Crescent Point ENERGY TRUST

strategicallyfocused

Third Quarter 2004 Interim Report
Three Months and Nine Months
Ended September 30, 2004

Crescent Point Energy Trust ("Crescent Point" or the "Trust") is pleased to announce its operating and financial results for the third quarter and nine-month period ended September 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 third quarter and first nine months of 2004 with those of its predecessor organization, Crescent Point Energy Ltd. and its subsidiaries, for the third quarter and first nine months of 2003 up to September 5 combined with the Trust and its subsidiaries for the period September 5 to September 30, 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 September 30,			Nine months ended September 30,		
($000s except Trust units and per Trust unit amounts)	**2004**	**2003 [4]**	**% Change**	**2004**	**2003 [4]**	**% Change**
Financial						
Production revenue (net of royalties and transportation)	31,992	15,077	112	84,590	42,435	99
Financial instruments – realized income (losses)	(5,415)	(486)	(1,014)	(12,904)	(2,163)	(497)
Total [1]	26,577	14,591	82	71,686	40,272	78
Cash flow from operations	18,096	6,084	197	49,953	24,651	103
Per unit (2003 - combined A&B shares)	0.65	0.40	63	1.85	1.66	11
Per unit - diluted	0.64	0.40	60	1.83	1.66	10
Net income	3,058	1,376	122	6,250	9,760	(36)
Per unit (2003 - combined A&B shares)	0.11	0.09	22	0.23	0.66	(65)
Per unit - diluted	0.11	0.09	22	0.23	0.66	(65)
Cash distributions	13,490	2,800	382	39,043	2,800	1,294
Cash distributions per unit	0.51	0.17	200	1.53	0.17	800
Payout ratio - per unit - diluted (percent)	80	43	37	84	10	74
Capital expenditures and corporate acquisitions, net [2]	74,947	45,290	65	167,819	81,068	107
Net debt [3]	82,693	50,131	65	82,693	50,131	65
Trust units outstanding (MM)						
Units	28.8	16.4	76	28.8	16.4	76
Exchangeable Shares	1.4	2.0	(30)	1.4	2.0	(30)
Weighted average Trust units outstanding (MM)						
Basic (2003 - combined A&B shares)	28.0	15.2	84	26.9	14.8	82
Diluted	28.3	15.2	86	27.2	14.8	84

	Three months ended September 30,			Nine months ended September 30,		
	2004	2003	% Change	2004	2003	% Change
Operations						
Average daily production						
Crude oil and NGLs (bbl/d)	6,905	4,781	44	6,194	4,119	50
Natural gas (mcf/d)	15,733	7,308	115	16,967	5,859	190
Barrels of oil equivalent (boe/d)	9,527	5,999	59	9,021	5,096	77
Average product prices						
Crude oil and NGLs ($/bbl)	50.56	35.62	42	45.54	38.04	20
Financial instruments – realized income (losses) ($/bbl)	(8.46)	(0.91)	(830)	(7.40)	(1.71)	(333)
	42.10	34.71	21	38.14	36.33	5
Natural gas ($/mcf)	6.19	5.72	8	6.48	6.70	(3)
Financial instruments - realized income (losses) ($/mcf)	(0.03)	(0.13)	77	(0.07)	(0.15)	53
	6.16	5.59	10	6.41	6.55	(2)
Netback ($/boe)	23.41	21.63	8	22.89	23.50	(3)
Wells drilled						
Gross	12.0	4.0	200	28.0	16.0	75
Net	9.5	1.4	579	23.4	12.6	86
Success rate (percent)	100	100	-	93	100	(7)

(1) The total excludes the non-cash unrealized losses of $10,167,000 for the third quarter of 2004 and $22,524,000 for the nine months ended September 30, 2004 relating to the fair value adjustments pursuant to financial instruments.
(2) The capital expenditures and corporate acquisitions include the purchase price of corporate acquisitions. These amounts differ from the amounts allocated to property, plant and equipment as there were allocations made to goodwill as well as allocations made to other assets and liabilities.
(3) Net debt is debt net of the working capital deficiency excluding the risk management liability of $23,149,000 and the deferred financial instrument loss of $625,000.
(4) All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

CORPORATE HIGHLIGHTS

- The Trust initiated a 12 (9.5 net) well development drilling program in the Manor, Tatagwa and Glen Ewen areas of southeast Saskatchewan which has achieved excellent results with a drilling success rate of 100 percent.

- Crescent Point completed three highly accretive strategic property acquisitions in the Trust's main operating area of southeast Saskatchewan for a combined purchase price of $64.5 million. These acquisitions have added approximately 1,725 boe/d of production and 6.8 mmboe of proved plus probable reserves, based on independent engineering.

- Based on continued development drilling success at Manor, Tatagwa and Glen Ewen in southeast Saskatchewan and the three major acquisitions, Crescent Point revised upwards the Trust's 2004 average daily production from 8,750 boe/d to more than 9,150 boe/d. In addition, the Trust has revised upward its fourth quarter average daily production target from 8,750 boe/d to more than 10,150 boe/d.

- In August 2004, Crescent Point's 2004 development drilling capital expenditure program was expanded from $18 million to $26 million. In the fourth quarter, the Trust plans to drill up to 14 gross (11.7 net) low risk development wells, four of which are at the Trust's newly acquired Innes, Tatagwa, Hastings and Edenvale properties in southeast Saskatchewan and the remaining 10 at existing core properties.

- The Trust's credit facility was increased to $135 million on October 7, 2004. On November 1, 2004, the Trust's credit facility was syndicated to two additional Canadian chartered banks.

- On September 9, 2004, Crescent Point closed a bought deal equity financing of 3,000,000 Trust units at $15.00 per Trust unit for gross proceeds of $45 million.

- Crescent Point's acquisitions and successful drilling program increased average daily production by 59 percent from 5,999 boe/d in the third quarter of 2003 to 9,527 boe/d in the third quarter of 2004. Approximately 550 boe/d of the increase is attributable to the closing of three acquisitions late in the third quarter.

- Crescent Point's cash flow from operations increased by 197 percent from $6.1 million in the third quarter of 2003 to $18.1 million in the third quarter of 2004.

- Crescent Point maintained consistent monthly distributions of $0.17 per unit, totaling $0.51 per unit for the third quarter of 2004, representing a payout ratio - diluted of 80 percent.

