MANAGEMENT'S DISCUSSION & ANALYSIS ("MD&A")

The following discussion and analysis is provided by the management of Seaview Energy Inc. ("Seaview" or the "Company") as of June 20, 2011 and should be read in conjunction with the unaudited condensed interim consolidated financial statements and selected notes for the periods ended March 31, 2011 and 2010 and the audited consolidated financial statements and notes and MD&A of Seaview for the years ended December 31, 2010 and 2009. This financial data has been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting" ("IFRS"). The effective date of transition to IFRS was January 1, 2010. Previously, the Company prepared its interim and annual consolidated annual financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP" or "CGAAP"). The adoption of IFRS has not had an impact on the Company's operations, strategic decisions or operating netbacks. The reporting and the measurement currency is the Canadian dollar.

Description of the Company

Seaview is a Calgary based, natural gas and light crude oil focused, exploration and development company established on December 13, 2006. The Company completed its Initial Public Offering on October 17, 2007. The primary area of operation is the Peace River Arch area of northwest Alberta. The Class A and Class B shares of Seaview trade on the TSX Venture Exchange ("TSX – Venture") under the symbols CVU.A and CVU.B. As Seaview commenced operations in October, 2007, and has since completed several material acquisitions, the financial results may not be indicative of future periods.

Non-GAAP measures

This MD&A contains the terms "funds flow from operations" and "funds flow from operations per share" which do not have any standardized meaning prescribed by IFRS. Management uses funds flow from operations and funds flow from operations per share to analyze operating performance and leverage and considers funds flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds flow from operations should not be considered an alternative to, or more meaningful than, cash flow from operating activities, as determined in accordance with IFRS, as an indicator of the Company's performance. Therefore, references to funds flow from operations or funds flow from operations per share (basic and diluted) may not be comparable with the calculation of similar measures of other entities. Funds flow from operations per share is calculated using the basic and diluted weighted average number of shares for the period. The reconciliation between funds flow from operations and cash flow from operating activities after changes in working capital for the three months ended March 31, 2011 and 2010 is as follows:

	Three months ended March 31	
($ thousands except per share amounts)	**2011**	2010
Funds flow from operations	**$ 2,947**	$ 4,441
Decommissioning expenditures	**(2)**	(21)
Changes in non-cash working capital	**270**	2,572
Cash provided by operating activities	**$ 3,215**	$ 6,992
Funds flow from operations per share (basic)	**$ 0.05**	$ 0.07
Expenditures on abandonments	**0.00**	0.00
Changes in non-cash working capital per share (basic)	**0.00**	0.04
Cash provided by operating activities per share (basic)	**$ 0.05**	$ 0.11

Management uses certain industry benchmarks such as operating netback to analyze financial and operating performance. This benchmark, 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. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. The Company uses these measures to help evaluate its performance and in capital allocation decisions.

Boe presentation

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet ("mcf") to one barrel ("bbl") is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting natural gas to oil in the ratio of six mcf of gas to one barrel of oil. A list of other commonly used abbreviations is included at the end of this report.

Forward-looking information

Certain information regarding the Company set forth in this document, including management's assessment of the Company's future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing, and transportation, such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

SELECTED INFORMATION

Financial ($000's except per share amounts)	**Q1 2011**	Q4 2010	% Change
Petroleum and natural gas sales	**$ 6,382**	$ 6,950	(8%)
Funds flow from operations (1)	**2,947**	3,938	(25%)
Basic and diluted per share (2)	**0.05**	0.06	(17%)
Net loss	**(2,778)**	(2,895)	4%
Basic and diluted per share (2)	**(0.04)**	(0.04)	-
Capital expenditures (3)	**12,967**	11,517	13%
Shares Outstanding at period end (000's)			
Class A	**65,553**	65,537	-
Class B	**1,054**	1,054	-
Operations			
Daily production			
Natural gas (mcf/d)	**12,286**	14,016	(12%)
Light oil and NGLs (bbl/d)	**277**	305	(9%)
Total production (boe/d)	**2,325**	2,641	(12%)
Average realized sales price (net of risk management gains)			
Natural gas (per mcf)	**$ 4.38**	$ 4.48	(2%)
Light oil and NGL (per bbl)	**71.78**	66.27	8%
Netback per boe (1)			
Sales price	**$ 30.50**	$ 28.60	7%
Realized risk management gains	**1.20**	2.85	(58%)
Sales price (net of realized risk management gains)	**31.70**	31.45	1%
Royalties	**(3.65)**	(3.02)	21%
Operating expenses	**(8.36)**	(5.44)	54%
Transportation	**(1.43)**	(1.63)	(12%)
Operating netback (1)	**$ 18.26**	$ 21.36	(15%)

(1) The Company uses "funds flow from operations" and "funds flow from operations per share" which do not have any standardized meaning prescribed by IFRS. The terms are used to analyze operating performance and leverage. The Company uses "Netback per boe" and "Operating Netback" which do not have any standardized meaning prescribed by IFRS. The terms are used to evaluate performance and in capital allocation decisions.
(2) Weighted average diluted shares outstanding for all periods exclude both the impact of the conversion of the Class B shares and the effect of the granted options as they would have been anti-dilutive.
(3) Capital expenditures include only the cash additions for the period.

FINANCIAL AND OPERATIONAL OVERVIEW OF FIRST QUARTER 2011

- Funds flow from operations for Q1 2011 was $2.9 million compared to Q4 2010 funds flow of $3.9 million. The reduction in funds flow is primarily attributed to the combination of natural production declines and a reduction in hedging gains;
- Average production for Q1 2011 was 2,325 boe per day compared to Q4 2010 volumes of 2,641 boe per day. The decrease in volumes is attributed to natural declines as a result of minimal capital investment on the Peace River Arch natural gas assets and delays in completions at Wapiti due to service equipment constraints and weather related issues;

- During the quarter, the Company successfully completed 2 Wapiti Cardium horizontal wells (1.1 net) utilizing liquid propane gas ("LPG") fracturing technology; the initial application of this technology. The IP rates from these new wells are more than three times better than that of the previous oil fractures completed by the Company in 2010 (see table below). Advances in the initial production ("IP") rates in the Cardium zone in the Wapiti area continue to be encouraging;
- New production additions from 4 Cardium horizontal wells (2.4 net) were brought on stream late in Q1 2011 or early Q2 2011. As a result, the production from these wells had minimal impact on the average reported production for Q1 2011;
- During Q1 2011, Seaview completed the following operations:
  - Drilled 1 Wapiti Cardium horizontal well (0.7 net) located at 100/01-17-066-08W6 ("1-17") which has subsequently been completed and placed on production on March 19th with a 30 day IP rate of 361 boe per day (41% crude oil and natural gas liquids);
  - Successfully completed 3 Wapiti Cardium horizontal wells (1.7 net), which were drilled in Q4 2010, utilizing liquid propane gas ("LPG") fracturing technology. Tie-in of each of these projects was completed late in Q1 2011 and therefore had minimal impact on Q1 2011 production;
  - Initial 30-day production from the recent LPG fraced wells averaged 476 boe per day on a producing day basis and 306 boe per day on a calendar day basis (61% crude oil and natural gas liquids); and
  - Completed installation of additional compression in Boundary Lake to optimize the Company's 100% operated Kiskatinaw gas property, and also completed the equip and tie-in of 1 natural gas well (1.0 net) adding 145 boe per day of production over Q1 2011.

