

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A") of Iteration Energy Ltd. (the "Company" or "Iteration") operating and financial results as at and for the three and six month period ended June 30, 2007 as well as information and estimates concerning the Company's future outlook based on currently available information. This discussion should be read in conjunction with Iteration's unaudited interim consolidated financial statements as at and for the three and six months ended June 30, 2007 and the audited consolidated financial statements as at and for the year ended December 31, 2006, together with accompanying notes. Readers should also refer to Iteration's 2006 Annual Information Form and Management's Discussion and Analysis for the year ended December 31, 2006. All financial information is reported in Canadian dollars, unless noted otherwise, and in accordance with Canadian generally accepted accounting principles ("GAAP").

Certain amounts in prior periods have been reclassified to enable comparison with the current period's presentation.

Natural gas is converted to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Additional information about Iteration Energy Ltd. filed with Canadian securities commissions, including periodic quarterly and annual reports and the Annual Information Form (AIF), is available on-line at www.iterationenergy.com and at www.sedar.com.

ITERATION OVERVIEW

Iteration is a Canadian oil and gas company with focus areas in Northeast British Columbia/Northwest Alberta and East Central Alberta. The most significant currently producing properties are Boundary Lake, Umbach and Rigel in Northeast British Columbia and Atmore and Wild River in Alberta.

The Company strives to operate its properties whenever possible and to maintain high working interests. Iteration believes this high level of operatorship can translate to controlling costs, timing of capital outlays and projects as well as providing competitive advantages for future opportunities.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

The major highlights of the three months ended June 30, 2007 include:

- Drilled 4.0 net gas wells and 1.0 net oil well with a 100% success rate. There was relatively little drilling during the quarter due to limited surface access over breakup.
- Average production for the quarter of 6,311 boed (94% gas) which represents an 8% increase from the previous quarter and a 62% increase from the second quarter of 2006.
- Funds from operations for the quarter were \$14.5 million, which represents a 17% increase from the previous quarter and a 111% increase from the second quarter of 2006.
- Capital program for the quarter of \$15.0 million which included a \$2.0 million acquisition which increased our working interest in one of our British Columbia properties.
- Production expenses were higher than expected at \$8.55 per boe reflecting ongoing inflationary pressure.
- Issued \$39.2 million in equity at \$5.60 per common share. Net proceeds were applied to reduce bank debt.

- June 30, 2007 net debt to annualized cash flow of 0.36 : 1.

Financial Highlights

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
	Total	Total	Total	Total
Financial				
(\$thousands, except as noted)				
Production revenue before royalties	\$26,806	\$12,394	\$50,550	\$29,711
Funds from operations ⁽²⁾	\$14,464	\$6,854	\$26,842	\$16,962
Per Share (\$) ⁽¹⁾				
- basic	\$0.23	\$0.13	\$0.45	\$0.34
- diluted	\$0.23	\$0.13	\$0.45	\$0.32
Net earnings (loss)				
Per Share (\$) ⁽¹⁾				
- basic	\$(639)	\$(1,472)	\$(4,308)	\$1,177
- diluted	\$(0.01)	\$(0.03)	\$(0.07)	\$0.02
- diluted	\$(0.01)	\$(0.03)	\$(0.07)	\$0.02
Royalties, net of ARTC	\$4,601	\$2,502	\$9,419	\$6,754
Production expense	\$4,910	\$2,259	\$9,098	\$4,137
Transportation expense	\$846	\$132	\$1,577	\$546
General and administrative	\$1,360	\$645	\$2,451	\$1,422
Stock based compensation expense (recovery)	\$708	\$(102)	\$5,208	\$(1,682)
Depletion	\$14,846	\$9,503	\$27,701	\$17,119
Total assets	\$259,420	\$221,479	\$259,420	\$221,479
Capital expenditures:				
Property acquisitions, net of dispositions	\$2,019	\$41,642	\$2,251	\$50,383
Exploration, development and other	\$12,948	\$10,021	\$52,951	\$31,158
Shares outstanding				
Common shares	64,844,047	55,129,847	64,844,047	55,129,847
Weighted average – basic	62,489,432	50,973,803	60,032,567	49,940,317
Weighted average – diluted ⁽¹⁾	62,489,432	50,973,803	60,032,567	53,405,949
Warrants	4,930,000	5,000,000	4,930,000	5,000,000
Stock options	5,714,442	5,250,722	5,714,442	5,250,722

- (1) For periods with positive net earnings, per share amounts are based on weighted average basic and diluted common shares outstanding for the period. For periods with a net loss, basic and diluted common shares outstanding for the period are the same.