- On August 23, 2004, Crescent Point announced the appointment of Mr. Greg Tisdale as Chief Financial Officer and Ms. Tamara MacDonald as Manager of Land.

- The Board of Directors is pleased to announce the promotion of Mr. Scott Saxberg to Chief Executive Officer and President. Mr. Saxberg has been Chief Operating Officer and President since inception of the Trust.

OPERATIONS REVIEW

During the third 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's successful third quarter drilling results and three highly accretive property acquisitions have further strengthened the Trust's reserves, production and cash flow.

Based on continued development drilling success at Manor, Tatagwa and Glen Ewen in southeast Saskatchewan and the three major acquisitions, Crescent Point revised upwards the Trust's 2004 average daily production from 8,750 boe/d to more than 9,150 boe/d. In addition, the Trust has revised upward its fourth quarter average daily production target from 8,750 boe/d to more than 10,150 boe/d.

DRILLING RESULTS

Crescent Point drilled 10 (8.1 net) oil wells and two (1.4 net) water injectors in the third quarter of 2004, achieving an overall success rate of 100 percent. This is in addition to the two (1.3 net) successful drills announced in the second quarter program.

The following table summarizes the Trust's drilling results for the quarter:

Three months ended September 30, 2004	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Southeast Saskatchewan	-	10	-	2	-	12	9.5	100
South/Central Alberta	-	-	-	-	-	-	-	-
Northeast BC and West Peace River Arch, Alberta	-	-	-	-	-	-	-	-
Total	-	10	-	2	-	12	9.5	100

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

Nine months ended September 30, 2004	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Southeast Saskatchewan	-	18	-	3	-	21	17.1	100
South/Central Alberta	-	-	-	-	-	-	-	-
Northeast BC and West Peace River Arch, Alberta	5	-	-	-	2	7	6.3	71
Total	5	18	-	3	2	28	23.4	93

Southeast Saskatchewan

In the third quarter of 2004, Crescent Point drilled three (2.8 net) successful horizontal development wells in its two new pool discoveries in the Manor-Auburton area, three (2.4 net) successful horizontal development wells extending its Manor-Wildwood pool, two (1.4 net) wells in its Tatagwa waterflooded property, one (1.0 net) well in the Manor-Queensdale property and one (0.5 net) successful horizontal development well in its Glen Ewen property. Production facilities are currently being designed and constructed to accommodate the increased production in the Auburton area and to eliminate trucking costs.

Including the recently acquired properties, the Trust has identified more than 60 locations remaining in inventory in southeast Saskatchewan. Based on 2004 drilling success to date, Crescent Point expects to drill a total of 24 (20.3 net) wells on the existing program and up to four wells on the recently acquired properties in the fourth quarter of 2004.

South/Central Alberta

Crescent Point continued to exploit its existing properties at Little Bow, Sounding Lake and John Lake. One previously suspended well at Little Bow was plugged back and re-perforated adding 30 bopd of initial production. At least three other candidates have been identified for similar workovers, one of which is planned for the fourth quarter of 2004. In addition, the replacement of the existing solution gas driven compressor with an electric drive compressor has further optimized gas production.

Compression optimization and workovers have continued to sustain production and add value to the John Lake property.

Eight workovers to optimize production on the Killam property were completed and recently acquired seismic is being reviewed to identify possible drill locations.

The waterflood at the Sounding Lake Cummings A pool has continued to outperform and currently exceeds Crescent Point's 2004 budget forecasts.

Northeast British Columbia and Peace River Arch, Alberta

During the third quarter of 2004, the Trust continued its well testing and pressure survey program at Doe, British Columbia. Based on this program, three locations will be drilled in the fourth quarter of 2004 to further optimize pool depletion and gain additional reservoir information. Several individual well equipment upgrades were conducted to optimize individual well deliverability and ongoing compression optimization continues.

ACQUISITIONS

On August 23, 2004, Crescent Point announced it had entered into three separate property acquisition agreements for total consideration of $64.5 million adding approximately 1,725 boe/d of operated, high quality, long life, light oil and natural gas production and 30 net low risk infill development drilling locations providing more than 1,500 boe/d of risked production additions. These acquisitions added 6.8 million boe of proved plus probable and 4.8 million boe of proven reserves with a reserve life index of 10.8 proved plus probable and 7.7 years proven, based on independent engineering. The acquisitions were all closed by September 30, 2004. The acquisitions are highly accretive to Crescent Point on a reserve, production and cash flow per unit basis.

FOURTH QUARTER 2004 UPDATE

Crescent Point expanded the Trust's 2004 development drilling capital expenditure program from $18 million to $26 million. In the fourth quarter, the Trust plans to drill up to 14 gross (11.7 net) low risk development wells of which four horizontals will be drilled on the Trust's newly acquired Innes, Tatagwa, Hastings and Edenvale properties of southeast Saskatchewan, three gas wells at Doe, British Columbia, one gas well at Garden Plains, Alberta, two non-operated gas wells at Cold Lake, Alberta, four horizontal wells at Auburton, Manor and Tatagwa of southeast Saskatchewan.

OUTLOOK

Crescent Point has a high quality, predictable production, reserve and cash flow base strategically focused in large oil or gas in place properties. Each of these properties is characterized by high working interests, is operated by Crescent Point and has significant development upside.

In the third quarter of 2004, the Trust completed three highly accretive property acquisitions in its main operating area of southeast Saskatchewan. These acquisitions added over 30 net low risk development locations and expanded the Trust's reserves and production in the prolific Midale Marly reservoir in the Tatagwa area of southeast Saskatchewan. Crescent Point now has an inventory of more than 130 low risk development locations in its core areas, which will provide sustainable production volumes and distributions through the remainder of 2004 and beyond. Current production exceeds 10,150 boe/d.

Crescent Point continues to lock in commodity price swaps for 2005 and 2006 at increasing crude oil pricing parameters to reduce risk on distribution levels.

Crescent Point has an excellent balance sheet with net debt to annualized cash flow of less than 1.0 and approximately $50 million of unutilized credit lines.

With an excellent balance sheet, 130 low risk development locations and strong hedge position, Crescent Point is well-positioned to maintain its production, cash flow and distributions through 2005 and beyond.

For 2005, Crescent Point has revised upward its average daily production outlook from 9,150 boe/d to 10,150 boe/d. The Trust is projecting to maintain this production with capital expenditures of approximately $26 million for drilling, land and seismic in 2005.

