FORM 51-1O1F1
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMA TION
OF
YANGARRA RESOURCES LTD.

PART 1 DATE OF STATEMENT

This Statement of Reserves Data and Other Oil and Gas Information of Yangarra Resources Ltd. ("Yangarra" or the "Company") is dated March 26, 2008. The effective date of the information provided in this Statement is December 31, 2007 unless otherwise indicated. The information was prepared between December 31, 2007 and March 26, 2008.

PART 2 DISCLOSURE OF RESERVES DATA

In accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, AJM Petroleum Consultants ("AJM") prepared a report (the "AJM Report") dated March 26, 2008, in which it has evaluated as at December 31, 2007, Yangarra's oil, NGL, and natural gas reserves.

The reserves definition and ownership classification used in this evaluation are the standards defined by COGEH reserve definitions and consistent with NI 51-101 and used by AJM Petroleum Consultants.

The tables below are a summary of the oil, NGL and natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the AJM Report based on forecast price and cost assumptions. The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production cost, developments costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by AJM.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by AJM represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates for the Companys' oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The AJM Report is based on certain factual data supplied by the Company and AJM's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to AJM and accepted without any further investigation. AJM accepted this data as presented and neither title searches nor field inspections were performed.

Item 2.1 RESERVES DATA (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2007

	Light and Medium Oil		**Natural Gas Solution**		**Natural Gas** (Associated & Non-Associated)		**Natural Gas Liquids**	
Reserves Category	Gross (Mstb)	Net (Mstb)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf))	Gross (Mbbl)	Net (Mbbl)
Proved Developed Producing	0.7	0.6	581.0	426.5	2,556.9	2,147.9	51.2	31.2
Proved Developed Non-Producing	8.8	7.2	5.8	3.3	920.1	731.4	4.4	2.3
Proved Undeveloped	12.0	10.9	0.0	0.0	4,310.1	3,509.9	40.9	26.6
Total Proved	**21.5**	**18.8**	**586.8**	**429.8**	**7,787.2**	**6,389.2**	**96.5**	**60.1**
Probable	**44.0**	**38.2**	**202.4**	**132.8**	**5,321.1**	**4,560.4**	**42.9**	**27.0**
Total Proved Plus Probable	**65.5**	**57.0**	**789.2**	**562.6**	**13,108.2**	**10,949.6**	**139.4**	**87.1**

SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUE
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2007

	Before Income Taxes				
Reserves Category	0.0% (M$)	5.0% (M$)	10.0% (M$)	15.0% (M$)	20.0% (M$)
Proved Developed Producing	17,132.2	13,958.4	11,872.4	10,399.2	9,301.9
Proved Developed Non-Producing	4,553.2	3,945.1	3,472.4	3,096.5	2,791.6
Proved Undeveloped	15,772.9	11,892.3	9,237.0	7,288.0	5,795.4
Total Proved	37,458.4	29,795.8	24,581.8	20,783.7	17,889.0
Probable	31,426.3	22,058.6	16,417.4	12,698.1	10,090.7
Total Proved Plus Probable	68,884.7	51,854.4	40,999.2	33,481.8	27,979.7

	After Income Taxes				
Reserves Category	0.0% (M$)	5.0% (M$)	10.0% (M$)	15.0% (M$)	20.0% (M$)
Proved Developed Producing	17,132.2	13,958.4	11,872.4	10,399.2	9,301.9
Proved Developed Non-Producing	4,553.2	3,945.1	3,472.4	3,096.5	2,791.6
Proved Undeveloped	13,532.3	10,252.3	7,986.4	6,306.7	5,008.7
Total Proved	35,217.7	28,155.8	23,331.2	19,802.4	17,102.3
Probable	23,557.4	16,451.1	12,154.6	9,322.9	7,340.2
Total Proved Plus Probable	58,775.1	44,606.9	35,485.8	29,125.3	24,442.5

Note
M$ = Thousands of Dollars
Values may not add due to rounding

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2007

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Future Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved	81,640.6	15,324.7	17,629.0	9,116.5	2,111.9	37,458.4	2,240.6	35,217.7
Proved Plus Probable	141,499.1	24,320.2	31,375.8	14,305.0	2,613.4	68,884.7	10,109.6	58,775.1

NET PRESENT VALUES OF FUTURE NET REVENUE
BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2007

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Net Reserves Unit Value Before Income Taxes (Discounted at 10%/Year) ($/bbl)
Proved	Light and Medium Oil (including solution gas and associated by-products)	3,156.0	23.12
	Natural Gas (including associated by-products)	21,425.8	15.56
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	4,380.1	19.93
	Natural Gas (including associated by-products)	36,619.0	15.91

Notes to Reserves Tables:

(1) Columns may not add due to rounding.
(2) M$ = Thousands of Dollars
(3) The Company has no non-conventional gas or oil activities.