- (2) Management uses funds from operations and funds from operations per share (before changes in non-cash working capital and asset retirement expenditures) to analyze operating performance and leverage. Funds from operations and funds from operations per share as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore they may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or income from operations for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds from operations and funds from operations per share throughout this Management's Discussion and Analysis are based on cash flow from operating activities before changes in non-cash working capital.

Operating Highlights

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Operating				
Gas production				
Total natural gas (bcf)	3.3	1.9	6.2	3.8
Daily average natural gas (mcf/d)	35,719	21,348	34,260	21,225
Average price (\$/mcf)	\$7.58	\$5.44	\$7.48	\$6.88
Oil and liquids production				
Total oil and liquids (Mbbls)	32.7	30.8	67.1	56.9
Daily average oil and liquids (bbls/d)	358	339	371	314
Average price oil and liquids (\$/bbl)	\$66.82	\$59.37	\$62.16	\$51.91
Daily average production (boed)	6,311	3,897	6,081	3,852
Land				
Net undeveloped land holdings ('000's acres)	230	126	230	126
Drilling				
Wells drilled (net)				
Gas	4.0	-	2.0	8.2
Oil	1.0	1.0	1.0	3.0
Dry	=	=	1.0	1.6
Total	5.0	1.0	22.0	12.8
Success rate (%)	100	100	95.5	87

Quarterly Financial Data

(\$ thousands except per share data)

	2007	2006	2005
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Quarter ended	June 30	Mar 31	Dec 31	Sept 30	June 30	Mar 31	Dec 31	Sept 30
Revenues	\$26,806	\$23,744	\$17,940	\$16,888	\$12,394	\$17,317	\$20,719	\$13,956
Net earnings (loss)	\$(639)	\$(3,669)	\$(3,223)	\$(2,370)	\$(1,472)	\$2,649	4,271	\$1,519
Net earnings (loss) per common share – basic and diluted (\$)	\$(0.01)	\$(0.06)	\$(0.06)	\$(0.04)	\$(0.03)	\$0.05	\$0.09	\$0.01

OPERATING RESULTS

Net Earnings (Loss)

Iteration's net loss for the three months ended June 30, 2007 was \$0.6 million, as compared to a net loss of \$1.5 million for the three months ended June 30, 2006. Included in the calculation of net loss for the quarter is stock based compensation expense of \$0.7 million as compared to a recovery of stock based compensation of \$0.1 million for the same quarter in 2006. Without taking into consideration stock based compensation, Iteration's net earnings for the three months ended June 30, 2007 would have been \$0.1 million, as compared to a net loss of \$1.6 million for the three months ended June 30, 2006. Although production was 62% higher and realized commodity prices were also higher during the quarter, as compared to the corresponding period in 2006, financial results were impacted by higher operating and transportation costs associated with increasing production in east central Alberta and northeastern British Columbia.

Production

Average daily production for the three months ended June 30, 2007 increased by 2,414 boed as compared to the three months ended June 30, 2006. This 62% increase includes 905 boed of production from three acquisitions that closed during the first and second quarters of 2006. The production increase was further enhanced by the successful drilling and re-completion of a number of wells in the Company's core areas.

Daily production <i>Average for the period</i>	Three months ended June 30			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Natural gas (Mcf/d)	35,719	21,348	67	34,260	21,225	61
Crude oil and natural gas liquids (bbl's/d)	358	339	6	371	314	18
Total (boed)	6,311	3,897	62	6,081	3,852	58

The Company will continue to monitor gas prices and service costs for the remainder of the year in order to optimize the timing of its remaining 2007 drilling program. The Company has had only intermittent production from some of its Western Alberta wells over the past few months due to limited access to third party facilities. The Company expects to continue building its land base and project inventory in Western Alberta so as to justify the construction of its own facilities in an effort to mitigate the intermittent production issues it has experienced to date. However, it therefore now expects 2007 average production to be at the lower end of the previously provided 6,400 to 6,500 boed guidance range.

Commodity Prices

Industry benchmarks <i>Average for the period</i>	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Natural gas (Alberta spot –						

monthly) Cdn \$/GJ at AECO	\$6.70	\$5.95	13	\$6.86	\$7.37	(7)
Natural gas (Alberta spot-daily) Cdn \$/GJ at AECO	\$6.70	\$5.70	18	\$6.69	\$6.42	4
Natural gas (BC Westcoast Station 2) Cdn \$/GJ	\$6.54	\$5.99	9	\$6.65	\$7.18	(7)
Edmonton pentane Cdn\$/bbl	\$72.21	\$80.21	(10)	\$70.47	\$76.79	(8)
Edmonton light crude Cdn\$/bbl	\$72.66	\$79.06	(8)	\$70.20	\$74.23	(5)
Hardisty lloydblend Cdn\$/bbl	\$49.40	\$53.35	(7)	\$45.95	\$42.00	9