RESULTS OF OPERATIONS

Operations

For the three months ended March 31, 2011, the Company recorded a net loss of $2.8 million (net loss of $0.2 million for the three months ended March 31, 2010).

The following table summarizes selected information for the three months ended March 31, 2011 (the "Quarter" or "Q1 2011"), for the three months ended December 31, 2010 (the "Previous Quarter" or "Q4 2010"), as well as the three months ended March 31, 2010 (the "Prior Year Q1" or "Q1 2010"):

	Q1 2011	Q4 2010	Q1 2010
Daily Production			
Natural gas (mcf/d)	**12,286**	14,016	16,544
Crude oil and NGL's (bbl/d)	**277**	305	480
Boe/d day @ 6:1	**2,325**	2,641	3,237
Petroleum and natural gas sales ($000's)	**$ 6,382**	$ 6,950	$ 11,056
Funds flow from operations ($000's)	**2,947**	3,938	4,441
Per share – basic and diluted	**0.05**	0.06	0.07
Net loss ($000's)	**(2,778)**	(2,895)	(235)
Per share – basic and diluted	**(0.04)**	(0.04)	0.00

The decrease in volumes is attributed to natural declines as a result of minimal capital investment on the Peace River Arch natural gas assets, delays in completions at Wapiti due to service equipment constraints and weather related issues.

Commodity prices

Average realized prices	**Q1 2011**	Q4 2010	Q1 2010
Light crude oil (per bbl)	**$ 84.74**	$ 79.35	$ 77.28
after realized risk management gains/losses	**72.55**	69.96	73.80
Natural gas (per mcf)	**3.97**	3.80	5.23
after realized risk management gains/losses	**4.38**	4.48	5.12
Natural gas liquids (per bbl)	**70.36**	57.96	68.47
Total per boe	**30.50**	28.60	37.95
after realized risk management gains	**31.70**	31.45	36.98
BENCHMARK PRICES			
WTI oil (US$ per bbl)	**94.13**	85.04	78.70
AECO Daily Index (CAD$ per gj)	**3.58**	3.43	4.68
Currency (US$/CAD$)	**0.9860**	1.013	1.040

The AECO Daily Index gas price averaged $3.58 per gj or $3.78 per mcf for Q1 2011 as compared to $3.43 per gj or $3.62 per mcf during the Previous Quarter. The natural gas price received by Seaview, before risk management gains, was $3.97 per mcf for the Quarter compared to $3.80 per mcf for Q4 2010. Seaview receives a premium to the stated AECO Indexes as the Company produces high heat content natural gas that attracts premium market prices.

The price of West Texas Intermediate ("WTI") crude averaged US$94.13 per bbl during the Quarter compared to US$85.04 per bbl during Q4 2010. Seaview received a combined average price, including natural gas liquids and before risk management effects, of $79.72 per bbl during the Quarter compared to $72.76 during the Previous Quarter.

The Canadian dollar averaged US$0.9860 during the Quarter as compared to $1.013 during the Previous Quarter. As the price of WTI crude oil and Nymex natural gas is quoted in US dollars, appreciation in the Canadian dollar decreases the average Canadian price received. Seaview mitigates exposure to the impact of exchange rate fluctuations by economically hedging a portion of the production in Canadian dollar denominated puts, swaps and collars.

Commodity price risk management

The prices received for petroleum and natural gas can fluctuate significantly due to weather patterns, the economic environment or political uncertainty.

Seaview's commodity price risk management program is designed to provide price protection on a portion of the future production in the event of adverse commodity price movement, while retaining the opportunity to participate in favourable price movements. This practice allows the Company to generate stable funds flow for capital development and acquisition activities, and to ensure positive economic returns on those activities. The Company may also sell a portion of its natural gas production on the AECO Monthly Index in addition to the AECO Daily Index to mitigate the volatility in price movement.

The Company has elected not to use hedge accounting and consequently will record the fair value of any crude oil and natural gas financial contract at each reporting period, with the change in the fair value being classified as unrealized gains and losses in revenue in the statement of earnings. The fair value of the commodity price risk contracts are estimated based on the mark-to-market method of accounting, using publicly quoted market prices or, in their absence, third-party market indications and forecasts priced on the last trading day of the applicable period and are therefore classified as Level 2. For the three months ended March 31, 2011, realized gains of $0.3 million were recorded as revenue (three months ended March 31, 2010 – realized losses of $0.3 million). As at March 31, 2011, the Company recorded a liability related to the unrealized losses on financial contracts of $2.4 million reflecting the fair value of the crude oil and natural gas contracts outstanding at March 31, 2011 (December 31, 2010 – a liability of $1.0 million; March 31, 2010 – an asset of $1.1 million).

As at March 31, 2011, the Company had the following financial contracts:

Natural gas	Volume	Pricing Point		Price	Term
Put [1]	2,000 gj/d	AECO Monthly	$	4.75/gj	January '10 – December '11
Put	6,140 gj/d	AECO Monthly	$	4.00/gj	January '11 – December '11
Call	3,000 gj/d	AECO Monthly	$	7.04/gj	January '12 – December '12
Crude Oil					
Put [2]	200 bbl/d	WTI – Nymex CAD	$	75.00/bbl	January '10 – December '11
Call	100 bbl/d	WTI – Nymex CAD	$	88.25/bbl	January '13 – December '13
Call	200 bbl/d	WTI – Nymex	$	72.50/bbl	January '13 – December '13

(1) The net floor for this contract reflects the deferred cost of $1.05/gj paid over the course of the contract. The strike price of the put is $5.80/gj before the deferred cost.

(2) The net floor for this contract reflects the deferred cost of $11.00/bbl paid over the course of the contract. The strike price of the put is $86.00/bbl before the deferred cost.

Subsequent to the end of the quarter, the Company terminated the natural gas call for 3,000 gj/d at $7.04/gj for 2012 and replaced it with a natural gas call for 3,000 gj/d at $7.40/gj for 2013.

The total volumes hedged for the period of April 2011 to December 2013 are detailed below.

Natural Gas	**Q2 '11**	**Q3 '11**	**Q4 '11**	**2013**
Puts				
Volumes – gj/d	8,140	8,140	8,140	
Net floor ($/gj)	$4.18	$4.18	$4.18	
Call				
Volumes – gj/d				3,000
Net ceiling ($/gj)				$7.40
Crude Oil				
Put				
Volumes – bbl/d	200	200	200	
Net floor (CAD$/bbl)	$75.00	$75.00	$75.00	
Call				
Volumes – bbl/d				300
Net ceiling (CAD$/bbl)				$77.75

The Company will continue to monitor forecasted volumes and commodity prices and may layer in additional downside protection, generally using puts, in order to allow full exposure to any positive price movements.

