Crescent Point ENERGY TRUST

strategicallyfocused

Second Quarter 2004 Interim Report
Three Months and Six Months
Ended June 30, 2004

Crescent Point Energy Trust ("Crescent Point" or the "Trust") is pleased to announce its operating and financial results for the second quarter and six-month period ended June 30, 2004.

The Trust commenced operations as an oil and gas income trust on September 5, 2003. This interim report compares financial and operating results for the Trust for the second quarter and first half of 2004 with those of its predecessor organization, Crescent Point Energy Ltd. and its subsidiaries, for the second quarter and first half of 2003.

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after September 5, 2003 as well as the Class A common shares of the Corporation outstanding prior to the conversion on September 5, 2003. All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended June 30			Six months ended June 30		
($000s except Trust units and per Trust unit amounts)	2004	2003 [5]	% Change	2004	2003 [5]	% Change
Financial						
Production revenue (net of royalties and transportation)	27,971	12,880	117	52,598	27,358	92
Financial instruments – realized income (losses)	(4,704)	(127)	(3,604)	(7,489)	(1,677)	(347)
Total [1]	23,267	12,753	82	45,109	25,681	76
Cash flow from operations	16,348	9,368	75	31,857	18,567	72
Per unit (2003 – combined A & B shares)	0.61	0.68	(10)	1.21	1.35	(10)
Per unit – diluted	0.60	0.66	(9)	1.20	1.29	(7)
Net income [2]	2,754	5,125	(46)	3,192	8,384	(62)
Per unit (2003 – combined A & B shares)	0.10	0.37	(73)	0.12	0.61	(80)
Per unit – diluted	0.10	0.36	(72)	0.12	0.58	(79)
Net income before non-cash fair value adjustments [2]	6,494	5,125	27	11,183	8,384	33
Per unit (2003 – combined A & B shares)	0.24	0.37	(35)	0.42	0.61	(31)
Per unit – diluted	0.24	0.36	(33)	0.42	0.58	(28)
Cash distributions	12,929	–	–	25,553	–	–
Cash distributions per unit	0.51	–	–	1.02	–	–
Payout ratio - per unit - diluted (percent)	85	–	–	85	–	–
Capital expenditures and corporate acquisitions, net [3]	8,875	5,676	56	92,872	35,778	160
Net debt [4]	59,420	22,532	164	59,420	22,532	164
Trust units outstanding (MM)						
Units (2003 – combined A & B shares)	25.5	13.8	85	25.5	13.8	85
Exchangeable Shares	1.4	–	–	1.4	–	–
Weighted average Trust units outstanding (MM)						
Basic (2003 – combined A & B shares)	26.8	13.8	94	26.3	13.7	92
Diluted	27.0	14.2	90	26.6	14.4	85

	Three months ended June 30			Six months ended June 30		
	2004	2003	% Change	2004	2003	% Change
Operations						
Average daily production						
Crude oil and NGLs (bbl/d)	5,808	4,124	41	5,834	3,809	53
Natural gas (mcf/d)	17,097	5,116	234	17,590	5,162	241
Barrels of oil equivalent (boe/d)	8,658	4,977	74	8,766	4,669	88
Average product prices						
Crude oil and NGLs ($/bbl)	44.86	35.08	28	42.54	39.57	8
Financial instruments – realized income (losses) ($/bbl)	(8.39)	0.06	(14,083)	(6.76)	(2.22)	(205)
	36.47	35.14	4	35.78	37.35	(4)
Natural gas ($/mcf)	7.16	6.70	7	6.61	7.39	(11)
Financial instruments – realized income (losses) ($/mcf)	(0.21)	(0.32)	34	(0.10)	(0.16)	38
	6.95	6.38	9	6.51	7.23	(10)
Wells drilled						
Gross	2	7	(71)	16	12	33
Net	1.3	5.4	(76)	13.9	10.2	36
Success rate (percent)	100	100	–	88	100	(12)

(1) The total excludes the non-cash unrealized losses of $5,784,000 for the first quarter of 2004 and $12,357,000 for the six months ended June 30, 2004 relating to the fair value adjustments pursuant to financial instruments.
(2) Net income is after non-cash unrealized losses of $3,740,000 ($5,784,000 net of future tax recovery of $2,044,000) for the first quarter of 2004 and $7,991,000 ($12,357,000 net of future tax recovery of $4,366,000) for the six months ended June 30, 2004 relating to fair value adjustments pursuant to financial instruments. Net income before non-cash fair value adjustments does not have any standardized meaning prescribed by Canadian generally accepted accounting principles and therefore may not be comparable with the calculation of similar measures presented by other issuers.
(3) The capital expenditures and corporate acquisitions includes the purchase price of Capio Petroleum Corporation of $76,901,000. This amount differs from the amount of $61,688,000 allocated to property, plant and equipment, as there was an allocation of $36,976,000 to goodwill as well as allocations made to other assets and liabilities.
(4) Net debt is debt net of the working capital deficiency excluding the risk management liability of $13,760,000 and the deferred financial instrument loss of $1,403,000.
(5) All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

CORPORATE HIGHLIGHTS

- Crescent Point's acquisitions and successful drilling program increased average daily production by 74 percent from 4,977 boe/d in the second quarter of 2003 to 8,658 boe/d in the second quarter of 2004.

- The Trust commenced its 2004 second quarter drilling program at the end of June 2004 and has to date achieved excellent results with a drilling success rate of 100 percent and six wells tied in at the end of July 2004, adding more than 750 boe/d initial net (900 boe/d gross) production. These production additions are not reflected in the second quarter of 2004 results.

- Crescent Point's cash flow from operations increased by 75 percent from $9,368,000 in the second quarter of 2003 to $16,348,000 in the second quarter of 2004.

- The Trust's net debt to annualized cash flows as at June 30, 2004 was 0.91 times.

- Crescent Point maintained consistent monthly distributions of $0.17 per unit, totaling $0.51 per unit for the second quarter of 2004, representing a payout ratio of 85 percent.

- Crescent Point completed a strategic property acquisition in Central Alberta during the second quarter of 2004 for a purchase price of $3,885,000, generating additional crude oil production of approximately 150 boe/d.

- The Trust drilled two wells (1.3 net) in the second quarter, achieving an overall success rate of 100 percent.

- Crescent Point approved a reclamation fund to provide for future asset retirement costs. The Trust is contributing $0.15 per barrel of production to the reclamation fund effective July 1, 2004.

- Crescent Point is pleased to announce the appointment of Dave Balutis to Vice President, Geosciences effective July 1, 2004. Mr. Balutis most recently held the position of Manager of Geology with the Trust.

OPERATIONS REVIEW

During the second quarter of 2004, Crescent Point continued to aggressively implement management's business strategy of creating sustainable, value-added growth in reserves, production and cash flow through acquiring, exploiting and developing high-quality, long-life, light oil and natural gas properties.

Crescent Point commenced its second quarter drilling program at the end of June 2004. Excellent results have been achieved from the program with six light oil wells tied in at the end of July 2004, adding more than 750 boe/d of initial net production. These production additions are not reflected in the second quarter of 2004 results.

DRILLING RESULTS

Crescent Point drilled two wells (1.3 net) in the second quarter of 2004, achieving an overall success rate of 100 percent. An unusually wet spring in southeast Saskatchewan delayed second quarter drilling by as much as four weeks. The expected production additions will not be realized until the third quarter of 2004 due to the delay in the drilling program. The following table summarizes the Trust's drilling results for the quarter:

Three months ended June 30, 2004	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Southeast Saskatchewan	–	2	–	–	–	2	1.3	100
South/Central Alberta	–	–	–	–	–	–	–	–
Northeast British Columbia and West Peace River Arch, Alberta	–	–	–	–	–	–	–	–
Total	–	2	–	–	–	2	1.3	100

The following table summarizes the Trust's drilling results for the first half of 2004:

Six months ended June 30, 2004	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Southeast Saskatchewan	–	8	–	1	–	9	7.6	100
South/Central Alberta	–	–	–	–	–	–	–	–
Northeast British Columbia and West Peace River Arch, Alberta	5	–	–	–	2	7	6.3	71
Total	5	8	–	1	2	16	13.9	88

Southeast Saskatchewan

In the second quarter of 2004, Crescent Point drilled two (1.3 net) successful horizontal development wells in Glen Ewen. The Trust has identified an additional 39 locations remaining in inventory in southeast Saskatchewan and based on 2004 drilling success to date expects to drill a total of 18 wells (14.9 net) in 2004.

South/Central Alberta

Crescent Point continued to exploit its existing properties at Little Bow, Sounding Lake and John Lake. The Trust is evaluating the additional land and seismic acquired at John Lake to follow-up on the drilling success of 2003. Ongoing compression optimization and workovers have continued to sustain production and add value to the John Lake property. Facility and battery modifications were conducted at Little Bow, John Lake and Whitecourt which reduced quarterly production by approximately 200 boe/d.

