ENERNORTH INDUSTRIES INC
Form 6-K
October 03, 2005

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 6-K

Report of Foreign Private Issuer Pursuant to Rule 13a-16 or 15d-16 under the

Securities Exchange Act of 1934

For the month of

September 2005

Commission File Number

0-29586

EnerNorth industries inc.

(formerly: Energy Power Systems Limited)

(Address of Principal executive offices)

2 Adelaide Street West, Suite 301, Toronto, Ontario, M5H 1L6, Canada

(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F:

Form 20-F__X__

Form 40-F ______

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7):

Yes

No __X____

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934:

Yes _____

No__X___

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3- 2(b):

82- _________ ____________________

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EnerNorth industries inc.

(formerly: Energy Power Systems Limited)

Date: September 28, 2005

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By: "Sandra J. Hall"

Sandra J. Hall,

President, Secretary & Director

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 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" 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.

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 22, 2005
2.	Effective Date of Statement:	June 30, 2005
3.	Preparation Date of Statement:	September 15, 2005

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, 2005 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	69.87 $/stb
Natural Gas:	Alberta AECO-C	7.00 $/mcf
Natural Gas by-Products:	Propane	40.95 $/bbl
	Butanes	46.45 $/bbl
	Pentanes Plus	65.95 $/bbl
	Sulphur	40.00 $/lt
Exchange Rate:		0.816 $US/$CDN

Item 3.2 Forecasted Prices Used in Estimates:

Table 5 attached

PART 4
RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Item 4.1 Reserves Reconciliation (Forecast Prices and Costs):

Table 10 attached

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, 2004 against such reserves as at June 30, 2005.

Canada	
Estimated Future Net Revenue at June 30, 2004	3,349.0
Oil and Gas Sales During the Period, Net of Production Costs and Royalties	(345.7)
Net Change in Prices, Production Costs and Royalties Related to Future Production	577.1
Changes in previously estimated development costs incurred during the period	(181.0)
Net change resulting from extensions and improved recovery	20.0
Net change resulting from discoveries	-
Changes resulting from acquisition of reserves	-
Changes resulting from disposition of reserves	-
Accretion of discount	178.9
Net Change resulting from revisions in quantity estimates	(1,518.2)
Net change in income taxes	-
Any other significant factors	14.0
Estimated Future Net Revenue at June 30, 2005	2,094.1

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. The Company commenced oil and gas operations during the financial year ended June 30, 2001.

	Light and Medium Oil and	Associated and
	Natural Gas Liquids	Non-Associated Gas
	Net Probable	Net Probable
	(Mbbl)	(Mmcf)
June 30, 2001	-	226.0
June 30, 2002	1.0	255.0
June 30, 2003	1.0	250.0
June 30, 2004	-	-
June 30, 2005	-	-

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. The Company commenced oil and gas operations during the financial year ended June 30, 2001.

Year	**Light and Medium Oil and**	**Associated and**
	Natural Gas Liquids	**Non-Associated Gas**
	Net Probable	**Net Probable**
	(Mbbl)	**(Mmcf)**
June 30, 2001	5.5	318.0
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

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 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, 2005 primarily relate to two non-operated wells that the Company has either a minor working interest in or that requires additional capital for pipeline and water disposal facilities in order to place on production. At present the operator of these wells has not provided the Company with any tie in programs.

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 serves; (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, 2005.

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)
-	-	181	174

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. During the fiscal year ended June 30, 2005 the Company repaired a seized bottom hole pump and placed the oil well back on production in November 2004. For the fiscal year ended June 30, 2005 this well accounted for approximately 13% of the Company's overall production. In addition, the Company has a 33.33% interest in 640 gross acres (213 net acres) and during the year participated in drilling a natural gas exploratory well at 10-35-19-24 W4M to the Foremost formation. The well is currently standing pending further evaluation.