Estimates for 2005 are as follows:

Production	
Oil and NGLs (bbl/d)	**7,650**
Natural gas (mcf/d)	**15,000**
boe/d (6:1)	**10,150**
Cash flow ($000s)	**80,500**
Cash flow per outstanding unit ($)	**2.48**
Capital expenditures ($000s) (1)	**26,000**
Wells drilled, net	**28.9**
Pricing	
Crude oil ($US/bbl) - WTI	**38.50**
($Cdn/bbl) – Corporate	**49.36**
Natural gas ($US/mcf) AECO	**5.42**
($Cdn/mcf) Corporate	**6.95**
Exchange rate ($Cdn/$US)	**0.78**

(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 Executive Officer
November 10, 2004

MANAGEMENT'S DISCUSSION & ANALYSIS

Management's discussion and analysis ("MD&A") is dated November 10, 2004 and should be read in conjunction with the unaudited interim consolidated financial statements for the period ended September 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, market value and payout. 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.

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 months and nine months ended September 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 nine months ended September 30, 2003 reflects the results of operations and cash flows of Crescent Point Energy and its subsidiaries up to September 5, 2003, and the results of the Trust and its subsidiaries from September 5 to September 30, 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.

Results of Operations

Production

Average daily production increased by 59 percent to an average of 9,527 boe/d in the third quarter of 2004 compared to 5,999 boe/d in the third quarter of 2003. This increase was comprised of a 44 percent increase in average crude oil and natural gas liquids ("NGLs") production to 6,905 bbl/d in the third quarter of 2004 from 4,781 bbl/d in the third quarter of 2003, and a 115 percent increase in average natural gas production to 15,733 mcf/d in the third quarter of 2004 from 7,308 mcf/d in the third quarter of 2003. The overall increase in production in both the quarter and the nine month period ended September 30, 2004 is 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 three property acquisitions that closed in the third quarter of 2004 and the optimization of existing properties.

Daily Production Volumes	Three months ended September 30,			Nine months ended September 30,		
	2004	2003	% Change	2004	2003	% Change
Crude oil and NGLs (bbl/d)	6,905	4,781	44	6,194	4,119	50
Natural gas (mcf/d)	15,733	7,308	115	16,967	5,859	190
Total (boe/d)	9,527	5,999	59	9,021	5,096	77
Crude oil and NGLs	72%	80%	(8)	69%	81%	(12)
Natural gas	28%	20%	8	31%	19%	12
Total	100%	100%	-	100%	100%	-

Marketing and Prices

Crescent Point's average realized crude oil and NGL price (before realized financial instruments) increased by 42 percent in the third quarter of 2004 to $50.56 per bbl from $35.62 per bbl in the third quarter of 2003. The increase is mainly attributable to the strong oil prices experienced throughout the industry. For instance, benchmark Edmonton light sweet oil averaged $56.61 per bbl for the third quarter of 2004, 37 percent higher than the average for the third quarter of 2003 of $41.27 per bbl.

The average realized natural gas price (before realized financial instruments) increased eight percent in the third quarter of 2004 to $6.19 per mcf from $5.72 per mcf in the third quarter of 2003. In comparison, the AECO monthly index increased six percent to $6.20 per mcf in the third quarter of 2004 from $5.85 per mcf in the third quarter of 2003.

Average Realized Prices (1)(2)	Three months ended September 30,			Nine months ended September 30,		
	2004	2003	% Change	2004	2003	% Change
Crude oil and NGLs ($/bbl)	50.56	35.62	42	45.54	38.04	20
Natural gas ($/mcf)	6.19	5.72	8	6.48	6.70	(3)
Total ($/boe)	46.86	35.36	33	43.45	38.45	13

(1) The average realized prices reported are before realized financial instrument losses.
(2) The realized prices are no longer net of transportation charges. See the transportation expense section below.

Benchmark Pricing	Three months ended September 30,			Nine months ended September 30,		
	2004	2003	% Change	2004	2003	% Change
Edmonton light sweet oil (Cdn$/bbl)	56.61	41.27	37	51.20	44.36	15
WTI crude oil (US$/bbl)	43.82	30.24	45	39.12	31.13	26
AECO natural gas (Cdn$/mcf)	6.20	5.85	6	6.54	6.95	(6)
Exchange rate – Cdn$/US$	0.77	0.73	5	0.75	0.70	7

Financial Instruments and Risk Management

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/US exchange rate.

The realized losses on financial instruments for the third quarter of 2004 increased to $5,415,000 or $6.18 per boe from $486,000 or $0.89 per boe in the third quarter of 2003. This increase is attributable to the increase in market commodity prices, a decrease in the fixed prices received by the Trust and an increase in the production volumes hedged.

The following is a summary of the realized financial instrument income (losses):

Risk Management	**Three months ended September 30,**			**Nine months ended September 30,**		
($000 except per unit and volume amounts)	**2004**	**2003**	**% change**	**2004**	**2003**	**% change**
Average crude oil volumes hedged (bbl/d)	2,924	1,882	55	3,114	1,672	86
Crude oil realized financial instrument income (loss)	(5,377)	(397)	(1,254)	(12,557)	(1,925)	(552)
per bbl	(8.46)	(0.91)	(830)	(7.40)	(1.71)	(333)
Average natural gas volumes hedged (GJ/d)	4,500	2,000	125	3,338	1,341	149
Natural gas realized financial instrument income (loss)	(38)	(89)	57	(347)	(238)	(46)
per mcf	(0.03)	(0.13)	77	(0.07)	(0.15)	53
Average barrels of oil equivalent hedged (boe/d)	3,638	2,199	65	3,644	1,885	93
Total realized financial instrument income (loss)	(5,415)	(486)	(1,014)	(12,904)	(2,163)	(497)
per boe	(6.18)	(0.89)	(594)	(5.22)	(1.55)	(237)

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 September 30, 2004, $2,584,000 of this deferred loss has been amortized. The unrealized loss on financial instruments (net of amortization) of $10,167,000 for the quarter ended September 30, 2004 is comprised of a loss of $10,519,000 for crude oil, a gain of $295,000 for natural gas, and a gain of $57,000 for interest rate swaps. See Note 12 to the consolidated financial statements for additional information regarding the accounting for financial instruments and risk management.

