

FINANCIAL AND OPERATING SUMMARY

(\$000s except per share amounts)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% change	2011	2010	% change
Financials highlights						
Oil and NGL sales	25,172	9,818	156%	46,822	20,930	124%
Natural gas sales	4,637	1,301	257%	8,794	4,051	117%
Other revenue	(14)	22	nm	52	138	(62%)
Total oil, natural gas and NGL revenue	29,796	11,141	167%	55,668	25,119	122%
Funds from Operations ¹	11,898	4,740	151%	21,670	10,779	101%
Per share basic (\$)	0.21	0.17	24%	0.39	0.46	(15%)
Per share diluted (\$)	0.21	0.17	24%	0.38	0.46	(17%)
Net earning (loss) ²	3,317	(7,109)	nm	2,815	(4,360)	nm
Per share basic (\$)	0.06	(0.26)	nm	0.05	(0.19)	nm
Per share diluted (\$)	0.06	(0.26)	nm	0.05	(0.19)	nm
Total cash-based capital expenditures ³	21,436	2,422	785%	66,436	8,776	657%
Net debt (cash) at end of period ⁴	90,954	(22,007)	nm	90,954	(22,007)	nm
Operating highlights						
Production:						
Oil and NGL (bbls per day)	2,995	1,621	85%	3,042	1,663	83%
Natural gas (mcf per day)	12,334	3,823	223%	12,126	4,843	150%
Total (boe per day) (6:1)	5,051	2,258	124%	5,063	2,471	105%
Average realized price (excluding hedges):						
Oil and NGL (\$per bbl)	92.36	66.57	39%	85.04	69.52	22%
Natural gas (\$ per mcf)	4.13	3.74	11%	4.01	4.62	(13%)
Realized gain (loss) on commodity contracts (\$ per boe)	(2.58)	4.57	nm	(2.10)	2.62	nm
Net back (excluding hedges) (\$ per boe)						
Oil, natural gas and NGL sales	64.83	54.22	20%	60.75	56.17	8%
Royalties	(9.24)	(10.30)	(10%)	(8.63)	(8.95)	(4%)
Operating expenses	(16.39)	(15.29)	7%	(16.56)	(15.73)	5%
Transportation expenses	(3.25)	(2.33)	39%	(2.90)	(2.81)	3%
Operating netback	35.95	26.30	37%	32.66	28.68	14%
G&A expenses	(5.44)	(6.76)	(20%)	(5.10)	(5.58)	(9%)
Interest expense	(1.75)	(0.94)	86%	(1.36)	(1.37)	(1%)
Corporate netback	28.76	18.60	55%	26.20	21.73	21%
Common shares (000s)						
Common shares outstanding, end of period	56,102	31,109	80%	56,102	31,109	80%
Weighted average basic shares outstanding	56,098	27,589	103%	56,096	23,188	142%
Stock option dilution (treasury method)	1,188	-	nm	1,041	-	nm
Weighted average diluted shares outstanding	57,286	27,589	108%	57,137	23,188	146%

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 Net earnings before unrealized gains on financial contracts was \$547,000 or \$0.01 per share and \$2,652,000 or \$0.05 per share, respectively, for the three and six months ended June 30, 2011.

3 Please see capital expenditures note.

4 The Corporation defines net debt as outstanding bank debt plus or minus working capital excluding the fair value of financial contracts.

OVERVIEW, HIGHLIGHTS AND FORECAST

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

During the second quarter of 2011, the Corporation continued executing on its drilling program targeting light oil, which is projected to significantly increase Surge's operating netbacks and increase Surge's light/medium oil weighting to approximately 70 percent by the fourth quarter of 2011. Based on the Corporation's recent upward revision to production guidance, management is now forecasting to exit 2011 at more than 7,500 boe per day, with oil and NGL production weighting increasing from 58 percent in the fourth quarter of 2010 to approximately 70 percent in the fourth quarter of 2011.

The second quarter 2011 financial and operating data presented below includes reduced light oil production from both Valhalla South and Waskada. Production was curtailed during certain time periods throughout the quarter as a result of a planned 18 day turnaround at Valhalla South and eight weeks of unanticipated shut-in production at Waskada (caused by road closures due to extended wet conditions and flooding in the area). The Corporation estimates that the total impact of the curtailed production at Valhalla South and Waskada was approximately 350 boe per day for the quarter.

In the second quarter of 2011, Surge closed the second of two acquisitions in North Dakota and more than doubled its inventory of Spearfish locations. This results in Surge achieving a significant undeveloped land base of more than 500,000 net acres, internally estimated DPIIP¹ of more than 460 million barrels (gross) and more than 460 gross (350 net) oil drilling locations.