"**Reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.
"**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. At least 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves is the targeted level of certainty.
"**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 Proved plus Probable Reserves. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probably reserves is the targeted level of certainty.
"**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 (for example, when compared to the cost of drilling a well) to put the Reserves on production. The developed category may be subdivided into producing and non-producing.
"**Developed Producing Reserves**" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
"**Developed Non-Producing Reserves**" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
"**Undeveloped Reserves**" are those Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (proved, probable) to which they are assigned.

PART 3 PRICING ASSUMPTIONS

Item 3.1 Forecast Prices Used in Estimates

The forecast price and market forecasts assume the continuance of current laws and regulations and consider inflation forecasts and exchange rates. AJM's forecast has the exchange rate of $0.98 for 2008, then dropping off to $0.90 by the year 2011 and beyond. AJM's forecast anticipated inflation will continue in the low percentages, therefore a two percent rate was used over the life of the evaluation.

Oil, NGLs, and natural gas base case prices, and exchange rates utilized by AJM in the AJM Report were as follows:

Summary of Pricing Assumptions
Price Forecast
Used in Estimates

	Oil			Natural Gas			Natural Gas Liquids		
Year	WTI Cushing (Oklahoma)	Edmonton City Gate 40° API	Med. Oil 25° API Hardisty	Alberta AECO – Gas Prices	Alberta Direct Spot System Plant Gate	Alberta System Plant Gate Sales	Pentanes + Condensate Edmonton	Butanes Edmonton	Propane Edmonton
	($US/bbl)	($Cdn/bbl)	($Cnd/bbl)	($Cdn/mcf)	($Cdn/mcf)	($Cdn/Mcf)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)
Historical									
2002	$26.11	$40.16	$32.82	$4.07	$3.91	$3.85	$41.22	$27.78	$20.92
2003	$31.01	$43.17	$32.96	$6.70	$6.53	$6.11	$45.18	$36.03	$32.31
2004	$41.45	$52.75	$38.04	$6.57	$6.40	$6.32	$55.49	$44.07	$35.20
2005	$56.61	$68.99	$45.68	$8.78	$8.61	$8.56	$74.67	$51.91	$43.23
2006	$66.06	$73.10	$51.68	$6.54	$6.35	$6.63	$78.19	$58.16	$44.11
2007	$72.13	$76.53	$54.05	$6.47	$6.26	$6.47	$80.60	$58.01	$49.09
Forecast									
2008	$85.00	$85.65	$61.65	$6.90	$6.70	$6.60	$89.95	$68.50	$55.65
2009	$81.60	$84.75	$60.75	$7.75	$7.55	$7.45	$89.00	$67.80	$55.10
2010	$81.15	$87.05	$63.05	$8.10	$7.90	$7.80	$91.40	$69.65	$56.60
2011	$79.60	$87.25	$63.25	$8.50	$8.30	$8.20	$91.60	$69.80	$56.70
2012	$77.95	$85.40	$61.40	$8.65	$8.45	$8.35	$89.65	$68.30	$55.50

Notes:

- All prices are in Canadian dollars except WTI which are in U.S. dollars
- Edmonton city gate prices based on light sweet crude posted at major Canadian refineries (40 Deg. API <0.5% Sulphur)
- Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point.
- 1 Mcf is equivalent to 1 mmbtu.
- System gas prices includes TCGSL, Progas, Pan Alberta and Alliance
- Alberta gas prices, except AECO, include an Average cost of service to the plant gate

Weighted average historical prices realized by Yangarra for the year ended December 31, 2007 before transportation were $7.22/Mcf for natural gas, $55.64/Bbl for NGLs and $73.71/Bbl for oil. Yangarra had a minimal amount of oil production in 2007 which is included with natural gas liquids production in its financial statements.

