NUVISTA ENERGY LTD

SECOND QUARTER INTERIM REPORT 2009

Press Release August 13, 2009

Calgary – NuVista Energy Ltd. is pleased to announce its financial and operating results for the three and six months ended June 30, 2009, as follows:

Corporate Highlights

	Three months ended June 30, 2009	2008	% Change	Six months ended June 30, 2009	2008	% Change
Financial						
($ thousands, except per share)						
Production revenue	78,092	161,712	(52)	169,821	258,760	(34)
Funds from operations (1)	41,779	89,582	(53)	98,442	143,016	(31)
Per share – basic	0.53	1.14	(54)	1.24	2.05	(40)
Per share – diluted	0.53	1.11	(52)	1.24	2.02	(39)
Net earnings (loss)	(7,312)	2,905	(352)	(4,680)	10,054	(147)
Per share – basic	(0.09)	0.04	(325)	(0.06)	0.14	(143)
Per share – diluted	(0.09)	0.04	(325)	(0.06)	0.14	(143)
Total assets				1,429,854	1,356,172	5
Long-term debt, net of working capital				350,580	365,282	(4)
Long-term debt, net of adjusted working capital (1)				351,451	338,900	4
Shareholders' equity				812,128	728,591	11
Total capital expenditures	8,318	16,213	(49)	89,546	67,114	33
Corporate acquisition (non-cash)	-	-	-	-	594,944	-
Weighted average common shares outstanding (thousands):						
Basic	79,209	78,830	-	79,187	69,754	14
Diluted	79,209	80,368	(1)	79,187	70,753	12
Operating						
(boe conversion – 6:1 basis)						
Production						
Natural gas (mmcf/d)	109.6	113.0	(3)	110.9	99.2	12
Natural gas liquids (bbls/d)	3,247	2,609	24	3,138	1,857	69
Oil (bbls/d)	4,269	4,714	(9)	4,358	4,349	-
Total oil equivalent (boe/d)	25,777	26,153	(1)	25,974	22,746	14
Product prices (2)						
Natural gas ($/mcf)	4.52	9.44	(52)	5.53	8.74	(37)
Natural gas liquids ($/bbl)	32.00	81.88	(61)	35.46	80.65	(56)
Oil ($/bbl)	64.14	91.82	(30)	59.66	84.95	(30)
Operating expenses						
Natural gas and natural gas liquids ($/mcfe)	1.05	1.16	(9)	1.11	1.15	(3)
Oil ($/bbl)	15.69	13.76	14	16.31	12.34	32
Total oil equivalent ($/boe)	7.84	8.19	(4)	8.27	7.95	4
General and administrative expenses ($/boe)	1.61	1.52	6	1.43	1.40	2
Funds from operations netback ($/boe) (1)	17.81	37.64	(53)	20.95	34.56	(39)

NOTES:

(1) Funds from operations, funds from operations per share, funds from operations netback and adjusted working capital are not defined by GAAP in Canada and are referred to as non-GAAP measures. Funds from operations are based on cash flow from operating activities as per the statement of cash flows before changes in non-cash working capital and asset retirement expenditures. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net earnings (loss) per share. Funds from operations netback equals the total of revenues including realized commodity derivative gains/losses less royalties, transportation, general and administrative, restricted stock units, interest expenses and cash taxes calculated on a boe basis. Adjusted working capital excludes the current portions of the commodity derivative asset or liability and the future income tax asset or liability. Total boe is calculated by multiplying the daily production by the number of days in the period. For more details on non-GAAP measures, refer to "Management's Discussion and Analysis" section of this press release.

(2) Product prices include realized gains/losses on commodity derivatives.

MESSAGE TO SHAREHOLDERS

NuVista Energy Ltd. ("NuVista") is pleased to report to its shareholders the financial and operating results for the three and six months ended June 30, 2009. During the second quarter of 2009, natural gas prices declined significantly as continued weakness in the North American economy reduced demand for natural gas and supply from United States production remained relatively strong. We responded to lower natural gas prices by taking a disciplined approach to our capital program, focusing on financial flexibility and completing a strategic property acquisition. We believe that we have positioned NuVista to create significant shareholder value when natural gas prices recover by taking this time to build our drilling inventory and make strategic and timely acquisitions.

During the second quarter of 2009, we achieved average production of 25,777 boe/d, approximately 600 boe/d less than expected due to unscheduled third party plant outages but only slightly lower than production of 26,175 boe/d in the first quarter of 2009. Lower natural gas prices had an impact on second quarter funds from operations; however, this decline was partially mitigated by $9.2 million of gains realized from our financial and physical sale price risk management program. During the second quarter, exploration and development capital expenditures were $10.7 million as we focused on debt reduction following the $54 million property acquisition in January 2009 and responded to lower natural gas prices.

Significant highlights for NuVista in the second quarter:

- Implemented an $8.3 million exploration and development capital program that was primarily directed toward our Oyen core area in order to maximize the benefit of Alberta royalty drilling credits. In addition, our drilling program benefited from lower drilling and completion costs resulting from reduced industry activity levels. During the second quarter, we participated in 13 (11.8 net) wells with a 77% success factor;

- Entered into an agreement to purchase strategic properties located in the Martin Creek area of British Columbia and in Northwest Alberta for cash consideration of approximately $174 million. This acquisition closed on July 27, 2009;

- Entered into agreements to issue 9.0 million subscription receipts for gross proceeds of $99 million in order to fund a significant portion of the acquisition with equity. The subscription receipt offerings closed on July 7, 2009 and on July 27, 2009 the subscription receipts were exchanged into common shares and the proceeds of the offerings were released from escrow; and

- Maintained financial flexibility by reducing net debt to approximately $334 million (after adjusting for the $18 million deposit relating to the recent property acquisition) from a peak net debt level of approximately $390 million following the property acquisition in January 2009.

Looking forward to the remainder of 2009, we will be focused on prudently managing NuVista's business plan during a period of low natural gas prices, integrating the recent property acquisition and continuing with our core capital program focused on evaluating plays with potential for significant development in 2010 and beyond.

Prudently Manage our Business Plan

We will continue to prudently manage NuVista's business during this period of low natural gas prices. We will continue to invest capital on strategic projects and pursue acquisition opportunities available in this environment, while maintaining our financial flexibility. We believe natural gas prices will increase as supply and demand fundamentals adjust but the timing of this increase is uncertain. During the first half of 2009, we managed our capital program in a disciplined manner spending less than cash flow on our drilling program and achieving our debt reduction targets. Our recent property acquisition was financed with a significant amount of equity in order to maintain our financial flexibility and during the second half of 2009, we will spend less than cash flow on our drilling program in order to further reduce debt levels following this latest acquisition. Our drilling program for the remainder of the year will be focused on evaluating resource gas plays with potential for follow-up drilling, lease expiries and competitive drainage situations. In response to low natural gas prices, NuVista plans to shut-in approximately 400 boe/d of high operating costs natural gas production in August and will consider shutting-in additional natural gas production if prices decline further. In addition, TCPL has notified us of pipeline constraints in our Northwest Alberta core area that are anticipated to continue until the first quarter of 2010 that will result in shut-in production of approximately 500 boe/d.

Integrate our Recent Property Acquisition

With the closing of the recent property acquisition on July 27, 2009, we will integrate these new properties into our business with a focus on optimizing production, reducing operating costs, building an inventory of drilling locations and evaluating small complementary acquisition opportunities. This acquisition was strategic and creates a new core area characterized by longer life reserves which lowers our overall corporate production decline rate and adds over 140,000 net undeveloped acres. These properties were acquired at attractive valuation metrics and are accretive to NuVista's production and reserves per share. These properties also will provide opportunities for continued growth over the long-term and they have significant leverage to rising natural gas prices. We have identified over 30 drilling opportunities on the acquired lands. These drilling opportunities are expected to be economically robust and generate favourable rates of return even in a low natural gas price environment and we are planning a nine well winter drilling program.

Evaluate Plays for Development in 2010

During the second half of 2009, our capital program will be focused on drilling the remaining nine wells in our Oyen core area drilling program and implementing horizontal drilling and multi-stage facing technology on several tight gas projects. With the extension of the Alberta royalty drilling credit into 2011, we have reallocated our capital program with less emphasis on the Oyen core area for the remainder of the year and prioritized plays with larger resource potential. During the second half of 2009, a horizontal Montney well will be drilled in our Fir/Kaybob core area where we have 10 vertical Montney producing wells on seven and one-half sections of land. This project may ultimately result in 5 to 10 additional horizontal Montney wells, beginning in 2010. In our Wapiti core area, we plan to investigate the thicker tight gas charged lower Dunvegan sands by drilling one horizontal well and we will follow up on the success of vertical wells in the upper Dunvegan zones by drilling two additional vertical wells. Also in our Wapiti core area, we plan to complete one additional vertical well in the Montney formation and monitor production from another vertical well brought on during the second quarter, and monitor drilling and completion results for horizontal Montney wells drilled by other companies in the greater Wapiti area. Both the Dunvegan and Montney plays, if successful, possess the size and scope to dramatically impact NuVista's capital program and financial results over the next five years.

