reserves have been discovered. Upon determination of proven and/or probable reserves, intangible exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to petroleum and natural gas properties.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units (CGUs), as detailed below.

Development and production costs

Items of petroleum and natural gas properties, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The cost of development and production assets includes; transfers from exploration and evaluation assets, which generally include the cost to drill the well and the cost of the associated land upon determination of technical feasibility and commercial viability; the cost to complete and tie-in the wells; facility costs; the cost of recognizing provisions for future restoration and decommissioning; geological and geophysical costs; and directly attributable overheads.

Development and production assets are grouped into CGU's for impairment testing. When significant parts of an item of petroleum and natural gas properties have different useful lives, then they are accounted for as separate components.

Gains and losses on disposal of an item of petroleum and natural gas properties are determined by comparing the proceeds from disposal with the carrying amount of petroleum and natural gas properties and are recognized net in profit or loss.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of petroleum and natural gas properties are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of petroleum and natural gas properties are recognized in profit or loss as incurred.

Depletion and Depreciation

The net carrying value of development and production assets is depleted using the unit of production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production and the estimated salvage value of the assets at the end of their useful lives. Future development costs are estimated taking into account the level of development required to produce the reserves.

Proved plus probable reserves are estimated annually by independent qualified reserve evaluators and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. For interim financial statements internal estimates of changes in reserves and future development costs are used for determining depletion for the period. For purposes of this calculation, petroleum and gas reserves are converted to a common unit of measure on the basis of their relative energy content, where six thousand cubic feet of gas equals one barrel of oil or liquids.

Surge has deemed the estimated useful lives for gas processing plants, pipeline facilities, and compression facilities to be consistent with the reserve lives of the areas for which they serve. As a result, Surge includes the cost of these assets within their associated major component (area or group of areas) for the purpose of depletion using the unit of production method.

Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Corporation will obtain ownership by the end of the lease term.

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(e) Impairment

Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the statement of income.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the statement of income.

Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than exploration and evaluations (E&E) assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to petroleum and natural gas properties, as oil and natural gas interests, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

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

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's are allocated to reduce the carrying amounts of the assets in the CGU on a pro rata basis.

In respect of petroleum and natural gas properties and exploration and evaluation assets, impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(f) Provisions

Decommissioning obligations

The Corporation's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of abandonment and site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation as at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as accretion (within finance expense) whereas increases/decreases due to changes in the estimated future cash flows or changes in the discount rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(g) Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

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

(h) Stock-based compensation and warrant valuation

The Corporation uses the fair value method for valuing stock options and warrants. Under the fair value method, compensation costs attributable to all stock options and warrants granted are measured at fair value at the date of grant and expensed over the vesting period with a corresponding increase to contributed surplus or warrants. The fair value of each option or warrant granted is estimated using the Black-Scholes option pricing model that takes into account the grant date, the exercise price and expected life of the option or warrant, the price of the underlying security, the expected volatility, the risk-free interest rate and dividends if any on the underlying security. Upon the exercise of the stock options and warrants, consideration received together with the amount previously recognized in contributed surplus or warrants is recorded as an increase to share capital and the contributed surplus or warrants balance is reduced.

The Corporation has included an estimated forfeiture rate for stock options or warrants that will not vest, which is adjusted for actual forfeitures as they occur and upon final vesting of the award.

(i) Revenue recognition

Revenue from the sale of petroleum and natural gas is recorded on a gross basis when title passes to an external party and collection is reasonably assured based on volumes delivered to customers at contractual delivery points and rates and when collection is reasonably assured. The costs associated with the delivery, including production costs, transportation and production based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

(j) Finance income and expenses

Finance expense comprises interest expense on borrowings, accretion of the discount on provisions and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in profit or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Corporation’s outstanding borrowings during the period.

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

(k) Per share information

Per share amounts are calculated based on the weighted average number of common shares outstanding during the year. The diluted weighted average number of shares is adjusted for the dilutive effect of options and warrants. Under the treasury stock method, only “in the money” options and warrants are included in the weighted average diluted number of shares. It is also assumed that any proceeds obtained upon the exercise of options and warrants plus the unamortized portion of stock-based compensation would be used to purchase common shares at the average price during the period. The weighted average number of shares is then reduced by the number of shares acquired.

(l) Flow-through shares

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. On issuance the premium received on the flow-through shares, being the difference in price over a common share with no tax attributes, is recognized on the statement of financial position. As expenditures are incurred the deferred tax liability associated with the renounced tax deductions are recognized through profit and loss along with a pro-rata portion of the deferred premium.

(m) Leased assets

Leases where the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

Other leases are operating leases, which are not recognized on the Corporation's balance sheet.

Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

(n) Financial instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial assets and financial liabilities are recognized on the statement of financial position at the time the Corporation becomes a party to the contractual provisions. Upon initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods is dependent on the classification of the financial instrument. The Corporation has made the following classifications:

- Cash and cash equivalents and accounts receivable are classified as loans and receivables and are initially measured at fair value plus directly attributable transaction costs. Subsequently, they are recorded at amortized cost using the effective interest method.
- Bank debt and accounts payable and accrued liabilities are classified as other liabilities and are initially measured at fair value less directly attributable transaction costs. Subsequently, they are recorded at amortized cost using the effective interest method.
- Derivative financial instruments that do not qualify as hedges, or are not designated as hedges on the statement of financial position, including risk management commodity contracts, are classified as fair value through profit or loss and are recorded and carried at fair value. The Corporation may use derivative financial instruments to manage economic exposure to market risks relating to commodity prices. The Corporation does not utilize derivative financial instruments for speculative purposes.

Transaction costs related to financial instruments classified as fair value through profit or loss are expensed as incurred. All other transaction costs related to financial instruments are recorded as part of the instrument and are amortized using the effective interest method.

Contracts that are entered into for the purpose of the receipt or delivery of a non-financial item in accordance with the Corporation's expected purchase, sale or usage requirements (such as physical delivery commodity contracts) do not qualify as financial instruments and thus, are accounted for as executory contracts. These contracts are not fair valued on the statement of financial position. Settlements are recognized in the statement of income as they occur.

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(o) Comparative figures

Certain comparative figures have been reclassified to conform with the current year's presentation.

(p) Future Accounting Changes

The following pronouncements from the IASB will become effective for financial reporting periods beginning on or after January 1, 2013 and have not yet been adopted by the Corporation. All of these new or revised standards permit early adoption with transitional arrangements depending upon the date of initial application:

- IFRS 9 - Financial Instruments addresses the classification and measurement of financial assets.

- IFRS 10 - Consolidated Financial Statements builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company.
- IFRS 11 - Joint Arrangements establishes the principles for financial reporting by entities when they have an interest in arrangements that are jointly controlled.
- IFRS 12 Disclosure of Interest in Other Entities provides the disclosure requirements for interests held in other entities including joint arrangements, associates, special purpose entities and other off balance sheet entities.
- IFRS 13 - Fair Value Measurement defines fair value, requires disclosure about fair value measurements and provides a framework for measuring fair value when it is required or permitted within the IFRS standards.
- IAS 27 - Separate Financial Statements revised the existing standard which addresses the presentation of parent company financial statements that are not consolidated financial statements.
- IAS 28 - Investments in Associate and Joint Ventures revised the existing standard and prescribes the accounting for investments and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

The Corporation has not completed its evaluation of the effect of adopting these standards on its financial statements.

RISK FACTORS

Additional risk factors can be found under "Risk Factors" in the Corporation's 2010 Annual Information Form, which can be found on www.sedar.com. Many risks are discussed below and in the 2010 Annual Information Form, but these risk factors should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause actual results or events to differ materially from forecast results.

On October 25, 2007, the Alberta Government announced the New Royalty Framework (NRF) which took after January 1, 2009. On March 3, 2009, the Alberta Government announced a drilling royalty credit and new well incentive program that will be in effect from April 1, 2009 to March 31, 2010. On November 29, 2008, the Alberta Government announced that in response to the global economic crisis and a slowdown in oil and natural gas drilling in Alberta, companies drilling certain new wells after November 19, 2008 have a one-time option of selecting a transitional rate or the NRF rate. All wells drilled between 2009 and 2013 that adopt the transitional rate will required to shift to the NRF on January 1, 2014. All wells drilled prior to November 19, 2008 will move to the NRF on January 1, 2009.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Surge depends on its ability to find, acquire, develop, and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Surge may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Surge's reserves will depend not only on the Corporation's ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Surge.

Surge's principal risks include finding and developing economic hydrocarbon reserves efficiently and being able to fund the capital program. The Corporation's need for capital is both short-term and long-term in nature. Short-term working capital will be required to finance accounts receivable, drilling deposits and other similar short-term assets, while the acquisition and development of oil and natural gas properties requires large amounts of long-term capital. Surge anticipates that future capital requirements will be funded through a combination of internal funds from operations, debt and/or equity financing. There is no assurance that debt and equity financing will be available on terms acceptable to the Corporation to meet its capital requirements. If any components of the Corporation's business plan are missing, the Corporation may not be able to execute the entire business plan.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil, or water may give rise to liabilities to governments and third parties and may require Surge's operating entities to incur costs to remedy such discharge. Although Surge believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environment laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Surge's financial condition, results of operations or prospects.

Surge's involvement in the exploration for and development of oil and natural gas properties may result in Surge becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although, prior to drilling, Surge will obtain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liability. In addition, such risks may not, in all circumstances, be insurable or, in certain circumstances, Surge may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Surge. The occurrence of a significant event that was not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Surge's financial position, results of operations or prospects and will reduce income otherwise used to fund operations.

The Corporation utilizes financial derivatives contracts 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.