GALLEON ENERGY

2009

Second Quarter

INTERIM REPORT

Report to the Shareholders

SECOND QUARTER 2009 HIGHLIGHTS

- Drilled and cased for production seven (6.8 net) wells in Q2 2009: three (3 net) Eastern Montney gas wells, two (1.8 net) Central Montney gas wells, one (1.0 net) light oil resource well and one (1.0 net) multi zone shallow gas well;
- Revenues (including realized net gains of $3.8 million from financial derivatives) of $54.1 million and funds from operations of $29.6 million ($0.39/share) were generated from average production of 16,076 BOE/d (64% gas) in Q2 2009;
- Operating expenses averaged $9.43/BOE in Q2 2009, a decrease of 26% from Q2 2008 and a 12% decrease from Q1 2009. Operating expenses from Galleon's four major properties, comprising 68% of total production, have averaged $5.85/BOE in 2009;
- In Q2 2009, an operating netback of $24.11/BOE (including $2.58/BOE of realized net gains from financial derivatives) was recorded. This netback continues to be strong as crude oil and NGL production comprises 36% of total production;
- A loss of $22.0 million was recorded in Q2 2009 which includes an unrealized loss of $25.0 million relating to crude oil financial derivatives marked to market at June 30, 2009;
- In Q2 2009, exploration and development capital expenditures of $19.6 million (including $7.8 million in plant and facility expenditures) were incurred and the disposition of $4.6 million of minor properties was completed;
- On June 23, 2009, an equity financing closed for gross proceeds of $36 million through the issuance of 7,500,000 Class A shares;
- At June 30, 2009, net debt was $233.2 million comprised of $235.8 million in bank debt and positive working capital of $2.6 million. Credit facilities of $310 million are available to the Corporation.

EASTERN MONTNEY

In the second quarter of 2009, Galleon successfully drilled three (100% interest) Eastern Montney horizontal multi-fractured wells. Results have met Galleon's expectations. All three wells were drilled from the same surface pad thereby reducing tie in costs. Galleon has slowed the pace of the drilling program in this area because of low gas prices, but this program will be accelerated when gas prices increase. Galleon plans to continue utilizing pad drilling as the pool continues to be developed. Galleon has identified 350 horizontal drilling locations on over 200 sections of owned land within the delineated Eastern Montney fairway.

In Q2 2009, Galleon completed an optimization study of the Eastern Montney gas gathering system. A new booster compressor is planned to be installed to lower line pressure and recover some of the gas backed out by the high pressure horizontal wells. This project is scheduled for completion at the beginning of Q4 2009 subject to regulatory approvals. Galleon continues to view this play as being one of the most economic gas projects in the Western Canadian basin.

The first horizontal well 02/03-21 (100% interest) (drilled in Q1 2008 and on stream during Q2 2008) has produced approximately 0.6 Bcf in the last 13 months. Current production is approximately 0.8 MMcf/d excluding oil and NGLs. On average per well, the Eastern Montney natural gas wells have produced approximately 15 Bbls of oil and NGLs per 1 Mmcf.

CENTRAL MONTNEY

Production in the Central Montney project #1 increased to a record level of 2,339 BOE/d net in the second quarter of 2009. This production level was achieved from wells on production at the end of Q1 2009. Currently a plant expansion is in progress in this project and is scheduled for completion at the end of the third quarter 2009.

In Q2 2009, one light oil well was drilled with encouraging results in the Central Montney project #1. Two successful natural gas wells were drilled in the Central Montney project #2 in Q2 2009.

LIGHT OIL

In 2009, Galleon has identified two new light oil projects:

1. The initial horizontal light oil well (100% interest) in the Nordegg project is currently producing over 100 BOE/d net of oil and associated gas. To date, this key well has produced over 94,500 barrels of oil and 0.45 Bcf of natural gas. Prior to the end of 2009, Galleon plans to delineate the size of the pool by drilling up to four wells.

2. The new Doig light oil resource project has been tested with two successful wells drilled to date. The first horizontal well has been producing for approximately eight months. This well has produced over 10,000 barrels of oil and is currently producing approximately 60 BOE/d net. The second horizontal well is located approximately 3.2 km from the first well. It has been recently completed and is producing at a similar rate to the first well. Up to three wells are planned prior to the end of 2009 to further delineate the size of the pool. Galleon currently has access to over 10 sections of land in this project.

2009 GUIDANCE

Galleon plans to direct a large portion of the capital expenditure program in Q3 2009 towards optimizing infrastructure and increasing facility capacity. The plant expansion in Central Montney project #1 has received necessary regulatory approvals with completion expected at the end of the third quarter of 2009. Drilling projects are anticipated to receive the largest portion of the Q4 2009 and Q1 2010 capital budget in order to take advantage of the benefits from the recently announced Alberta royalty incentive programs and to fill the expanded facility capacity. This approach is both financially prudent and positions Galleon to quickly ramp up production as commodity prices recover.

At the end of the third quarter 2009, the Central Montney #1 natural gas plant is expected to be temporarily shut in for up to three weeks due to the plant capacity expansion from 14 MMcf/d to 28 MMcf/d. Once fully operational in early October 2009, it is expected that an additional net 1,200 BOE/d production will be processed through the expanded plant.

In third quarter 2009, the Eastern Montney gas gathering system will be optimized to lower line pressures and recover some of the gas backed out by the high pressure horizontal wells. Incremental production is expected. However, during this process, production will be temporarily reduced for a period of approximately one to two weeks.

Based on current commodity prices, Galleon plans to drill up to 22 wells in the second half of 2009 of which 60% will target light oil. One vertical well and up to six horizontal wells are planned in the Eastern Montney project to capture new reserves and to further advance the developed area of the project. Up to three wells are planned in the Central Montney #2 project to further advance the developed area of the project. Up to four horizontal Nordegg oil wells are planned to increase production and to prove up reserves in this new project. Up to three wells are planned in the Doig light oil resource project. One exploration well is planned in B.C. targeting light oil. The remaining four wells will be development locations on existing Galleon projects.

Production in 2009 is expected to average approximately 17,000 BOE/d.

Management's Discussion and Analysis

This Management's Discussion & Analysis ("MD&A") is intended to assist in the understanding of the trends and significant changes in the financial condition and results of operations of Galleon Energy Inc. ("Galleon" or the "Corporation") for the three and six month periods ended June 30, 2009 with comparisons to the three and six months ended June 30, 2008 and as at December 31, 2008. The MD&A has been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") and should be read in conjunction with the unaudited interim financial statements as at and for the three and six month periods ended June 30, 2009 and 2008 and the audited financial statements and MD&A for the year ended December 31, 2008.

Petroleum and natural gas reserves and volumes are converted to a common unit of measure on a basis of six thousand cubic feet (Mcf) of gas to one barrel (Bbl) of oil. BOEs may be misleading, particularly if used in isolation. The forgoing conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Amounts are shown in Canadian dollars unless otherwise stated. All production volumes disclosed herein are sales volumes.

This MD&A is based on information available as of, and is dated, August 13, 2009.

NON-GAAP MEASUREMENTS

The MD&A contains terms commonly used in the oil and gas industry, such as funds from operations, funds from operations per share, and operating netback. These terms are not defined by GAAP and should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings as determined in accordance with Canadian GAAP as an indicator of Galleon's performance. Management believes that in addition to net earnings, funds from operations is a useful financial measurement which assists in demonstrating the Corporation's ability to fund capital expenditures necessary for future growth or to repay debt. Galleon's determination of funds from operations may not be comparable to that reported by other companies. 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 abandonment expenditures. The Corporation calculates funds from operations per share by dividing funds from operations by the weighted average number of Class A shares outstanding.

Galleon uses the term net debt in the MD&A and presents a table showing how it has been determined. This measure does not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other companies.

FORWARD-LOOKING STATEMENT

Statements that are not historical facts may be considered forward looking statements including management's assessment of future plans and operations, expected production rates, expected decline rates of certain wells, expected operating costs in 2009, expectation that the Corporation will not be taxable in 2009, drilling plans and the timing thereof, capital expenditures, the timing thereof and the method of funding thereof, plans to continue hedging and to sell non-core assets, plans related to the adoption of IFRS and timing of construction of facilities and shut-in of facilities and the effects thereof. These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Corporation's objectives, goals or future plans are forward-looking statements. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, Galleon's actual results may differ materially from those expressed in, or implied by, the forward-looking statements.

Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Corporation believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Corporation can give no assurance that such expectations will prove to be correct.

In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Corporation has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors and assumptions is not exhaustive. Additional information on these and other factors that could affect Galleon's operations and financial results are included elsewhere herein and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or at Galleon's website (www.galleonenergy.com). Furthermore, the forward looking statements contained herein are made as at the date hereof and Galleon does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Financial and Operating Highlights

($000s except per share amounts)	*Three months ended June 30*		*Six months ended June 30*	
	2009	*2008*	***2009***	*2008*
FINANCIAL				
Revenue before royalties and financial derivatives	**50,373**	120,602	**107,360**	222,118
Funds flow from operations [1]	**29,605**	61,157	**55,755**	116,602
Per share – basic	**0.39**	0.86	**0.74**	1.69
Per share – diluted	**0.39**	0.84	**0.74**	1.66
Net income (loss)	**(22,012)**	5,673	**(27,103)**	16,090
Per share – basic	**(0.29)**	0.08	**(0.36)**	0.23
Per share – diluted	**(0.29)**	0.08	**(0.36)**	0.23
Capital expenditures – Exploration & Development	**19,619**	34,856	**50,010**	106,182
Total assets	**1,141,506**	1,070,765	**1,141,506**	1,070,765
Net debt [2]	**233,225**	229,340	**233,225**	229,340
Shareholders' equity	**700,400**	620,436	**700,400**	620,436
Weighted average shares outstanding				
Basic	**76,040,581**	70,741,901	**75,638,439**	68,862,794
Diluted	**76,040,581**	72,575,607	**75,638,439**	70,419,898
OPERATING				
Average daily production				
Light oil (Bbl/d)	**4,323**	4,629	**4,508**	5,015
Heavy oil (Bbl/d)	**899**	2,066	**939**	2,228
NGLs (Bbl/d)	**565**	501	**625**	471
Natural gas (Mcf/d)	**61,733**	53,971	**65,660**	53,307
Total (BOE/d)	**16,076**	16,191	**17,016**	16,599
Average selling prices [3]				
Light oil ($/Bbl)	**60.49**	122.97	**53.37**	108.17
Heavy oil ($/Bbl)	**52.60**	89.51	**42.91**	75.77
NGLs ($/Bbl)	**39.23**	71.19	**36.41**	66.42
Natural gas ($/Mcf)	**3.61**	9.92	**4.41**	8.96
Total ($/BOE)	**34.43**	81.85	**34.86**	73.53

