EXPEDITION ENERGY INC.

FORM 51-101F1

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

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GLOSSARY OF ABBREVIATIONS

AECO-C	Alberta Energy Company “C” Meter Station of the Nova Pipeline System
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Bbl	Barrels
Bbl/d	Barrels per day
BOE	Barrel of oil equivalent (6 Mcf = 1Bbl)
BOE/d	Barrels of oil equivalent per day
CICA	Canadian Institute of Chartered Accountants
GJ	Gigajoules
GJ/d	Gigajoules per day
Mbbl	Thousand Barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousand cubic feet
Mcf/d	Thousand cubic feet per day
Mmcf	Million cubic feet
Mmcf/d	Million cubic feet per day
Mmbtu	Millions of British thermal units
NGLs	Natural gas liquids
OPEC	Organization of Petroleum Exporting Countries
stb	Standard stock tank barrel
WTI	West Texas Intermediate
M$	Thousands of dollars
MM$	Millions of dollars

CONVERSION OF UNITS

1 acre	0.4 hectares
2.5 acres	1 hectare
1 bbl	0.159 cubic metres
6.29 bbls	1 cubic metre
1 foot	0.3048 metres
3.281 feet	1 metre
1 mcf	28.2 cubic metres
0.035 mcf	1 cubic metre
1 mile	1.61 kilometres
0.62 miles	1 kilometre
1 mmbtu	1.054 GJ
0.949 mmbtu	1 GJ

In this Statement of Reserves Data and Other Oil and Gas Information (the “**Statement**”) for Expedition Energy Inc. (“**Expedition**” or the “**Corporation**”) where amounts are expressed on a barrel of oil equivalent basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CURRENCY

In this Statement, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Statement and in certain documents incorporated by reference into this Statement, constitute forward-looking statements. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Statement should not be unduly relied upon. These statements speak only as of the date of this Statement or as of the date specified in the documents incorporated by reference into this Statement, as the case may be. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements.

In particular, this Statement and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- the quantity of reserves;
- oil and natural gas production levels;
- capital expenditure programs;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under government regulatory and taxation regimes.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Statement:

- volatility in market prices for oil and natural gas;
- liabilities and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility; and
- changes in government regulations.

These factors should not be considered exhaustive.

Petroleum and Natural Gas Reserves

GLJ Petroleum Consultants Ltd. ("**GLJ**"), independent petroleum engineers of Calgary, Alberta prepared a Reserves Assessment and Evaluation of Canadian Oil and Gas Properties - Corporate Summary dated April 3, 2006 of Expedition's oil and gas reserves (the "**GLJ Report**") which evaluation is effective December 31, 2005. In preparing its report, GLJ obtained basic information from Expedition, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the GLJ Report is based, was obtained from public records, other operators and from GLJ's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by GLJ as represented.

The following tables set forth certain information relating to the oil and natural gas reserves of the Corporation's properties and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2005 which numbers may vary slightly from those presented in the GLJ Report due to rounding. Also due to rounding, certain columns may not add exactly. Certain tables which are derived by utilizing forecast prices and costs are presented with December 31, 2005 pricing assumptions. The information set forth below is derived from the GLJ Report which has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in National Instrument 51-101 - *Standards of Disclosure For Oil and Gas Activities* ("**NI 51-101**"). **All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Corporation's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that he estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.**

PART 1 DATE OF STATEMENT

1. Date of the Statement: April 27, 2006.
2. Effective date of the Statement: December 31, 2005.
3. Preparation date of the Statement: April 27, 2006.

PART 2 DISCLOSURE OF RESERVES DATA

Definitions used for reserve categories in the GLJ Report are attached as Appendix A hereto.

The following table summarizes Expedition's oil and gas reserves as of December 31, 2005 based on constant price and cost assumptions:

SUMMARY OF OIL AND GAS RESERVES as of December 31, 2005 CONSTANT PRICES AND COSTS										
	Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated & associated)		Natural Gas Liquids		Oil Equivalent	
Reserves Category	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf))	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED										
Developed Producing	9	8	99	82	3447	2921	84	59	766	635
Developed Non-Producing	0	0	0	0	549	442	15	13	106	87
Undeveloped	0	0	0	0	0	0	0	0	0	0
TOTAL PROVED	9	8	99	82	3996	3363	99	72	873	722
PROBABLE	4	4	26	21	2043	1713	39	28	408	338
TOTAL PROVED PLUS PROBABLE	13	11	124	103	6039	5075	137	100	1281	1060