Through challenging and at times difficult industry conditions, we continue to maintain a disciplined approach to our business. We will continue to employ an "acquire and develop" business model focused on reserves per share and production per share growth while maintaining our balance sheet strength. Due to low commodity prices and an uncertain economic environment, prudent financial management requires a responsive and flexible capital program in 2009 while continuing to plan for our future. For the remainder of 2009, we will continue to closely manage capital spending levels and focus on maintaining financial flexibility. We pride ourselves on being able to make business decisions based on timely and accurate data and this approach will continue to enable us to adapt to rapidly changing economic and market conditions.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of financial conditions and results of operations should be read in conjunction with NuVista's audited consolidated financial statements for the three and six months ended June 30, 2009 and the audited consolidated financial statements for the year ended December 31, 2008. The following MD&A of financial condition and results of operations was prepared at and is dated August 13, 2009. Our audited consolidated financial statements, Annual Report, Annual Information Form and other disclosure documents for 2008 are available through our filings on SEDAR at **www.sedar.com** or can be obtained from our website at **www.nuvistaenergy.com**.

> ***Basis of presentation –*** *The financial data presented below has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil, unless otherwise stated. In certain circumstances natural gas liquid volumes have been converted to thousand cubic feet equivalent ("mcfe") on the basis of one barrel of natural gas liquids to six thousand cubic feet. Boe's and mcfe's may be misleading, particularly if used in isolation. A conversion ratio of one barrel to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*
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> ***Forward-looking statements –*** *Certain information set forth in this document contain forward-looking statements, including management's assessment of NuVista's future plans and operations, forecast production and growth and production and reserves, drilling plans and results, NuVista's planned capital budget, targeted debt level, the timing, allocation and efficiency of NuVista's capital program and the results therefrom, forecast funds from operations and targeted operating costs, benefits from the Alberta Government's announcement of royalty incentives, expectations regarding the payment of future taxes,*

expectations regarding future commodity prices, netbacks and industry conditions which are provided to allow investors to better understand our business. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond NuVista's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management and services, stock market volatility, changes in environmental regulations, tax laws and royalties and the ability to access sufficient capital from internal sources and bank and equity markets. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. NuVista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, or if any of them do so, what benefits that NuVista will derive therefrom. NuVista disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP measurements – *Within MD&A, references are made to terms commonly used in the oil and natural gas industry. Management uses funds from operations to analyze operating performance and leverage. Funds from operations as presented, does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, per the statement of cash flows, net earnings (loss) or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net earnings (loss) per share. Funds from operations netbacks equal total revenue including realized commodity derivative gains/losses less royalties, transportation, operating costs, general and administrative, restricted stock unit, interest expense and cash taxes. Management also uses field netbacks to analyze operating performance and adjusted working capital to analyze leverage. Field netbacks and adjusted working capital as presented, do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities. Field netbacks equal the total of revenue including realized commodity derivative gains/losses less royalties, transportation and operating costs. Adjusted working capital equals working capital excluding the current portion of the commodity derivative asset or liability and the future income tax asset or liability. Total boe is calculated by multiplying the daily production by the number of days in the period.*

A reconciliation of funds from operations is presented in the following table:

	Three months ended June 30,		*Six months ended June 30,*	
($ thousands)	*2009*	*2008*	*2009*	*2008*
Cash provided by operating activities	*39,516*	*67,453*	*97,940*	*102,619*
Add back:				
Asset retirement expenditures	*614*	*483*	*1,189*	*537*
Change in non-cash working capital	*1,649*	*21,646*	*(687)*	*39,860*
Funds from operations	*41,779*	*89,582*	*98,442*	*143,016*

Plan of arrangement with Rider Resources Ltd. – On March 4, 2008, NuVista closed a business combination with Rider Resources Ltd. ("Rider" or the "Rider Acquisition") and a private placement financing with the Ontario Teachers' Pension Plan Board ("OTPP"). The Rider Acquisition resulted in the combination of NuVista and Rider, pursuant to which all of the issued and outstanding Rider shares were exchanged for common shares of NuVista. Rider shareholders received, for each Rider share held, 0.3540 of a NuVista share. The results of operations from the Rider assets have been included effective March 4, 2008.

Operating activities – During the second quarter of 2009, NuVista participated in 13 (11.8 net) wells, all of which were operated wells, with an average working interest of 91%. Of these wells, 12 were drilled in the Oyen core area and one in the West Central Saskatchewan core area. The success rate of 77% in this drilling program resulted in nine natural gas wells, one oil well and three dry holes. For the six months ended June 30, 2009, NuVista drilled 23 (17.4

net) wells resulting in 13 natural gas wells, five oil wells and five dry holes. NuVista has approximately 15 wells planned for the third quarter, primarily in our Oyen, Wapiti and Pembina core areas.

Production

Three months ended June 30,	2009	2008	% Change
Natural gas (mcf/d)	109,564	112,979	(3)
Liquids (bbls/d)	3,247	2,609	24
Oil (bbls/d)	4,269	4,714	(9)
Total oil equivalent (boe/d)	25,777	26,153	(1)

Six months ended June 30,	2009	2008	% Change
Natural gas (mcf/d)	110,870	99,238	12
Liquids (bbls/d)	3,138	1,857	69
Oil (bbls/d)	4,358	4,349	-
Total oil equivalent (boe/d)	25,974	22,746	14

For the three months ended June 30, 2009, NuVista's average production was 25,777 boe/d, comprised of 109.6 mmcf/d of natural gas, 3,247 bbls/d of associated natural gas liquids ("liquids") and 4,269 bbls/d of oil, This is a 1% decrease compared to the same period in 2008 and a 2% decrease compared to the three months ended March 31, 2009. The slight decrease in NuVista's production during the three months ended June 30, 2009 was primarily due to unscheduled downtime experienced at third-party gas processing plants primarily in the Wapiti and Pembina core areas.

NuVista's production for the six months ended June 30, 2009 averaged 25,974 boe/d comprised of 110.9 mmcf/d of natural gas, 3,138 bbls/d of liquids and 4,358 bbls/d of oil, which represents a 14% increase over the same period in 2008. Production increases for the six month period compared to the same period in 2008 are primarily due to the full inclusion of six months of Rider properties in 2009 compared to four months in 2008.

Revenues

Three months ended June 30,						
($ thousands, except per unit amounts)	2009		2008		% Change	
Natural gas	$	$/mcf	$	$/mcf	$	$/mcf
Production revenue	45,059	4.52	98,050	9.54	(54)	(53)
Realized gain (loss) on commodity derivatives	(2)	-	(1,026)	(0.10)	(100)	(100)
Total	45,057	4.52	97,024	9.44	(54)	(52)
Liquids	$	$/bbl	$	$/bbl	$	$/bbl
Production revenue	9,457	32.00	19,440	81.88	(51)	(61)
Realized gain (loss) on commodity derivatives	-	-	-	-	-	-
Total	9,457	32.00	19,440	81.88	(51)	(61)
Oil	$	$/bbl	$	$/bbl	$	$/bbl
Production revenue	23,576	60.69	44,222	103.09	(47)	(41)
Realized gain (loss) on commodity derivatives	1,341	3.45	(4,835)	(11.27)	128	131
Total	24,917	64.14	39,387	91.82	(37)	(30)

	Six months ended June 30,					
($ thousands, except per unit amounts)	2009		2008		% Change	
Natural gas	$	$/mcf	$	$/mcf	$	$/mcf
Production revenue	109,613	5.46	158,894	8.80	(31)	(38)
Realized gain (loss) on commodity derivatives	1,421	0.07	(1,026)	(0.06)	238	217
Total	111,034	5.53	157,868	8.74	(30)	(37)
Liquids	$	$/bbl	$	$/bbl	$	$/bbl
Production revenue	20,141	35.46	27,256	80.65	(26)	(56)
Realized gain (loss) on commodity derivatives	-	-	-	-	-	-
Total	20,141	35.46	27,256	80.65	(26)	(56)
Oil	$	$/bbl	$	$/bbl	$	$/bbl
Production revenue	40,067	50.80	72,610	91.73	(45)	(45)
Realized gain (loss) on commodity derivatives	6,986	8.86	(5,368)	(6.78)	230	231
Total	47,053	59.66	67,242	84.95	(30)	(30)

For the three months ended June 30, 2009, revenues including realized commodity derivative gains and losses, were $79.4 million, a 49% decrease from $155.9 million for the same period in 2008. The decrease in revenues for the three months ended June 30, 2009 compared to the same period of 2008 is primarily due to the significant decrease in realized prices for all products. Revenues were comprised of $45.1 million of natural gas revenue, $9.5 million of liquids revenue, and $24.9 million of oil revenue. The decrease in average realized commodity prices is comprised of a 52% decrease in the natural gas price to $4.52/mcf from $9.44/mcf, a 61% decrease in the liquids price to $32.00/bbl from $81.88/bbl and a decrease of 30% in the oil price to $64.14/bbl from $91.82/bbl.

For the six months ended June 30, 2009, revenues including realized commodity derivative gains and losses were $178.2 million, a 29% decrease from $252.4 million, for the same period in 2008. The decrease in revenues for the first six months of 2009 compared to the same period of 2008 is primarily due to the decline in commodity prices offset by the 14% increase in production. These revenues were comprised of $111.0 million of natural gas revenue, $47.1 million of oil revenue, and $20.1 million of liquids revenue. The decrease in average realized commodity prices is comprised of a 37% decrease in the natural gas price to $5.53/mcf from $8.74/mcf, a 30% decrease in the oil price to $59.66/bbl from $84.95/bbl, and a decrease of 56% in the liquids price to $35.46/bbl from $80.65/bbl.