ACHIEVEMENTS AND FORECAST

- Continued execution of the Corporation's 2011 drilling program targeting light oil, which is projected to increase Surge's light/medium oil weighting to approximately 70 percent by the fourth quarter of 2011.
- Achieved a 100 percent success rate drilling 1 gross (0.54 net) well in the second quarter of 2011. In the first half of 2011, Surge achieved a 100 percent success rate drilling 5 gross (4.54 net) wells. Surge has 20 gross (19.6 net) wells planned for the second half of 2011, including 3 gross (2.7 net) wells at Valhalla, 5 gross (5 net) wells at Windfall, and 9 gross (9 net) wells at Waskada.
- Increased production by 124 percent to 5,051 boe per day in the second quarter of 2011 from an average of 2,258 boe per day in the second quarter 2010.
- Increased production by 105 percent to 5,063 boe per day in the first half of 2011 from an average of 2,471 boe per day in the first half of 2010.
- Approximately 84 percent of Surge's revenue in the second quarter of 2011 resulted from oil and natural gas liquids production.
- 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 approximately 70 percent in the fourth quarter of 2011.
- Increased Surge's operating netback by 37 percent to \$35.95 for the second quarter of 2011 as compared to \$26.30 in the second 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.

- Surge's operating netback has increased in every quarter since the recapitalization. The Corporation's operating netback increased by 22 percent in the second quarter as compared to the first quarter of 2011.
- Increased funds from operations by 151 percent to \$11.9 million in the second quarter of 2011 from \$4.7 million in the second quarter of 2010. Increased funds from operations per share by 24 percent to \$0.21 in the second quarter of 2011 from \$0.17 in the second quarter of 2010.
- Increased funds from operations per share by 24 percent to \$0.21 in the second quarter from \$0.17 in the first quarter of 2011. Increased funds from operations by 21 percent to \$11.9 million in the second quarter from \$9.8 million in the first quarter of 2011.
- Established a non-core dispositions package which has successfully resulted in a total of more than \$6.5 million of proceeds for Surge in the first half of 2011, with an additional \$2.0 million forecast for the second half of 2011.
- In the second quarter of 2011, Surge syndicated and increased its bank line to \$120 million.

Netback Comparison

	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Average production (boe per day)	5,051	5,076	4,005	3,138	2,258
Revenue	\$ 64.83	\$ 56.64	\$ 50.33	\$ 49.41	\$ 54.22
Royalties	(9.24)	(8.02)	(6.43)	(6.07)	(10.30)
Operating expenses	(16.39)	(16.73)	(14.87)	(14.98)	(15.29)
Transportation expenses	(3.25)	(2.54)	(1.72)	(1.86)	(2.33)
Operating netback	\$ 35.95	\$ 29.35	\$ 27.31	\$ 26.50	\$ 26.30

Surge's operating netback has increased in every quarter since the recapitalization. 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 \$29.1 million of borrowing capacity at quarter-end on the Corporation's \$120 million bank line, with \$91 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 continued to demonstrate this ability in the second quarter by closing its second acquisition in North Dakota, where the Corporation significantly strengthened its position in the Spearfish light oil resource play by adding a total of 205 gross (120 net) light oil horizontal drilling locations on 6,000 net acres of highly prospective lands with the two acquisitions. Management estimates DPIIP to be approximately 125 million barrels (gross) within these lands.

Complementing 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.

During the remainder of 2011, Surge will continue to grow the Company organically by drilling in each of its core areas. The Company will also continue the development of its waterflood projects in southeast Alberta and is planning to submit applications for secondary recovery pilot programs for each of its light oil resource plays at Valhalla South, Windfall and Waskada by year end. Additionally, the Company will continue to make accretive acquisitions that fit its business plan of positioning Surge in high impact, emerging crude oil resource plays.

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.

Surge forecasts a 2011 capital program of \$120 million with guidance to achieve 2011 exit production of 7,500 boe per day (approximately 70 percent light/medium oil & NGLs), a 67 percent increase over 2010.

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 and six months ended June 30, 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 second 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 second 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, (xiv) future proceeds from disposals, and (xv) 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 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", "net earnings (loss) before unrealized gains (losses) on financial contracts" 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)	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Cash flow from operating activities (per IFRS)	11,338	9,007	473	10,576	(324)
Change in non-cash working capital	560	765	7,313	(4,462)	(345)
Non-recurring recapitalization costs	-	-	-	-	5,409
Funds from operations	11,898	9,772	7,786	6,114	4,740

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 August 9, 2011.

OPERATIONS

Drilling

	Drilling		Success rate (%) gross	Working interest (%)
	Gross	Net		
Q1 2011	4	4	100%	100%
Q2 2011	1	0.54	100%	54%
Total	5	4.54	100%	91%

Surge achieved a 100 percent success rate in the six months ended June 30, 2011, drilling five gross (4.54 net) wells, resulting in five gross (4.54 net) oil wells. The five wells drilled in the first half include three wells at Valhalla South and two wells at Windfall.

Production

	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Oil and NGL (bbls per day)	2,995	3,090	2,308	1,841	1,621
Natural gas (mcf per day)	12,334	11,915	10,182	7,783	3,823
Total (boe per day) (6:1)	5,051	5,076	4,005	3,138	2,258
% Oil and NGL	59%	61%	58%	59%	72%

Surge achieved production of 5,051 boe per day in the second quarter of 2011, a 124 percent increase from the second quarter of 2010 production rate of 2,258 boe per day. The increase in second quarter 2011 production volumes compared to the same period in 2010 was primarily due to increased production from acquisitions and new drills in 2011, 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.

