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crew energy inc.

TSX: CR

CREW ENERGY INC. (TSX-CR) OF CALGARY, ALBERTA IS PLEASED TO PRESENT ITS FINANCIAL AND OPERATING RESULTS FOR THE THREE AND SIX MONTH PERIODS ENDED JUNE 30, 2006.

Highlights

- 20% increase in production over the second quarter of 2005 to 5,049 boe/d and a 34% increase in first half production over the same period in 2005;
- 10% increase in production per share in the second quarter of 2006 over the same period of 2005 despite shut-in production volumes and delays in placing production on-stream;
- Exited the second quarter with over 1,400 boe/d of production awaiting start-up;
- Maintained a low cost structure with operating costs of $5.40/boe and total cash costs of $7.62/boe; and
- On July 28, 2006, announced a “bought-deal” $40 million equity financing which is comprised of 1,666,800 common shares at $15.00 per share and 759,500 flow through shares at $19.75 per share.

FINANCE ($ thousands, except per share amounts)	**Three months ended June 30, 2006**	Three months ended June 30, 2005	% Chg	**Six months ended June 30, 2006**	Six months ended June 30, 2005	% Chg
Petroleum and natural gas sales	**19,164**	18,673	3	**43,956**	34,708	27
Funds from operations (note 1)	**10,645**	12,521	(15)	**25,708**	22,984	12
Per share - basic	**0.32**	0.47	(32)	**0.77**	0.86	(10)
- diluted	**0.31**	0.40	(23)	**0.75**	0.73	3
Net income	**3,753**	5,279	(29)	**7,347**	9,567	(23)
Per share - basic	**0.11**	0.20	(45)	**0.22**	0.36	(39)
- diluted	**0.11**	0.17	(35)	**0.22**	0.30	(27)
Exploration and development capital expenditures	**14,373**	10,213	41	**54,615**	31,853	121
Acquisitions (net of dispositions)	**–**	–	N/A	**15,929**	–	N/A
Total capital expenditures	**14,373**	10,213	41	**70,544**	31,853	121
Working capital deficiency (excl. bank loan)				**8,149**	3,442	137
Bank loan				**43,138**	9,303	364
Net debt				**51,287**	12,745	302
Weighted average shares (thousands)						
Basic	**33,306**	26,785	24	**33,295**	26,783	24
Diluted	**34,128**	31,440	9	**34,125**	31,448	9

Notes:

(1) Funds from operations is calculated as cash provided by operating activities from the statement of cash flows, adding change in non-cash working capital and asset retirement expenditures. Funds from operations does not have a standardized measure prescribed by Canadian Generally Accepted Accounting Principles and therefore may not be comparable with the calculations of similar measures for other companies.

OPERATIONS	Three months ended June 30, 2006	Three months ended June 30, 2005	% Chg	Six months ended June 30, 2006	Six months ended June 30, 2005	% Chg
Daily production						
Light oil and ngl (bbl/d)	**634**	858	(26)	**729**	892	(18)
Natural gas (mcf/d)	**26,490**	20,151	31	**27,955**	18,799	49
Oil equivalent (boe/d @ 6:1)	**5,049**	4,217	20	**5,388**	4,025	34
Average prices (note 1)						
Light oil and ngl ($/bbl)	**66.70**	58.22	15	**62.80**	57.12	10
Natural gas ($/mcf)	**6.35**	7.71	(18)	**7.05**	7.49	(6)
Oil equivalent ($/boe)	**41.71**	48.66	(14)	**45.07**	47.64	(5)
Operating expenses						
Light oil and ngl ($/bbl)	**5.88**	4.06	45	**5.52**	4.06	36
Natural gas ($/mcf)	**0.89**	0.68	31	**0.86**	0.66	30
Oil equivalent ($/boe)	**5.40**	4.07	33	**5.23**	3.98	31
Operating netback ($/boe) (2)	**25.40**	34.30	(26)	**28.02**	32.77	(14)
G&A ($/boe)	**1.09**	1.07	2	**0.92**	0.95	(3)
Interest and other ($/boe)	**1.13**	0.58	95	**0.74**	0.27	174
Funds from operations netback ($/boe) (2)	**23.18**	32.65	(29)	**26.36**	31.55	(16)
Drilling Activity						
Gross wells	**7**	5	40	**27**	13	108
Working interest wells	**6.1**	2.9	110	**22.9**	9.7	136
Success rate, net wells (%)	**84**	100		**96**	100	

Notes:

(1) Average prices are before deduction of transportation costs.