Commodity price risk management

	Three months ended June 30,					
	2009			2008		
($ thousands)	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural gas	(2)	-	(2)	(1,026)	(5,826)	(6,852)
Oil	1,341	(7,478)	(6,137)	(4,835)	(34,205)	(39,040)
Total gain (loss)	1,339	(7,478)	(6,139)	(5,861)	(40,031)	(45,892)

	Six months ended June 30,					
	2009			2008		
($ thousands)	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Gain (Loss)
Natural gas	1,421	(1,094)	327	(1,026)	(9,710)	(10,736)
Oil	6,986	(14,226)	(7,240)	(5,368)	(40,065)	(45,433)
Total gain (loss)	8,407	(15,320)	(6,913)	(6,394)	(49,775)	(56,169)

As part of our financial risk management strategy, NuVista has adopted a disciplined commodity price risk management program. The purpose of this program is to reduce volatility in our financial results, protect acquisition economics and stabilize cash flow against the unpredictable commodity price environment. NuVista's Board of Directors has approved a price risk management limit of up to 60% of forecast production, net of royalties, using fixed price, put option and costless collar contracts. To achieve NuVista's price risk management objectives, we enter into both commodity derivative and physical sale contracts. For the three months ended June 30, 2009, the commodity derivative price risk management program resulted in a loss of $6.1 million consisting of realized gains of $1.3 million on natural gas and oil hedges and a $7.5 million unrealized loss on crude oil hedges. For the six months ended June 30, 2009, the commodity derivative price risk management program resulted in a loss of $6.9 million consisting of realized gains of $8.4 million and an unrealized loss of $15.3 million.

For the six months ended June 30, 2009, price risk management gains on our physical sale contracts totaled $18.0 million. As at June 30, 2009, the mark-to-market value of our financial commodity derivative contracts was a gain of $1.2 million and the mark-to-market value of our physical sales contracts was a gain of $7.9 million, net of the deferred put option costs of $5.6 million.

The following is a summary of commodity price risk management contracts in place as at June 30, 2009:

(a) Financial contracts

Crude oil:

Volume	Average Price (Cdn$/bbl)	Term
1,000 bbls/d	CDN. $64.00 – Bow River	January 1, 2009 – December 31, 2009
1,000 bbls/d	CDN. $95.01 – $110.01 – WTI (1)	January 1, 2009 – December 31, 2009

(1) This is a US$ denominated crude oil contract with an associated fixed price foreign exchange contract of 1.0262 US$/Cdn$.

(b) Physical sale contracts

Natural gas:

Volume	Average Price (Cdn$/gj)	Term
20,000 gj/d	CDN. $7.45 – Fixed Price AECO	April 1, 2009 – October 31, 2009
5,000 gj/d	CDN. $5.65 – AECO Floor (1), (4)	April 1, 2009 – October 31, 2009
20,000 gj/d	CDN. $5.97 – $6.56 – AECO (2), (4)	November 1, 2009 – October 31, 2010
20,000 gj/d	CDN. $5.55 – AECO Floor (3), (4)	November 1, 2009 – March 31, 2010

(1) The AECO put was purchased at a deferred cost of $0.82/gj for a total cost of $0.9 million.
(2) The deferred cost associated with the funded collar was $0.30/gj for a total cost of $2.2 million.
(3) The AECO put was purchased at a deferred cost of $0.97/gj for a total cost of $2.9 million.
(4) The deferred costs are incurred monthly over the term of the contract and will be offset against revenues.

Royalties

	Three months ended June 30,		Six months ended June 30,	
Royalty rates (%)	2009	2008	2009	2008
Natural gas and liquids	10	25	14	26
Oil	12	18	10	16
Weighted average rate	10	22	13	22

Royalties of $8.2 million for the three months ended June 30, 2009 were 77% lower than the $35.9 million for the same period of 2008. Royalties for the six months ended June 30, 2009 were $23.5 million as compared to $58.2 million reported for the six months ended June 30, 2008. The decrease in royalties are primarily due to lower revenues associated with low commodity prices in both the second quarter and first half of 2009 compared to the same periods in 2008.

As a percentage of revenue, the average royalty rate for the second quarter of 2009 was 10% compared to 22% for the comparative period of 2008. Royalty rates by product for the three months ended June 30, 2009, were 10% for natural gas and liquids and 12% for oil compared to 25% for natural gas and liquids and 18% for oil for the same period in 2008. For the six months ended June 30, 2009, the average royalty rate as a percentage of revenue was 13% compared to 22% for the same period in 2008. Royalty rates by product were 14% for natural gas and liquids and 10% for oil compared to 26% for natural gas and liquids and 16% for oil for the same period in 2008.

The lower royalty rates are primarily due to the impact of the New Alberta Royalty Framework in a low commodity price environment and the impact of price risk management activities on the reported royalty rates. Our price risk management activities impact reported royalty rates as royalties are based on government market reference prices and not our average realized prices that include price risk management activities. As a result, the gains from our price risk management activities included in revenue result in a lower royalty rate as a percentage of revenue than if no price risk management activities had taken place. Excluding the impact of price risk management activities, Alberta natural gas royalty rates for the three months ended June 30, 2009 were approximately 12% compared to 21% for the same period in 2008 and Alberta oil royalty rates for the three months ended June 30, 2009 were approximately 11% compared to 13% for the same period in 2008.

Netbacks – The table below summarizes field netbacks by product for the three months ended June 30, 2009:

	Natural gas and liquids		Oil		Total	
	129.0 mmcfe/d		4,269 bbl/d		25,777 boe/d	
($ thousands, except per unit amounts)	$	$/mcfe	$	$/bbl	$	$/boe
Production revenue	54,516	4.64	23,576	60.69	78,092	33.29
Realized gain (loss) on commodity derivatives	(2)	-	1,341	3.45	1,339	0.57
	54,514	4.64	24,917	64.14	79,431	33.86
Royalties	(5,236)	(0.45)	(3,001)	(7.72)	(8,237)	(3.51)
Transportation costs	(1,687)	(0.14)	(694)	(1.79)	(2,381)	(1.02)
Operating costs	(12,292)	(1.05)	(6,096)	(15.69)	(18,388)	(7.84)
Field netback	35,299	3.00	15,126	38.94	50,425	21.49

The following table summarizes field netbacks by product for the six months ended June 30, 2009:

	Natural gas and liquids		Oil		Total	
	129.7 mmcfe/d		4,358 bbl/d		25,974 boe/d	
($ thousands, except per unit amounts)	$	$/mcfe	$	$/bbl	$	$/boe
Production revenue	129,754	5.53	40,067	50.80	169,821	36.12
Realized gain on commodity derivatives	1,421	0.06	6,986	8.86	8,407	1.79
	131,175	5.59	47,053	59.66	178,228	37.91
Royalties	(18,857)	(0.80)	(4,604)	(5.84)	(23,461)	(4.99)
Transportation costs	(3,093)	(0.13)	(1,065)	(1.35)	(4,158)	(0.88)
Operating costs	(26,035)	(1.11)	(12,865)	(16.31)	(38,900)	(8.27)
Field netback	83,190	3.55	28,519	36.16	111,709	23.77

The tables below summarizes funds from operations netbacks for the three months ended June 30, 2009 compared to the three months ended June 30, 2008, and the six months ended June 30, 2009 compared to the six months ended June 30, 2008.

	Three months ended June 30,					
	2009		2008		% Change	
($ thousands, except per unit amounts)	$	$/boe	$	$/boe	$	$/boe
Production revenue	78,092	33.29	161,712	67.95	(52)	(51)
Realized gain (loss) on commodity derivatives	1,339	0.57	(5,861)	(2.46)	123	123
	79,431	33.86	155,851	65.49	(49)	(48)
Royalties	(8,237)	(3.51)	(35,926)	(15.10)	(77)	(77)
Transportation	(2,381)	(1.02)	(2,296)	(0.96)	4	6
Operating costs	(18,388)	(7.84)	(19,481)	(8.19)	(6)	(4)
Field netback	50,425	21.49	98,148	41.24	(49)	(48)
General and administrative	(3,777)	(1.61)	(3,606)	(1.52)	5	6
Restricted stock units	(637)	(0.27)	(865)	(0.36)	(26)	(25)
Interest	(4,232)	(1.80)	(4,095)	(1.72)	3	5
Funds from operations netback	41,779	17.81	89,582	37.64	(53)	(53)

	Six months ended June 30,					
	2009		2008		% Change	
($ thousands, except per unit amounts)	$	$/boe	$	$/boe	$	$/boe
Production revenue	169,821	36.12	258,760	62.51	(34)	(42)
Realized gain (loss) on commodity derivatives	8,407	1.79	(6,394)	(1.54)	231	216
	178,228	37.91	252,366	60.97	(29)	(38)
Royalties	(23,461)	(4.99)	(58,153)	(14.05)	(60)	(64)
Transportation	(4,158)	(0.88)	(3,737)	(0.90)	11	(2)
Operating costs	(38,900)	(8.27)	(32,898)	(7.95)	18	4
Field netback	111,709	23.77	157,578	38.07	(29)	(38)
General and administrative	(6,728)	(1.43)	(5,811)	(1.40)	16	2
Restricted stock units	(598)	(0.13)	(1,118)	(0.27)	(47)	(52)
Interest	(5,941)	(1.26)	(7,633)	(1.84)	(22)	(32)
Funds from operations netback	98,442	20.95	143,016	34.56	(31)	(39)

Transportation – Transportation costs were $2.4 million ($1.02/boe) for the three months ended June 30, 2009 as compared to $2.3 million ($0.96/boe) for the same period of 2008. Transportation costs were $4.2 million ($0.88/boe) for the six months ended June 30, 2009 compared to $3.7 million ($0.90/boe) for the same period in 2008. The increase in transportation costs in 2009 compared to 2008 is primarily due to an increase in oil and liquids production as a percentage of overall production and their higher associated transportation costs.