Crescent Point completed a strategic property acquisition in Central Alberta during the second quarter of 2004 for a purchase price of $3,885,000, generating crude oil production of approximately 150 boe/d for the second quarter of 2004.

Northeast British Columbia and Peace River Arch, Alberta

During the second quarter of 2004, the Trust commenced a well testing and pressure survey program at Doe, British Columbia. Several individual well optimization workovers were conducted to optimize well deliverability and ongoing compression optimization continues.

THIRD QUARTER 2004 DRILLING UPDATE

The drilling program that commenced at the end of June 2004 has achieved excellent results to date, with a success rate of 100 percent and six light oil wells tied in at the end of July 2004, adding 750 boe/d of initial net production. Based on this success, an additional four wells are planned in this program for the remainder of the third quarter of 2004. In addition, two horizontal producers and two vertical injectors are planned to expand the waterflood and increase production at the Tatagwa field.

OUTLOOK

Crescent Point has a high-quality, predictable production, reserve and cash flow base focused in six principal properties. Each of these properties is characterized by high working interests, is operated by Crescent Point and has significant development upside.

During the second quarter of 2004, Crescent Point continued to expand the Trust's development drilling inventory. Crescent Point now has an inventory of more than 100 low risk development locations in its core areas, which will provide for sustainable production volumes and distributions through the remainder of 2004 and beyond.

The drilling program that commenced at the end of June 2004 has achieved excellent results to date, with a success rate of 100 percent and six light oil wells tied in at the end of July 2004, adding 750 boe/d of initial net production. Based on this success, an additional four wells are planned in this program for the remainder of the third quarter of 2004. In addition, two horizontal producers and two vertical injectors are planned to expand the waterflood and increase production at the Tatagwa field.

Crescent Point continues to hedge commodity prices for 2004, 2005 and 2006 at attractive crude oil and gas pricing parameters to reduce risk on distribution levels.

Crescent Point has an excellent balance sheet with net debt of 0.91 times current annualized cash flow and approximately $45 million of unutilized credit lines.

During the second quarter of 2004, the Trust established a reclamation fund to provide for the cost of future asset retirements. The Trust will contribute $0.15 per barrel of production to the reclamation fund effective July 1, 2004.

For 2004, Crescent Point is projecting to maintain its 8,750 boe/d of production with capital expenditures of approximately $18 million for drilling, land and seismic. Estimates for 2004 are as follows:

Production	
Oil and NGLs (bbl/d)	5,750
Natural gas (mcf/d)	18,000
boe/d (6:1)	8,750
Cash flow ($000s)	65,000
Cash flow per outstanding unit ($)	2.41
Capital expenditures ($000s) (1)	18,000
Wells drilled, net	28
Pricing	
Crude oil ($US/bbl) – WTI	34.00
($Cdn/bbl) – Corporate	45.50
Natural gas ($US/mcf) AECO	4.95
($Cdn/mcf) Corporate	6.00
Exchange rate ($Cdn/$US)	0.75

(1) The projection of capital expenditures excludes acquisitions, which are separately considered and evaluated.

ON BEHALF OF THE BOARD OF DIRECTORS

Scott Saxberg
President and Chief Operating Officer
August 11, 2004

MANAGEMENT'S DISCUSSION & ANALYSIS

Management's discussion and analysis ("MD&A") is dated August 11, 2004 and should be read in conjunction with the unaudited interim consolidated financial statements for the period ended June 30, 2004 and the audited consolidated financial statements and MD&A for the year ended December 31, 2003 for a full understanding of the financial position and results of operations of Crescent Point Energy Trust ("Crescent Point" or the "Trust"). All amounts are expressed in Canadian dollars. A barrel of oil equivalent ("boe") is based on a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Throughout this discussion and analysis, Crescent Point uses the terms cash flow from operations, cash flow per unit, cash flow per unit - diluted, net income before non-cash fair value adjustments, net income before non-cash fair value adjustments per unit and net income before non-cash fair value adjustments per unit - diluted. These terms do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles and therefore they may not be comparable with the calculation of similar measures presented by other issuers. These measures have been described and presented in order to provide unitholders and potential investors with additional information regarding the Trust's liquidity and its ability to generate funds to finance its operations. Management utilizes cash flow from operations as a key measure to assess the ability of the Trust to finance operating activities and capital expenditures. All references to cash flow from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital. All references to net income before non-cash fair value adjustments throughout this report are based on net income after adding back the unrealized losses on financial instruments (net of tax).

Forward-Looking Information

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Crescent Point's control, including: the impact of general economic conditions; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition, and the lack of availability of qualified personnel or management; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and obtaining required approvals of regulatory authorities. In addition there are numerous risks and uncertainties associated with oil and gas operations and the evaluation of oil and gas reserves. Therefore Crescent Point's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits Crescent Point will derive therefrom.

All tabular amounts are in thousands, except per unit and volume amounts.

Plan of Arrangement

During 2003, Crescent Point Energy Ltd. ("Crescent Point Energy" or the "Corporation") completed a strategic merger whereby it acquired Tappit Resources Ltd. ("Tappit") and converted into an oil and gas income trust through a Plan of Arrangement (the "Plan"). In addition, the shareholders of Crescent Point Energy and Tappit received shares in StarPoint Energy Ltd. ("StarPoint"), a separate, publicly listed, exploration and production company. The special meeting of the shareholders approving the Plan was held on August 21, 2003. The effective date for the transaction was September 5, 2003.

The Plan involving conversion to the Trust has been accounted for as a continuity of interests. Accordingly, the consolidated financial statements for the three-month and six-month period ended June 30, 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by Crescent Point Energy. The comparative information for the three months and six months ended June 30, 2003 reflects the results of operations and cash flows of Crescent Point Energy and its subsidiaries.

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after September 5, 2003 as well as the Class A common shares of the Corporation outstanding prior to the conversion on September 5, 2003. All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

Results of Operations

Production

Average daily production increased by 74 percent to an average of 8,658 boe/d in the second quarter of 2004 compared to 4,977 boe/d in the second quarter of 2003. This increase consisted of a 41 percent increase in average crude oil and natural gas liquids ("NGLs") production to 5,808 bbl/d in the second quarter of 2004 from 4,124 bbl/d in the second quarter of 2003, and a 234 percent increase in average natural gas production to 17,097 mcf/d in the second quarter of 2004 from 5,116 mcf/d in the second quarter of 2003. The overall increase in production is mainly attributable to the Plan of Arrangement completed with Tappit on September 5, 2003, the acquisition of Capio

Petroleum Corporation ("Capio") on January 6, 2004, the acquisition of additional working interest in certain properties and the optimization of existing properties.

In the six months ended June 30, 2004, average daily production increased by 88 percent to an average of 8,766 boe/d compared to 4,669 boe/d in the six months ended June 30, 2003. This increase consisted of a 53 percent increase in average crude oil and natural gas liquids production to 5,834 bbl/d in the six months ended June 30, 2004 from 3,809 bbl/d in the six months ended June 30, 2003, and a 241 percent increase in average natural gas production to 17,590 mcf/d in the six months ended June 30, 2004 from 5,162 mcf/d in the six months ended June 30, 2003. The overall increase in production is also attributable to the 2003 Plan of Arrangement, the acquisitions made in 2003 and 2004 and the optimization of existing properties.

Daily Production Volumes	Three months ended June 30,			Six months ended June 30,		
	2004	2003	% Change	2004	2003	% Change
Crude oil and NGLs (bbl/d)	5,808	4,124	41	5,834	3,809	53
Natural gas (mcf/d)	17,097	5,116	234	17,590	5,162	241
Total (boe/d)	8,658	4,977	74	8,766	4,669	88
Crude oil and NGLs	67%	83%	(16)	67%	82%	(15)
Natural gas	33%	17%	16	33%	18%	15
Total	100%	100%	–	100%	100%	–

Marketing and Prices

Crescent Point's average crude oil and NGL price increased by 28 percent in the second quarter of 2004 to $44.86 per bbl from $35.08 per bbl in the second quarter of 2003. Benchmark Edmonton light sweet oil averaged $51.00 per bbl for the second quarter of 2004, 25 percent higher than the second quarter of 2003 average of $40.71 per bbl.

The average natural gas price increased seven percent in the second quarter of 2004 to $7.16 per mcf from $6.70 per mcf in the second quarter of 2003. In comparison, the AECO monthly index increased three percent to $7.00 per mcf in the second quarter of 2004 from $6.82 per mcf in the second quarter of 2003.

In the six months ended June 30, 2004, the Trust's average crude oil and NGL price increased by eight percent to $42.54 from $39.57 for the six months ended June 30, 2003. Benchmark Edmonton light sweet oil averaged $48.50 per bbl for the six months ended June 30, 2004, six percent higher than the average of $45.90 in the six months ended June 30, 2003.