(2) Operating netback equals total revenue less royalties, operating costs and transportation costs calculated on a boe basis. Operating netback and funds from operations netback do not have a standardized measure prescribed by Canadian Generally Accepted Accounting Principles and therefore may not be comparable with the calculations of similar measures for other companies.

OPERATIONAL UPDATE

Edson, Alberta

Crew initiated Edson gas production processing through its 15% interest in the 90 Mmcf/d Rosevear natural gas plant in mid-April. In the second quarter, the Company installed two new field compressors in the area to further expand the area's take-away capacity. Crew has four (4.0 net) wells to place on production and has plans to drill five additional wells in the area by the end of 2006. Crew now owns 64 net sections at Edson and has a number of downspacing, outpost and exploratory drilling opportunities to continue its production growth in the area.

Ferrier, Alberta

Crew drilled two (1.125 net) wells at Ferrier in the second quarter of 2006. The first well (Crew - 12.5%) is currently awaiting completion. The second well (Crew – 100%) is a Viking oil discovery that is now on production at over 200 bbl/d of oil and 450 mcf/d of natural gas. In July, at Medicine River, the Company drilled an Ellerslie sandstone well (Crew - 100%) which has recently been completed and has production tested at 2.9 Mmcf/d of natural gas and 120 bbls/d of natural gas liquids. Area plans include the drilling of three additional wells in 2006.

Viking-Kinsella, Alberta

Crew drilled four (4.0 net) gas wells in the Viking-Kinsella area in the second quarter. The Company continues to evaluate its 18 section farm-in in the area through seismic acquisition and the drilling of earning wells. Crew owns over 155 sections in the area and plans to drill another nine wells in the Viking-Kinsella area in 2006.

Wimborne/Drumheller, Alberta

Crew has five (3.625 net) wells to complete or tie-in in this area. The Company has plans to recomplete one well (Crew – 84.5%) and drill three (1.9 net) additional wells in this area by the end of 2006. Crew continues to hold an inventory of 112 drilling locations targeting natural gas from the Edmonton group sandstones and the Horseshoe Canyon coals.

Laprise/Inga, British Columbia

Crew was inactive in these areas in the second quarter of 2006 as access was restricted due to road bans and wet weather. The Company is now drilling a 3,200 meter exploratory test at Laprise which is anticipated to reach total depth in September. At Inga, the Company has plans to complete and tie-in a well (Crew – 100%) and drill another well (Crew – 100%) before the end of the year.

EXPLORATION

At Hanlan, Alberta, the Company (Crew - 70% to earn 50%) is drilling a 4,200 meter test targeting gas/condensate from the Nisku Formation.

At Laprise, British Columbia, the Company (Crew - 100% BPO and 65% APO) is drilling a 3,200 meter test targeting gas from multiple zones with the primary target being the Slave Point.

At Kakwa, Alberta, the Company (Crew - 25%) is drilling a 3,200 meter test targeting gas/condensate from the Falher Formation.

At Brewster, Alberta the Company (Crew - 50% to earn 35%) is drilling a 3,300 meter test targeting gas/condensate from the Viking and Lower Mannville Formations.

At Ferrier, Alberta, the Company (Crew - 100%) is drilling a 2,900 meter test targeting gas/condensate from the Ellerslie Formation. Also at Ferrier, Crew plans to drill a 3,200 meter test targeting oil from the Leduc Formation.

OUTLOOK

The second quarter and early third quarter was challenging for the Company as a combination of wet weather delayed drilling and completion operations and a number of facility turnarounds resulted in reduced production volumes. Current production, based on field estimates, is 6,100 boe/d and the Company now has approximately 1,400 boe/d of behind pipe production awaiting start-up. As a result of the delays experienced to date, average 2006 production is forecast to be 5,900 to 6,100 boe/d and exit production is forecast at 7,000 to 7,500 boe/d.

The Company's successful 2006 drilling program has produced a number of follow-up drilling locations. This drilling has also lead to the development of several new play types in a number of prospective zones in the Company's core areas of operations. Crew currently has six drilling rigs, two service rigs and three pipeline crews active in the field. The Company is in a strong financial position to fund its exploration and development capital program and has the flexibility to make selective acquisitions. Crew plans to drill up to 28 wells in the third and fourth quarter of 2006, five of which are high impact wells which if successful could add materially to the Company's reserve and production base. Crew is looking forward to this very active period and updating shareholders on its drilling program in the third quarter report.

On behalf of the Board,

Dale Shwed
President and C.E.O.

