ENERNORTH INDUSTRIES INC.

FORM 51-101F1

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The following information is related to our estimated reserves, estimated future net revenue and discounted value of estimated future net cash flow of oil and natural gas using constant and forecast prices as determined by our independent engineering evaluators, Sproule Associates Limited ("Sproule") a member of the Association of Professional Engineers Geologists and Geophysicists of Alberta, Canada. The information set forth below is derived from the Sproule report and has been prepared in accordance with the standards contained in the COGE Handbook and with the requirements of National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities. The estimate of our proved reserves, on a constant-pricing basis, and their associated net present values, have been based on the June 30, 2005 actual posted commodity prices on as determined by ("Sproule"). Appropriate adjustments have been made to account for quality and transportation, to the constant natural gas prices, and to the constant natural gas by-products prices to reflect historical prices received for each area.

All of the Company's Petroleum and Natural Gas reserves covered by this report are located in the Provinces of Alberta, British Columbia, Saskatchewan and Ontario, Canada.

All monetary references contained in this Statement of Reserves Data and Other Oil and Gas Information are in Canadian dollars unless otherwise specified.

In certain instances, numbers may not total due to computer-generated rounds. In such cases differences are not material.

FORWARD LOOKING STATEMENTS

This Statement of Reserves Data and Other Oil and Gas Information contain forward-looking statements. These statements relate to future events on EnerNorth's future performance. All statements other than statements of historical fact are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology. These statements are only predictions. Actual events or results may differ materially. Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur.

Although EnerNorth believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. EnerNorth cannot guarantee future results, levels of activity, performance, or achievements. Moreover, EnerNorth does not assume responsibility for the accuracy and completeness of the forward-looking statements.

Statements relating to "reserves" or "resources" are deemed forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. All forward-looking statements contained in this Statement of Reserves Data and Other Oil and Gas Information are expressly qualified by this cautionary statement. EnerNorth is not under any duty to update any of the forward-looking statements after the date hereof to conform such statements to actual results or to changes in EnerNorth's expectations unless required by securities law.

GLOSSARY OF TERMS

Natural Gas

Mcf	1,000 cubic feet
MMcf	1,000,000 cubic feet
Mcf/d	1,000 cubic feet per day
MMcf/d	1,000,000 cubic feet per day
McfGE	oil to gas in the ratio of 1 barrel of oil to six thousand cubic feet of gas (1 bbl: 6 Mcf)
Bcf	1,000,000,000 cubic feet
GJ	Gigajoules

Oil and Natural Gas Liquids

Bbl	Barrel
Mbbls	1,000 barrels
Blpd	Barrels of liquid per day
Boe	Barrel of oil equivalent (1)
Mboe	1,000 boe
Mmboe	1,000,000 boe
Bpd	Barrels per day
Boepd	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
NGLs	Natural gas liquids
Stb	Stock tank barrels of oil (oil volume at 60 degrees F and 14.65 pounds per square inch absolute)
Mstb	1,000 stock tank barrels

(1) A BOE conversion ratio 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. Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation.

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
Metres	cubic feet	35.494
Bbls	cubic metres	0.159
Cubic metres	Bbls	6.2901
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

PART 1
DATE OF STATEMENT

Relevant Dates:

1. Date of Statement: September 25, 2006
2. Effective Date of Statement: June 30, 2006
3. Preparation Date of Statement: September 19, 2006

PART 2
DISCLOSURE OF RESERVES DATA

Item 2.1 Reserves Data (Constant Prices and Costs):

1. Breakdown of Proved Reserves:

Table 6 attached– Constant Prices

2. Net Present Value of Future Net Revenue:

Table 7 attached – Constant Prices

3. Additional Information Concerning Future Net Revenue:

Table 8 attached – Constant Prices

Table 9 attached – Constant Prices

Item 2.2 Reserves Data (Forecast Prices and Costs):

1. Breakdown of Reserves:

Table 1 attached – Forecast prices

2. Net Present Value of Future Net Revenue:

Table 2 attached – Forecast prices

3. Additional Information Concerning Future Net Revenue:

Table 3 attached – Forecast prices

Table 4 attached – Forecast prices

Item 2.3 Reserves Disclosure Varies With Accounting:

Not Applicable

Item 2.4 Future Net Revenue Disclosure Varies With Accounting:

Not Applicable

PART 3
PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used in Estimates:

The estimate of our proved reserves on a constant-pricing basis, and their associated net present values, have been based on the June 30, 2006 actual posted commodity prices on as determined by our independent engineering evaluators, Sproule Associates Limited ("Sproule"). Appropriate adjustments have been made to account for quality and transportation, to the constant natural gas prices, and to the constant natural gas by-products prices to reflect historical prices received for each area. The table below sets out the constant prices and exchange rate used.

