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TRUST

2006 SECOND QUARTER REPORT

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FINANCIAL

HIGHLIGHTS

	Three months ended June 30,			Six months ended June 30,		
	2006	2005	% Change	**2006**	2005	% Change
Financial ($000s, except per unit data)						
Petroleum and natural gas sales	**41,504**	32,729	27	**87,746**	62,079	41
Funds from operations[1]	**18,894**	19,168	(1)	**41,707**	35,767	17
Per unit[2] – basic ($)	**0.40**	0.74	(46)	**0.89**	1.38	(36)
– diluted ($)	**0.36**	0.73	(51)	**0.79**	1.35	(41)
Net income	**18,744**	4,621	306	**22,469**	7,864	186
Per unit[2] – basic ($)	**0.39**	0.18	117	**0.48**	0.30	60
– diluted ($)	**0.36**	0.18	100	**0.43**	0.30	43
Capital expenditures	**21,530**	10,131	113	**39,713**	42,710	(7)
Deferred transaction costs	–	2,312	(100)	–	2,312	(100)
Distributions declared	**18,303**	–	100	**38,788**	–	100
Distributions declared per unit ($)	**0.39**	–	100	**0.84**	–	100
Payout ratio[3] – before DRIP	**97%**	–	100	**93%**	–	100
– after DRIP	**50%**	–	100	**52%**	–	100
Total debt including working capital deficiency	**178,313**	116,133	54	**178,313**	116,133	54
Average units outstanding – basic	**47,491**	25,954	83	**46,762**	25,900	81
– diluted	**54,534**	26,365	107	**53,806**	26,438	104
Operations						
Daily production						
Natural gas (mcf/d)	**34,001**	37,978	(10)	**35,280**	38,076	(7)
Oil and NGL (bbls/d)	**3,640**	1,190	206	**3,774**	1,168	223
Barrels of oil equivalent (boe/d)	**9,307**	7,520	24	**9,654**	7,514	28
Average sale price[4]						
Natural gas ($/mcf)	**5.83**	7.41	(21)	**6.64**	7.07	(6)
Oil and NGL ($/bbl)	**67.21**	49.81	35	**62.12**	49.25	26
Wells drilled – gross (net)						
Gas	**5 (3.6)**	–		**23 (11.6)**	17 (12.8)	
Oil	**6 (4.5)**	4 (4.0)		**7 (4.8)**	8 (7.0)	
Dry	**2 (1.6)**	–		**6 (3.6)**	1 (1.0)	
Total	**13 (9.7)**	4 (4.0)		**36 (20.0)**	26 (20.8)	

Barrels of oil equivalent are reported with a 6:1 conversion with six mcf = one barrel

[1] Non-GAAP financial measures are identified and defined in the Management's Discussion and Analysis.

[2] The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after July 7, 2005 as well as the common shares of Thunder Energy Inc. issued prior to conversion on July 7, 2005.

[3] The payout ratio is calculated using distributions declared divided by funds from operations.

[4] Average sale price at the wellhead before hedging gain or loss.

PRESIDENT'S MESSAGE

In accordance with Canadian generally accepted accounting principles ("GAAP"), results for the three and six months ended June 30, 2005 are for the Trust's predecessor, Thunder Energy Inc., and therefore are not directly comparable with the 2006 results for the Trust.

During the second quarter, we continued to see trends that have created a challenging environment not only for Thunder Trust, but also the rest of the industry. Since the beginning of the year, we have seen softening gas prices, while the high level of industry activity has continued to put pressure on the availability of field resources and slowed regulatory approvals, resulting in delays in the tie-in of volumes currently behind pipe. Offsetting those trends is the continued strength of prices for crude oil and NGL, and a significant increase in Thunder's behind pipe volumes due to our second quarter drilling and completion operations which recorded a success rate of 84%.

DISTRIBUTIONS

Thunder Energy Trust has declared a distribution of 12 cents per trust unit to be paid on September 15, 2006, in respect of August production, for unitholders of record on August 22, 2006. The ex-distribution date is August 18, 2006.

Declared monthly distributions for the second quarter totalled $0.39 per unit and $0.84 per unit for the first six months of 2006. Declared distributions totalled $18.3 million for the second quarter, representing a payout ratio of 97% before the Trust's Distribution Reinvestment Program (DRIP) and 50% after taking into account the DRIP. Year to date, declared distributions totalled $38.8 million with a payout ratio of 93% before the DRIP, 52% after DRIP. Current monthly distributions provide an annualized cash-on-cash yield of 16.2% based on the August 9, 2006 closing price of $8.90 per unit. Cumulative distributions since Trust inception to June 30, 2006 are $1.74/unit.

FINANCIAL

Quarterly funds from operations totalled $18.9 million ($0.40 per unit basic, $0.36 per unit diluted). In Q1 2006, funds from operations were $22.8 million ($0.50 per unit basic; $0.49 per unit diluted). The quarter over quarter decline reflects a lower average natural gas price at the wellhead ($5.83/mcf in Q2 versus $7.40/mcf in Q1), offsetting growth in the average wellhead price for oil and NGL ($67.21/bbl in Q2 versus $57.34/bbl in Q1), and a decrease in second quarter average production to 9,307 boe/d from 10,005 boe/d in Q1 2006. For the six months, funds from operations totalled $41.7 million ($0.89 per unit basic; $0.79 per unit diluted).

The Trust recorded net income of $18.7 million for the quarter ($0.39 per unit basic and $0.36 per unit diluted). This was a substantial increase from first quarter 2006 net income of $3.7 million ($0.08 basic and diluted). The increase is attributable to, among other factors, future tax recoveries due to the federal and provincial governments enacting significant future tax deductions during the quarter. For the six months, net income totalled $22.5 million ($0.48 per unit basic, $0.43 per unit diluted).

PRODUCTION

Production for the second quarter 2006 averaged 9,307 boe/d, 61% natural gas. Gas volumes averaged 34.0 mmcf/d versus 36.6 mmcf/d in Q1 2006. Second quarter production of oil and NGL averaged 3,640 bbls/d, down from 3,910 bbls/d in first quarter 2006. Total production was down from 10,005 boe/d in first quarter 2006 and reflects a combination of factors; these include natural volume declines along with the high level of industry activity that is causing delays in regulatory approvals and shortages of manpower and equipment. However, a drilling success rate of 84% has resulted in significant growth in estimated behind pipe volumes.

Behind pipe tested volumes have grown significantly to approximately 1,930 boe/d at June 30 from 1,000 to 1,300 boe/d at March 31. Most of these volumes are scheduled for tie in by late in the third quarter, primarily in two core areas, Fenn-Big Valley and Greater Sylvan Lake. These behind pipe volumes are estimated from completion test rates exceeding 3,800 boe/d, and forecast the initial three-month average production rates from each successful well.

HEDGING

Thunder's hedging policy is designed to mitigate downside commodity price risk. In light of weak natural gas prices, an additional costless collar was placed in July 2006 for the period November 1, 2006 to March 31, 2007 for 10,000 GJ/day of production at a floor of $8.00 per GJ and ceiling of $9.40 per GJ.

Q2 2006 ACTIVITY

Thunder Trust drilled 13 wells (9.7 net) in the second quarter comprising five gas wells (3.6 net), six oil wells (4.5 net) and two (1.6 net) dry and abandoned wells (D&A). Drilling and completion results for Q2 2006 yielded an 84% success rate as detailed below. Capital expenditures for the second quarter totalled $21.5 million.

Q2 2006 DRILLING ACTIVITY

		Oil		Gas		D&A		**Total**	
District	Sub-Area	Gross	Net	Gross	Net	Gross	Net	**Gross**	**Net**
Central AB	Fenn-Big Valley	0	0.0	1	1.0	1	0.6	**2**	**1.6**
	Rosalind	0	0.0	2	2.0	1	1.0	**3**	**3.0**
Alberta West	Gr. Sylvan Lake	2	0.7	2	0.6	0	0.0	**4**	**1.3**
SE Sask.	Willmar	2	2.0	0	0.0	0	0.0	**2**	**2.0**
Other	Skiff	2	1.8	0	0.0	0	0.0	**2**	**1.8**
		6	4.5	5	3.6	2	1.6	**13**	**9.7**

Drilling Success = 84%

Thunder is very pleased with the high success of our drilling programs and continues to maintain a multi-well inventory of fully-evaluated drilling locations that will allow us to continue an active capital program for the next four years at least. While we are always subject to the volatility of commodity prices, our ability to maintain a robust drilling location inventory is an important component of maintaining stability in our distributions. We continue to optimize our capital programs, and focus on delivering unitholder value through the drill bit while undertaking a constant assessment of strategic acquisitions.