Buick Creek Area, North East British Columbia: The Company entered into a Farmout and Participation Agreement (the "Agreement") effective May 16, 2005 to acquire a working interest in a British Columbia Crown Drilling License. The License is located in 094-A-15/E and F consisting of 28 spacing units (approximately 4,895 gross acres). As consideration the Company paid $250,000 and subsequent to year end, drilled a natural gas development well (C-011-E/94-A-15) to the Doig formation and paid 75% of the costs to earn a 75% working interest in the well and 16 spacing units from base Baldonnel to base Artex-Halfway-Doig. The Company, as operator, drilled a natural gas exploratory well (B-064-E/94-A-15) to the Baldonnel formation and paid 75% of the costs to earn a 75% working interest in the well and 12 spacing units from surface to base Baldonnel.

On this License, 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. All of the four wells have been drilled and cased and are pending completion, production testing and potential tie in. These multi formation lands are prospective for natural gas in the Notikewan, Bluesky and Gething formations and for oil in the Halfway formation. The Company anticipates further exploration and development on these lands pending results from the first four wells.

Sibbald Area, Alberta: The Company has a working interest in 5,760 gross acres (3,848 net acres) located in Townships 28 and 29, Range 2 W4M. For the fiscal year ended June 30, 2005 the Company's Sibbald wells accounted for approximately 24% of the Company's overall production. During the year 640 gross acres (400 net acres) expired and the Company is undertaking the abandonment of the 12-29-28-2 W4M well. Subsequent to the fiscal year ended June 30, 2005 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.

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, 2005 this area accounted for approximately 15% of the Company's overall production. In March 2005, the Company was served notice for a title forfeiture operation for its 25% interest in a well located in Township 35, Range 28 W4M. The Company determined that the costs associated with the operation would not be economic and accordingly forfeited its interest in 640 gross acres (160 net) and the well.

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, 2005 this area accounted for approximately 35% of the Company's overall production.

Edson Property, Alberta: The Company has a 10% working interest in three sections of land, 1,920 gross acres (192 net acres) in the Edson area of Alberta. The Edson exploratory well 10-13-52-16W5M was spud on December 10, 2001, drilled to a depth of 3,149 meters (approximately 10,328 feet) to the Winterburn formation, and cased as a Winterburn Gas well. At June 30, 2005 the 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.

Brazeau River Property, Alberta: This prospect is comprised of two sections of land 1,280 gross acres (320 net acres). During fiscal 2002, the Company participated in the re-entry of a cased well bore and earned a 25% interest in the wellbore and lands. The development well was re-entered and tested in the Rock Creek and Elkton formation and completed as a Rock Creek oil well. At June 30, 2005 the Company's reserve report had attributed probable reserves to this property. This non-operated well is currently standing pending economic evaluation of pipeline tie in of approximately 1.5 kilometers.

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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	7	17.75	11	39.39	1	100.00	1	50.00
Ontario	1	11.25	-	-	2	14.41		

Item 6.2 Properties With No Attributed Reserves:

1. The Company has an interest in approximately 8,320 gross acres (3,541 net acres) of land with no attributed reserves all of which are located in Alberta, Canada. As of the date of this report, the Company is not aware of any work commitments.

2. The Company has an interest in 8,320 gross acres (3,541 net acres) of land with no attributed reserves, which 2,560 gross acres (384 net acres) will expire prior to fiscal 2006 unless the lands are proved capable of production or continued.

Item 6.3 Forward Contracts:

The Company has no forward contracts.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs:

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 6.59 net wells for our fiscal year ended June 30, 2005 was $268,708 and $173,204 calculated using a credit-adjusted risk free discount rate of 5 percent. An provision $162,000 was deducted in the estimated Future Net Revenue using Forecast Prices, and $134,000 was deducted in the estimated Future Net Revenue using Constant Prices. The Company expects to pay $59,000 in abandonment and reclamation costs over the next 3 fiscal years.

Item 6.5 Tax Horizons:

As of June 30, 2005, the Company had non-capital losses of approximately $6,944,172 that are available to reduce future taxable income. The Company also has Cumulative Canadian oil and gas property expenses of $7,778,236 and capital loss carry forwards of $10,449,015. 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, 2005, the Company's unproved property acquisition costs were $297,809 and proved property acquisition costs were $Nil.
   (b) During the fiscal year ended June 30, 2005 the Company incurred exploration costs of $289,128.
   (c) During the fiscal year ended June 30, 2005 the Company's development costs were $414,806.
2. Not Applicable.