Crescent Point currently has the following fixed price oil contracts, fixed price gas contracts and interest rate swaps in place:

Fixed Price Oil Contracts	**Weighted average volume (bbl/d)**	**Weighted average price ($Cdn/bbl)**	**Index**
October 1, 2004 to December 31, 2004	2,705	36.58	WTI
January 1, 2005 to December 31, 2005	3,450	43.37	WTI
January 1, 2006 to December 31, 2006	1,432	51.59	WTI

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

Interest Rate Swaps	**Amount ($)**	**Interest rate (%)**
October 1, 2004 to February 15, 2005	8,000,000	4.20
October 1, 2004 to March 4, 2005	12,000,000	4.03

Revenue

Revenue, prior to hedging transactions, increased 113 percent to $41,077,000 in the third quarter of 2004 from $19,305,000 in the third quarter of 2003. This increase in revenue consists of a 107 percent increase in crude oil and NGL revenue, and a 135 percent increase in natural gas revenue. Revenues increased in both the quarter and nine months ended September 30, 2004 mainly due to the increase in production volumes from the Plan of Arrangement completed with Tappit, the acquisition of Capio, the three property acquisitions in the third quarter of 2004 and the higher commodity prices as compared to the prior year.

Revenue ($000)	Three months ended September 30, 2004	2003	% Change	Nine months ended September 30, 2004	2003	% Change
Crude oil and NGL sales [1]	32,117	15,500	107	77,290	42,782	81
Natural gas sales [1]	8,960	3,805	135	30,114	10,713	181
Total revenue	41,077	19,305	113	107,404	53,495	101
Financial instrument - realized income (loss)	(5,415)	(486)	(1,014)	(12,904)	(2,163)	(497)
	35,662	18,819	89	94,500	51,332	84

(1) 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. This adjustment has no impact on net income or cash flow.

The transportation expenses for the third quarter ended September 30, 2004 were $1,247,000 or $1.42 per boe, as compared with transportation expenses of $634,000 or $1.16 per boe for the third quarter ended September 30, 2003. The quarter over quarter transportation expense per boe increased due to higher trucking costs for oil in 2004 as compared to the prior year.

Transportation Expenses ($000)	Three months ended September 30 2004	2003	% Change	Nine months ended September 30 2004	2003	% Change
Transportation expenses	1,247	634	97	2,621	1,400	87
Per boe	1.42	1.16	22	1.06	1.01	5

Royalty Expenses

Royalties, net of Alberta Royalty Tax Credit ("ARTC") remained consistent in the third quarter of 2004 at $7,838,000 or 19 percent of revenue, compared with $3,594,000 or 19 percent of revenue in the third quarter of 2003.

Royalties ($000)	Three months ended September 30, 2004	2003	% Change	Nine months ended September 30, 2004	2003	% Change
Total royalties, net of ARTC	7,838	3,594	118	20,193	9,660	109
As a % of oil and gas sales	19%	19%	-	19%	18%	1
Per boe	8.94	6.58	36	8.17	6.94	18

Operating Expenses

Operating expenses increased 35 percent to $6.91 per boe in the third quarter of 2004, from $5.10 per boe in the third quarter of 2003. The Trust experienced an increase in operating costs per boe for both the quarter and the nine months ended September 30, 2004 due to the purchase of higher operating cost properties in the first and third quarters of 2004 and an increase in overall operating costs in the oil and gas industry.

Operating Expenses ($000)	Three months ended September 30, 2004	2003	% Change	Nine months ended September 30, 2004	2003	% Change
Operating expenses	6,058	2,783	118	15,114	7,579	99
Per boe	6.91	5.10	35	6.11	5.45	12

Netbacks

Note: The following discussion of netbacks refers to netbacks after realized financial instrument losses.

In the third quarter of 2004, Crescent Point received an average crude oil and NGL netback of $24.16 per bbl as compared to $22.74 in the third quarter of 2003, and a natural gas netback of $3.57 per mcf as compared to $2.87 per mcf in the third quarter of 2003. On a total commodity basis, the Trust received a netback of $23.41 per boe in the third quarter of 2004, as compared to $21.63 per boe in the third quarter of 2003. The Trust's overall netback increased by $1.78 per boe or eight percent primarily due to higher average realized prices in the third quarter of 2004 as compared to the third quarter of 2003. The netback received on a total commodity basis for the nine

months ended September 30, 2004 decreased by $0.61 per boe or three percent due to lower fixed prices on risk management contracts and increased operating costs which were partially offset by higher commodity prices.

Netbacks	Three months ended September 30,			Nine months ended September 30,		
	2004	2003	% Change	2004	2003	% Change
Crude oil and NGLs						
Production (bbl/d)	6,905	4,781	44	6,194	4,119	50
Price ($/bbl)	50.56	35.62	42	45.54	38.04	20
Transportation ($/bbl)	(1.46)	(1.14)	28	(1.11)	(1.05)	6
Financial instruments – realized income (losses) ($/bbl)	(8.46)	(0.91)	(830)	(7.40)	(1.71)	(333)
Royalties, net ($/bbl)	(9.17)	(6.11)	50	(8.38)	(6.35)	32
Operating expenses ($/bbl)	(7.31)	(4.72)	55	(6.53)	(5.03)	30
Netback ($/bbl)	24.16	22.74	6	22.12	23.90	(7)
Natural gas						
Production (mcf/d)	15,733	7,308	115	16,967	5,859	190
Price ($/mcf)	6.19	5.72	8	6.48	6.70	(3)
Transportation ($/mcf)	(0.22)	(0.21)	5	(0.16)	(0.14)	14
Financial instruments – realized income (losses) ($/mcf)	(0.03)	(0.13)	77	(0.07)	(0.15)	53
Royalties, net ($/mcf)	(1.39)	(1.41)	(1)	(1.28)	(1.58)	(19)
Operating expenses ($/mcf)	(0.98)	(1.10)	(11)	(0.87)	(1.20)	(28)
Netback ($/mcf)	3.57	2.87	24	4.10	3.63	13
Total						
Production (boe/d)	9,527	5,999	59	9,021	5,096	77
Price ($/boe)	46.86	35.36	33	43.45	38.45	13
Transportation ($/boe)	(1.42)	(1.16)	22	(1.06)	(1.01)	5
Financial instruments – realized income (losses) ($/boe)	(6.18)	(0.89)	(594)	(5.22)	(1.55)	(237)
Royalties, net ($/boe)	(8.94)	(6.58)	36	(8.17)	(6.94)	18
Operating expense ($/boe)	(6.91)	(5.10)	35	(6.11)	(5.45)	12
Netback ($/boe)	23.41	21.63	8	22.89	23.50	(3)

General and Administrative Expenses

General and administrative costs incurred by the Trust during the third quarter of 2004 totaled $1,188,000. Of this, $246,000 was capitalized as part of the Trust's drilling and development program, resulting in net administrative expenses of $942,000 or $1.07 per boe. This compares with general and administrative costs in the third quarter of 2003 of $1,309,000 of which $918,000 was capitalized, resulting in net administrative expenses of $391,000 or $0.71 per boe. Capitalized general and administrative expenses are expected to continue to be minimal due to the Trust's focus on development rather than exploration activities.