OPERATIONAL UPDATE

CENTRAL ALBERTA

Fenn-Big Valley: Behind pipe volumes of approximately 640 boe/d are scheduled for start-up by mid-September 2006 following expansion of a third party compression facility.

Twenty-six wells (26.0 net) are planned in 2006 for drilling in the Fenn-Big Valley area of Central Alberta pursuant to Thunder's well and facility cost sharing agreement with Ember Resources Inc. (Ember). Four wells (4.0 net) were drilled in the first quarter and an additional two wells (1.0 net gas, 0.6 net D&A) were drilled in Q2 once drilling operations resumed at the end of June following spring break-up. At press release date, 19 additional wells have been drilled and are in the process of being completed. Production start-up from the 2006 drilling program is scheduled for early fourth quarter.

Under the agreement with Ember, joint drilling is targeting Thunder's 100%-owned conventional Belly River sand potential and Ember's 100%-owned coalbed methane (CBM) resource potential in a single well bore. This cost sharing enhances the economics of the Belly River development program in the Fenn-Big Valley area. Drilling costs to the base of the Belly River sands are shared 60% by Thunder and 40% by Ember. Thunder pays approximately 40% of major facility costs and 100% of Belly River completion costs; Ember pays 100% of the CBM completion costs. Projected capital cost savings pursuant to this strategic alliance are approximately 30%. This alliance provides the opportunity to fully evaluate the Belly River sand potential on a higher drilling density basis.

Rosalind: Three wells (3.0 net) were drilled at Rosalind in Q2 2006 based on Thunder's 3-D seismic interpretation and resulted in two (2.0 net) successful gas wells and one (1.0 net) D&A. The two (2.0 net) successful wells tested at 870 boe/d (870 net). This brings first half drilling at Rosalind to six wells (5.0 net), with an associated success rate of 80%. An additional five wells (3.9 net) are planned for the remainder of the year; however, given the success of the 3-D interpretation and well deliverability, capital may be reallocated from other areas to Rosalind.

Manola: Processing and interpretation of a 35-square kilometre 3-D seismic survey was completed in Q2 2006, which significantly expanded Thunder's Manola drilling location inventory. Currently two wells (1.0 net) remain to be drilled at Manola in 2006 as part of a four (2.0 net) well program. Additional locations are contingent primarily on timelines to production and capital allocation.

WEST ALBERTA

Greater Sylvan Lake: A total of 14 wells (4.5 net) are planned in Sylvan Lake for 2006, of which five (2.0 net) were drilled in the first half of 2006. Thunder is currently drilling one (0.25 net) additional well in the Sylvan Lake area.

Four wells (1.3 net) were drilled in Q2 2006 in the Greater Sylvan Lake area as detailed below.

One (0.5 net) development well was drilled into the Sylvan Lake "B" pool in Q2. It encountered 138 feet of net pay, and tested at a combined rate of 1,160 boe/d (580 net) at less than 2% drawdown. Thunder has 50% interest before payout and 65% interest after payout. Production start-up from this well is anticipated in early August.

The second well (50% interest) was drilled at Ferrier and encountered two separate gas formations with a combined net pay of 57 feet and flow tested over a 24-hour period at a combined rate of 426 boe/d (213 net) of gas at a flowing pressure of 650 to 725 psig. Completion of pipeline and lease facility installation is targeted for the end of August 2006.

A third well (17.75% interest after payout of completion and tie-in costs) was drilled and encountered 125 feet of net pay in the Leduc formation. Test rates were approximately 540 boe/d at less than 1% drawdown.

A fourth well (12.5% interest) was drilled late in the second quarter in Westerose and is awaiting completion.

SOUTHEAST SASKATCHEWAN

Willmar: Two (2.0 net) successful horizontal oil wells were drilled in Q2 2006, one of which was a sidetrack leg on an existing horizontal well. Both wells are currently producing from the Frobisher horizon at a combined rate of 120 boe/d net to Thunder.

FOOTHILLS

Whiskey Creek: Surface facilities installation was completed at a third well in Whiskey Creek and associated production began July 2006 at 167 boe/d (100 net) through the low-pressure inlet to the plant on a temporary basis. To optimize flowing conditions for the Whiskey Creek area, additional compression is scheduled for installation and start-up in the fourth quarter at Imperial Oil's Quirk Creek gas plant.

SKIFF (OTHER)

Thunder plans to drill five wells (3.1 net) at Skiff in 2006 with three (1.3 net) of these locations targeting a significant pool extension. The Skiff program began as scheduled in Q2 with the drilling of two (1.8 net) development oil wells at 100% success rate. The initial production rate from these wells is approximately 50 boe/d (45 net).

In the third quarter, exploitation efforts will also attempt to extend the pool to the south via the re-completion of two suspended wells (0.8 net); an additional three wells (1.3 net) will also be drilled as part of this initiative. Since the Trust's inception, rates from this pool have more than doubled and now total 225 boe/d (200 net). The Skiff Sawtooth oil reservoir is highly permeable with low energy drive, and is therefore viewed as an ideal candidate to expand the existing water flood and is ultimately targeted for enhanced oil recovery. Significant production and reserve increases are internally projected.

N.E. BRITISH COLUMBIA

Laprise: Exploitation efforts proved successful in determining gas charge and permeability in a seismically defined new horizon at Laprise. One (0.75 net) additional well will be re-completed in the zone to further determine the risk parameters and economic viability of a potential drill program.

FORWARD STRATEGY

Thunder's large inventory of exploitation and drillable prospects has the potential to establish production stability, a key component of the sustainability of distributions, although they remain subject and highly sensitive to commodity prices. At the end of the second quarter, Thunder's opportunity base included:

- More than four years of defined drilling inventory;
- Over 21 townships (756 square miles) of 3-D seismic;
- Undeveloped land holdings were approximately 153,000 net acres at June 30, 2006.

On behalf of the Board

Stuart Keck

Stuart J. Keck
President and Chief Executive Officer

August 10, 2006

FORWARD-LOOKING STATEMENTS

This President's message contains forward-looking statements. More particularly, this President's message contains statements concerning the Trust's volumes of oil and natural gas that are currently behind pipe and planned exploration and development activities.

The forward-looking statements are based on certain key expectations and assumptions made by the Trust, including expectations and assumptions concerning prevailing commodity prices and exchange rates, availability and cost of labor and services, the timing of receipt of regulatory approvals, the performance of existing wells, the success obtained in drilling new wells and the performance of new wells and the sufficiency of budgeted capital expenditures in carrying out the Trust's planned activities.

Although the Trust believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Trust can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity price and exchange rate fluctuations and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. These risks are set out in more detail in the Trust's annual information form for the year ended December 31, 2005, which can be accessed at www.sedar.com.

Note: Boe means barrel of oil equivalent on the basis of 1 boe to 6,000 cubic feet of natural gas. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6,000 cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion is management's analysis of Thunder Energy Trust's ("Thunder" or the "Trust") operating and financial data for the quarter ended June 30, 2006, as well as their estimate of future operating and financial performance based on information currently available. It should be read in conjunction with the unaudited interim consolidated financial statements of the Trust for the three and six months ended June 30, 2006 and the audited consolidated financial statements and notes for the year ended December 31, 2005. These financial statements and additional information about the Trust are available on Sedar at www.sedar.com. The Management Discussion and Analysis ("MD&A") and consolidated financial statements of the Trust have been prepared on a continuity of interest basis which recognizes the Trust as the successor to Thunder Energy Inc. ("Thunder Energy"). Accordingly, the MD&A and consolidated financial statements for periods prior to July 7, 2005 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by Thunder Energy. As a result, certain prior period information may not be directly comparable. The MD&A was prepared as of August 8, 2006.