Realized commodity prices <i>Average for the period</i>	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Natural gas (\$/Mcf)	\$7.58	\$5.44	39	\$7.48	\$6.88	9
Crude oil and natural gas liquids (\$/bbl's)	\$66.82	\$59.37	13	\$62.16	\$57.31	8
Total (\$/boed)	\$46.68	\$34.91	34	\$45.92	\$42.62	8

For purposes of comparing realized prices to benchmark prices, the Company's British Columbia natural gas production is sold at Station 2 pricing (BC Westcoast Station 2) and the Company's Alberta natural gas production is sold at AECO spot - daily. Therefore for comparative purposes, the realized price for the commodity should be compared to the benchmark prices for BC Westcoast Station 2 and Alberta spot - daily at AECO.

Realized commodity prices during the quarter increased by more than the change in benchmark as a result of the positive heating differential from our British Columbia production combined with additional revenue of \$0.6 million realized during the quarter from fixed price contracts discussed below.

For guidance purposes, based on the July 23, 2007 commodity strip, the Company expects its average 2007 natural gas price to decrease from \$7.66 to \$6.60 Cdn./gj and the blended price for oil to increase from \$60 to \$65 Cdn./bbl.

Revenue

Production revenue was \$26.8 million for the three months ended June 30, 2007, compared with \$12.4 million for the three months ended June 30, 2006. The production revenue increase was due to higher production volumes and higher realized commodity prices during the quarter, combined with the additional revenue realized from the fixed price contracts discussed below.

Production revenue before royalties (\$ thousands)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Production revenue	26,806	12,394	116	50,550	29,711	70

For each of the three months ended June 30, 2007 and 2006, natural gas production accounted for 94% of the Company's total production.

At June 30, 2007 the Company had the following fixed price contracts for the future physical delivery of natural gas:

Period	Volume	Type	Pricing	Price
Apr 1 – Oct 31, 2007	5,270 mcf/day	Collar	AECO – monthly	\$7.91 floor, \$8.54 ceiling
Apr 1 – Oct 31, 2007	7,900 mcf/day	Fixed price	BC Westcoast Station 2	\$7.44

Royalties

Royalty expense, net of the Alberta Royalty Tax Credit, was \$4.2 million for the three months ended June 30, 2007, compared with \$2.5 million for the three months ended June 30, 2006. The increase in royalty expense was the result of increased production revenue and higher realized commodity prices for the quarter, as compared to the prior year.

While production revenue during the quarter increased by 116%, royalty expense only increased by 84%. This change is due to a one time reduction during the quarter of \$350,000 relating to the impact of additional gas cost allowance, which is an allowed deduction for purposes of calculating crown royalties, on facilities acquired in 2006. This reduction reduced actual crown royalty expense during the quarter, but crown royalty per boe increased due to higher revenue rates realized, as compared to 2006

Effective January 1, 2007, the Alberta Royalty Tax Credit program was terminated. Historically, the Company has been eligible for an annual recovery under the program of approximately \$400,000.

Royalties (\$ thousands except where noted)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Royalties	4,601	2,502	84	9,419	6,754	39
Per boe (\$/boe)	\$8.01	\$7.05	14	\$8.56	\$9.69	(12)
Percentage of revenue (%)	17.2	20.2	(15)	18.6	22.7	(18)

For 2007, the Company expects the crown royalty burden on production to be approximately 21 percent of revenue, reflecting an increase in royalty rate as a result of the termination of the Alberta Royalty Tax Credit program. However, taking into consideration the one time gas cost allowance credit realized during the quarter, our average crown royalty rate for the year is expected to be approximately 20%. The Alberta government is currently conducting a review of the royalty regime for the oil and gas industry. At this time, the impact of this review on future royalty rates cannot be determined.

Production Expenses

Production expenses were \$4.9 million for the three months ended June 30, 2007, compared with \$2.3 million for the three months ended June 30, 2006. The increase in expenses was due to the following:

- 1) A 62 % increase in production for the quarter as compared to the previous year.
- 2) Continuing inflationary pressure on production expenses throughout the industry.
- 3) Continued efforts to enhance production from existing wells through workovers and facility maintenance. These costs are expensed for financial reporting purposes, even though they have resulted in significant increases in production.