In the six months ended June 30, 2004, the average natural gas price decreased 11 percent to $6.61 per mcf from $7.39 per mcf in the six months ended June 30, 2003. In comparison, the AECO monthly index decreased 11 percent to $6.71 per mcf in the six months ended June 30, 2004 from $7.51 per mcf in the six months ended June 30, 2003.

As part of its ongoing business, Crescent Point has entered into a number of marketing, transportation and blending contracts that reflect the Trust's increasing focus on obtaining competitive commodity prices for its production.

Average Realized Prices	Three months ended June 30,			Six months ended June 30,		
	2004	2003	% Change	2004	2003	% Change
Crude oil and NGLs – before realized financial instruments ($/bbl) (1)	44.86	35.08	28	42.54	39.57	8
Realized financial instruments income (loss) ($/bbl)	(8.39)	0.06	(14,083)	(6.76)	(2.22)	(205)
Crude oil and NGLs – after realized financial instruments ($/bbl)	36.47	35.14	4	35.78	37.35	(4)
Natural gas – before realized financial instruments ($/mcf) (1)	7.16	6.70	7	6.61	7.39	(11)
Realized financial instruments income (loss) ($/mcf)	(0.21)	(0.32)	34	(0.10)	(0.16)	38
Natural gas– after realized financial instruments ($/mcf)	6.95	6.38	9	6.51	7.23	(10)
Total – before realized financial instruments ($/boe) (1)	44.23	35.96	23	41.57	40.45	3
Realized financial instruments income (loss) ($/boe)	(6.05)	(0.28)	(2,061)	(4.69)	(1.98)	(137)
Total – after realized financial instruments ($/boe)	38.18	35.68	7	36.88	38.47	(4)

(1) The realized prices are no longer net of transportation charges. See the transportation expense section below.

Benchmark Pricing	Three months ended June 30,			Six months ended June 30,		
	2004	2003	% Change	2004	2003	% Change
Edmonton light sweet oil (Cdn$/bbl)	51.00	40.71	25	48.50	45.90	6
WTI crude oil (US$/bbl)	38.34	29.06	32	36.77	31.58	16
AECO natural gas (Cdn$/mcf)	7.00	6.82	3	6.71	7.51	(11)
Exchange rate – Cdn$/US$	0.74	0.72	3	0.75	0.69	9

Risk Management and Hedging Activities

Management of cash flow variability comprises an integral component of Crescent Point's business strategy. Changing business conditions are monitored regularly and reviewed with the Board of Directors to establish hedging guidelines used by management in carrying out the Trust's strategic hedging program. The risk exposure inherent in movements in the price of crude oil and natural gas, fluctuations in the Cdn/U.S. dollar exchange rate and interest rate movements on long term debt are all proactively managed by Crescent Point through the use of forward sale financial transactions with reputable financially sound counterparties. The Trust considers these contracts to be an effective means to manage cash flow.

All of the Trust's hedges are in Canadian dollars and referenced to WTI and AECO, unless otherwise noted. These hedges allow the Trust to hedge both commodity prices and fluctuations in the Cdn/U.S. exchange rate.

In the second quarter of 2004, the Trust hedged an average of 3,245 bbl/d of crude oil at $36.62, compared to 1,600 bbl/d at $40.17 in the second quarter of 2003. The Trust also hedged 4,500 GJ/day of natural gas at $5.82/GJ during the second quarter of 2004. In the second quarter of 2003, the Trust had a costless collar for 1,000 GJ/day of natural gas for the period April 1, 2003 to June 30, 2003 at a collar price of $5.40/GJ to $7.00/GJ, and 1,000 GJ/day at $5.00/GJ for the same period. These hedges resulted in a realized financial instrument loss of $4,763,000 or $6.05 per boe in the second quarter of 2004, as compared to a loss of $127,000 or $0.28 per boe in the second quarter of 2003. The hedges decreased the second quarter of 2004 crude oil and NGLs price by $8.39 per bbl, and decreased the second quarter of 2004 realized natural gas price by $0.21 per mcf. This compares to hedges in the second quarter of 2003 which increased the realized crude oil and NGLs price by $0.06 per bbl, and decreased the second quarter of 2003 realized natural gas price by $0.32 per mcf.

In the six months ended June 30, 2004, the Trust hedged an average of 3,210 bbl/d of crude oil at $36.61, as compared to 1,566 bbl/d at $40.08 in the six months ended June 30, 2003. The Trust also locked in a costless collar for 1,000 GJ/day of natural gas for the period January 1, 2004 to March 31, 2004 at a collar price of $6.50/GJ – $9.25/GJ and hedged 4,500 GJ/day of natural gas at $5.82/GJ during the three months ended June 30, 2004. In the six months ended June 30, 2003, the Trust had a costless collar for 1,000 GJ/day of natural gas for the period April 1, 2003 to June 30, 2003 at a collar price of $5.40/GJ – $7.00/GJ, and 1,000 GJ/day at $5.00/GJ for the same period. These hedges resulted in a realized financial instrument loss of $7,489,000 or $4.69 per boe in the six months ended June 30, 2004, as compared to a loss of $1,677,000 or $1.98 per boe in the six months ended June 30, 2003. The hedges decreased the six months ended June 30, 2004 crude oil and NGLs price by $6.76 per bbl, and decreased the six months ended June 30, 2004 realized natural gas price by $0.10 per mcf. This compares to hedges in the six months ended June 30, 2003 which decreased the realized crude oil and NGLs price by $2.22 per bbl, and decreased the six months ended June 30, 2003 realized natural gas price by $0.16 per mcf.

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-13 "Hedging Relationships." Financial instruments that are not designated as hedges under the guideline are recorded on the balance sheet as either an asset or liability with the change in fair value recognized in net earnings. The Trust has not designated any of its risk management activities as accounting hedges under AcG-13, and accordingly has marked-to-market its financial instruments.

The impact on the Trust's financial statements as at January 1, 2004, is the recognition of a risk management liability and a deferred financial instrument loss of $3,209,000. The deferred financial instrument loss is being recognized in earnings as the contracts expire. At June 30, 2004, $1,806,000 of this deferred loss has been amortized. The net unrealized loss on financial instruments of $5,784,000 for the quarter ended June 30, 2004 is comprised of a loss of $5,949,000 for crude oil, a gain of $114,000 for natural gas, and a gain of $51,000 for interest rate swaps. See Note 10 to the consolidated financial statements for additional information regarding the accounting for financial instruments and risk management.

Looking forward into 2004, the Trust continues to strategically hedge up to 50 percent of its after royalty volumes at prices above long term commodity and budget levels. Presently the Trust has hedged 2,814 bbl/d of crude oil at a price of approximately $36.55 per barrel for the remainder of 2004, 2,700 bbl/d at a price of $40.27 in 2005 and 250

bbl/d at a price of $46.75 for the period January 1 to March 31, 2006. In addition, the Trust has locked in 4,500 GJ/day of natural gas for the period July 1, 2004 to October 31, 2004 at a fixed price of $5.82/GJ.

Crescent Point currently has two interest rate swaps with two separate banks. The first interest rate swap is at a rate of 4.20 percent on $8,000,000, expiring February 15, 2005. The second interest rate swap is at 4.03 percent on $12,000,000 of debt and expires on March 4, 2005.

Revenue

Revenue, prior to hedging transactions, increased 114 percent to $34,847,000 in the second quarter of 2004 from $16,286,000 in the second quarter of 2003. This increase in revenue consists of an 80 percent increase in crude oil and NGL revenue, and a 257 percent increase in natural gas revenue. Revenues increased mainly due to higher production volumes and an increase in world commodity prices.

In the six months ended June 30, 2004, revenue prior to hedging transactions increased 94 percent to $66,327,000 from $34,190,000 in the six months ended June 30, 2003. This increase in revenue consists of a 66 percent increase in crude oil and NGL revenue, and a 206 percent increase in natural gas revenue. Again, revenues increased mainly due to an increase in production and an increase in world commodity prices which has been partially offset by an increase in the Cdn/U.S. exchange rate as compared with the first half of 2003.

Revenue	**Three months ended June 30**			**Six months ended June 30**		
($000)	**2004**	**2003**	**% Change**	**2004**	**2003**	**% Change**
Crude oil and NGL sales [1]	23,712	13,167	80	45,173	27,282	66
Natural gas sales [1]	11,135	3,119	257	21,154	6,908	206
Total revenue	34,847	16,286	114	66,327	34,190	94
Financial instrument – realized income (loss)	(4,704)	(127)	(3,604)	(7,489)	(1,677)	(347)
	30,143	16,159	87	58,838	32,513	81

(1) The revenue is no longer reported net of transportation charges. See the transportation expense discussion below.

Transportation Expenses

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles," which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation charges against revenue rather than showing transportation as a separate expense on the income statement. Beginning January 1, 2004, the Trust has recorded revenue gross of transportation charges and a transportation expense on the income statement. Prior periods have been reclassified for comparative purposes.