Light oil production was curtailed during certain time periods throughout the quarter as a result of a planned 18 day turnaround at Valhalla South and eight weeks of unanticipated shut-in production at Waskada (caused by road closures due to extended wet conditions and flooding in the area). The Corporation estimates that the total impact of the curtailed production at Valhalla South and Waskada was approximately 350 boe per day for the quarter.

Surge realized a 59 percent oil and natural gas liquids production weighting in the second quarter of 2011. The Corporation realized average oil and natural gas liquids production of 2,995 bbls per day for the second quarter of 2011.

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

A 20 percent increase in revenue per boe, combined with a 124 percent increase in production, resulted in revenues of \$29.8 million in the three months ended June 30, 2011, up 167 percent from \$11.1 million in the second quarter of 2010. During the six months ended June 30, 2011, an eight percent increase in revenue per boe, combined with a 105 percent increase in production, resulted in revenues of \$55.7 million, up 122 percent from \$25.1 million during the same period in 2010.

Surge had certain oil and gas commodity contracts in place as of June 30, 2011. The Corporation recognized an unrealized gain of \$2.8 million and a realized loss of \$1.2 million on its commodity contracts in the second quarter of 2011. This compares to an unrealized gain of \$0.02 million and a realized gain of \$0.9 million on its commodity contracts in the second quarter of 2010.

The realized commodity contract loss resulted in a decrease of \$2.10 per boe to average revenue, including commodity contracts, for the six months ended June 30, 2011. The unrealized commodity contract gains resulted in an increase of \$0.18 per boe to average revenue, including commodity contracts, for the six months ended June 30, 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 second quarter of 2011, Surge realized average revenue of \$64.83 per boe, before realized commodity contract losses, an increase of 20 percent from the \$54.22 per boe recorded in the second quarter of 2010. During the six months ended June 30, 2011, Surge realized average revenue of \$60.75 per boe, before realized commodity contract losses, an increase of eight percent from the \$56.17 per boe during the same period of 2010.

The Corporation realized an average of \$92.36 per bbl of oil and natural gas liquids in the second quarter of 2011, an increase of 39 percent from the \$66.57 per bbl realized in the second quarter of 2010. This compares to an average Edmonton Light Sweet price of \$103.07 per bbl during the second quarter of 2011, which increased 37 percent per barrel from the \$75.09 per bbl during the second quarter of 2010. The increase in oil and natural gas liquids prices is consistent with the increase in benchmark prices.

The Corporation realized an average of \$85.04 per bbl of oil and natural gas liquids during the six months ended June 30, 2011, an increase of 22 percent from the \$69.52 per bbl realized during the same period of 2010. This compares to an average Edmonton Light Sweet price of \$95.52 per bbl during the six months ended June 30, 2011, which increased 23 percent per barrel from the \$77.58 per bbl during the six months ended June 30, 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 \$4.13 per mcf in the second quarter of 2011, a 11 percent increase from the \$3.74 per mcf averaged in the second quarter of 2010. This compares to an average Alberta Plant Gate reference price of \$3.80 per mcf in the second quarter of 2011 and \$3.68 per mcf in the second quarter of 2010. The increase in realized natural gas prices as compared to average Alberta Plant Gate reference pricing is due to higher than average heat content associated with the natural gas produced in the Valhalla and Windfall areas.

The Corporation realized an average natural gas price of \$4.01 per mcf during the six months ended June 30, 2011, a 13 percent decrease from the \$4.62 per mcf averaged during the same period of 2010. This compares to an average Alberta Plant Gate reference price of \$3.80 per mcf during the six months ended June 30, 2011 and \$4.19 per mcf during the six months ended June 30, 2010, reflecting a 13 percent decrease. The decrease in natural gas prices is relatively consistent with the decrease in benchmark prices.

In the second 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.

Realized commodity contract losses resulted in a decrease of \$2.58 per boe to the average revenue including commodity contracts in the second quarter of 2011.

Realized commodity contract losses resulted in a decrease of \$2.10 per boe to the average revenue including commodity contracts during the six months ended June 30, 2011.

Revenue and Realized Prices

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Oil and NGL (\$000s)	25,172	9,818	156%	46,822	20,930	124%
Natural gas (\$000s)	4,637	1,301	257%	8,794	4,051	117%
Processing and other (\$000s)	(14)	22	nm	52	138	(62%)
Total oil, natural gas and NGL revenue (\$000s)	29,796	11,141	167%	55,668	25,119	122%
Oil and NGL (\$ per bbl)	92.36	66.57	39%	85.04	69.52	22%
Natural gas (\$ per mcf)	4.13	3.74	11%	4.01	4.62	(13%)
Total oil, natural gas and NGL revenue (\$ per boe)	64.83	54.22	20%	60.75	56.17	8%
Unrealized gain on commodity contracts (\$ per boe)	6.03	0.11	nm	0.18	3.15	nm
Realized gain (loss) on commodity contracts (\$ per boe)	(2.58)	4.57	nm	(2.10)	2.62	nm
Total oil, natural gas, and NGL revenue after commodity contracts (\$ per boe)	68.28	58.90	16%	58.83	61.94	(5%)
Reference Prices						
Edmonton Light Sweet (\$ per bbl)	103.07	75.09	37%	95.52	77.58	23%
Alberta Plant Gate (\$ per mcf)	3.80	3.68	3%	3.80	4.19	(9%)