Basis of Presentation *The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.*

Non-GAAP Measurements *Management uses funds from operations (before changes in non-cash working capital and settlement of asset retirement obligations) to analyze operating performance and leverage. The term distributable cash is used to present the amount of cash that the Trust distributes to unitholders. The payout ratio is used to present the amount of cash as a percentage of the Trust's funds from operations which are distributed before and after the distribution reinvestment program ("DRIP"). Distributable cash, funds from operations and payout ratio presented have no standardized meaning prescribed by GAAP; therefore, they may not be comparable with the calculation of similar measures for other entities. Distributable cash, funds from operations and the payout ratio as presented are not intended as alternates to, or to be more meaningful than, GAAP performance measures such as net income. The reconciliation between net income and funds from operations can be found in the consolidated statements of cash flows in the consolidated financial statements. The Trust also presents funds from operations per unit whereby per unit amounts are calculated using weighted average units outstanding consistent with the calculation of earnings per unit. Distributable cash is calculated using funds from operations less funds withheld for capital expenditures. Payout ratio is calculated as funds from operations divided by declared distributions before and after DRIP. The Trust considers funds from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt, and to fund future capital investments. Distributable cash, funds from operations and payout ratio are used by research analysts to value and compare oil and gas trusts and are frequently included in published third-party research when providing investment recommendations.*

BOE Presentation *The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. The boe conversion ratio used by the Trust of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.*

Forward-looking Statements Statements throughout this MD&A that are not historical facts may be considered "forward-looking statements". These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. Forward-looking statements included in the MD&A concern anticipated cash flow to fund distributions and capital expenditures.

Forward-looking statements and information are based on the Trust's current beliefs as well as assumptions made by and information currently available to the Trust concerning anticipated financial performance, business prospects, strategies and regulatory developments. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks that predictions, forecasts, projections and other forward-looking statements will not be achieved. We caution readers not to place undue reliance on these statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in such forward-looking statements. These factors include, but are not limited to: the volatility of oil and gas prices; production and development costs and capital expenditures; the imprecision of reserve estimates and estimates of recoverable quantities of oil and gas reserves; environmental claims and liabilities; incorrect assessments of value when making acquisitions; increases in debt service charges; the loss of key personnel; the marketability of production; defaults by third-party operators; fluctuations in foreign currency and exchange rates; inadequate insurance coverage; compliance with environmental laws and regulations; changes in tax laws; the failure to qualify as a mutual fund trust; and the Trust's ability to access external sources of debt and equity capital. Further information regarding these factors may be found in the Trust's annual report for the year ended December 31, 2005 under the headings "Critical Accounting Estimates" and "Risks and Uncertainties" in the MD&A.

The Trust cautions that the foregoing list of factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to the Trust, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. The forward-looking statements and information contained in this MD&A are as of the date hereof and the Trust undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

CORPORATE REORGANIZATION

Effective July 7, 2005, Thunder Energy, Mustang Resources Inc. ("Mustang") and Forte Resources Inc. ("Forte") entered into a business combination resulting in the conversion into an energy trust through a Plan of Arrangement. The reorganization resulted in the shareholders of Thunder Energy receiving Trust units in the new oil and natural gas energy trust, Thunder Energy Trust, and common shares in two new publicly-listed companies: Ember Resources Inc. ("Ember"), a coalbed methane company, and Alberta Clipper Energy Inc. ("Clipper") an exploration and production company. An additional exploration and production company was created, Valiant Energy Inc. ("Valiant"), which owns certain Forte exploration assets and undeveloped lands.

Shareholders of Thunder Energy received common shares of Ember and Clipper and at their election, either units of the Trust or exchangeable shares which may be exchanged into units of the Trust. Specifically, shareholders of the respective companies, after the consolidation of shares, received:

For each Thunder Energy common share owned:

- (a) 0.5 Trust units or exchangeable shares
- (b) 0.3333 common shares of Clipper
- (c) 0.3333 common shares of Ember

For each Mustang common share owned:

- (a) 0.55 Trust units or exchangeable shares
- (b) 0.3666 common shares of Clipper
- (c) 0.0833 common shares of Ember

For each Forte common share owned:

- (a) 0.175 Trust units or exchangeable shares
- (b) 0.3333 common shares of Valiant

RESULTS OF OPERATIONS

Gross oil and gas revenues increased 27% to $41.5 million for the three months ended June 30, 2006 compared with the same period in 2005 and 41% to $87.7 million for the six months ended June 30, 2006. These increases were due to the acquisitions of Mustang and Forte as well as strong crude oil prices.

In the second quarter of 2006, natural gas revenues decreased 28% from the same period in 2005 due to a 21% decrease in Thunder's average price at the wellhead and a 10% decline in gas production offset by a realized hedging gain of $0.3 million. Oil and NGL revenues increased 285% in the second quarter of 2006 compared with 2005 due to a 35% increase in the average price at the wellhead and a 206% increase in production offset by a $1.5 million realized hedging loss.

For the first six months of 2006 natural gas revenues decreased 13% due to a 6% decline in Thunder's average natural gas price at the wellhead and a 7% production decrease, offset by a realized hedging gain of $0.3 million. Oil and NGL revenues increased 293% due to a 26% rise in Thunder's average price at the wellhead and a 223% increase in oil and NGL production offset by a realized hedging loss of $1.5 million.

In 2006 the Trust entered into financial contracts to mitigate the effect of commodity price fluctuations. The above noted hedging gains and losses during the second quarter of 2006 relate to contracts to hedge 15,000 GJ/d of natural gas and 2,400 bbls/d of crude oil in the period. The net effect of these contracts was a realized loss of $1.2 million and an unrealized loss of $2.3 million.

	Three months ended June 30,		Six months ended June 30,	
OIL AND GAS REVENUES ($000s)	**2006**	2005	**2006**	2005
Gross revenues	**41,504**	32,729	**87,746**	62,079
Transportation expenses	**(1,201)**	(1,691)	**(2,911)**	(2,818)
Net revenues	**40,303**	31,038	**84,835**	59,261
Realized net loss on commodity contracts	**(1,226)**	–	**(1,226)**	–
Net revenues after realized hedging loss	**39,077**	31,038	**83,609**	59,261
Unrealized net loss on commodity contracts	**(2,259)**	–	**(2,259)**	–
Net revenues after realized and unrealized hedging losses	**36,818**	31,038	**81,350**	59,261

OIL AND GAS REVENUES ($000s, net of transportation expenses and realized hedging loss)	Natural Gas	Crude Oil and NGL	**Total**
Three months ended June 30, 2005	25,655	5,383	31,038
Effect of change in product prices	(4,935)	5,774	839
Effect of change in sales volumes	(2,681)	11,107	8,426
Effect of realized gains/losses on commodity contracts	315	(1,541)	(1,226)
Three months ended June 30, 2006	**18,354**	**20,723**	**39,077**
Six months ended June 30, 2005	48,851	10,410	59,261
Effect of change in product prices	(2,876)	8,795	5,919
Effect of change in sales volumes	(3,579)	23,234	19,655
Effect of realized gains/losses on commodity contracts	315	(1,541)	(1,226)
Six months ended June 30, 2006	**42,711**	**40,898**	**83,609**

PRODUCTION	Three months ended June 30, 2006	2005	Six months ended June 30, 2006	2005
Crude oil (bbls/d)	**3,228**	1,018	**3,344**	1,007
NGL (bbls/d)	**412**	172	**430**	161
Total crude oil and NGL (bbls/d)	**3,640**	1,190	**3,774**	1,168
Natural gas (mcf/d)	**34,001**	37,978	**35,280**	38,076
Total (boe/d)	**9,307**	7,520	**9,654**	7,514
Percentage gas (%)	**61**	84	**61**	84

AVERAGE COMMODITY PRICES	Three months ended June 30, 2006	2005	Six months ended June 30, 2006	2005
Natural gas ($/mcf)				
NYMEX ($US/mmbtu)	**6.85**	6.95	**7.96**	6.73
AECO ($/mmbtu)	**6.04**	7.37	**6.77**	7.13
Thunder price before hedging and transportation	**6.07**	7.75	**6.90**	7.37
Transportation	**(0.24)**	(0.34)	**(0.26)**	(0.30)
Thunder price at the wellhead	**5.83**	7.41	**6.64**	7.07
Realized gain on commodity contracts	**0.10**	–	**0.05**	–
Thunder price after hedging	**5.93**	7.41	**6.69**	7.07
Crude oil ($/bbl)				
WTI ($US/bbl)	**70.70**	53.20	**67.09**	51.52
Edmonton posted	**78.55**	65.76	**73.76**	63.61
Thunder price before hedging and transportation	**68.62**	53.95	**63.93**	52.76
Transportation	**(1.41)**	(4.14)	**(1.81)**	(3.51)
Thunder price at the wellhead	**67.21**	49.81	**62.12**	49.25
Realized loss on commodity contracts	**(4.65)**	–	**(2.26)**	–
Thunder price after hedging	**62.56**	49.81	**59.86**	49.25
Cdn/US $ average exchange rate	**1.122**	1.232	**1.138**	1.223

Transportation expenses were down 29% compared with second quarter 2005 and up 3% for the first six months of 2006. The Trust's transportation expenses per barrel for crude oil have not increased proportionately with the rise in production, as the majority of crude oil production acquired from Mustang and Forte in 2005 is pipeline connected.