Production expenses (\$ thousands)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change

Field operating costs	4,728	2,107	103	8,776	3,876	126
Allocated general and administrative costs	182	152	20	322	261	23
Total production expense	4,910	2,259	117	9,098	4,137	120

Production expenses per boe (\$ per boe)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Field operating costs	\$8.23	\$5.94	39	\$7.97	\$5.56	43
Allocated general and administrative costs	\$0.32	\$0.43	(26)	\$0.29	\$0.37	(22)
Total production expense	\$8.55	\$6.37	34	\$8.26	\$5.93	39

The Company had previously published guidance with respect to expected production expenses for 2007 of \$7.50 per boe. Continued upward pressure on costs, combined with delays experienced during the quarter with respect to tying in production and a fire at the Atmore compressor (which resulted in a lower than expected average production rate for the quarter) has contributed to the increase in production expense per boe. With the continuing pressure on production expenses the Company now expects operating costs for 2007 to average approximately \$8.50 per boe.

Transportation Expenses

Transportation expenses for the quarter were \$0.8 million versus \$0.1 million for the period ended June 30, 2006. Transportation expenses increased for the following reasons:

- 1) The east central Alberta assets were acquired at the end of the second quarter in 2006. Transportation expenses incurred during the second quarter of 2007 related to these assets were \$333,000.
- 2) Marketers for our Wild River production were changed during the third quarter of 2006. Under the previous marketing agreement, transportation costs related to this production were not segregated from the price realized. Under the new agreement, transportation costs are disclosed separately. During the second quarter, transportation costs incurred relating to this property were \$63,000.
- 3) Production increased 62% from the prior year, which resulted in additional transportation expense

As a result of the acquisition of the east central Alberta assets, and the change at Wild River, on a per BOE basis, transportation expense increased from \$0.37 to \$1.47. However, there is no net effect on either reported netbacks or cashflow of the Company as a result of separately reporting transportation expenses as opposed to including these amounts in the calculation of blended realized commodity prices.

Transportation expenses (\$ thousands except where noted)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Transportation expenses	846	132	541	1,577	546	189
Per boe (\$ / boe)	\$1.47	\$0.37	297	\$1.43	\$0.78	83

Operating Netback

The operating netback (before general and administrative expenses) realized for the three months ended June 30, 2007 was \$28.65/boe versus \$21.12/boe for the three months ended June 30, 2006. The increase in netback realized was due to increased gas prices realized during the quarter, offset by increased royalties, production and transportation costs.

Operating netback (\$/boe)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Production revenue	\$46.68	\$34.91	34	\$45.92	\$42.62	8
Royalties	(8.01)	(7.05)	14	(8.56)	(9.69)	(12)
Production expenses	(8.55)	(6.37)	34	(8.26)	(5.93)	39
Transportation expenses	(1.47)	(0.37)	297	(1.43)	(0.78)	83
Operating netback	\$28.65	\$21.12	36	\$27.67	\$26.22	6

The Company expected a netback of approximately \$25.40/boe for 2007. For guidance purposes, based on our revised budgeted commodity prices for 2007 of \$6.60 Cdn./GJ AECO for natural gas, a blended price for oil of \$65.00 Cdn./bbl, and increased production expenses, the Company expects an average operating netback (before general and administrative expenses) for 2007 of approximately \$23.90/boe.

General and Administrative Expenses

Total general and administrative costs, excluding overhead recoveries, allocation to production expense and capitalized G&A, increased by 40% to \$2.1 million for the three months ended June 30, 2007, versus \$1.5 million for the three months ended June 30, 2006. However, general and administrative expenses for the quarter increased by 111% to \$1.4 million, as compared to \$0.6 million for the second quarter of 2006. The reasons for the increase in general and administrative expenses were as follows:

- 1) General and administrative costs incurred during the quarter were higher as compared to the prior year due to the hiring of additional staff.
- 2) During the third quarter of 2006, the Company changed the calculation methodology with respect to overhead recoveries and capitalized overhead. Had overhead and capitalized general and administrative expenses been calculated using the current methodology for the three months ended June 30, 2006, overhead recoveries would have been \$44,000 less, and capitalized general and administrative expenses would have been \$191,000 less.

On a per boe basis, general administrative expenses increased by 27 % from the comparative quarter in 2006 (not taking into consideration of the impact of the change in methodology in calculating overhead recoveries and capitalized overhead) to \$2.37 per boe.

General and administrative expenses (\$ thousands except where noted)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
General and administrative costs before the following:	2,131	1,524	40	3,925	3,189	23
Overhead recoveries	(17)	(280)	(94)	(65)	(641)	(90)
Allocation to production expenses	(182)	(152)	20	(322)	(261)	23
Capitalized overhead	(572)	(447)	28	(1,087)	(865)	26
General and administrative expense	1,360	645	111	2,451	1,422	72
Per boe (\$ / boe)	\$2.37	\$1.87	27	\$2.23	\$2.04	9

Management continues to expect general and administrative expenses for 2007 to be approximately \$2.05/boe.