Benchmark prices

	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010
(\$ per bbl)					
Benchmark - Edmonton Light Sweet	103.07	87.77	80.33	74.42	75.09
Surge realized prices	92.36	77.86	70.70	69.33	66.57
Difference	(10.71)	(9.91)	(9.63)	(5.09)	(8.52)
% Difference	(10%)	(11%)	(12%)	(7%)	(11%)
(\$ per mcf)					
Benchmark - Alberta Plant Gate	3.80	3.56	3.43	3.53	3.68
Surge realized prices	4.13	3.88	3.55	3.71	3.74
Difference	0.33	0.32	0.12	0.18	0.06
% Difference	9%	9%	3%	5%	2%

ROYALTIES

Surge realized a royalty expense of \$4.2 million or 14 percent of revenue in second quarter of 2011, compared to \$2.1 million or 19 percent of revenue in the second quarter of 2010. During the six months ended June 30, 2011, Surge realized royalty expense of \$7.9 million or 14 percent of revenue, compared to \$4.0 million or 16 percent of revenue during the six months ended June 30, 2010. The reduction in royalties as a percent of revenue is primarily the result of the Alberta government's royalty incentive program, which reduced royalties on newly drilled wells.

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 June 30, 2011, Surge recorded \$0.5 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. Credits recorded during the three months ended June 30, 2011 are the result of adjustments relating to both 2010 and the first quarter of 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 of the program for the government of Manitoba, only the first horizontal leg drilled from a horizontal well is eligible for this holiday oil volume. The 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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Royalties (\$000s)	4,245	2,117	100%	7,910	4,001	98%
% of Revenue	14%	19%	(5%)	14%	16%	(2%)
\$ per boe	9.24	10.30	(10%)	8.63	8.95	(4%)

OPERATING EXPENSES

Operating expenses per boe decreased two percent in the second quarter to \$16.39 per boe as compared to \$16.73 per boe in the first quarter of 2011. Operating expenses per boe increased seven percent in the second quarter of 2011 to \$16.39 per boe as compared to \$15.29 per boe in the same period of 2010. Operating expenses per boe during the six months ended June 30, 2011 were \$16.56 per boe, up five percent from \$15.73 per boe during the same period of 2010.

Operating expenses per boe in the second quarter and first half of 2011 were impacted by wet conditions in Waskada and Windfall. Start-up costs in the first quarter of 2011 and the impact of the shut-in production in the second quarter of 2011 negatively impacted per boe costs in the Waskada area. Additionally, operating costs were impacted by higher operating costs in areas acquired in the third quarter of 2010 that are not included in the comparative 2010 figures as at June 30, 2010.

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

Operating Expenses

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Operating expenses (\$000s)	7,531	3,140	140%	15,173	7,035	116%
% of Revenue	25%	28%	(3%)	27%	28%	(1%)
\$ per boe	16.39	15.29	7%	16.56	15.73	5%

TRANSPORTATION EXPENSES

Transportation expenses on per boe increased 39 percent in the second quarter of 2011 to \$3.25 per boe as compared to \$2.33 recorded in the same period of 2010. Transportation expenses per boe during the six months ended June 30, 2011 were \$2.90 per boe, up three percent from \$2.81 per boe during the same period of 2010.

The increase in transportation costs per boe in the quarter and first half was primarily the result of weather related increases in trucking costs at Windfall as well as delivery adjustments in Valhalla.

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 to \$13.00 per boe in the fourth quarter of 2011.

Transportation Expenses

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Transportation expenses (\$000s)	1,496	478	213%	2,658	1,255	112%
% of Revenue	5%	5%	0%	5%	5%	0%
\$ per boe	3.25	2.33	39%	2.90	2.81	3%

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

Net G&A expenses per boe for the second quarter of 2011 decreased 20 percent to \$5.44 per boe as compared to \$6.76 per boe in the same period of 2010. G&A expenses for the second quarter of 2011, net of recoveries and capitalized amounts of \$1.7 million, were \$2.5 million, compared to \$1.4 million in the same period of 2010, after recoveries and capitalized

amounts of \$0.6 million. The decrease in G&A per boe is due to the increased production levels in the second quarter of 2011, as compared to the same period in 2010.

Net G&A expenses per boe during the six months ended June 30, 2011 decreased nine percent to \$5.10 per boe as compared to \$5.58 per boe in the same period of 2010. G&A expenses during the six months ended June 30, 2011, net of recoveries and capitalized amounts of \$3.2 million, were \$4.7 million, compared to \$2.5 million in the same period of 2010, after recoveries and capitalized amounts of \$1.0 million. The decrease in G&A per boe is due to the increased production levels in the second half of 2011, as compared to the same period in 2010.

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.

The management team continues to focus on general and administrative efficiencies and expects net G&A expenses per boe to decline throughout 2011. The management team is forecasting to reduce net G&A expenses to \$3.00 per boe in the fourth quarter of 2011.