Financial Instruments

The Trust entered into the following financial transactions to mitigate its exposure to future fluctuations in commodity prices.

Gas Contracts	Volume (GJ/d)	Pricing Point	Strike Price ($/GJ)	Term
Costless Collar	15,000	AECO	Cdn$6.00 to Cdn$6.50	April 1/06 to Oct 31/06
Costless Collar	10,000	AECO	Cdn$8.00 to Cdn$10.00	Nov 1/06 to March 31/07

Oil Contracts	Volume (bbls/d)	Pricing Point	Strike Price ($/bbl)	Term
Costless Collar	2,400	WTI NYMEX	US$61.00 to US$64.40	April 1/06 to June 30/06
Costless Collar	2,400	WTI NYMEX	US$61.00 to US$67.50	July 1/06 to Sept 30/06
Costless Collar	800	WTI NYMEX	US$61.00 to US$72.70	Oct 1/06 to Dec 31/06
Costless Collar	800	WTI NYMEX	US$65.00 to US$80.70	Oct 1/06 to Dec 31/06
Costless Collar	800	WTI NYMEX	US$61.00 to US$73.05	Jan 1/07 to Mar 31/07
Costless Collar	800	WTI NYMEX	US$65.00 to US$80.00	Jan 1/07 to Mar 31/07

The net effect of these contracts was a realized loss of $1.2 million and an unrealized loss of $2.3 million during the three and six months ended June 30, 2006.

Subsequent to June 30, 2006, the Trust entered into the following financial transaction to mitigate its exposure to future fluctuations in natural gas prices.

Gas Contract	Volume (GJ/d)	Pricing Point	Strike Price ($/GJ)	Term
Costless Collar	10,000	AECO	Cdn$8.00 to Cdn$9.40	Nov 1/06 to March 31/07

Royalties increased to $6.7 million in the second quarter of 2006 and to $15.5 million for the first six months of the year, increases of 69% and 78% respectively over the corresponding prior periods in 2005. Royalties as a percentage of net revenue increased to 16.6% in the second quarter and 18.3% for the six month period. These increases were due to a gas cost allowance refund in the second quarter of 2005. Royalties have not increased significantly with strong commodity prices due to Crown royalty incentives.

	Three months ended June 30,		Six months ended June 30,	
ROYALTIES ($000s)	**2006**	2005	**2006**	2005
Crown	**4,218**	2,717	**11,520**	6,735
Freehold and other	**2,593**	1,358	**4,252**	2,214
Gross royalties	**6,811**	4,075	**15,772**	8,949
ARTC	**(125)**	(115)	**(250)**	(240)
Net royalties	**6,686**	3,960	**15,522**	8,709

	Three months ended June 30,		Six months ended June 30,	
ROYALTY RATES (as a % of net revenue)	**2006**	2005	**2006**	2005
Crown	**10.5**	8.8	**13.6**	11.4
Freehold and other	**6.4**	4.4	**5.0**	3.7
Gross royalties	**16.9**	13.2	**18.6**	15.1
ARTC	**(0.3)**	(0.4)	**(0.3)**	(0.4)
Net royalties	**16.6**	12.8	**18.3**	14.7

Operating costs increased 64% to $8.9 million during the second quarter 2006 from 2005 and 67% to $18.0 million in the first six months of 2006. In addition to the general rise in costs for services and supplies in the oil industry and high fuel and power costs, the increase was due to the acquisitions of Mustang and Forte and the transition into a Trust. The acquisition of Forte increased the Trust's operations in northeast B.C. and northern Alberta where operating costs are generally higher compared with central Alberta. In the current commodity price environment, low-rate, high cost wells that would otherwise be unprofitable continue to contribute to the overall production base.

	Three months ended June 30,		Six months ended June 30,	
OPERATING COSTS	**2006**	2005	**2006**	2005
Operating costs ($000s)	**8,881**	5,431	**18,036**	10,768
Per boe ($)	**10.49**	7.94	**10.32**	7.92

Gross general and administrative expenses (G&A) increased 55% to $3.2 million for the second quarter of 2006 and 64% to $6.5 million for the six months ended June 30, 2006 compared to the same periods in 2005 due to increased salaries and benefits and office space as a result of the transition into a Trust. Net G&A was $2.18 per boe and $2.14 per boe for the three and six months ended June 30, 2006 respectively. The increases over the corresponding prior periods was due to the increased size of the Trust as well as several budgeted, one-time costs such as audit and tax services, annual filing costs and consulting services.

Effective July 1, 2005, the Trust changed its policy for G&A expenses and now capitalizes indirect G&A related to acquisition, exploration and development activities. As a result, prior year G&A expenses have been restated.

	Three months ended June 30,		Six months ended June 30,	
G&A EXPENSES ($000s)	**2006**	2005	**2006**	2005
Gross G&A expenses	**3,222**	2,075	**6,545**	3,992
Capitalized G&A	**(887)**	(405)	**(1,658)**	(810)
Overhead recoveries				
Capital	**(195)**	(250)	**(555)**	(925)
Operating	**(290)**	(276)	**(599)**	(529)
Net G&A expenses	**1,850**	1,144	**3,733**	1,728

G&A EXPENSES ($/boe)				
Gross G&A expenses	**3.80**	3.03	**3.75**	2.94
Capitalized G&A	**(1.05)**	(0.59)	**(0.95)**	(0.60)
Overhead recoveries				
Capital	**(0.23)**	(0.37)	**(0.32)**	(0.68)
Operating	**(0.34)**	(0.40)	**(0.34)**	(0.39)
Net G&A expenses	**2.18**	1.67	**2.14**	1.27

Interest expense on bank debt increased 6% in the second quarter of 2006 compared to 2005 due to a higher effective interest rate. For the first six months of 2006 interest expense increased 39% compared to the same period in 2005 due to a higher average bank debt outstanding and a higher effective interest rate.

	Three months ended June 30,		Six months ended June 30,	
INTEREST EXPENSE ON BANK DEBT	**2006**	2005	**2006**	2005
Interest expense ($000s)	**1,165**	1,100	**2,607**	1,876
Average bank debt outstanding ($000s)	**84,608**	110,367	**110,885**	102,689
Effective annualized interest rate for the period (%)	**5.5**	4.0	**4.7**	3.7

Interest expense on convertible debentures was $1.3 million for the second quarter of 2006. Thunder issued convertible debentures of $75.0 million during the quarter. The net proceeds were used to repay bank debt.

Depletion, depreciation and accretion expense (DD&A) increased to $22.7 million in the second quarter and $47.1 million in the first six months of 2006. The increases reflect the rise in general industry costs and the reduction in proved reserves at year-end 2005. As required under full cost accounting, a ceiling test was performed at June 30, 2006 and it was determined that there was no impairment to the carrying value of the Trust's unamortized capitalized costs.

DD&A expense also includes the amortization of deferred financing costs of $0.2 million.

	Three months ended June 30,		Six months ended June 30,	
DD&A EXPENSE	**2006**	2005	**2006**	2005
DD&A expense ($000s)	**22,714**	11,494	**47,112**	22,454
Per boe ($)	**26.82**	16.80	**26.96**	16.51

Unit-based compensation expense was $0.2 million in the second quarter of 2006 and $0.8 million for the first six months of 2006, down from $0.9 million and $1.8 million in the corresponding periods of 2005. The Trust's unit-based compensation is determined based on the intrinsic value of the Trust units at each period end.

Provision for Income Taxes The Trust is a taxable entity under the Tax Act (Canada), but is taxable only on income that is not distributed or distributable to the unitholders. To the extent that cash distributions represent taxable distributions to unitholders, the distributions will reduce the Trust's future income tax expense. The Trust had a future income tax recovery of $25.0 million for the second quarter and $30.9 million for the six months ended June 30, 2006 primarily due to the estimated taxability of distributions as well as future tax rate reductions enacted by the federal and provincial governments during the quarter.

During the quarter the federal budget eliminated the large corporations tax effective for the 2006 taxation year. The current tax expense for 2006 represents payments due to prior period adjustments.

Funds from operations for the second quarter decreased 1% from the same period in 2005 to $18.9 million due to lower natural gas prices and higher operating costs and G&A expenses offset by increased oil and NGL prices and production. For the six months of 2006 funds from operations increased 17% from 2005 to $41.7 million due to strong commodity prices in the first quarter of 2006 and increased production reflecting Thunder's larger size following conversion into an energy trust.

