



**CREW ENERGY PROVIDES 2007 FOURTH QUARTER AND ANNUAL FINANCIAL AND OPERATING RESULTS
CALGARY, ALBERTA – March 10, 2008**

Crew Energy Inc. (TSX-CR) of Calgary, Alberta is pleased to present its operating and financial results for the three month period and year ended December 31, 2007.

Highlights

- Fourth quarter production averaged 9,641 boe per day, an increase of 55% over the fourth quarter of 2006 with production per share increasing 15% over the prior year's fourth quarter while 2007 production increased 53% to 8,696 boe per day with production per share increasing 16% for the year;
- Funds from operations in the fourth quarter totalled a record \$22.4 million, a 34% increase over the fourth quarter of 2006 while 2007 funds from operations increased 44% to \$81.4 million or \$1.74 per diluted share;
- Maintained a strong balance sheet with net debt of \$110 million at year-end and a current bank facility of \$180 million;
- Positioned the Company for continued growth with significant fourth quarter gas discoveries and land acquisitions in northeast B.C. on the Triassic Montney and Horn River Basin, Muskwa Shale natural gas resource plays;
- Completed a fourth quarter, 2007 equity offering raising approximately \$53 million to strengthen the Company's balance sheet in a period when access to capital was limited;
- The Company's proved plus probable reserves increased 59% over 2006 to 33.5 Mmboe with the Company adding 15.5 Mmboe through acquisitions and exploration and development drilling;
- Achieved finding, development and acquisition costs of \$15.57 per boe including future development costs and successfully replaced 2007 production by 490%;
- Crew's proved plus probable reserve life index (RLI) increased to 9.5 years from 9.3 at the end of 2006;
- Increased the net present value of the Company's reserves discounted at 8% to \$626 million, a 57% increase over 2006.

Financial	Three months ended	Three months ended	Year ended	Year ended
(\$ thousands, except per share amounts)	Dec. 31, 2007	Dec. 31, 2006	Dec. 31, 2007	Dec. 31, 2006
Petroleum and natural gas sales	38,942	26,590	140,466	92,813
Funds from operations (note 1)	22,390	16,705	81,433	56,658
Per share - basic	0.43	0.43	1.75	1.62
- diluted	0.43	0.43	1.74	1.59
Net income	6,889	1,796	9,110	10,776
Per share - basic	0.13	0.05	0.20	0.31
- diluted	0.13	0.05	0.19	0.30
Exploration and development expenditures	31,033	30,330	102,092	123,859
Property acquisitions (net of dispositions)	(266)	267	(315)	16,196
Business Acquisition	-	71,151	137,051	71,151
Working capital deficiency (note 2)			14,297	17,714
Bank loan			95,374	41,157
Net indebtedness			109,671	58,871
Weighted average shares (thousands)				
Basic	51,929	38,404	46,483	34,896
Diluted	52,307	38,872	46,862	35,586

Notes:

- (1) Funds from operations is calculated as cash provided by operating activities, adding change in non-cash working capital, excess transportation liability charge and asset retirement expenditures. Funds from operations is used to analyze the Company's operating performance and leverage. 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.
- (2) Working capital deficiency does not include the fair value of financial instruments or current portion of other long-term obligations.

Operations	Three months ended Dec. 31, 2007	Three months ended Dec. 31, 2006	Year ended Dec. 31, 2007	Year ended Dec. 31, 2006
Daily production				
Light oil and ngl (bbl/d)	1,774	1,316	1,497	941
Natural gas (mcf/d)	47,204	29,464	43,193	28,526
Oil equivalent (boe/d @ 6:1)	9,641	6,227	8,696	5,695
Per million diluted shares	184	160	186	160
Average prices (note 1)				
Light oil and ngl (\$/bbl)	68.27	58.84	62.44	63.47
Natural gas (\$/mcf)	6.50	7.18	6.81	6.82
Oil equivalent (\$/boe)	44.39	46.41	44.57	44.65
Operating expenses				
Light oil and ngl (\$/bbl)	6.44	5.67	6.26	5.26
Natural gas (\$/mcf)	1.06	1.00	1.04	0.90
Oil equivalent (\$/boe @ 6:1)	6.35	5.92	6.23	5.40
Netbacks				
Operating netback (\$/boe) (note 2)	28.22	30.75	28.78	28.88
G&A (\$/boe)	1.09	0.73	1.05	0.81
Interest and other (\$/boe)	1.88	0.86	2.08	0.81
Funds from operations (\$/boe)	25.25	29.16	25.65	27.26
Drilling Activity				
Gross wells	11	12	31	54
Working interest wells	7.4	11.0	25.3	47.2
Success rate, net wells	86%	100%	96%	97%

Notes:

- (1) Average prices are before deduction of transportation costs and include realized gains and losses on financial instruments.
- (2) Operating netback equals petroleum and natural gas sales including realized gains and losses on financial instruments less royalties, operating costs and transportation costs calculated on a boe basis. Operating netback and funds from operations 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.

OVERVIEW

Crew's fourth quarter was one of many milestones. It was highlighted by production setting a record of 9,641 boe per day representing a 55% increase while production per share was up 15% over the fourth quarter of 2006. For 2007, the Company achieved total production of 8,696 boe per day representing a 53% increase over 2006. Crew also achieved a new high in funds flow of \$22.4 million in the quarter. During the quarter, the Company completed its most prolific well in our history with an absolute open flow of 56 mmcf per day. Crew invested \$31 million in the fourth quarter, drilling 11 (7.4 net) wells for an 86% success rate. The Company also invested heavily in Crown land acquisitions and production infrastructure in northeastern British Columbia and west central Alberta.

OPERATIONAL UPDATE

Edson, Alberta

Crew drilled the first two wells in the planned five well development drilling program in the Rock Creek Formation after receiving approval from the Alberta Energy Utilities Board in the third quarter. Crew currently has a two to three year inventory of development drilling opportunities in this area with plans to drill approximately ten wells per year. The Company's 2006 investment in infrastructure has resulted in lower costs and quick tie-ins leading to attractive economic returns in this active area.

Pine Creek, Alberta

This area has been transformed into a core producing area from an exploration concept in less than one year. Crew now owns an interest in over 50 sections of land in the area. In the fourth quarter, the Company initiated production from its new gas facility and early in the first quarter of 2008 doubled the compression in order to process up to 15 mmcf per day of raw gas. Natural gas production from this area is liquids rich yielding 45 to 50 bbls of natural gas liquids per one mmcf of natural gas produced. The area is characterized by drilling depths of 2,000 to 2,800 meters with multiple prospective horizons. The Company has been able to develop a significant land position in a short period of time which has resulted in a two to three year drilling inventory. Current plans for 2008 are to drill 7 to 10 wells in the Pine Creek area.

Viking-Kinsella, Alberta

Crew drilled two net gas wells in the fourth quarter and continued its land and seismic acquisition programs in this area. This has led to the confirmation of five drillable gas prospects and two drillable oil prospects. Should the oil targets be successful Crew has identified 12 additional potential locations. Two wells are expected to be drilled in the first quarter of 2008.

Hanlan, Alberta

Crew (WI - 42.5%) recompleted one well in the fourth quarter. This well is a new pool wildcat discovery and represents the highest flow rate that Crew has tested since the Company's inception in 2003. The well had an absolute open flow of 56 mmcf per day and is expected to commence production by the end of the first quarter at 15 to 20 mmcf per day. Crew now owns an interest in 18.25 sections of land on this play and is currently operating a second recompletion (WI - 41.5%) approximately two kilometres away from the discovery well. We now have three additional recompletion opportunities in the area with working interests ranging from 41.5% to 100%. Current take away capacity from the area is estimated to be over 50 mmcf per day which is expected to accommodate near term productive capacity. Once the pool has been produced for an extended time period we will be able to better assess reservoir continuity and size. Crew controls four 100% sections of land on the up dip side of the discovery.

Carrot Creek, Alberta

This is another full cycle exploration area the Company has taken from an exploration concept, to posting and purchasing Crown land, drilling three wells, purchasing a gas plant including associated infrastructure and production and increasing the controlled land position to 36 sections to create a new core area. Current production is estimated to be over 500 boe per day. Based on drilling success Crew has an inventory in excess of 21 drilling locations identified on this liquids rich natural gas play. In the first quarter of 2008, Crew purchased a 100% interest in a 5.5 mmcf per day gas plant, associated pipeline infrastructure and approximately 500 mcf per day of production. The acquisition of this facility is expected to reduce area operating costs from \$1.00 per mcf to \$0.23 per mcf. Targets for 2008 include filling the capacity of the gas plant and being in a position to expand the facility to 12 mmcf per day.

Inga, British Columbia

Crew plans to drill its first horizontal well targeting natural gas production from the Baldonnel formation in the first quarter. If successful, the Company could drill six additional locations targeting this formation. Crew (WI - 100%) owns an underutilized gas plant to accommodate production from this area.

Yoyo-Sierra, British Columbia

The Sierra compressor station continued to experience downtime in the fourth quarter until repairs were completed in November. This facility is now operating with much improved efficiencies at approximately 11.5 mmcf per day of raw gas (7.5 mmcf per day sales gas). Crew expects to drill one well in this area targeting natural gas in the first quarter. For the first time in several years, we are now generating revenue from sulphur sales. The Sierra well had estimated net sulphur revenue in January, 2008 of over \$300,000 as world sulphur prices have hit new highs and continue to climb.

EXPLORATION

Strachan, Alberta

At Strachan, Alberta Crew (WI - 15% bpo, 46.5% apo) plans to drill a 3,700 meter Leduc prospect. The licensing of this well is awaiting surface access approvals and is expected to spud in the fourth quarter of 2008. Successful wells in the area have produced ten to several hundred bcf of gas with corresponding high daily production rates.

West Brazeau, Alberta

Crew (WI - 37.5% to 100%) is targeting thrustured Belly River sandstone reservoirs on 30 sections of land the Company has accumulated at West Brazeau. Crew is currently drilling its first well on this prospect with analogous offsetting wells producing up to 5.5 mmcf per day. Crew has identified up to 12 net drilling locations on this play.