G&A Expenses

(\$000s except per boe)	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
G&A expenses	4,236	1,973	115%	7,888	3,458	128%
Recoveries and capitalized amounts	(1,736)	(580)	199%	(3,214)	(964)	233%
Net G&A expenses	2,500	1,393	79%	4,675	2,494	87%
Net G&A expenses \$ per boe	5.44	6.76	(20%)	5.10	5.58	(9%)

TRANSACTION COSTS

Transaction costs of \$0.01 million or \$0.10 per boe during the six months ended June 30, 2011 were related to evaluation and review of business and property acquisitions.

Transaction Costs

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Transaction costs (\$000s)	8	-	nm	95	-	nm
\$ per boe	0.02	-	nm	0.10	-	nm

FINANCE EXPENSES

Surge incurred an interest expense of \$0.8 million or \$1.75 per boe in the three months ended June 30, 2011 as compared to \$0.2 million or \$0.94 per boe in the same period of 2010. During the six months ended June 30, 2011, Surge incurred an interest expense of \$1.2 million or \$1.36 per boe, compared to \$0.6 million or \$1.37 per boe during the same period of 2010. The increase per boe during Q2 2011 is due to higher debt levels 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 and six months ended June 30, 2011 compared to the same period of 2010 due to new obligations from wells drilled and the 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

(\$000s except per boe)	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Interest expense	801	194	313%	1,249	614	104%
\$ per boe	1.75	0.94	86%	1.36	1.37	(1%)
Accretion expense	263	122	116%	524	214	145%
\$ per boe	0.57	0.60	(5%)	0.58	0.48	21%
Finance expenses	1,064	316	237%	1,773	828	114%
\$ per boe	2.32	1.54	51%	1.94	1.85	5%

NETBACKS

Surge's operating netback (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) has increased in every quarter since the recapitalization. The Corporation's operating netback increased by 22 percent in the second quarter as compared to the first quarter of 2011.

During the three months ended June 30, 2011, the operating netback per boe of the Corporation was \$35.95, a 37 percent increase over the \$26.30 recorded during the same period of 2010. The increase in operating netback was attributable to a 20 percent increase in revenue per boe, a 10 percent decrease in royalty per boe, a seven percent increase in operating expense per boe, and a 39 percent increase in transportation expense per boe, as compared to the same period in 2010. The increase in corporate netback was impacted by the 20 percent decrease in G&A expense per boe in 2011 and offset by an increase in interest expense per boe, as compared to the same period in 2010.

During the six months ended June 30, 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 \$32.66, a 14 percent increase over the \$28.68 recorded during the same period of 2010. The increase in operating netback was largely due to an eight percent increase in revenue per boe, a four percent decrease in royalty per boe, a five percent increase in operating expense per boe, and a three percent increase in transportation expense per boe, as compared to the same period in 2010. The increase in corporate netback was impacted by the nine percent decrease in G&A expense per boe in 2011 and 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)	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Average production (boe per day)	5,051	2,258	124%	5,063	2,471	105%
Revenue	64.83	54.22	20%	60.75	56.17	8%
Royalties	(9.24)	(10.30)	(10%)	(8.63)	(8.95)	(4%)
Operating expenses	(16.39)	(15.29)	7%	(16.56)	(15.73)	5%
Transportation expenses	(3.25)	(2.33)	39%	(2.90)	(2.81)	3%
Operating netback	35.95	26.30	37%	32.66	28.68	14%
G&A expense	(5.44)	(6.76)	(20%)	(5.10)	(5.58)	(9%)
Interest expense	(1.75)	(0.94)	86%	(1.36)	(1.37)	(1%)
Corporate netback	28.76	18.60	55%	26.20	21.73	21%

FUNDS FROM OPERATIONS AND CASH FLOW FROM OPERATIONS

During the three months ended June 30, 2011, funds from operations increased by 151 percent to \$11.9 million compared to \$4.7 million during the three months ended June 30, 2010. On a per share basis, funds from operations increased by 24 percent to \$0.21 per basic share in the second quarter of 2011 from \$0.17 per basic share in both the second quarter of 2010 and the first quarter of 2011. Funds from operations increased by 12 percent on a per boe basis to \$25.89 during the three months ended June 30, 2011 from \$23.07 during the three months ended June 30, 2010.

During the six months ended June 30, 2011, funds from operations increased by 101 percent to \$21.7 million compared to \$10.8 million during the six months ended June 30, 2010. On a per share basis, funds from operations decreased by 15 percent to \$0.39 per basic share during the six months ended June 30, 2011 from \$0.46 per basic share in the same period of 2010 due to equity issuances in 2010 related to the transformation of the Corporation since the recapitalization in the second quarter of 2010. Funds from operations decreased by two percent on a per boe basis to \$23.65 during the six months ended June 30, 2011 from \$24.10 during the six months ended June 30, 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 June 30, 2011, was \$11.3 million as compared to a loss of \$0.3 million in the same period of 2010. Included in cash flow from operations is decrease in non-cash working capital of \$0.6 million for the three months ended June 30, 2011 and an increase of \$0.3 million for the same period of 2010.

Cash flow from operations for the six months ended June 30, 2011, was \$20.3 million as compared to \$5.1 million in the same period of 2010. Included in cash flow from operations is a decrease in non-cash working capital of \$1.3 million for the six months ended June 30, 2011 and a decrease of \$0.3 million for the same period of 2010.