Item 6.7 Exploration and Development Activities:

1. As of June 30, 2005 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 Exploratory gas wells drilled	2005	
	Gross	Net
Standing	1	.33

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	2.65	58

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.

	Light/Medium Oil and	Associated and
June 30, 2005	Natural Gas Liquids	Non Associated Gas
	(Mbbl)	(Mmcf)
Farrow, Alberta	2.3	
Edson, Alberta		13.0
Kaybob, Alberta		25.5
Sibbald, Alberta		12.5

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 2005.

	Fiscal 2005			
	June 30/05	Mar. 31/05	Dec. 31/04	Sept. 30/04
Average Daily Production				
Natural gas (mcf per day)	270	237	290	171
Natural gas liquids (bbls per day)	10	14	9	5
Crude oil (bbls per day)	13	13	16	1
Total (boe per day)	40	66	74	62
Average Commodity Prices				
Natural gas ($/mcf)	$7.41	$7.33	$6.42	$6.07
Natural gas liquids ($/bbl)	$41.81	$38.61	$38.38	$37.95
Crude oil ($/bbl)	$65.76	$58.73	$44.13	$55.91
Total ($/boe)	$48.15	$45.63	$39.70	$37.29
Royalties				
Natural gas ($/mcf)	$1.69	$1.18	$1.48	$1.77
Natural gas liquids ($/bbl)	$9.48	$10.03	$11.23	$19.83
Crude oil ($/bbl)	$8.55	$9.07	$6.07	$4.92
Total royalties ($/boe)	$9.75	$8.07	$8.58	$11.72
Production Costs				
Natural gas ($/mcf)	$2.80	$1.60	$4.27	$2.77
Natural gas liquids ($/bbl)	$7.28	$5.86	$5.71	$10.94
Crude oil ($/bbl)	$37.00	$21.12	$34.03	$35.82
Total production costs ($/boe)	$19.24	$10.99	$24.93	$16.52
Netback by Product				
Natural gas ($/mcf)	$2.91	$4.55	$0.67	$1.52
Natural gas liquids ($/bbl)	$25.05	$22.72	$21.44	$7.18
Crude oil ($/bbl)	$20.21	$28.55	$4.04	$15.17
Netback ($/boe)	$19.16	$26.57	$6.20	$9.06

2.

The following table indicates the Company's total production for fiscal 2005 from its core properties.

Field/Area	Natural Gas (Mcf)	Natural Gas Liquids (Bbl)	Oil (Bbl)
Kaybob, Alberta	29,024	2,152	
Sibbald, Alberta	29,183	-	284
Olds/Davey, Alberta	17,135	433	2
Farrow, Alberta	-	-	2,834
Other	11,785	867	687
Total	**87,127**	**3,470**	**3,676**

Table 1
NI 51-101
Summary of Oil and Gas Reserves
as of June 30,2005
Forecast Prices and Costs

Reserves

	Light and Medium Oil		Heavy Oil		Natural Gas (nonassociated & associated)		Natural Gas (solution)		Natural Gas Liquids	
Reserve Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved										
Developed Producing	17.2	13.5	-	-	509	440	-	-	11.5	7.9
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Developed	-	-	-	-	-	-	-	-	-	-
Total Proved	**17.2**	**13.5**	-	-	**509**	**440**	-	-	**11.5**	**7.9**
Probable	12.7	9.7	-	-	502	385	-	-	12.0	8.2
Total Proved Plus Probable	**29.8**	**23.3**	-	-	**1,011**	**824**	-	-	**23.5**	**16.1**

Reference: Item 2 3 1) of Form 51-10lF1

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Table 2
NI 51-101
Summary of Net Present Values of
Future Net Revenue
as of June 30,2005
Forecast Prices and Costs

Net Present Values of Future Net Revenue

Reserves Category	Before Income Taxes Discounted at (%Near) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved					
Developed Producing	3,071	2,375	1,978	1,720	1,537
Developed Non-Producing	–	–	–	–	–
Undeveloped	–	–	–	–	–
Total Proved	**3,071**	**2,375**	**1,978**	**1,720**	**1,537**
Probable	2,654	1,759	1,313	1,050	876
Total Proved Plus Probable	**5,726**	**4,134**	**3,291**	**2,770**	**2,413**