The transportation expenses for the second quarter ended June 30, 2004 were $717,000 or $0.91 per boe, as compared with transportation expenses of $459,000 or $1.01 per boe for the second quarter ended June 30, 2003.

For the six months ended June 30, 2004, transportation expenses were $1,374,000 or $0.86 per boe, as compared with transportation expenses of $766,000 or $0.91 per boe for the six months ended June 30, 2003. This adjustment has no impact on net income or cash flow.

Transportation Expenses	**Three months ended June 30**			**Six months ended June 30**		
($000)	**2004**	**2003**	**% Change**	**2004**	**2003**	**% Change**
Transportation expenses	717	459	56	1,374	766	79
Per boe	0.91	1.01	(10)	0.86	0.91	(5)

Royalty Expenses

Royalties, net of Alberta Royalty Tax Credit ("ARTC") in the second quarter of 2004 were $6,159,000 or 18 percent of revenue, compared with $2,947,000 or 18 percent of revenue in the second quarter of 2003.

For the six months ended June 30, 2004, royalties, net of ARTC, were $12,355,000 or 19 percent of revenue, compared with $6,066,000 or 18 percent of revenue for the first six months of 2003.

Royalties	**Three months ended June 30**			**Six months ended June 30**		
($000)	**2004**	**2003**	**% Change**	**2004**	**2003**	**% Change**
Total royalties, net of ARTC	6,159	2,947	109	12,355	6,066	104
As a % of oil and gas sales	18%	18%	–	19%	18%	1
Per boe	7.82	6.51	20	7.74	7.18	8

Operating Expenses

Operating expenses increased 16 percent to $5.87 per boe in the second quarter of 2004, from $5.04 per boe in the second quarter of 2003. The Trust experienced an increase in quarter-over-quarter operating expenses per boe due to a higher operating cost property acquired during the quarter, and an increase in the overall operating costs in the oil and gas industry.

For the six months ended June 30, 2004, operating expenses were $5.68 per boe, consistent with the $5.68 per boe experienced for the first half of 2003.

Operating Expenses	Three months ended June 30			Six months ended June 30		
($000)	2004	2003	% Change	2004	2003	% Change
Operating expenses	4,621	2,281	103	9,056	4,796	89
Per boe	5.87	5.04	16	5.68	5.68	–

Netbacks

In the second quarter of 2004, Crescent Point received an average crude oil and NGL netback of $21.30 per bbl as compared to $23.68 per bbl in the second quarter of 2003, and a natural gas netback of $4.71 per mcf as compared to $3.41 per mcf in the second quarter of 2003. On a total commodity basis, the Trust received a netback of $23.58 per boe in the second quarter of 2004, as compared to $23.12 per boe in the second quarter of 2003. The Trust's overall netback increased by $0.46 per boe or two percent primarily due to higher average realized commodity prices.

In the six months ended June 30, 2004, Crescent Point received an average crude oil and NGL netback of $20.91 per bbl as compared to $24.63 per bbl in the six months ended June 30, 2003, and a natural gas netback of $4.33 per mcf as compared to $4.17 per mcf in the second quarter of 2003. On a total commodity basis, the Trust received a netback of $22.60 per boe in the six months ended June 30, 2004, as compared to $24.70 per boe in the six months ended June 30, 2003. The Trust's overall netback decreased by $2.10 per boe or nine percent primarily due to higher realized losses on financial instruments, resulting mainly from the increase in commodity prices over the prior year.

Netbacks	Three months ended June 30			Six months ended June 30		
	2004	2003	% Change	2004	2003	% Change
Crude oil and NGLs						
Production (bbl/d)	5,808	4,124	41	5,834	3,809	53
Price ($/bbl)	44.86	35.08	28	42.54	39.57	8
Transportation ($/bbl)	(0.93)	(1.12)	(17)	(0.90)	(0.99)	(9)
Financial instruments – realized income (losses) ($/bbl)	(8.39)	0.06	(14,083)	(6.76)	(2.22)	(205)
Royalties, net ($/bbl)	(7.97)	(5.78)	38	(7.91)	(6.50)	22
Operating expenses ($/bbl)	(6.27)	(4.56)	38	(6.06)	(5.23)	16
Netback ($/bbl)	21.30	23.68	(10)	20.91	24.63	(15)
Natural gas						
Production (mcf/d)	17,097	5,116	234	17,590	5,162	241
Price ($/mcf)	7.16	6.70	7	6.61	7.39	(11)
Transportation ($/bbl)	(0.15)	(0.08)	88	(0.13)	(0.09)	44
Financial instruments – realized income (losses) ($/bbl)	(0.21)	(0.32)	34	(0.10)	(0.16)	38
Royalties, net ($/mcf)	(1.25)	(1.67)	(25)	(1.23)	(1.70)	(28)
Operating expenses ($/mcf)	(0.84)	(1.22)	(31)	(0.82)	(1.27)	(35)
Netback ($/mcf)	4.71	3.41	38	4.33	4.17	4
Total						
Production (boe/d)	8,658	4,977	74	8,766	4,669	88
Price ($/boe)	44.23	35.96	23	41.57	40.45	3
Transportation ($/bbl)	(0.91)	(1.01)	(10)	(0.86)	(0.91)	(5)
Financial instruments – realized income (losses) ($/bbl)	(6.05)	(0.28)	(2,061)	(4.69)	(1.98)	(137)
Royalties, net ($/boe)	(7.82)	(6.51)	20	(7.74)	(7.18)	8
Operating expense ($/boe)	(5.87)	(5.04)	16	(5.68)	(5.68)	–
Netback ($/boe)	23.58	23.12	2	22.60	24.70	(9)

General and Administrative Expenses

General and administrative costs incurred by the Trust during the second quarter of 2004 totaled $1,069,000. Of this, $198,000 was capitalized as part of the Trust's drilling and development program, resulting in net administrative expenses of $871,000 or $1.11 per boe. This compares with general and administrative costs in the second quarter of 2003 of $807,000 of which $213,000 was capitalized, resulting in net administrative expenses of $594,000 or $1.31 per boe.

During the six months ended June 30, 2004, general and administrative costs incurred by the Trust totaled $2,115,000. Of this, $459,000 was capitalized as part of the Trust's drilling and development program, resulting in net administrative expenses of $1,656,000 or $1.04 per boe. This compares with general and administrative costs in the six months ended June 30, 2003 of $1,548,000 of which $446,000 was capitalized, resulting in net administrative expenses of $1,102,000 or $1.31 per boe. Capitalized general and administrative expenses are expected to be minimal in the remainder of 2004 due to the Trust's focus on development rather than exploration activities.

General and administrative costs expensed on a per boe basis decreased by $0.20 per boe or 15 percent in the second quarter of 2004, largely due to the significant increase in production volumes with a minimal increase in staff size. The same trend was experienced for the first half of 2004 as compared to the first half of 2003 where general and administrative costs expensed decreased by $0.27 per boe or 21 percent.

General and Administrative Expenses	Three months ended June 30			Six months ended June 30		
($000, except per unit and volume amounts)	2004	2003	% Change	2004	2003	% Change
General and administrative costs	1,069	807	32	2,115	1,548	37
Capitalized	(198)	(213)	(7)	(459)	(446)	3
General and Administrative Expenses	871	594	47	1,656	1,102	50
Per boe	1.11	1.31	(15)	1.04	1.31	(21)

Interest Expense

Interest expense for the second quarter of 2004 amounted to $671,000 compared with $300,000 in the second quarter of 2003. Interest expense for the first half of 2004 was $1,223,000 compared with $606,000 in the first half of 2003. The higher interest expense in the three-month and six-month periods ended June 30, 2004 was the result of a higher average debt balance.

Depletion, Depreciation and Amortization

Crescent Point's depletion, depreciation and amortization for the second quarter of 2004 was $8,731,000 or $11.08 per boe, as compared to $3,758,000 or $8.30 per boe in the second quarter of 2003. For the six months ended June 30, 2004, depletion, depreciation and amortization was $17,578,000 or $11.02 per boe compared with $7,162,000 or $8.47 per boe in the six months ended June 30, 2003. The depletion, depreciation and amortization rate increased in the three-month and six-month periods ended June 30, 2004 due to the increase in the cost of property acquisitions made throughout 2003 and 2004 as compared to 2002, a trend observed throughout the oil and gas industry.

Depletion, Depreciation and Amortization	Three months ended June 30			Six months ended June 30		
($000)	2004	2003	% Change	2004	2003	% Change
Depletion, Depreciation and Amortization	8,731	3,758	132	17,578	7,162	145
Per boe	11.08	8.30	33	11.02	8.47	30

Ceiling Test

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-16 "Oil and Gas Accounting – Full Cost." The new guideline modifies how the ceiling test is performed, and requires cost centres to be tested for recoverability using undiscounted future cash flows which are determined using management's estimate of future prices applied to proved reserves. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties as well as the future value of reserves when determining expected cash flows.