Funds from Operations

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Funds from operations (\$000s)	11,898	4,740	151%	21,670	10,779	101%
Per share - basic (\$)	0.86	0.17	406%	1.03	0.46	124%
Per share - diluted (\$)	0.84	0.17	394%	1.01	0.46	120%
\$ per boe	104.47	23.07	353%	63.06	24.10	162%
Cash flow from operations (\$000s)	11,338	(324)	nm	20,345	5,079	nm

STOCK-BASED COMPENSATION

Surge recorded net stock-based compensation expense of \$0.7 million during the three months ended June 30, 2011 compared to \$4.1 million for the same period of 2010, calculated using the Black-Scholes option-pricing model. The increase in the comparative period expense was due to the 2010 recapitalization.

Surge recorded net stock-based compensation expense of \$1.4 million during the six months ended June 30, 2011 compared to \$4.2 million for the same period of 2010, calculated using the Black-Scholes option-pricing model. The increase in the comparative period expense was due to the 2010 recapitalization.

During the six months ended June 30, 2011, 866,000 options were issued at a weighted average exercise price of \$8.37 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 six months ended June 30, 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 except per boe)	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Stock-based compensation	1,669	5,947	(72%)	3,365	6,137	(45%)
Capitalized stock-based compensation	(959)	(1,863)	(49%)	(1,932)	(1,977)	(2%)
Net stock-based compensation	710	4,084	(83%)	1,433	4,160	(66%)
Net stock-based compensation \$ per boe	1.54	19.88	(92%)	1.56	9.30	(83%)

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 \$26.9 million. Future development costs for proved reserves of \$53.4 million have been included in the depletion calculation.

Surge recorded \$8.3 million or \$18.07 per boe in depletion and depreciation expense during the three months ended June 30, 2011, an 11 percent increase per boe as compared to \$16.26 per boe in depletion and depreciation expense in the same period of 2010.

Surge recorded \$16.6 million or \$18.12 per boe in depletion and depreciation expense during the six months ended June 30, 2011, a 17 percent increase per boe as compared to \$15.52 per boe in depletion and depreciation expense in the same period of 2010.

The depletion and depreciation calculation is based on production volumes of 459,597 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 a 124 percent increase in production.

Depletion and Depreciation Expense

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Depletion and depreciation expense (\$000s)	8,305	3,342	149%	16,608	6,939	139%
\$ per boe	18.07	16.26	11%	18.12	15.52	17%

NET INCOME (LOSS)

The Corporation recorded a net income for the three months ended June 30, 2011 of \$3.3 million or \$0.06 per basic share, compared to net loss of \$7.1 million or \$0.26 per basic share for the same period of 2010. During the six months ended June 30, 2011, the Corporation recorded a net income of \$2.8 million or \$0.05 per basic share, compared to a net loss of \$4.4 million or \$0.19 per basic share.

Net income before unrealized gains on financial contracts was \$0.5 million or \$0.01 per share and \$2.7 million or \$0.05 per share, respectively, for the three and six months ended June 30, 2011.

Net Income (Loss)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change	2011	2010	% Change
Total (\$000s)	3,317	(7,109)	nm	2,815	(4,360)	nm
Per share - basic (\$)	0.06	(0.26)	nm	0.05	(0.19)	nm
Per share - diluted (\$)	0.06	(0.26)	nm	0.05	(0.19)	nm

CAPITAL EXPENDITURES

Cash-based capital expenditures, net of any applicable Alberta drilling royalty credits, for the second quarter and six months ended June 30, 2011, were \$21.4 million and \$66.4 million respectively, a substantial increase from the capital expenditures in the first half of 2010.

During the six months ended June 30, 2011, Surge invested \$25.8 million net of \$1.8 million in Alberta drilling royalty credits to drill 5 gross (4.54 net) wells, as well as complete 5 gross (4.54 net) wells and frac 4 existing vertical wells. At Valhalla, Surge drilled 3 gross (2.54 net) wells, as well as 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 \$11.9 million in facilities, pipeline, and equipment, \$6.9 million in seismic and land acquisitions, \$24.9 million in property acquisitions, and \$3.4 million on other capital items. Surge disposed of certain oil and gas properties for proceeds of \$6.5 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)	Q1 2011	Q2 2011	YTD 2011	YTD 2010	YTD Change
Gross drilling and intangibles	21,781	5,864	27,645	4,304	542%
Alberta drilling royalty credits	(1,287)	(520)	(1,807)	(587)	208%
Net drilling and intangibles	20,494	5,344	25,838	3,717	595%
Land and seismic	269	290	559	3,140	(82%)
Facilities and equipment	8,354	3,526	11,880	581	1,945%
Other (including Capitalized G&A and Office)	1,496	1,919	3,415	1,234	177%
Property acquisitions	4,926	11,504	16,430	104	nm
Property dispositions	(1,301)	(5,224)	(6,525)	-	nm
Total petroleum and natural gas properties	34,238	17,359	51,597	8,776	488%
Land and seismic	5,284	341	5,625	-	nm
Property acquisitions	5,478	3,736	9,214	-	nm
Total exploration and evaluation	10,762	4,077	14,839	-	nm
Total cash based capital expenditures	45,000	21,436	66,436	8,776	657%
Property acquisitions, dispositions and tax effect	1,902	(3,556)	(1,654)	-	nm
Goodwill	-	(7,043)	(7,043)	-	nm
Capitalized stock based compensation	973	959	1,932	-	nm
ARO asset additions (reductions)	(1,175)	1,707	532	-	nm
Total non-cash based capital expenditures	1,700	(7,933)	(6,233)	-	nm
Total capital expenditures	46,700	13,503	60,203	8,776	586%