Reference Item 2.2(2) of Form 51-101F1

Notes:

- NPV of FNR include all resource income:
  - Sale of oil, gas, by-product reserves
  - Processing third party reserves
  - Other income

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National Instrument 51-101

Table 3
NI 51 -101
Total Future Net Revenue
(Undiscounted)
as of June 30,2005
Forecast Prices and Costs

Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Development Costs (M$)**	**Well Abandonment Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**
Proved	5,268	659	1,405	0	132	3,071
Proved Plus Probable	10,409	1,461	2,880	181	162	5,726

Reference Item 2.2(3)(b) of Form 51-101 F1

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National Instrument 51-101

Table 4
NI 51-101
Net Present Value of Future Net Revenue
by Production Group
as of June 30,2005
Forecast Prices and Costs

Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)**
Proved	Light and Medium Crude oil (including solutiuon gas and associate by-products)	339
	Heavy Oil (including solution gas and associate by-products)	0
	Natural Gas (including associate by-products)	1,544
Proved Plus Probable	Light and Medium Crude oil (including solutiuon gas and associate by-products)	595

Heavy Oil (including solution gas and associate by-products)	0
Natural Gas (including associate by-products)	2,478

Reference Item 2.1(3)(c) of Form 51-101F1

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National Instrument 51-101

Table 5
NI 51-101
Summary of Pricing and
Inflation Rate Assumptions
as of June 30,2005
Forecast Prices and Costs

Year	WTI Cushing Oklahoma ($US/bbl)	Oil Edmonton Par Price 40 API ($Cdn/bbl)	Cromer Medium 29.3 API ($Cdn/bbl)	Natural Gas AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes F.O.B. Field Gate ($Cdn/bbl)	Inflation Rate (%/Yr)	Exchange Rate ($US/$Cdn)
Historical								
2001	25.94	39.06	31.56	6.23	42.46	27.93	2.0	0.646
2002	26.09	40.12	35.46	4.04	40.80	25.39	2.7	0.637
2003	31.14	43.23	37.53	6.66	44.16	34.55	2.5	0.716
2004	41.42	52.91	45.72	6.87	53.91	41.37	2.5	0.815

Forecast

2005	55.55	66.27	55.57	8.10	67.87	44.45	2.3	0.820
2006	55.85	66.63	56.89	8.42	68.24	44.70	2.5	0.820
2007	51.42	61.21	54.21	7.55	62.69	41.06	2.5	0.820
2008	43.92	52.04	46.04	6.62	53.30	34.91	2.5	0.820
2009	42.45	50.24	44.24	6.39	51.45	33.70	1.5	0.820

Thereafter Various Escalation Rates

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting* issuer.

(2) Inflationrates for forecasting prices and costs.

(3) Exchange rates used to generate the benchmark reference prices in this table.

Notes:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

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National Instrument 51-101

Table 6
NI 51-101
Summary of Oil and Gas Reserves
as of June 30, 2005
Constant prices and Costs

Reserves

	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated & associated)		Natural Gas (solution)		Natural Gas Liquids	
Reserve Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved										
Developed Producing	18.9	14.9	–	–	509	440	–	–	11.5	7.9
Developed Non-Producing	–	–	–	–	–	–	–	–	-	-
Undeveloped	–	–	–	–	–	–	–	–	-	-
Total Proved	**18.9**	**14.9**	–	–	**509**	**440**	–	–	**11.5**	**7.9**
Probable	13.3	10.2	–	–	502	385	–	–	12.0	8.2
Total Proved Plus Probable	**32.2**	**25.1**	–	–	**1,012**	**825**	–	–	**23.5**	**16.1**

Reference: Item 2.2(1) of Form 51-101F1

National Instrument 51-101

Table 7
NI 51 -101
Summary of Net Present Values of Future Net Revenue as of June 30,2005 Constant Prices and Costs