[1] *See "Non-GAAP Measurements"*

[2] *Net debt includes bank indebtedness, working capital and capital leases, but excludes financial derivatives.*

[3] *The average prices reported are before realized derivatives and transportation charges.*

RESULTS OF OPERATIONS

Comparative financial results for the quarter are as follows:

Three months ended June 30	**2009**		2008	
($000s)	*1,462,922 BOE*	*$/BOE*	*1,473,414 BOE*	*$/BOE*
Revenues	50,373	34.43	120,602	81.85
Realized gain (loss) on financial derivative	3,774	2.58	(10,317)	(7.00)
Other income	74	0.05	105	0.07
Royalties	(11,560)	(7.90)	(27,155)	(18.43)
GCA[1]	8,477	5.79	6,097	4.14
Transportation costs	(2,056)	(1.41)	(2,416)	(1.64)
Operating costs	(13,790)	(9.43)	(18,726)	(12.71)
Net	35,292	24.11	68,190	46.28
G&A	(3,827)	(2.62)	(3,698)	(2.51)
Interest costs	(1,702)	(1.16)	(2,977)	(2.02)
Capital and other taxes	(158)	(0.11)	(358)	(0.24)
Funds from operations[2]	29,605	20.22	61,157	41.51

Six months ended June 30	**2009**		2008	
($000s)	*3,079,901 BOE*	*$/BOE*	*3,020,890 BOE*	*$/BOE*
Revenues	107,360	34.86	222,118	73.53
Realized gain (loss) on financial derivative	8,111	2.63	(13,678)	(4.53)
Other income	746	0.24	228	0.08
Royalties	(27,137)	(8.81)	(47,823)	(15.83)
GCA[1]	13,702	4.45	8,520	2.82
Transportation costs	(4,398)	(1.43)	(4,031)	(1.33)
Operating costs	(31,087)	(10.09)	(36,186)	(11.98)
Net	67,297	21.85	129,148	42.76
G&A	(8,028)	(2.61)	(6,069)	(2.01)
Interest costs	(3,287)	(1.07)	(5,780)	(1.91)
Capital and other taxes	(227)	(0.07)	(697)	(0.23)
Funds from operations[2]	55,755	18.10	116,602	38.61

[1] GCA means Gas Cost Allowance

[2] See "Non-GAAP Measurements"

PETROLEUM AND NATURAL GAS REVENUES

Three months ended June 30		*2009*		*2008*
($000s)		*%*		*%*
Light oil	**23,748**	**47**	51,789	43
Heavy oil	**4,304**	**9**	16,830	14
NGLs	**2,017**	**4**	3,244	3
Natural gas	**20,197**	**40**	48,537	40
Royalty income	**107**	**–**	202	–
Total	**50,373**	**100**	120,602	100

Six months ended June 30		*2009*		*2008*
($000s)		*%*		*%*
Light oil	**43,411**	**40**	98,648	44
Heavy oil	**7,293**	**7**	30,717	14
NGLs	**4,122**	**4**	5,696	3
Natural gas	**52,204**	**49**	86,718	39
Royalty income	**330**	**–**	339	–
Total	**107,360**	**100**	222,118	100

Revenues for the three months ended June 30, 2009 decreased by 58% to $50.4 million from $120.6 million for the same period in 2008. The decrease is primarily due to a 48% decrease in oil prices and a 64% decrease in natural gas prices. In the second quarter of both 2009 and 2008, on a revenue basis, oil and liquids generated 60% of revenues.

PRODUCTION

	Three months ended June 30				*Six months ended June 30*			
		2009		*2008*		***2009***		*2008*
		%		*%*		*%*		*%*
Light oil (Bbls/d)	**4,323**	**27**	4,629	29	**4,508**	**26**	5,015	30
Heavy oil (Bbls/d)	**899**	**6**	2,066	13	**939**	**6**	2,228	13
NGLs (Bbls/d)	**565**	**3**	501	3	**625**	**4**	471	3
Natural gas (Mcf/d)	**61,733**	**64**	53,971	55	**65,660**	**64**	53,307	54
BOE/d (6:1)	**16,076**	**100**	16,191	100	**17,016**	**100**	16,599	100

Average production was 16,076 BOE/d for the second quarter of 2009, 1% lower then the average production of 16,191 BOE/d for the second quarter of 2008. Daily production volumes varied by product as follows: light oil decreased by 7%; and heavy oil decreased by 56%; natural gas increased by 14% and natural gas liquid increased by 13%.

Light oil production decreased as a function of reduced drilling activity in the first half of 2009. Fewer light oil wells have been drilled in the first half of 2009, and, as a result, production from the flush, high decline phase of existing wells has not been replaced. The production declines have flattened off and rates of decline going forward are expected to be reduced.

Natural gas volumes have increased as a result of increased production from the Central Montney and the Eastern Montney projects.

COMMODITY PRICING AND MARKETING

Petroleum products are sold to major Canadian marketers at spot reference prices or prices subject to commodity contracts based on US WTI for crude oil and AECO for natural gas. As a means of managing the risk of commodity price volatility, Galleon has entered into several natural gas and crude oil financial contracts.

As at June 30, 2009, the Corporation had entered into the following financial contracts.

Natural gas

March 1, 2009 – March 31, 2010	5,000 GJ/d	CDN $5.96/GJ
March 1, 2009 – March 31, 2010	5,000 GJ/d	CDN $6.01/GJ

Crude Oil

Fixed Price:

March 1, 2009 – December 31, 2009	1,000 Bbl/d	WTI CDN $68.25/Bbl
February 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $63.30/Bbl
February 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $63.85/Bbl
April 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $70.15/Bbl
May 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $72.00/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $74.30/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $74.50/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $76.25/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $76.50/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $77.00/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $77.00/Bbl

Costless Collar:

March 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $60.00-$70.00/Bbl

For the three and six month periods ended June 30, 2009, the Corporation recorded a realized gain of $3.8 million and $8.1 million, respectively, on financial contracts. For the three and six month periods ended June 30, 2009, unrealized losses of $25.0 million and $20.3 million, respectively, have been recorded with respect to the financial contracts. The Corporation would pay $19.1 million if the contracts were unwound at June 30, 2009.

Subsequent to June 30, 2009, the Corporation has entered into two physical costless collar contracts:

Natural gas

August 1, 2009 – March 31, 2010	5,000 GJ/d	CDN $3.00/GJ floor - $6.53/GJ ceiling
August 1, 2009 – March 31, 2010	5,000 GJ/d	CDN $3.00/GJ floor - $6.60/GJ ceiling

In addition, one financial contract for the period of September 1, 2009 to December 31, 2009 for 10,000 GJ/d has been entered into. This put contract requires a payment of $0.44/GJ by the Corporation. The counterparty is required to pay the Corporation when the floating AECO price is less than $3.25 CAD/GJ.

Prices – prior to realized gains or losses on financial contracts and prior to transportation

	Three months ended June 30		*Six months ended June 30*	
	2009	*2008*	***2009***	*2008*
Light oil ($/Bbl)	**60.49**	122.97	**53.37**	108.17
Heavy oil ($/Bbl)	**52.60**	88.51	**42.91**	75.77
NGLs ($/Bbl)	**39.23**	71.19	**36.41**	66.42
Natural gas ($/Mcf)	**3.61**	9.92	**4.41**	8.96

Comparing the three month period ending June 30, 2009 to 2008, the light oil price decreased by 51% to $60.49/Bbl, the heavy oil price decreased by 41% to $52.60/Bbl, and the natural gas price decreased by 64% to $3.61/Mcf.

CRUDE OIL PRICES

Three months ended June 30		***2009***		*2008*
	$000s	*$/Bbl*	*$000s*	*$/Bbl*
Crude oil	**28,101**	**59.13**	68,633	112.64
Realized financial contracts	**(738)**	**(1.55)**	(10,317)	(16.93)
Transportation	**(545)**	**(1.15)**	(1,072)	(1.76)
Net crude oil	**26,818**	**56.43**	57,244	93.95

Six months ended June 30		***2009***		*2008*
	$000s	*$/Bbl*	*$000s*	*$/Bbl*
Crude oil	**50,841**	**51.57**	129,446	98.20
Realized financial contracts	**(521)**	**(0.53)**	(13,678)	(10.37)
Transportation	**(1,101)**	**(1.12)**	(1,463)	(1.11)
Net crude oil	**49,219**	**49.92**	114,305	86.72

Natural Gas Prices

Three months ended June 30		***2009***		*2008*
	$000s	*$/Mcf*	*$000s*	*$/Mcf*
Natural gas	**20,255**	**3.61**	48,725	9.92
Realized financial contracts	**4,599**	**0.82**	–	–
Transportation	**(1,511)**	**(0.27)**	(1,344)	(0.27)
Net natural gas	**23,343**	**4.16**	47,381	9.65

Six months ended June 30		***2009***		*2008*
	$000s	*$/Mcf*	*$000s*	*$/Mcf*
Natural gas	**52,397**	**4.41**	86,976	8.96
Realized financial contracts	**8,720**	**0.73**	–	–
Transportation	**(3,297)**	**(0.28)**	(2,568)	(0.26)
Net natural gas	**57,820**	**4.86**	84,408	8.70

PERFORMANCE BY PROPERTY

Three months ended June 30	*2009* Production BOE/d	%	Operating netbacks/ BOE[1] $	*2008* Production BOE/d	%	Operating netbacks/ BOE[1] $	*2009* Funds from operations[2] %
Eastern Montney	**4,118**	**26**	**13.05**	3,267	20	43.06	**21**
Eaglesham	**2,292**	**14**	**17.12**	2,628	16	61.57	**16**
Puskwa	**2,231**	**14**	**29.74**	2,392	15	65.83	**26**
Kakut	**2,323**	**14**	**12.78**	397	2	42.79	**12**
Alexis / St.Anne	**1,034**	**6**	**4.40**	1,363	8	44.68	**2**
Culp / Kimiwan	**642**	**4**	**22.04**	725	4	79.92	**6**
Edam	**578**	**4**	**23.42**	1,350	8	34.96	**5**
Other	**2,858**	**18**	**11.05**	4,069	27	43.97	**12**
	16,076	**100**	**15.73**	16,191	100	50.76	**100**

Six months ended June 30	*2009* Production BOE/d	%	Operating netbacks/ BOE[1] $	*2008* Production BOE/d	%	Operating netbacks/ BOE[1] $	*2009* Funds from operations[2] %
Eastern Montney	**4,278**	**25**	**13.94**	3,579	22	37.59	**24**
Eaglesham	**2,623**	**15**	**17.49**	2,801	17	52.99	**19**
Puskwa	**2,313**	**14**	**27.06**	2,548	15	61.13	**25**
Kakut	**2,339**	**14**	**15.29**	413	2	37.91	**14**
Alexis / St.Anne	**1,038**	**6**	**6.61**	1,171	7	39.54	**3**
Culp /Kimiwan	**671**	**4**	**16.93**	770	5	67.57	**5**
Edam	**594**	**3**	**9.55**	1,576	9	28.96	**2**
Other	**3,160**	**19**	**6.32**	3,741	23	41.20	**8**
	17,016	**100**	**14.56**	16,599	100	45.33	**100**

[1] Operating netbacks/BOE excludes GCA and are calculated by subtracting royalties and operating costs from revenues.