Colt, British Columbia

Crew (100%) has assembled by way of Crown land acquisitions a five section block of land over a large foothills structure. This seismically defined feature has been interpreted to have 125 to 200 meters of structural closure over an area encompassing 2,200 acres. An offsetting well on a similar geophysical feature is currently producing 21 to 25 mmcf per day. Crew has identified three locations on this play with undiscovered conventional natural gas resource potential of over 120 bcf mapped with the primary target being the Mississippian Debolt Formation.

EMERGING RESOURCE PLAYS

Septimus-Triassic Montney Play

Crew has now assembled 20 net sections of land on this play. We have mapped over two trillion cubic feet of potential natural gas resource on our lands and we are currently drilling one vertical well and one horizontal well. The Upper Montney at Septimus is approximately 450 feet thick. This play is expected to be developed using vertical delineation wellbores and horizontal producing wells. With success, Crew expects to initially develop its lands using four horizontal wells per section.

With positive drilling results, it is likely that Crew will construct a gas processing facility to accommodate expected production volumes due to limited processing capacity in the area. Project economics include the construction of a gas processing facility and related infrastructure. Technology surrounding the drilling and stimulation of these wells continues to evolve with initial production rates of 2.5 to over 10 mmcf per day being recorded. It is our belief that costs, production rates and ultimate recoveries will improve over time.

Current plans for 2008 include the drilling of up to six wells and the design and planning of a natural gas processing facility. Construction of the facility will be dependent on drilling success over the next three quarters.

Horn River Basin/Cordova Embayment Muskwa Devonian Shale Gas Play

Crew has 15 net sections of land on this shale gas play. The Muskwa Shale is approximately 500 feet thick and has gained a significant amount of attention since the February 28, 2008 announcement by an industry participant of their successful drilling and testing of the Muskwa Shale in the Horn River Basin. It was noted in the company's release that they attribute a resource of 265 to 318 bcf of natural gas per section on their lands in a specific geographic area in the Horn River Basin. The company's resource estimates were based on well test and petrophysical data derived from a drilling program targetting the Devonian aged Muskwa Shales in the area. The play is in its infancy but does appear to be prospective over a large area in a relatively homogeneous geologic environment.

Cautionary Statement – The information provided above includes references to discovered and undiscovered natural gas resources. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resource.

OUTLOOK

Business Environment

Natural gas prices have rallied in the past month but natural gas continues to be an inexpensive source of energy in North America when compared to oil or natural gas in other consuming countries. Our view remains that long term natural gas fundamentals will improve as we see a Canadian supply response from reduced activity levels, an increase in domestic industrial demand and the globalization of the commodity. With our low cost structure and healthy balance sheet, Crew is well prepared to profit in a low price environment and uniquely positioned to prosper in a higher price environment. We will continue to use funds flow from conventional oil and gas operations to fund our expansion into resource based assets that provide large gas in place opportunities and repeatable multi-year drilling programs.

Alberta Royalty Review

During the past year, The Government of Alberta commissioned a review by an independent panel to perform a review of the province's royalty system to determine if the people of Alberta were receiving their "fair share" of the resource extracted by the oil and gas industry. On September 18, 2007 a report was issued by the Alberta Royalty Review Panel. Utilizing this report as a framework, on October 25, 2007 the Government of Alberta released its proposed New Royalty Framework ("NRF") for the province.

Crew has reviewed the modifications proposed in the NRF that, if implemented, would take effect on January 1, 2009. The government has not yet clarified certain aspects of the new royalty calculations and has stated its intention to consult with industry and review the NRF for unintended consequences. While Crew will continue to monitor government announcements and proposed revisions as they become available, we wish to make the following preliminary observations:

- The proposed NRF rewards the development of low productivity wells and deters multi-well, full cycle exploration where cash flow from high productivity wells is reduced by significantly higher royalties but is still required to recover the costs of seismic and land acquisitions, dry holes, pipelines and processing facilities;
- If not altered, the proposed NRF will reduce exploratory drilling and industry activity levels as it fails to recognize the current cost structure in Alberta;
- We believe the proposed NRF has resulted in a loss of confidence and attraction of capital in the oil and gas industry particularly as it relates to conventional oil and gas development;
- 30% of Crew's current production is from properties located in British Columbia and therefore is not affected by the NRF and;
- GLJ Petroleum Consultants Ltd., our third party engineering firm, has calculated the net present value of our reserves using its commodity price assumptions under the NRF. The effect on Crew's net present values were negligible.

Strong Production Growth and Solid Balance Sheet

At the end of the fourth quarter Crew has \$110 million of debt and working capital deficiency on a \$180 million bank facility. The Company is currently engaged in a very active first quarter capital expenditure program which is expected to total \$55 to \$65 million. Capital spending in the second quarter on exploration and development is expected to be less than funds flow and is anticipated to restore our debt to forward funds flow from operations ratio to approximately one time. Crew expects to average 11,400 to 12,200 boe per day in 2008 which at the midpoint is a 36% increase in average production over 2007. This production growth represents a 47% compounded annual growth rate in production since the Company was formed in September, 2003. Using the midpoint of the projected average production range, the February 28, 2008 strip reference pricing of AECO - \$7.90 per gj and Edmonton light oil of \$98.00 per bbl and the Company's other 2008 operating assumptions identified in the attached MD&A, the Company is currently forecasting funds flow from operations of approximately \$143 million or \$2.61 per diluted share.

Significant reserve and production potential

At the end of 2007 Crew had 33.5 million boe of proved and probable reserves. We currently have no reserves assigned to the northeast British Columbia Montney or the Muskwa Shale natural gas plays. We are excited about our exposure to these significant natural gas prospects that have now transformed the Company to one with a tremendous resource base with the potential to materially impact our reserve and production base. We have added materially to our Alberta based operations in a time when there has been reduced competition for land and services. We are confident these strategies will prove successful and position Crew with the ability to advance to the next level. Finally, I would like to thank our Board of Directors for their continued support and guidance and commend our staff on their hard work and dedication.

LAND HOLDINGS

During 2007, Crew used the reduction in natural gas activity in Alberta to further expand its land holdings through Crown land sales, freehold mineral leasing and farm-in arrangements. These additions were primarily in the Company's greater Edson, Alberta operating area including significant additions at Pine Creek, Hanlan and Carrot Creek. Crew also substantially added to its holdings in northeastern British Columbia with the acquisition of a private company in May with operations predominantly in this region. The Company further added to its holdings in northeast British Columbia by acquiring 11 sections of undeveloped land on the developing Triassic Montney natural gas resource play.

A summary of the Company's land holdings at December 31, 2007 is outlined below:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	211,257	111,002	207,623	167,939	418,880	278,940
British Columbia	96,801	37,618	118,344	67,585	215,145	105,204
Total	308,058	148,620	325,967	235,524	634,025	384,144
Average working interest				72%		61%

RESERVES

The reserves data set forth below is based upon an independent reserve assessment and evaluation by GLJ Petroleum Consultants ("GLJ") with an effective date of December 31, 2007 and dated March 3, 2008 (the "GLJ Report"). The following presentation summarizes the Company's crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for the Company's reserves using forecast prices and costs based on the GLJ Report. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101.

Cautionary Statements

BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf to 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.

All evaluations and reviews of future net cash flows are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Reserves Summary

The Company's total proved plus probable reserves increased by 59% in 2007 to 33.5 Mboe. Proved reserves increased by 70% to 22.6 Mboe and comprised 68% of the Company's total proved plus probable reserves. Proved producing reserves of 16.4 Mboe were 72% of total proved reserves. Crew's probable reserves totalled 10.9 Mboe of which 47% are producing probable reserves.

The following table provides summary reserve information based upon the GLJ Report and using the GLJ (2008-01) price forecast.

	Light/medium oil		Natural gas liquids		Natural gas		Barrels of oil equivalent	
	Comp Int. (Mbbl)	Net (Mbbl)	Comp Int. (Mbbl)	Net (Mbbl)	Comp Int. (Mmcf)	Net (Mmcf)	Comp Int. (Mboe)	Net (Mboe)
Proved								
Producing	441	383	2,617	1,824	79,944	62,429	16,382	12,612
Non-producing	45	42	355	254	25,975	20,013	4,729	3,632
Undeveloped	0	0	78	59	8,658	7,300	1,521	1,276
Total proved	487	426	3,049	2,137	114,576	89,742	22,632	17,519
Probable	224	199	1,393	975	55,494	43,869	10,867	8,485
Total proved & probable	711	625	4,442	3,112	170,070	133,610	33,498	26,005

Notes:

- (1) "Comp Int." reserves means, Crew's working interest (operating and non-operating) share before deduction of royalties and including any royalty interest of the Company.
- (2) "Net" reserves means, Crew's working interest (operated and non-operated) share after deduction of royalties obligations, plus Crew's royalty interest in reserves.
- (3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.
- (4) May not add due to rounding.

Reserves Values

The estimated before tax future net revenues associated with Crew's reserves effective December 31, 2007 and based on the GLJ (2008 – 01) future price forecast are summarized in the following table:

(MM\$)	0%	5%	8%	10%	15%	20%
Proved						
Producing	491.7	400.6	362.8	342.0	300.9	270.2
Non-producing	127.6	102.8	91.9	85.8	73.4	64.0
Undeveloped	27.1	16.2	12.1	10.0	6.3	3.9
Total proved	646.4	519.6	466.8	437.8	380.6	338.1
Probable	316.3	198.4	158.9	139.4	105.2	83.3
Total proved and probable	962.7	718.0	625.7	577.2	485.8	421.4

Notes:

- (1) The estimated future net revenues are stated before deducting future estimated site restoration costs and are reduced for estimated future abandonment costs and estimated capital for future development associated with the reserves.
- (2) Determined under the existing Alberta Royalty framework as the proposed new Alberta Royalty Framework has not been enacted
- (3) May not add due to rounding.