Oil:	Edmonton Par	84.49$/stb
	Cromer Medium	78.16$/stb
Natural Gas:	Alberta AECO-C	5.05$/Mcf
	British Columbia Average Wellhead	4.05$/Mcf
Natural Gas by-Products:	Propane	47.22$/bbl
	Butanes	63.92$/bbl
	Pentanes Plus	83.32$/bbl
	Sulphur	40.00$/lt
Exchange Rate:		0.896$US/$CDN

Item 3.2 Forecasted Prices Used in Estimates:

(a) Table 5 attached - Forecast Prices as prepared by Sproule Associates Limited

(b) The Company's weighted average historical prices for the year ended June 30, 2006 were as follows:

Oil:	$67.01/bbl
Natural Gas:	$9.08/mcf
Natural Gas Liquids:	$48.05/bbl

PART 4
RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Item 4.1 Reserves Reconciliation:

Table 11 attached – Forecast Prices and Costs

Item 4.2 Future Net Revenue Reconciliation:

RECONCILIATION OF THE CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED AT 10% BASED ON CONSTANT PRICES AND COSTS ATTRIBUTED TO PROVED RESERVES

The following table sets forth changes between future net revenue estimates attributable to net proved reserves as at June 30, 2005 against such reserves as at June 30, 2006 in thousands.

Canada	
Estimated Future Net Revenue at June 30, 2005	$2,094.10
Oil and Gas Sales During the Period, Net of Production Costs and Royalties	-585.41
Net Change in Prices, Production Costs and Royalties Related to Future Production	-76.89
Changes in previously estimated development costs incurred during the period	-
Changes in estimated future development costs	-
Net change resulting from extensions and improved recovery	-
Net change resulting from discoveries	151.00
Changes resulting from acquisition of reserves	974.50
Changes resulting from disposition of reserves	0.00

Accretion of discount	206.92
Net Change resulting from revisions in quantity estimates	425.55
Net change in income taxes	-
Any other significant factors	-38.77
Estimated Future Net Revenue at June 30, 2006	$3,151.00

PART 5
ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves:

1. Proved Undeveloped Reserves:

The following table sets forth the Company's volumes of proved undeveloped reserves that were attributed to each of our reserve categories for each of the most recent five financial years.

	Light and Medium Oil and Natural Gas Liquids Net Proved Undeveloped (Mbbl)	**Associated and Non-Associated Gas Net Proved Undeveloped (Mmcf)**
June 30, 2002	1.0	255.0
June 30, 2003	1.0	250.0
June 30, 2004	-	-
June 30, 2005	-	-
June 30, 2006	-	18

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied in.

2. Probable Undeveloped Reserves:

The following table sets forth the Company's volumes of probable undeveloped reserves that were attributed to each of our reserve categories for each of the most recent five financial years.

Year	**Light and Medium Oil and Natural Gas Liquids Net Probable Undeveloped (Mbbl)**	**Associated and Non-Associated Gas Net Probable Undeveloped (Mmcf)**
June 30, 2002	27.9	278.0
June 30, 2003	28.1	505.4
June 30, 2004	19.4	499.0
June 30, 2005	18.4	385.5
June 30, 2006	18.9	578.0

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proves plus probable reserves.

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure to put the reserves on production.

Undeveloped reserves are those reserves that are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive. Our probable undeveloped reserves at June 30, 2006 primarily relates to two non-operated properties, one in the Edson Area of Alberta that requires additional capital for pipeline and water disposal facilities in order to place on production and the Company's interest in a gas unit located in Brock, Saskatchewan. At present the Company has not been notified of programs to further develop these interests.

Item 5.2 Significant Factors or Uncertainties:

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economics data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs changes. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. These factors and assumptions include among others (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates, (iii) production decline rates, (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production, (vii) effects of government regulation; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required for changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserve estimates can arise from changes in year–end prices, reservoir performance and geological conditions or production. These revisions can be either positive or negative. (For additional Risk Factors, please refer to the Company's annual Form 20F filed as an Annual Information Form on www.sedar.com).

Item 5.3 Future Development Costs:

The table below sets out future development costs deducted in the estimation of future net revenue attributable to proved reserves (using constant and forecast prices and costs) and proved plus probable reserves undiscounted and discounted by 10% (using forecast prices) at June 30, 2006.