There is no impact on the Trust's carrying amount for property, plant and equipment or to net income as a result of adopting this guideline.

Taxes

Capital and other taxes paid or payable amounted to $703,000 in the second quarter of 2004 as compared to $210,000 in the second quarter of 2003.

For the six months ended June 30, 2004, capital and other taxes were $1,264,000 as compared to $610,000 in the six months ended June 30, 2003. It is expected that the Trust's Saskatchewan Resource Surcharge will continue to increase in 2004 as the Trust continues to focus on developing its Saskatchewan properties.

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. In the Trust structure, payments are made between the operating companies and the Trust transferring both the income and tax liability to the unitholders. It is therefore expected that the Trust will not incur any cash income taxes in the future, and as such the future tax liability recorded on the balance sheet will be recovered through future earnings.

In the first quarter of 2004, the Alberta government passed legislation to reduce provincial corporate income tax rates to 11.5 percent from 12.5 percent effective April 1, 2004. Crescent Point's expected future income tax rate incorporating this rate reduction is approximately 35 percent.

The future income tax recovery for the second quarter of 2004 is ($1,469,000), as compared to future income tax expense in the second quarter of 2003 of $441,000. The future income tax recovery for the second quarter of 2004 of ($1,469,000) includes a ($2,044,000) recovery relating to the non-cash unrealized loss on financial instruments. The future income recovery for the first half of 2004 is ($2,415,000) compared with future income tax expense of $2,933,000 for the first half of 2003. Included in the ($2,415,000) future income tax recovery is a ($4,366,000) recovery relating to the non-cash unrealized loss on financial instruments and a ($250,000) recovery due to the change in Alberta corporate tax rates.

Taxes	**Three months ended June 30**			**Six months ended June 30**		
($000)	**2004**	**2003**	**% Change**	**2004**	**2003**	**% Change**
Capital and other taxes	703	210	235	1,264	610	107
Future income expense (recovery)	(1,469)	441	(433)	(2,415)	2,933	(182)

Cash Flow and Net Income

Note - all per unit amounts discussed in this section of the MD&A represent per unit - diluted amounts.

Crescent Point generated cash flow from operations for the second quarter of 2004 of $16,348,000 or $0.60 per unit, and net income before non-cash fair value adjustments[1] of $6,494,000 or $0.24 per unit. This compares to the second quarter of 2003, which generated cash flow of $9,368,000 or $0.66 per unit, and net income of $5,125,000 or $0.36 per unit. The increase in cash flow and net income before non-cash fair value adjustments is mainly attributable to the increase in realized commodity prices and the overall growth of the Trust's operations . Net income in 2004 including all non-cash fair value adjustments is $2,754,000 or $0.10 per unit. The decrease in net income can be mainly attributed to the new accounting standard for hedging relationships whereby financial instruments must be marked-to-market unless they are designated as effective hedges. In the second quarter of 2004, the pre-tax unrealized loss on financial instruments was $5,784,000 or $0.21 per unit.

For the six months ended June 30, 2004, Crescent Point generated cash flow from operations of $31,857,000 or $1.20 per unit, and net income before non-cash fair value adjustments of $11,183,000 or $0.42 per unit. This compares to the six months ended June 30, 2003, which generated cash flow of $18,567,000 or $1.29 per unit, and net income of $8,384,000 or $0.58 per unit. Again, the increase in cash flow and net income before non-cash fair value adjustments is mainly attributable to the increase in realized commodity prices and the overall growth of the Trust's operations. The increase in the quarter-over-quarter cash flow and net income before non-cash fair value adjustments would have been more significant, however the Cdn/U.S. dollar exchange rate strengthened by nine percent in this time period, lowering the realized commodity prices received by the Trust by approximately nine percent. Net income in 2004 including all non-cash fair value adjustments is $3,192,000 or $0.12 per unit. As described above, the decrease in net income can be mainly attributed to the new accounting standard for hedging relationships whereby financial instruments must be marked-to-market unless they are designated as effective hedges. In the six months ended June 30, 2004, the pre-tax unrealized loss on financial instruments was $12,357,000 or $0.46 per unit.

[1] Net income before non-cash fair value adjustments is net income excluding non-cash unrealized losses of $3,740,000 ($5,784,000 net of future tax recovery of $2,044,000) for the first quarter of 2004 and $7,991,000 ($12,357,000 net of future tax recovery of $4,366,000) for the six months ended June 30, 2004 relating to fair value adjustments pursuant to financial instruments. Net income before non-cash fair value adjustments does not have any standardized meaning prescribed by Canadian generally accepted accounting principles and therefore may not be comparable with the calculation of similar measures presented by other issues.

Cash Flow and Net Income ($000, except per unit amounts)	Three months ended June 30			Six months ended June 30		
	2004	2003	% Change	2004	2003	% Change
Cash flow from operations	16,348	9,368	75	31,857	18,567	72
Cash flow from operations per unit – diluted	0.60	0.66	(9)	1.20	1.29	(7)
Net income before non-cash fair value adjustments[(1)]	6,494	5,125	27	11,183	8,384	33
Net income before non-cash fair value adjustments per unit – diluted[(1)]	0.24	0.36	(33)	0.42	0.58	(28)
Net income	2,754	5,125	(46)	3,192	8,384	(62)
Net income per unit – diluted	0.10	0.36	(72)	0.12	0.58	(79)

(1) Net income before non-cash fair value adjustments is net income excluding non-cash unrealized losses of $3,740,000 ($5,784,000 net of future tax recovery of $2,044,000) for the first quarter of 2004 and $7,991,000 ($12,357,000 net of future tax recovery of $4,366,000) for the six months ended June 30, 2004 relating to fair value adjustments pursuant to financial instruments. Net income before non-cash fair value adjustments does not have any standardized meaning prescribed by Canadian generally accepted accounting principles and therefore may not be comparable with the calculation of similar measures presented by other issues.

Cash Distributions

Cash distributions of $0.51 per Trust unit were declared for the second quarter of 2004. Of this amount, $0.34 per unit was paid in the second quarter of 2004, and $0.17 per unit was paid on July 15, 2004. Cash flow from operations for the second quarter of 2004 was $0.60 per unit. This represents a payout ratio of approximately 85 percent on a per unit basis (including the exchangeable shares) for the second quarter of 2004. The payout ratio excluding exchangeable shares (which do not receive cash distributions) was 79 percent for the second quarter of 2004.

For the six months ended June 30, 2004, cash distributions of $1.02 per Trust unit were declared. Of this amount, $0.85 per unit was paid in the six months ended June 30, 2004, and $0.17 per unit was paid on July 15, 2004. Cash flow from operations for the six months ended June 30, 2004 was $1.20 per unit – diluted. This represents a payout ratio of approximately 85 percent on a per unit basis (including exchangeable shares) for the six months ended June 30, 2004. The payout ratio excluding exchangeable shares (which do not receive cash distributions) was 80 percent for the first half of 2004.

The Trust has paid out accumulated distributions of $1.70 per unit since its inception on September 5, 2003.

Capital Expenditures

In the second quarter of 2004, capital expenditures (net of dispositions) totaled $8,875,000 as compared to $5,676,000 in the second quarter of 2003. The capital expenditures for the second quarter of 2004 include the acquisition of a property in Central Alberta. This property was acquired on April 19, 2004 for a purchase price of $3,885,000, generating an additional 150 boe/d of crude oil production.

Capital expenditures (net of dispositions) totaled $77,659,000 for the six months ended June 30, 2004 as compared to $35,778,000 for the six months ended June 30, 2003. The capital expenditures are summarized as follows:

Capital Expenditures (net)[(1)] ($000)	Three months ended June 30,			Six months ended June 30,		
	2004	2003	% Change	2004	2003	% Change
Property acquisitions	4,179	1,434	191	66,059	23,678	179
Drilling and development	4,390	3,979	10	10,507	11,347	(7)
Capitalized administration	198	213	(7)	459	446	3
Other	108	50	116	634	307	107
Total	8,875	5,676	56	77,659	35,778	117

(1) The capital expenditures do not include the amounts recorded to property, plant and equipment in respect of Asset Retirement Obligations.

Goodwill

The Trust recorded goodwill of $36,976,000 during the six months ended June 30, 2004 on the January 6, 2004 acquisition of Capio. The balance of the goodwill arose on the acquisition of Tappit in the third quarter of 2003.

Asset Retirement Obligation

Effective January 1, 2004, the Trust retroactively adopted the new accounting standard CICA Handbook section 3110 "Asset Retirement Obligations." This new section changes the method of accruing for costs associated with the retirement of fixed assets which an entity is legally obligated to incur. Previously, asset retirement obligations were accrued on an undiscounted unit-of-production basis over the entire life of the asset. The new accounting standard requires that companies record the fair value of legal obligations associated with the retirement of tangible long-lived assets. The obligations are recorded as liabilities on a discounted basis when incurred and amounts recorded for the related assets are increased by the amount of these liabilities. Over time the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets.