[2] See "Non-GAAP Measurements".

Eastern Montney production increased by 26% to an average of 4,118 BOE/d (88% natural gas and 12% oil and liquids) during Q2 2009 compared to 3,267 BOE/d in Q2 2008. The Eastern Montney natural gas project continues to be a significant resource to Galleon and is currently the largest producing area contributing 21% to total funds from operating activities in Q2 2009 based on 26% of production volumes. The operating netback of $13.05/BOE decreased by 70% from Q2 2008 mainly due to significantly weaker natural gas prices.

In the second quarter of 2009, Galleon successfully drilled three (100% working interest) Eastern Montney horizontal multi-fractured wells. All three wells were drilled from the same surface pad thereby reducing tie in costs. Galleon has slowed the pace of the drilling program in this area because of low gas prices, but this program can be accelerated at any time when gas prices increase. Galleon plans to continue utilizing pad drilling as the pool continues to be developed. Galleon has identified 350 horizontal drilling locations on over 200 sections of owned land within the delineated Eastern Montney fairway.

In Q2 2009, Galleon completed an optimization study of the Eastern Montney gas gathering system. A new booster compressor is planned to be installed to lower line pressure and recover some of the gas backed out by the high pressure horizontal wells. This project is scheduled for completion at the beginning of Q4 2009 subject to regulatory approvals. Galleon continues to view this play as being one of the lowest cost projects in the Western Canadian basin.

Average production at Eaglesham decreased by 13% in the second quarter of 2009 to an average of 2,292 BOE/d (75% natural gas and 25% oil and liquids) compared to 2,628 BOE/d in Q2 2008. The decrease in production is mainly due to reduced drilling on this project.

Drilling for high decline Wabamun oil was curtailed as oil prices softened in the second half of 2008. Eaglesham is the second largest producing property and contributed 16% of the second quarter 2009 funds from operations from 14% of production. The operating netback of $17.12/BOE has decreased by 72% compared to $61.57/BOE in the same period of the prior year as a result of significantly weaker commodity prices.

In Q2 2009, Galleon successfully drilled two (90% working interest) wells at Eaglesham. One was a vertical well targeting both the Wabamun and Montney zones and the other was a Montney horizontal multi fractured well. The dual zone vertical well showed gas charge on the logs in both the Wabamun and the Montney zones. The Wabamun zone was completed first, being the deeper horizon and was put on stream at an initial production rate of approximately 1.5 Mmcf/d. The Montney zone is planned to be completed in the future. The Montney horizontal well was placed on stream at a restricted production rate of approximately 2.0 Mmcf/d as the H_2S content was 0.03% higher than plant specifications. The plant is currently being modified so that this well can produce at its full capability.

At Puskwa, average production for Q2 2009 was 2,231 BOE/d (86% oil and liquids and 14% natural gas) contributing 26% of Q2 2009 funds from operations from 14% of total production. Operating netbacks of $29.74/BOE decreased by 55% compared to Q2 2008 due to the substantially lower oil prices and to an increase in royalty rates as a result of the Alberta Royalty Framework (“ARF”). The Puskwa project is in the development stage with the implementation of two enhanced recovery schemes.

Production at Puskwa is managed with minor quarterly variations occurring due to the ongoing operation of the enhanced oil recovery (“EOR”) project. One well was drilled for EOR purposes in Q3 2008 and a second well was converted into an injection well in Q1 2009. These low cost wells provide a low risk method of increasing production by allowing an incremental increase in oil production for every barrel of water injected. Up to two more wells may be drilled at Puskwa over the remainder of 2009.

Kakut production increased by 485% in the second quarter of 2009 compared to the same period of 2008 and contributed 14% of total production in Q2 2009. The operating netback was $12.78/BOE in Q2 2009, a decrease of 70% compared to Q2 2008 as a result of much lower commodity prices. Currently a plant expansion is in progress at Kakut and is scheduled for completion at the end of the third quarter 2009. It is expected that this plant expansion will allow behind pipe production of 1,200 BOE/d to be brought on production in Q4 2009. In Q2 2009 one successful light oil well was drilled with encouraging results

ROYALTIES

Three months ended June 30	***2009***	*2008*
($000s, except as indicated)		
Crown	**9,765**	25,007
Freehold	**602**	302
GORR and other	**1,193**	1,846
Gross royalties	**11,560**	27,155
GCA	**(8,477)**	(6,097)
Net royalties	**3,083**	21,058
% of revenue	**23.0**	22.5
% of revenue net of GCA	**6.1**	17.5

Six months ended June 30	***2009***	*2008*
($000s, except as indicated)		
Crown	**23,603**	43,570
Freehold	**1,249**	756
GORR and other	**2,285**	3,497
Gross royalties	**27,137**	47,823
GCA	**(13,702)**	(8,520)
Net royalties	**13,435**	39,303
% of revenue	**25.3**	21.5
% of revenue net of GCA	**12.5**	17.7

Gross royalties were 23.0% for the second quarter of 2009 compared to 22.5% for the same period in 2008. By product the royalty rates were 22.6% for heavy oil, 24.3% for light oil, 18.9% for gas and 43.0% for liquids for Q2 2009. For the second quarter of 2008, the royalty rates were 22.4% for heavy oil, 18.6% for light oil, 26.1% for natural gas and 32.6% for liquids.

Net royalties were 6.1% for the second quarter of 2009 compared to 17.5% for the same period in 2008. Q2 2009 GCA includes adjustments from 2008 of $4.5 million.

Gross royalties for light oil as a percentage of light oil revenue increased by 5.7% in Q2 2009 mainly due to implementation of the ARF on January 1, 2009. The Corporation has recorded higher royalties on light oil and has realized a reduction in the number of light oil wells qualifying for a royalty holiday.

Gross royalties for natural gas as a percentage of natural gas revenue decreased by 7.2% for Q2 2009 compared to the same period in Q2 2008 due to the substantial decrease in natural gas prices.

Gross royalties for heavy oil as a percentage of heavy oil revenue were 22.6% for Q2 2009 and 22.4% for Q2 2008.

Gross royalties for liquids as a percentage of liquids revenue increased by 10.4% in Q2 2009 compared to Q2 2008 as the liquid crown royalty rates have increased substantially with the implementation of the ARF.

The Alberta Government announced new royalty incentives which are expected to benefit the Corporation until expiry on March 31, 2011. A Drilling Royalty Credit ("DRC") is expected to result in a $200 per metre credit on new wells drilled that may be applied against approximately 50% of crown royalties payable by the Corporation during the period April 1, 2009 to March, 2011. No DRC amounts have been accrued by the Corporation in Q2 2009 as the required legislation has not been passed into law.

OPERATING COSTS

Three months ended June 30		***2009***				*2008*
	Production	*Operating Costs*		*Production*	*Operating Costs*	
	%	*%*	*$/BOE*	*%*	*%*	*$/BOE*
Eastern Montney	26	21	7.80	20	12	7.65
Eaglesham	14	10	6.42	16	8	6.64
Puskwa	14	8	5.16	15	11	9.43
Kakut	14	5	3.28	2	2	10.82
Alexis / St.Anne	6	15	21.97	8	6	8.91
Culp /Kimiwan	4	7	17.01	4	8	23.50
Edam	4	6	16.69	8	19	29.00
Other	18	28	14.80	27	34	16.74
	100	100	9.43	100	100	12.71

Six months ended June 30		***2009***				*2008*
	Production	*Operating Costs*		*Production*	*Operating Costs*	
	%	*%*	*$/BOE*	*%*	*%*	*$/BOE*
Eastern Montney	25	19	7.46	22	12	6.44
Eaglesham	15	10	6.28	17	10	7.01
Puskwa	14	6	4.55	15	12	9.20
Kakut	14	5	3.72	2	2	9.36
Alexis / St.Anne	6	11	18.57	7	5	8.99
Culp /Kimiwan	4	8	21.04	5	9	22.70
Edam	3	8	22.66	9	20	24.73
Other	19	33	18.13	23	30	16.64
	100	100	10.09	100	100	11.98

Operating costs were $13.8 million or $9.43/BOE for the second quarter of 2009 compared to $18.7 million or $12.71/BOE for the same period of the prior year. This represents a decrease year over year of 26% on a per unit basis.

The four major properties comprising 68% of Galleon's production continued to show improvement in operating costs. Operating costs for these properties averaged $5.85/BOE for the first six months of 2009.

In the Eastern Montney natural gas project, operating costs were $7.80/BOE in Q2 2009 compared to $7.65/BOE in the same period of the prior year. Eastern Montney is one of Galleon's low cost producing properties. Operating costs are expected to average under $8.00/BOE in 2009 in this area.

Eaglesham operating costs for Q2 2009 were $6.42/BOE a decrease of 3% compared to $6.64/BOE in second quarter 2008. Decreased operating costs are mainly due to the tie in of single well batteries to the Eaglesham oil battery therefore reducing the equipment rentals and emulsion trucking previously required. As well, propane and fuel costs have been greatly reduced with prices substantially lower in Q2 2009 compared to Q2 2008. Operating costs at Eaglesham are expected to reduce further in 2009 due to electrification of the plant and well sites in Q3 2009.

Operating costs at Puskwa were $5.16/BOE in second quarter 2009 compared to $9.43/BOE in the same period of 2008. The operating costs at Puskwa continue to improve and it continues to be one of Galleon's low cost producing properties. Operating costs were higher in Q2 2008 due to the expansion of the water flood operations which resulted in temporary water trucking and pump equipment rental costs which have now been largely eliminated.