	Three months ended June 30,		Six months ended June 30,	
FUNDS FROM OPERATIONS	**2006**	2005	**2006**	2005
Funds from operations ($000s)	**18,894**	19,168	**41,707**	35,767
Per unit – basic ($)	**0.40**	0.74	**0.89**	1.38
– diluted ($)	**0.36**	0.73	**0.79**	1.35

Net income increased 306% in the second quarter 2006 to $18.7 million and 186% to $22.5 million for the six months ended June 30 compared with the same periods in 2005. The increases are attributable to, amongst other things, future income tax recoveries offset by higher DD&A expenses.

	Three months ended June 30,		Six months ended June 30,	
NET INCOME	**2006**	2005	**2006**	2005
Net income ($000s)	**18,744**	4,621	**22,469**	7,864
Per unit – basic ($)	**0.39**	0.18	**0.48**	0.30
– diluted ($)	**0.36**	0.18	**0.43**	0.30

Asset retirement obligations are accrued by the Trust resulting from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. A reconciliation of the asset retirement obligations is provided below:

	Three months ended June 30,		Six months ended June 30,	
ASSET RETIREMENT OBLIGATIONS ($000s)	**2006**	2005	**2006**	2005
Balance, beginning of period	**25,431**	13,972	**24,774**	13,417
Liabilities incurred in the period	**167**	85	**400**	356
Liabilities settled in the period	**(205)**	(369)	**(390)**	(369)
Accretion expense	**611**	287	**1,220**	571
Balance, end of period	**26,004**	13,975	**26,004**	13,975

CAPITAL AND LIQUIDITY

Capital expenditures for the second quarter totalled $21.5 million and $39.7 million for the year-to-date. Drilling, completion, equipping and tie-in costs totalled $30.8 million for the six month period for the drilling of 23 gas wells (11.6 net), seven oil wells (4.8 net), and six dry holes (3.6 net). The Trust's drilling success ratio was 82%. The following table breaks out the capital expenditures by category:

	Three months ended June 30,		Six months ended June 30,	
CAPITAL EXPENDITURES SUMMARY ($000s)	**2006**	2005	**2006**	2005
Land and rentals	**643**	1,474	**1,925**	2,302
Seismic	**998**	649	**1,881**	4,037
Drilling and completions	**12,868**	2,752	**25,414**	24,242
Well equipping and tie-in	**2,532**	5,522	**5,384**	10,514
Facilities and gas gathering	**214**	(678)	**694**	822
Other, including capitalized G&A	**4,275**	412	**4,415**	793
Total oil and gas capital expenditures	**21,530**	10,131	**39,713**	42,710
Deferred transaction costs	**–**	2,312	**–**	2,312
Total capital expenditures	**21,530**	12,443	**39,713**	45,022

Liquidity For the six months ended June 30, 2006, capital expenditures of $39.7 million, the settlement of asset retirement obligations of $0.4 million, a combined decrease to long-term debt and working capital of $50.3 million and cash distributions (net of DRIP) of $22.9 million were funded by funds from operations of $41.7 million and net proceeds from convertible debentures of $71.6 million.

The Trust has a credit facility with a syndicate of chartered banks consisting of a $145.0 million revolving term credit facility and a $15.0 million operating credit facility. The credit facilities are available on a revolving basis and subject to extension annually with the agreement of the lenders. The credit facilities are collateralized by the Trust's assets and are subject to semi-annual review at which time the lenders may re-determine the borrowing base. The next scheduled semi-annual review is scheduled for October 31, 2006.

Management anticipates that Thunder will continue to have adequate liquidity to fund future working capital and forecasted capital expenditures during 2006 through a combination of cash flow, debt and equity. Cash flow used to finance these commitments may reduce the amount of cash distributions paid to unitholders.

Convertible Debentures

On April 5, 2006, the Trust issued $75.0 million principal amount of 7.25% Convertible Unsecured Subordinated Debentures (the "Debentures") for net proceeds of $71.6 million. The Debentures have a conversion price of $11.70 per Trust unit and a maturity date of April 30, 2011. The Debentures pay interest semi-annually in arrears on April 30 and October 31 each year, commencing October 31, 2006. The Debentures will not be redeemable by the Trust prior to April 30, 2009. The Debentures are redeemable by the Trust, on not more than 60 days and not less than 30 days prior notice, at a price of $1,050 per Debenture after April 30, 2009 and on or before April 30, 2010, and at a price of $1,025 per Debenture after April 30, 2010 and before the maturity date, in each case, plus accrued and unpaid interest thereon, if any. On redemption or maturity the Trust may elect to satisfy its obligations to repay the principal and may satisfy its interest obligations by issuing Thunder Energy Trust units. The Debentures are traded on the Toronto Stock Exchange under the trading symbol THY.DB.

The Debentures have been classified as debt net of the fair value of the conversion feature at the date of issue, which has been classified as part of unitholders' equity. The debt portion will accrete up to the principal balance at maturity. Issue costs have been classified under deferred financing charges and are being amortized over the term of the Debentures. If the Debentures are converted into units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to Trust units along with the conversion price paid. The following table sets forth a reconciliation of the Debenture activity:

	As at June 30,
CONVERTIBLE DEBENTURES ($000s)	**2006**
Debt portion on April 5, 2006	**73,298**
Accretion of non-cash interest	**67**
Debt portion, end of period	**73,365**
Equity portion	**1,702**
Total Debentures, end of period	**75,067**

Distributable Cash and Distributions

Management monitors the Trust's distribution payout policy with respect to forecasted net cash flow, debt levels and capital expenditures. During the second quarter of 2006, 97% of funds from operations before the distribution reinvestment plan ("DRIP") were distributed, 50% after DRIP. For the six months ended June 30, 2006, 93% of funds from operations before the distribution reinvestment plan ("DRIP") were distributed, 52% after DRIP. Exchangeable shares are convertible into Trust units based on the Exchange Ratio, which is adjusted monthly to reflect that distributions are not paid on the exchangeable shares and cash flow related to the exchangeable shares is retained by the Trust for additional capital expenditures or debt repayment. The key drivers of the Trust's cash flow, as is generally the case with other energy trusts, are commodity prices and production.

The amount of distributable cash is calculated in accordance with the Trust's indenture. Distributable cash is not a measure under GAAP and there is no standard measure of distributable cash. Distributable cash, as presented, may not be comparable to similar measures presented by other trusts.

	Three months ended June 30,	Six months ended June 30,
DISTRIBUTIONS ($000s, except per unit amounts)	**2006**	**2006**
Funds from operations	**18,894**	**41,707**
Cash used to fund capital expenditures	**(8,890)**	**(18,792)**
Distributable cash	**10,004**	**22,915**
Cash distributions declared and payable at June 30, 2006	**5,703**	**5,703**
Cash distributions paid	**10,004**	**22,915**
Total distributions, including amounts reinvested under the distribution reinvestment program	**18,303**	**38,788**
Cash distributions payable per unit ($)	**0.12**	**0.12**
Cash distributions paid per unit ($)	**0.27**	**0.72**
Accumulated cash distributions paid and payable per unit ($)	**0.39**	**0.84**

DISTRIBUTIONS DECLARED ($000s)	Cash distributions	DRIP	Total
Balance December 31, 2005	34,362	4,384	38,746
January distribution	4,501	2,248	6,749
February distribution	4,127	2,705	6,832
March distribution	3,554	3,350	6,904
Balance March 31, 2006	46,544	12,687	59,231
April distribution	3,543	3,428	6,971
May distribution	2,907	2,722	5,629
June distribution	2,987	2,716	5,703
Balance June 30, 2006	**55,981**	**21,553**	**77,534**

TAX TREATMENT OF DISTRIBUTIONS

The Trust has provided to unitholders general comments regarding the taxability of distributions but does not intend to provide legal or tax advice. Trust unitholders, exchangeable shareholders, or potential investors should seek their own legal or tax advice in this regard.

For the year ended December 31, 2005, Trust distributions provided an 81% return on capital and 19% return of capital. For the six months ended June 30, 2006, the Trust's distributions provided an 88% return on capital and a 12% return of capital.

RELATED PARTY TRANSACTIONS

During the three and six months ended June 30, 2006, the Trust incurred expenditures of $0.2 million and $0.3 million respectively for general corporate legal fees to a legal firm of which a director is a partner. Legal fees were included in general and administrative expenses, debenture issue costs, property and equipment and unit issue costs. At June 30, 2006, there were no amounts payable. The related party transactions were recorded at the exchange amount as services were provided in the normal course of business under the same terms and conditions as transactions with unrelated companies.