Total Proved Estimated Future Development Costs Constant Prices ($000)	Total Proved Estimated Future Development Costs Forecast Prices ($000)	Total Proved Plus Probable Estimated Future Development Costs Forecast Prices ($000)	Total Proved Plus Probable Estimated Future Development Costs Forecast Prices Discounted at 10% ($000)
-	-	226	217

The future development costs are capital expenditures required in the future for the Company to convert probable reserves into proved developed reserves.

In the past the Company used its cash obtained from prior equity financings and its cash flow generated from the oil and gas division to develop its existing properties and fund new capital expenditures. The Company expects that its available cash and current cash flow to be sufficient to move its probable reserves into a proved reserve category. Alternatively, the Company may look to farm out a portion of its interest in certain lands on favorable terms. The Company may be required to find new equity issues in order to participate in any future acquisitions or exploration programs.

PART 6
OTHER OIL AND GAS INFORMATION

Item 6.1 Oil & Gas Properties and Wells:

Farrow Area, Alberta: The Company's has a 100% working interest in 320 net acres located in Township 19 Range 24 W4M and an oil well 8-26-29-24 W4M producing from the Glauconite formation. For the fiscal year ended June

30, 2006 this well accounted for approximately 15% of the Company's overall production. In addition, the Company has a 33.33% interest in 640 gross acres (213 net acres) and a natural gas well at 10-35-19-24 W4M. The well is currently standing pending economic tie in.

Buick Creek Area, North East British Columbia: During the fiscal year ended June 30, 2006 the Company, drilled a natural gas development well (C-011-E/94-A-15) to the Doig formation and earned a 75% working interest in the well and 16 spacing units from base Baldonnel to base Artex-Halfway-Doig. The Company also drilled a natural gas exploratory well (B-064-E/94-A-15) to the Baldonnel formation and earned a 75% working interest in the well and 12 spacing units from surface to base Baldonnel.

The Company participated in drilling two more 25% working interest exploratory gas wells (D-019-F/94-A-15 and B-046-E/94-A-15) and earned a 25% working interest in 16 spacing units from surface to base Baldonnel.

On August 14, 2006 the Company entered into Purchase and Sale Agreement, for the sale of a portion of it interests in the Buick Creek Area of British Columbia for proceeds of $825,000.00. The Company sold a 50% working interest in the well (C-011-E/94-A-15) and 16 spacing units from base Baldonnel to base Artex-Halfway-Doig, a 50% working interest in the well (B-064-E/94-A-15) and 12 spacing units from surface to base Baldonnel and a 10% working interest in the wells (D-019-F/94-A-15 and B-046-E/94-A-15) and 16 spacing units from surface to base Baldonnel.

Under an Area of Mutual Interest Agreement dated August 1, 2006 the Company participated in drilling a 7.5% working interest in the well (B-13-E/94-A-15) and earned a 7.5% working interest in the well and 12 spacing units. The well is slated for completed.

The Company also participated in the tie in B-046-E/94-A-15 for its 15% working interest and the well was placed on production in August 2006.

These multi formation lands are prospective for natural gas in the Notikewan, Bluesky and Gething formations and for oil in the Halfway formation.

Sibbald Area, Alberta: The Company has a working interest in 7,040 gross acres (5,032 net acres) located in Townships 28 and 29, Range 2 W4M. During the fiscal year ended June 30, 2006 the Company entered into a 50/50 Joint Exploration Agreement including an area of mutual interest encompassing nine townships of lands in the Sibbald Area (excluding the Company's working interest lands) to further acquire, develop and explore this area. The Company and its partners acquired 1,280 gross acres (896 net acres) of land and drilled a Belly River formation natural gas test well (50% net working interest to the Company) that was dry and abandoned during the fiscal year ended June 30, 2006. For the fiscal year ended June 30, 2006 this area accounted for 7% of the Company's overall production. Effective February 1, 2006, the Company farmed out its 50% working interest in 640 gross acres (320 net acres) of land to a third party who drilled a natural gas test well to the Belly River formation. The Company has a 7.5% gross overriding royalty in this well that is currently pending tie in.

Cherhill Area, Alberta: Effective June 1, 2006 the Company exercised its Right of First refusal and acquired a 30% before payout interest and an 18% after payout interest in a producing gas well 13-10-57-5 W5M and 115.2 net acres of land in the Cherhill area of Alberta for gross proceeds of $6,750.00.