The Company's financial derivative trading activities are conducted pursuant to the Company's Hedging Policy Manual approved by the board of directors. The Hedging Policy Manual has the objectives of reducing risk exposure to budgeted annual funds generated from operations resulting from uncertainty or changes in commodity prices; limiting financial contract volumes up to a maximum of 50% of forecasted production, unless otherwise approved by the Board of Directors; and limiting financial derivative trading activity to counter-parties that provide sufficient collateral in support of payment or have investment grade credit ratings.

Petroleum and natural gas sales

($000's)		**Q1 2011**		Q4 2010		Q1 2010
Natural gas	**$**	**4,394**	$	4,906	$	7,784
Crude oil and natural gas liquids		**1,988**		2,044		3,272
Realized risk management gains		**250**		692		(283)
Petroleum and natural gas sales (net)	**$**	**6,632**	$	7,642	$	10,773
$/boe	**$**	**31.70**	$	31.45	$	36.98

Petroleum and natural gas sales for the Quarter, before royalties and transportation costs, were $6.6 million ($7.6 million – Previous Quarter; $10.8 million – Q1 2010). The decrease from Q4 2010 is attributable to a 12% decrease in production during the Quarter offset by somewhat higher realized prices. The Company realized gains of $0.3 million, net of premiums, on crude oil and natural gas financial contracts during the Quarter (gains of $0.7 million – Previous Quarter).

Royalties

($000's)		**Q1 2011**		Q4 2010		Q1 2010
Royalties	**$**	**764**	$	735	$	1,725
Percentage of petroleum and natural gas sales (before realized risk management gains)		**12.0%**		10.6%		15.6%
$/boe	**$**	**3.65**	$	3.02	$	5.92

Royalties are paid to the owners of the mineral rights with whom leases are held, including provincial governments. Overriding royalties are also paid to other parties according to contracts. In Alberta, a Crown royalty is invoiced on the Crown's share of production based on a monthly established Alberta Reference Price. The Alberta Reference Price is a monthly weighted average price of gas consumed in Alberta and gas exported from Alberta reduced for transportation and marketing allowances. Gas cost allowance and other incentive schemes serve to reduce the effective royalty rate.

With the introduction of a New Royalty Framework ("NRF") by the Province of Alberta, commencing January 1, 2009, and the Amended Royalty Framework ("ARF") which took effect January 1, 2011, Crown royalties are sensitive to production rates for each well and to changes in the commodity price. In this low commodity price environment, the decrease in the reference price used for the calculation of Crown royalties has had a significant impact on the royalty rates charged by the Crown. Additionally, the Province of Alberta introduced a reduced royalty rate of 5% for wells that are brought on production after April 1, 2009. This applies for the first 12 months of production or to a maximum of 500,000 Mcfs for natural gas wells or 50,000 barrels for crude oil wells, amended to 60,000 barrels and 24 months for horizontal oil wells drilled on or after May 1, 2010 and more than 2,500 meters in total length. Seaview has brought on several new wells since April 1, 2009 which qualified for this reduced royalty rate, several of which currently remain at this rate.

Royalties for the Quarter totaled $0.8 million ($0.7 million – Previous Quarter; $1.7 million – Q1 2010). As a percentage of sales, royalties averaged 12.0% or $3.65 per boe during the Quarter (10.6% and $3.02 per boe for the Previous Quarter; 15.6% and $5.92 per boe – Q1 2010). The royalty rate for Q1 2011 is higher than the Previous Quarter due to a higher Crown reference price as well as having several wells reaching their production limits for the above referenced 5% royalty rate during the quarter. The overall royalty rate remains lower than the Prior Year Q1 as the Company still has approximately 27% of its production attracting the 5% royalty rate.

Operating expenses

($000's)		**Q1 2011**		Q4 2010		Q1 2010
Operating expenses	**$**	**1,749**	$	1,322	$	3,232
$/boe	**$**	**8.36**	$	5.44	$	11.10

Operating expenses for the Quarter were $1.7 million ($1.3 million – Previous Quarter; $3.2 million – Q1 2010) and on a unit-of-production basis, operating expenses averaged $8.36 per boe ($5.44 per boe – Previous Quarter; $11.10 per boe – Q1 2010). The operating expenses on a per boe basis for the Quarter have increased over the Previous Quarter as Q4 2010 operating expenses per boe were reduced due to the receipt of 13th month recoveries from operators of gas plants the Company has a working interest in. Operating expenses per boe for the Quarter compared to Q1 2010 have decreased as the Prior Year Q1 included the oil producing Southeast Saskatchewan assets that had higher operating costs per boe than the Company's Alberta gas properties.

Transportation expense

($000's)		**Q1 2011**		Q4 2010		Q1 2010
Transportation expense	**$**	**300**	$	396	$	376
$/boe	**$**	**1.43**	$	1.63	$	1.29

For the Quarter, transportation expense totaled $0.3 million or $1.43 per boe ($0.4 million or $1.63 per boe – Previous Quarter; $0.4 million or $1.29 per boe – Q1 2010). As Seaview's production is weighted more than 85% to natural gas, the majority of Seaview's transportation expenses relate to natural gas pipeline tariff charges. Transportation expense per boe for the Quarter is lower than the Previous Quarter as the trucking distance to oil terminals was reduced for clean oil production related to the new Wapiti area.

General and administrative ("G&A")

($000's)		**Q1 2011**		Q4 2010		Q1 2010
G&A expenses	**$**	**1,023**	$	1,551	$	1,301
Capitalized G&A		**(340)**		(474)		(519)
Overhead recoveries		**(181)**		(222)		(117)
Net G&A expenses		**502**		855		665
$/boe	**$**	**2.40**	$	3.52	$	2.28

During the Quarter, G&A, net of overhead recoveries on operated properties and capitalized expenditures, totaled $0.5 million ($0.9 million – Previous Quarter; $0.7 million – Q1 2010). On a unit-of-production basis, G&A expenses were $2.40 per boe ($3.25 per boe – Previous Quarter; $2.05 per boe – Q1 2010). The G&A per boe for the Quarter was lower than the Previous Quarter due mainly to costs related to yearend activities including the annual financial statement audit and the evaluation of corporate reserves being recognized in Q4 2010.