QUARTERLY INFORMATION

The following table is a summary of quarterly results for the last eight quarters relating to the years 2006, 2005 and 2004. Because the consolidated financial statements of the Trust have been prepared on a continuity of interest basis which recognized the Trust as the successor to Thunder Energy, results prior to July 7, 2005 may not be directly comparable to those of the Trust.

The Trust recorded a write-down of the carrying value of its petroleum and natural gas property and equipment in the fourth quarter of 2005 resulting in a net loss of $25.4 million. Declines in natural gas prices in the first and second quarter of 2006 resulted in lower revenues and distributable cash from the fourth quarter of 2005. The Trust recognized a future tax recovery of $25.0 million in the second quarter of 2006 related to a reduction in future federal and provincial income tax rates as well as the taxability of distributions.

QUARTERLY INFORMATION	2004		2005				**2006**	
($000s, except per unit data)	Q3	Q4	Q1	Q2	Q3	Q4	Q1	**Q2**
Petroleum and natural gas sales	28,245	29,049	29,350	32,729	65,866	67,833	46,242	**41,504**
Funds from operations	15,908	15,525	16,599	19,168	35,037	39,587	22,813	**18,894**
Per unit – basic ($)	0.63	0.61	0.64	0.74	0.79	0.86	0.50	**0.40**
– diluted ($)	0.62	0.60	0.63	0.73	0.79	0.85	0.49	**0.36**
Net income	3,542	1,407	3,243	4,621	7,718	(25,433)	3,725	**18,744**
Per unit – basic ($)	0.14	0.06	0.13	0.18	0.17	(0.55)	0.08	**0.39**
– diluted ($)	0.14	0.05	0.12	0.18	0.17	(0.55)	0.08	**0.36**

CONSOLIDATED BALANCE SHEETS

($000s) (unaudited)	June 30, 2006	December 31, 2005
Assets (Note 4)		
Current		
Accounts receivable	**$ 45,145**	$ 49,810
Commodity contracts (Note 8)	**1,516**	–
Prepaid expenses	**1,192**	1,219
	47,853	51,029
Deferred financing costs (Note 5)	**3,238**	–
Property and equipment	**652,525**	658,069
Goodwill	**108,292**	108,292
	$ 811,908	$ 817,390
Liabilities and Unitholders' Equity		
Current		
Bank indebtedness	**$ 5,227**	$ 4,409
Accounts payable and accrued liabilities	**50,302**	57,542
Distributions payable	**5,703**	6,595
Commodity contracts (Note 8)	**3,775**	–
	65,007	68,546
Bank debt (Note 4)	**87,794**	136,359
Convertible debentures (Note 5)	**73,365**	–
Unit-based compensation (Note 7)	**2,047**	1,295
Asset retirement obligations (Note 6)	**26,004**	24,774
Future income taxes (Note 9)	**115,995**	146,876
	370,212	377,850
Unitholders' equity		
Unitholders' capital (Note 7)	**428,114**	411,341
Equity component of convertible debentures (Note 5)	**1,702**	–
Contributed surplus	**3,025**	3,025
Retained earnings	**8,855**	25,174
	441,696	439,540
	$ 811,908	$ 817,390

See accompanying notes

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
($000s, except per share data) (unaudited)	**2006**	2005	**2006**	2005
		(restated – Note 3)		(restated – Note 3)
Revenue				
Petroleum and natural gas sales	**$ 41,504**	$ 32,729	**$ 87,746**	$ 62,079
Royalties, net of ARTC	**(6,686)**	(3,960)	**(15,522)**	(8,709)
Transportation expenses	**(1,201)**	(1,691)	**(2,911)**	(2,818)
Petroleum and natural gas sales, after royalties and transportation	**33,617**	27,078	**69,313**	50,552
Realized net loss on commodity contracts (Note 8)	**(1,226)**	–	**(1,226)**	–
Unrealized net loss on commodity contracts (Note 8)	**(2,259)**	–	**(2,259)**	–
Petroleum and natural gas sales, net	**30,132**	27,078	**65,828**	50,552
Expenses				
Operating	**8,881**	5,431	**18,036**	10,768
General and administrative	**1,850**	1,144	**3,733**	1,728
Unit-based compensation (Note 7)	**204**	905	**752**	1,790
Interest on bank debt	**1,165**	1,100	**2,607**	1,876
Interest on convertible debentures	**1,294**	–	**1,294**	–
Depletion, depreciation and accretion	**22,714**	11,494	**47,112**	22,454
	36,108	20,074	**73,534**	38,616
Income (loss) before income taxes	**(5,976)**	7,004	**(7,706)**	11,936
Provision for income taxes (recovery) (Note 9)	**(24,720)**	2,383	**(30,175)**	4,072
Net income for the period	**18,744**	4,621	**22,469**	7,864
Accumulated distributions	**(77,534)**	–	**(77,534)**	–
Retained earnings				
Beginning of period	**67,645**	77,014	**63,920**	73,771
End of period	**$ 8,855**	$ 81,635	**$ 8,855**	$ 81,635
Units and exchangeable shares outstanding (weighted average)				
Basic	**47,491**	25,954	**46,762**	25,900
Diluted	**54,534**	26,365	**53,806**	26,438
Net income per unit (Note 7)				
Basic	**$ 0.39**	$ 0.18	**$ 0.48**	$ 0.30
Diluted	**$ 0.36**	$ 0.18	**$ 0.43**	$ 0.30

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended June 30,		Six months ended June 30,	
($000s) (unaudited)	**2006**	2005	**2006**	2005
		(restated – Note 3)		(restated – Note 3)
Operating Activities				
Net income for the period	$ 18,744	$ 4,621	$ 22,469	$ 7,864
Add items not requiring cash:				
Unit-based compensation (Note 7)	204	905	752	1,790
Unrealized loss on commodity contracts (Note 8)	2,259	–	2,259	–
Depletion, depreciation and accretion	22,714	11,494	47,112	22,454
Future income taxes (Note 9)	(25,027)	2,148	(30,885)	3,659
Funds from operations	18,894	19,168	41,707	35,767
Settlement of asset retirement obligations	(205)	(369)	(390)	(369)
Changes in non-cash working capital related to operating activities (Note 10)	(17,107)	11,775	(9,526)	(26,742)
Cash provided by operating activities	1,582	30,574	31,791	8,656
Financing Activities				
Issue of units for cash, net of costs	–	684	12	834
Convertible debenture issue costs	(3,406)	–	(3,406)	–
Proceeds on convertible debentures	75,000	–	75,000	–
Increase (decrease) in bank indebtedness	(2,313)	(10,399)	818	1,388
Increase (decrease) in bank debt	(54,025)	(4,908)	(48,565)	25,062
Cash distributions	(10,004)	–	(22,915)	–
Cash provided by (used in) financing activities	5,252	(14,623)	944	27,284
Investing Activities				
Expenditures on property and equipment	(21,530)	(10,131)	(39,713)	(42,710)
Deferred transaction costs	–	(2,312)	–	(2,312)
Changes in non-cash working capital related to investing activities (Note 10)	14,696	(6,754)	6,978	9,061
Cash used in investing activities	(6,834)	(19,197)	(32,735)	(35,961)
Net change in cash position	–	(3,246)	–	(21)
Cash position – beginning of period	–	3,246	–	21
Cash position – end of period	$ –	$ –	$ –	$ –

See accompanying notes

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. BASIS OF PRESENTATION

The interim consolidated financial statements of Thunder Energy Trust (the "Trust") have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2005, except that certain disclosures required in annual financial statements have been condensed or omitted.

The interim consolidated financial statements should be read in conjunction with the Trust's consolidated financial statements and notes as at and for the year ended December 31, 2005. The results of operations for the three and six months ended June 30, 2006 may not be indicative of the results for the 2006 fiscal year.

The Trust was established as part of a Plan of Arrangement (the "Arrangement"), which became effective on July 7, 2005. The Arrangement gave effect to the transaction completed with Thunder Energy Inc. ("Thunder Energy"), Mustang Resources Inc. ("Mustang") and Forte Resources Inc. ("Forte") to combine the entities to create a new oil and gas trust, two exploration-focused production companies: Alberta Clipper Energy Inc. ("Clipper") and Valiant Energy Inc. ("Valiant"); and a resource-based coalbed methane company, Ember Resources Inc. ("Ember"). As a result of the combination, shareholders of Thunder Energy received 0.5 Trust units or exchangeable shares of the Trust, 0.3333 common shares of Clipper and 0.3333 common shares of Ember. The Trust accounted for Mustang and Forte as acquisitions under the purchase method of accounting. Certain Mustang assets acquired by Thunder Energy were transferred to Clipper. As the former Thunder Energy shareholders had the majority of the voting control of Clipper, Ember and the Trust (including its subsidiaries), the transfer of assets and liabilities from Thunder Energy to Clipper and Ember was accounted for at Thunder Energy's net book value; the transfer of the Mustang assets to Clipper was at fair value, being Thunder Energy's acquisition cost.