Alberta Royalty Review

During the past year, the Government of Alberta commissioned an independent panel to perform a review of the province's royalty system to determine if the people of Alberta were receiving their "fair share" of the resource extracted by the oil and gas industry. On September 18, 2007 a report was issued by the Alberta Royalty Review Panel. Utilizing this report as a framework, on October 25, 2007 the Government of Alberta released its proposed New Royalty Framework ("NRF") for the province.

GLJ, at the Company's request, has recalculated our December 31, 2007 reserves under the NRF. As the government has not yet clarified certain aspects of the new royalty calculations, GLJ has provided a range for the impact. The range includes "NRF High" Scenario representing a more optimistic or high value sensitivity of the NRF impact, and the "NRF Low" Scenario representing the low value sensitivity.

The results indicate that the change in royalty rates would have a minimal impact on Crew's reserve base as at December 31, 2007. Using the NRF High Scenario Crew's December 31, 2007 before tax present value using a 10% discount rate is \$583 million, a 1% increase over the Company's December 31, 2007 base value. The NRF Low Scenario results in Crew's December 31, 2007 before tax present value, discounted at 10% being \$570 million or a 1% reduction from the Company's base value. This evaluation presents a "blowdown" of our existing production and development of our existing non-producing reserves at the effective date of the report and does not reflect the impact the NRF will have on future exploration success the Company will have in Alberta.

Price Forecast

The GLJ (2008-01) price forecast is summarized as follows:

Year	WTI @ Cushing (US\$/bbl)	Edmonton light crude oil (C\$/bbl)	Natural gas at AECO-C spot (C\$/MMbtu)	Westcoast Station 2 (C\$/MMbtu)
2008	92.00	91.10	6.75	6.55
2009	88.00	87.10	7.55	7.35
2010	84.00	83.10	7.60	7.40
2011	82.00	81.10	7.60	7.40
2012	82.00	81.10	7.60	7.40
2013	82.00	81.10	7.60	7.40
2014	82.00	81.10	7.80	7.60
2015	82.00	81.10	7.97	7.77
2016	82.02	81.12	8.14	7.94
2017	83.66	82.76	8.31	8.11
2018 +	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Notes:

(1) Inflation is accounted for at 2.0% per year and the \$US/\$Cdn exchange rate was constant at 1.00.

Reserves Reconciliation

The following reconciliation of Crew's Company Interest reserves compares changes in the Company's reserves as at December 31, 2006 to the reserves as at December 31, 2007 based on the GLJ (2008 - 01) future price forecast.

	Proved Producing (Mboe)	Total Proved (Mboe)	Total Proved plus Probable (Mboe)
Balance December 31, 2006	8,615	13,350	21,116
Technical revisions	299	1	(1,391)
Exploration discoveries	88	848	1,326
Drilling extensions	2,509	3,200	4,678
Improved recoveries	2,320	0	0
Acquisitions	5,726	8,407	10,943
Production	(3,174)	(3,174)	(3,174)
Balance December 31, 2007	16,382	22,632	33,498

Notes:

- (1) "Company Interest" reserves means, Crew's working interest (operating and non-operating) share before deduction of royalties and including any royalty interest of the Company.
- (2) May not add due to rounding

Capital Program Efficiency

The efficiency of the Company's capital program for the year ended December 31, 2007 is summarized below.

	2007		2006		Three Year Average 2005-2007	
	Proved	Proved plus Probable	Proved	Proved plus Probable	Proved	Proved plus Probable
Exploration and Development expenditures (\$ thousands)	102,092	102,092	123,859	123,859	327,649	327,649
Acquisitions (\$ thousands) (note 2)	136,685	136,685	86,904	86,904	223,589	223,589
Change in future development capital (\$ thousands)						
- Exploration and Development	(3,959)	(12,038)	11,098	29,548	10,840	29,943
- Acquisitions	9,750	15,445	2,113	6,730	11,863	22,175
Reserves additions after revisions (Mboe)						
- Exploration and Development	4,049	4,613	3,213	4,212	11,743	16,166
- Acquisitions	8,407	10,943	2,447	3,839	10,854	14,782
	12,456	15,556	5,660	8,051	22,597	30,948
Finding, Development & Acquisition Costs (F,D&A)						
Exploration and development	24.24	19.52	42.00	36.42	28.82	22.12
Acquisitions	17.42	13.90	36.38	24.39	21.69	16.63
Total F,D&A (note3)	19.63	15.57	39.57	30.68	25.40	19.50
Reserves Replacement Ratio	392%	490%	272%	387%	333%	456%
Recycle Ratio based on annual operating netbacks	1.5	1.9	0.7	0.9	1.2	1.6
Reserve Life Index based on fourth quarter production	6.4	9.5	5.9	9.3		

Notes:

- (1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.
- (2) The acquisition costs related to corporate acquisitions reflects the consideration paid for the shares acquired plus the net debt assumed, both valued at closing and does not reflect the fair market value allocated to the acquired oil and gas assets under Generally Accepted Accounting Principles.
- (3) Includes reserve revisions and changes in future development costs

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORIES

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 month periods and years ended December 31, 2007 and 2006 and the audited and consolidated financial statements and Management Discussion and Analysis for the year ended December 31, 2006.

Forward Looking Statements

This MD&A contains forward-looking statements. Management's assessment of future plans and operations, capital expenditures, the timing of these expenditures and the method of funding thereof, available bank lines, production estimates, wells to be drilled, timing of drilling, tie-in and completion of wells and the production resulting therefrom, expected royalty rates, transportation costs and operating costs, and the taxability of the Company, may constitute forward-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploration, 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, the timing and length of plant turnarounds and the impact of such turnarounds and the timing thereof, delays resulting from or inability to obtain required regulatory approvals and the ability to access sufficient capital from internal and external sources. As a consequence, the company's actual results could differ materially from those expressed in, or implied by, the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or at the Company's website (www.crewenergy.com). Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A and the Company 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.

Conversions

The oil and gas industry commonly expresses production volumes and reserves on a "barrel of oil equivalent" basis ("boe") whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants.

Throughout this MD&A, Crew has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the plant gate which is where Crew sells its production volumes and therefore may be a misleading measure if used in isolation.

Non-GAAP Measures

Crew evaluates performance based on net income and funds from operations. Funds from operations is a measure not based on GAAP that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital, asset retirement expenditures and the excess transportation liability charge. 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. Funds from operations should not be considered as an alternative to, or more meaningful than cash flow provided by operating activities as determined in accordance with GAAP as an indicator of the Company's performance. Crew's determination of funds from operations may not be comparable to that reported by other companies. Crew also presents funds from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of income per share.

(\$ thousands)	Three months ended Dec. 31, 2007	Three months ended Dec. 31, 2006	Year ended Dec. 31, 2007	Year ended Dec. 31, 2006
Cash provided by operating activities	11,882	16,522	74,400	57,455
Asset retirement expenditures	205	203	237	448
Excess transportation liability charge	313	-	784	-
Change in non-cash working capital	9,990	(20)	6,012	(1,245)
Funds from operations	22,390	16,705	81,433	56,658

Management also uses operating netback, a non-GAAP term, to analyze operating performance and leverage. Netback equals total petroleum and natural gas sales including realized gains and losses on financial instruments less royalties, operating costs and transportation costs calculated on a boe basis.

RESULTS OF OPERATIONS

Production

	Three months ended December 31, 2007			Three months ended December 31, 2006		
	Oil and ngl (bbl/d)	Natural gas (mcf/d)	Total (boe/d)	Oil and ngl (bbl/d)	Natural gas (mcf/d)	Total (boe/d)
Plains Core	1,199	33,700	6,815	1,182	27,409	5,750
North Core	575	13,504	2,826	134	2,055	477
Total	1,774	47,204	9,641	1,316	29,464	6,227

Fourth quarter production increased over the fourth quarter of 2006 as a result of a successful drilling program that added new natural gas liquids (“ngl”) rich natural gas production at Edson and Ferrier and the closing of two private company acquisitions on November 21, 2006 and May 3, 2007 with production primarily in the Company’s Ferrier area in the plains core and northeastern British Columbia in the north core. Fourth quarter production increases were partially offset by an unplanned Company owned facility outage at Sierra in the north core and outages at third party facilities affecting production at Carrot Creek and Ferrier in the plains core. These outages resulted in approximately 500 boe per day of lost production during the quarter.

	Year ended December 31, 2007			Year ended December 31, 2006		
	Oil and ngl (bbl/d)	Natural gas (mcf/d)	Total (boe/d)	Oil and ngl (bbl/d)	Natural gas (mcf/d)	Total (boe/d)
Plains Core	1,181	32,352	6,573	774	25,220	4,977
North Core	316	10,841	2,123	167	3,306	718
Total	1,497	43,193	8,696	941	28,526	5,695

Production increased throughout 2007 due to a successful drilling program and the previously mentioned corporate acquisitions. Natural gas production increased 51% over 2006 due to a successful drilling program in the Company’s Edson and Ferrier, Alberta areas and the November 2006 corporate acquisition in the plains Core and increased production from northeastern British Columbia due to the closing of the corporate acquisition in May, 2007. Crew’s oil and ngl production increased 59% over 2006 due to increased ngl production from the Edson area and the northeast British Columbia acquisition.

Revenue

	Three months ended Dec. 31, 2007	Three months ended Dec. 31, 2006	Year ended Dec. 31, 2007	Year ended Dec. 31, 2006
Revenue (\$ thousands)				
Light oil and ngl	11,141	7,122	34,112	21,796
Natural gas	27,801	19,468	106,354	71,017
Realized gain on financial instruments	432	-	1,011	-
Total	39,374	26,590	141,477	92,813

Crew average prices

Light oil and ngl (\$/bbl)	\$ 68.27	\$ 58.84	\$ 62.44	\$ 63.47
Natural gas (\$/mcf)	\$ 6.40	\$ 7.18	\$ 6.75	\$ 6.82
Realized gain on financial instruments (\$/mcf)	\$ 0.10	-	\$ 0.06	-
Total natural gas (\$/mcf)	\$ 6.50	\$ 7.18	\$ 6.81	\$ 6.82
Oil equivalent (\$/boe)	\$ 44.39	\$ 46.41	\$ 44.57	\$ 44.65

Benchmark pricing

Natural Gas – AECO C daily index (Cdn \$/ mcf)	\$ 6.24	\$ 7.00	\$ 6.53	\$ 6.60
Oil and ngl – Light Sweet @ Edmonton (Cdn \$/bbl)	\$ 84.73	\$ 64.52	\$ 75.67	\$ 72.81

Crew's 2007 fourth quarter revenue increased 48% over the fourth quarter 2006 due to the 55% increase in production. This was partially offset by a four percent decrease in the Company's average prices. Crew's 11% drop in natural gas prices was consistent with the 11% decrease in the benchmark price. The Company had a disproportionate increase in light oil and ngl prices as compared with the Company's benchmark primarily due to increased sales of lower valued ethane production from the Ferrier area that was acquired as part of the November, 2006 corporate acquisition.