Finance expense

($000's)		**Q1 2011**		Q4 2010		Q1 2010
Interest expense	**$**	**202**	$	155	$	334
Unrealized gain on financial contracts		**-**		(5)		(19)
Accretion on decommissioning obligations		**44**		42		53
Accretion on Convertible Class B share liability		**182**		179		169
Net finance expense		**428**		371		537
$/boe	**$**	**2.05**	$	1.55	$	1.84

Interest expense, representing interest paid on drawn amounts of the secured credit facility, standby fees and banking fees, during the Quarter was $0.2 million or $0.96 per boe ($0.2 million or $0.64 per boe – Previous Quarter; $0.3 million or $1.15 per boe – Q1 2010). The average balance of debt drawn during the Quarter was $21.0 million ($13.6 million – Previous Quarter; $37.1 million – Q1 2010), with an average interest rate of 3.4% per annum paid during the Quarter (3.6% per annum – Previous Quarter; 3.2% per annum – Q1 2010). Included in interest expense are standby fees of 0.4% per annum based on an average unutilized debt capacity of $31.0 million for the Quarter ($38.4 million – Previous Quarter; $14.9 million – Q1 2010).

Stock based compensation

The Company has a stock option plan, which is fully described in Note 10 of the unaudited condensed interim consolidated financial statements. At March 31, 2011, 5,589,500 options were outstanding with an average exercise price of $1.40 and a weighted average remaining contractual life of 2.9 years (5,453,499 options outstanding at March 31, 2010 at an average exercise price of $1.50 with a weighted average remaining contractual life of 3.6 years). Of the total number of options outstanding at March 31, 2011, options totaling 3,168,354 are vested and available for exercise at a weighted average exercise price of $1.37 per option.

For the Quarter, the Company recorded a compensation expense of $0.1 million ($0.2 million – Previous Quarter; $0.3 million – Q1 2010) and capitalized $0.1 million, ($0.2 million – Previous Quarter; $0.3 million – Q1 2010).

On January 5, 2011, the Company granted options to acquire up to 187,500 Class A shares at a price of $1.19 per share, none of which were granted to officers or directors of the Company.

Depletion and depreciation ("D&D")

The Quarter provision for D&D totaled $4.9 million ($5.7 million – Previous Quarter; $6.0 million – Q1 2010). On a unit-of-production basis, D&D costs averaged $23.54 per boe for Q1 2011 ($23.42 per boe – Previous Quarter; $20.45 per boe – Q1 2010). D&D per boe for Q1 2011 has remained consistent with Q4 2010. The increase in the depletable base due to capital spending on the new Wapiti wells during the quarter had a corresponding increase in the proven reserve base. In comparing the Quarter to the Prior Year Q1, the D&D per boe has increased due to a significant increase in depletable base due to the capital spending on the new Wapiti wells while there has been no corresponding increase in the proven reserve base.

Exploration and evaluation expenditures ("E&E")

During the Quarter, the Company expensed $0.2 million of pre-license exploration costs ($0.2 million – Previous Quarter; nil – Q1 2010). The expenditures are due to efforts relating to new core areas to the Company and relate mostly to geological and geophysical costs associated with new prospective plays.

Unrealized gains (losses) on financial contracts

The Company has elected not to use hedge accounting and accordingly, the fair value of the financial contracts (as discussed in Note 4 of the unaudited condensed interim consolidated financial statements) is recorded at each period end. The fair value may change substantially from period to period based on the period ending commodity forward strip prices for the financial contracts outstanding at the balance sheet date. The change in fair value from period end to period end is reflected in the earnings for that period. As a result, earnings may fluctuate considerably based on the period ending commodity forward strip prices.

The fair value at March 31, 2011 of commodity contracts outstanding was an unrealized loss or a liability, net of unrealized gains, of $2.4 million (December 31, 2010 – unrealized loss (liability) of $1.0 million). During the Quarter, the Company recorded an unrealized loss of $1.4 million as a result of the change in fair value over the respective periods ($1.7 million loss – Previous Quarter; $2.7 million gain – Q1 2010). Forward strip prices for crude oil have increased during Q1 2011 resulting in unrealized losses for the quarter while natural gas prices have decreased only slightly from the year end 2010 prices resulting in offsetting unrealized gains for Q1 2011.

Future income taxes

A future income tax recovery of $1.0 million has been recorded for the Quarter (a recovery of $0.9 million – Previous Quarter; an expense of $0.9 million – Q1 2010). As the Company has recorded a loss before taxes for the Quarter, a recovery for future income taxes is expected. No current tax expense has been recorded as Seaview is not subject to capital taxes and has no current income tax liability.

Net loss and funds flow from operations

Net loss for the Quarter was $2.8 million ($2.9 million net loss – Previous Quarter; $0.2 million net loss – Q1 2010). Basic and diluted net loss per share for the Quarter was $0.04 (basic and diluted net loss per share of $0.04 – Previous Quarter; basic and diluted net loss per share of nil – Q1 2010). Funds flow from operations was $2.9 million for the Quarter ($3.9 million – Previous Quarter; $4.4 million – Q1 2010). Basic and diluted funds flow from operations per share for the Quarter was $0.05 (basic and diluted funds flow from operations per share was $0.06 – Previous Quarter; basic and diluted funds flow from operations per share was $0.07 – Q1 2010).

Netbacks, Funds Flow from Operations and Net Loss *($/boe)*

	Q1 2011	Q4 2010	Q1 2010
Petroleum and natural gas sales	**$ 31.70**	$ 31.45	$ 36.98
Less:			
Royalties	**3.65**	3.02	5.92
Operating expenses	**8.36**	5.44	11.10
Transportation expense	**1.43**	1.63	1.29
Net operating income (operating netback)	**$ 18.26**	$ 21.36	$ 18.67
General and administrative	**2.40**	3.52	2.28
Finance expense	**2.05**	1.55	1.84
Funds flow from operations	**$ 13.81**	$ 16.29	$ 14.55
Depletion and depreciation	**23.54**	23.42	20.45
Unrealized (gain) loss on financial derivatives	**6.71**	7.07	(9.14)
Stock option compensation	**0.69**	0.65	1.08
Pre-license expenditures and other	**0.80**	0.56	-
Future income tax (reduction) expense	**(4.65)**	(3.50)	2.97
Net loss *($/boe)*	**$ (13.28)**	$ (11.91)	$ (0.81)