Upon adoption, all prior periods have been restated for the change in the accounting policy. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $5,195,000, an increase to property, plant and equipment of $3,443,000, an increase in accumulated earnings of $139,000, a decrease in the site restoration liability of $1,972,000 and an increase to the future tax liability of $81,000.

The previously reported 2003 amounts have been restated due to the retroactive application of this new standard. At January 1, 2003, this resulted in an increase to the asset retirement obligation of $2,224,000, an increase to property, plant and equipment of $1,902,000, an increase in accumulated earnings of $24,000, a decrease in the site restoration liability of $363,000 and an increase to the future tax liability of $17,000. Net income for the three months and six months ended June 30, 2003 increased by $28,000 and $40,000 respectively as a result of the retroactive application of this accounting standard.

There is no impact on the Trust's cash flow or liquidity as a result of adopting this new accounting standard. See Note 7 to consolidated financial statements for additional information regarding the asset retirement obligation and impact on the consolidated financial statements.

Reclamation Fund

During the second quarter of 2004, the Trust established a reclamation fund to provide for future asset retirement costs. The Trust will contribute $0.15 per barrel of production to the reclamation fund effective July 1, 2004.

Liquidity and Capital Resources

As at June 30, 2004, the Trust had net debt[1] of $59,420,000 compared with $22,532,000 as at June 30, 2003. The bank debt is comprised of a revolving operating demand loan with a Canadian financial institution. On January 6, 2004, the maximum amount available under the credit facility was increased to $105,000,000. Approximately $45,000,000 of the credit facility remains unutilized at June 30, 2004. Given the significant amount available but unutilized under the credit facility, and the success raising new equity during the first half of 2004 (see Unitholders' Equity discussion below), the Trust believes it has sufficient capital resources to meet obligations and achieve excellent financial results going forward.

At the end of the second quarter of 2004, Crescent Point was capitalized with 13 percent debt and 87 percent equity, as compared with 12 percent debt and 88 percent equity at the end of the second quarter of 2003 (based on quarter-end market capitalization). The Trust's net debt to annualized cash flow ratio was approximately 0.91 times at the end of the second quarter of 2004, as compared to 0.60 times at the end of the second quarter of 2003.

Unitholders' Equity

Crescent Point's total capitalization increased 140 percent to $460,899,000 during the second quarter of 2004 with the market value of Trust units representing 87 percent of total capitalization. This compares with total capitalization of $192,316,000 at the end of the second quarter of 2003, with the market value of Trust units representing 88 percent of total capitalization.

Units of the Trust trade on the Toronto Stock Exchange. During the period April 1 to June 30, 2004, the units traded in the range of $13.55 to $15.95, with an average daily trading volume of 84,075 units.

Unitholders electing to participate in the distribution reinvestment plan and premium distribution reinvestment plan resulted in an additional 297,067 units being issued in the second quarter of 2004 at an average price of $13.88, raising a total of $4,122,000. For the six months ended June 30, 2004, the distribution reinvestment plans resulted in an additional 598,539 units being issued at an average price of $13.83, raising a total of $8,275,000. Participation in these plans is currently in excess of 30 percent. The cash raised through these alternative equity programs is used for general corporate purposes. Crescent Point will continue to monitor participation levels, and will continue to utilize these funds in the most effective manner

[1] The net debt is debt net of the working capital deficiency excluding the risk management liability and deferred financial instrument loss.

The Trust established the Restricted Unit Bonus Plan on September 5, 2003. Under the terms of the Restricted Unit Bonus Plan, the Trust may grant restricted units to directors, officers, employees and consultants. Restricted units vest at 33 ⅓ percent on each of the first, second and third anniversaries of the grant date. Restricted unitholders are eligible for the first third of their monthly distributions for the first year, immediately upon grant. On the date the restricted units vest, the restricted unitholders are entitled to the distributions accrued from the date of grant to the date of vesting on the other two thirds of their restricted units.

The unitholders have approved a maximum number of units allowable under the Restricted Unit Bonus Plan of 935,000 units. The Trust granted 187,950 restricted units on October 1, 2003, and a further 73,683 restricted units (net of cancelled restricted units) in the six months ended June 30, 2004. The Trust recorded compensation expense and contributed surplus of $474,000 in the second quarter of 2004 and $952,000 in the six months ended June 30, 2004, based on the estimated fair value of the units on the date of grant.

Summary of Quarterly Results

	2004		2003 (Restated [3])				2002 (Restated [3])	
($000, except per unit amounts)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Total revenue [1]	34,130	30,823	22,676	18,754	15,827	17,597	9,887	7,322
Net income (loss) [2]	2,754	438	(626)	1,377	5,125	3,259	1,513	940
Net income (loss) per unit [2]	0.10	0.02	(0.03)	0.09	0.37	0.24	0.12	0.08
Net income (loss) per unit - diluted [2]	0.10	0.02	(0.03)	0.09	0.36	0.23	0.11	0.08

(1) The total revenue reported is net of transportation expenses.
(2) Net income and net income before discontinued operations and extraordinary items are the same.
(3) The comparative quarterly results have been restated for the retroactive impact of adopting the accounting standard Asset Retirement Obligations.

Business Risks and Prospects

Crescent Point is exposed to several operational risks inherent in exploiting, developing, producing and marketing crude oil and natural gas. These risks include:

- Economic risk of finding and producing reserves at a reasonable cost;
- Financial risk of marketing reserves at an acceptable price given market conditions;
- Cost of capital risk to carry out the trust's operations; and
- The risk of carrying out operations with minimal environmental impact.

Crescent Point strives to manage or minimize these risks in a number of ways, including:

- Employing qualified professional and technical staff;
- Concentrating in a limited number of areas with low cost exploitation and development objectives;
- Utilizing the latest technology for finding and developing reserves;
- Constructing quality, environmentally sensitive, safe production facilities;
- Maximizing operational control of drilling and producing operations;
- Mitigating price risk through strategic hedging; and
- Adhering to conservative borrowing guidelines.

CONSOLIDATED BALANCE SHEET

(UNAUDITED) ($000)	As at June 30, 2004	Dec. 31, 2003
	$	$
ASSETS		
		Restated
Current assets:		*(Note 3(b))*
Cash	82	82
Accounts receivable	16,808	17,505
Investments in marketable securities	–	188
Deferred financial instrument loss (Note 10)	1,403	–
Prepaids and deposits	234	318
	18,527	18,093
Deposits on property, plant and equipment	–	1,000
Property, plant and equipment (Note 5)	229,141	168,591
Goodwill (Note 5)	58,147	21,171
	305,815	208,855
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	14,531	13,945
Cash distributions payable	2,993	2,345
Bank indebtedness (Note 6)	59,020	40,220
Risk management liability (Note 10)	13,760	–
	90,304	56,510
Asset retirement obligation (Note 7)	6,484	5,195
Future income taxes	42,680	29,713
	139,468	91,418
Unitholders' equity:		
Unitholders' capital (Note 8(a))	186,749	113,880
Exchangeable shares (Note 8(a))	8,232	10,782
Contributed surplus (Note 8(b))	1,291	339
Accumulated earnings	7,325	4,133
Accumulated cash distributions (Note 4)	(37,250)	(11,697)
	166,347	117,437
	305,815	208,855

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED EARNINGS

(UNAUDITED) ($000)	Three months ended June 30, 2004	Three months ended June 30, 2003	Six months ended June 30, 2004	Six months ended June 30, 2003
	$	$ *Restated (Note 3(b)&(d))*	$	$ *Restated (Note 3(b)&(d))*
Revenue:				
Oil and gas sales	34,847	16,286	66,327	34,190
Transportation expenses (Note 3(d))	(717)	(459)	(1,374)	(766)
Royalties, net of ARTC	(6,159)	(2,947)	(12,355)	(6,066)
Financial instruments				
Realized losses	(4,704)	(127)	(7,489)	(1,677)
Unrealized losses (Note 10)	(5,784)	–	(12,357)	–
	17,483	12,753	32,752	25,681
Expenses:				
Operating	4,621	2,281	9,056	4,796
General and administrative	871	594	1,656	1,102
Unit-based compensation (Note 8(b))	474	–	952	–
Interest on bank indebtedness	671	300	1,223	606
Depletion, depreciation and amortization	8,731	3,758	17,578	7,162
Accretion on asset retirement obligation (Note 7)	127	44	246	88
Capital and other taxes	703	210	1,264	610
	16,198	7,187	31,975	14,364
Income before future income tax	1,285	5,566	777	11,317
Future income tax expense (recovery)	(1,469)	441	(2,415)	2,933
Net income for the period	2,754	5,125	3,192	8,384
Accumulated earnings, beginning of the period	4,571	6,364	3,994	3,117
Retroactive application of change in accounting policy (Note 3(b))	–	36	139	24
Accumulated earnings, end of the period	7,325	11,525	7,325	11,525
Net income per unit (Note 9)				
Basic	0.10	0.37	0.12	0.61
Diluted	0.10	0.36	0.12	0.58