Brock Area, Saskatchewan: During the fiscal year ended June 30, 2006, the Company acquired two private Alberta corporations and as a result, holds a 20% working interest 19,549 gross acres (3,910 net acres) of land and a producing Viking Sand natural gas unit located in Townships 27 and 28 Range 20 and 21 W3M in Brock, Saskatchewan. The natural gas unit has a compressor station, a dehydrator unit and a water disposal well. The unit also generates revenue from third party gas processing and water disposal. For the fiscal year ended June 30, 2006 this unit, from the date of acquisition, accounted for 16% of the Company's overall production.

Olds Davey Area, Alberta: The Company has a working interest in 1,760 gross acres (320 net acres) located in Township 33 Range 28, W4M and Township 34 Range 1 W5M. For the fiscal year ended June 30, 2006 this area accounted for approximately 15% of the Company's overall production from three wells. During the fiscal year ended June 30, 2006 the Company participated in drilling a 12.5% working interest Viking formation gas well. The well commenced production in May 2006. For the fiscal year ended June 30, 2006 this area accounted for 11% of the Company's overall production.

Bigstone & Kaybob Area, Alberta: The Company has an interest in 2,560 gross acres (435 net acres) located in Township 61, Range 19 and 22 W5M in Alberta. For the fiscal year ended June 30, 2006 this area accounted for approximately 36% of the Company's overall production from three wells.

Edson Property, Alberta: The Company has a 10% working interest in three sections of land, 1,920 gross acres (192 net acres) and a well 10-13-52-16W5M in the Edson area of Alberta. At June 30, 2006the Company's reserve report had attributed probable reserves to this property. This non-operated well is currently standing, pending pipeline tie in, water disposal facilities and compression. The Company expects that the 10-13-52-16W5M well will be tied in during fiscal 2007.

2. The following table sets out the number of gross and net Producing oil and natural gas wells and the number of gross and net Non-Producing oil and natural gas wells that the Company has an interest in by location.

Location	Gross Producing Gas Wells	Net Producing Gas Wells	Gross Non-Producing Gas Wells	Net Non-Producing Gas Wells	Gross Producing Oil Wells	Net Producing Oil Wells	Gross Non-Producing Oil Wells	Net Non-Producing Oil Wells
Alberta	9	1.65	10	3.88	3	1.45	1	.50
Ontario	1	.1125	-	-	2	.93	-	-
British Columbia	-	-	4	2.00	-	-	-	-
Saskatchewan	15	2.70	11	2.20	-	-	-	-

Item 6.2 <u>Properties With No Attributed Reserves:</u>

1. The Company has an interest in approximately 28,192 gross acres (8,554 net acres) of land with no attributed reserves that are located in Alberta, British Columbia and Saskatchewan, Canada. As of the date of this report, the Company is not aware of any work commitments.

2. The Company has an interest in 2,560 gross acres (448 net acres) that are set to expire prior to fiscal 2007 unless the lands are proved capable of production or continued.

Item 6.3 <u>Forward Contracts:</u>

The Company has no forward contracts.

Item 6.4 <u>Additional Information Concerning Abandonment and Reclamation Costs:</u>

The Company bases its estimates for costs of abandonment and reclamation of surface leases and wells on previous experience with similar well site locations and area terrain. The Company believes that its range of estimates between $25,000 to $35,000 gross per well for abandonment and reclamation costs are reasonable and applicable to its wells. Our independent engineering evaluator has also estimated similar costs in deriving the Company's estimate of future net revenue. Ultimately all wells will require abandonment and reclamation. The total of such costs estimated for 15.42 net wells for our fiscal year ended June 30, 2006 was $502,186 and $285,219 calculated using a credit-adjusted risk free discount rate of 10 percent. A provision $56,000 was deducted in the estimated Future Net Revenue using Forecast Prices, and $157,000 was deducted in the estimated Future Net Revenue using Constant Prices. The Company expects to pay $ 67,545 in abandonment and reclamation costs over the next 3 fiscal years.

Item 6.5 <u>Tax Horizons:</u>

As of June 30, 2006, the Company had non-capital losses of approximately $7,380,712 that are available to reduce future taxable income. The Company also has Cumulative Canadian oil and gas property expenses of $11,545,106 and capital loss carry forwards of $11,594,718. The tax reserves are more than the future undiscounted net revenues to be derived from the oil and gas reserves. As a result the expected future tax payable is nil.