The Company's 2007 revenue increased 52% as a result of its 55% increase in production. This was partially offset by a slight decline in Crew's natural gas price that was consistent with the Company's benchmark pricing for 2007. The sales price for Crew's light oil and ngl production declined slightly as compared with a four percent increase in the benchmark due to increased sales of lower valued ethane production from the Ferrier area that was acquired as part of the November, 2006 corporate acquisition.

Royalties

(\$ thousands, except per BOE)	Three months ended Dec. 31, 2007	Three months ended Dec. 31, 2006	Year ended Dec. 31, 2007	Year ended Dec. 31, 2006
Royalties	6,929	5,100	23,749	19,580
Per BOE	\$ 7.81	\$ 8.90	\$ 7.48	\$ 9.42
Percentage of revenue	17.6%	19.2%	16.8%	21.1%

Royalties as a percentage of revenue decreased in the quarter compared to the same quarter of 2006 due to increased gas cost allowance credits booked in the fourth quarter of 2007 and lower royalty rates on the assets acquired in the May, 2007 corporate acquisition. This decrease was partially offset by higher natural gas and ngl royalties on new production in Edson and Ferrier which attracts a higher royalty rate.

Royalties as a percentage of revenue decreased in 2007 over 2006 due to increased deep gas royalty holidays received in 2007 primarily in the Company's plains core areas of Hanlan and Ferrier. The Company also received benefits from government programs reducing royalties on production in northeastern British Columbia. In addition, Crew received higher than forecasted Alberta gas cost allowance credits related to capital spent on facilities constructed during 2006. Crew expects royalties as a percentage of revenue to average 20% to 21% in 2008.

Financial Instruments

On occasion, the Company will enter into commodity price risk management contracts in order to reduce volatility in financial results, to protect acquisition economics and to ensure a certain level of cash flow to fund planned capital projects. Crew's strategy will focus on the use of natural gas price "puts" and costless collars to limit exposure to downturns in commodity prices, while allowing for participation in commodity price increases. The Company's financial derivative trading activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors.

For the quarter and year ended December 31, 2007 the Company realized net gains of \$0.4 million and \$1.0 million, respectively on commodity price risk management contracts that were entered into during the second quarter of the year. As at December 31, 2007, the Company had entered into direct sales agreements to sell natural gas as follows:

	Volume (gj/day)	Term	Price (Cdn \$/gj)	Floor (Cdn\$/gj)	Fair Value (thousands)
AECO/Station 2 Differential Swap	10,000	November 1, 2007– October 31, 2008	AECO 5A less \$0.16	-	\$(436)

Subsequent to December 31, 2007, the Company entered into the following direct sales agreements to sell natural gas:

	Volume (gj/day)	Term	Price (Cdn \$/gj)	Ceiling (Cdn \$/gj)	Floor (Cdn \$/gj)
AECO	10,000	April 1, 2008 – October 31, 2008	AECO C – Monthly Index	\$8.00	\$7.00
AECO	10,000	April 1, 2008 – October 31, 2008	AECO Daily wkd	\$8.30	\$7.00

Operating Costs

	Three months ended Dec. 31, 2007	Three months ended Dec. 31, 2006	Year ended Dec. 31, 2007	Year ended Dec. 31, 2006
(\$ thousands, except per BOE)				
Operating costs	5,634	3,393	19,763	11,221
Per BOE	\$ 6.35	\$ 5.92	\$ 6.23	\$ 5.40

The Company's operating costs increased in the fourth quarter as compared to the same period in 2006 as a result of the Company's increased production. On a per unit basis, operating costs in the fourth quarter increased 7% over the fourth quarter of 2006. This increase was the result of the production outage in northeast British Columbia which impacted the Company's lower cost production volumes. In addition, the Company has added higher cost production in the Ferrier, Alberta area in 2007 compared to the prior year and has incurred increased third party processing fees in the Viking and Plain Lake, Alberta areas.

Crew's increase in operating costs in 2007 was a result of increased production, inflationary pressures experienced throughout all of its operations and increased production of higher cost natural gas at Ferrier. Increased third party processing costs at Viking and Plain Lake also contributed to the increase in total and per unit operating costs in 2007. Per unit operating costs were 4% higher than forecasted for 2007 as a result of higher than expected inflationary pressures on third party processing fees. The Company expects operating costs to range between \$6.30 and \$6.60 per boe in 2008.

Transportation

(\$ thousands, except per BOE)	Three months ended	Three months ended	Year ended	Year ended
	Dec. 31, 2007	Dec. 31, 2006	Dec. 31, 2007	Dec. 31, 2006
Transportation costs	1,779	481	6,603	1,979
Per BOE	\$ 2.01	\$ 0.84	\$2.08	\$ 0.95

The Company's 2007 fourth quarter and annual increase in transportation costs and transportation costs per unit compared to 2006 is the result of the May, 2007 acquisition of a private company with natural gas production mainly in northeast British Columbia which has a higher transportation cost. In northeast British Columbia, natural gas is produced into a third party owned gathering and processing infrastructure that enables producers to avoid facility construction. The all-in regulated fees charged for gathering, processing and transmission of the Company's natural gas through this system is included in transportation expense.

Transportation costs were lower than forecasted in the fourth quarter of 2007 due to an insurance recovery from the Company's Sierra facility outage during the third and fourth quarter of 2007.

In 2007, Crew's higher than projected transportation costs are a result of the May, 2007 acquisition of the private company with the all-in gathering, processing and transmission charge as described above. The Company forecasts transportation costs in 2008 to range between \$2.00 to \$2.25 per boe.

Operating Netbacks

	Three months ended December 31, 2007			Three months ended December 31, 2006		
	Oil and ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)	Oil and ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)
Revenue	\$ 68.27	\$ 6.50	\$ 44.39	\$ 58.84	\$ 7.18	\$ 46.41
Royalties	(17.67)	(0.93)	(7.81)	(11.84)	(1.40)	(9.12)
Alberta royalty tax credit	-	-	-	-	-	0.22
Operating costs	(6.44)	(1.06)	(6.35)	(5.67)	(1.00)	(5.92)
Transportation costs	(0.44)	(0.39)	(2.01)	(1.16)	(0.13)	(0.84)
Operating netbacks	\$ 43.72	\$ 4.12	\$ 28.22	\$ 40.17	\$ 4.65	\$ 30.75

	Year ended December 31, 2007			Year ended December 31, 2006		
	Oil and ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)	Oil and ngl (\$/bbl)	Natural gas (\$/mcf)	Total (\$/boe)
Revenue	\$ 62.44	\$ 6.81	\$ 44.57	\$ 63.47	\$ 6.82	\$ 44.65
Royalties	(13.77)	(1.03)	(7.48)	(13.53)	(1.48)	(9.66)
Alberta royalty tax credit	-	-	-	-	-	0.24
Operating costs	(6.26)	(1.04)	(6.23)	(5.26)	(0.90)	(5.40)
Transportation costs	(0.97)	(0.39)	(2.08)	(1.32)	(0.15)	(0.95)
Operating netbacks	\$ 41.44	\$ 4.35	\$ 28.78	\$ 43.36	\$ 4.29	\$ 28.88

General and Administrative

	Three months ended December 31, 2007	Three months ended December 31, 2006	Year ended December 31, 2007	Year ended December 31, 2006
(\$ thousands, except per boe)				
Gross costs	2,355	1,415	8,328	5,413
Operator's recoveries	(415)	(581)	(1,666)	(2,039)
Capitalized costs	(970)	(417)	(3,331)	(1,687)
General and administrative expenses	970	417	3,331	1,687
Per boe	\$ 1.09	\$ 0.73	\$ 1.05	\$ 0.81

Increased general and administrative costs before recoveries and capitalization was the result of increased staff levels and higher salary levels in the fourth quarter of 2007 compared to 2006. In the fourth quarter of 2007, the Company's net general and administrative costs increased due to a reduced overhead recovery as a result of decreased drilling and completion expenditures in the quarter.

General and administrative expenses increased in 2007 as compared to 2006 and were higher than projected as a result of the addition of new staff to handle the Company's increased activity and inflationary pressure on salaries in order for the Company to remain competitive in the industry's tight employment market. Crew expects general and administrative costs per boe to range between \$1.00 and \$1.05 per boe in 2008.

Interest

	Three months ended December 31, 2007	Three months ended December 31, 2006	Year ended December 31, 2007	Year ended December 31, 2006
(\$ thousands, except per boe)				
Interest expense	1,882	494	6,808	1,688
Average debt level	107,300	32,200	103,300	27,800
Effective interest rate	7.0%	6.1%	6.6%	6.1%
Per boe	\$ 2.12	\$ 0.86	\$ 2.15	\$ 0.81

In 2007, higher interest rates combined with higher average debt levels due to debt financing of a portion of the Company's May, 2007 corporate acquisition and its 2007 exploration and development program have increased the Company's interest expense. Crew's effective interest rate increased in 2007 compared with 2006 due to the amortization of financing fees incurred in May, 2007 when a new credit facility was arranged.

Stock-Based Compensation

	Three months ended December 31, 2007	Three months ended December 31, 2006	Year ended December 31, 2007	Year ended December 31, 2006
(\$ thousands)				
Gross costs	1,516	1,047	5,324	4,462
Capitalized costs	(758)	(523)	(2,662)	(2,231)
Total stock-based compensation	758	524	2,662	2,231

The Company's stock-based compensation expense has increased in 2007 as a result of increased staff levels and the issuance of stock options in late 2006 and in early 2007.