August 9, 2006

Management's Discussion and Analysis

Management's discussion and analysis ("MD&A") is the Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position. Comments relate to and should be read in conjunction with the consolidated financial statements of the Company for the three and six months ended June 30, 2006 and 2005 and the audited consolidated financial statements and MD&A for the year ended December 31, 2005. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada.

Barrel of oil equivalent ("boe") may be misleading, particularly if used in isolation. All boe conversions in this report are derived by converting natural gas to oil in the ratio of six thousand cubic feet ("mcf") of gas to one barrel ("bbl") of oil. This 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. Certain financial values are presented on a per boe basis. Such measurements may not be consistent with those used by other companies.

Crew evaluates performance based on net income and funds from operations. Funds from operations is a measure not based on GAAP and is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital and asset retirement expenditures. The Company considers it a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. In addition, management uses netbacks, a non-GAAP term to analyze operating performance. Operating netback equals total revenue less royalties and operating costs calculated on a boe basis.

Certain of the statements set forth under "Management's Discussion and Analysis" and elsewhere in this press release, including statements which may contain words such as "could", "expect", "believe", "will", "budgeted", "forecasted" and similar expressions and statements relating to matters that are not historical facts, are forward-looking and are based upon the Company's current belief as to the outcome and timing of such future events. There are numerous risks and uncertainties that can affect the outcome and timing of such events, including many factors beyond the control of the Company. These factors include, but are not limited to the matters described under the heading "Risk and Risk Management" in the Company's December 31, 2005 MD&A. Should one or more of these events occur, or should any of the underlying assumptions prove incorrect, the Company's actual results and plans for 2006 and beyond could differ materially from those expressed in the forward-looking statements. The Company does not undertake to update, revise or correct any of the forward-looking information except as required by law or regulations. Such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: "CAUTIONARY STATEMENT" contained in this release.

PRODUCTION Production for the quarter ended June 30, 2006 averaged 5,049 boe per day, an increase of 20% over the 4,217 boe per day produced in the second quarter of 2005. Natural gas volumes grew to 26.5 Mmcf per day, a 31% increase over the second quarter of 2005's production of 20.2 Mmcf per day. Increased gas production came from new wells at Edson, Alberta and Inga, British Columbia. Light oil and natural gas liquids ("ngl") production decreased 26% to 634 bbls per day in the second quarter compared to 858 bbls per day in the second quarter of 2005. Light oil and ngl production decreased as a result regulatory restrictions on light oil production in the Laprise area.

Production for the six months ended June 30, 2006 averaged 5,388 boe per day, an increase of 34% over the 4,025 boe per day produced in the first half of 2005. Natural gas volumes grew to 28.0 Mmcf per day, a 49% increase over the 18.8 Mmcf per day produced in the first half of 2005. Light oil and ngl production decreased 18% to 729 bbls per day in the first half of 2006 compared to 892 bbls per day in the first half of 2005. The production changes during the first half were the result of the changes as described above.

REVENUE Revenue for the second quarter of 2006 totalled $19.2 million including natural gas revenue of $15.3 million and light oil and ngl revenue of $3.9 million. These amounts compared to second quarter 2005 revenue of $18.7 million including natural gas revenue of $14.1 million and light oil and ngl revenue of $4.6 million. The increased second quarter 2006 natural gas revenue was the result of a 31% increase in natural gas production partially offset by an 18% decrease in natural gas prices from $7.71 in the second quarter of 2005 to $6.35 in 2006. The decrease in oil and ngl revenue was the result of the 26% decrease in production partially offset by a 15% increase in oil and ngl pricing from $58.22 in 2005 to $66.70 in the second quarter of 2006.

Revenue for the six months ended June 30, 2006 totalled $44.0 million including natural gas revenue of $35.7 million and light oil and ngl revenue of $8.3 million. These amounts compared to first half 2005 revenue of $34.7 million including natural gas revenue of $25.5 million and light oil and ngl revenue of $9.2 million. The increased 2006 natural gas revenue was the result of the 49% increase in natural gas production which was partially offset by a 6% decrease in natural gas prices from $7.49 in the first half of 2005 to $7.05 in 2006. The decrease in oil and ngl revenue was the result of the 18% decrease in production partially offset by a 10% increase in oil and ngl pricing from $57.12 in 2005 to $62.80 in the first half of 2006.