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

(UNAUDITED) ($000)	Three months ended June 30, 2004	Three months ended June 30, 2003	Six months ended June 30, 2004	Six months ended June 30, 2003
	$	$ *Restated (Note 3(b))*	$	$ *Restated (Note 3(b))*
Cash provided by (used in)				
Operating activities				
Net income for the period	2,754	5,125	3,192	8,384
Items not affecting cash				
Future income taxes	(1,469)	441	(2,415)	2,933
Unit-based compensation	474	-	952	-
Depletion, depreciation and amortization	8,731	3,758	17,578	7,162
Accretion on asset retirement obligation	127	44	246	88
Gain on sale of investment	(53)	–	(53)	–
Unrealized losses on financial instruments	5,784	–	12,357	–
Cash flow from operations	16,348	9,368	31,857	18,567
Change in non-cash working capital				
Accounts receivable	(1,529)	4,368	2,979	3,387
Prepaid expenses and deposits	575	96	299	(55)
Accounts payable	(1,254)	(7,836)	(7,562)	(18,874)
	14,140	5,996	27,573	3,025
Investing activities				
Expenditures on petroleum and natural gas properties	(8,875)	(5,676)	(15,971)	(35,778)
Acquisition of Capio Petroleum Corporation (Note 5)	–	–	(76,845)	–
Petroleum and natural gas deposits	–	–	1,000	3,225
Proceeds on sale of investment	241	–	241	–
Change in non-cash working capital				
Accounts receivable	233	–	175	324
Accounts payable	(624)	5,931	220	11,513
	(9,025)	255	(91,180)	(20,716)
Financing activities				
Issue of trust units, net of issue costs	4,052	(73)	70,319	9,294
Increase in bank indebtedness	3,600	(6,200)	18,193	8,320
Cash distributions	(12,929)	–	(25,553)	–
Change in non-cash working capital				
Cash distributions payable	161	-	648	-
	(5,116)	(6,273)	63,607	17,614
Increase (decrease) in cash	(1)	(22)	-	(77)
Cash at beginning of period	83	30	82	85
Cash at end of period	82	8	82	8

See accompanying notes to the consolidated financial statements.

1. CORPORATE REORGANIZATION AND BASIS OF PRESENTATION

Crescent Point Energy Trust (the "Trust") is an open-ended unincorporated investment trust created pursuant to a Declaration of Trust and operating under the laws of the Province of Alberta. The Trust was established as part of a Plan of Arrangement (the "Arrangement") that became effective on September 5, 2003.

The Arrangement gave effect to the transactions contemplated by the agreement entered into on May 26, 2003 by Crescent Point Energy Ltd. ("old Crescent Point" or the "Corporation") and Tappit Resources Ltd. ("Tappit"). The reorganization resulted in the shareholders of old Crescent Point and Tappit receiving trust units in the Trust, a new oil and natural gas energy trust that owns all of old Crescent Point's and Tappit's producing assets. In addition, the shareholders of old Crescent Point and Tappit received shares in a separate, publicly-listed, growth and exploration focused producer StarPoint Energy Ltd. ("StarPoint"), which owns old Crescent Point's exploration assets and undeveloped lands in its northeast British Columbia exploration focus area.

The Arrangement involving conversion to the Trust has been accounted for as a continuity of interests. Accordingly, these consolidated financial statements reflect the financial position, results of operations and cash flows as if the Trust had always carried on the businesses formerly carried on by old Crescent Point. All assets and liabilities are recorded at historical cost. The three months and six months ended June 30, 2003 reflect the results of operations and cash flows of old Crescent Point and its subsidiaries. Due to the conversion into an income trust, certain information included in the financial statements for prior periods may not be directly comparable.

The term "units" has been used in these financial statements to identify both the Trust units and exchangeable shares of the Trust issued on or after September 5, 2003 as well as the Class A common shares of the Corporation outstanding prior to the conversion on September 5, 2003. All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

2. SIGNIFICANT ACCOUNTING POLICIES

These interim consolidated financial statements of Crescent Point Energy Trust have been prepared by management in accordance with Canadian generally accepted accounting principles and follow the same accounting policies as the most recent annual audited financial statements except as noted below in Note 3. The specific accounting policies used are described in the annual consolidated financial statements appearing on pages 41 through 44 of the Trust's 2003 Annual Report. All amounts reported in these statements are in Canadian dollars.

3. CHANGES IN ACCOUNTING POLICIES

a) Full Cost Accounting

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-16 "Oil and Gas Accounting – Full Cost." The new guideline modifies how the ceiling test is performed, and requires cost centres to be tested for recoverability using undiscounted future cash flows which are determined using management's estimate of future prices applied to proved reserves. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties as well as the future value of reserves when determining expected cash flows.

There is no impact on the Trust's carrying amount for property, plant and equipment or to net income as a result of adopting this guideline. The following are the prices that were used in the ceiling test:

Average Price Forecast	2004	2005	2006	2007	2008	2009-2014	2015+[1]
WTI ($US/bbl)	29.00	26.00	25.00	25.00	25.00	25.00	1.5%
Exchange Rate	0.75	0.75	0.75	0.75	0.75	0.75	-
WTI ($Cdn/bbl)	38.67	34.67	33.33	33.33	33.33	33.00	1.5%
AECO ($Cdn/mcf)	5.85	5.15	5.00	5.00	5.00	5.00	1.5%

(1) Percentage change represents the change in each year after 2014 to the end of the reserve life.

b) Asset Retirement Obligation

Effective January 1, 2004, the Trust retroactively adopted the new accounting standard CICA Handbook section 3110 "Asset Retirement Obligations." This new section changes the method of accruing for costs associated with the retirement of fixed assets which an entity is legally obligated to incur. Previously, asset retirement obligations were accrued on an undiscounted unit-of-production basis over the entire life of the asset. The new accounting standard requires that companies record the fair value of legal obligations associated with the retirement of tangible long-lived assets. The obligations are recorded as liabilities on a discounted basis when incurred and amounts recorded for the related assets are increased by the amount of these liabilities. Over time the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets.

Upon adoption, all prior periods have been restated for the change in the accounting policy. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $5,195,000, an increase to property, plant and equipment of $3,443,000, an increase in accumulated earnings of $139,000, a decrease in the site restoration liability of $1,972,000 and an increase to the future tax liability of $81,000.

The previously reported 2003 amounts have been restated due to the retroactive application of this new standard. At January 1, 2003, this resulted in an increase to the asset retirement obligation of $2,224,000, an increase to property, plant and equipment of $1,902,000, an increase in accumulated earnings of $24,000, a decrease in the site restoration liability of $363,000 and an increase to the future tax liability of $17,000. Net income for the three months and six months ended June 30, 2003 increased by $28,000 and $40,000 respectively as a result of the retroactive application of this accounting standard.

There is no impact on the Trust's cash flow or liquidity as a result of adopting this new accounting standard. See Note 7 for additional information regarding the asset retirement obligation and impact on the consolidated financial statements.

c) Financial Instruments

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-13 "Hedging Relationships." Financial instruments that are not designated as hedges under the guideline are recorded on the balance sheet as either an asset or liability with the change in fair value recognized in net earnings. The Trust has elected not to designate any of its risk management activities as accounting hedges under AcG-13, and accordingly has marked-to-market its financial instruments.

The impact on the Trust's financial statements as at January 1, 2004 is the recognition of a risk management liability and a deferred financial instrument loss of $3,209,000. The deferred financial instrument loss is being recognized in earnings as the contracts expire. See Note 10 for additional information regarding the financial instruments and risk management.

d) Transportation Expenses

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles," which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation charges against revenue rather than showing transportation as a separate expense on the income statement. Beginning January 1, 2004, the Trust has recorded revenue gross of transportation charges and a transportation expense on the income statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow.

4. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

($000, except per unit amounts)	Three months ended June 30, 2004	Six months ended June 30, 2004
Cash flow from operations before changes in non-cash working capital		
Add (deduct)	16,348	31,857
Cash withheld to fund current period capital expenditures	(3,419)	(6,304)
Reclamation fund contributions and interest earned on fund [1]	–	–
Debt repayments	–	–
Cash distributions declared to unitholders	12,929	25,553
Accumulated cash distributions, beginning of period	24,321	11,697
Accumulated cash distributions, end of period	37,250	37,250
Cash distributions per unit [2]	0.51	1.02
Accumulated cash distributions per unit – beginning of period	1.19	0.68
Accumulated cash distributions per unit – end of period	1.70	1.70

(1) The Trust established a reclamation fund during the second quarter of 2004 that will be implemented effective July 1, 2004.
(2) Cash distributions per unit reflect the sum of the per unit amounts declared monthly to unitholders.