The conversion of Thunder Energy to a trust was accounted for on a continuity of interest basis. Due to the conversion into a trust, certain information included in the consolidated financial statements for prior periods may not be directly comparable.

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after July 7, 2005 as well as the common shares of Thunder Energy outstanding prior to the conversion on July 7, 2005.

2. ACCOUNTING POLICIES

The Trust is exposed to market risks resulting from fluctuations in commodity prices in the normal course of its business. The Trust may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, the Trust accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in income as an unrealized gain or loss on commodity contracts. Fair values of financial instruments are determined from third party quotes or valuations provided by independent third parties. Any realized gains or losses on commodity contracts are recognized in income in the period they occur. The Trust may elect to use hedge accounting when there is a high degree of correlation between the price movements in the financial instruments and the items designated as being hedged and it has documented the relationship between the instruments and the hedged item as well as its risk management objective and strategy.

3. CHANGE IN ACCOUNTING POLICY

Effective July 1, 2005, the Trust changed its accounting policy for general and administrative (G&A) expenses in order to better reflect the cost of bringing assets on production. Formerly the Trust expensed all indirect G&A expenses related to acquisition, exploration and development activities. Under the new policy, certain salaries and benefits related to these activities are being included in the full cost pool and depleted. The effect of this change in accounting policy has been recorded retroactively with restatement of prior periods. The effect of the adoption is presented below as increases (decreases):

	Three months ended June 30,	Six months ended June 30,
INCOME STATEMENT ($000s, except per unit data)	2005	2005
General and administrative expenses	$ (405)	$ (810)
Depletion, depreciation, and accretion expense	128	245
Future income tax expense	48	92
Net income impact	$ 229	$ 473
Net income per unit – basic	$ 0.01	$ 0.02
– diluted	$ 0.01	$ 0.02

4. BANK DEBT

The Trust has a credit facility with a syndicate of chartered banks consisting of a $145 million extendible revolving term credit facility and a $15 million operating credit facility. The credit facilities are available on a revolving basis and are subject to extension annually with the agreement of the lenders. The credit facilities bear interest at the lenders' prime rate or bankers' acceptance rates plus an applicable margin, based on the debt to cash flow ratio. The credit facilities are collateralized by a $500 million demand debenture providing for a fixed and floating charge over the petroleum and natural gas properties and all other assets of the Trust and are subject to semi-annual review, at which time the lenders may re-determine the borrowing base. The effective annualized interest rates for the three and six months ended June 30, 2005 were 5.5% and 4.7%, respectively (2005 – 4.0% and 3.7%).

5. CONVERTIBLE DEBENTURES

On April 5, 2006, the Trust issued $75.0 million principal amount of 7.25% Convertible Unsecured Subordinated Debentures (the "Debentures") for net proceeds of $71.6 million. The Debentures have a conversion price of $11.70 per Trust unit and a maturity date of April 30, 2011. The Debentures pay interest semi-annually in arrears on April 30 and October 31 each year, commencing October 31, 2006. The Debentures will not be redeemable by the Trust prior to April 30, 2009. The Debentures are redeemable by the Trust, on not more than 60 days and not less than 30 days prior notice, at a price of $1,050 per Debenture after April 30, 2009 and on or before April 30, 2010, and at a price of $1,025 per Debenture after April 30, 2010 and before the maturity date, in each case, plus accrued and unpaid interest thereon, if any. On redemption or maturity the Trust may elect to satisfy its obligations to repay the principal and may satisfy its interest obligations by issuing Thunder Energy Trust units. The Debentures are traded on the Toronto Stock Exchange under the trading symbol THY.DB.

The Debentures have been classified as debt net of the fair value of the conversion feature at the date of issue, which has been classified as part of unitholders' equity. The debt portion will accrete up to the principal balance at maturity. Issue costs have been classified under deferred financing charges and are being amortized over the term of the Debentures. If the Debentures are converted into units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to Trust units along with the conversion price paid. The following table sets forth a reconciliation of the Debenture activity:

	As at June 30,
CONVERTIBLE DEBENTURES ($000s)	**2006**
Debt component on April 5, 2006	**$ 73,298**
Accretion of non-cash interest in the period	**67**
Debt portion, end of period	**73,365**
Equity component	**1,702**
Total Debentures, end of period	**$ 75,067**

6. ASSET RETIREMENT OBLIGATIONS

The Trust's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Trust estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations to be approximately $53.0 million which will be incurred between the years 2006 and 2034. The majority of the costs are expected to be incurred between 2010 and 2034. A credit-adjusted risk-free rate of 9.0% and an inflation rate of 1.5% were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	Three months ended June 30,		Six months ended June 30,	
ASSET RETIREMENT OBLIGATIONS ($000s)	**2006**	2005	**2006**	2005
Balance, beginning of period	**$ 25,431**	$ 13,972	**$ 24,774**	$ 13,417
Liabilities incurred in the period	**167**	85	**400**	356
Liabilities settled in the period	**(205)**	(369)	**(390)**	(369)
Accretion expense	**611**	287	**1,220**	571
Balance, end of period	**$ 26,004**	$ 13,975	**$ 26,004**	$ 13,975

7. UNITHOLDERS' CAPITAL

(a) Trust Units of Thunder Energy Trust

The Trust Indenture provides that an unlimited number of Trust units may be authorized and issued. Each Trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the assets of the Trust in the event of termination or winding-up of the Trust. All Trust units are of the same class with equal rights and privileges.

TRUST UNITS OF THUNDER ENERGY TRUST	Number of units (000s)	($000s)
Balance December 31, 2004	–	$ –
Issued for common shares of Thunder Energy	24,246	174,050
Issued on Forte acquisition	6,475	99,288
Issued on Mustang acquisition	9,607	123,810
Reduction of capital, Ember conveyance	–	(19,893)
Reduction of capital, Clipper conveyance	–	(28,047)
Issued for cash on exercise of stock options	1,921	19,332
Stock-based compensation on options	–	7,080
Exchangeable shares converted	1,543	14,713
Unit issue costs, net of tax of $2,353	–	(6,445)
DRIP	175	2,072
Balance December 31, 2005	43,967	$ 385,960
Unit issue costs, net of tax of $4	–	8
DRIP	697	7,265
Exchangeable shares converted	1,364	14,676
Balance March 31, 2006	46,028	$ 407,909
DRIP	1,031	9,500
Issued on exercise of Restricted Trust Units	104	–
Exchangeable shares converted	491	5,023
Balance June 30, 2006	**47,654**	**$ 422,432**

The Trust has a distribution reinvestment program ("DRIP") whereby unitholders can elect to reinvest their distributions back into the Trust and receive additional units rather than receive the cash payment. This accounted for a $16.8 million increase in unitholders' capital for the six months ended June 30, 2006.

(b) Exchangeable Shares of Thunder Energy Trust

Authorized: unlimited number of exchangeable shares

EXCHANGEABLE SHARES	Number of units (000s)	($000s)
Balance December 31, 2004	–	$ –
Issued for common shares of Thunder Energy	1,759	13,030
Issued on Forte acquisition	927	14,215
Issued on Mustang acquisition	997	12,849
Exchanged for Trust units	(1,495)	(14,713)
Balance December 31, 2005	2,188	$ 25,381
Exchanged for Trust units	(1,265)	(14,676)
Balance March 31, 2006	923	$ 10,705
Exchanged for Trust units	(433)	(5,023)
Balance June 30, 2006	**490**	**$ 5,682**

Exchangeable shares accrue notional distributions in-kind and are convertible into Trust units at the shareholder's option. Exchangeable shares are non-transferable and are ultimately required to be exchanged for units of the Trust.

The exchangeable shares are not entitled to cash distributions. The Exchange Ratio increases on a monthly basis. The increase in the Exchange Ratio is calculated by multiplying the Thunder Energy Trust distribution per unit by the Exchange Ratio immediately prior to the Record Date and dividing by the weighted average trading price per unit of THY.UN on the TSX for the five trading days preceding the Record Date. A holder of Thunder Energy Inc. exchangeable shares can exchange all or a portion of their holdings into Thunder Energy Trust units, at any time by giving notice to their investment advisor or the Trust Agent. The Exchange Ratio to convert each exchangeable share to a Trust unit was 1.00000 at the time of issuance. Effective June 30, 2006, the Exchange Ratio was 1.14861. If the 0.5 million exchangeable shares outstanding at June 30, 2006 were exchanged at that time, 0.6 million Trust units would have been issued.