ROYALTIES Royalties for the second quarter of 2006 totalled $4.6 million or 23.9% of revenue compared to $3.4 million or 18.2% of revenue for the second quarter of 2005. Royalties for the first half of 2005 totalled $10.6 million or 24.0% of revenue compared to $6.9 million or 20.0% of revenue for the first half of 2005. Royalty rates as a percentage of revenue have increased in 2006 due to certain wells coming off royalty holiday status and the addition of new production from wells with higher royalty rates.

OPERATING COSTS Operating costs for the three months ended June 30, 2006 totalled $2.5 million or $5.40 per boe compared to $1.6 million or $4.07 per boe for the same period in 2005. Oil and ngl operating costs per bbl have increased to $5.88 per bbl in the second quarter of 2006 from $4.06 per bbl in the second quarter of 2005 due to lower liquids production offsetting related fixed costs. Natural gas operating costs per unit have increased in the second quarter of 2006 to $0.89 per mcf from $0.68 per mcf in the second quarter of 2005. This increase was the result of facility turnarounds in Ferrier, Plain Lake, and Wimborne, third party processing cost increases at Viking and inflationary cost increases being experienced throughout the industry.

Operating costs for the six months ended June 30, 2006 totalled $5.1 million or $5.23 per boe compared to $2.9 million or $3.98 per boe for the same period in 2005. Oil and ngl operating costs for the first half of 2006 averaged $5.52 per bbl up from $4.06 per bbl in the first half of 2005 and natural gas operating costs averaged $0.86 per mcf in the first half of 2006 compared to $0.66 per mcf in the first half of 2005. Lower liquids production and facility turnarounds combined with inflationary pressures have negatively impacted the Company's per unit operating costs. Operating costs per unit are expected to decrease for the remainder of the year as the Company increases production.

TRANSPORTATION Transportation costs for the second quarter of 2006 were $0.4 million or $0.94 per boe compared to $0.5 million or $1.41 per boe in the second quarter of 2005. Oil and ngl transportation costs per unit have decreased in the second quarter of 2006 to $1.72 per bbl from $3.68 per bbl in 2005 due to decreased production from Laprise and Phoenix, which attract a higher transportation charge. Gas transportation costs per unit have remained consistent at $0.14 per mcf in the second quarter. Transportation costs for the first half of 2006 were $1.0 million or $1.00 per boe compared to $1.0 million or $1.35 per boe in the first half of 2005. Oil and ngl transportation costs per unit in the first half of 2006 were $1.45 per bbl down from $3.15 per bbl in the first half of 2005. Gas transportation costs per unit have increased slightly to $0.15 per mcf throughout the first half of 2006 compared with $0.14 per mcf for the first half of 2005.

OPERATING NETBACKS

	Three months ended June 30, 2006			Three months ended June 30, 2005		
	Oil and ngl ($/bbl)	Natural Gas ($/mcf)	Total ($/boe)	Oil and ngl ($/bbl)	Natural Gas ($/mcf)	Total ($/boe)
Revenue	$ 66.70	$ 6.35	$ 41.71	$ 58.22	$ 7.71	$ 48.66
Royalties	(17.14)	(1.54)	(10.24)	(9.87)	(1.51)	(9.21)
Alberta royalty tax credit			0.27			0.33
Operating costs	(5.88)	(0.89)	(5.40)	(4.06)	(0.68)	(4.07)
Transportation costs	(1.72)	(0.14)	(0.94)	(3.68)	(0.14)	(1.41)
Operating netbacks	$ 41.96	$ 3.78	$ 25.40	$ 40.61	$ 5.38	$ 34.30

	Six months ended June 30, 2006			Six months ended June 30, 2005		
	Oil and ngl ($/bbl)	Natural Gas ($/mcf)	Total ($/boe)	Oil and ngl ($/bbl)	Natural Gas ($/mcf)	Total ($/boe)
Revenue	$ 62.80	$ 7.05	$ 45.07	$ 57.12	$ 7.49	$ 47.64
Royalties	(15.00)	(1.74)	(11.07)	(10.23)	(1.63)	(9.88)
Alberta royalty tax credit			0.25			0.34
Operating costs	(5.52)	(0.86)	(5.23)	(4.06)	(0.66)	(3.98)
Transportation costs	(1.45)	(0.15)	(1.00)	(3.15)	(0.14)	(1.35)
Operating netbacks	$ 40.83	$ 4.30	$ 28.02	$ 39.68	$ 5.06	$ 32.77

GENERAL AND ADMINISTRATIVE General and administrative expenses for the second quarter of 2006 totalled $0.5 million or $1.09 per boe compared to $0.4 million or $1.07 per boe for the second quarter of 2005. General and administrative expenses for the first half of 2006 totalled $0.9 million or $0.92 per boe compared to $0.7 million or $0.95 per boe for the first half of 2005. The Company's general and administrative costs per boe have decreased in the first half of 2006 as a result of the Company's increased production volumes. Crew follows the full cost method of accounting for its petroleum and natural gas operations under which, $0.5 million (2005 - $0.4 million) of corporate expenses were capitalized during the second quarter and $0.9 million (2005 - $0.7 million) were capitalized in the first half.