Depletion, Depreciation and Accretion

(\$ thousands, except per BOE)	Three months ended Dec. 31, 2007	Three months ended Dec. 31, 2006	Year ended Dec. 31, 2007	Year ended Dec. 31, 2006
Depletion, depreciation and accretion	20,489	13,840	75,427	41,458
Per BOE	23.10	24.16	23.76	19.94

The Company experienced a decrease in per unit depletion in the fourth quarter of 2007 due to its successful drilling program in the quarter resulting in new reserve additions. Per unit depletion has increased in 2007 due to an increase in the average cost of adding proved reserves in 2007. This increase has resulted from inflationary pressures experienced throughout the industry, the addition of higher priced proven reserves acquired through the corporate acquisitions in November, 2006 and May, 2007 and the acquisition and construction of facilities in order to maintain low operating costs and to ensure processing capacity for the Company's natural gas production.

Taxes

The future income tax recovery for 2007 was \$6.2 million compared to an expense of \$2.2 million in 2006. The Company's current year provision was impacted by the recovery of \$8.0 million relating to the federal income tax rate reduction enacted during the year. In 2006, Crew also had a \$3.3 million recovery relating to federal and provincial income tax rate reductions enacted during the year.

A summary of the Company's estimated income tax pools at December 31, 2007 is outlined below:

(\$ thousands)	Balance Dec. 31, 2007	Balance Dec. 31, 2006
Cumulative Canadian Exploration Expense	46,500	41,000
Cumulative Canadian Development Expense	70,000	49,500
Cumulative Canadian Oil and Gas Property Expense	54,500	48,000
Undepreciated Capital Cost	65,000	50,500
Share issue costs	5,000	3,500
Non-capital loss	500	5,500
	241,500	198,000

The estimated income tax pools have been reduced by the estimated deferred partnership income for 2007 and the reduction in the CEE tax pools due to the renunciation of the 2006 flow through expenditures.

Cash and Funds from Operations and Net Income

(\$ thousands, except per share amounts)	Three months ended December 31, 2007	Three months ended December 31, 2006	Year ended December 31, 2007	Year ended December 31, 2006
Cash provided by operations	11,882	16,522	74,400	57,455
Funds from operations	22,390	16,705	81,433	56,658
Per share - basic	0.43	0.43	1.75	1.62
- diluted	0.43	0.43	1.74	1.59
Net Income	6,889	1,796	9,110	10,776
Per share - basic	0.13	0.05	0.20	0.31
- diluted	0.13	0.05	0.19	0.30

The Company's increase in cash provided by operations and funds from operations was due to the Company's increased production and lower royalties in 2007. Increased production was partially offset by slightly increased operating costs and the transportation cost associated with the Company's corporate acquisition in northeast British Columbia. Net income was impacted by the reduction in Federal income tax rates in 2007.

Capital Expenditures and Acquisitions

During the fourth quarter, the Company drilled a total of 11 (7.4 net) wells resulting in 10 (6.4 net) natural gas wells and one (1.0 net) dry and abandoned well. During all of 2007, Crew drilled a total of 31 (25.3 net) wells resulting in 28 (22.3 net) gas wells, two (2.0 net) oil wells, and one (1.0 net) dry and abandoned well representing a success rate of 97% (96% net). The Company also continued to follow its strategy of, where possible, owning and controlling its processing and gathering facilities. As a result, in 2007 the Company spent 19% of its total capital expenditures on acquiring gas processing and compression equipment and gathering systems. The highlights of these expenditures included the first quarter completion of a pipeline and surface facilities for tie-in of the Company's natural gas discovery at Hanlan, Alberta and the fourth quarter construction of a pipeline and compression facility to tie-in the Company's natural gas discovery at Pine Creek, Alberta.

During 2007, Crew also used the reduction in natural gas activity in Alberta to further expand its land holdings through Crown land sales, freehold mineral leasing and farm-in arrangements. These additions were primarily in the Company's greater Edson, Alberta operating area including significant additions at Pine Creek, Hanlan and Carrot Creek.

In May, 2007 the Company closed the acquisition of a private company with the majority of its operations in the Company's north core in northeastern British Columbia. Details of the purchase price are included in the Business Acquisition, note 3 to the Company's December 31, 2007 consolidated financial statements. The Company further added to its holdings in northeast British Columbia by acquiring 11 sections of undeveloped land on a developing Triassic Montney natural gas resource play.

Total exploration and development expenditures for 2007 were \$102.1 million compared to \$123.9 million for the same period in 2006. The Company's exploration and development expenditures for 2007 were lower than the prior year and the originally forecasted \$134 million due to the Company reducing its exploration and development spending after the successful private company acquisition in May. The expenditures are detailed below:

(\$ thousands)	Three months ended December 31, 2007	Year ended December 31, 2007	Year ended December 31, 2006
Land	7,080	14,756	8,024
Seismic	1,750	4,492	3,567
Drilling and completions	14,836	58,271	80,922
Facilities, equipment and pipelines	5,829	19,791	29,347
Other	1,538	4,782	1,999
Total exploration and development	31,033	102,092	123,859
Property acquisitions (dispositions)	(266)	(315)	16,196
Corporate acquisition	(405)	137,051	71,151
Total	30,362	238,828	211,206

The Company's Board of Directors has approved a \$120 million exploration and development budget for 2008.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

Funding for the Company's 2007 capital expenditure program has come from a combination of bank debt, equity financing and cash flow from ongoing operations.

On May 3, 2007, Crew acquired all of the issued and outstanding shares of a private oil and gas company with producing oil and natural gas properties in northeastern British Columbia and central Alberta. Crew's total consideration for the acquisition was approximately \$137 million before closing adjustments and costs. In conjunction with the acquisition, Crew issued, on a bought deal basis, 5,750,000 Common Shares at \$10.30 per share for aggregate gross proceeds of \$59.2 million. The common shares were issued concurrently with the closing of the acquisition and the net proceeds of approximately \$56 million were used to partially fund the acquisition price.

The remainder of the acquisition price was provided by a newly arranged credit facility with a syndicate of banks. The facility consists of a revolving line of credit of \$165 million (the "Syndicated Facility") and an operating line of credit of \$15 million (the "Operating Facility"). The facility revolves for a 364 day period and will be subject to its next 364 day extension by April 28, 2008. If not extended, the Syndicated Facility will cease to revolve and all outstanding advances under the facility will become repayable in one year. At December 31, 2007 Crew had drawings of \$95.4 million on its bank facility which leaves the Company with significant unused credit capacity available to fund the Company's working capital deficit and future capital expenditures.

On October 25, 2007, the Company completed a bought deal share financing with a syndicate of underwriters resulting in an issuance of 4,181,860 common shares at \$8.25 per common share and 1,860,500 common shares on a flow through basis at \$10.75 per flow through share for aggregate proceeds of \$54.5 million.

The Company will continue to fund its on-going operations from a combination of cash flow, debt, and equity financings as needed. As the majority of our ongoing capital expenditure program is directed to the further growth of reserves and production volumes, Crew is readily able to adjust its budgeted capital expenditures should the need arise. Currently, Crew has considerable financial strength through its cash flows and credit capacity to fund its budgeted capital expenditure program for 2008.

Working Capital

The capital intensive nature of Crew's activities generally results in the Company carrying a working capital deficit. However, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At December 31, 2007, the Company's working capital deficiency totaled \$14.3 million which, when combined with the drawings on its bank line, represented only 61% of its currently available bank facility.

Share Capital

As at March 10, 2008, Crew had 53,674,319 Common Shares outstanding along with 4,450,550 options to acquire Common Shares of the Company.

Contractual Obligations

Throughout the course of its ongoing business, the Company enters into various contractual obligations such as credit agreements, purchase of services, royalty agreements, operating agreements, processing agreements, right of way agreements and lease obligations for office space and automotive equipment. All such contractual obligations reflect market conditions prevailing at the time of contract and none are with related parties. The Company believes it has adequate sources of capital to fund all contractual obligations as they come due. The following table lists the Company's obligations with a fixed term.

(\$ thousands)	Total	2008	2009	2010	2011
Bank Loan (note 1)	95,374	-	95,374		
Operating Leases	3,712	990	990	990	742
Capital commitments	2,200	2,200	-	-	-
Exploration and development	17,800	17,800	-	-	-
Firm transportation agreements	27,071	6,224	7,026	7,243	6,578
Total	146,157	27,214	103,390	8,233	7,320

Note 1 – Based on the existing terms of the Company's bank facility the first possible repayment date may come in 2009. However, it is expected that the revolving bank facility will be extended and no repayment will be required in the near term.

The exploration and development commitment relates to the Company's obligation under its October 25, 2007 flow-through share issue.

The firm transportation commitments were acquired as part of the Company's May, 2007 private company acquisition and represent firm service commitments for transportation and processing of natural gas in British Columbia.

OUTLOOK

Natural gas prices have rallied in the past month but natural gas continues to be an inexpensive source of energy in North America when compared to oil. Our view remains that long term natural gas fundamentals will improve as we see a Canadian supply response from reduced activity levels, an increase in domestic industrial demand and the globalization of the community itself. With our low cost structure and healthy balance sheet Crew is well prepared to profit in a low price environment.

We are uniquely positioned to prosper in a higher price environment. We will continue to use funds flow from conventional oil and gas operations to fund our expansion into resource based assets that provide large gas in place opportunities and repeatable multi year drilling programs.

At the end of 2007 Crew had \$110 million of combined debt and working capital deficiency on a \$180 million bank facility. The Company is currently engaged in a very active first quarter capital expenditure program which is expected to total approximately \$55 to \$65 million. Exploration and development spending in the second quarter is expected to be well under funds from operations. Our capital program for 2008 was approved by the Board of Directors in December, 2007 at \$120 million which is forecasted to be primarily funded by the Company's 2008 funds flow from operations. This program is expected yield Crew average production of 11,400 to 12,200 boe per day in 2008 which at the midpoint is a 36% increase in average production over 2007.