Quarterly and Annual Financial Information

IFRS	Q2 2011	Q1 2011	Year end 2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Oil, natural gas & NGL sales	29,796	25,872	57,927	18,544	14,264	11,141	13,978
Unrealized gain (loss) on financial contracts	2,770	(2,607)	(2,349)	(2,648)	(1,110)	23	1,386
Provision for bad debt	(29)	-	506	391	-	-	115
Net earnings (loss)	3,317	(502)	(7,695)	(3,638)	(147)	(7,109)	2,749
Net earnings (loss) per share (\$):							
Basic	0.06	(0.01)	(0.21)	(0.09)	-	(0.26)	0.15
Diluted	0.06	(0.01)	(0.21)	(0.09)	-	(0.26)	0.15
Total assets	-	-	378,544	-	-	-	-
Total long-term financial liabilities	-	-	30,000	-	-	-	-
Average daily sales							
Oil & NGL (bbls/d)	2,995	3,090	1,871	2,308	1,841	1,621	1,707
Natural gas (mcf/d)	12,334	11,915	6,930	10,182	7,783	3,823	5,874
Barrels of oil equivalent (boe per day) (6:1)	5,051	5,076	3,026	4,005	3,138	2,258	2,686
Average sales price							
Natural gas (\$/mcf)	4.13	3.88	3.96	3.55	3.71	3.74	5.20
Oil & NGL (\$/bbl)	92.36	77.86	69.83	70.70	69.33	66.57	72.35
Barrels of oil equivalent (\$/boe)	64.83	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	Q1 2009
Oil, natural gas & NGL sales	42,853	12,932	10,788	9,829	9,304
Unrealized gain (loss) on financial contracts	(1,222)	(1,116)	1,026	(22)	(1,110)
Provision for bad debt	840	-	-	840	-
Net earnings (loss)	(2,112)	(21)	844	(1,294)	(1,641)
Net earnings (loss) per share (\$):					
Basic	(0.13)	-	0.05	(0.08)	(0.10)
Diluted	(0.13)	-	0.05	(0.08)	(0.10)
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	1,339
Natural gas (mcf/d)	6,995	6,887	6,295	7,586	7,223
Barrels of oil equivalent (boe per day) (6:1)	2,643	2,762	2,478	2,638	2,695
Average sales price					
Natural gas (\$/mcf)	4.85	4.63	4.28	3.59	5.41
Oil & NGL (\$/bbl)	58.84	69.52	62.39	58.48	42.18
Barrels of oil equivalent (\$/boe)	45.32	51.44	47.34	39.88	37.82

Share Capital and Option Activity

	<i>IFRS</i>	<i>IFRS</i>	<i>IFRS</i>	<i>IFRS</i>	<i>IFRS</i>	<i>IFRS</i>	<i>Previous GAAP</i>	<i>Previous GAAP</i>
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
	2011	2011	2010	2010	2010	2010	2009	2009
Weighted Common Shares	56,098,181	56,094,747	53,065,155	30,874,642	27,589,374	18,576,487	16,669,721	16,666,811
Stock option dilution (treasury method) ¹	1,187,618	-	-	-	-	457,033	-	69,353
Weighted average dilution shares outstanding ¹	57,285,799	56,094,747	53,065,155	30,874,642	27,589,374	19,033,520	16,669,721	16,736,164

¹ In computing the net income per diluted share in the current period, 1,187,618 shares were added to the weighted average number of shares outstanding.

On August 9, 2011 Surge had 56,121,881 common shares, 2,076,136 performance warrants and 3,619,332 options outstanding.

LIQUIDITY AND CAPITAL RESOURCES

On June 30, 2011, Surge had net debt of \$91.0 million and a net working capital deficit of \$92.5 million including current unrealized hedging losses of \$1.5 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 and 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	\$ (86,459)
Accounts receivable	13,981
Prepaid expenses and deposits	2,579
Accounts payable and accrued liabilities	(21,055)
Total	\$ (90,954)

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 and six months ended June 30, 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 \$9.0 million, as summarized below:

Commitments	
(\$000s)	
2011	\$ 825
2012	2,248
2013	1,595
2014	1,254
2015	1,046
2016+	2,012
Total	\$ 8,981

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 June 30, 2011 Corporation had incurred \$1.1 million towards this flow-through share obligation and has until December 31, 2011 to incur the \$1.9 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 losses on interest rate contracts for the three and six months ended June 30, 2011:

Term	Type (floating to fixed)	Amount (C\$)	Company Fixed Interest Rate (%) ⁽¹⁾	Counter party Floating Rate Index	Three months ended June 30, 2011		Six months ended June 30, 2011	
					Realized loss (\$000s CDN)	Unrealized loss (\$000s CDN)	Realized loss (\$000s CDN)	Unrealized loss (\$000s CDN)
Jan 1, 2012 to Dec 31, 2014	Swap	\$50,000,000	2.74%	CAD-BA- CDOR	-	(836)	-	(836)
Total					-	(836)	-	(836)

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

The following table outlines the realized and unrealized gains (losses) on oil and gas commodity contracts for the three and six months ended June 30, 2011:

Term	Type (floating to fixed)	Volume	Swap Price (Surge receives) (C\$)	Index (Surge pays) (C\$)	Three months	Three months	Six months	Six months
					June 30, 2011	June 30, 2011	June 30, 2011	June 30, 2011
					Unrealized gains (losses) (\$000s CDN)	Realized gains (losses) (\$000s CDN)	Unrealized gains (losses) (\$000s CDN)	Realized gains (losses) (\$000s CDN)
Jan 1 to Dec 31, 2011	Call	500 GJs/d	\$ 6.55	AECO Monthly	(1)	(1)	(0)	(1)
Jan 1 to Dec 31, 2011	Put	500 GJs/d	\$ 5.00	AECO Monthly	(58)	66	(109)	130
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	\$ 80.00	WTI - NYMEX	1,086	(436)	618	(726)
Jan 1 to Dec 31, 2011	Call	250 bbls/d	\$ 96.55	WTI - NYMEX	(695)	78	(270)	109
Jan 1 to Dec 31, 2011	Call	125 bbls/d	\$ 78.40	WTI - NYMEX	572	(236)	389	(399)
Jan 1 to Dec 31, 2011	Put	250 bbls/d	\$ 78.40	WTI - NYMEX	(22)		(89)	
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	\$ 85.50	WTI - NYMEX	962	(311)	372	(477)
Jan 1 to Dec 31, 2011	Swap	250 bbls/d	\$ 80.00	WTI - NYMEX	1,085	(436)	618	(726)
Jan 1 to Dec 31, 2011	Call	250 bbls/d	\$ 91.00	WTI - NYMEX	(854)	186	(389)	260
Jan 1 to Dec 31, 2012	Swap	250 bbls/d	\$ 97.00	WTI - NYMEX	622		(51)	
Jan 1 to Dec 31, 2012	Call	63 bbls/d	\$ 80.00	WTI - NYMEX	162		(474)	
Jan 1 to Dec 31, 2012	Put	250 bbls/d	\$ 90.00	WTI - NYMEX	(33)		318	
Jan 1 to Dec 31, 2012	Call	250 bbls/d	\$ 89.95	WTI - NYMEX	(622)		1,259	
Apr 1 to Dec 31, 2011	Call	250 bbls/d	\$ 84.35	WTI - NYMEX	(1,013)	337	497	337
Apr 1 to Dec 31, 2011	Swap	250 bbls/d	\$ 80.00	WTI - NYMEX	1,085	(435)	(629)	(435)
Jan 1 to Dec 31, 2012	Swap	250 bbls/d	\$ 80.00	WTI - NYMEX	612		(1,582)	
Jul 1 to Dec 31, 2011	Put	250 bbls/d	\$ 90.00	WTI - NYMEX	(9)		131	
Jan 1 to Dec 31, 2012	Put	250 bbls/d	\$ 90.00	WTI - NYMEX	(3)		575	
Jan 1 to Dec 31, 2012	Call	93 bbls/d	\$ 90.00	WTI - NYMEX	230		(465)	
Jul 1 to Dec 31, 2011	Call	65 bbls/d	\$ 90.00	WTI - NYMEX	141		(79)	
Jan 1 to Dec 31, 2012	Put	500 bbls/d	\$ 90.00	WTI - NYMEX	1,149		1,149	
Jan 1 to Dec 31, 2012	Call	158 bbls/d	\$ 90.00	WTI - NYMEX	(790)		(790)	
Total					3,606	(1,188)	999	(1,928)

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 June 30, 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) Goodwill

The Corporate records goodwill relating to a business combination when the purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired business. The goodwill balance is assessed for impairment annually or as events occur that could result in impairment. Goodwill is tested for impairment at an operating segment level by combining the carrying amounts of PP&E, E&E assets and goodwill and comparing this to the recoverable amount. The recoverable amount is the greater of fair value less cost to sell or value-in-use. Fair value less cost to sell is derived by estimating the discounted after-tax future net cash flows as described in the PP&E impairment test, plus the fair market value of undeveloped land and seismic. Value-in-use is assessed using the present value of the expected future cash flows discounted at a pre-tax rate. Any excess of the carrying amount over the recoverable amount is the impairment amount.

Impairment charges, which are not tax affected, are recognized in net income. Goodwill is reported at cost less any impairment; impairments are not reversed.

(f) 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.

(g) 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.

(h) 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.

(i) 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.

(j) 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.

(k) 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.

(l) 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.

(m) 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.

(n) 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.

(o) 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.

(p) Comparative figures

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

(q) 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 be 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.