5. ACQUISITION OF CAPIO PETROLEUM CORPORATION

On January 6, 2004, the Trust purchased all of the issued and outstanding shares of Capio Petroleum Corporation, a private oil and gas company. The purchase was paid for with cash and accounted for using the purchase method of accounting. The net assets acquired and consideration is allocated as follows:

	($000)
Net assets acquired	
Cash	56
Property, plant and equipment	61,688
Goodwill	36,976
Working capital deficiency	(5,862)
Asset retirement obligation	(575)
Future income taxes	(15,382)
Total net assets acquired	76,901
Consideration	
Cash	76,488
Acquisition costs (net of option proceeds of $2.58 million)	413
Total purchase price	76,901

6. BANK INDEBTEDNESS

On January 6, 2004, the Trust's revolving term demand bank loan facility was increased to $105,000,000. The interest charged on the facility is calculated based on a sliding scale ratio of the Trust's debt to cash flows.

7. ASSET RETIREMENT OBLIGATION

The total future asset retirement obligation was estimated by management based on the Trust's net ownership in all wells and facilities. This includes all estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total asset retirement obligation to be $6,484,000 at June 30, 2004 (December 31, 2003 – $5,195,000) based on total estimated undiscounted cash flows to settle the obligation of $16,187,000 (December 31, 2003 – $13,532,000). The expected period until settlement ranges from a minimum of two years to a maximum of 42 years, with the costs expected to be paid over an average of 20 years. The estimated cash flows have been discounted using a credit-adjusted risk-free rate of eight percent and an inflation rate of two percent.

During the second quarter of 2004, the Trust approved a reclamation fund to provide for future asset retirement costs. The Trust will contribute $0.15 per barrel of production to the reclamation fund effective July 1, 2004.

The following table reconciles the asset retirement obligation:

	June 30, 2004 ($000)	December 31, 2003 ($000)
Asset retirement obligation, beginning of the period	5,195	2,224
Liabilities acquired through corporate acquisitions	575	829
Liabilities incurred	468	1,964
Liabilities settled	–	–
Accretion expense	246	178
Asset retirement obligation, end of the period	6,484	5,195

8. UNITHOLDERS' EQUITY

a) Issued and Outstanding

	June 30, 2004	
	Number of Shares / Trust Units	Amount ($000)
Trust Units		
Balance, January 1, 2004	19,282,049	118,038
Issued for cash	5,150,000	65,663
Issued on conversion of exchangeable shares	489,470	2,550
Issued pursuant to the distribution reinvestment plans	503,460	6,931
To be issued pursuant to the distribution reinvestment plans	95,079	1,344
Balance, June 30, 2004	25,520,058	194,526
Cumulative unit issue costs, net of tax	–	(7,777)
Total Unitholders' capital, June 30, 2004	25,520,058	186,749
Exchangeable Shares		
Balance, January 1, 2004	1,902,901	10,782
Exchanged for Trust units	(449,955)	(2,550)
Balance, June 30, 2004	1,452,946	8,232
Exchange ratio, June 30, 2004	1.11858	–
Trust units issuable upon conversion, June 30, 2004	1,625,236	8,232

b) Restricted Unit Bonus Plan

The Trust established the Restricted Unit Bonus Plan on September 5, 2003. Under the terms of the Restricted Unit Bonus Plan, the Trust may grant restricted units to directors, officers, employees and consultants. Restricted units vest at 33 1/3 percent on each of the first, second and third anniversaries of the grant date. Restricted unitholders are eligible for the first third of their monthly distributions for the first year, immediately upon grant. On the date the restricted units vest, the restricted unitholders are entitled to the distributions accrued from the date of grant to the date of vesting on the other two thirds of their restricted units. Although this balance is not restricted, the distributions of $239,000 accrued to date on the other two thirds of the restricted units at June 30, 2004 have been segregated in a separate bank account.

The unitholders have approved a maximum number of units allowable under the Restricted Unit Bonus Plan of 935,000 units. The Trust granted 187,950 restricted units on October 1, 2003, and a further 73,683 restricted units (net of cancelled restricted units) in the six months ended June 30, 2004. The Trust recorded compensation expense and contributed surplus of $474,000 in the three-month period ended June 30, 2004 and $952,000 in the six-month period ended June 30, 2004, based on the fair value of the units on the date of grant.

9. PER TRUST UNIT AMOUNTS

The following table summarizes the Trust units used in calculating net income per Trust unit:

	Three months ended		Six months ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
Weighted average Trust units/shares	25,187,947	13,771,661	24,739,359	13,741,398
Trust units issuable on conversion of exchangeable shares (1)	1,625,236	–	1,625,236	–
Weighted average Trust units/shares and exchangeable shares	26,813,183	13,771,661	26,364,595	13,741,398
Dilutive impact of restricted units/stock options	259,238	472,392	256,593	671,761
Dilutive Trust units/shares and exchangeable shares	27,072,421	14,244,053	26,621,188	14,413,159

(1) The Trust units issuable on conversion of the exchangeable shares reflects the exchangeable shares outstanding at the end of the period converted at the exchange ratio in effect at the end of the period.

(2) All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

10. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

As discussed in Note 3(c), as at January 1, 2004, the fair value of all outstanding instruments was recorded on the balance sheet with an offsetting deferred financial instrument loss. The deferred financial instrument loss is recognized in net income over the life of the associated contracts. Changes in fair value after that time are recorded on the balance sheet with the associated unrealized gain or loss recorded in net income. The estimated fair value of all financial instruments is based on quoted market prices or, in their absence, third party market indicators and forecasts.

The following table presents a reconciliation of the risk management liability and the deferred financial instrument loss:

	($000)
Risk management liability, January 1, 2004	3,209
Change in mark-to-market unrealized loss	10,551
Risk management liability, June 30, 2004	13,760
Deferred financial instrument loss, January 1, 2004	3,209
Amortization	(1,806)
Deferred financial instrument loss, June 30, 2004	1,403

The Trust presently has a number of fixed oil contracts outstanding, the details of which are as follows:

	Volume (boe/d)	Weighted average price ($Cdn/bbl)	Index
July 1, 2004 to December 31, 2004	2,814	36.55	WTI
January 1, 2005 to December 31, 2005	2,700	40.27	WTI
January 1, 2006 to March 31, 2006	250	46.75	WTI

The Trust has the following fixed price gas contracts currently in place:

	Volume (GJ/day)	Price ($Cdn/GJ)	Index
July 1, 2004 to October 31, 2004	4,500	5.82	AECO

The Trust has two third-party interest rate swaps outstanding at June 30, 2004:

	Amount $	Interest rate %
July 1, 2004 to February 15, 2005	8,000,000	4.20
July 1, 2004 to March 4, 2005	12,000,000	4.03

11. COMPARATIVE INFORMATION

Certain information provided for the previous period has been restated to conform with the current period presentation.

CORPORATE INFORMATION

DIRECTORS:
Scott Saxberg (4)
Paul Colborne, Chairman (2)(4)
Hugh Gillard (1)(2)
Peter Bannister (1)(3)
Ken Cugnet (3)(4)
Greg Turnbull (2)
Gerald Romanzin (1)(3)

1. Member of the Audit Committee of the Board of Directors
2. Member of the Compensation Committee of the Board of Directors
3. Member of the Reserves Committee of the Board of Directors
4. Member of the Health, Safety and Environment Committee of the Board of Directors

OFFICERS:
Scott Saxberg, President and Chief Operating Officer
C. Neil Smith, Vice President, Engineering and Business Development
Wade Becker, Vice President, Land
Dan Toews, Treasurer and Controller
Dave Balutis, Vice President, Geosciences
Richard McHardy, Corporate Secretary

Head Office:	Suite 1800, 500 - 4th Avenue SW, Calgary, Alberta T2P 2V6 Tel: (403) 693-0020; Fax: (403) 693-0070
Banker:	The Bank of Nova Scotia, Calgary, Alberta
Auditor:	PricewaterhouseCoopers LLP, Calgary, Alberta
Legal Counsel:	McCarthy Tétrault LLP, Calgary, Alberta
Evaluation Engineers:	Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta

INVESTOR RELATIONS:

Registrar and Transfer Agent:	Investors are encouraged to contact Crescent Point's Registrar and Transfer Agent for information regarding their security holdings: Olympia Trust Company 2300, 125 – 9th Avenue SE, Calgary, Alberta T2G 0P6 Tel: (403) 261-0900
Stock Exchange:	Toronto Stock Exchange – TSX
Stock Symbols:	CPG.UN
Investor Contacts:	Scott Saxberg, President and Chief Operating Officer Dan Toews, Treasurer and Controller

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