Operating – Operating expenses were $18.4 million ($7.84/boe) for the three months ended June 30, 2009 as compared to $19.5 million ($8.19/boe) for the three months ended June 30, 2008 and $20.5 million ($8.71/boe) for the three months ended March 31, 2009. The reduction in per unit costs resulted primarily from lower electricity costs and cost savings initiatives completed by NuVista's field staff during the second quarter. For the three months ended June 30, 2009, natural gas and natural gas liquid operating costs averaged $1.05/mcfe and oil operating expenses were $15.69/bbl as compared to $1.16/mcfe and $13.76/bbl respectively for the same period in 2008.

Operating expenses were $38.9 million ($8.27/boe) for the six months ended June 30, 2009 as compared to $32.9 million ($7.95/boe) for the six months ended June 30, 2008. This increase resulted from the 14% increase in production volumes and a 4% increase in per unit costs. For the six months ended June 30, 2009, natural gas and natural gas liquid operating expenses averaged $1.11/mcfe and oil operating expenses were 16.31/bbl as compared to $1.15/mcfe and $12.34/bbl respectively for the same period of 2008.

NuVista is forecasting operating expenses to average $9.25/boe for the last half of 2009 which increases our 2009 annual operating expense estimate to $8.75/boe. The increase in projected costs (on a per boe basis) is due primarily to the inclusion of the newly acquired northwest Alberta properties for the last five months of 2009. These properties' cost structure is currently higher than NuVista's average operating costs per boe for 2009.

General and administrative – General and administrative expenses, net of overhead recoveries, for the three months ended June 30, 2009 were $3.8 million ($1.61/boe) compared to $3.6 million ($1.52/boe) in the same period of 2008. General and administrative expenses, net of overhead recoveries, for the six months ended June 30, 2009 were $6.7 million ($1.43/boe) as compared to $5.8 million ($1.40/boe) for the six months ended June 30, 2008. This increase in general and administrative expenses is directly attributable to the higher production base in NuVista associated with the Rider Acquisition. Higher per unit costs reflect increased staffing costs and lower capital overhead recoveries. NuVista is forecasting 2009 general and administrative costs for the remainder of the year to average approximately $1.40/boe.

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except per unit amounts)	2009	2008	2009	2008
Gross general and administrative expenses	4,889	5,384	9,359	8,947
Overhead recoveries	(1,112)	(1,778)	(2,631)	(3,136)
Net general and administrative expenses	3,777	3,606	6,728	5,811
Per boe	1.61	1.52	1.43	1.40

Stock-based compensation

($ thousands)	Three months ended June 30, 2009	2008	Six months ended June 30, 2009	2008
Stock-based compensation	1,313	1,025	3,354	2,030
Restricted stock units	637	865	598	1,118
Total	1,950	1,890	3,952	3,148

NuVista recorded a stock-based compensation charge of $2.0 million for the three months ended June 30, 2009 compared to $1.9 million for the same period in 2008. For the six months ended June 30, 2009, NuVista recorded a stock-based compensation charge of $4.0 million compared to $3.1 million for the same period in 2008. The stock-based compensation charge relates to the amortization of the value of stock option awards and the accrual for future payments under the Restricted Stock Unit ("RSU") Incentive Plan. The increase in the second quarter of 2009 relates primarily to an increase in the number of stock options outstanding. In January 2008, NuVista implemented an RSU Incentive Plan. Each RSU entitles participants to receive cash equal to the market value of the equivalent number of shares of NuVista. The RSUs become payable as they vest, typically over three years. The decrease in RSU expense for the three and six months ended 2009 was a result of the number of RSUs outstanding and movement in NuVista's share price.

Interest – Interest expense for the three months ended June 30, 2009 was $4.2 million ($1.80/boe) compared to $4.1 million ($1.72 /boe) for the same period of 2008. For the six months ended June 30, 2009, interest expense was $5.9 million ($1.26/boe) compared to $7.6 million ($1.84/boe) in the same period of 2008. For the three months ended June 30, 2009, borrowing costs averaged 3.25% compared to 4.0% in the same period of 2008. The revolving term of NuVista's credit facility was extended on March 3, 2009, and as part of the terms of this extension NuVista's borrowing margin was increased to current market rates. Currently, NuVista's average borrowing rate is approximately 3.25%. Cash paid for interest for the three and six months ended June 30, 2009 was $3.9 million (2008 – $5.0 million) and $5.5 million (2008 - $7.2 million) respectively.

Depreciation, depletion and accretion – Depreciation, depletion and accretion expenses were $42.5 million for the second quarter of 2009 as compared to $43.1 million for the same period in 2008. The average per unit cost was $18.12/boe in the second quarter of 2009 as compared to $18.11/boe for the same period in 2008. Depreciation, depletion and accretion expenses for the six months ended June 30, 2009, were $84.9 million as compared to $75.8 million for the same period in 2008. The average per unit cost was $18.06/boe in the first half of 2009 as compared to $18.31/boe in the same period in 2008.

Income taxes – For the three months ended June 30, 2009, the provision for income and other taxes was a recovery of $2.2 million compared to an expense of $1.9 million for the same period in 2008. For the six months ended June 30, 2009, the provision for income and other taxes was a recovery of $0.5 million compared to an expense of $4.7 million in the same period of 2008. The effective tax rate was 23% for the three months ended June 30, 2009.

Capital expenditures – Capital expenditures were $8.3 million during the second quarter of 2009 compared to $16.2 million in the same period of 2008, with $10.6 million of exploration and development spending and $18.1 million spent on a complementary property acquisition. Second quarter capital excludes $18.0 million for the deposit on the acquisition which closed on July 27, 2009 and is net of an estimated $2.3 million credit on drilling costs resulting from the Alberta government drilling incentive program. Capital expenditures for the six months ended June 30, 2009 were $89.5 million, consisting of $37.8 million for exploration and development spending, $54.1 million for acquisitions and $2.3 million in drilling credits. This compares to $67.1 million incurred for the same period of 2008, consisting of $25.4 million of acquisitions and exploration and development spending of $41.7 million.

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except per unit amounts)	2009	2008	2009	2008
Exploration and development				
Land and retention costs	851	4,451	1,775	5,123
Seismic	1,906	2,385	4,490	4,986
Drilling and completion	5,538	6,176	17,528	17,881
Facilities and equipment	2,146	2,278	13,513	12,386
Corporate and other	203	1,188	491	1,340
Subtotal	10,644	16,478	37,797	41,716
Acquisitions				
Property	4	(265)	54,075	25,398
Subtotal	4	(265)	54,075	25,398
Total capital expenditures	10,648	16,213	91,872	67,114
Alberta drilling incentive credits	(2,326)	-	(2,326)	-
Net capital expenditures	8,322	16,213	89,546	67,114
Corporate acquisition – non-cash	-	-	-	594,944

Net earnings and funds from operations – For the three months ended June 30, 2009, net earnings decreased to a loss of $7.3 million (($0.09)/share, basic) from $2.9 million ($0.04/share, basic) for the same period in 2008. Second quarter 2009 net earnings were lower when compared to the same period in 2008 primarily due to the impact of lower oil and natural gas prices. For the three months ended June 30, 2009, realized gains on our financial and physical sales price risk management programs totaled $9.2 million, partially mitigating the impact of lower oil and natural gas prices. Net earnings per share decreased due to the decrease in net earnings and increase in number of shares outstanding following the Rider Acquisition.

For the three months ended June 30, 2009, NuVista's funds from operations were $41.8 million ($0.53/share, basic), a 53% decrease from $89.6 million ($1.14/share, basic) for the three months ended June 30, 2008. Funds from operations for the three months ended June 30, 2009 were lower than the same period in 2008 primarily due to lower commodity prices, partially offset by higher production volumes, and increased operating and general and administrative costs. Funds from operations per share decreased 54% due to the decrease in funds from operations and an increase in number of shares outstanding following the Rider Acquisition.

Liquidity and capital resources – As at June 30, 2009, debt net of adjusted working capital was $351.5 million, resulting in a net debt to annualized second quarter funds from operations ratio of 2.1:1. At June 30, 2009, NuVista had an adjusted working capital surplus of $24.9 million. Adjusted working capital excludes the current portion of the fair value of the commodity derivative asset of $1.2 million and the related current portion of future income tax liability of $0.3 million. We believe it is appropriate to exclude these amounts when assessing financial leverage. At June 30, 2009, NuVista had $73.7 million of unused bank borrowing capacity based on the current credit facility of $450.0 million. On July 27, 2009, NuVista's credit facility was increased to $510.0 million.

NuVista has a credit facility from a syndicate of primarily Canadian banks with a maximum borrowing amount of $450.0 million. The credit facility is a 364-day revolving facility subject to an annual review by the bank syndicate, at which time a lender can provide an extension of the 364-day revolving period or request conversion to a one year term loan. During the revolving period, a determination of the maximum borrowing amount occurs semi-annually on or before April 30 and October 31.

On March 3, 2009, NuVista and the bank syndicate agreed to an extension of the revolving period from March 3, 2009 until April 30, 2009, in order for the bank syndicate to complete their annual review of NuVista's reserves and financial results. On April 3, 2009, NuVista's bank syndicate completed their annual review and extended the revolving period of the credit facility to April 29, 2010, and the term period to April 29, 2011. Under the term period, no principal payments would be required until April 29, 2011.