Kakut is Galleon's lowest cost producing area. Operating costs at Kakut were $3.28/BOE in Q2 2009 a decrease of 70% compared to $10.82/BOE in the same period of the prior year. Due to production increases, the natural gas plant was expanded in Q4 2008 which resulted in significantly lower operating costs on a per BOE basis.

GENERAL AND ADMINISTRATION EXPENSES

Three months ended June 30		***2009***		*2008*
($000s)		*$/BOE*		*$/BOE*
Gross	**4,988**	**3.41**	4,919	3.34
Capitalized overhead	**(657)**	**(0.45)**	(833)	(0.57)
Overhead recoveries	**(504)**	**(0.34)**	(388)	(0.26)
	3,827	**2.62**	3,698	2.51

Six months ended June 30		***2009***		*2008*
($000s)		*$/BOE*		*$/BOE*
Gross	**10,492**	**3.41**	8,803	2.91
Capitalized overhead	**(1,455)**	**(0.47)**	(2,042)	(0.68)
Overhead recoveries	**(1,009)**	**(0.33)**	(692)	(0.23)
	8,028	**2.61**	6,069	2.00

Gross and net G&A expenses have increased by 1% and 3% respectively in Q2 2009 as compared to Q2 2008.

For the three months ended June 30, 2009 G&A expenses by category were: salary and employee – 51%, office – 24%, consulting – 6%, computer – 6%, shareholder costs – 2%, audit, engineering and legal – 7%, and corporate – 4%.

INTEREST

Interest expense was $1.7 million for the three months ended June 30, 2009, as compared to $3.0 million for the same periods in 2008. The decrease from the prior year is primarily due to lower interest rates charged on bank credit facilities. As a result of the renewal of the bank credit facilities in late May 2009, interest expenses have increased by approximately 2-3% due to higher interest rates charged on these facilities. At June 30, 2009 an amount of $235.8 million was drawn against the Corporation's credit facilities compared to $223.6 million at June 30, 2008.

STOCK BASED COMPENSATION

Stock based compensation was a non-cash expense of $1.3 million for the three month period ended June 30, 2009 (June 30, 2008 – $2.3 million). During the second quarter of 2009, 80,000 stock options were granted to employees at an average exercise price of $4.52 per option.

At June 30, 2009, 6,837,901 stock options were outstanding at an average exercise price of $11.95.

In July 2009, 5,085,067 share options in aggregate were surrendered to the Corporation for cancellation. No new share options were granted.

DEPLETION, DEPRECIATION AND ACCRETION

For the three month period ended June 30, 2009, depletion and depreciation ("D&D") totaled $32.3 million ($22.05/BOE), as compared to $32.4 million ($22.01/BOE) for the same period in the prior year. Reserve additions for the second quarter of 2009 were estimated internally.

Capital expenditures of $103.9 million ($109.9 million – June 30, 2008) related to acquisition of undeveloped land and seismic have been excluded from the depletion and depreciation calculation and $164.1 million ($112.8 million – June 30, 2008) of future development costs have been added.

Accretion expense on the Corporation's asset retirement obligation was $664,000 for the three month period ended June 30, 2009. This compares to $464,000 for the same period in 2008. The increase is due to an increase in the number of wells and facilities in which Galleon has an interest.

CAPITAL AND FUTURE TAXES

The current tax provision was $158,000 for the three month period ended June 30, 2009. For the same period in 2008, the expense was $358,000. The provision relates to Saskatchewan capital and resource tax and is calculated based on revenues earned in Saskatchewan. It is not expected that Galleon will pay income taxes in 2009.

The provision for future income taxes was a recovery of $7.6 million for the three month period ended June 30, 2009 (June 30, 2008 – expense of $2.9 million). The future tax recovery is a result of the net losses recorded in 2009.

CAPITAL EXPENDITURES

	($000s)
Property & equipment balance at December 31, 2008	1,071,150
Additions to property and equipment	49,942
Dispositions of property and equipment	(4,633)
Acquisition of property and equipment	68
Asset retirement obligation additions	622
Asset retirement obligation disposed	(83)
Depletion and depreciation	(67,738)
Property & equipment balance at June 30, 2009	**1,049,328**

Three months ended June 30		***2009***		*2008*
($000s)		*%*		*%*
Land	**581**	**3**	3,732	11
Geological and geophysical	**344**	**2**	2,723	8
Drilling and completion	**10,856**	**55**	19,008	54
Plant and facilities	**7,769**	**40**	8,512	24
Acquisitions	**68**	**–**	–	–
Other assets	**1**	**–**	881	3
Exploration and Development Expenditures	**19,619**	**100**	34,856	100

Six months ended June 30		***2009***		*2008*
($000s)		*%*		*%*
Land	**1,359**	**3**	5,771	5
Geological and geophysical	**1,399**	**3**	8,076	8
Drilling and completion	**32,401**	**65**	63,401	60
Plant and facilities	**14,738**	**29**	27,920	26
Acquisitions	**68**	**–**	–	–
Other assets	**45**	**–**	1,014	1
Exploration and Development Expenditures	**50,010**	**100**	106,182	100

Exploration and development expenditures during the second quarter of 2009 were $19.6 million. Drilling and completions expenditures comprised 55% of exploration and development activity. Galleon drilled seven gross wells resulting in six (5.1 net) natural gas wells and one (1.0 net) light oil wells for a success rate of 100% for the quarter.

Facilities expenditures were $7.8 million in Q2 2009 or 40% of total expenditures. Land and seismic expenditures totaled $0.6 million and $0.3 million, respectively, in the second quarter 2009.

The capital expenditure program to date has been partially funded through the disposition of four non- core oil and gas properties in the Howard, Lashburn, Doe Creek and Gift Lake areas for cash consideration of $4.6 million. Due to the substantially lower commodity prices to date in 2009, Galleon's capital expenditure program has been modified to a level which is expected to match funds from operations. The Corporation does not plan to fund the 2009 capital program with incremental bank debt.

LIQUIDITY AND CAPITAL RESOURCES

June 30	**2009**	2008
($000s)		
Bank debt	**235,829**	223,562
Capital leases – non current	**1,135**	2,467
Working capital (asset) deficiency (excluding future income taxes and fair value of financial derivatives)	**(3,739)**	3,311
Total net debt	**233,225**	229,340

FUNDING OF CAPITAL PROGRAM

Three months ended June 30	**2009**	2008
($000s)		
Issuance / repurchase of shares, net of costs	**34,489**	7,966
Funds from operations	**29,605**	61,157
Change in bank debt	**(27,790)**	(6,304)
Change in debt and working capital from acquisitions	**–**	9,336
Change in capital leases	**(202)**	(624)
Disposition of properties	**4,633**	–
Change in inventory	**1,896**	(2,444)
Change in working capital and other	**(23,012)**	(24,382)
	19,619	44,705

Six months ended June 30	**2009**	2008
($000s)		
Net issuance of shares, net of costs	**34,947**	9,712
Funds from operations	**55,755**	116,602
Change in bank debt	**(13,186)**	60,184
Change in debt and working capital from acquisitions	**–**	(36,947)
Change in capital leases	**(406)**	(1,108)
Disposition of properties	**4,633**	–
Change in inventory	**4,420**	(2,567)
Change in working capital and other	**(36,153)**	(28,062)
	50,010	117,814

The Corporation has $310 million in credit facilities available consisting of a $270 million extendible 364 day revolving term facility and a $40 million non-revolving facility. The $40 million facility is available subject to mutual approval of the banking syndicate and Galleon, including repayment terms. Collateral for the facilities consists of a demand debenture for $500 million collateralized by a first floating charge over all of the property and equipment of the Corporation, excluding the capital leases. At June 30, 2009, an amount of $235.8 million was drawn against the credit facilities (December 31, 2008 - $249.0 million). As at June 30, 2009, the Corporation is in compliance with all covenants, obligations and conditions of its credit facilities.

COMMITMENTS

Drilling Rig

The Corporation has entered into a Master Daywork Contract whereby it is entitled to the use of a drilling rig for a two year period which commenced November 15, 2007. Future minimum payments under this contract are as follows:

Year	*Amount ($000s)*
2009	1,638

Office Lease Payments

At June 30, 2009 the Corporation has committed to future minimum payments under operating leases that cover office space as follows:

Year	*Amount ($000)*
2009	1,228
2010	1,801

The above commitment includes an estimate of the Corporation's share of operating expenses, utilities and taxes for the duration of the office lease.

Equipment

At June 30, 2009 the Corporation has commitments to future minimum payments for leased equipment, under operating leases as follow:

Year	*Amount ($000s)*
2009	877
2010	867

Capital leases

The Corporation has entered into a series of equipment lease financing arrangements. Under these arrangements, the Corporation is committed to annual minimum lease payments as follows:

	$
2009	990
2010	1,605
Total minimum lease payments	2595
Less interest included in payments	(122)
Principal portion of minimum lease payments	2473
Less current portion	(1,338)
Capital lease obligation at June 30, 2009	**1,135**

The applicable terms and commitments are summarized in the following table:

End of lease term	*Outstanding principal*	*Purchase price at end of lease*	*Interest rate*
October 2009	$67	$1	2.1 percent above the 30-day banker's acceptance rate
December 2009	$462	$1	6.0 percent
September 2010	$1,944	$1,000	6.3 percent

A general security agreement and a first charge against the equipment have been provided as collateral

FINANCIAL INSTRUMENTS

Refer to the "Commodity Pricing and Marketing" section.

BUSINESS RISKS

General

Galleon is engaged in the exploration, development and production of crude oil and natural gas. The oil and gas business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Operational risks include competition, reservoir performance uncertainties, environmental factors, and regulatory, environment and safety concerns. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Corporation's revenues have declined as a result of decreased commodity pricing, it has been required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Financial Risks

Financial risks include fluctuations in commodity prices, interest rates and the Canadian/US dollar exchange rate, and the cost of goods and services. The Corporation currently has financial contracts with Canadian chartered banks (see "Commodity Pricing and Marketing" for details). The Corporation also manages these risks by maintaining a balance sheet with prudent levels of debt measured by debt to funds from operations and debt coverage ratios. This allows for sufficient financial capacity to maintain exploration and development activities in any downturn in commodity prices.

Third Party Credit Risk

An additional risk is credit risk for failure of performance by counter-parties. This risk is controlled by an evaluation of the credit risk before contract initiation and ensuring product sales and delivery contracts are made with well-known and financially strong crude oil and natural gas marketers.

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition.

CRITICAL ACCOUNTING ESTIMATES

There are a number of critical estimates underlying the accounting policies employed in preparing the Financial Statements.