INTEREST Interest expense totalled $0.6 million or $1.23 per boe for the second quarter of 2006 compared with $0.2 million or $0.59 per boe in 2005. Interest expense for the first half of 2006 totalled $0.8 million compared with $0.2 million for the first half of 2005.In 2006, higher debt levels and Canadian interest rates have increased the Company's interest expense for the three and six month periods. Interest paid for the first half of 2006 totalled $0.9 million compared to $0.1 million in the first half of 2005.

STOCK-BASED COMPENSATION For the second quarter of 2006, the Company has recorded a stock-based compensation expense totalling $0.6 million or $1.22 per boe compared to $0.1 million or $0.28 per boe for the second quarter of 2005. In the first half of 2006 the Company recorded stock-based compensation expense totaling $1.1 million or $1.14 per boe compared to $0.2 million or $0.28 per boe in 2005. The increase in stock-based compensation is a result of granting stock options to new and existing employees in the second half of 2005. In conjunction with its full cost method of accounting for its petroleum and natural gas operations, in the first half of 2006, the Company has capitalized $1.1 million (2005 - $0.2 million) of stock-based compensation costs.

DEPLETION, DEPRECIATION AND ACCRETION Depletion, depreciation and accretion The provision for depletion, depreciation and accretion was $8.2 million or $17.84 per boe for three months ended June 30, 2006. This compares to a second quarter 2005 provision of $4.4 million or $11.56 per boe. For the six months ended June 30, 2005 depletion, depreciation and accretion was $17.1 million or $17.52 per boe compared to $8.2 million or

$11.31 per boe. Per unit depletion has increased in 2006 due to an increase in the average cost of the Company's reserve additions over the past year and increased capital expenditures on facilities through the first half of 2006.

INCOME TAXES The Company had a future income tax recovery of $1.9 million for the second quarter of 2006 compared with a future income tax expense of $2.7 million for the second quarter of 2005. For the first six months of 2006, the Company's future income tax expense was $0.2 million compared with $5.0 million for the same period in 2005. During 2006, the Canadian federal and provincial governments substantively enacted income tax rate reductions which resulted in a second quarter future tax reduction of $2.6 million.

NET INCOME Net income in the second quarter of 2006 was $3.8 million compared with $5.3 million in the second quarter of 2005. On a per share basis net income was $0.11 per basic share and $0.11 per diluted share compared to $0.20 per basic and $0.17 per diluted share in the second quarter of 2005. Net income was $7.3 million or $0.22 per basic share and $0.22 per diluted share for the first half of 2006 compared to $9.6 million or $0.36 per basic share and $0.30 per diluted share in the first half of 2005. The decrease in net income was the result of lower natural gas prices and increased expenses resulting from inflationary pressures the Company has experienced over the past year.

LIQUIDITY AND CAPITAL RESOURCES At June 30, 2006 the Company had drawn $43.1 million on its bank lines and had a working capital deficiency of $8.1 million. The Company currently has a demand operating facility of $90 million. On July 28, 2006, the Company came to an agreement with a syndicate of underwriters to issue 1,666,800 common shares at $15.00 per common share and 759,500 common shares on a flow through basis at a price of $19.75 per flow through share for aggregate gross proceeds of $40 million. This financing is scheduled to close on August 17, 2006 with the proceeds directed towards the funding of the Company's 2006 and 2007 drilling program.

In February the Company renounced $10.0 million of Canadian tax deductions to purchasers of the Company's December 2005 flow-through share issue. The future tax impact of this renouncement was charged to the Company's future tax liability and share capital in the first quarter.

As at August 9, 2006, 33,330,882 Common Shares and 762,000 Class C Performance Shares of the Company were outstanding along with 1,984,500 options to acquire Common Shares of the Company.