Stock Based Compensation Expense

The Company's stock option plan provides stock option holders the choice, upon exercise, to receive a cash payment in exchange for surrendering the option. The cash payment is equal to the appreciated value of the stock option, as determined by the difference between the option's exercise price and the Company's closing share price the day prior to electing to exercise the option. In July, 2005, the stock option plan was further amended to limit the total number of common shares that may be issued under the stock option plan to 10% of the issued and outstanding Common Shares at that time.

For the three months ended June 30, 2007, a stock based compensation expense of \$0.7 million was recorded based on the increase in value of the outstanding stock options as determined using the June 30, 2007 closing share price, as compared to the closing share price at March 31, 2007. Future fluctuations in the stock based compensation expense or recoveries are dependent on the movement of the Company's share price and the number of vested options outstanding. Based on the June 30, 2007 share price of \$5.63, had all 5,714,442 stock options outstanding been vested, stock based compensation expense and a corresponding liability of \$ 13.4 million would have been recognized. Of this amount, \$ 9.3 million has been recognized as a current liability in the June 30, 2007 financial statements.

Interest Expense

Interest expense on current debt (the Company had no long term debt) for the three months ended June 30, 2007 was \$0.4 million as compared to \$0.1 million for the three months ended June 30, 2006. Interest expense for the three months ended June 30, 2007 was as a result of utilizing a portion of a \$65 million credit facility to fund the capital drilling program and acquisitions. The effective interest rate for the first quarter of 2007 on the outstanding Credit Facility was 6%.

Interest expense (<i>\$ thousands except where noted</i>)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Interest expense	390	105	271	861	160	438
Interest income	-	-	-	-	(167)	100
	390	105	271	861	(7)	100
Per boe (\$/boe)	\$0.68	\$0.30	126	\$0.78	-	100

Depletion and Depreciation

Depletion and depreciation expense was \$14.8 million for the three months ended June 30, 2007 compared to \$9.5 million for the three months ended June 30, 2006. The 56% increase in the amount of depletion recorded was due to the magnitude of capital spending undertaken by the Company combined with the 63 % increase in production for the three months ended June 30, as compared to the corresponding period in 2006.

Depletion and depreciation (<i>\$ thousands except where noted</i>)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Depletion	14,846	9,503	56	27,701	17,119	62
Per boe (\$/boe)	\$25.85	\$26.79	(4)	\$25.17	\$24.56	2

Capital Expenditures

Exploration and development capital spending for the three months ended June 30, 2007 was \$12.9 million, versus \$10.0 million for the three months ended June 30, 2006.

Capital expenditures (\$ thousands)	Three months ended June 30,			Six months ended June 30,		
	2007	2006	% Change	2007	2006	% Change
Acquisition of oil and gas properties, net of disposition proceeds	2,019	41,642	(95)	2,251	50,383	(95)
Exploration and development expenditures	12,948	10,021	29	52,951	31,158	70
Total	14,967	51,663	(71)	55,202	81,541	(32)

As a result of a \$2 million asset acquisition subsequent to quarter end, whereby the Company purchased a partners interest in some British Columbia properties, total capital expenditures for 2007 are now expected to increase from approximately \$90 to \$92 million. In addition, as a result of drilling cost reductions realized during the third quarter and a reallocation of the drilling program between gas and oil wells, our expected well count for 2007 has increased from 53 to 60 net wells.

Capital and Liquidity

As an oil and gas company, the Company has a declining asset base and therefore relies on ongoing development and acquisitions to replace production and add additional reserves. Future oil and natural gas production and reserves are highly dependent on success in exploiting the Company's asset base and in acquiring additional reserves. To the extent the Company is successful or unsuccessful in these activities, funds flow could be increased or reduced.

As at June 30, 2007, the Company had drawn \$21.9 million of its \$65 million facility. In addition to this debt, the Company had a working capital surplus, not including the liability recorded for stock based compensation, of \$ 0.8 million, for a total net debt of \$21.1 million. The ratio of total net debt at June 30, 2007 to annualized funds flow for the quarter ended June 30, 2007 was 0.36:1. As the Company's capital expenditure program is heavily weighted to the first and fourth quarters of the year, it is expected that this ratio will increase over the balance of the year. There was very little drilling in the second quarter due to limited surface access and the Company will continue to evaluate commodity prices and service costs as the year progresses in order to optimize the timing of drilling for the remainder of the year. Projected capital spending for 2007, including acquisitions to date, is approximately \$92.0 million.

The Company successfully completed a bought deal equity financing issue on April 26th, 2007. Under the financing, the Company issued 7,000,000 common shares at \$5.60 per share, for gross proceeds of \$39.2 million. Net proceeds from this equity issue were approximately \$37.0 million.