Oil and Gas Accounting

Galleon follows the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit-of-production method based on estimated proved oil and gas reserves.

Proved Reserves

Full cost accounting relies on the estimated proved reserves believed to be recoverable from the oil and gas properties. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering/production and other relevant economic data. These estimates are subject to change as economic conditions change and ongoing production and development activities provide new information. The Corporation's reserves are evaluated annually by an independent firm and by the Corporation on a quarterly basis. Reserve estimates are critical to the following accounting estimates:

- Calculation of unit of production depletion. Proved reserve estimates are used to determine the depletion and depreciation rate applied to each unit of production.
- Ceiling test calculation, measurement and impairment of oil and gas assets. Estimated future undiscounted cash flows are determined using the estimate of proved reserves.

An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

The calculation of proved reserves is affected by events, including the following:

- Changes to commodity prices
- Production performance of wells
- Changes to reservoir performance/pressures
- New geological and geophysical data
- Competitor production practices
- Changes to government regulations

As circumstances change and additional data becomes available, revisions are made to these estimates.

Unproved Properties

Certain costs related to unproved properties may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted. The costs related to unproved properties are also excluded from the book value subject to the ceiling test measurement and are assessed for impairment separately.

Full Cost Accounting Ceiling Test

The Corporation is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

The ceiling test is based on estimates of reserves, production rate, 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.

Asset Retirement Obligation

The Corporation is required to provide for future abandonment and site restoration costs. The Corporation must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to property, plant and equipment and the appropriate liability account over the expected service life of the asset. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of economic life of the asset, costs associated with abandonment and site restoration, and review of potential abandonment methods.

Income Tax Accounting

The determination of the Corporation's 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 subsequent to the financial statement reporting period. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Goodwill

The Corporation recognizes goodwill on corporate acquisitions when the total purchase price exceeds the fair value of net identifiable assets and liabilities of the acquired entity. Goodwill is tested quarterly for impairment or as events occur that could result in impairment. Impairment is recognized based on the fair value of the Corporation compared to the book value of the Corporation. If the fair value of the Corporation is less than the book value, impairment is measured allocating the fair value to the identifiable assets and liabilities as if the Corporation had been acquired in a business combination for its fair value. The excess of the fair value over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period which it occurs. Goodwill is stated at cost less impairment and is not amortized.

CHANGES IN ACCOUNTING POLICIES

As of January 1, 2009, Galleon has adopted the requirements under CICA 3064 "Goodwill and Intangible Assets". The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard has had no impact on Galleon's financial statements.

On January 20, 2009 the CICA issued EIC-173 "Credit Risk and the Fair value of Financial Assets and Financial Liabilities". Under the requirements of EIC-173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Galleon adopted the requirements of EIC-173 effective January 1, 2009. This has had no impact on Galleon's financial statements or additional disclosure.

Future accounting policies

The Canadian Accounting Standards Board (AcSB) has confirmed that the use of the International Financial Reporting Standards ("IFRS") will be required in 2011 for publicly accountable profit-oriented enterprises. IFRS will replace Canada's current GAAP for those enterprises that are responsible to large or diverse groups of stakeholders. The official changeover date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Companies will be required to provide comparative IFRS information for the fiscal year of 2010.

In July 2009, the International Accounting Standards Board (IASB) issued an amendment to IFRS 1 "First Time Adoption of International Reporting Standards." The amendment allows full cost accounting corporations to elect, at the time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP. The amendment will also permit full cost accounting corporations to measure, at the time of adoption, oil and gas assets in the development or production phases, by using the total value determined under the entity's previous GAAP and allocating values at the unit of account level based on the Corporation's reserve volumes or reserve values as of the date of conversion. This exemption will relieve the Corporation from retrospective application of IFRS for its oil and gas assets. The Corporation currently anticipates that this exemption will be used.

Galleon is in the initial stages of evaluating the impact of adopting IFRS and is in the process of developing a changeover plan which includes determining appropriate changes to accounting policies and required amendments to financial disclosures; identifying changes required in associated processes and information systems; compliance with internal control requirements; and education and training of internal stakeholders.

A project team has been established who will monitor the effect of the transition to IFRS on information systems, internal controls over financial reporting and disclosure controls and procedures. The differences between IFRS and Galleon's current accounting policies will be analyzed and the impact of various alternatives will be assessed. Changes in accounting policy are likely and may materially impact the financial statements. Due to anticipated changes in IFRS prior to the conversion date, the final impact of the conversion of Galleon's financial statements cannot be measured.

CONTROLS AND PROCEDURES OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Internal Controls over Financial Reporting

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with the Canadian GAAP.

The Corporation's CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the Corporation's most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No material changes in the Corporation's internal controls over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

SHARE INFORMATION

The following table summarizes the outstanding shares of Galleon as of June 30:

	2009	*2008*
Class A shares outstanding		
Basic	82,890,883	72,817,827
Diluted[1]	82,890,883	79,031,312
Class B shares outstanding	–	922,500
Class A shares issuable on conversion of Class B shares [2]	–	447,816

[1] *Includes no options (June 30, 2008 – 6,213,485).*

[2] *Assumes a conversion at the June 30, 2008 closing price of $20.60 per Class A share*

At June 30, 2009, the market value of Galleon's Class A shares was $352.3 million based on the closing price of $4.25 per share. As of August 13, 2009, the number of Class A shares and options outstanding are 82,890,883 and 1,612,834 respectively.

ADDITIONAL INFORMATION

Additional information relating to Galleon, including Galleon's Annual Information Form, can be accessed on-line on SEDAR at www.sedar.com, or from the Corporation's website at www.galleonenergy.com.

OUTLOOK

Galleon plans to direct a large portion of the capital expenditure program in Q3 2009 towards optimizing infrastructure and increasing facility capacity. The plant expansion in Central Montney project #1 has received necessary regulatory approvals with completion expected at the end of the third quarter of 2009. Drilling projects are anticipated to receive the largest portion of the Q4 2009 and Q1 2010 capital budget in order to take advantage of the benefits from the recently announced Alberta royalty incentive programs and to fill the expanded facility capacity. This approach is both financially prudent and positions Galleon to quickly ramp up production as commodity prices recover.

At the end of the third quarter 2009, the Central Montney #1 natural gas plant is expected to be temporarily shut in for up to three weeks due to the plant capacity expansion from 14 MMcf/d to 28 MMcf/d. Once fully operational in early October 2009, it is expected that an additional net 1,200 BOE/d production will be processed through the expanded plant.

In third quarter 2009, the Eastern Montney gas gathering system will be optimized to lower line pressures and recover some of the gas backed out by the high pressure horizontal wells. Incremental production is expected. However, during this process, production will be temporarily reduced for a period of approximately 1-2 weeks.

Based on current commodity prices, Galleon plans to drill up to 22 wells in the second half of 2009 of which 60% will target light oil. One vertical well and up to six horizontal wells are planned in the Eastern Montney project to capture new reserves and to further advance the developed area of the project. Up to three wells are planned in the Central Montney #2 project to further advance the developed area of the project. Up to four horizontal Nordegg oil wells are planned to increase production and to prove up reserves in this new project. Up to three wells are planned in the Doig light oil resource project. One exploration well is planned in B.C. targeting light oil. The remaining four wells will be development locations on existing Galleon projects.

Production in 2009 is expected to average approximately 17,000 BOE/d.

Quarterly Highlights

	2009					2008		2007
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
PRODUCTION								
Light oil (Bbl/d)	4,323	4,695	5,491	5,222	4,629	4,871	4,419	3,375
Heavy oil (Bbl/d)	899	979	1,046	1,257	2,066	2,919	1,746	1,949
Natural Gas (Mcf/d)	61,733	69,632	67,875	61,329	53,971	52,644	49,486	48,989
Liquids (Bbl/d)	565	687	604	499	501	441	283	237
BOE/d	**16,076**	**17,965**	**18,453**	**17,200**	**16,191**	**17,005**	**14,695**	**13,726**
Total BOE produced	1,462,922	1,616,979	1,697,711	1,582,369	1,473,414	1,547,476	1,351,986	1,262,762
Daily BOE of production per million Class A shares – basic	**211**	**239**	**250**	**236**	**229**	**254**	**232**	**229**
PRICES (prior to realized gains or losses on financial contracts and prior to transportation)								
Light oil ($/Bbl)	60.49	46.75	63.14	116.45	122.97	95.48	84.52	80.54
Heavy oil ($/Bbl)	52.60	33.88	25.46	98.70	89.51	66.83	37.75	40.50
Crude oil ($/Bbl)	59.13	44.53	57.12	113.00	112.64	85.79	71.27	65.88
Natural Gas ($/Mcf)	3.61	5.13	6.97	8.00	9.92	7.98	6.37	5.88
NGLs ($/Bbl)	39.23	34.07	42.76	73.16	71.19	61.02	72.89	64.05
PER BOE ($)								
Revenues	34.43	35.24	47.29	73.20	81.85	65.60	52.77	47.64
Royalties, net of ARTC and GCA	(2.11)	(6.40)	(6.51)	(13.13)	(14.29)	(11.79)	(8.55)	(8.41)
Transportation costs	(1.41)	(1.45)	(1.39)	(1.35)	(1.64)	(1.04)	(1.18)	(1.13)
Operating costs	(9.43)	(10.70)	(12.20)	(11.95)	(12.71)	(11.28)	(10.52)	(8.35)
Net	21.48	16.69	27.19	46.77	53.21	41.49	32.52	29.75
Other revenue	0.05	0.42	0.06	0.07	0.07	0.08	–	–
G&A	(2.62)	(2.60)	(2.37)	(2.05)	(2.51)	(1.53)	(2.00)	(1.19)
Interest	(1.16)	(0.98)	(1.53)	(1.74)	(2.02)	(1.81)	(1.83)	(2.14)
Capital and other taxes	(0.11)	(0.04)	(0.05)	(0.18)	(0.24)	(0.22)	0.05	(0.18)
Realized gain (loss) on financial derivative	2.58	2.68	15.78	(6.00)	(7.00)	(2.18)	(2.49)	(0.44)
Funds from operations[1]	20.22	16.17	39.08	36.87	41.51	35.83	26.25	25.80