OPERATIONS AND CAPITAL EXPENDITURES Exploration and development expenditures for the second quarter were $14.4 million compared to $10.2 million for the second quarter of 2005. During the second quarter Crew drilled seven (6.1 net) wells, resulting in five (4.1 net) gas wells, one (1.0 net) oil well, and one (1.0 net) dry and abandoned well. The total number of wells drilled for the first half of 2006 is 27 (22.9 net) with a 96% success rate. The Company continued to add to its infrastructure in the second quarter of 2006 spending $5.7 million on facilities and pipelines primarily in the Edson and Ferrier areas. The total expenditures are detailed below:

(thousands)	**Three months ended June 30, 2006**	Three months ended June 30, 2005	**Six months ended June 30, 2006**	Six months ended June 30, 2005
Land	**$ 912**	$ 4,427	**$ 4,458**	$ 7,442
Seismic	**359**	725	**3,069**	1,685
Drilling and completions	**6,726**	2,484	**30,897**	13,043
Facilities, equipment and pipelines	**5,658**	2,081	**15,096**	8,848
Other	**718**	496	**1,095**	835
Total exploration and development	**14,373**	10,213	**54,615**	31,853
Property acquisitions	**–**	–	**15,929**	–
Total	**$ 14,373**	$ 10,213	**$ 70,544**	$ 31,853

QUARTERLY ANALYSIS The following table summarizes Crew's key quarterly financial results for the last eight quarters:

($ thousands, except per share amounts)	**June 30, 2006**	Mar. 31, 2006	Dec. 31, 2005	Sept. 30, 2005	June 30, 2005	Mar. 31, 2005	Dec. 31, 2004	Sept. 30, 2004
Petroleum and natural gas sales	**19,164**	24,792	30,520	22,304	18,673	16,035	12,721	9,194
Funds from operations	**10,645**	15,063	21,084	15,423	12,521	10,463	8,330	5,906
Per share – basic	**0.32**	0.45	0.69	0.56	0.47	0.39	0.33	0.23
– diluted	**0.31**	0.44	0.65	0.48	0.40	0.33	0.28	0.20
Net income	**3,753**	3,594	8,746	6,328	5,279	4,288	3,358	2,064
Per share – basic	**0.11**	0.11	0.28	0.23	0.20	0.16	0.13	0.08
– diluted	**0.11**	0.11	0.27	0.20	0.17	0.14	0.11	0.07
Total daily production (boe/d)	**5,049**	5,731	4,730	4,093	4,217	3,833	3,112	2,428

Prior to 2006, the Company's petroleum and natural gas sales, funds from operations and net income all grew quarter over quarter. In 2006, all three performance measures have declined. Petroleum and natural gas sales and funds from operations have decreased due to lower natural gas prices. In addition, funds from operations and net income have been negatively impacted by the higher costs being experienced throughout the industry.

Dated as of August 9, 2006

Consolidated Balance Sheets

(thousands)	June 30, 2006 (unaudited)	December 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalent	**$ –**	$ 16,302
Accounts receivable	**13,118**	18,874
	13,118	35,176
Property, plant and equipment (note 2)	**218,987**	162,428
	$ 232,105	$ 197,604
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 21,267**	$ 41,751
Bank loan (note 4)	**43,138**	–
	64,405	41,751
Asset retirement obligations (note 3)	**8,468**	7,182
Future income tax liability (note 6)	**23,181**	19,177
SHAREHOLDERS' EQUITY		
Share capital (note 5)	**89,789**	92,653
Contributed surplus (note 5)	**3,761**	1,687
Retained earnings	**42,501**	35,154
	136,051	129,494
Subsequent event (note 7)		
	$ 232,105	$ 197,604

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Operations and Retained Earnings

(unaudited) (thousands, except per share amounts)	**Three months ended June 30, 2006**	Three months ended June 30, 2005	**Six months ended June 30, 2006**	Six months ended June 30, 2005
Revenue				
Petroleum and natural gas sales	**$ 19,164**	$ 18,673	**$ 43,956**	$ 34,708
Royalties	**(4,582)**	(3,409)	**(10,555)**	(6,948)
Other revenue	**18**	10	**59**	59
	14,600	15,274	**33,460**	27,819
Expenses				
Operating	**2,483**	1,563	**5,097**	2,899
Transportation	**430**	543	**975**	984
General and administrative	**502**	412	**897**	695
Interest	**584**	226	**783**	234
Stock-based compensation	**559**	109	**1,110**	207
Depletion, depreciation and accretion	**8,197**	4,435	**17,082**	8,243
	12,755	7,288	**25,944**	13,262
Income before taxes	**1,845**	7,986	**7,516**	14,557
Taxes (note 6)				
Current	**(44)**	9	**–**	23
Future	**(1,864)**	2,698	**169**	4,967
	(1,908)	2,707	**169**	4,990
Net income	**3,753**	5,279	**7,347**	9,567
Retained earnings, beginning of period	**38,748**	14,801	**35,154**	10,513
Retained earnings, end of period	**$ 42,501**	$ 20,080	**$ 42,501**	$ 20,080
Per share amounts (note 5(d))				
Basic	**$ 0.11**	$ 0.20	**$ 0.22**	$ 0.36
Diluted	**$ 0.11**	$ 0.17	**$ 0.22**	$ 0.30