NuVista anticipates that funds from operations will provide the flexibility to fund its planned 2009 capital program. In this period of lower commodity prices and challenging economic environment, NuVista will place increased emphasis on maintaining its financial flexibility. NuVista plans to closely monitor its 2009 business plan and adjust capital programs in the context of commodity prices and access to bank and equity capital. It is NuVista's intent to have a reduced capital program for the second half of 2009, which in turn is expected to reduce net debt to the targeted level of approximately $365 million.

As at June 30, 2009, there were 79.3 million common shares outstanding. There were 3.0 million of common share purchase warrants which expired on March 4, 2009. In addition, there were 6.3 million stock options outstanding, with an average exercise price of $13.46 per share.

Subsequent events

(a) ***Property acquisition and equity financing*** – On June 15, 2009 NuVista announced the acquisition of certain properties in the Martin Creek area of Northeast British Columbia and in Northwest Alberta and two subscription receipt financings. On July 27, 2009, NuVista closed the acquisition for a purchase price of $174 million. The acquisition was financed through a combination of bank debt and the net proceeds from two equity offerings. NuVista entered into an agreement to issue 7,500,000 subscription receipts at a price of $11.00 per subscription receipt on a bought deal basis for gross proceeds of $82.5 million. In addition, NuVista issued 1,500,000 subscription receipts at a price of $11.00 per subscription receipt, by way of a private placement to Ontario Teachers' Pension Plan for gross proceeds of $16.5 million. The subscription receipt offerings closed on July 7, 2009. Each subscription receipt was exchanged for one common share of NuVista for no additional consideration on July 27, 2009.

(b) ***Long-term debt*** – On July 27, 2009, the Company's credit facility was increased to a maximum borrowing amount of $510.0 million. Terms and conditions remain the same as disclosed in note 5 of the financial statements.

Related party activities – In 2003, as part of the Plan of Arrangement with Bonavista Petroleum Ltd. ("Bonavista"), NuVista entered into a Technical Services Agreement ("TSA") with Bonavista for the provision of certain services to NuVista. On August 31, 2007, the TSA was terminated and replaced with a new services agreement that reflected the remaining ongoing services that will be provided by Bonavista. On November 1, 2008, this services agreement was terminated and Bonavista no longer provides any ongoing services to NuVista.

NuVista and Bonavista are considered related as two directors of NuVista, one of whom is NuVista's chairman, are also directors and officers of Bonavista and a director and an officer of NuVista are also officers of Bonavista. For the three months ended June 30, 2009, NuVista paid Bonavista $nil (2008 – $0.4 million) in fees relating to general and administrative services provided by Bonavista. In 2009, NuVista charged Bonavista management fees for jointly owned partnerships totalling $0.3 million (2008 – $0.3 million). In addition, during the second quarter of 2009, Bonavista charged NuVista $56,000 (2008 - $63,000) for costs that are outside of the new services agreement relating to NuVista's share of direct charges from third parties.

For the six months ended June 30, 2009, NuVista paid Bonavista $nil (2008 - $0.8 million) in fees relating to general and administrative services provided by Bonavista, and NuVista charged Bonavista management fees for jointly owned partnerships totaling $0.6 million (2008 - $0.6 million). In addition, Bonavista charged NuVista $76,000 (2008 - $72,000) for costs that are outside of the new services agreement relating to NuVista's share of direct charges from third parties. As at June 30, 2009, the amount receivable from Bonavista was $0.2 million (2008 - $2.9 million).

Contractual obligations and commitments – NuVista enters into contract obligations as part of conducting business. The following is a summary of NuVista's contractual obligations and commitments as at June 30, 2009:

($ thousands)	Total	2009	2010	2011	2012	Thereafter
Transportation	13,817	2,426	3,368	2,668	2,004	3,351
Office lease	6,849	1,027	2,055	2,055	1,712	-
Physical sale contract premiums	5,620	2,050	3,570	-	-	-
Physical power contract	6,900	-	-	2,300	2,300	2,300
Long-term debt	376,305	-	-	376,305	-	-
Total commitments	409,491	5,503	8,993	383,328	6,016	5,651

Quarterly financial information **–** The following table highlights NuVista's performance for the eight quarterly reporting periods from September 30, 2007 to June 30, 2009:

	2009		2008				2007	
	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30
Production (boe/d)	25,777	26,175	25,688	26,065	26,153	19,339	14,251	13,590
($ thousands, except per share amounts)								
Production revenue	78,092	91,729	106,982	149,648	161,794	97,064	53,790	48,166
Net earnings (loss)	(7,312)	2,632	24,443	53,699	2,905	7,150	11,063	754
Net earnings (loss)								
Per share – basic	(0.09)	0.03	0.31	0.68	0.04	0.12	0.21	0.01
Per share – diluted	(0.09)	0.03	0.31	0.68	0.04	0.12	0.21	0.01

NuVista has seen production volumes remain in a range of 25,688 boe/d to 26,175 boe/d for the last five quarters as NuVista reduced capital spending during this period in order to allocate cash flow to debt reduction following the Rider Acquisition and in response to lower commodity prices. The increases in production during the first and second quarters of 2008 relate primarily to the Rider Acquisition that closed on March 4, 2008. Over the prior eight quarters, quarterly revenue has been in a range of $48.2 million to $161.8 million with revenue primarily influenced by production volumes, and oil and natural gas prices in the quarter. Net earnings (loss) have been in a range of $53.7 million to $(7.3) million primarily influenced by production volumes, commodity prices and realized and unrealized gains and losses on commodity derivatives.

Critical accounting estimates **–** The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Certain accounting policies are critical to understanding the financial condition and results of operations of NuVista.

(a) ***Proved oil and natural gas reserves*** **–** Proved oil and natural gas reserves, as defined by the Canadian Securities Administrators in National Instrument 51-101 with reference to the Canadian Oil and Natural Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

An independent reserve evaluator using all available geological and reservoir data as well as historical production data has prepared NuVista's oil and natural gas reserve estimates. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's development plans. The effect of changes in proved oil and natural gas reserves on the financial results and position of the Company is described below.

(b) ***Depreciation, depletion and accretion expense*** **–** NuVista uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depreciation and depletion expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depreciation and depletion expense.

(c) ***Full cost accounting ceiling test*** **–** The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the asset is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

(d) ***Asset retirement obligation*** **–** The asset retirement obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The costs are included in property, plant and equipment and amortized over its useful life. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

(e) ***Income taxes –*** The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

(f) ***Goodwill –*** Goodwill is recorded on a business combination when the total purchase consideration exceeds the fair value of the net identifiable assets and liabilities of the acquired entity. The goodwill balance is not amortized, however, and must be assessed for impairment at least annually. Impairment is initially determined based on the fair value of a reporting unit compared to its book value. Any impairment must be charged to earnings in the period the impairment occurs. The Company has one reporting unit, being the entity as a whole, and as at June 30, 2009, we have determined there was no goodwill impairment.

Update on regulatory matters

(a) ***New Alberta Royalty Framework –*** On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "NRF") containing the Government's proposals for Alberta's new royalty regime, which was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF establishes new royalty rates for conventional oil, natural gas and oil sands.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, 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 deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. 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 NRF.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per metre royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and June 30, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on NuVista's 2008 production it will be entitled to a maximum credit of 40% of royalties payable in the period April 1, 2009 to March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 mmcf of natural gas. On June 25, 2009, the Government of Alberta extended this incentive program to March 31, 2011.

As royalties under the NRF are sensitive to both commodity prices and production levels, the estimated NRF Alberta 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.

(b) ***British Columbia Royalty Incentive Program*** – On August 6, 2009 the Government of British Columbia introduced a new royalty incentive program that provides for a 2% royalty rate for the first year of production from all wells drilled between September 2009 and June 2010. In addition, the existing royalty deductions available under the Deep Royalty Credit Program were increased by 15% and horizontal wells drilled between 1,900 and 2,300 metres now qualify for the Deep Royalty Credit Program.

Update on accounting policies and financial reporting matters

(a) ***Goodwill and intangible assets –*** Effective January 1, 2009, NuVista adopted Section 3064, Goodwill and Intangible Assets issued by the Canadian Institute of Chartered Accountants ("CICA"). Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. This new section has no current impact on NuVista's consolidated financial statements.

(b) ***International Financial Reporting Standards –*** In February 2008, the Canadian Accounting Standards Board confirmed January 1, 2011, as the effective date for the requirement to report under International Financial Reporting Standards ("IFRS") with comparative 2010 periods converted as well. Canadian GAAP, as we currently know them, will cease to exist for all public reporting entities.

In order to meet the requirement to transition to IFRS, NuVista has appointed internal staff to lead the conversion project along with sponsorship from an executive steering committee. NuVista involves external auditors and external consultants, as required, during the conversion project. NuVista has provided training to key employees, completed a preliminary analysis of the accounting differences and is monitoring the impact of the transition on its business practices, information systems and internal control over financial reporting. During NuVista's preliminary analysis, accounting implementation for certain areas was identified as having the greatest potential impact to NuVista's consolidated financial statements in terms of complexity and effort. NuVista has determined that accounting for property, plant and equipment, impairment testing, asset retirement obligation, stock-based compensation and income taxes will be impacted by the conversion to IFRS. In July 2009, the International Accounting Standards Board issued amendments to IFRS 1 – First-Time Adoption of International Financial Reporting Standards. This amendment allows first-time adopters using full cost accounting to elect to measure oil and gas assets at the date of transition to IFRS using amounts determined based on the entity's previous GAAP. During the second quarter of 2009, NuVista performed an analysis of IFRS in comparison with currently applied accounting principles on the key areas previously identified as high priority. NuVista is currently analyzing the various accounting policy choices available and will implement those determined to be the most appropriate. The impact of IFRS on NuVista's consolidated financial statements is not reasonably determinable at this time.