General and Administrative Expenses ($000, except per unit and volume amounts)	Three months ended September 30,			Nine months ended September 30,		
	2004	2003	% Change	2004	2003	% Change
General and administrative costs	1,188	1,309	(9)	3,303	2,857	16
Capitalized	(246)	(918)	(73)	(705)	(1,364)	(48)
General and Administrative Expense	942	391	141	2,598	1,493	74
Per boe	1.07	0.71	51	1.05	1.07	(2)

Interest Expense

Interest expense for the third quarter of 2004 amounted to $1,040,000 compared with $410,000 in the third quarter of 2003. The higher interest expense in the third quarter of 2004 was the result of a higher average debt balance during the quarter due to funding of two of the three acquisitions totaling $55,761,000 prior to the closing of the $45,000,000 equity financing on September 9, 2004.

Depletion, Depreciation and Amortization

Crescent Point's depletion, depreciation and amortization for the third quarter of 2004 was $10,385,000 or $11.85 per boe, as compared to depletion of $4,479,000 or $8.20 per boe in the third quarter of 2003. The depletion, depreciation and amortization rate increased in both the three month and nine month periods ended September 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 entire oil and gas industry.

Depletion, Depreciation and Amortization	Three months ended September 30			Nine months ended September 30		
($000)	2004	2003	% Change	2004	2003	% Change
Depletion, Depreciation and Amortization	10,385	4,479	132	27,963	11,641	140
Per boe	11.85	8.20	45	11.31	8.37	35

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 $441,000 in the third quarter of 2004 as compared to a recovery of ($31,000) in the third quarter of 2003. It is expected that the Trust's Saskatchewan Resource Surcharge will continue to increase through the remainder of 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 third quarter of 2004 is ($6,229,000), as compared to future income tax expense in the third quarter of 2003 of $498,000. Included in the ($6,229,000) future income tax recovery for the third quarter of 2004 is a ($3,618,000) recovery relating to the non-cash unrealized loss on financial instruments.

Taxes	Three months ended September 30			Nine months ended September 30		
($000)	2004	2003	% Change	2004	2003	% Change
Capital and other tax expense (recovery)	441	(31)	1,523	1,705	579	194
Future income expense (recovery)	(6,229)	498	(1,351)	(8,644)	3,431	(352)

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 of $18,096,000 or $0.64 per unit in the third quarter of 2004, compared with $6,084,000 or $0.40 per unit in the third quarter of 2003. The Trust's net income for the third quarter of 2004 was $3,058,000 or $0.11 per unit compared with $1,376,000 or $0.09 per unit in the third quarter of 2003. The increase in cash flow and net income is mainly attributable to the increase in production levels and the increase in realized commodity prices. The increase in net income would have been more significant however a pre-tax unrealized loss on financial instruments of $10,167,000 or $0.36 per unit was recorded in the third quarter of 2004. This unrealized loss was recorded pursuant to a new accounting standard for hedging relationships whereby financial instruments must be marked-to-market unless they are designated as effective hedges.

Cash Flow and Net Income ($000, except per unit amounts)	Three months ended September 30, 2004	2003	% Change	Nine months ended September 30, 2004	2003	% Change
Cash flow from operations	18,096	6,084	197	49,953	24,651	103
Cash flow from operations per unit - diluted	0.64	0.40	60	1.83	1.66	10
Net income	3,058	1,376	122	6,250	9,760	(36)
Net income per unit - diluted	0.11	0.09	22	0.23	0.66	(65)

Cash Distributions

Cash distributions of $0.51 per Trust unit were declared for the third quarter of 2004. Of this amount, $0.34 per unit was paid in the third quarter of 2004, and $0.17 per unit was paid on October 15, 2004. Cash flow from operations for the third quarter of 2004 was $0.64 per unit - diluted. This represents a payout ratio of approximately 80 percent on a per unit - diluted basis (including the exchangeable shares and restricted units) for the third quarter of 2004 compared with a payout ratio of 43 percent for the third quarter of 2003. The payout ratio was significantly less in 2003 as Crescent Point did not complete the Plan of Arrangement involving a conversion to a trust until September 5, 2003. Accordingly, the Trust only paid out distributions in respect of cash flows from September 5 to 30, 2003. The payout ratio excluding exchangeable shares and restricted units (which do not receive cash distributions) was 74 percent for the third quarter of 2004.

For the nine months ended September 30, 2004, cash distributions of $1.53 per Trust unit were declared. Of this amount, $1.36 per unit was paid in the nine months ended September 30, 2004, and $0.17 per unit was paid on October 15, 2004. Cash flow from operations for the nine months ended September 30, 2004 was $1.83 per unit – diluted. This represents a payout ratio of approximately 84 percent on a per unit basis (including exchangeable shares and restricted units) for the nine months ended September 30, 2004 as compared with a payout ratio of 10 percent for the nine months ended September 30, 2003. Again, the payout ratio was less in 2003 as the conversion to a trust did not occur until September 5, 2003. The payout ratio excluding exchangeable shares and restricted units (which do not receive cash distributions) was 77 percent for the first nine months of 2004.

The Trust has paid out accumulated distributions of $2.21 per unit since its inception on September 5, 2003.

Capital Expenditures

In the third quarter of 2004, capital expenditures (net of dispositions) totaled $74,947,000 as compared to $66,102,000 in the third quarter of 2003. The property acquisitions (net of dispositions) of $64,724,000 in the third quarter of 2004 includes three major acquisitions in the Trust's main operating area of southeast Saskatchewan. These acquisitions were made for a total purchase price of $64,572,000 and added approximately 1,725 boe/d of production.