[1]*See "Non-GAAP Measurements"*

Quarterly Highlights

(unaudited)		***2009***		*2008*
	Q2	*Q1*	*Q4*	*Q3*
FINANCIAL ($000s)				
Revenues	50,373	56,987	80,280	115,835
Operating costs	(13,790)	(17,297)	(20,704)	(18,917)
General & Administrative expenses	(3,827)	(4,201)	(4,019)	(3,238)
Interest expense	(1,702)	(1,585)	(2,599)	(2,759)
Funds from operations[1]	**29,605**	**26,150**	**66,365**	**58,331**
Per share, basic[1]	0.39	0.35	0.90	0.80
Per share, diluted[1]	0.39	0.35	0.90	0.79
Earnings (loss)	**(22,012)**	**(5,091)**	**25,113**	**38,061**
Per share, basic	(0.29)	(0.07)	0.34	0.52
Per share, diluted	(0.29)	(0.07)	0.34	0.51
Total assets	**1,141,506**	**1,158,329**	**1,181,003**	**1,121,339**
Weighted average outstanding Class A shares-basic	76,040,581	75,231,828	73,710,516	72,938,357
Weighted average outstanding Class A shares-diluted	76,040,581	75,231,828	74,032,935	73,955,365

(unaudited)		*2008*		*2007*
	Q2	*Q1*	*Q4*	*Q3*
FINANCIAL ($000s)				
Revenues	120,602	101,516	71,339	60,156
Operating costs	(18,726)	(17,460)	(14,227)	(10,547)
General & Administrative expenses	(3,698)	(2,371)	(2,712)	(1,507)
Interest expense	(2,977)	(2,803)	(2,476)	(2,707)
Funds from operations[1]	**61,157**	**55,445**	**35,483**	**32,566**
Per share, basic[1]	0.86	0.83	0.56	0.54
Per share, diluted[1]	0.84	0.81	0.55	0.53
Earnings (loss)	**5,673**	**10,417**	**(495)**	**1,590**
Per share, basic	0.08	0.16	(0.01)	0.03
Per share, diluted	0.08	0.15	(0.01)	0.03
Total assets	**1,070,765**	**975,911**	**799,359**	**743,932**
Weighted average outstanding Class A shares-basic	70,741,901	67,034,895	63,206,585	59,880,135
Weighted average outstanding Class A shares-diluted	72,575,607	68,630,474	64,716,872	61,724,550

[1] *See "Non-GAAP Measurements".*

Consolidated Balance Sheets

As at	June 30, **2009**	December 31, 2008
($000s) (unaudited)		
ASSETS		
Current		
Accounts receivable	31,790	54,864
Deposits and prepaid expenses	9,106	6,661
Future income taxes *(note 10)*	3,667	–
Fair value of financial derivatives *(note 12)*	4,995	1,237
	49,558	62,762
Goodwill *(notes 3)*	34,891	34,891
Equipment inventory	7,729	12,200
Property and equipment *(notes 3, 4, 5, 6, 7 and 8)*	1,049,328	1,071,150
	1,141,506	1,181,003
LIABILITIES		
Current		
Accounts payable and accrued liabilities	35,819	91,305
Capital leases *(notes 3 and 8)*	1,338	2,110
Bank loan *(note 7)*	235,829	249,015
Fair value of financial derivatives *(note 12)*	17,242	–
	290,228	342,430
Asset retirement obligation *(note 6)*	41,243	39,905
Capital leases *(notes 3 and 8)*	1,135	1,541
Fair value of financial derivatives *(note 12)*	6,824	–
Future income taxes *(note 10)*	101,676	107,603
	441,106	491,479
SHAREHOLDERS' EQUITY		
Share capital *(note 9)*	582,946	547,298
Contributed surplus *(note 9)*	25,340	23,009
Retained earnings	92,114	119,217
	700,400	689,524
	1,141,506	1,181,003

See accompanying notes

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

($000s, except per share amounts) (unaudited)	Three months ended June 30 2009	Three months ended June 30 2008	Six months ended June 30 2009	Six months ended June 30 2008
REVENUE				
Petroleum and natural gas revenue	50,373	120,602	107,360	222,118
Royalties, net of GCA	(3,083)	(21,058)	(13,435)	(39,303)
Realized gain on gas contract	–	763	–	763
Realized gain (loss) on financial derivative *(note 12)*	3,774	(10,317)	8,111	(13,678)
Unrealized loss on financial derivative *(note 12)*	(24,999)	(18,178)	(20,308)	(23,105)
Other income	74	105	746	228
	26,139	71,917	**82,474**	147,023
EXPENSES				
Operating	13,790	18,726	31,087	36,186
Transportation	2,056	2,416	4,398	4,031
General and administration	3,827	3,698	8,028	6,069
Interest	1,702	2,977	3,287	5,780
Stock-based compensation *(note 9)*	1,290	2,271	2,569	5,042
Accretion	664	464	1,323	1,032
Depletion and depreciation	32,259	32,433	67,789	66,052
	55,588	62,985	**118,481**	124,192
EARNINGS (LOSS) BEFORE TAXES	**(29,449)**	8,932	**(36,007)**	22,831
Income taxes *(note 10)*				
Capital and other taxes	158	358	227	697
Future income taxes (recovery)	(7,595)	2,901	(9,131)	6,044
	(7,437)	3,259	(8,904)	6,741
NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS)	**(22,012)**	5,673	**(27,103)**	16,090
RETAINED EARNINGS, BEGINNING OF PERIOD	**114,126**	50,370	**119,217**	39,953
RETAINED EARNINGS, END OF PERIOD	**92,114**	56,043	**92,114**	56,043
NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS) PER SHARE *(note 9)*				
Basic	(0.29)	0.08	(0.36)	0.23
Diluted	(0.29)	0.08	(0.36)	0.23
Weighted average Class A shares – basic	76,040,581	70,741,901	75,638,439	68,862,794
– diluted	76,040,581	72,575,607	75,638,439	70,419,898

See accompanying notes

Consolidated Statements of Cash Flows

	Three months ended June 30		Six months ended June 30	
($000) (unaudited)	***2009***	*2008*	***2009***	*2008*
Cash provided by (used in):				
OPERATING ACTIVITIES				
Net (loss) earnings	(22,012)	5,673	(27,103)	16,090
Items not requiring cash:				
Future income taxes (recovery)	(7,595)	2,901	(9,131)	6,044
Depletion and depreciation	32,259	32,433	67,789	66,052
Accretion	664	464	1,323	1,032
Stock-based compensation	1,290	2,271	2,569	5,042
Unrealized loss on financial derivative	24,999	18,178	20,308	23,105
Realized gain on gas contract	–	(763)	–	(763)
Abandonment costs	(228)	(91)	(524)	(1,194)
Change in non-cash working capital	(1,992)	(4,613)	7,616	(17,570)
	27,385	56,453	**62,847**	97,838
FINANCING ACTIVITIES				
Issue of common shares	36,205	8,055	36,695	9,893
Repurchase of common shares	–	–	(32)	–
Share issue costs	(1,716)	(89)	(1,716)	(181)
Capital lease payment	(202)	(624)	(406)	(1,108)
Working capital assumed on acquisition of ExAlta *(note 3)*	–	1,317	–	(44,966)
Working capital assumed on acquisition of Adamant *(note 4)*	–	8,019	–	8,019
Bank loan (repayment)	(27,790)	(6,304)	(13,186)	60,184
	6,497	10,374	**21,355**	31,841
INVESTING ACTIVITIES				
(Additions to) disposal of equipment inventory	1,896	(2,444)	4,420	(2,567)
Additions to oil and gas properties	(19,619)	(34,856)	(50,010)	(106,182)
Acquisition of oil and gas properties *(note 3 and 4)*	–	(9,849)	–	(11,632)
Disposition of oil and gas properties	4,633	–	4,633	–
Change in non-cash working capital	(20,792)	(19,678)	(43,245)	(9,298)
	(33,882)	(66,827)	**(84,202)**	(129,679)
CHANGE IN CASH	–	–	–	–
CASH, BEGINNING AND END OF PERIOD	–	–	–	–
SUPPLEMENTARY INFORMATION				
Cash interest paid	1,293	2,972	3,091	5,775
Cash taxes paid	150	56	375	446

See accompanying notes

Notes to the Consolidated Financial Statements

For the three and six month periods ended June 30, 2009 and 2008 (unaudited)

Unless otherwise stated, amounts presented in these notes are in Canadian dollars and tabular amounts are in thousands of Canadian dollars, except number of shares and per share amounts.

1. ACCOUNTING POLICIES

Nature of Business and Basis of Presentation

Galleon Energy Inc. ("Galleon" or the "Corporation") was incorporated under the Business Corporations Act of Alberta on March 27, 2003. The business of the Corporation is the acquisition of, exploration for and development of petroleum and natural gas properties in western Canada. Galleon is listed on the TSX under the symbol "GO".

On January 1, 2009, the Corporation's wholly owned subsidiaries, Exalta Energy Inc. and Adamant Energy Inc., were amalgamated with Galleon Energy Inc.

These unaudited interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), and follow the same accounting policies as the financial statements for the year ended December 31, 2008, except as noted below.

These notes do not include all disclosures required in annual financial statements and are incremental to, and should be read in conjunction with the audited financial statements for the year ended December 31, 2008.

2. CHANGES IN SIGNIFICANT ACCOUNTING POLICIES

As of January 1, 2009, Galleon has adopted the requirements under CICA 3064 "Goodwill and Intangible Assets". The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard has had no impact on Galleon's financial statements.

On January 20, 2009 the CICA issued EIC-173 "Credit Risk and the Fair value of Financial Assets and Financial Liabilities". Under the requirements of EIC-173, an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Galleon adopted the requirements of EIC-173 effective January 1, 2009. This has had no material impact on Galleon's financial statements or additional disclosure.

Future accounting policies

The Canadian Accounting Standards Board (AcSB) has confirmed that the use of the International Financial Reporting Standards ("IFRS") will be required in 2011 for publicly accountable profit-oriented enterprises. IFRS will replace Canada's current GAAP for those enterprises that are responsible to large or diverse groups of stakeholders. The official changeover date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Corporations will be required to provide comparative IFRS information for the fiscal year of 2010. Galleon is in the initial stages of evaluating the impact of adopting IFRS and is in the process of developing a changeover plan which includes determining appropriate changes to accounting policies and required amendments to financial disclosures; identifying changes required in associated processes and information systems; compliance with internal control requirements; and education and training of internal stakeholders.

In July 2009, the International Accounting Standards Board (IASB) issued an amendment to IFRS 1 "First Time Adoption of International Reporting Standards." The amendment allows full cost accounting corporations to elect, at the time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP. The amendment will also permit full cost accounting corporations to measure, at the time of adoption, oil and gas assets in the development or production phases, by using the total value determined under the entity's previous GAAP and allocating values at the unit of account level based on the Corporation's reserve volumes or reserve values as of the date of conversion. This exemption will relieve the Corporation from retrospective application of IFRS for its oil and gas assets. The Corporation currently anticipates that this exemption will be used.