The following tables summarize the undiscounted value and the present value, discounted at 5%, 10%, 15% and 20%, of Expedition's estimated future net revenue based on constant price and cost assumptions as of December 31, 2005:

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE as of December 31, 2005 CONSTANT PRICES AND COSTS										
Reserves Category	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0 (M$)	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
PROVED										
Developed Producing	25740	20336	17001	14719	13053	21170	17000	14402	12608	11286
Developed Non-Producing	2999	2419	2012	1715	1489	1975	1552	1256	1040	876
Undeveloped	0	0	0	0	0	0	0	0	0	0
TOTAL PROVED	28738	22755	19013	16434	14542	23145	18552	15658	13648	12163
PROBABLE	14430	8356	5665	4206	3309	9607	5535	3731	2752	2149
TOTAL PROVED PLUS PROBABLE	43168	31111	24678	20640	17851	32752	24088	19389	16399	14311

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2005 CONSTANT PRICES AND COSTS								
Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Develop-ment Costs (M$)**	**Well Abandon-ment Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**	**Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
Proved Reserves	46740	6193	10384	1039	386	28738	5593	23145
Proved Plus Probable Reserves	69191	9301	14834	1486	401	43168	10416	32752

NET PRESENT VALUE OF FUTURE NET REVENUE BY PRODUCTION GROUP as of December 31, 2005 CONSTANT PRICES AND COSTS		
RESERVES CATEGORY	**PRODUCTION GROUP**	**FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)**
Proved Reserves	Light and Medium Oil (including solution gas and associated by products)	218
	Heavy Oil (including solution gas and associated by-products)	872
	Natural Gas (including associated by-products)	10305
	Non-conventional natural gas from CBM activity	7619
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and associated by products)	298
	Heavy Oil (including solution gas and associated by-products)	1054
	Natural Gas (including associated by-products)	12515
	Non-conventional natural gas from CBM activity	10811

The following table summarizes Expedition's oil and gas reserves as of December 31, 2005 based on forecast price and cost assumptions:

SUMMARY OF OIL AND GAS RESERVES as of December 31, 2005 FORECAST PRICES AND COSTS										
	Reserves									
	Light and Medium Oil		**Heavy Oil**		**Natural Gas (non-associated & associated)**		**Natural Gas Liquids**		**Oil Equivalent**	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED										
Developed Producing	9	8	99	82	3402	2878	81	57	755	626
Developed Non-Producing	0	0	0	0	537	430	14	13	104	84
Undeveloped	0	0	0	0	0	0	0	0	0	0
TOTAL PROVED	9	8	99	82	3939	3309	95	69	859	710
PROBABLE	4	3	26	21	2093	1756	41	29	419	347
TOTAL PROVED PLUS PROBABLE	12	11	124	103	6031	5065	136	99	1278	1057

The following tables summarize the undiscounted value and the present value, discounted at 5%, 10%, 15% and 20%, of Expedition's estimated future net revenue based on forecast price and cost assumptions as of December 31, 2005:

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005
FORECAST PRICES AND COSTS

Reserves Category	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0 (M$)	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
PROVED										
Developed Producing	19991	16615	14405	12830	11643	17316	14509	12663	11341	10338
Developed Non-Producing	2195	1851	1598	1404	1251	1442	1175	980	833	718
Undeveloped	0	0	0	0	0	0	0	0	0	0
TOTAL PROVED	22186	18466	16002	14234	12894	18758	15684	13643	12174	11057
PROBABLE	10776	6332	4378	3310	2647	7196	4196	2877	2157	1708
TOTAL PROVED PLUS PROBABLE	32961	24798	20380	17545	15541	25954	19880	16521	14331	12765

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2005
FORECAST PRICES AND COSTS

Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Develop-ment Costs (M$)**	**Well Abandon-ment Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**	**Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
Proved Reserves	40567	5482	11364	1044	491	22186	3428	18758
Proved Plus Probable Reserves	61837	8286	18509	1492	588	32961	7007	25954

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2005
FORECAST PRICES AND COSTS

RESERVES CATEGORY	**PRODUCTION GROUP**	**FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)**
Proved Reserves	Light and Medium Oil (including solution gas and associated by products)	178
	Heavy Oil (including solution gas and associated by-products)	1121
	Natural Gas (including associated by-products)	8519
	Non-conventional natural gas from CBM activity	6185
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and associated by products)	232
	Heavy Oil (including solution gas and associated by-products)	1343
	Natural Gas (including associated by-products)	10266
	Non-conventional natural gas from CBM activity	8538

PART 3 PRICING ASSUMPTIONS

Constant Prices and Costs - December 31, 2005

GLJ employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2005 in estimating Expedition's reserves data using constant prices and costs.