SELECTED QUARTERLY INFORMATION

Financial ($000's except per share amounts) [4]	**Q2 2009** (CGAAP)	**Q3 2009** (CGAAP)	**Q4 2009** (CGAAP)	**Q1 2010** (restated)	**Q2 2010** (restated)	**Q3 2010** (restated)	**Q4 2010** (restated)	**Q1 2011**
Petroleum and natural gas sales	$ 7,463	$ 8,664	$ 10,377	$ 11,056	$ 8,893	$ 6,486	$ 6,950	$ 6,382
Funds flow from operations [1]	3,076	4,110	5,024	4,441	4,321	4,388	3,938	2,947
Basic per share	0.06	0.06	0.08	0.07	0.07	0.07	0.06	0.05
Diluted per share [2]	0.06	0.06	0.08	0.07	0.06	0.07	0.06	0.05
Net income (loss)	(3,273)	(2,907)	(2,366)	(235)	9,953	(777)	(2,895)	(2,778)
Basic per share	(0.06)	(0.04)	(0.04)	0.00	0.15	(0.01)	(0.04)	(0.04)
Diluted per share [2]	(0.06)	(0.04)	(0.04)	0.00	0.13	(0.01)	(0.04)	(0.04)
Capital expenditures [3]	1,354	3,931	5,368	8,017	4,758	5,556	11,517	12,967
Property acquisitions (dispositions)	26,615	-	3,840	-	(16,807)	-	3,315	-
Net debt	36,107	36,131	40,309	43,896	11,230	12,395	23,240	33,244
Shares outstanding at period end (000's)								
Class A	54,172	65,419	65,433	65,454	65,479	65,489	65,537	65,553
Subscription receipts	11,246	-	-	-	-	-	-	-
Class B	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054
Operations								
Daily production								
Natural gas (mcf/d)	9,976	12,486	13,703	16,544	17,084	13,299	14,016	12,286
Light oil and NGLs (bbl/d)	403	432	445	480	374	322	305	277
Total production (boe/d)	2,066	2,513	2,729	3,237	3,221	2,538	2,641	2,325
Natural gas (per mcf)	$ 5.79	$ 5.43	$ 6.06	$ 5.12	$ 4.59	$ 4.34	$ 4.48	$ 4.38
Light oil and NGL (per bbl)	60.20	61.03	66.92	72.92	70.87	64.46	66.27	71.78
Netback per boe								
Sales price (net of risk management gains or losses)	$ 39.70	$ 37.47	$ 41.33	$ 36.98	$ 32.57	$ 30.89	$ 31.45	$ 31.70
Royalties	4.57	3.50	4.52	5.92	4.83	2.14	3.02	3.65
Operating expenses	12.86	11.34	11.80	11.10	8.07	5.12	5.44	8.36
Transportation	1.49	1.35	1.27	1.29	1.38	1.48	1.63	1.43
Operating netback	$ 20.78	$ 21.28	$ 23.74	$ 18.67	$ 18.29	$ 22.15	$ 21.36	$ 18.26

(1) The Company uses "funds flow from operations" and "funds flow from operations per share" which do not have any standardized meaning prescribed by IFRS. The terms are used to analyze operating performance and leverage. The Company uses "Netback per boe" and "Operating Netback" which do not have any standardized meaning prescribed by IFRS. The terms are used to evaluate performance and in capital allocation decisions.
(2) Weighted average diluted shares outstanding for Q2 2010 includes the impact of the conversion of the Class B shares and the effect of the granted options. All other quarters exclude both the conversion of the Class B shares and the effect of the granted options as they would have been anti-dilutive.
(3) Capital expenditures include the cash additions for the period.
(4) The quarterly table contains both IFRS and CGAAP numbers. Comparatives before 2010 have not been restated to reflect the changes in accounting policies as a result of adopting IFRS.

SHARE INFORMATION

	Three months ended March 31	
	2011	2010
Weighted average shares outstanding		
Basic and diluted	**65,542,004**	65,438,024
Outstanding securities at period end		
Class A shares	**65,553,018**	65,453,933
Convertible Class B shares	**1,053,540**	1,053,540
Options, Class A shares	**5,589,500**	5,453,499
Outstanding securities at June 20, 2011		
Class A shares	**65,553,018**	
Convertible Class B shares	**1,053,540**	
Options, Class A shares	**5,589,500**	

Per share amounts have been calculated using the weighted average number of shares outstanding during the year. The effect of the conversion of the Class B shares and the effect of options granted have both been excluded in the diluted share calculation for the three months ended March 31, 2011 and 2010 as they would have been anti-dilutive.

The Company's Class B shares are convertible (at the option of the Company) at any time after June 1, 2010 and before May 31, 2012, into Class A shares. The number of Class A shares obtained upon the conversion of each Class B share will be equal to $10.00 divided by the greater of $1.00 and the weighted average trading price of the Class A shares during the thirty days prior to the conversion date. If conversion has not occurred by the close of business on May 31, 2012, the Class B shares become convertible (at the option of the holder) into Class A shares on the same basis. Effective June 30, 2012, all remaining Class B shares will automatically convert to Class A shares.

CAPITAL EXPENDITURES

For the Quarter, capital expenditures totaled $13.1 million ($15.2 million – Previous Quarter; $8.4 million – Q1 2010). The table below summarizes the capital expenditures during the Quarter, the Previous Quarter and Q1 2010.

($000's)	**Q1 2011**	Q4 2010	Q1 2010
Geological and geophysical	**$ -**	$ 153	$ 12
Drilling and Completions (gross)	**8,538**	13,015	4,508
Alberta Drilling Credits	**-**	-	(1,559)
Tangible equipment	**4,160**	3,298	1,661
Development Capital	**$ 12,698**	$ 16,466	$ 4,622
Exploration & evaluation capital (note 9)	**399**	(1,382)	3,680
Asset retirement obligations	**43**	102	73
Total capital expenditures	**$ 13,140**	$ 15,186	$ 8,375

For the quarter ending March 31, 2011, the Company drilled one successful horizontal well. This well and a previously drilled well were completed with multi-frac completion techniques. The capital expenditures for the quarter included these drilling and completion costs as well as pipeline and facility costs to bring these wells on production at the end of the quarter or beginning of Q2 2011. As of March 31, 2011, the Company earned a total of $6.2 million dollars of Alberta Royalty Drilling Credits of which $2.3 million had been collected and $0.4 million remains in accounts receivable. Due to the low commodity price environment during this credit program, the Company did not incur sufficient Crown royalty expense to collect the remaining $3.5 million. As most companies that earned credits during this program also had excess credits over royalty expense, there was no market to sell any of these surplus credits and accordingly, these amounts expired at March 31, 2011.

CAPITALIZATION AND CAPITAL RESOURCES

The Company's total capitalization was $130.7 million at March 31, 2011 with the market value of Class A and Class B shares representing 75% of the total capitalization ($109.9 million at December 31, 2010 with the market value of Class A and Class B shares representing 79%). The market value of the Company's shares at March 31, 2011 was $97.4 million ($86.6 million – December 31, 2010).

Capitalization	**March 31, 2011**	December 31, 2010
Bank debt ($000's)	**$ 26,522**	$ 16,494
Working capital deficiency ($000's)[1]	**6,721**	6,746
Net debt ($000's)	**33,243**	23,240
Class A shares outstanding	**65,553,018**	65,536,768
Class A share price [2]	**$ 1.35**	$ 1.19
Class A market capitalization ($000's)	**$ 88,497**	$ 77,989
Class B shares outstanding	**1,053,540**	1,053,540
Class B share price [2]	**$ 8.46**	$ 8.20
Class B market capitalization ($000's)	**$ 8,913**	$ 8,639
Total market capitalization ($000's)	**$ 97,410**	$ 86,628
Total capitalization ($000's)	**$ 130,653**	$ 109,868
Net debt as a percent of total capitalization	**25%**	21%
Funds flow from operations ($000's)[3]	**$ 11,792**	$ 17,088
Net debt to funds flow from operations ratio	**2.82**	1.36

(1) Working Capital excludes the current portion of deferred income taxes and financial contracts.