With the change in commodity prices and operating costs, projected funds from operations for the year is expected to be approximately \$52 million. Funds from operations, combined with a \$2.0 million increase in projected capital spending, will result in net debt at the end of 2007 increasing to approximately \$34 million. The impact on the Company's projected 2007 funds flow of a \$1.00/GJ swing in average AECO price for the remainder of 2007 is approximately \$2.8 million.

The Company continues to anticipate no unusual working capital requirements in 2007. There are currently no capital commitments, other than those associated with the Company's 2007 drilling and exploration program, and no known unusual trends or liquidity issues as at June 30, 2007. The Company expects to be able to meet future obligations associated from ongoing operations from funds flow from operations and draws on the Company's Credit Facility.

Operating Leases

The Company has entered into various operating leases with respect to its premises. The leases expire June 30, 2009 and require the following future minimum lease payments, by calendar year (\$thousands);

2007	343
2008	687
2009	344

Related Party Transactions

For the three months ended June 30, 2007, there were no related party transactions.

Outstanding Common Shares

As at August 8, 2007, there were 64,844,047 common shares, 4,930,000 warrants, and 5,714,442 options outstanding.

Critical Accounting Estimates

In the application of accounting policies, management is often required to make judgments based on underlying estimates and assumptions about future events and their effects. Underlying estimates and assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances. These estimates and assumptions are subject to change as new events occur and additional information is obtained. The Company believes the following are the most critical accounting estimates used in determining its financial results.

Full Cost Accounting

The Company follows the full cost method of accounting whereby all costs relating to the acquisition of, exploration for and development of oil and gas reserves are capitalized, whether successful or not. The aggregate of these costs, net of costs of unproved properties and estimated salvage values, and estimated future development costs are depleted and depreciated by the unit of production method based on estimated gross proven reserves as determined by independent engineers. Changes in estimated gross proven reserves, salvage values or future development costs have a direct impact on depletion and depreciation.

Ceiling Test

The Company calculates the ceiling test on reserves based upon estimates of future prices for commodities, production rates, royalty rates, operating costs and inflation rates. Future prices for commodities are based on forward curve amounts. Future production rates, decline rates, royalty rates and operating costs are based on historical amounts. Inflation for commodity prices and operating costs is 2% per annum.

In the calculation of the ceiling test, the carrying value of property and equipment is compared to the sum of undiscounted cash flows expected to result from the future production of proved reserves, salvage value of equipment and the value of seismic over undeveloped land. Cash flows are based on third party quoted forward prices, adjusted for transportation and quality. Should the ceiling test result in an excess of carrying value, the Company would then measure the amount of impairment by comparing the carrying amounts of property, plant and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves, salvage value of equipment and value of seismic over undeveloped land. A risk-free interest rate of 6% was used to arrive at the net present value of the future cash flows. Any excess is recorded in the statement of earnings.

The carrying value of undeveloped properties (land and seismic data) is reviewed periodically and written down to net realizable value if impairment is determined.

Reserve Estimates

On an annual basis, the Company engages independent petroleum consultants to evaluate 100% of its oil and gas reserves. The estimation of reserves is a subjective process. The accuracy of reserve estimates is a product of the quality and quantity of data available, interpretation and judgment. Reserve estimates are

based on engineering and geological data, projected future rates of production, commodity price forecasts and estimated timing of future expenditures, all of which are subject to interpretation and uncertainties.

Reserve estimates are used in the calculation of depletion and depreciation. A change in estimated reserves would result in a higher or lower depletion and depreciation charge to net earnings. Downward revisions to reserve estimates could also result in an impairment write-down of property, plant and equipment under the ceiling test.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred and records a corresponding increase in the carrying value of the related long-lived asset. The fair value is determined through a review of engineering studies, industry guidelines, and management's estimates on a site by site basis. The liability is subsequently adjusted for the passage of time, and is recognized as an accretion expense in the statement of earnings under asset retirement obligations. The liability is also adjusted due to revisions in either the timing or the amount of the original estimated cash flows associated with the liability. Estimates of the asset retirement costs are subject to uncertainty associated with the method, timing and extent of future retirement activities.

The Company calculates the asset retirement obligation based on estimates of the date of abandonment, abandonment costs, and inflation. These amounts are then discounted to a present value amount. The estimates used are as follows:

Abandonment and reclamation costs:

Well bore and surface reclamation	\$ 35,000 per well
Pipelines	10,000 per pipeline segment
Roads	15,000 per km
Batteries	15,000 per battery
Compressors	200,000 per compressor

Inflation	2 % per annum
Discount rate	6% per annum

Income Taxes

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its consolidated financial statements and its tax returns. These amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. The Company periodically assesses the realizability of its future tax assets. A valuation allowance is recorded to the extent that there is uncertainty regarding utilization of future tax assets.