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2005

CONSTANT PRICES AND COSTS

	OIL[1]				NATURAL GAS[1]		NATURAL GAS LIQUIDS			
Year	WTI Cushing Oklahoma ($US/Bbl)	Hardisty Bow River 24.9° API ($Cdn/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Cromer Medium 29.3° API ($Cdn/Bbl)	AECO-C Gas Price ($Cdn/mm btu)	Alberta Reference Plantgate ($Cdn/mm btu)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butanes ($Cdn/Bbl)	Edmonton Pentanes Plus ($Cdn/Bbl)	Exchange Rate[2] ($US/$Cdn)
Dec 31, 2005	61.04	39.00	68.27	51.84	9.71	9.46	43.69	50.52	71.67	0.8577

Notes:

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

(2) The exchange rate used to generate the benchmark reference prices in this table.

Forecast Prices and Costs - December 31, 2005

GLJ employed the following pricing, exchange rate and inflation rate assumptions in estimating Expedition's reserves data using forecast prices and costs as of December 31, 2005.

FORECAST PRICES USED IN PREPARING RESERVES DATA
GLJ Price Forecast
Effective January 1, 2006

	Light Oil		Heavy & Medium Oil		Natural Gas Liquids and Sulphur			
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Heavy Crude Oil 12° API At Hardisty ($Cdn/Bbl)	Hardisty Bow River 24.9° API ($Cdn/Bbl)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	Edmonton Pentanes Plus ($Cdn/Bbl)	Alberta Plantgate Sulphur ($Cdn/LT)
Historical								
2001	25.97	39.40	16.94	27.70	31.85	31.17	42.48	-14.66
2002	26.08	40.33	26.57	31.83	21.39	27.08	40.73	3.04
2003	31.07	43.66	26.26	32.11	32.14	34.36	44.23	39.83
2004	41.38	52.96	29.11	36.86	34.70	39.97	54.07	38.61
2005	56.60	69.11	34.14	44.96	42.55	51.41	69.45	34.04
Forecast								
2006	57.00	66.25	33.25	43.00	42.50	49.00	67.00	31.00
2007	55.00	64.00	32.75	42.50	41.00	47.25	65.25	21.00
2008	51.00	59.25	32.5	41.00	38.00	43.75	60.50	9.50
2009	48.00	55.75	32.00	39.50	35.75	41.25	56.75	9.50
2010	46.50	54.00	32.00	39.50	34.50	40.00	55.00	10.50
2011	45.00	52.25	33.50	39.75	33.50	38.75	53.25	12.00
2012	45.00	52.25	33.50	39.75	33.50	38.75	53.25	13.00
2013	46.00	53.25	34.00	40.50	34.00	39.50	54.25	14.00
2014	46.75	54.25	34.75	41.25	34.75	40.25	55.25	15.50
2015	47.75	55.50	35.25	42.25	35.50	41.00	56.50	17.00
Escalation rate of 2.0% thereafter								