(2) Represents the closing price on the TSX Venture Exchange at period end.

(3) Funds flow from operations is calculated as cash flow from operations before the change in non-cash operating working capital and expenditures on abandonments. Funds flow from operations at March 31, 2011 is the Quarter funds flow of $2.9 million annualized.

Bank facility

As at March 31, 2011, the Company had a revolving demand credit facility with an authorized borrowing amount of $52 million, with interest and other fees charged at the bank's prime rate plus a rate as determined by a pricing grid. Collateral for the facility consists of a general security agreement, providing a security interest over all present and after acquired personal property and a floating charge on all present and after acquired land interests of the Company.

At March 31, 2011, the revolving demand credit facility was drawn to $26.5 million. The Company also had an issued letter of credit in the amount of approximately $0.1 million.

The next interim review is scheduled for September, 2011. These reviews are based primarily on reserves and using commodity prices estimated by the lender, as well as other factors. A decrease in the borrowing base could result in a reduction to the credit facility available upon the next scheduled review which may require a repayment to the bank.

Investing program funding

	Three months ended March 31	
($000's)	**2011**	2010
Funds flow from operations	**$ 2,947**	$ 4,441
Changes in non-cash working capital	**(25)**	5,631
Expenditures on abandonments	**(2)**	(21)
Proceeds from issuance of shares/options (net of costs)	**19**	10
Proceeds from (repayment of) bank debt	**10,028**	(2,044)
Change in cash during the period	**-**	-
Capital expenditures funded by cash during the period	**$ 12,967**	$ 8,017

The Company's capital investment program during the relevant periods was funded by the issuance of equity, draws or repayments on credit facilities and cash flows.

Working capital

The capital intensive nature of the Company's activities may create a negative working capital position in periods with high levels of capital investment. The working capital (excluding the current portion of financial contracts) increased to a deficit of $33.2 million as at March 31, 2011 from a deficit of $23.2 million as at December 31, 2010 as a result of the capital program during the quarter and decreased from a deficit of $43.9 million as at March 31, 2010 as a result of the disposition of the Saskatchewan assets in April 2010 for proceeds of $33.1 million, offset by the capital program during the year.

Substantially all of the Company's petroleum and natural gas production is marketed to purchasers with investment grade credit ratings. The industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of crude oil and natural gas. This occurs on the 25th day following the month of sale. As a result, the Company's production revenues are collected in a timely fashion. The Company monitors its revenue counterparty credit positions to mitigate any potential credit losses. To the extent the Company has joint interest partners in its activities it must collect, on a monthly basis, all of its partners' share of capital and operating expenses. These are subject to normal collection risk. The Company normally collects significant amounts related to partners' share of capital amounts in advance of expenditures taking place, in accordance with standard industry operating procedures. Accounts payable consist of amounts payable to suppliers on field operating activities and capital spending activities. These invoices are processed within the Company's normal payment period. At March 31, 2011, the Company had no material accounts receivable that it deemed uncollectible.

The Company actively manages its capital structure. The Company's objectives when managing capital are to maintain a flexible capital structure to allow it to execute on its capital investment program, which includes investing in oil and gas activities that may or may not be successful. The Company will strive to balance the proportion of debt and equity in its capital structure to take into account the level of risk being incurred in its capital expenditures.

GUARANTEES/OFF-BALANCE SHEET ARRANGEMENTS

The Company has no guarantees or off-balance sheet arrangements, except for certain lease agreements. Seaview has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or G&A expense depending on the nature of the lease. No asset or liability value has been assigned to these leases on the balance sheet as at March 31, 2011. The total future obligation from these operating leases is described below in the section "Contractual obligations and commitments".

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company must pay Crown royalties, surface rentals, mineral taxes and abandonment and reclamation costs with respect to its ongoing ownership of hydrocarbon production rights. The amounts paid with respect to these burdens will depend on the future ownership, production, commodity prices and regulatory environment at the time.

The Company enters into natural gas and crude oil financial contracts from time to time, some of which may have premiums attached to them (see Note 4). The future premiums Seaview is committed to pay are included in the table below.

The Company's future contractual commitments are highlighted below:

		Total	2011	2012
Operating leases	$	478	215	263
Financial instrument premiums	$	1,183	1,183	-
Total contractual obligations	$	1,661	1,398	263

OUTLOOK

The Company's focused long-life, low cost Peace River Arch assets and available credit capacity provides a stable capital base to support continued capitalization of Seaview's emerging Wapiti Cardium light oil resource play. Management believes that continued improvement on the latest LPG based fracture treatments has significantly enhanced the economic viability of Wapiti.

The drilling program over the remainder of 2011 will be financed through available cash-flow and focus on completing earning on farm-in lands as first priority and drilling development locations offsetting existing Cardium horizontal producers offering the highest potential.

Seaview has the following characteristics:

- Total Proven reserves of 6,578 Mboe (23% light oil and natural gas liquids);
- Total Proven plus Probable reserves of 11,823 Mboe (26% light oil and natural gas liquids), effective December 31, 2010, as evaluated by Sproule Associates Ltd. using National Instrument 51-101 reserve definitions;
- Reserve life index is 13.9 years based on Total Proven plus Probable reserves and Q1 2011 production of 2,325 boe per day;
- Seaview has established significant positions in resource plays providing for longer-term growth potential in a diverse portfolio of assets targeting both light oil and natural gas plays, including:
    - In Wapiti, the Company has assembled a sizable land position targeting a Cardium light oil resource play:
        - Exposure to earn up to 42.5 sections (22.8 net) of prospective Cardium rights;
        - An extensive drilling inventory with over 170 horizontal development locations (91 net);
        - Scalable project targeting high quality light oil (41 degree API), and natural gas with high liquid recovery NGL's; and
        - Excellent operational focus featuring a large contiguous land position directly offsetting the Company's recent successful Cardium exploration activities.
    - In Pouce Coupe, the Company holds interests in 21 sections (4.5 net) of land targeting a Doig-Montney natural gas resource play. Seaview's land position is on trend with successful industry development activities further reducing the risk of full development when economics are more viable;
- Commodity hedging program providing for downside protection on 8,913 mcfe per day for 2011 at a "net of cost" floor price of $5.50/mcfe, providing minimum 2011 revenue of $17.9 million; and
- 65.55 million Class A shares and 1.0 million Class B shares outstanding, as at March 31, 2011.