Impact of New Accounting Pronouncements

On January 1, 2007, the Company adopted the three new accounting standards that were issued by the Canadian Institute of Chartered Accountants; Handbook Section 1530, *Comprehensive Income*, Handbook Section 3855, *Financial Instruments-Recognition and Measurement*, Handbook Section 3861, *Financial Instruments-Disclosure and Presentation* and Handbook Section 3865, *Hedges*. As required by the new standards, prior periods have not been restated. The adoption of these standards has had no material impact on the Company's net earnings or cashflows. The other effects of the implementation of the new standards are discussed below.

Comprehensive Income

Section 1530 introduces Comprehensive Income, which consists of net income and other comprehensive income ("OCI"). This section requires companies to present a statement of comprehensive income, defined as a change in net assets arising from transactions and other events from non-owner sources. The statements present net income and each component recognized in other comprehensive income. For the three and six months ended June 30, 2007, the Company did not recognize any OCI. Should the Company recognize any OCI in the future, the cumulative changes in OCI would be recognized in Accumulated

Other Comprehensive Income (“AOCI”), which would be presented as a new category within Shareholders’ Equity in the Consolidated Balance Sheet.

Financial Instruments – Recognition and Measurement

The Financial Instruments standard, Section 3855 establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods is dependent on whether the financial instrument has been classified as “held-for-trading”, “available-for-sale”, “held-to-maturity”, “loans and receivables”, or “other financial liabilities” as defined by the standard.

Financial assets and financial liabilities “held-for-trading” are measured at fair value with changes in those fair values recognized in net earnings. Financial assets “available-for-sale” are measured at fair value, with changes in those fair values measured in OCI. Financial assets “held-to-maturity”, “loans and receivables”, and “other financial liabilities” are measured at amortized cost using the effective interest method of amortization. The methods used by the Company in determining the fair value of financial instruments is unchanged as a result of implementing the new standard.

Cash and bank indebtedness is designated as “held-for-trading” and are measured at carrying value, which approximates fair value due to the short-term nature of these instruments. Accounts receivable are designated as “loans and receivables”. Bank indebtedness, accounts payable and accrued liabilities and stock based compensation payable are designated as “other liabilities”.

The adoption of the financial instruments standard has resulted in no change in the previous accounting treatment or reporting by the Company.

Hedges

One of the new standards dealt with Hedges and the criteria needed to qualify for hedge accounting, as well as the timing for recognition of applicable hedge gains and losses. As the Company had no material fixed price contracts in place at December 31, 2006, there was no effect on the financial reporting of the Company as a result of the implementation of the new standard. The Company considers the current fixed price contracts in place to be future sales contracts at an agreed price with our current gas marketer, which will be satisfied by the future delivery of natural gas. As a result, the Company has not calculated a fair value for the instruments for purposes of recording the contracts on the balance sheet.

Disclosure Controls and Procedures

The Company has implemented disclosure controls and procedures to ensure that information required to be disclosed by the Company is accumulated and communicated to the Company’s management, as appropriate, to allow timely decisions regarding required disclosures. The Company’s Chief Executive Officer and Chief Financial Officer, together with management concluded, based on their evaluation as of the year-end, that the Company’s disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer is made known to them by others.

It should be noted that while the Company’s Chief Executive Officer and Chief Financial Officer believe that the Company’s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures will necessarily prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Internal Controls over Financial Reporting

Under the supervision of, and with the participation of the Company’s management, including the Chief Executive Officer and the Chief Financial Officer, internal control over financial reporting has been designed and maintained in order to provide reasonable assurance regarding the reliability of financial reporting, as of the end of the period covered by the filings. During the quarter ended June 30, 2007, there

have been no material changes in internal control over financial reporting. In common with many small companies, with limited accounting support staff, segregation of duties is difficult, however, management is satisfied that compensating controls are in place including key management authorizations and reviews.

Outlook for 2007

The Company had previously given guidance of 6,400 to 6,500 boed average production for 2007, based on a capital program of \$90 million. Access to third party facilities for some of our western Alberta gas has been somewhat more restricted than we had anticipated, so we now expect the 2007 average to be at the low end of that range. The anticipated capital program has increased slightly due to an increase in the number of wells from 53 to 60, offset by a mid year reduction in drilling costs. The Company has also completed a small acquisition which increased our working interest in one of our British Columbia properties.