Dated as of March 7, 2008

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, transportation costs, operating costs, cash flow and debt levels. 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 is a junior oil and gas exploration and production company whose shares are traded on The Toronto Stock Exchange under the trading symbol "CR".

Financial statements for the three month periods and years ended December 31, 2007 and 2006 are attached.

FOR DETAILED INFORMATION, PLEASE CONTACT:

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CREW ENERGY INC.
 Consolidated Balance Sheets
 (unaudited, thousands)

	December 31, 2007	December 31, 2006
Assets		
Current Assets:		
Accounts receivable	\$ 28,438	\$ 22,063
Income taxes receivable (note 3)	496	-
	<u>28,934</u>	<u>22,063</u>
Property, plant and equipment (note 4)	552,805	338,660
Goodwill (note 3)	20,800	14,558
	<u>\$ 602,539</u>	<u>\$ 375,281</u>
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	\$ 43,231	\$ 39,777
Fair value of financial instruments (note 9)	423	-
Current portion of other long-term obligations (note 6)	1,313	-
	<u>44,967</u>	<u>39,777</u>
Bank loan (note 5)	95,374	41,157
Other long-term obligations (note 6)	2,759	-
Asset retirement obligations (note 7)	18,668	10,485
Future income taxes (note 10)	77,045	39,552
Shareholders' Equity		
Share capital (note 8)	298,129	192,814
Contributed surplus (note 8)	10,557	5,566
Retained earnings	55,040	45,930
	<u>363,726</u>	<u>244,310</u>
Commitments (note 12)		
	<u>\$ 602,539</u>	<u>\$ 375,281</u>

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.

Consolidated Statements of Operations, Comprehensive Income and Retained Earnings
 (unaudited, thousands except per share amounts)

	Three months ended Dec. 31, 2007	Three months ended Dec. 31, 2006	Year ended Dec. 31, 2007	Year ended Dec. 31, 2006
Revenue				
Petroleum and natural gas sales	\$ 38,942	\$ 26,590	\$ 140,466	\$ 92,813
Royalties	(6,929)	(5,100)	(23,749)	(19,580)
	32,013	21,490	116,717	73,233
Other income	210	-	210	-
Realized gain on financial instruments (note 9)	432	-	1,011	-
Unrealized loss on financial instruments (note 9)	(840)	-	(423)	-
	31,815	21,490	117,515	73,233
Expenses				
Operating	5,634	3,393	19,763	11,221
Transportation	1,779	481	6,603	1,979
General and administrative	970	417	3,331	1,687
Interest	1,882	494	6,808	1,688
Stock-based compensation	758	524	2,662	2,231
Depletion, depreciation and accretion	20,489	13,840	75,427	41,458
	31,512	19,149	114,594	60,264
Income before income taxes	303	2,341	2,921	12,969
Income taxes (reduction) (note 10)				
Future	(6,586)	545	(6,189)	2,193
Net income and comprehensive income	6,889	1,796	9,110	10,776
Retained earnings, beginning of period	48,151	44,134	45,930	35,154
Retained earnings, end of period	\$ 55,040	\$ 45,930	\$ 55,040	\$ 45,930
Net income per share (note 8(e))				
Basic	\$ 0.13	\$ 0.05	\$ 0.20	\$ 0.31
Diluted	\$ 0.13	\$ 0.05	\$ 0.19	\$ 0.30

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.
 Consolidated Statements of Cash Flows
 (unaudited, thousands)

	Three months ended Dec. 31, 2007	Three months ended Dec. 31, 2006	Year ended Dec. 31, 2007	Year ended Dec. 31, 2006
Cash provided by (used in):				
Operating activities:				
Net income	\$ 6,889	\$ 1,796	\$ 9,110	\$ 10,776
Items not involving cash:				
Depletion, depreciation & accretion	20,489	13,840	75,427	41,458
Stock-based compensation	758	524	2,662	2,231
Future income taxes (reduction)	(6,586)	545	(6,189)	2,193
Unrealized loss on financial instruments	840	-	423	-
Transportation liability charge (note 6)	(313)	-	(784)	-
Asset retirement expenditures	(205)	(203)	(237)	(448)
Change in non-cash working capital	(9,990)	20	(6,012)	1,245
	11,882	16,522	74,400	57,455
Financing activities:				
Increase (decrease) in bank loan	(44,363)	13,876	54,217	36,686
Issue of common shares	54,606	332	113,880	40,841
Share issue costs	(2,988)	(2)	(6,315)	(2,202)
	7,255	14,206	161,782	75,325
Investing activities:				
Exploration and development	(31,033)	(30,330)	(102,092)	(123,859)
Property acquisitions	266	(267)	315	(16,196)
Business acquisition (note 3)	405	(346)	(136,920)	(346)
Change in non-cash working capital	11,225	215	2,515	(8,681)
	(19,137)	(30,728)	(236,182)	(149,082)
Change in cash and cash equivalents	-	-	-	(16,302)
Cash and cash equivalents, beginning of period	-	-	-	16,302
Cash and cash equivalents, end of period	\$ -	\$ -	\$ -	\$ -

See accompanying notes to the consolidated financial statements.

CREW ENERGY INC.

Notes to Consolidated Financial Statements
For the three months and years ended December 31, 2007 and 2006
(Unaudited, Tabular amounts in thousands)

1. Significant accounting policies:

The consolidated financial statements of Crew Energy Inc. ("Company") have been prepared by management in accordance with Canadian generally accepted accounting principles. Since the determination of certain assets, liabilities, revenues and expenses is dependent upon future events, the preparation of these financial statements requires the use of estimates and assumptions, which have been made with careful judgement. Specifically, the amounts recorded for depletion and depreciation of property, plant and equipment and the provision for asset retirement obligations and abandonment costs are based on estimates. The ceiling test is based on estimates of reserves, future production rates, future petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of such changes in such estimates in future periods could be significant. In the opinion of management, these financial statements have been properly prepared in accordance with Canadian generally accepted accounting principles within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

(a) Principles of consolidation:

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, Crew Resources Inc., Gladius Energy Inc. ("Gladius"), Enco Gas Ltd. ("Enco") and a partnership, Crew Energy Partnership. On January 17, 2007, Gladius was amalgamated into Crew Energy Inc. and on January 1, 2008, Enco was amalgamated into Crew Energy Inc.

(b) Cash and cash equivalents:

Cash and cash equivalents include monies on deposit and highly liquid short-term investments accounted for at cost and having a maturity date of not more than 90 days.

(c) Petroleum and natural gas properties:

The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized. Capitalized costs include land acquisition costs, geological and geophysical expenses, cost of drilling both productive and non-productive wells, production facilities, the fair value of asset retirement obligations and related overhead expenses.

Capitalized costs, excluding costs relating to unproved properties, are depleted using the unit-of-production method based on estimated proved reserves of petroleum and natural gas before royalties determined using forecast product prices and as determined by independent petroleum engineers. For purposes of the depletion calculation, natural gas reserves and production are converted to equivalent volumes of crude oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized unless such a sale would alter depletion by more than 20%.

The cost of acquiring unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically for impairment. When proved reserves are assigned or the property is considered impaired the costs of the property or the amount of impairment is added to the costs subject to depletion.

Petroleum and natural gas assets are evaluated in each reporting period (the "ceiling test") to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre. The carrying amounts are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an

1. Significant accounting policies (continued):

impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects of the cost centre. The cash flows are estimated using forecast product prices and costs and are discounted using a risk-free interest rate.

(d) Goodwill

Goodwill is the residual amount that results when the purchase price of a business exceeds the fair value of the net identifiable assets and liabilities acquired. Goodwill is stated at cost and is not amortized. The goodwill balance is assessed for impairment each year end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by comparing the book value to the fair value of the reporting entity. Impairment is charged to income in the period it occurs.

(e) Interest in joint operations:

A portion of the Company's petroleum and natural gas exploration and development activity is conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(f) Asset retirement obligations:

The fair value of the liability for the Company's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using Crew's credit adjusted risk-free interest rate and the corresponding amount is recognized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would result in an increase or decrease to the asset retirement obligation. Actual costs incurred upon settlement of the asset retirement obligation are charged against the asset retirement obligation.

(g) Revenue recognition:

Revenue from the sale of petroleum and natural gas are recorded when title passes to a third party.

(h) Financial instruments:

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition all financial instruments, including all derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and other liabilities. The Company has designated its cash and cash equivalents as held for trading which are measured at fair value.

Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities and bank debt are classified as other liabilities which are measured at amortized cost, which is determined using the effective interest method.

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The Company does not use these derivative instruments for trading or speculative purposes. The Company considers all of these transactions to be economic hedges, however, the majority of the Company's contracts do not qualify or have not been designated as hedges for accounting purposes.

1. Significant accounting policies (continued):

As a result, all derivative contracts are classified as held for trading and are recorded on the balance sheet at fair value, with changes in the fair value recognized in net income, unless specific hedge criteria are met. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices and other relevant factors. Proceeds and costs realized from holding the derivative contracts are recognized in net income at the time each transaction under a contract is settled.

The Company has elected to account for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as non-financial derivatives.

The Company measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value.

The Company immediately expenses all transaction costs incurred in relation to the acquisition of a financial asset or liability.

The Company applies trade-date accounting for the recognition of a purchase or sale of cash equivalents and derivative contracts.

(i) Comprehensive income:

The new standard introduced the statements of comprehensive income and accumulated other comprehensive income to temporarily provide for gains, losses and other amounts arising from changes in fair value until they are realized and recorded in net earnings. The Company has determined that it had no items that would affect comprehensive income nor accumulated other comprehensive income for the period ended December 31, 2007 and therefore comprehensive income equals net income.

(j) Flow through shares:

Flow through shares are issued at a fixed price and the proceeds are used to fund qualifying exploration expenditures within a defined period. The expenditures funded by flow through arrangements are renounced to investors in accordance with income tax legislation. Share capital is reduced and future income tax liability is increased by the total estimated future income tax costs of the renounced income tax deductions in the period of renouncement.