Internal control reporting

NuVista's President and Chief Executive Officer ("CEO") and Vice President, Finance and Chief Financial Officer ("CFO") are responsible for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting as defined in National Instrument 52-109. NuVista's CEO and CFO have designed disclosure controls and procedures, or caused them to be designed under their supervision, to provide reasonable assurance that information to be disclosed by NuVista is accumulated and communicated to management as appropriate to allow timely decisions regarding the required disclosure. The CEO and CFO have also designed internal controls over financial reporting, or caused them to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. During the quarter ended June 30, 2009, there have been no changes to NuVista's internal control over financial reporting that have materially or are reasonably likely to materially affect the internal control over financial reporting.

Because of their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, error or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance, that the objectives of the control system are met.

Assessment of business risks

The following are the primary risks associated with the business of NuVista. Most of these risks are similar to those affecting others in the conventional oil and natural gas sector. NuVista's financial position and results of operations are directly impacted by these factors:

- Operational risk associated with the production of oil and natural gas;
- Reserves risk with respect to the quantity and quality of recoverable reserves;
- Commodity risk as crude oil and natural gas prices fluctuate due to market forces;
- Financial risk such as volatility of the Canadian/US dollar exchange rate, interest rates and debt service

obligations;

- Risk associated with the current global financial crisis;
- Risk associated with the re-negotiation of NuVista's credit facility and the continued participation of NuVista's lenders;
- Market risk relating to the availability of transportation systems to move the product to market;
- Environmental and safety risk associated with well operations and production facilities; and
- Changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection relating to the oil and natural gas industry.

NuVista seeks to mitigate these risks by:

- Acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
- Maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
- Diversifying properties to mitigate individual property and well risk;
- Maintaining product mix to balance exposure to commodity prices;
- Conducting rigorous reviews of all property acquisitions;
- Monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
- Maintaining a price risk management program to manage commodity prices and foreign exchange currency rates risk and transacting with creditworthy counterparties;
- Ensuring strong third-party operators for non-operated properties;
- Adhering to NuVista's safety program and keeping abreast of current operating best practices;
- Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
- Carrying industry standard insurance to cover losses;
- Establishing and maintaining adequate cash resources to fund future abandonment and site restoration costs;
- Closely monitoring commodity prices and capital programs to manage financial leverage; and
- Monitoring the bank and equity markets to understand how changes in the capital market may impact NuVista's business plan.

OUTLOOK

Although the current financial and commodity markets create considerable uncertainty in the near term, NuVista will be responsive to economic conditions and continue with its disciplined acquire and develop business model. The low natural gas price environment presents challenges but with our disciplined counter-cyclical approach to business and our financial flexibility, it can also provide opportunities to create shareholder value. During this period of low natural gas prices we will continue to evaluate opportunities for strategic or smaller complementary acquisitions to position NuVista for future success. Prudent management of our capital program and financial leverage should provide us with the financial flexibility to take advantage of these opportunities. We plan to spend less than forecast cash flow on our exploration and development capital program for the second half of 2009 in order to reduce our debt levels following the latest acquisition. In addition, concurrent with the closing of the acquisition our credit facility was increased from $450 million to $510 million.

NuVista forecasts 2009 funds from operations of approximately $190 million based on current pricing assumptions. These assumptions for 2009 include an AECO natural gas price of $4.15/mcf, a WTI crude oil price of US$60.00, a foreign exchange rate of 0.87 CDN/USD and include price risk management contracts currently in place. Based on this forecast of funds from operations, our Board of Directors has approved a 2009 capital budget of $320 million with capital spending of approximately $50 million in the second half of 2009. This capital program has the flexibility to either accelerate or defer capital expenditures based upon market conditions. We expect to drill 20 to 30 wells during the second half of the year. Our constrained 2009 capital program will result in a high-grading of opportunities in 2009 and a growing prospect inventory heading into 2010. Based on this capital budget, forecast funds from operations, and closing of the recent acquisition and related equity financing, we are targeting year end net debt of approximately $365 million.

We have revised our average 2009 production guidance to 27,000 boe/d to 27,500 boe/d due to the shut-in of up to 900 boe/d of natural gas production relating to high operating cost production and constraints on the TCPL pipeline for the remainder of 2009. The loss of this natural gas production has minimal impact on our funds from operations.

For the remainder of the year, we will continue to invest human resources and capital on our emerging tight gas resource plays in order to develop a thorough understanding of recovery concepts. We will advance these projects in the remainder of 2009 by drilling new wells to assess recovery from each of these resource plays. During this period we will also pursue the benefits from royalty incentive programs announced by the Alberta and British Columbia governments and lower industry drilling and completion costs.

Over the long term we believe that supply and demand fundamentals should result in significant upside for both oil and natural gas prices; however, we must be prepared to endure an extended period of low prices before this recovery occurs. We believe our counter-cyclical strategy of acquiring premium assets at attractive prices over the next two to three years and optimizing production from these assets will richly reward our stakeholders over the long term. Throughout our six year history, NuVista has demonstrated a disciplined and flexible approach to spending and allocating capital with a focus on profitable per share growth while maintaining a strong balance sheet. NuVista will continue with this approach in 2009 and beyond.

Sincerely,

Alex G. Verge
President & CEO
August 13, 2009

Robert F. Froese
Vice-President, Finance & CFO

NUVISTA ENERGY LTD.

Consolidated Balance Sheets

($ thousands)	**June 30, 2009**	December 31, 2008
(unaudited)		
Assets		
Current assets		
Cash and cash equivalents	**$ -**	$ 139
Accounts receivable and prepaids	**69,008**	64,712
Commodity derivative asset (note 7)	**1,194**	16,513
	70,202	81,364
Oil and natural gas properties and equipment (note 3)	**1,275,936**	1,242,216
Goodwill	**83,716**	83,716
	$ 1,429,854	$ 1,407,296
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 44,154**	$ 50,710
Future income taxes	**323**	4,954
	44,477	55,664
Long-term debt (note 5)	**376,305**	355,407
Compensation liability (note 6)	**274**	850
Asset retirement obligations (note 4)	**54,228**	46,296
Future income taxes	**142,442**	137,779
Shareholders' equity		
Share capital, warrants and contributed surplus (note 6)	**603,550**	598,042
Retained earnings	**208,578**	213,258
	812,128	811,300
	$ 1,429,854	$ 1,407,296

Commitments (note 9)
Subsequent events (note 10)

See accompanying notes to consolidated financial statements.

NUVISTA ENERGY LTD.

Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss) and Retained Earnings

($ thousands)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
(unaudited)				
Revenues				
Production	**$ 78,092**	$ 161,712	**$ 169,821**	$ 258,760
Royalties	**(8,237)**	(35,926)	**(23,461)**	(58,153)
Realized gain (loss) on commodity derivatives	**1,339**	(5,861)	**8,407**	(6,394)
Unrealized loss on commodity derivatives	**(7,478)**	(40,031)	**(15,320)**	(49,775)
	63,716	79,894	**139,447**	144,438
Expenses				
Operating	**18,388**	19,481	**38,900**	32,898
Transportation	**2,381**	2,296	**4,158**	3,737
General and administrative	**3,777**	3,606	**6,728**	5,811
Bad debt provision	**-**	661	**-**	661
Interest	**4,232**	4,095	**5,941**	7,633
Stock-based compensation (note 6)	**1,950**	1,890	**3,952**	3,148
Depreciation, depletion and accretion	**42,495**	43,091	**84,918**	75,792
	73,223	75,120	**144,597**	129,680
Earnings (loss) before income and other taxes	**(9,507)**	4,774	**(5,150)**	14,758
Future income tax expense (recovery)	**(2,195)**	1,869	**(470)**	4,704
Net earnings (loss)	**(7,312)**	2,905	**(4,680)**	10,054
Other comprehensive income				
Amortization of fair value of financial instruments	**-**	-	**-**	(17)
Comprehensive income (loss)	**(7,312)**	2,905	**(4,680)**	10,037
Retained earnings, beginning of period	**215,890**	132,212	**213,258**	125,063
Retained earnings, end of period	**$ 208,578**	$ 135,117	**$ 208,578**	$ 135,117
Net earnings per share – basic	**$ (0.09)**	$ 0.04	**$ (0.06)**	$ 0.14
Net earnings per share – diluted	**$ (0.09)**	$ 0.04	**$ (0.06)**	$ 0.14

See accompanying notes to the consolidated financial statements.

NUVISTA ENERGY LTD.