Based on the July 23, 2007 commodity price strip, the Company now expects a lower average natural gas price for 2007 of \$6.60/GJ and an average 2007 blended price for oil of \$65.00/bbl. Using these estimates for commodity prices and expected results from currently budgeted activities, the revised guidance for 2007 is as follows:

Average production:	approximately 6,400 boed
Capital program:	approximately \$92 million
Operating netback:	approximately \$24 per boe
Funds from operations:	approximately \$52 million
Year end net debt:	approximately \$34 million

The Company will continue to focus on adding new drilling locations and prospective lands in order to grow production through an ongoing exploitation and exploration program. We will continue to evaluate commodity prices and drilling costs as the year progresses in order to optimize the timing of drilling for the remainder of the year. The Company is aggressively pursuing acquisition and farm-in opportunities in its core areas and will continue to be active at land sales.

Directors, Officers and Auditors

Current Officers and Directors of the Company are as follows;

Officers

Brian Illing	President and CEO
Mark Ariss	VP Exploration East
Sean Johnson	CFO
Jane Mactaggart	VP Exploitation
Carmen McKay-Illing	VP Corporate Affairs
Kevin Stromquist	VP Exploration West

Directors

Pat Breen P. Eng.	President- Foremost Income Fund
Dallas Droppo Q.C.	Partner- Blake, Cassels and Graydon LLP
Jim Grenon	President- TOM Capital Associates
Michael Hibberd	President- MJH Services Inc.
Brian Illing P. Geol	President and CEO- Iteration Energy Ltd.
Robert Waters CA	Senior VP and CFO- Enerplus Resources Fund

Corporate Secretary

Tony Grenon	Managing Director- TOM Capital Associates
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Auditors

Ernst & Young LLP

Advisory – Forward-Looking Information

This MD&A was prepared on August 8, 2007 and is management's assessment of Iteration's historical financial and operating results. The reader should be aware that historical results are not necessarily indicative of future performance. This MD&A contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof affecting the economic performance of Iteration. Undue reliance should not be placed on these forward-looking statements which are based upon management's assumptions and are subject to known and unknown risks and uncertainties, including the business risks discussed below, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted. The Company undertakes no obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise.

The forward looking statements contained herein are expressly qualified by this cautionary statement. Readers are cautioned that the following list of risk factors is not exhaustive.

In particular, this discussion contains forward-looking statements and information pertaining to the following:

- The quantity and recoverability of our reserves;
- The timing and amount of future production;
- Prices for natural gas produced;
- Operating and other costs;
- Business strategies and plans of Management;
- Supply and demand of natural gas;
- Expectations regarding our ability to raise capital and to add to our reserves through acquisitions as well as exploration and development;
- The focus of capital expenditures on development activity rather than exploration;
- The sale, farming in, farming out or development of certain exploration properties using third party resources;
- The use of development activity and acquisitions to replace and add to reserves;
- The impact of changes in natural gas prices on cash flow after hedging;
- Drilling plans;
- The existence, operations and strategy of the commodity price risk management program;
- The approximate and maximum amount of forward sales and hedging to be employed;
- The Company's acquisition strategy, and the criteria to be considered and the benefits to be derived;
- The impact of Canadian federal and provincial governmental regulation on the Company relative to other issuers of similar size;
- Our treatment under governmental regulatory regimes;
- The goal to sustain or grow production and reserves through prudent management and acquisition;
- The emergence of accretive growth opportunities; and
- The Company's ability to benefit from the combination of growth opportunities and the means to grow through the capital markets.

Iteration's actual results could differ materially from those anticipated in our forward-looking statements as a result of the risk factors set forth below and noted elsewhere in this MD&A which include but are not limited to:

- Volatility in market prices for natural gas;
- Risks inherent in our operations;
- Uncertainties associated with estimating reserves;
- Competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- Incorrect assessments of the value of acquisitions;
- Geological, technical, drilling and process problems;
- General economic conditions including fluctuations in the price of natural gas;
- Royalties payable in respect of Iteration's production;
- Governmental regulation of the oil and gas industry, including environmental regulation;
- Fluctuation in foreign exchange or interest rates;
- Unanticipated operational events that can reduce production or cause production to be shut-in or delayed;
- Stock market volatility and market valuations;
- The need to obtain required approvals from regulatory authorities;
- Environmental risks;
- Insurance limitations risks;
- Risks inherent in replacing reserves;
- Reliance on operators and key employees;
- Access to funding and issuance of debt;
- Aboriginal claims; and
- Availability of drilling equipment, access restrictions and cost inflation.

Additional Information on the Company

Other information about the Company, including the Unaudited Interim Consolidated Financial Statements for the three and six months ended June 30, 2007, and the Audited Consolidated Financial Statements, Management's Discussion and Analysis and the Annual Information Form for the year ended December 31, 2006, are available through the internet on the Company's website at www.iterationenergy.com and on the Company's SEDAR profile at www.sedar.com.