CRITICAL ACCOUNTING ESTIMATES

The reader is advised that the critical accounting estimates, policies and practices as described in the MD&A at December 31, 2010 in conjunction with those discussed in the notes to the unaudited condensed interim consolidated financial statements at March 31, 2011 continue to be critical in determining Seaview's financial results as at March 31, 2011.

CHANGES IN ACCOUNTING POLICIES AND RECENT ACCOUNTING PRONOUNCEMENTS

International Financial Reporting Standards ("IFRS")

On January 1, 2011, the Company transitioned to IFRS, with the date of adoption of January 1, 2010. On the date of adoption, the Company restated the account balances to IFRS and the financial reporting will be in accordance with IFRS hereafter. A full description of the new accounting policies is outlined in Note 3 to the unaudited condensed interim consolidated financial statements. Additionally, transition date information and reconciliations between IFRS and previous GAAP for comparative periods in 2010 are described in Note 15 to the unaudited condensed interim consolidated financial statements. The adoption of IFRS has not led to any changes in the business operations, capital strategies or funds flow of the Company.

Seaview's significant areas of impact include property, plant and equipment, share based payments, depletion, depreciation and accretion and Class B share classification. The following discussion provides an overview of these areas as well as the exemptions available under IFRS 1, "First-time Adoption of International Financial Reporting Standards" ("IFRS 1"). IFRS 1 provided entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS.

- Property, plant and equipment ("PP&E"): Under previous GAAP, Seaview applied full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves were capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre were depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, Seaview has adopted new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs, as discussed below.

  Pre-exploration costs are expenditures incurred prior to obtaining the legal right to explore and must be expensed under IFRS. Under previous GAAP, Seaview capitalized and depleted such costs within the full cost pool. These costs are not anticipated to be significant to the Company.

  Exploration and Evaluation costs ("E&E") are expenditures incurred for an area or property for which technical feasibility and commercial viability has not been determined. Upon transition to IFRS, Seaview has re-classified all E&E expenditures that were included in the PP&E balance under previous GAAP on the consolidated balance sheet. This includes the cost for Seaview's undeveloped exploratory land that relates to exploration properties. Seaview will not amortize its E&E assets but will assess them for impairment when there are indicators for possible impairment, such as allowing the mineral rights lease to expire or a decision to no longer pursue exploration and evaluation of a specific E&E asset, at which time the costs would be expensed. Upon transition to IFRS, approximately $0.4 million of PP&E was reclassified on the balance sheet to intangible exploration costs representing E&E assets.

  Development costs are expenditures incurred for an area or property where technical and commercial feasibility has been determined. Seaview will continue to capitalize these costs. Under previous GAAP, these costs were depleted on a unit-of-production basis at a country cost centre level but under IFRS these costs will be depleted on a unit-of-production basis over an area level (unit of account). Also under IFRS, a company has the option of choosing the reserve base that it will use for its depletion calculation, whether proven reserves, which is consistent with previous GAAP, or proven plus probable reserves. Seaview has determined that it will use proven reserves as the basis over which its depletion will be calculated. Accordingly, depletion costs will be consistent with the amount that would have been calculated under previous GAAP.

  Divestitures of an oil and gas property under IFRS will generally result in a gain or loss recognized in earnings. Under previous GAAP, proceeds of divestitures were deducted from the full cost pool without recognition of a gain or loss unless such a deduction resulted in a change to the depletion rate of 20 percent or greater. Seaview has a restatement to the comparative second quarter 2010 financial statements showing a gain on sale regarding the disposition of our Saskatchewan properties in April 2010.

  As at the date of transition, being January 1, 2010, for entities using the full cost accounting method, IFRS 1 provided an option to deem the cost of its PP&E assets to equal its previous GAAP net book value. Seaview has applied this option. The IFRS E&E costs will be equal to those that would have been recognized as such under previous GAAP using proved plus probable reserves as a basis for determining technical feasibility and commercial viability. The remaining net book value of the full cost pool on the date of transition following the removal of E&E costs was allocated to the unit of account development cost centres on the basis of Seaview's proved plus probable reserve values.

- Impairment of PP&E assets: Under IFRS, impairment tests of PP&E must be performed at a cash-generating unit level instead of at the country cost centre under previous GAAP using the greater of value in use or fair value less costs to sell. Assets will be assessed for impairment when indicators suggest the possibility of impairment; therefore, there may be more frequent impairments of assets under IFRS. Under IFRS, impairment losses, other than goodwill, are reversed when there is an increase in the recoverable amount. Seaview has grouped its assets into cash-generating units, which were identified on the basis of cash inflows being independent from other assets or groups of assets, and will test them for impairment using the greater of value in use or fair value less costs to sell. Assets were required to be assessed for impairment upon transition to IFRS. A small impairment of oil and gas assets of approximately $2.5 million was calculated on transition to IFRS, having used the fair value less costs to sell to measure the fair value of its cash-generating units. As well, Seaview has determined an impairment to its Goodwill balance at transition which has been written off from its opening IFRS balance sheet as at January 1, 2010.

- Provisions: Under IFRS, decommissioning obligations, disclosed as asset retirement obligations under previous GAAP, can be calculated using either a risk free discount rate, which differs from previous GAAP, or a credit adjusted risk-free interest rate, which is consistent with previous GAAP, to discount future cash flows. Seaview has used the credit adjusted risk-free rate and therefore charges remain the same as the amount that had been calculated under previous GAAP. Under IFRS, the unwinding of the discount rate is charged as interest expense versus accretion expense under previous Canadian standards.

- Share based compensation: Under IFRS 2 "Share-based Payments", awards that vest in installments must be accounted for as though each installment is a separate award and amortized using a graded vesting model. This results in front loading of share based compensation expense. In addition, under IFRS, a forfeiture rate must be included in the initial expense calculation, and adjusted prospectively if required, rather than accounting for forfeitures as they occur. IFRS 1 allows for an exemption from IFRS 2 for share based payments which have vested before Seaview's transition to IFRS. As a result of applying IFRS 2, the Company has an increase to contributed surplus of approximately $1.3 million with a corresponding increase to the January 1, 2010 deficit.

- Income taxes: IFRS does not use the terminology of future income taxes; IFRS refers to deferred income taxes. The transition to IFRS requires the Company to re-measure its deferred income taxes for its January 1, 2010 balance sheet. Adjustments to deferred income taxes were made accordingly in conjunction with other transitionary IFRS adjustments discussed earlier, with an offsetting adjustment to the January 1, 2010 deficit.

  In addition to the adjustments required to deferred income taxes as a result of the January 1, 2010 transitionary adjustments, the Company has made adjustments for its comparative periods in 2010 for share issue costs, flow-through shares and the reclassification of the Class B shares as a liability. Under previous GAAP, the accounting treatment of flow-through shares is addressed by EIC 146 – "Flow-Through Shares". The proceeds received for the flow-through shares are credited to shareholders' capital and the deferred tax liability is recognized when the company files the renouncement documents with the tax authorities to renounce the tax credits associated with the expenditures.