	Natural Gas						
Year	**Alberta Gas Reference Price Plantgate ($Cdn/Mmbtu)**	**Alberta AECO-C Spot ($Cdn/Mmbtu)**	**Aggregator Plantgate ($Cdn/Mmbtu)**	**Alliance Pipeline ($Cdn/Mmbtu)**	**Henry Hub Price ($US/ Mmbtu)**	**Operating Cost Inflation Rate (%/Yr)**	**Exchange Rate ($US/$Cdn)**
Historical							
2001	5.41	6.21	5.30	5.61	4.05	2.6	0.646
2002	3.88	4.04	3.83	3.82	3.36	2.2	0.637
2003	6.13	6.66	5.89	6.69	5.50	2.8	0.721
2004	6.31	6.88	6.16	6.44	6.19	1.8	0.768
2005	8.35	8.58	8.36	8.45	8.97	2.2	0.825
Forecast							
2006	10.35	10.60	10.25	10.50	10.50	2.0	0.850
2007	9.00	9.25	9.00	8.90	8.75	2.0	0.850
2008	7.75	8.00	7.75	7.45	7.50	2.0	0.850
2009	7.25	7.50	7.25	6.90	7.00	2.0	0.850
2010	6.95	7.20	6.95	6.65	6.75	2.0	0.850
2011	6.65	6.90	6.65	6.35	6.50	2.0	0.850
2012	6.65	6.90	6.65	6.35	6.50	2.0	0.850
2013	6.80	7.05	6.80	6.50	6.65	2.0	0.850
2014	6.95	7.20	6.95	6.65	6.75	2.0	0.850
2015	7.15	7.40	7.15	6.80	6.90	2.0	0.850
Escalation rate of 2.0% thereafter							

Expedition's weighted average realized sales prices by product type for the year ended December 31, 2005 were $31.09/Bbl for heavy oil, $66.72/Bbl for light & medium oil, $61.41/Bbl for NGLs and $9.53/Mcf for natural gas.

PART 4 RECONCILIATION OF CHANGES IN *RESERVES* AND *FUTURE NET REVENUE*

Reserves Reconciliation

The following table sets forth a reconciliation of Expedition's total net proved, probable and proved plus probable reserves as at December 31, 2005 against such reserves as at December 31, 2004 based on forecast price and cost assumptions.

	Light and Medium Oil (2)			Heavy Oil			Conventional Natural Gas			Coalbed Methane Gas(1) - Canada			BOE		
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))**	**Net Proved (MMcf)**	**Net Probable (MMcf)**	**Net Proved Plus Probable (MMcf)**	**Net Proved (Mboe)**	**Net Probable (Mboe)**	**Net Proved Plus Probable (Mboe)**
December 31, 2004	35	15	50	35	18	53	992	316	1308	1106	420	1526	419	156	575
Extensions	64	27	90	0	0	0	1091	562	1653	0	212	212	245	156	401
Improved Recovery	3	1	4	35	8	43	161	52	212	0	0	0	65	18	83
Technical Revisions	-26	-13	-39	29	-4	25	-393	-258	-651	560	426	986	31	10	41
Discoveries	6	3	9	0	0	0	82	27	108	0	0	0	20	7	27
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	2	0	2	2	0	2	1	0	1
Production	-5	0	-5	-18	0	-18	-153	0	-153	-140	0	-140	-71	0	-71
December 31, 2005	78	32	110	82	21	103	1782	698	2480	1527	1058	2585	710	347	1057

Notes:

(1) The Corporation has unconventional natural gas reserves from coal as detailed in the table above but no other unconventional reserves (Bitumen, Synthetic Crude Oil, etc.)

(2) Includes NGL's.

Future Net Revenue Reconciliation

The following table sets forth a reconciliation of Expedition's estimate of future net revenue discounted at 10%, attributable to net proved reserves as evaluated on the GLJ Report using constant prices and costs.

Period and Factor	After Tax 2005 (M$)	Before Tax 2005 (M$)
Estimated Net Present Value at January 1, 2005	**6,573**	**7,976**
Oil and Gas Sales During the Period Net of Production Costs and Royalties (1)	(2,931)	(2,931)
Changes due to Prices, Production Costs and Royalties Related to Forecast Production (2)	4,955	4,955
Development Costs During the Period (3)	10,094	10,094
Changes In Forecast Development Costs (4)	(10,439)	(10,439)
Changes Resulting from Extensions and Improved Recovery (5)	7,155	7,155
Changes Resulting from Discoveries (5)	407	407
Changes Resulting from Acquisitions of Reserves (5)	0	0
Changes Resulting from Dispositions of Reserves (5)	0	0
Accretion of Discount (6)	798	798
Net Change in Income Taxes (7)	(1,952)	0
Changes Resulting from Technical Reserves Revisions	123	123
All Other Changes	876	876
Estimated Net Present Value at End of Period December 31, 2005	**15,658**	**19,013**

Notes:

(1) Corporation actual before income taxes, excluding G&A.
(2) The impact of changes in prices and other economic factors on future net revenue.
(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.
(4) The change in forecast development costs for the properties evaluated at the beginning of the period.
(5) End of period net present value of the related reserves.
(6) Estimated as 10% of the beginning of period net present value.
(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.