3. ACQUISITION OF EXALTA ENERGY INC.

On January 16, 2008, the Corporation acquired all of the outstanding common shares of ExAlta Energy Inc. ("ExAlta"). The ExAlta acquisition was accounted for by the purchase method and shares were acquired for an aggregate of $62.5 million by the issuance of 4,334,856 Class A shares of Galleon at a value of $14.42 per share plus the assumption of $48.5 million of net debt including capital leases. The acquisition has been accounted for as a purchase as at the closing date of the transaction, with the purchase price allocated to assets and liabilities as follows:

Allocation of Purchase Price	*$*
Property and equipment	95,748
Equipment inventory	1,027
Goodwill	18,869
Future income taxes	582
Bank debt and working capital assumed (including bank debt of $43.1)	(44,966)
Asset retirement obligation	(3,403)
Capital lease	(3,575)
	64,282

Calculation of Purchase Price	
Fair value of shares issued	62,509
Transaction costs	1,773
	64,282

4. ACQUISITION OF ADAMANT ENERGY INC

On May 9, 2008, the Corporation acquired all of the outstanding common shares of Adamant Energy Inc. ("Adamant"). The Adamant acquisition was accounted for by the purchase method and shares were acquired for an aggregate of $65.2 million by the issuance of 4,193,288 Class A shares of Galleon at a value of $15.55 per share. The acquisition has been accounted for as a purchase as at the closing date of the transaction, with the purchase price allocated to assets and liabilities as follows:

Allocation of Purchase Price	*$*
Property and equipment	76,099
Equipment inventory	271
Working capital assumed (including cash of $2.4 million)	8,308
Future income taxes	(9,130)
Asset retirement obligation	(4,431)
Gas contract	(5,340)
	65,777

Calculation of Purchase Price	
Fair value of shares issued	65,206
Transaction costs	571
	65,777

The gas contract was amortized over the term of the contract which expired on December 31, 2008.

5. PROPERTY AND EQUIPMENT

On October 22, 2008 the Corporation purchased oil and gas properties in the Senex area of Alberta for cash, net of adjustments, of $5.8 million and issuance of 215,000 Class A shares for a total purchase price of $7.1 million.

Allocation of Purchase Price	*$*
Property and equipment	5,836
Undeveloped land	1,858
Asset retirement obligations	(551)
	7,143

As at June 30, 2009, $103.9 million (June 30, 2008- $109.9 million) of undeveloped land and seismic have been excluded from and $164.1 million (June 30, 2008 - $112.8 million) in future development costs have been added into the full cost pool for depletion purposes. For the three and six months ended June 30, 2009, $273,000 and $545,000, respectively (June 30, 2008 – $332,000 and $570,000) of exploration salaries have been capitalized.

As at June 30, 2009	*Cost* *$*	*Accumulated depletion* *$*	*Net book value* *$*
Petroleum and natural gas properties & equipment	1,460,662	(416,897)	1,043,765
Equipment under capital lease	5,159	(1,129)	4,030
Office furniture and equipment	2,536	(1,003)	1,533
	1,468,357	**(419,029)**	**1,049,328**

As at December 31, 2008	*Cost* *$*	*Accumulated depletion* *$*	*Net book value* *$*
Petroleum and natural gas properties & equipment	1,413,071	(348,822)	1,064,249
Equipment under capital lease	6,878	(1,278)	5,600
Office furniture and equipment	2,492	(1,191)	1,301
	1,422,441	**(351,291)**	**1,071,150**

During the three month period ended June 30, 2009, certain minor properties were sold for net proceeds of $4.6 million.

6. ASSET RETIREMENT OBLIGATION

The Corporation's asset retirement obligation results from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Corporation estimates the total undiscounted amount of cash flows required to settle its asset retirement obligation is approximately $86.2 million, which will be incurred over the next 18 years. Credit adjusted risk free rates of 5% and 8% and an inflation rate of 2% were used to calculate the fair value of the asset retirement obligation.

	Six months ended June 30, 2009 *$*	*Year ended December 31, 2008* *$*
Balance, beginning of year	39,905	25,535
Accretion expense	1,323	2,253
Liabilities incurred	622	6,668
Liabilities acquired	–	7,834
Disposition of liabilities	(83)	–
Settlement of liabilities	(524)	(2,385)
Balance, end of period	**41,243**	**39,905**

7. AVAILABLE CREDIT FACILITY

The Corporation has $310 million in credit facilities available consisting of a $270 million extendible 364 day revolving term facility and a $40 million non-revolving facility. The $40 million facility is available subject to mutual approval of the banking syndicate and the Corporation, including repayment terms. Collateral for the facilities consists of a demand debenture for $500 million collateralized by a first floating charge over all of the property and equipment of the Corporation, excluding the capital leases. At June 30, 2009, an amount of $235.8 million was drawn against the credit facilities (December 31, 2008 - $249.0 million). As at June 30, 2009, the Corporation is in compliance with all covenants, obligations and conditions of its credit facilities.

8. CAPITAL LEASE OBLIGATIONS

The Corporation has entered into a series of equipment lease financing arrangements. Under these arrangements, the Corporation is committed to annual minimum lease payments as follows:

	$
2009	990
2010	1,605
Total minimum lease payments	2,595
Less interest included in payments	(122)
Principal portion of minimum lease payments	2,473
Less current portion	(1,338)
Capital lease obligation at June 30, 2009	**1,135**

Interest expense of $32,000 and $72,000, respectively, was incurred on the capital leases during the three and six months ended June 30, 2009 (June 30, 2008 - $65,000 and $139,000).

The applicable terms and commitments are summarized in the following table:

End of lease term	*Outstanding principal*	*Purchase price at end of lease*	*Interest rate*
October 2009	$67	$1	2.1 percent above the 30-day banker's acceptance rate
December 2009	$462	$1	6.0 percent
September 2010	$1,944	$1,000	6.3 percent

A general security agreement and a first charge against the equipment have been provided as collateral.

9. SHARE CAPITAL

Authorized

Unlimited number of preferred shares with no par value

Unlimited number of voting Class A shares with no par value

Unlimited number of voting Class B shares with no par value.

On December 15, 2008 the Class B shares were converted into Class A shares. The conversion factor was calculated by dividing $10 by $5.36264, being the weighted average trading price for the Class A shares for the 30 consecutive trading days commencing October 15, 2008.

CLASS A SHARES	*Number of Shares*	*Amount $*
Balance at December 31, 2007	63,215,552	413,804
Issued as consideration for shares in ExAlta Energy Inc. *(e)*	4,334,856	62,509
Issued for cash on exercise of stock options	1,491,797	11,825
Tax effect of flow through shares	–	(16,200)
Share issue costs, net of tax of $49	–	(132)
Issued as consideration for shares in Adamant Energy Inc. *(d)*	4,193,288	65,206
Issued on acquisition of petroleum and natural gas properties *(c)*	215,000	1,354
Issued on conversion of Class B shares	1,720,240	5,207
Transfer from contributed surplus	–	3,725
Balance at December 31, 2008	**75,170,733**	**547,298**
Issued for cash on exercise of stock options	157,750	490
Common shares purchased *(b)*	(10,100)	(32)
Transfer from contributed surplus	–	167
Balance at March 31, 2009	**75,318,383**	**547,923**
Issued for cash on exercise of stock options	72,500	205
Issued for cash *(a)*	7,500,000	36,000
Share issue costs, net of tax of $463	–	(1,253)
Transfer from contributed surplus	–	71
Balance at June 30, 2009	**82,890,883**	**582,946**

a) On June 12, 2009, Galleon issued 7,500,000 Class A shares at $4.80 per share for cash proceeds.

b) On November 24, 2008, Galleon received regulatory approval for a Normal Course Issuer Bid ("Bid") to purchase, for cancellation, up to a maximum of 5,610,908 shares of the Corporation. The Bid commenced on November 26, 2008 and will terminate on November 25, 2009. As at June 30, 2009, Galleon has purchased 10,100 shares for total consideration of $32,627.

c) On October 22, 2008, the Corporation issued 215,000 Class A shares at a price of $6.30 per share to a third party as part of the consideration for the acquisition of certain petroleum and natural gas properties.

d) On May 9, 2008, the Corporation issued 4,193,288 Class A shares at $15.55 per share as consideration for shares in Adamant Energy Inc. as described in Note 4.

e) On January 16, 2008, the Corporation issued 4,334,856 Class A shares at $14.42 per share as consideration for shares in ExAlta Energy Inc. as described in Note 3.

The tax effect of $16.2 million related to the renouncement in January 2008 of flow-through shares issued in 2007 was recorded in 2008.

The Corporation has a share option plan which was approved on May 19, 2005 and amended on August 25, 2005, June 19, 2007 and May 13, 2008. The exercise price of each option may not be less than the closing price of the Corporation's Class A shares on the trading day immediately prior to the date of the grant. Compensation expense is recognized as the options vest. With options granted prior to November 2008 one third of the options vest immediately, and one third vest on each of the first and second anniversaries of the date of the grant. With options granted commencing November, 2008, the vesting period is one third on each of the next three anniversaries of the date of the grant. The options expire five years from the date of grant. The Corporation may grant up to 10% of the aggregate number of Class A shares outstanding and no one optionee is permitted to hold options entitling such optionee to purchase more than 5% of the aggregate number of issued and outstanding Class A shares. Class A shares have been reserved for all options granted.

	Six months ended June 30, 2009 $	Year ended December 31, 2008 $
Contributed surplus, beginning of period	23,009	19,064
Stock based compensation expense	2,569	7,670
Transfer to share capital	(238)	(3,725)
Contributed surplus, end of period	**25,340**	**23,009**

The fair value of options granted was estimated at the date of grant using a Black-Scholes Option Pricing Model with the following assumptions: risk-free interest rates of 1.33-4.51%; dividend yield of 0%; volatility factors of the market price of the Corporation's common shares of 36-45%; and an average expected life of the options of 3 years.

	Number of Shares	Weighted Average Exercise Price $
Outstanding, December 31, 2007	6,210,950	12.36
Granted	3,306,000	10.87
Cancelled	(987,502)	(10.40)
Exercised	(1,491,797)	(7.93)
Outstanding, December 31, 2008	7,037,651	11.87
Granted	120,000	3.45
Cancelled	(98,833)	(10.59)
Exercised	(157,750)	(3.10)
Outstanding, March 31, 2009	6,901,068	11.94
Granted	80,000	4.52
Cancelled	(70,667)	(12.06)
Exercised	(72,500)	(2.84)
Outstanding, June 30, 2009	**6,837,901**	**11.95**

Earnings per share

The Corporation utilizes the treasury stock method in the determination of diluted per share amounts. Under this method, the diluted weighted average number of shares is calculated assuming the proceeds that arise from the exercise of outstanding and in the money options are used to purchase common shares of the Corporation at their average market price for the period.