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(unaudited, thousands)	**Three months ended June 30, 2006**	Three months ended June 30, 2005	**Six months ended June 30, 2006**	Six months ended June 30, 2005
Cash provided by (used in):				
Operating activities:				
Net income	**$ 3,753**	$ 5,279	**$ 7,347**	$ 9,567
Items not involving cash:				
Stock-based compensation	**559**	109	**1,110**	207
Depletion, depreciation & accretion	**8,197**	4,435	**17,082**	8,243
Future income taxes	**(1,864)**	2,698	**169**	4,967
Asset retirement expenditures	**(147)**	–	**(232)**	–
Change in non-cash working capital	**2,669**	1,752	**3,473**	(61)
	13,167	14,273	**28,949**	22,923
Financing activities:				
Increase in bank loan	**7,234**	3,265	**43,138**	9,303
Issue of common shares	**337**	48	**356**	6
	7,571	3,313	**43,494**	9,309
Investing activities:				
Exploration and development	**(14,373)**	(10,213)	**(54,615)**	(31,853)
Property acquisitions	**–**		**(15,929)**	
Change in non-cash working capital	**(6,365)**	(7,373)	**(18,201)**	(7,448)
	(20,738)	(17,586)	**(88,745)**	(39,301)
Change in cash and cash equivalents	**–**	–	**(16,302)**	(7,069)
Cash and cash equivalents, beginning of period	**–**	–	**16,302**	7,069
Cash and cash equivalents, end of period	**$ –**	$ –	**$ –**	$ –

See accompanying notes to the consolidated financial statements.

Notes to Consolidated Financial Statements

For the three and six months ended June 30, 2006 and 2005

(unaudited) (Tabular amounts in thousands)

1. SIGNIFICANT ACCOUNTING POLICIES:

The interim consolidated financial statements of Crew Energy Inc. have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2005. The disclosure which follows is incremental to the disclosure included with the December 31, 2005 consolidated financial statements. These interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 2005.

Certain comparative amounts have been reclassified to conform to current period presentation.

2. PROPERTY, PLANT AND EQUIPMENT:

June 30, 2006	**Cost**	**Accumulated depletion & depreciation**	**Net book value**
Petroleum and natural gas properties and equipment	**$ 265,886**	**$ 46,899**	**$ 218,987**

December 31, 2005	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	$ 192,573	$ 30,145	$ 162,428

The costs of unproven lands at June 30, 2006 of $23,291,000 (2005 - $16,515,000) were excluded from the depletion calculation.

During the three months ended June 30, 2006, $1,530,000 (2005 – $518,000) of corporate expenses related to exploration and development activities were capitalized and during the six months ended June 30, 2006, $2,477,000 (2005 – $902,000) of corporate expenses related to exploration and development activities were capitalized.

3. ASSET RETIREMENT OBLIGATIONS:

Crew has estimated the net present value of its total asset retirement obligations as at June 30, 2006 to be $8,468,000 (December 31, 2005 - $7,182,000) based on a total future liability of $16,277,000 (December 31, 2005 - $13,414,000). These payments are expected to be made over the next 39 years. An 8% (2005 – 8%) credit adjusted risk free discount rate and 2% (2005 – 2%) inflation rate were used to calculate the present value of the asset retirement obligations.

The following table reconciles Crew's asset retirement obligations:

	Six months ended June 30, 2006	Year ended December 31, 2005
Carrying amount, beginning of period	**$ 7,182**	$ 4,984
Liabilities incurred	**954**	1,581
Liabilities acquired	**236**	–
Accretion expense	**328**	474
Change in estimate	–	242
Liabilities settled	**(232)**	(99)
Carrying amount, end of period	**$ 8,468**	$ 7,182

4. BANK LOAN:

As at June 30, 2006, the Company has a $90 million demand operating facility with a Canadian chartered bank which is available by way of prime rate based loans or bankers acceptances and bears interest at the bank's prime lending rate, bankers' acceptance rates plus scheduled margins. The facility revolves at the Company's discretion, is repayable on demand of the bank and is secured by a first floating charge debenture over all of Crew's petroleum and natural gas assets.