PART 4 RECONCILIATIONS OF CHANGES IN RESERVES

Item 4.1 Reconciliations of Changes in Reserves

The following table sets out the reconciliation of Yangarra's gross reserves as at December 31, 2007 compared to December 31, 2006 based on forecast prices and costs by principal product type:

	Light and Medium Oil			**Natural Gas Liquids**			**Associated and Non-Associated Gas**		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mmcf)	(Mmcf)	(Mmcf)
Opening	**2.7**	**18.6**	**21.2**	**149.7**	**132.2**	**281.9**	**8,645.0**	**7,139.0**	**15,784.0**
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	-	-	-	-	-	-	1,701.0	1,777.0	3,478.0
Recompletion	-	-	-	-	-	-	-	-	-
Transfer	-	-	-	-	-	-	-73.6	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Divestiture	-	-	-	-	-	-	-511.0	-123.0	-634.0
Revisions	23.3	25.4	48.8	-39.8	-89.3	-129.1	-475.5	-3,269.5	-3,818.6
Recovery	-	-	-	-	-	-	-	-	-
Econ Factors	-	-	-	-	-	-	-	-	-
Production	-4.5	-	-4.5	-13.4	-	-13.4	-911.9	-	-911.9
Dec 31, 2007	**21.5**	**44.0**	**65.5**	**96.5**	**42.9**	**139.4**	**8,374.0**	**5,523.5**	**13,897.5**

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

The following table sets forth the gross probable undeveloped reserves, each by product type, attributed to Yangarra's assets for the years ended December 2007, 2006, and 2005 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped reserves

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
Prior thereto	-	-	-
2003	-	5,469	128.3
2004	-	3,728	42.8
2005	-	4,802	59.4
2006	-	3,349	65.0
2007	12.0	4,310	40.9

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in for production or wells not yet drilled at year end that are adjacent to producing wells. In addition, such reserves may relate to planned infill drilling locations. Plans are included in the AJM

Report to develop these reserves. Yangarra plans to develop the proved undeveloped reserves within the next two years.

Probable undeveloped reserves

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
Prior thereto	-	-	-
2003	-	5,197	53.2
2004	77.5	4,191	97.3
2005	28	5,772	78
2006	18.6	7,139	132.2
2007		7,787	42.9

Probable undeveloped reserves are generally adjacent to proven undeveloped reserves, lands contiguous to production or indicated by analogy to be productive. In general, once proved and/or probable undeveloped reserves are identified, Yangarra schedules them into development plans within two years.

A number of factors that could result in delayed or cancelled development are changing economic conditions (due to pricing, operating and capital expenditure fluctuations), changing technical conditions (production anomalies (such as water breakthrough or accelerated depletion), multi-zone developments (for example, a prospective formation completion may be delayed until the initial completion is no longer economic); a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and surface access issues.

Item 5.2 Significant Factors or Uncertainties

The Company does not anticipate any significant economic factors or that significant uncertainties will affect any particular components of its Reserves Data. However, the Company's reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Company's control.

The Company, Subsequent to the December 31, 2007 year end, sold its interests in the Provost area. The AJM Report has estimated the Company's net proved plus probable reserves at 2.8 Mboe.

Item 5.3 Future Development Costs

The following table sets forth development costs deducted in the estimation of the Company's future net revenue attributable to the reserve categories noted below:

	Total Proved Estimated Using Forecast Prices and Costs ($M)	Total Proved Plus Probable Using Forecast Prices and Costs ($M)
2008	8,044.3	11,405.0
2009	1,072.2	2,900.0
2010	-	-
2011	-	-
2012	-	-
Thereafter	-	-
Total for all years undiscounted	9,116.5	14,305

Yangarra expects that such funding to finance its capital expenditure programs will be primarily obtained from cash flow from operations and will not have any associated funding costs. Therefore, the capital commitments will not affect the disclosed reserves or future net revenue.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

The following is a description of Yangarra's principal oil and natural gas properties as at December 31, 2007. The Company's proved plus probable reserves information is at December 31, 2007. Unless otherwise specified, gross and net acres and well information is at December 31, 2007.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Medicine Hat, Alberta				
Producing	-	-	40	40
Non-producing	-	-	34	33.4
Ferrier, Alberta				
Producing	3	1.375	10	3.74
Non-producing	-	-	8	3.22
Jaslan, Alberta				
Producing	-	-	3	1.125
Non-producing	-	-	2	1.375
Bigstone, Alberta				
Producing	-	-	1	0.25
Non-producing	-	-	1	0.25
Viking South, Alberta				
Producing	-	-	3	0.75
Non-producing	-	-	-	-
Provost, Alberta				
Producing	-	-	1	0.375
Non-producing	-	-	-	-
Mega, Alberta				
Producing	-	-	-	-
Non-producing	-	-	1	0.9

MEDICINE HAT

Yangarra holds 100% working interest in a total of 80 sections of land located 25 miles southwest of the city of Medicine Hat, Alberta.