(k) Per share amounts:

Basic per share amounts are calculated using the weighted average number of shares outstanding during the period. Diluted per share amounts are calculated based on the treasury-stock method, which assumes that any proceeds obtained on exercise of options, warrants and performance shares would be used to purchase common shares at the average market price. The weighted average number of shares outstanding is then adjusted by the net change.

(l) Stock-based compensation plans:

The Company accounts for its stock-based compensation programs including stock options, warrants and performance shares, using the fair value method. Under this method, compensation expense related to these programs is recorded in the consolidated statement of operations over the vesting period with a corresponding increase in contributed surplus. Consideration paid on exercise of stock options is credited to share capital.

1. Significant accounting policies (continued):

(m) Income taxes:

The Company uses the asset and liability method of accounting for future income taxes. The future income tax asset or liability is calculated assuming the financial assets and liabilities will be settled at their carrying amount. This amount is compared to the income tax assets and the difference is multiplied by the substantively enacted income tax rate when the temporary differences are expected to reverse.

(n) Comparative amounts:

Certain comparative amounts have been reclassified to conform with presentation adopted in the current year.

2. Changes in accounting policy:

On January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855, "Financial Instruments – Recognition and Measurement", Handbook Section 3865, "Hedges", and Handbook Section 1530, "Comprehensive Income".

The adoption of these standards had no material impact on the Company's net earnings or cash flows.

New Accounting Pronouncements

Financial Instruments

In December 2006, the AcSB issued two new sections in relation to financial instruments: Section 3862, Financial Instruments – Disclosures, and Section 3863, Financial Instruments – Presentation, which will replace Section 3861 - Financial Instruments – Disclosure and Presentation. The new disclosure standard will increase Crew's disclosure regarding the risks associated with financial instruments and how those risks are managed and will require additional disclosure as of January 1, 2008.

Capital Disclosures

As of January 1, 2008, Crew will be required to adopt CICA Handbook Section 1535 "Capital Disclosures", which will require Crew to disclose its objectives, policies and processes for managing capital.

Goodwill

As of January 1, 2009, Crew will be required to adopt CICA Handbook Section 3064 "Goodwill and Intangible Assets", which defines the criteria for the recognition of intangible assets.

Convergence with International Reporting Standards

On February 13, 2008, Canada's Accounting Standards Board confirmed January 1, 2011 as the effective date for the convergence of Canadian GAAP to International Financial Reporting Standards. The Canadian Securities Administrators are in the process of examining changes to securities rules as a result of this initiative. We continue to monitor and assess the impact of these convergence efforts.

3. Business acquisition:

In May, 2007, Crew acquired all of the issued and outstanding shares of a private oil and gas company with producing oil and natural gas properties in northeast British Columbia and central Alberta. Total consideration paid for the acquisition was approximately \$137.1 million which was financed through a financing and a credit facility. The operating results of the acquired company were included in the accounts of Crew from May 3, 2007.

The acquisition has been accounted for using the purchase method of accounting as follows:

	Amount
Consideration	
Cash	\$ 136,775
Transaction costs	276
	<u>\$ 137,051</u>
Net assets received at fair value	
Cash	131
Accounts receivable	5,345
Income tax receivable	6,159
Property and equipment	182,397
Goodwill	6,242
Accounts payable	(11,584)
Excess transportation obligation (note 6)	(4,856)
Asset retirement obligations	(6,646)
Future income taxes	(40,137)
	<u>\$ 137,051</u>

The income tax receivable relates to non-capital loss carrybacks from the acquired company's May 3, 2007 and December 31, 2006 tax returns. These amounts have been pledged to the vendor upon receipt by the Company. As at December 31, 2007, the Company had paid to the vendor approximately \$5.7 million relating to the May 3, 2007 and December 31, 2006 tax returns. The income tax receivable is offset by an equivalent amount included in accounts payable.

On November 21, 2006, the Company acquired all of the issued and outstanding common shares of a private oil and gas company. Under the terms of the agreement, the purchase price paid by Crew was 0.47875 of a Crew share for each private company share which resulted in the issuance of 5,318,998 shares of Crew to the former private company shareholders. The operating results were included in the accounts of the Company from November 21, 2006.

The acquisition has been accounted for using the purchase method of accounting as follows:

	Amount
Consideration	
Common shares issued	\$ 63,618
Transaction costs	346
	<u>\$ 63,964</u>
Net assets received at fair value	
Accounts receivable	\$ 1,817
Property and equipment	71,151
Goodwill	14,558
Accounts payable	(4,090)
Bank loan	(4,471)
Asset retirement obligations	(443)
Future income taxes	(14,558)
	<u>\$ 63,964</u>

4. Property, plant and equipment:

December 31, 2007	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	\$ 698,251	\$ 145,446	\$ 552,805

December 31, 2006	Cost	Accumulated depletion & depreciation	Net book value
Petroleum and natural gas properties and equipment	\$ 409,608	\$ 70,948	\$ 338,660

The cost of unproved properties at December 31, 2007 of \$40,359,000 (2006 - \$26,665,000) was excluded from the depletion calculation. Estimated future development costs associated with the development of the Company's proved reserves of \$31,057,000 (2006 - \$25,266,000) have been included in the depletion calculation and estimated salvage values of \$21,231,000 (2006 - \$15,840,000) have been excluded from the depletion calculation.

The following corporate expenses related to exploration and development activities were capitalized:

	Year ended December 31, 2007	Year ended December 31, 2006
General and administrative expense	\$ 3,331	\$ 1,688
Stock-based compensation expense, including future income taxes	3,624	3,176
	\$ 6,955	\$ 4,864

Crew performed a ceiling test as at December 31, 2007. Based on the calculation, the carrying values of the Company's property, plant and equipment are less than the sum of the undiscounted cash flows of the Company's proved reserves based on the following benchmark and company prices.

Years	WTI Oil (\$US/Bbl)	F/X Rate (\$Cdn/\$US)	Edmonton Oil (\$/bbl)	Company Liquids (\$/bbl)	AECO Gas (\$/mmbtu)	Company Gas (\$/mcf)
2008	\$92.00	1.00	\$91.10	\$73.78	\$6.75	\$6.49
2009	\$88.00	1.00	\$87.10	\$70.30	\$7.55	\$7.35
2010	\$84.00	1.00	\$83.10	\$66.55	\$7.60	\$7.42
2011	\$82.00	1.00	\$81.10	\$64.54	\$7.60	\$7.43
2012	\$82.00	1.00	\$81.10	\$64.29	\$7.60	\$7.45
2013	\$82.00	1.00	\$81.10	\$64.13	\$7.60	\$7.47
2014	\$82.00	1.00	\$81.10	\$63.81	\$7.80	\$7.74
2015	\$82.00	1.00	\$81.10	\$63.54	\$7.97	\$7.92
2016	\$82.02	1.00	\$81.12	\$63.56	\$8.14	\$8.10
2017	\$83.66	1.00	\$82.76	\$64.97	\$8.31	\$8.27

Annual escalation thereafter +2.0%/yr.

5. Bank loan:

The Company's bank facility consists of a revolving line of credit of \$165 million and an operating line of credit of \$15 million (the "Facility"). The Facility revolves for a 364 day period and will be subject to its next 364 day extension by April 28, 2008. If not extended, the Facility will cease to revolve, the margins there under will increase by 0.25 per cent and all outstanding advances there under will become repayable in one year.

Advances under the Facility are available by way of prime rate loans with interest rates of up to 0.75 per cent over the bank's prime lending rate and bankers' acceptances and LIBOR loans which are subject to stamping fees and margins ranging from 0.95 per cent to 1.75 per cent depending upon the debt to EBITDA ratio of the Company calculated at the Company's previous quarter end. As at December 31, 2007, the Company's applicable pricing included a 0.20 percent margin on prime lending and a 1.2 percent stamping fee and margin on Bankers' Acceptances and LIBOR loans. The facility is secured by a first floating charge debenture over the Company's consolidated assets.

6. Other long-term obligations:

As part of the May, 2007 private company acquisition, the Company acquired several firm transportation agreements. These agreements had a fair value at the time of the acquisition of a \$4.9 million liability. This amount was accounted for as part of the acquisition cost and will be charged as a reduction to transportation expenses over the life of the contracts as they are incurred. This charge for the three and twelve months ended December 31, 2007 was \$0.3 million and \$0.8 million, respectively.

7. Asset retirement obligations:

Total future asset retirement obligations were determined by management and were based on Crew's net ownership interest, the estimated future costs to reclaim and abandon the wells and facilities and the estimated timing of when the costs will be incurred. Crew estimated the net present value of its total asset retirement obligations as at December 31, 2007 to be \$18,668,000 (2006 - \$10,485,000) based on a total future liability of \$35,166,000 (2006 - \$23,503,000). These payments are expected to be made over the next 49 years. An 8% (2006 – 8%) credit adjusted risk free discount rate and 2% (2006 – 2%) inflation rate were used to calculate the present value of the asset retirement obligation.

The following table reconciles Crew's asset retirement obligations:

	Year ended December 31, 2007	Year ended December 31, 2006
Carrying amount, beginning of year	\$ 10,485	\$ 7,182
Liabilities incurred	845	1,690
Liabilities acquired	6,646	679
Accretion expense	929	655
Liabilities settled	(237)	(448)
Change in estimate	-	727
Carrying amount, end of year	\$18,668	\$10,485

8. Share capital:

(a) Authorized:

Unlimited number of Common Shares

1,881,000 Class C non-voting performance shares ("performance shares")

(b) Common Shares issued:

	Number of shares	Amount
Common Shares, December 31, 2005	33,282	\$ 92,645
Public offering issued for cash	1,667	25,002
Public offering of flow through shares issued for cash	759	15,000
Issued for corporate acquisition	5,319	63,618
Exercise of Class C performance shares	316	4
Exercise of stock options	97	839
Stock-based compensation	-	583
Share issue costs, net of income taxes of \$686	-	(1,516)
Flow through shares income tax adjustment	-	(3,365)
Common Shares, December 31, 2006	41,440	\$ 192,810
Public offering issued for cash	9,932	93,725
Public offering of flow through shares issued for cash	1,860	20,000
Exercise of Class C performance shares	315	4
Exercise of stock options	30	155
Stock-based compensation	-	333
Share issue costs, net of income taxes of \$1,818	-	(4,497)
Flow through shares income tax adjustment	-	(4,401)
Common Shares, December 31, 2007	53,577	\$ 298,129

In conjunction with the Company's private company acquisition on May 3, 2007 (note 3), Crew issued 5,750,000 Common Shares at \$10.30 per share for aggregate gross proceeds of \$59.2 million (\$56 million net of issue costs).