Interest paid during the six months ended June 30, 2006 totalled $876,000 (2005 – $68,000).

5. SHARE CAPITAL:

(a) Common Shares:

	Number of shares	Amount
Common shares, December 31, 2005	33,282	$ 92,645
Exercise of stock options	36	356
Stock-based compensation		145
Flow through share tax adjustment	–	(3,365)
Common shares, June 30, 2006	33,318	$ 89,781

(b) Contributed Surplus:

	Amount
Contributed surplus, December 31, 2005	$ 1,687
Stock-based compensation	2,219
Conversion of stock options	(145)
Contributed surplus, June 30, 2006	$ 3,761

(c) Stock-based compensation:

During the first six months of 2006, the Company recorded $2,219,000, (2005 - $414,000) of compensation expense related to the performance shares and stock options, of which $1,109,000 (2005 - $206,000) was capitalized in accordance with the Company's full cost accounting policy.

(i) Performance shares

	Number of shares	Amount
Class C performance shares, December 31, 2005	787	$ 8
Reacquired and cancelled	(25)	–
Class C performance shares, June 30, 2006	**762**	**$ 8**

(ii) Stock options

The fair value of the stock options granted during the six months ended June 30, 2006 as calculated by the Black-Scholes method was $4.80 (2005 – $4.60) per option.

	Number of Options	Price Range	Weighted average exercise price
Stock options, 31, 2005	1,848	$3.50 to $18.60	$ 15.65
Granted	246	$11.95	$ 11.95
Cancelled	(60)	$10.43	$ 10.43
Exercised	(36)	$3.60 to $10.43	$ 9.89
Stock options, June 30, 2006	**1,998**	**$3.50 to $18.60**	**$ 15.46**

(d) Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the three month period ended June 30, 2006 was 33,306,000 (June 30, 2005 – 26,785,000) and for the six month period ended June 30, 2006, the weighted average number of shares outstanding was 33,295,000 (June 30, 2005 – 26,783,000).

In computing diluted earnings per share for the three month period ended June 30, 2006, 822,000 (June 30, 2005 – 4,655,000) shares were added to the weighted average number of common shares outstanding for the dilution added by the performance shares and stock options and for the six months ended June 30, 2006, 830,000 (June 30, 2005 – 4,665,000) shares were added to the weighted average number of common shares for the dilution.

(e) Flow through shares

On December 20, 2005, the Company closed a public offering in which 1,790,600 shares were issued for gross proceeds of $35,006,000. Of the shares issued, 416,700 shares were issued on a flow-through basis in which the Company has committed to renounce to the purchasers certain Canadian tax deductions totalling $10,000,800. Pursuant to the terms of the flow-through arrangement, the Company renounced $10,000,800 of Canadian tax deductions and recorded the future tax liability associated with this renouncement in the first quarter of 2006. As at June 30, 2006, the Company had $0.5 million of expenditures to incur under this arrangement.

6. INCOME TAXES:

During the second quarter of 2006, the federal and provincial governments substantively enacted legislation reducing the tax rates. This legislation has reduced the Corporation's future income tax liability and provision for future taxes by $2,563,000.

7. SUBSEQUENT EVENT:

On July 27, 2006, the Company agreed with a syndicate of underwriters to issue 1,666,800 common shares at $15.00 per common share and 759,500 common shares on a flow through basis at $19.75 per flow through share for aggregate proceeds of $40 million. The proceeds will help finance a portion of the Company's 2006 and 2007 drilling program and is expected to close on or about August 17, 2006.

Corporate Information

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ABBREVIATIONS

bbl	barrels
bbl/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf: 1 bbl)
bopd	barrels of oil per day
mmbtu	million British thermal units
mboe	thousand barrels of oil equivalent (6 mcf: 1 bbl)
mmboe	million barrels of oil equivalent (6 mcf: 1 bbl)
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
ngl	natural gas liquids

CAUTIONARY STATEMENT

This press release contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, company production, commodity prices, foreign exchange rates, royalties, operating costs and funds flow. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Crew at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in the Company's areas of operations; and other factors, many of which are beyond the control of the Company. There is no representation by Crew that actual results achieved during the forecast period will be the same in whole or in part as that forecast.

crew
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