	Net Present Values of Future Net Revenues Before Income Taxes Discounted at (%/Year)				
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
Proved					
Developed Producing	3,328	2,548	2,094	1,796	1,585
Developed Non-Producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
Total Proved	**3,328**	**2,548**	**2,094**	**1,796**	**1,585**
Probable	2,853	1,900	1,412	1,119	925
Total Proved Plus Probable	**6,181**	**4,448**	**3,506**	**2,916**	**2,509**

Reference Item 2.2(2) of Form 51-101F1

Notes:

NPV of FNR include all resource income:

- Sale of oil, gas, by-productreserves
- Processing third party reserves
- Other income

Table 8
NI 51 -101
Total Future Net Revenue
(Undiscounted) as of June 30,2005
Constant Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)
Proved	5,466	765	1,261	0	112	3,328
Proved Plus Probable	10,633	1,669	2,468	181	134	6,181

Reference Item 2.2(3)(b)of **Form** 51-101 **F1**

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Table 9
NI 51 -101
Net Present Value of Future Net Revenue
by Production Group
as of June 30,2005
Constant Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 1O%Near) (M$)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	481
	Heavy Oil (including solution gas and associated by-products)	0
	Natural Gas (including associated by-products)	1,520
Proved Plus Probable		808

Light and Medium Crude Oil (including solution gas and associated by-products)	
Heavy Oil (including solution gas and associated by-products)	0
Natural Gas (including associated by-products)	2,480

Reference Item 2.1(3)(c) of Form 51-101 F1

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National Instrument 51-1 01

Table 10
NI 51-101
Reconciliation of Company Net Reserves (After Royalty)
by Principal Product Type
as of June 30,2005
Forecast (Escalated) Prices and Costs

	Light and Medium Oil*			**Heavy Oil**			**Associated and Non-Associated Gas**		
Factors	**Net Proved (Mbbl)**	**Net Probable (Mbbl)**	**Net Proved Plus Probable (Mbbl)**	**Net Proved (Mbbl)**	**Net Probable (Mbbl)**	**Net Proved Plus Probable (Mbbl)**	**Net Proved (MMcf)**	**Net Probable (MMcf)**	**Net Proved Plus Probable (MMcf)**
June 30,2004	**23.6**	**19.2**	**42.8**	–	–	–	**1,149**	**498**	**1,647**
									–
Extensions	–	–	–	–	–	–	15	–	15
Improved Recovery	–	–	–	–	–	–	–	–	–
Technical Revisions	(1.6)	(1.3)	(2.9)	–	–	–	(643)	(113)	(757)
Discoveries	–	–	–	–	–	–	–	–	–
Acquisitions	–	–	–	–	–	–	–	–	–
Dispositions	–	–	–	–	–	–	–	–	–
Economic Factors	–	–	–	–	–	–	–	–	–
Production	(0.6)	–	(0.6)	–	–	–	(81)	–	(81)
June 30,2005	**21.4**	**17.9**	**39.3**				**440**	**385**	**824**

* Light and Medium Oil includes Natural Gas Liquids.

Reference: Item 4.1 of ***Form 51-101F1***

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ENERNORTH INDUSTRIES INC.
FORM 51-101F3
STATEMENT OF RESERVES DATA REPORT OF MANAGEMENT AND DIRECTORS
September 22, 2004

Management of EnerNorth Industries Inc. ("the Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at June 30, 2005 using the forecast prices and costs; and (ii) the related estimated future net revenue; and
(ii) the related estimate future net revenue; and
(b) (i) proved oil and gas reserves estimated as at June 30, 2005 using constant prices and costs; and
(ii) the related estimate future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Petroleum and Natural Gas Reserve Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation;
(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Petroleum and Natural Gas Reserve Committee of the board of directors has reviewed the Company's procedure for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management.

The board of directors has approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

"SANDRA J. HALL"
Sandra J. Hall, President and Director

"JAMES C. CASSINA"
James C. Cassina, Chairman and Director

"IAN DAVEY"
Ian Davey, Director

"MILTON KLYMAN"
Milton Klyman, Director

"RAMESH K. NAROOLA"
Ramesh K. Naroola, Director

September 22, 2005