A total of 74 wells have been drilled, re-entered, or acquired on the property. A 100% owned compressor station, capable of 4.0 million cubic feet per day situated at 5-25-9-6W4 was built at the end of 2003. Production is from the Sunburst, Bow Island, Second White Specks, Medicine Hat and Milk River Formations.

The Company's proved plus probable reserves for the Medicine Hat area is estimated at 1,622.5 Mboe.

Plans for Medicine Hat area includes further development of the Bow Island and the shallow horizons. Wells assigned reserves that are drilled and capable of producing and have been but not tied in, will be tied in as development of the field reaches these outlying wells.

FERRIER

Yangarra holds interests ranging from 24.375 to 100% working interest position in 34 sections in this multi-zone area. The field is located 60 miles north west of Red Deer, near the town of Rocky Mountain House, Alberta. Yangarra has a 50% ownership in the compressor station capable of 10 Mmcf/d constructed in early 2004, which also processes third party volumnes providing the Company incremental profit. A total of 23 wells, (3 oil, 17 gas, 3 abandoned) have been drilled, re-entered, or acquired in this area.

The Company's proved plus probable reserves are estimated at 666.6 Mboe.

Further development of the Cardium, Viking, and Rock Creek pools are planned for the area.

JASLAN

The Jaslan property is located 100 miles north east of Edmonton and consists of 5 sections (100% working interest) in the north block, and 8 sections (37.5% working interest) in the south block. A compressor station capable of 3.0 million cubic feet per day (45% working interest) and gathering system was completed in November 2006. One 100% working interest standing well was tied in to the Jaslan compressor gas gathering system early 2008. To date one well had been drilled in the north block, and a total of five wells have been drilled or re-entered in the south block.

Yangarra's proved plus probable reserves are estimated at 229.4 Mboe.

BIGSTONE

The Bigstone area is located 20 miles south west of FoxCreek, northwest of Edmonton, Alberta. Yangarra holds a 25% working interest in 3 sections. One Bigstone area well was shut-in till fall 2007, and one remains shut in. The Company's proved plus probable reserves are estimated at 31.3 Mboe. Both wells were put back on production in the first quarter 2008.

VIKING SOUTH

Yangarra holds a 25% working interest in the Viking area, located 10 kms north of Wainwright, Alberta. Yangarra's proved plus probable reserves, from the three producing wells are estimated at 11.2 Mboe.

PROVOST

The Provost area is located in east central Alberta. Yangarra holds a 37.5% working interest in 1 ½ sections in the Provost area. The Company's proved plus probable reserves are estimated at 3.4 Mboe. The property was subsequently sold in the first quarter 2008.

Item 6.2 Properties With No Attributed Reserves

	Undeveloped Hectares	
Location	Gross	Net
Alberta	29,303	21,889
Saskatchewan	3,620	1,086

There are no work commitments on the undeveloped land holdings in which Yangarra has an interest. The Company expects that rights to explore, develop, and exploit 5,081 net acres of undeveloped land holdings will expire within one year, but intends to drill or submit applications to continue selected portions of the above acreage.

An independent evaluation of these properties by Seaton Jordan & Associates Ltd. estimated a value of $2,903,764 as of December 31, 2007.

Item 6.3 Forward Contracts

In February 2008, the Company committed to the following European Commodity Collars for the sale of natural gas: 500 GJ per day from April 1 to December 31, 2008 at a ceiling price of $8.46 per GJ and a floor price of $7.25 per GJ; 500 GJ per day from April 1 to December 31, 2008 at a ceiling price of $8.31 per GJ and a floor price of $7.75 per GJ, 500 GJ per day from April 1 to December 31, 2008 at a ceiling price of $8.25 per GJ and a floor price of $7.00 per GJ, and 500 GJ per day from April 1 to December 31, 2008 at a ceiling price of $8.15 per GJ and a floor price of $7.50 per GJ.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

The Company uses its internal historical costs and industry's historical costs when available, to estimate its abandonment and reclamation costs. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements.