The capital expenditures are summarized as follows:

Capital Expenditures (net) [1] ($000)	Three months ended September 30, 2004	2003	% Change	Nine months ended September 30, 2004	2003	% Change
Property acquisitions[2]	64,724	61,297	6	130,783	84,975	54
Drilling and development	9,711	3,603	170	20,218	14,950	35
Capitalized administration	246	918	(73)	705	1,364	(48)
Other	266	284	(6)	900	591	52
Total	74,947	66,102	13	152,606	101,880	50

(1) The capital expenditures do not include the amounts recorded to property, plant and equipment in respect of Asset Retirement Obligations.
(2) The property acquisitions for the three months and nine months ended September 30, 2003 are net of the transfer of exploration assets with a net book value of $10,055,000 to StarPoint.

Goodwill

The Trust recorded goodwill of $36,976,000 during the nine months ended September 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 nine months ended September 30, 2004 increased by $37,000 and $77,000 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 9 to consolidated financial statements for additional information regarding the asset retirement obligation and impact on the consolidated financial statements.

Reclamation Fund

During the third quarter of 2004, the Trust implemented a reclamation fund to provide for future asset retirement costs. Effective July 1, 2004, the Trust began contributing $0.15 per barrel of production to the reclamation fund which results in minimum annual contributions of approximately $575,000 based upon properties owned at September 30, 2004. Contributions to the fund during the third quarter totaled $132,000, $117,000 of which was used in asset retirement activities during the quarter.

Liquidity and Capital Resources

As at September 30, 2004, the Trust had net debt of $82,693,000 compared with $50,131,000 as at September 30, 2003. The bank debt comprised 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. The amount available under the facility was temporarily increased to $117,000,000 for the period August 16, 2004 to October 7, 2004 in connection with the financing of three acquisitions. On October 7, 2004, the credit facility was increased to $135,000,000 and on November 1, 2004 the Trust syndicated its loan agreement and two additional Canadian chartered banks became lenders to the Trust.

Approximately $34,000,000 of the credit facility remains unutilized at September 30, 2004. Currently $50,000,000 of the credit facility remains unutilized. Given the significant amount available but unutilized under the credit facility at September 30, 2004, the increase in the amount made available under the credit facility in October 2004, and the success raising new equity during the period (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 third quarter of 2004, Crescent Point was capitalized with 14 percent debt and 86 percent equity, as compared with 19 percent debt and 81 percent equity at the end of the third quarter of 2003 (based on quarter-end market capitalization). The Trust's net debt to annualized cash flow ratio was approximately 0.96 times at the end of the third quarter of 2004, as compared to 1.22 times at the end of the third quarter of 2003.

Unitholders' Equity

Crescent Point's total capitalization increased 116 percent to $581,441,000 at September 30, 2004 with the market value of Trust units representing 86 percent of total capitalization. This compares with the total capitalization of $269,124,000 at September 30, 2003, with the market value of Trust units representing 81 percent of total capitalization.

On September 9, 2004, the Trust closed a bought deal equity financing pursuant to which 3,000,000 units were sold for proceeds of $45,000,000 ($15.00 per Trust unit). The proceeds from this financing were used to fund three separate property acquisitions totaling $64,570,000.

Units of the Trust trade on the Toronto Stock Exchange. During the period July 1 to September 30, 2004, the units traded in the range of $14.60 to $16.80, with an average daily trading volume of 82,676 units.

Unitholders electing to participate in the distribution reinvestment plan and premium distribution reinvestment plan in the third quarter of 2004 resulted in an additional 312,696 units being issued at an average price of $14.71,

raising a total of $4,600,000. For the nine months ended September 30, 2004 the distribution reinvestment and premium distribution reinvestment plan resulted in an additional 911,235 units being issued at an average price of $14.13, raising a total of $12,875,000. Participation levels in these plans is currently approximately 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.

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 other two thirds of the restricted units vest, the restricted unitholders are entitled to the distributions accrued from the date of grant to the date that is one year before the vesting date.

The unitholders have approved a maximum number of units allowable under the Restricted Unit Bonus Plan of 935,000 units. The Trust granted 180,200 restricted units on October 1, 2003, and a further 214,533 restricted units (net of exercised and cancelled restricted units) in the nine months ended September 30, 2004. The Trust recorded compensation expense and contributed surplus of $568,000 in the third quarter of 2004 and $1,520,000 in the nine months ended September 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)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Total revenue [1]	39,830	34,130	30,823	22,676	18,754	15,827	17,597	9,887
Net income (loss) [2]	3,058	2,754	438	(626)	1,377	5,125	3,259	1,513
Net income (loss) per unit [2]	0.11	0.10	0.02	(0.03)	0.09	0.37	0.24	0.12
Net income (loss) per unit - diluted [2]	0.11	0.10	0.02	(0.03)	0.09	0.36	0.23	0.11
Cash flow from operations	18,096	16,348	15,509	11,975	6,085	9,368	9,199	4,694
Cash flow from operations per unit	0.65	0.61	0.60	0.63	0.40	0.68	0.67	0.37
Cash flow from operations per unit - diluted	0.64	0.60	0.59	0.62	0.40	0.66	0.64	0.36
Capital expenditures	74,947	8,875	68,784	22,584	66,103	5,676	30,102	11,267
Cash distributions	13,490	12,929	12,624	8,897	2,800	-	-	-
Cash distributions per unit	0.51	0.51	0.51	0.51	0.17	-	-	-

(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 September 30, 2004	As at December 31, 2003
	$	$
ASSETS		
		Restated
Current assets:		*(Note 3(b))*
Cash	70	82
Accounts receivable	30,300	17,505
Investments in marketable securities	-	188
Deferred financial instrument loss (Note 12)	625	-
Prepaids and deposits	339	318
	31,334	18,093
Deposits on property, plant and equipment	-	1,000
Reclamation fund (Note 7)	15	-
Property, plant and equipment (Note 6)	295,340	168,591
Goodwill (Note 6)	58,147	21,171
	384,836	208,855
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	28,849	13,945
Cash distributions payable	3,233	2,345
Bank indebtedness (Note 8)	81,320	40,220
Risk management liability (Note 12)	23,149	-
	136,551	56,510
Asset retirement obligation (Note 9)	8,151	5,195
Future income taxes	36,451	29,713
	181,153	91,418
Unitholders' equity:		
Unitholders' capital (Note 10(a))	234,067	113,880
Exchangeable shares (Note 10(a))	8,220	10,782
Contributed surplus (Note 10(b))	1,753	339
Accumulated earnings	10,383	4,133
Accumulated cash distributions (Note 5)	(50,740)	(11,697)
	203,683	117,437
	384,836	208,855