(c) Unit-based Compensation

For the three and six months ended June 30, 2006, the Trust recorded a compensation expense relating to its Trust Unit Incentive Plan of $0.3 million and $0.9 million, respectively (2005 – $0.9 million and $1.8 million). The compensation expense was based on the June 30, 2006 unit closing price of $8.33, distributions of $0.15 per unit in January, February, March, and April and a $0.12 distribution in May and June as well as management's estimate of the number of Restricted Trust Units ("RTUs") and Performance Trust Units ("PTUs") to be issued on maturity. No estimate has been made for forfeitures. The following table summarizes the RTU and PTU movement for the three and six months ended June 30, 2006.

RESTRICTED AND PERFORMANCE TRUST UNITS (000s)	RTUs	PTUs
Balance December 31, 2004	–	–
Granted	283	59
Balance December 31, 2005	283	59
Granted	6	1
Cancelled	(3)	(1)
Balance March 31, 2006	286	59
Granted	224	104
Cancelled	(3)	–
Redeemed	(103)	–
Balance June 30, 2006	**404**	**163**

(d) Per Unit Amounts

Diluted Trust units include the dilutive impact of units issuable under the Trust Unit Incentive Plan and include the effect of the convertible debentures which included an adjustment to the numerator of $0.8 million for the three and six months ended June 30, 2006.

8. FINANCIAL INSTRUMENTS

The Trust entered into the following financial transactions to mitigate its exposure to future fluctuations in commodity prices.

Gas Contracts	Volume (GJ/d)	Pricing Point	Strike Price ($/GJ)	Term
Costless Collar	15,000	AECO	Cdn$6.00 to Cdn$6.50	April 1/06 to Oct 31/06
Costless Collar	10,000	AECO	Cdn$8.00 to Cdn$10.00	Nov 1/06 to March 31/07

Oil Contracts	Volume (bbls/d)	Pricing Point	Strike Price ($/bbl)	Term
Costless Collar	2,400	WTI NYMEX	US$61.00 to US$64.40	April 1/06 to June 30/06
Costless Collar	2,400	WTI NYMEX	US$61.00 to US$67.50	July 1/06 to Sept 30/06
Costless Collar	800	WTI NYMEX	US$61.00 to US$72.70	Oct 1/06 to Dec 31/06
Costless Collar	800	WTI NYMEX	US$65.00 to US$80.70	Oct 1/06 to Dec 31/06
Costless Collar	800	WTI NYMEX	US$61.00 to US$73.05	Jan 1/07 to Mar 31/07
Costless Collar	800	WTI NYMEX	US$65.00 to US$80.00	Jan 1/07 to Mar 31/07

Subsequent to June 30, 2006, the Trust entered into the following financial transaction to mitigate its exposure to future fluctuations in natural gas prices.

Gas Contracts	Volume (GJ/d)	Pricing Point	Strike Price ($/GJ)	Term
Costless Collar	10,000	AECO	Cdn$8.00 to Cdn$9.40	Nov 1/06 to March 31/07

9. INCOME TAXES

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. To the extent that cash distributions represent taxable distributions to the unitholders, the distributions will reduce the Trust's future income tax expense. Income taxes recorded in the consolidated statements of income and accumulated earnings differ from the tax calculated by applying the combined Canadian corporate federal and provincial income tax rate to income before taxes as follows:

	Three months ended June 30,		Six months ended June 30,	
INCOME TAXES ($000s)	**2006**	2005	**2006**	2005
Statutory income tax rate for the period	**34.81%**	37.75%	**35.03%**	37.75%
Computed income tax expense	**$ (2,080)**	$ 2,644	**$ (2,699)**	$ 4,506
Add (deduct) income tax effect of:				
Non deductible Crown charges, net of ARTC	**(43)**	471	**(88)**	1,141
Resource allowance	**–**	(789)	**–**	(1,637)
Estimated taxable distribution	**(6,244)**	–	**(11,997)**	–
Tax rate adjustments	**(16,733)**	(521)	**(16,385)**	(1,047)
Unit-based compensation	**66**	342	**263**	676
Other	**7**	1	**21**	20
Future income tax	**(25,027)**	2,148	**(30,885)**	3,659
Large corporations tax	**307**	235	**710**	413
Provision for income taxes	**$ (24,720)**	$ 2,383	**$ (30,175)**	$ 4,072

10. SUPPLEMENTAL CASH FLOW INFORMATION

	Three months ended June 30,		Six months ended June 30,	
SUPPLEMENTAL CASH FLOW INFORMATION ($000s)	**2006**	2005	**2006**	2005
Changes in non-cash working capital:				
Accounts receivable	**$ 3,004**	$ 3,409	**$ 4,665**	$ 9,539
Prepaid expenses	**194**	51	**27**	381
Accounts payable and accrued liabilities	**(5,609)**	1,573	**(7,240)**	(27,601)
Capital lease payment included in capital expenditures on property and equipment	**–**	(12)	**–**	–
	$ (2,411)	$ 5,021	**$ (2,548)**	$ (17,681)
Changes in non-cash working capital:				
Operating activities	**(17,107)**	11,775	**$ (9,526)**	$ (26,742)
Investing activities	**14,696**	(6,754)	**6,978**	9,061
	$ (2,411)	$ 5,021	**$ (2,548)**	$ (17,681)
Cash payments made for interest	**$ 1,080**	$ 1,184	**$ 2,907**	$ 2,096
Cash payments made for taxes	**$ 816**	$ 61	**$ 1,585**	$ 61

11. RELATED PARTY TRANSACTIONS

During the three and six months ended June 30, 2006, the Trust incurred expenditures of $0.2 million and $0.3 million, respectively for general corporate legal fees to a legal firm of which a director is a partner. Legal fees were included in general and administrative expenses, debenture issue costs, property and equipment and unit issue costs. At June 30, 2006, there were no amounts payable. The related party transactions were recorded at the exchange amount as services were provided in the normal course of business under the same terms and conditions as transactions with unrelated companies.

CORPORATE INFORMATION

DIRECTORS

DOUGLAS A. DAFOE, C.A.(2) (4) (5)
Chairman of the Board,
Chairman and Chief Executive Officer,
Ember Resources Inc.

COLIN D. BOYER, P. Eng(1) (3)
President,
Birchill Resources Partnership

JOHN CLARK(1) (5)
President,
Investments and Technical
Management Corp.

STUART J. KECK, P. Eng(4)
President and Chief Executive Officer,
Thunder Energy Trust

THOMAS J. MACKAY(3) (4)
Chairman and Chief Executive Officer,
Valiant Energy Inc.

PATRICK MILLS(1) (3)
President and Chief Executive Officer,
Pegasus Oil and Gas Inc.

JAMES M. PASIEKA(2)
Barrister & Solicitor,
Heenan Blaikie LLP

RICHARD A. M. TODD(2) (5)
President and Chief Executive Officer,
Todd Properties Inc.

(1) Audit Committee
(2) Compensation Committee
(3) Reserve Evaluation Committee
(4) Health, Safety and Environment Committee
(5) Hedging Committee

OFFICERS

STUART J. KECK, P. Eng
President and Chief Executive Officer

BRENT T. KIRKBY, CMA
Vice President, Finance
and Chief Financial Officer

STEVEN R. GELL, P. Eng
Vice President, Production

G.L. (GERRY) BOYER, P. Eng
Vice President, Engineering

BRAD CROWE
Vice President, Land

TONY CADRIN, Ph.D., P. Geol.
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Calgary, Alberta

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CIBC
ATB Financial
Société Générale
Calgary, Alberta

TRANSFER AGENT
AND REGISTRAR

Olympia Trust Company
Calgary, Alberta

STOCK LISTING

The Toronto Stock Exchange
Symbol: THY.UN, THY.DB

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit	mbbl	thousand barrels
bbl	barrels of oil or natural gas liquids	mmbbl	million barrels
bcf	billion cubic feet of natural gas	mboe	thousand barrels of oil equivalent
boe	barrels of oil equivalent (6,000 cubic feet of natural gas is equivalent to one barrel of oil)	mcf	thousand cubic feet of natural gas
		mmcf	million cubic feet of natural gas
/d	per day	mmbtu	million British thermal units
GJ	gigajoule	NGL	natural gas liquids

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