10. INCOME TAXES

The future income tax liability is comprised of the following temporary differences as at:

	June 30, 2009 $	December 31, 2008 $
Property and equipment	94,753	101,197
ACRI benefit	(1,260)	(870)
Share issue costs	(2,384)	(2,712)
Asset retirement obligation	(1,085)	(869)
Non-capital losses	(27,198)	(54,628)
Partnership income tax deferral	41,000	66,137
Capital leases	(668)	(986)
Financial derivative	(5,149)	334
Future income tax liability	98,009	107,603
Add current future income tax asset	3,667	–
Long term future income tax liability	**101,676**	**107,603**

11. COMMITMENTS

Drilling Rig

The Corporation has entered into a Master Daywork Contract whereby it is entitled to the use of a drilling rig for a two year period which commenced in November, 2007. Future minimum payments under this contract are as follows:

Year	*Amount $*
2009	1,638

Office Lease Payments

At June 30, 2009 the Corporation has committed to future minimum payments under operating leases that cover office space as follows:

Year	*Amount $*
2009	1,228
2010	1,801

The above commitment includes an estimate of the Corporation's share of operating expenses, utilities and taxes for the duration of the office lease.

Equipment

At June 30, 2009 the Corporation committed to future minimum payments for leased equipment, under operating leases, as follows:

Year	*Amount $*
2009	877
2010	867

Litigation

The Corporation is involved in various other claims and legal actions arising from the normal course of business. The Corporation does not expect that the outcome of these proceedings will have a material adverse effect on the Corporation as a whole.

12. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

Fair value of financial assets

The Corporation's financial instruments recognized in the balance sheet consist of accounts receivable, accounts payable, bank loan and financial derivatives ("financial instruments"). The carrying value of accounts receivable and accounts payable approximated their fair values at June 30, 2009 due to their short-term nature. The carrying value of the bank loan approximates fair value due to the floating interest rate on the facility. The fair value of the financial derivatives is recognized on the balance sheet as described below.

Credit risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The Corporation's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal credit risks. A portion of the Corporation's production is currently sold through joint venture partners under normal industry sale and payment terms. As at June 30, 2009, approximately 43% of the accounts receivable balance is due from three customers, compared to 27%, due from two customers, at December 31, 2008. These customers are considered to have high credit worthiness. The Corporation generally grants unsecured credit but routinely assesses the financial strength of its customers and joint venture partners. No provision has been made for past due receivables as of June 30, 2009 as the Corporation has assessed there are no impaired receivables.

	2009 $
Current	17,704
30 - 60 days	7,109
60 - 90 days	2,323
greater than 90 days	4,654
Total	31,790

Liquidity risk

Liquidity risk arises through excess financial obligations over available financial assets due at any point in time. The Corporation's objective in managing liquidity risk is to maintain sufficient available reserves in order to meet its liquidity requirements at any point in time. The Corporation believes that it has access to sufficient capital through internally generated cash flows and external equity sources, and to undrawn committed credit facilities to meet current spending forecasts. All of the Corporation's current liabilities mature within a one year period.

Interest rate risk

The Corporation is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair value of its financial instruments. The Corporation's primary debt facility has a floating interest rate that will fluctuate based on prevailing market conditions. Cash flows are sensitive to changes in interest rates on this instrument. Given the amount of debt employed, the Corporation's strategy is to manage interest rate risk. If interest rates on the floating instrument were to change by 1% it is estimated that annual cash flow would change by approximately $2.5 million.

Market risk

Market risk is the risk of uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the Corporation's financial assets, liabilities and expected future cash flows include commodity price risk and interest rate risk. It is estimated that annual cash flow would change approximately by $2.0 million and by $5.0 million, respectively, due to a $1 USD WTI and a $0.25/Mcf CDN change in oil and natural gas prices.

The Corporation has the following financial contracts in place as at June 30, 2009:

Natural Gas:

March 1, 2009 – March 31, 2010	5,000 GJ/d	CDN $5.96/GJ
March 1, 2009 – March 31, 2010	5,000 GJ/d	CDN $6.01/GJ

Crude Oil:

Fixed Price:		
March 1, 2009 – December 31, 2009	1,000 Bbl/d	WTI CDN $68.25/Bbl
February 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $63.30/Bbl
February 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $63.85/Bbl
April 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $70.15/Bbl
May 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $72.00/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $74.30/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $74.50/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $76.25/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $76.50/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $77.00/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN $77.00/Bbl
Costless Collar:		
March 1, 2009 – December 31, 2009	500 Bbl/d	WTI CDN $60.00-$70.00/Bbl

Interest Rate Swap

Notional Amount CAD $100 million Term: January 20, 2009 – January 20, 2011

Fixed rate 1.1% — Floating rate is reset against CAD — CDOR on each three month anniversary

Galleon has entered into the above contracts for the purpose of protecting funds generated from operations from the volatility of commodity prices and interest rates. The Corporation recognizes the fair value of its financial derivatives on the balance sheet each reporting period with the change in fair value recognized as an unrealized gain or loss on the statement of earnings. The fair value is based on quoted market prices. At June 30, 2009 the fair value is estimated to be a net liability of $19.1 million, composed of a $5.0 million short term asset, a $17.2 million short term liability and a $6.8 million long term liability.

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act. Fair values for commodity price and interest rate derivatives are provided by the financial intermediary with whom the transactions were completed and tested by the Corporation for reasonableness based on comparative market prices and the fixed prices of the contracts. In determining fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange and the Natural Gas Exchange, or obtained directly from counterparties, or other publicly available market data providers.

13. CAPITAL STRUCTURE FINANCIAL POLICIES

The Corporation defines capital as total debt and shareholders' equity comprised of retained earnings and share capital. The Corporation's primary capital management objective is to maintain a strong balance sheet affording the Corporation financial flexibility to achieve goals of continued growth and access to capital. The basis for the Corporation's capital structure is dependent on the Corporation's expected business growth and changes in the business environment.

The Corporation manages its capital structure and makes adjustments according to market conditions to maintain flexibility while achieving the objectives stated above. To manage the capital structure, the Corporation may adjust capital spending, issue new shares, issue new debt or repay existing debt.

The Corporation monitors its progress through the following two measures utilizing book values: net debt to funds from operations and total debt to total debt and shareholders' equity. Net debt to funds from operations is calculated as current liabilities and long term debt less current assets divided by the most recent two quarters annualized funds from operations. Total debt to total debt plus shareholders' equity is calculated as short term debt plus long term debt divided by short term debt plus long term debt plus shareholders' equity.

The Corporation's strategy is to maintain net debt to funds from operations at or below a level of 1.5 to 1. While the corporation may exceed this rate from time to time, variations are viewed as short term, and efforts are made after a period of variation to bring the measure back in line.

The Corporation's strategy concerning capitalization is to utilize more equity than debt. This is measured by targeting total debt to total debt plus shareholders' equity at a ratio of less than 0.4 to 1. The Corporation has no externally imposed capital requirements.

At June 30 ($000s)	*Target Measure*	*2009 $*	*2008 $*
Components of ratios			
Current assets (excluding fair value of financial derivative and future income tax)		40,896	65,773
Current liabilities (including short term debt; excluding fair value of financial derivative)		272,986	292,646
Short term debt (bank loan and current portion of capital lease)		237,167	225,846
Net debt		233,225	229,340
Total debt (bank loan and capital leases)		238,302	228,313
Shareholders' equity (share capital plus retained earnings)		675,060	599,456
Total capitalization (total debt plus shareholders' equity)		913,362	827,769
Funds from operations[1] (six months ended June 30 annualized)		111,510	233,204
Net debt/funds from operations	< 1.5 times	2.1	1.0
Total debt/total debt plus shareholders' equity	< 0.4 times	0.3	0.3

[1] *Funds from operations is a non-GAAP measure and is based on cash flow from operating activities before changes in non-cash working capital and abandonment expenditures.*

The increase in the net debt to funds from operations ratio from 2008 to 2009 resulted primarily from the large decrease of 52% in funds from operations compared to an increase of 2% in net debt.

14. SUBSEQUENT EVENTS

In July 2009, 5,085,067 share options in aggregate were surrendered to the Corporation for cancellation. No new share options have been granted.

The Corporation has entered into three commodity contracts subsequent to June 30, 2009. For the period August 1, 2009 to March 31, 2010, two physical natural gas contracts have been entered into. Each contract is for 5,000 GJ/d with a floor price of $3.00 CAD/GJ. One contract has a ceiling price of $6.53 CAD/GJ and one contract has a ceiling price of $6.60 CAD/GJ.

The third commodity contract is for 10,000 GJ/d for the period September 1, 2009 to December 31, 2009. This is a financial put contract set at $3.69 CAD GJ/d whereby the Corporation pays a fixed amount of $0.44 CAD/GJ and receives a payment by the counterparty when the floating AECO price is less than $3.25 CAD/GJ.

15. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current period's consolidated financial statement presentation.

Corporate Information

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William L. Cooke [1 3 4]

Lawrence Fenwick [2 3]

Daryl H. Gilbert [1 2]

Brad R. Munro [1 2 4]

Steve Sugianto

[1] Member of the Audit Committee

[2] Member of the Reserves Committee

[3] *Member of the Compensation Committee*

[4] *Member of the Corporate Governance Committee*

OFFICERS

Steve Sugianto, *President and Chief Executive Officer*

Glenn R. Carley, *Executive Chairman*

Shivon M. Crabtree, *Vice President, Finance & Chief Financial Officer*

Jim Iverson, *Vice President, Exploration*

Dale Orton, *Vice President, Engineering & Corporate Development*

Devin Sundstrom, *Vice President, Production*

Chris Tibbles, *Vice President, Land*

Bill Wee, *Vice President, Operations*

C. Steven Cohen, *Secretary*

AUDITOR

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Calgary, Alberta

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Calgary, Alberta

HSBC Bank Canada
Calgary, Alberta

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Calgary, Alberta

Union Bank
Canada Branch
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DeGolyer and MacNaughton
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REGISTRAR AND TRANSFER AGENT

Valiant Trust Company
Calgary, Alberta

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading Symbol GO

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