Consolidated Statement of Cash Flows

($ thousands)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
(unaudited)				
Cash provided by (used in)				
Operating Activities				
Net earnings (loss)	**$ (7,312)**	$ 2,905	**$ (4,680)**	$ 10,054
Items not requiring cash from operations				
Depreciation, depletion and accretion	**42,495**	43,091	**84,918**	75,792
Stock-based compensation	**1,313**	1,025	**3,354**	2,030
Bad debt provision	**-**	661	**-**	661
Unrealized loss on commodity derivatives	**7,478**	40,031	**15,320**	49,775
Future income tax expense (recovery)	**(2,195)**	1,869	**(470)**	4,704
Asset retirement expenditures	**(614)**	(483)	**(1,189)**	(537)
Decrease (increase) in non-cash working capital items	**(1,649)**	(21,646)	**687**	(39,860)
	39,516	67,453	**97,940**	102,619
Financing Activities				
Issue of share capital and warrants, net of share issuance costs	**801**	4,260	**801**	89,074
Increase in long-term debt	**-**	-	**20,898**	184,867
Repayment of long-term debt	**(15,202)**	(51,267)	**-**	(303,538)
	(14,401)	(47,007)	**21,699**	(29,597)
Investing Activities				
Oil and natural gas properties and equipment	**(8,318)**	(16,478)	**(35,471)**	(41,716)
Transaction costs on Rider acquisition	**-**	-	**-**	(4,130)
Property acquisition	**(4)**	265	**(54,075)**	(22,798)
Deposit on property acquisition (note 3)	**(18,084)**	-	**(18,084)**	-
Decrease (increase) in non-cash working capital items	**1,115**	475	**(12,148)**	1,215
	(25,291)	(15,738)	**(119,778)**	(67,429)
Increase (decrease) in cash and cash equivalents	**(176)**	4,708	**(139)**	5,593
Cash and cash equivalents, beginning of period	**176**	885	**139**	-
Cash and cash equivalents, end of period	**$ -**	$ 5,593	**$ -**	$ 5,593

See accompanying notes to consolidated financial statements.

The unaudited consolidated financial statements of NuVista Energy Ltd. ("Nuvista" or "the Company") have been prepared by management in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), using the same accounting policies as those set out in note 1 to the consolidated financial statements for the year ended December 31, 2008, except as noted below in note 1. The consolidated financial statements for the three and six months ended June 30, 2009, should be read in conjunction with the annual audited consolidated financial statements for the year ended December 31, 2008. Certain amounts have been reclassified to conform with the current year's presentation. All tabular amounts are in thousands, except per share amounts, unless otherwise stated.

1. Adoption of new accounting policies

Goodwill and intangible assets

Effective January 1, 2009, the Company adopted Section 3064, Goodwill and Intangible Assets issued by the Canadian Institute of Chartered Accountants ("CICA"). Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. This new section has no current impact on the Company's consolidated financial statements.

2. Future accounting changes

International Financial Reporting Standards

In February 2008, the Canadian Accounting Standards Board confirmed January 1, 2011, as the effective date for the requirement to report under International Financial Reporting Standards ("IFRS") with comparative 2010 periods converted as well. Canadian GAAP as we currently know them, will cease to exist for all public reporting entities.

In order to meet the requirement to transition to IFRS, the Company has appointed internal staff to lead the conversion project along with sponsorship from an executive steering committee. The Company involves external auditors and external consultants, as required, during the conversion project. The Company has provided training to key employees, completed a preliminary analysis of the accounting differences and is monitoring the impact of the transition on its business practices, information systems and internal control over financial reporting. During the Company's preliminary analysis, accounting implementation for certain areas was identified as having the greatest potential impact to the Company's consolidated financial statements in terms of complexity and effort. The Company has determined that accounting for property, plant and equipment, impairment testing, asset retirement obligation, stock-based compensation and income taxes will be impacted by the conversion to IFRS. In July 2009, the International Accounting Standards Board issued amendments to IFRS 1 – First-Time Adoption of International Financial Reporting Standards. This amendment allows first-time adopters using full cost accounting to elect to measure oil and gas assets at the date of transition to IFRS using amounts determined based on the entity's previous GAAP. During the second quarter of 2009, the Company performed an analysis of IFRS in comparison with currently applied accounting principles on the key areas previously identified as high priority. The Company is currently analyzing the various accounting policy choices available and will implement those determined to be the most appropriate. The impact of IFRS on the Company's consolidated financial statements is not reasonably determinable at this time.

3. Property acquisitions

(a) Ferrier, Sunchild, Wapiti and Northwest Saskatchewan properties

On January 29, 2009, the Company acquired certain natural gas properties and related facilities in the Ferrier/Sunchild, Wapiti and northwest Saskatchewan core areas. The purchase price was approximately $54.1 million, net of asset retirement obligations. The acquisition was financed through bank borrowings. The results of operations of these properties have been included in the consolidated financial statements of the Company since the acquisition date.

(b) Northeast British Columbia and Northwest Alberta properties

On June 15, 2009, the Company entered into an agreement to acquire certain properties in the Martin Creek area of northeast British Columbia and in northwest Alberta for a purchase price of $174 million, net of asset retirement obligations. A cash deposit of $18.0 million was paid as part of the transaction. The acquisition closed on July 27, 2009. See subsequent events, note 10.

4. Asset retirement obligations

Total asset retirement obligations are based on estimated costs to reclaim and abandon ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. At June 30, 2009, the estimated total undiscounted amount of cash flows required to settle the Company's asset retirement obligations is $225.8 million (2008 – $187.9 million), which will be incurred over the next 51 years. The majority of the costs will be incurred between 2010 and 2036. A credit-adjusted risk-free rate of 8% (2008 – 8%) and an inflation rate of 2% (2008 – 2%) were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	June 30, 2009	December 31, 2008
Balance, beginning of period	$ 46,296	$ 26,574
Accretion expense	1,923	3,026
Liabilities incurred	5,870	7,203
Liabilities acquired	1,328	8,505
Change in assumptions	-	3,504
Liabilities settled	(1,189)	(2,516)
Balance, end of period	$ 54,228	$ 46,296

5. Long-term debt

On April 3, 2009, the Company received an extension of the revolving credit facility until April 29, 2010. The maximum borrowing amount of the credit facility remains unchanged at $450.0 million (2008 – $450.0 million).

Borrowing under the credit facility may be made by prime loans, bankers' acceptances and/or US libor advances. These advances bear interest at the bank's prime rate and/or at money market rates plus a stamping fee. The credit facility is secured by a first floating charge debenture, general assignment of book debts and the Company's oil and natural gas properties and equipment. The credit facility has a 364-day revolving period and is subject to an annual review by the lenders, at which time a lender can request conversion to a one year term loan. During the revolving period, a determination of the maximum borrowing amount occurs semi-annually on or before April 30 and October 31. During the term period, no principal payments would be required until April 29, 2011. As such, this credit facility is classified as long-term. Cash paid for interest expense for the three months ended June 30, 2009 was $3.9 million (2008 – $5.0 million) and for the six months ended June 30, 2009 was $5.5 million (2008 - $7.2 million).

6. Shareholders' equity

(a) Share capital, warrants and contributed surplus

	June 30, 2009	December 31, 2008
Share capital	$ 588,506	$ 587,460
Warrants	-	3,454
Contributed surplus	15,044	7,128
Total	$ 603,550	$ 598,042

(b) Authorized

Unlimited number of voting Common Shares and 1,200,000 Class B Performance Shares.

Common shares issued

	June 30, 2009		December 31, 2008	
	Number	Amount	Number	Amount
Balance, beginning of period	79,164	$ 587,460	52,704	$ 240,245
Issued for cash	-	-	6,000	80,546
Issued on Rider acquisition	-	-	19,844	256,195
Exercise of stock options	116	801	616	6,545
Stock-based compensation	-	245	-	4,144
Cost associated with shares issued, net of future tax benefit of $nil (2008 - $84)	-	-	-	(215)
Balance, end of period	79,280	$ 588,506	79,164	$ 587,460

On March 4, 2008, the Company issued 6.0 million units of NuVista ("Unit") at a price of $14.00 per Unit for gross proceeds of $84.0 million by way of a private placement. Each Unit consisted of one common share and one-half of a warrant.

(c) Warrants

	June 30, 2009		December 31, 2008	
	Number	Amount	Number	Amount
Balance, beginning of period	3,000	$ 3,454	-	$ -
Issued	-	-	3,000	3,454
Transferred to contributed surplus on expiry	(3,000)	(3,454)	-	-
Balance, end of period	-	$ -	3,000	$ 3,454

At December 31, 2008, there were 3.0 million common share purchase warrants outstanding. Each warrant entitled the holder thereof to acquire, subject to adjustment, one common share for $15.50, prior to March 4, 2009. As of March 5, 2009, these warrants expired unexercised.

(d) Contributed surplus

	June 30, 2009	December 31, 2008
Balance, beginning of period	$ 7,128	$ 4,967
Stock-based compensation	4,707	6,305
Exercise of stock options	(245)	(4,144)
Expired warrants	3,454	-
Balance, end of period	$ 15,044	$ 7,128

(e) Per share amounts

During the three months ended June 30, 2009, there were 79,209,242 (2008 – 78,829,785) weighted average shares outstanding. On a diluted basis, there were 79,209,242 (2008 – 80,368,214) weighted average shares outstanding after giving effect for dilutive stock options. For the six months ended June 30, 2009, there were 79,187,032 (2008 – 69,753,816) weighted average shares outstanding and 79,187,032 (2008 – 70,752,811) weighted average shares outstanding on a dilutive basis. The number of anti-dilutive options totaled 5,462,467 at June 30, 2009 (2008 – 221,209).