Item 6.6 **Costs Incurred:**

1. (a) During the fiscal year ended June 30, 2006, the Company's unproved property acquisition costs were $2,219,123 and proved property acquisition costs were $4,355,583.
   (b) During the fiscal year ended June 30, 2006 the Company incurred exploration costs of $1,211,222.
   (c) During the fiscal year ended June 30, 2006 the Company's development costs were $1,227,689.

2. Not Applicable.

Item 6.7 **Exploration and Development Activities:**

1. As of June 30, 2006 the Company had the following drilling activities. A gross well is a well in which an interest is owned. The number of net wells represents the sum of a fractional interest the Company owns in gross wells.

Number of wells drilled	**2006**	
Development wells	Gross	Net (%)
Producing	-	-
Standing*	1	0.75
Abandoned	1	0.50
Exploratory wells		
Producing	1	0.125
Abandoned	-	-
Standing *	3	1.25

* Standing wells are pending further evaluation or tie in and pipeline facilities.

2. Refer to Part 6 - Other Oil and Gas Information.

Item 6.8 **Production Estimates:**

1. The following tables sets forth the net volume of production by product type estimated for the first year reflected in the constant price case of future net revenue.

	Light/Medium Oil and Natural Gas Liquids (Mbbl)	Associated and Non Associated Gas (Mmcf)
June 30, 2006	4.85	201

2. The following table reflects the fields or areas that represents 20% or more of the net volume of production estimated for the first year reflected in the constant price case of future net revenue.

June 30, 2005	Light/Medium Oil and Natural Gas Liquids (Mbbl)	Associated and Non Associated Gas (Mmcf)
Farrow, Alberta	2.1	-
Kaybob, Alberta	1.8	-
Brock, Saskatchewan	-	100.0

Item 6.9 **Production History:**

1. The following table sets forth certain information in respect of production, product prices received, production costs and netbacks received by the Company for each quarter of fiscal 2006.

	Fiscal 2006			
	June 30/06	Mar. 31/06	Dec. 31/05	Sept. 30/05
Average Daily Production				
Natural gas (mcf per day)	216	123	212	231
Natural gas liquids (bbls	9	4	16	13
Crude oil (bbls per day)	12	15	11	11
Total (boe per day)	57	39	62	62
Average Commodity Prices				
Natural gas ($/mcf)	$ 6.40	$ 8.71	$ 12.95	$ 9.73
Natural gas liquids ($/bbl)	$ 68.68	$ 48.17	$ 45.52	$ 47.01
Crude oil ($/bbl)	$ 66.03	$ 66.51	$ 67.28	$ 68.30
Total ($/boe)	$ 43.73	$ 57.30	$ 66.32	$ 57.67
Royalties				
Natural gas ($/mcf)	$ 1.52	$ 1.74	$ 1.42	$ 0.98
Natural gas liquids ($/bbl)	$ 10.26	$ 12.88	$ 11.39	$ 10.84
Crude oil ($/bbl)	$ 16.75	$ 9.33	$ 8.61	$ 4.95
Total royalties ($/boe)	$ 10.26	$ 10.27	$ 9.38	$ 6.77
Production costs				
Natural gas ($/mcf)	$ 3.06	$ 3.89	$ 3.15	$ 3.36
Natural gas liquids ($/bbl)	$ 13.86	$ 16.69	$ 7.34	$ 5.71
Crude oil ($/bbl)	$ 23.00	$ 26.35	$ 26.49	$ 24.07
Total production costs ($/boe)	$ 18.82	$ 23.84	$ 16.98	$ 17.81
Netback by Product				
Natural gas ($/mcf)	$ 1.82	$ 3.08	$ 8.38	$ 5.39
Natural gas liquids ($/bbl)	$ 44.56	$ 18.60	$ 26.79	$ 30.46
Crude oil ($/bbl)	$ 26.28	$ 30.83	$ 32.18	$ 39.28
Netback ($/boe)	$ 14.65	$ 23.19	$ 39.96	$ 33.09

2. The following table indicates the Company's total production for fiscal 2006 from its core properties.

Field/Area	**Natural Gas (Mcf)**	**Natural Gas Liquids (Bbl)**	**Oil (Bbl)**
Kaybob, Alberta	29,418	2,721	-
Sibbald, Alberta	7,860	-	65
Olds/Davey, Alberta	11,820	351	2
Brock, Saskatchewan	19,620	-	-
Farrow, Alberta	-	-	3,236
Other	10,245	392	970
Total	**78,963**	**3,464**	**4,273**