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED EARNINGS

(UNAUDITED) ($000)	Three months ended September 30, 2004	Three months ended September 30, 2003	Nine months ended September 30, 2004	Nine months ended September 30, 2003
	$	$ *Restated (Note 3(b)&(d))*	$	$ *Restated (Note 3(b)&(d))*
Revenue:				
Oil and gas sales	41,077	19,305	107,404	53,495
Transportation expenses (Note 3(d))	(1,247)	(634)	(2,621)	(1,400)
Royalties, net of ARTC	(7,838)	(3,594)	(20,193)	(9,660)
Financial instruments				
Realized losses	(5,415)	(486)	(12,904)	(2,163)
Unrealized losses (Note 12)	(10,167)	-	(22,524)	-
	16,410	14,591	49,162	40,272
Expenses:				
Operating	6,058	2,783	15,114	7,579
General and administrative	942	391	2,598	1,493
Unit-based compensation (Note 10(b))	568	-	1,520	-
Interest on bank indebtedness	1,040	410	2,263	1,016
Depletion, depreciation and amortization	10,385	4,479	27,963	11,641
Accretion on asset retirement obligation (Note 9)	147	44	393	132
Capital and other taxes	441	(31)	1,705	579
Reorganization costs	-	4,954	-	4,954
Gain on sale of investment (Note 4)	-	(313)	-	(313)
	19,581	12,717	51,556	27,081
Income before future income tax	(3,171)	1,874	(2,394)	13,191
Future income tax expense (recovery)	(6,229)	498	(8,644)	3,431
Net income for the period	3,058	1,376	6,250	9,760
Accumulated earnings, beginning of the period	7,325	11,460	3,994	3,117
Retroactive application of change in accounting policy (Note 3(b))	-	65	139	24
Transfer of assets pursuant to Plan of Arrangement (Note 6(c))	-	(8,855)	-	(8,855)
Accumulated earnings, end of the period	10,383	4,046	10,383	4,046
Net income per unit (Note 11)				
Basic	0.11	0.09	0.23	0.66
Diluted	0.11	0.09	0.23	0.66

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

(UNAUDITED) ($000)	Three months ended September 30, 2004	Three months ended September 30, 2003	Nine months ended September 30, 2004	Nine months ended September 30, 2003
	$	$	$	$
		Restated (Note 3(b))		*Restated (Note 3(b))*
Cash provided by (used in)				
Operating activities				
Net income for the period	3,058	1,376	6,250	9,760
Items not affecting cash				
Future income taxes	(6,229)	498	(8,644)	3,431
Unit-based compensation	568	-	1,520	-
Depletion, depreciation and amortization	10,385	4,479	27,963	11,641
Accretion on asset retirement obligation	147	44	393	132
Gain on sale of investment	-	(313)	(53)	(313)
Unrealized losses on financial instruments	10,167	-	22,524	-
Cash flow from operations	18,096	6,084	49,953	24,651
Asset retirement expenditures	(117)	-	(117)	-
Change in non-cash working capital				
Accounts receivable	(13,433)	(4,238)	(10,454)	(851)
Prepaid expenses and deposits	(108)	(26)	191	(81)
Accounts payable	4,905	14,190	(2,657)	(4,685)
	9,343	16,010	36,916	19,034
Investing activities				
Expenditures on petroleum and natural gas properties	(74,948)	(5,170)	(90,919)	(40,948)
Acquisition of Tappit Resources Ltd. (Note 6(b))	-	(7,992)	-	(7,992)
Acquisition of Capio Petroleum Corporation (Note 6(a))	-	-	(76,845)	-
Petroleum and natural gas deposits	-	-	1,000	3,225
Reclamation fund net contributions	(15)	-	(15)	-
Proceeds on sale of investments (Note 4)	-	741	241	741
Change in non-cash working capital				
Accounts receivable	(60)	1,552	115	1,876
Accounts payable	9,417	(12,678)	9,637	(1,165)
	(65,606)	(23,547)	(156,786)	(44,263)
Financing activities				
Issue of trust units, net of issue costs	47,201	1,972	117,520	11,266
Increase in bank indebtedness	22,300	5,617	40,493	13,938
Cash distributions	(13,490)	(2,800)	(39,043)	(2,800)
Change in non-cash working capital				
Cash distributions payable	240	2,800	888	2,800
	56,251	7,589	119,858	25,204
Increase (decrease) in cash	(12)	52	(12)	(25)
Cash at beginning of period	82	8	82	85
Cash at end of period	70	60	70	60

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 nine months ended September 30, 2003 reflect the results of operations and cash flows of old Crescent Point and its subsidiaries up to September 5, 2003, and the results of the Trust and its subsidiaries from September 5 to September 30, 2003. 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 nine months ended September 30, 2004 increased by $37,000 and $77,000 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 9 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 12 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. INVESTMENTS IN MARKETABLE SECURITIES

In July 2003, the Corporation divested its entire investment of 2.15 million common shares in Rise Energy Ltd. ("Rise") subsequent to DT Energy Ltd. purchasing Rise. The carrying value had been written down to $0.20 per share in 2002. Net proceeds from the disposition amounted to $743,000.

5. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

($000, except per unit amounts)	Three months ended September 30, 2004	Nine months ended September 30, 2004
Cash flow from operations before changes in non-cash working capital	18,096	49,953
Add (deduct)		
Cash withheld to fund current period capital expenditures	(4,474)	(10,778)
Reclamation fund contributions and interest earned on fund[1]	(132)	(132)
Cash distributions declared to unitholders	13,490	39,043
Accumulated cash distributions, beginning of period	37,250	11,697
Accumulated cash distributions, end of period	50,740	50,740
Cash distributions per unit [2]	0.51	1.53
Accumulated cash distributions per unit – beginning of period	1.70	0.68
Accumulated cash distributions per unit – end of period	2.21	2.21

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

6. ACQUISITIONS AND DISPOSITIONS

a) 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 $2,580,000)	413
Total purchase price	76,901

b) Acquisition of Tappit Resources Ltd.

On September 5, 2003, old Crescent Point purchased 100% of the shares of Tappit Resources Ltd., a public oil and gas company. The results of Tappit have been included in these financial statements from the date of acquisition. The transaction was accounted for as a business combination with net assets acquired and consideration allocated as follows:

	($000)
Net assets acquired	
Property, plant and equipment	73,223
Goodwill	21,171
Working capital deficiency	(1,948)
Bank debt	(23,699)
Asset retirement obligation	(830)
Future income taxes	(15,506)
Total net assets acquired	52,411
Consideration	
Cash	7,303
Units issued	44,698
Acquisition costs (net of option proceeds of $1,217,000)	410
Total purchase price	52,411

c) Assets transferred to StarPoint Energy Ltd.