On October 25, 2007, the Company closed a public offering resulting in the issuance of 6,042,360 shares for aggregate proceeds of \$54.5 million (\$51.5 million net of issue costs). Of the shares issued, 1,860,500 shares were issued on a flow through basis in which the Company has committed to renounce to the purchasers certain Canadian income tax deductions totalling \$20,000,375. At December 31, 2007, the Company had incurred \$2,200,000 of qualifying expenditures under this flow through offering.

On August 17, 2006, the Company closed a public offering in which 2,426,300 shares were issued for gross proceeds of \$40,002,125. Of the shares issued, 759,500 shares were issued on a flow through basis in which the Company has renounced to the purchasers certain Canadian income tax deductions totalling \$15,000,125. At December 31, 2007, the Company had incurred and renounced all expenditures required under this flow through offering.

(c) Contributed Surplus:

	Amount
Contributed surplus, December 31, 2005	\$ 1,687
Stock-based compensation	4,462
Conversion of Class C performance shares and stock options	(583)
Contributed surplus, December 31, 2006	\$ 5,566
Stock-based compensation	5,324
Conversion of Class C performance shares and stock options	(333)
Contributed surplus, December 31, 2007	\$ 10,557

8. Share capital (continued):

(d) Stock-based compensation:

The Company measures compensation costs associated with stock-based compensation using the fair market value method and the cost is recognized over the vesting period of the underlying security. The fair value of each stock option is determined at each grant date using the Black-Scholes model with the following weighted average assumptions: risk free interest rate 4.20% (2006 – 4.27%), expected life 4 years (2006 – 4 years), volatility 45% (2006 – 45%), and an expected dividend of nil (2006 – nil). The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather the Company accounts for actual forfeitures as they occur.

During 2007 the Company recorded \$5,324,000, (2006 - \$4,462,000) of stock-based compensation expense related to the stock options, of which \$2,662,000 (2006 - \$2,231,000) was capitalized in accordance with the Company's full cost accounting policy. As stock-based compensation is non-deductible for income tax purposes, a future income tax liability of \$962,000 (2006 - \$945,000) associated with the current year's capitalized stock-based compensation has been recorded.

(i) Performance shares

On September 1, 2003 the Company issued 1,881,000 performance shares to employees, officers and directors at a price of \$0.01 per share. Each performance share was convertible into a fraction of a Common Share over a three-year period with the conversion rights expiring on September 1, 2007. On conversion, each performance share converted at the rate determined by subtracting \$1.65 from the current market price of the Company's Common Shares and dividing the result by the current market price of the Company's Common Shares. The fair value of the performance shares at the date of issue, as calculated by the Black-Scholes method, was \$0.67 per share. All performance shares have been converted and cannot be re-issued.

	Number of shares	Amount
Class C, performance shares, December 31, 2005	787	\$ 8
Converted to Common Shares	(360)	(4)
Reacquired and cancelled	(25)	-
Class C, performance shares, December 31, 2006	402	4
Converted to Common Shares	(402)	(4)
Class C, performance shares, December 31, 2007	-	\$ -

(ii) Stock options

The Company has a floating stock option plan in which the Company may grant options to its employees, directors and consultants for up to 10% of its outstanding Common Shares. Under this plan, the exercise price of each option equals the market price of the Company's Common Shares on the date of grant. All granted options vest over a three-year period and have a four-year term. Stock options are granted periodically throughout the year. The fair value of the stock options granted during the year as calculated by the Black-Scholes method was \$3.99 per option (2006 - \$5.01).

	Number of options	Weighted average exercise price
Balance December 31, 2005	1,848	\$ 15.65
Granted	568	\$ 12.40
Exercised	(97)	\$ 8.70
Forfeited	(300)	\$ 16.33
Balance December 31, 2006	2,019	\$ 14.97
Granted	2,402	\$ 10.02
Exercised	(30)	\$ 5.18
Forfeited	(477)	\$ 13.41
Cancelled	(643)	\$ 16.22
Balance December 31, 2007	3,271	\$ 11.41

8. Share capital (continued):

The following table summarizes information about the stock options outstanding at December 31, 2007:

Range of exercise prices	Outstanding at December 31, 2007	Weighted average remaining life (years)	Weighted average exercise price	Exercisable at December 31, 2007	Weighted average exercise price
\$3.50 to \$6.50	45	0.58	\$5.59	45	\$5.59
\$6.51 to \$9.50	367	3.11	\$8.02	69	\$7.63
\$9.51 to \$12.50	2,295	3.19	\$10.51	91	\$12.06
\$12.51 to \$18.75	564	1.69	\$17.76	376	\$17.76
	3,271	2.89	\$11.41	581	\$14.72

(e) Per share amounts:

Per share amounts have been calculated on the weighted average number of shares outstanding. The weighted average shares outstanding for the year ended December 31, 2007 was 46,483,000 (December 31, 2006 – 34,896,000).

In computing diluted earnings per share for the year ended December 31, 2007, 379,000 (December 31, 2006 – 690,000) shares were added to the weighted average Common Shares outstanding to account for the dilution of the performance shares and stock options. There were 2,892,000 (December 31, 2006 – 1,140,500) stock options that were not included in the diluted earnings per share calculation because they were anti-dilutive.

9. Financial Instruments:

(a) Commodity price risk management

The Company uses derivative natural gas financial instruments to manage its exposure to the volatility in natural gas prices. As at December 31, 2007, the Company had entered into a direct sales agreement to sell natural gas as follows:

	Volume (gj/day)	Term	Price (Cdn \$/gj)	Floor (Cdn\$/gj)	Fair Value (thousands)
AECO/Station 2 Differential Swap	10,000	November 1, 2007–October 31, 2008	AECO 5A less \$0.16	-	\$ (423)

Derivatives are recorded on the balance sheet at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the consolidated statement of operations, comprehensive income and retained earnings. The effect of this contract was an unrealized loss of \$0.4 million for the year ended December 31, 2007. The Company realized a net gain of \$1.0 million on contracts that existed throughout 2007.

9. Financial instruments (continued):

Subsequent to December 31, 2007, the Company entered into the following direct sales agreements to sell natural gas:

	Volume (gj/day)	Term	Price (Cdn \$/gj)	Ceiling (Cdn \$/gj)	Floor (Cdn \$/gj)
AECO	10,000	April 1, 2008–October 31, 2008	AECO C – Monthly Index	\$8.00	\$7.00
AECO	10,000	April 1, 2008–October 31, 2008	AECO Daily wkd	\$8.30	\$7.00

(b) Credit Risk

Crew's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to several purchasers under normal industry sale and payment terms. Crew routinely assesses the financial strength of its customers.

(c) Fair value of other financial instruments

Financial instruments comprise accounts receivable, accounts payable and accrued liabilities. The fair values of these financial instruments approximate their carrying amounts due to their short-term maturities. The Company's long-term debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

(d) Foreign currency:

While all of the Company's sales are denominated in Canadian dollars, the market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar.

(e) Interest rate risk:

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's bank facility floating interest rates. The Company had no interest rate swaps or hedges at December 31, 2007.

10. Income taxes:

(a) Future income tax expense:

The provision for income tax expense in the financial statements differs from the result, which would have been obtained by applying the combined federal and provincial income tax rate to the Company's earnings before income taxes. This difference results from the following items:

	2007	2006
Earnings before income taxes	\$ 2,921	\$ 12,969
Combined federal and provincial income tax rate	32.33%	34.60%
Computed "expected" income tax expense	\$ 944	\$ 4,487
Increase (decrease) in income taxes resulting from:		
Non-deductible stock-based compensation	861	772
Benefits relating to change in income tax rates	(8,019)	(3,345)
Other	25	30
Non-deductible crown charges	-	165
Resource allowance	-	84
Future income tax expense (recovery)	\$ (6,189)	\$ 2,193

(b) Future income tax liability:

The components of the Company's future income tax liability are as follows:

	2007	2006
Future income tax:		
Property, plant and equipment	\$ 84,877	\$ 45,600
Asset retirement obligations	(4,935)	(3,095)
Share issue costs	(1,458)	(1,077)
Non-capital loss	(154)	(1,773)
Other	(1,285)	(103)
Future income tax liability	\$ 77,045	\$ 39,552

11. Supplemental cash flow information:

	2007	2006
Changes in non-cash working capital:		
Accounts receivable	\$ 4,633	\$ (1,372)
Accounts payable and accrued liabilities	(8,130)	(6,064)
	\$ (3,497)	\$ (7,436)
Operating activities	\$ (6,012)	\$ 1,245
Investing activities	2,515	(8,681)
	\$ (3,497)	\$ (7,436)

The Company made the following cash outlays in respect of interest expense and current income taxes:

	2007	2006
Interest	\$ 7,509	\$ 1,629
Income taxes	\$ -	\$ 151

12. Commitments:

The Company has the following fixed term commitments related to its on-going business:

	Total	2008	2009	2010	2011
Operating Leases	\$ 3,712	\$ 990	\$ 990	\$ 990	\$ 742
Capital commitments	2,200	2,200	-	-	-
Exploration and development	17,800	17,800	-	-	-
Firm transportation agreements	27,071	6,224	7,026	7,243	6,578
Total	\$ 50,783	\$ 27,214	\$ 8,016	\$ 8,233	\$ 7,320

The exploration and development commitment relates to the Company's obligation under its October 25, 2007 flow through share issue as described in note 8(b).

The firm transportation commitments were acquired as part of the Company's May 2007 private company acquisition and represent firm service commitments for transportation and processing of natural gas in British Columbia.