Yangarra has 60 net wells for which it expects to incur abandonment and restoration costs. These costs included well abandonment and surface lease reclamation. The estimated total abandonment and reclamation costs, forecast net of estimated salvage value, under the proved reserves category is $2,111.9 M (undiscounted), and $959.5 M (discounted at 10%). The total proved plus probable abandonment and reclamation costs are $2,613.4 M (undiscounted), and $1,051.0 M (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Company in respect of proved and proved plus probable reserves as disclosed above. Abandonment and reclamation estimated costs are included in the AJM Report as a deduction in arriving at future net revenue.

Forecast Prices and Costs – Proved (M$)

Year	Abandonment Costs (Undiscounted)	Abandonment Costs (Discounted at 10%)
2008	52.8	50.3
2009	88.7	76.9.
2010	66.7	52.6
Thereafter	1,903.7	779.7
Total	2,111.9	959.5

Forecast Prices and Costs – Proved Plus Probable (M$)

Year	Abandonment Costs (Undiscounted)	Abandonment Costs (Discounted at 10%)
2008	100	95.3
2009	100	86.7
2010	0.0	0
Thereafter	2,413.4	869
Total	2,613.4	1,051.0

Item 6.5 Tax Horizon

Yangarra was not required to pay income tax in 2007. Based on current tax pools, projected cash flow, and projected exploration costs, the Company does not expect to be taxable in 2008.

Item 6.6 Costs Incurred

The following summarizes certain expenditures related to Yangarra's activities for the year ended December 31, 2007

	Year Ended December 31, 2007
Property acquisitions	
Proved	7,410
Unproved	364,673
Exploration Costs	564,862
Development Costs	2,326,011

Item 6.7 Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Yangarra participated during the year ended December 31, 2007.

Exploration Wells	Gross	Net	**Development Wells**	Gross	Net
Light and Medium Oil	-	-	Light and Medium Oil	-	-
Natural Gas	-	-	Natural Gas	4.0	2.62
Service	-	-	Service	-	-
Dry	1.0	0.5	Dry	-	-
Total	1.0	0.5	Total	4.0	2.62

Item 6.8 Production Estimates

The following table sets out the volume of Yangarra's gross production (forecasted), estimated for the year end December 31, 2008, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	Total Proved Reserves			Total Probable Reserves		
	Light and medium oil (Bbls/d)	Natural Gas MMcf/d)	Natural Gas Liquids (Bbls/d)	Light and medium oil (Bbls/d)	Natural Gas (MMcf/d)	Natural Gas Liquids (Bbls/d)
Medicine Hat	-	793.4	-	-	127.2	-
Ferrier	4,026.5	329.5	13.5	4,935.3	51.7	2.5
Jaslan	-	265.2	-	-	7.8	-

* Table includes fields that account for more than 20% of the estimated production reflected in the estimate of future net reserves.

Item 6.9 Production History

Average Daily Production

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil (bbl/d)	20.4	15.7	12.3	6.3
Natural gas (mcf/d)	3,342.6	2,856.4	2,154.3	1,973.4
Natural gas liquids (bbl/d)	45.2	36.5	37.4	27.2
Total (BOE/d)	622.7	528.2	408.8	362.4

Prices Received, Royalties Paid, Production Costs and Net backs

Average Prices Received per Unit – (Before Deduction of Royalties)

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil ($/bbl)	$67.16	$70.50	$81.28	$87.71
Natural gas ($/mcf)	$7.60	$7.62	$6.59	$6.68
Natural gas liquids ($/bbl)	$48.41	$52.8	$56.85	$69.45

Royalties Paid per Unit

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil ($/bbl)				
Natural gas ($/mcf)				
Natural gas liquids ($/bbl)				
Total costs per $/BOE	$6.49	$7.453	$4.97	$2.74

Production and Transportation Costs

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil ($/bbl)				
Natural gas ($/mcf)				
Natural gas liquids ($/bbl)				
Total costs per $/BOE	$6.29	$8.56	$12.67	$12.28

Netbacks Received

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil ($/bbl)				
Natural gas ($/mcf)				
Natural gas liquids ($/bbl)				
Total per $/BOE	$33.71	$37.38	$24.74	$27.92

Production Volume by Field

The following table indicates the Company's average daily production from its important fields for the year ended December 31, 2007:

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
Medicine Hat	-	1,108	-	185.0
Ferrier	11.9	625	33.1	149.5
Jaslan	-	201	-	33.5