Under the Arrangement on September 5, 2003, old Crescent Point transferred to StarPoint Energy Ltd. its existing interests in its British Columbia exploration area. A future tax liability has been recorded by the Trust as a result of transferring tax pools of $14,481,000, which were in excess of the net book value of $10,055,000. The details are as follows:

	($000)
Petroleum and natural gas properties and equipment	10,055
Future tax asset	1,587
Total assets transferred	11,642
Bank indebtedness assumed	3,500
Net assets transferred and reduction in accumulated earnings	8,142

7. RECLAMATION FUND

A reclamation fund was established effective July 1, 2004 to fund future asset retirement obligation costs. The Board of Directors has approved contributions of $0.15 per barrel of production which results in minimum annual contributions of approximately $575,000 based upon properties owned at September 30, 2004. Contributions to the reclamation fund and interest earned on the reclamation fund balance have been deducted from the cash distributions to the unitholders and cash withheld to fund current period capital expenditures. During the period, $117,000 of actual expenditures were charged against the reclamation fund.

	September 30, 2004 ($000)
Balance, beginning of period	-
Contributions	132
Actual expenditures	(117)
Interest earned on fund	-
Balance, end of period	15

8. BANK INDEBTEDNESS

On January 6, 2004, the Trust's revolving term demand bank loan facility was increased to $105,000,000. The amount available under the banking facility was temporarily increased to $117,000,000 for the period August 16, 2004 to October 7, 2004 in connection with the financing of three acquisitions. See Note 13 for

information regarding changes made to the banking facility after September 30, 2004. The interest charged on the facility is calculated based on a sliding scale ratio of the Trust's debt to cash flows.

9. 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 $8,151,000 at September 30, 2004 (December 31, 2003 - $5,195,000) based on total estimated undiscounted cash flows to settle the obligation of $24,897,000 (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.

The following table reconciles the asset retirement obligation:

	September 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	2,105	1,964
Liabilities settled	(117)	-
Accretion expense	393	178
Asset retirement obligation, end of the period	8,151	5,195

During the third quarter of 2004, the Trust implemented a reclamation fund. See Note 7 for information regarding the reclamation fund.

10. UNITHOLDERS' EQUITY

a) Issued and Outstanding

	September 30, 2004	
	Number of Shares / Trust Units	Amount ($000)
Trust Units		
Balance, January 1, 2004	19,282,049	118,038
Issued for cash	8,150,000	110,663
Issued on conversion of exchangeable shares	491,809	2,562
Issued on vesting of restricted units	9,000	106
Issued pursuant to the distribution reinvestment plans	802,543	11,181
To be issued pursuant to the distribution reinvestment plans	108,692	1,694
Balance, September 30, 2004	28,844,093	244,244
Cumulative unit issue costs, net of tax	-	(10,177)
Total Unitholders' capital, September 30, 2004	28,844,093	234,067
Exchangeable Shares		
Balance, January 1, 2004	1,902,901	10,782
Exchanged for Trust units	(452,014)	(2,562)
Balance, September 30, 2004	1,450,887	8,220
Exchange ratio, September 30, 2004	1.15729	-
Trust units issuable upon conversion, September 30, 2004	1,679,097	8,220

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 other two thirds of the restricted units vest, the restricted unitholders are entitled to the distributions accrued from the date of grant to the date that is one year before the vesting date.

The unitholders have approved a maximum number of units allowable under the Restricted Unit Bonus Plan of 935,000 units. A summary of the changes in the restricted units outstanding under the plan is as follows:

	September 30, 2004	December 31, 2003
Restricted units, beginning of the period	180,200	-
Granted	248,083	180,200
Exercised	(9,000)	-
Cancelled	(24,550)	-
Restricted units, end of the period	394,733	180,200

The Trust recorded compensation expense and contributed surplus of $568,000 in the three-month period ended September 30, 2004 and $1,520,000 in the nine-month period ended September 30, 2004, based on the fair value of the units on the date of the grant.

11. PER TRUST UNIT AMOUNTS

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

	Three months ended		Nine months ended	
	September 30, 2004	September 30, 2003[2]	September 30, 2004	September 30, 2003[2]
Weighted average Trust units/shares	26,296,115	15,238,997	25,262,065	14,825,536
Trust units issuable on conversion of exchangeable shares [1]	1,679,097	-	1,679,097	-
Weighted average Trust units/shares and exchangeable shares	27,975,212	15,238,997	26,941,162	14,825,536
Dilutive impact of restricted units/stock options	361,779	-	291,911	-
Dilutive Trust units/shares and exchangeable shares	28,336,991	15,238,997	27,233,073	14,825,536

(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.

12. 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 indications 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	19,940
Risk management liability, September 30, 2004	23,149
Deferred financial instrument loss, January 1, 2004	3,209
Amortization	(2,584)
Deferred financial instrument loss, September 30, 2004	625

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

	Weighted average volume (bbl/d)	Weighted average price ($Cdn/bbl)	Index
October 1, 2004 to December 31, 2004	2,705	36.58	WTI
January 1, 2005 to December 31, 2005	3,200	42.38	WTI
January 1, 2006 to June 30, 2006	1,874	50.12	WTI

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

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

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

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

13. SUBSEQUENT EVENTS

On October 7, 2004, the Trust's credit facility was increased to $135,000,000. On November 1, 2004, the Trust's credit facility was restructured into a syndicated facility and two additional Canadian chartered banks were welcomed into the syndicate.

14. COMPARATIVE INFORMATION

Certain information provided for the previous period has been restated to conform to 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 Executive Officer
C. Neil Smith, Vice President, Engineering and Business Development
Greg Tisdale, Chief Financial Officer
Dan Toews, Treasurer and Controller
Dave Balutis, Vice President, Geosciences
Tamara MacDonald, Land Manager

Head Office:	Suite 1800, 500 – 4 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 - 9 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 Executive Officer Greg Tisdale, Chief Financial Officer

Suite 1800, 500 - 4th Avenue SW
Calgary, Alberta T2P 2V6
Tel: (403) 693-0020
Fax: (403) 693-0070

www.crescentpointenergy.com