  Under IFRS, Seaview has set up a liability for the difference between the proceeds received and the market price of the shares on the date of the transaction (the "premium"). As the qualifying expenditures are incurred, Seaview will record the tax liability associated with the expenditures and renouncements of the tax benefits and reverse the deferred liability originally set up related to those costs incurred in a particular quarter. The difference between the deferred tax liability and the original liability set up will go through profit and loss.

  A temporary difference exists for share issue costs under previous GAAP and IFRS. The difference between previous GAAP and IFRS result in a deferred tax liability being recorded. Unlike previous GAAP, changes in the deferred tax liability are recognized where they were originally recognized; therefore, changes in the deferred tax liability related to share issue costs are recorded against share capital as opposed to profit and loss. The Company does not have any transitionary adjustments related to share issue costs.

- Risk-Sharing Arrangements and Dispositions: Under IFRS, risk-sharing agreements in which Seaview cedes a portion of its working interest to a third party are generally considered to be disposals of property, plant and equipment, potentially resulting in a gain or loss on disposition. Under previous GAAP, no gain or loss was recorded on these or other dispositions where the change in consolidated depletion is less than 20 percent. There is no equivalent exemption in IFRS. As a result, Seaview will record gains or losses on risk-sharing arrangements and other disposition transactions under IFRS. There is no impact on transition to IFRS as a result of this requirement. Subsequent to transition, the significance of these gains or losses will be dependent on the details of specific transactions.

- Business Combinations: An exemption under IFRS 1 provides the entity with relief on the restatement of business combinations prior to the transition date. Under IFRS 3 – "Business Combinations", the determination of the fair value of share consideration differs from the determination under previous Canadian accounting standards. Any difference in the fair value calculation would have a resulting impact on the carrying amount of net assets acquired, non-controlling

interest and any goodwill. The Company has made the election under IFRS 1, allowing Seaview to be exempt from restating business combinations prior to the transition date to IFRS.

- Convertible Class B share liability: Under previous GAAP, the Company's convertible Class B shares were presented as equity while under IFRS, the Class B shares do not qualify for equity presentation and must be presented as a liability. This is because the number of Class A shares required to be issued on conversion is not known until the Company exercises the conversion. As such, the Company has retrospectively adjusted the presentation of its $11.7 million Initial Public Offering ("IPO") on October 17, 2007, which included the convertible Class B shares.
- Seaview does not expect changes to its financial statements as a result of IFRS to affect any covenants related to bank debt.

Seaview is determining which additional changes to internal controls over financial reporting will be required to deal with the changes in accounting policies. This will be ongoing throughout the balance of 2011 to ensure all changes in accounting policies include appropriate additional controls and procedures for future IFRS reporting requirements. Seaview does not expect any material changes to internal controls.

NEW AND PENDING ACCOUNTING STANDARDS

IFRS 9 – Financial Instruments.

In November 2009, the IASB published IFRS 9 "Financial Instruments" which covers the classification and measurement of financial assets as part of its project to replace IAS 39 "Financial Instruments: Recognition and Measurement". IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity managed its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39.

In October 2010, additional requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit and loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to own credit risk out of profit and loss and recognize the change in other comprehensive income.

IFRS 9 will become effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The implementation of this issued standard is not expected to have a significant impact on the Company's financial position or results.

IAS 12 – Income Taxes

IAS 12 "Income Taxes" was amended on December 21, 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. The Company is currently evaluating the impact of this amendment to its financial statements.

RISK ASSESSMENT

The reader is advised that the risk assessment for the Company is fully described in the MD&A at December 31, 2010 and is relevant to the readers' understanding of the Company's financial results as at March 31, 2011.

ADDITIONAL INFORMATION

Additional information relating to the Company is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Seaview Energy Inc. 1500, 444 - 5th Avenue S.W., Calgary, Alberta, Canada T2P 2T8 or by email at info@Seaviewenergy.com. Information is also accessible on the Company's web site at www.Seaviewenergy.com.

COMMONLY USED ABBREVIATIONS

boe	Barrel of oil equivalent
boe/d	Barrel of oil equivalent per day
gj	Gigajoule
gj/d	Gigajoule per day
mboe	Thousand barrels of oil equivalent
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
mmcf	Million cubic feet
mmcf/d	Million cubic feet per day
bbl	Barrel
bbl/d	Barrels per day
MMBTU	Million British Thermal Units
6:1	Boe conversion ratio of six mcf to one bbl

CORPORATE INFORMATION

OFFICERS AND SENIOR MANAGEMENT

Michael J.J. Wuetherick, P.Eng
President and Chief Executive Officer

H. Scott Oldale
Vice President, Exploration and Chief Operating Officer

Stephanie A. Bunch, CA
Vice President, Finance and Chief Financial Officer

Davin Chandler, P.Eng
Vice President, Engineering

Timothy L. Campbell
Vice President, Land

DIRECTORS

Daryl Gilbert, *P.Eng, Calgary, Alberta*
Chairman
Reserves Committee Chair and
Health, Safety & Environment Committee Chair

James Howe, [4] *CA, Calgary, Alberta*
Audit Committee Chair

Gregory Turnbull, [3] *LLB, Calgary, Alberta*
Corporate Governance Committee Chair

Steven VanSickle, [1],[2],[5] *Calgary, Alberta*
Compensation Committee Chair

Robert Peters, [3],[4] *Calgary, Alberta*
Director

Michael Culbert, [1] *Calgary, Alberta*
Director

Bruce Francis, [2],[5] *P.Eng, Calgary, Alberta*
Director

Michael J.J. Wuetherick, *P.Eng, Calgary, Alberta*
President, Chief Executive Officer and Director

H. Scott Oldale, *Calgary, Alberta*
Vice President, Exploration, Chief Operating Officer and Director

Sanjib Gill, *LLB, Calgary, Alberta*
Corporate Secretary

[1] *Member of the Audit Committee*
[2] *Member of the Reserves Committee*
[3] *Member of the Compensation Committee*
[4] *Member of the Corporate Governance Committee*
[5] *Member of the Health, Safety and Environment Committee*

BANKERS
National Bank of Canada

PETROLEUM CONSULTANTS
Sproule Associates Limited
Calgary, Alberta

LEGAL COUNSEL
McCarthy Tétrault LLP
Calgary, Alberta

AUDITORS
KPMG LLP
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT
Olympia Trust Company
Calgary, Alberta

STOCK EXCHANGE LISTING
TSX - Venture: CVU.A & CVU.B

INVESTOR RELATIONS

Telephone: (403) 450-3713
Investor Toll Free: 1-877-242-0222
E-mail: info@seaviewenergy.com

1500, 444-5th Avenue SW
Calgary, Alberta
Canada T2P 2T8

Telephone: (403) 450-3713
Toll Free: 1-877-242-0222
Facsimile: (403) 668-9177

Email: info@seaviewenergy.com
Website: www.seaviewenergy.com