(f) Stock options

The Company has established a stock option plan whereby officers, directors, employees and service providers may be granted options to purchase common shares. Options granted prior to December 2008 vest at the rate of 25% per year and expire two years from the vest date. The terms of future stock option grants were amended in December 2008. Pursuant to the amendment, options subsequently granted will vest at the rate of 33% per year and expire 2.5 years after the vest date. The total stock options outstanding plus the Class B

Performance Shares cannot exceed 10% of the outstanding common shares. The summary of stock option transactions is as follows:

	June 30, 2009		December 31, 2008	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Balance, beginning of period	6,111,945	$ 13.69	4,046,400	$ 13.46
Granted	747,036	10.78	3,263,260	13.64
Exercised	(115,750)	6.92	(615,675)	10.63
Forfeited	(375,400)	14.24	(508,715)	14.63
Expired	(95,950)	12.46	(73,325)	17.64
Balance, end of period	6,271,881	$ 13.46	6,111,945	$ 13.69

The Company uses the fair value based method for the determination of the stock-based compensation costs. The fair value of each option granted during the six months ended June 30, 2009, was estimated on the date of grant using the Black-Scholes option pricing model. In the pricing model, the risk-free interest rate used was 2% (2008 – 4.5%); volatility of 52% (2008 – 33%); an average expected life of 4.5 years (2008 – 4.5 years); an estimated forfeiture rate of 10% (2008 – 10%); and dividends of nil (2008 – nil). The weighted average fair value of stock options granted during the six months ended June 30, 2009 was $4.73 per option (2008 – $5.26 per option). For the six months ended June 30, 2009, the Company capitalized $1.4 million (2008 – $0.8 million) in stock based compensation.

(g) Restricted stock units

In January 2008, the Board of Directors approved a Restricted Stock Unit ("RSU") Incentive Plan for employees and officers. Each RSU entitles participants to receive cash equal to the market value of the equivalent number of shares of the Company. The RSUs become payable as they vest over their lives, typically three years.

For the six months ended June 30, 2009, the Company recorded an RSU stock-based compensation expense of $0.1 million (2008 – $1.1 million) and capitalized $nil (2008 – $0.3 million) to property, plant and equipment with a corresponding offset recorded in compensation liability. The stock-based compensation expense was based on the trading price of the Company's shares on June 30, 2009.

The following table summarizes the change in RSUs:

	June 30, 2009	December 31, 2008
	Number	Number
Balance, beginning of period	351,543	-
Vested	(103,974)	-
Granted	90,769	390,163
Forfeited	(14,720)	(38,620)
Balance, end of period	323,618	351,543

The following table summarizes the change in compensation liability relating to the RSUs:

	June 30, 2009	December 31, 2008
	Amount	Amount
Balance, beginning of period	$ 1,461	$ -
Change in accrued compensation liability	821	1,461
Cash payments	(740)	-
Balance, end of period	$ 1,542	$ 1,461
Compensation liability – current (included in accounts payable and accrued liabilities)	$ 1,268	$ 611
Compensation liability – long-term	$ 274	$ 850

For the six months ended June 30, 2009, cash payments of $0.7 million (2008 – $nil) were made relating to the RSU Incentive Plan.

7. Risk management activities

(a) Financial instruments

The Company's financial instruments recognized in the consolidated balance sheet consists of cash and cash equivalents, accounts receivable, commodity derivative contracts, accounts payable and accrued liabilities, and long-term debt. Unless otherwise noted, carrying values reflect the current fair value of the Company's financial instruments due to their short-term maturities. The estimated fair values of recognized financial instruments have been determined based on the Company's assessment of available market information and appropriate methodologies, through comparisons to similar instruments, or third party quotes.

As at June 30, 2009, the Company has entered into the following crude oil contracts:

Volume	Average Price (Cdn$/bbl)	Term
1,000 bbls/d	CDN. $64.00 – Bow River	January 1, 2009 – December 31, 2009
1,000 bbls/d	CDN. $95.01 – $110.01 – WTI (1)	January 1, 2009 – December 31, 2009

(1) This is a US$ denominated crude oil contract with an associated fixed price foreign exchange contract of 1.0262 US$/Cdn$.

As at June 30, 2009, the mark-to-market value of the financial commodity contracts was an asset of $1.2 million.

(b) Physical sale contracts

As at June 30, 2009, the Company has entered into direct natural gas sale contracts as follows:

Volume	Average Price (Cdn$/gj)	Term
20,000 gj/d	CDN. $7.45 – Fixed Price AECO	April 1, 2009 – October 31, 2009
5,000 gj/d	CDN. $5.65 – AECO Floor (1), (4)	April 1, 2009 – October 31, 2009
20,000 gj/d	CDN. $5.97– $6.56 AECO (2), (4)	November 1, 2009 – October 31, 2010
20,000 gj/d	CDN. $5.55 – AECO Floor (3), (4)	November 1, 2009 – March 31, 2010

(1) The AECO put was purchased at a deferred cost of $0.82/gj for a total cost of $0.9 million.
(2) The deferred cost associated with the funded collar was $0.30/gj for a total cost of $2.2 million.
(3) The AECO put was purchased at a deferred cost of $0.97/gj for a total cost of $2.9 million.
(4) The deferred costs are incurred monthly over the term of the contract and will be offset against revenues.

These physical sale contracts are normal purchase and sale transactions and as such are not considered derivative financial instruments.

8. Relationship with Bonavista Petroleum Ltd.

In 2003, as part of the Plan of Arrangement with Bonavista Petroleum Ltd. ("Bonavista"), NuVista entered into a Technical Services Agreement ("TSA") with Bonavista for the provision of certain services to NuVista. On August 31, 2007, the TSA was terminated and replaced with a new services agreement that reflected the remaining ongoing services that will be provided by Bonavista. On November 1, 2008, this services agreement was terminated and Bonavista no longer provides any ongoing services to NuVista.

NuVista and Bonavista are considered related as two directors of NuVista, one of whom is NuVista's chairman, are also directors and officers of Bonavista and a director and an officer of NuVista are also officers of Bonavista. For the three months ended June 30, 2009, NuVista paid Bonavista $ nil (2008 – $0.4 million) in fees relating to general and administrative services provided by Bonavista. In 2009, NuVista charged Bonavista management fees for jointly owned partnerships totalling $0.3 million (2008 – $0.3 million). In addition, during the second quarter of 2009, Bonavista charged NuVista $56,000 (2008 - $63,000) for costs that are outside of the new services agreement relating to NuVista's share of direct charges from third parties.

For the six months ended June 30, 2009, NuVista paid Bonavista $nil (2008 - $0.8 million) in fees relating to general and administrative services provided by Bonavista, and NuVista charged Bonavista management fees for jointly owned partnerships totaling $0.6 million (2008 - $0.6 million). In addition, Bonavista charged NuVista $76,000 (2008 - $72,000) for costs that are outside of the new services agreement relating to NuVista's share of direct charges from third parties. As at June 30, 2009, the amount receivable from Bonavista was $0.2 million (2008 - $2.9 million).

The above transactions are considered to be in the normal course of business and have been measured at their exchange amounts, being the amounts agreed to by both the parties.

9. Commitments

The following is a summary of the Company's contractual obligations and commitments as at June 30, 2009:

	Total	2009	2010	2011	2012	Thereafter
Transportation	$ 13,817	$ 2,426	$ 3,368	$ 2,668	$ 2,004	$ 3,351
Office lease	6,849	1,027	2,055	2,055	1,712	-
Physical sale contract premiums	5,620	2,050	3,570	-	-	-
Physical power contract	6,900	-	-	2,300	2,300	2,300
Long-term debt	376,305	-	-	376,305	-	-
Total commitments	$ 409,491	$ 5,503	$ 8,993	$ 383,328	$ 6,016	$ 5,651

10. Subsequent events

(a) Property acquisition and equity financing

On July 27, 2009, the Company completed the acquisition of certain properties in the Martin Creek area of Northeast British Columbia and in Northwest Alberta for a purchase price of $174 million, net of asset retirement obligations. The acquisition was financed through a combination of bank debt and the net proceeds from two equity offerings. The Company entered into an agreement to issue 7,500,000 subscription receipts at a price of $11.00 per subscription receipt on a bought deal basis for gross proceeds of $82.5 million. In addition, the Company issued 1,500,000 subscription receipts at a price of $11.00 per subscription receipt, by way of a private placement to Ontario Teachers' Pension Plan for gross proceeds of $16.5 million. The subscription receipt offerings closed on July 7, 2009. Each subscription receipt was exchanged for one common share of NuVista for no additional consideration on July 27, 2009.

(b) Long-term debt

On July 27, 2009, the Company's credit facility was increased to a maximum borrowing amount of $510.0 million. Terms and conditions remain the same as disclosed in note 5, long-term debt.

Corporate Information

Directors
Keith A. MacPhail, Chairman
W. Peter Comber, Barrantagh Investment Management Inc.
Pentti O. Karkkainen, KERN Partners
Ronald J. Poelzer, Bonavista Energy Trust
Craig W. Stewart, RMP Energy Ltd.
Alex G. Verge, President and CEO
Clayton H. Woitas, Range Royalty Management Ltd.
Grant A. Zawalsky, Burnet, Duckworth & Palmer LLP

Officers
Keith A. MacPhail, Chairman
Alex G. Verge, President and CEO
Robert F. Froese, Vice President, Finance and CFO
Ross L. Andreachuk, Vice President and Controller
Kevin J. Christie, Vice President, Exploration
Steven J. Dalman, Vice President, Business Development
D. Chris McDavid, Vice President, Operations
Daniel B. McKinnon, Vice President, Engineering
Joshua T. Truba, Vice President, Land
Glenn A. Hamilton, Corporate Secretary

Auditors
KPMG LLP
Chartered Accountants
Calgary, Alberta

Legal Counsel
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Bankers
Canadian Imperial Bank of Commerce
Bank of Montreal
Royal Bank of Canada
Toronto Dominion Bank
Bank of Nova Scotia
Alberta Treasury Branches
Union Bank of California, Canada Branch

Registrar and Transfer Agent
Valiant Trust Company
Calgary, Alberta

Engineering Consultants
GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Stock Exchange Listing
Toronto Stock Exchange
Trading Symbol "NVA"

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