PART 5 ADDITIONAL INFORMATION RELATING TO *RESERVES DATA*

Undeveloped Reserves

The following discussion generally describes the basis on which Expedition attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from Expedition gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two year timeframe.

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It required significant judgments and decisions based on available geological, geophysical, engineering and economic 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 change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Expedition's reserves are evaluated by GLJ, an independent engineering firm.

Estimates made are reviewed and revised, either upward to downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. Expedition's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue attributable to proved reserves (using both constant prices and costs and forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only).

	Constant Prices and Costs	**Forecast Prices and Costs**	
Year	**Proved Reserves (M$)**	**Proved Reserves (M$)**	**Proved Plus Probable Reserves (M$)**
2006	891	891	1339
2007	15	15	15
2008	130	135	135
2009	0	0	0
2010	0	0	0
Remaining Years	3	3	3
Total Undiscounted	1039	1044	1492
Total Discounted at 10% per year	967	971	1398

The Corporation has established a $10.0 million capital program to fund its exploration and development activities for 2006. The Corporation's capital program does not include any new acquisition opportunities, which would likely be financed through debt or equity financings.

Expedition estimates that its internally generated cash flow will be sufficient to fund the future development costs disclosed above. Expedition typically has available three sources of funding to finance its capital expenditure program; internally generated cash flow from operating activities, debt financing when appropriate and new equity issues, if available on favourable terms.

PART 6 OTHER *OIL AND GAS* INFORMATION

Oil and Gas Properties and Wells

Expedition has properties located in Alberta and Saskatchewan, all of which are the subject of the GLJ Report. The term "net", when used to describe the Corporation's share of production, means the total of the Corporation's working interest share before deducting royalties owned by others.

Principal Producing Properties

Ferrier Area, Alberta

In the Ferrier area the Corporation is currently producing 600 Mcf/d net from 1 gas well, producing from the Elkton zone where it holds a 50% working interest.

Kerrobert Area, Saskatchewan

In the Kerrobert area the Corporation is currently producing 100 Bbl/d net from 3 heavy oil wells, producing from the Waseca zone where it holds a 50% working interest.

Nevis Area, Alberta

In the Nevis area the Corporation holds a 100% working interest in 640 net acres. Eight (8) coalbed methane gas wells are currently producing at a combined rate of 1200 Mcf/d net.

Three Hills Creek Area, Alberta

In the Three Hills Creek area the Corporation holds a 100% working interest in 1 gas well which is currently producing at a rate of 85 Mcf/d.

Principal Non-Producing Properties

Cessford Area, Alberta

In the Cessford area the Corporation holds a 100% working interest in 1 standing gas well that is currently being tied-in. Production is expected to be 350 Mcf/d net commencing in Q2-2006.

Erskine Area, Alberta

In the Erskine area the Corporation holds a 78% working interest in 1 standing gas well that is currently being tied-in. Production is expected to be 200 Mcf/d net commencing in Q2-2006. In addition, the Corporation holds varying interests in shallow gas and coalbed methane probable reserves in the Erskine area.

Wells

As at December 31, 2005, the Corporation had an interest in 20 gross (13.75 net) producing and 10 gross (4.804 net) non-producing oil and natural gas wells and no service wells as set out in the following table.

	PRODUCING				NON-PRODUCING				SERVICE WELLS	
	Oil		Natural Gas		Oil		Natural Gas			
Location	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	2	.225	14	11.6	0	0	9	4.304	0	0
Saskatchewan	4	1.925	0	0	1	.5	0	0	0	0
TOTAL	6	2.150	14	11.6	1	.5	9	4.304	0	0

Notes:

(1) "Gross" wells means the number of wells in which Expedition has a working interest or a royalty interest that may be convertible to a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Expedition's percentage working interest therein.

Properties With No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by the Corporation and the net area of unproved property for which the Corporation expects its rights to explore, develop and exploit to expire during the next year.

UNPROVED PROPERTIES - UNDEVELOPED LAND (acres)			
LOCATION	**Gross(1)**	**Net(2)**	**Net Area to Expire in 2006**
Alberta	15,452	9,551	264
Saskatchewan	637	304	140
TOTAL	16,089	9,855	404

Notes:

(1) "Gross Acres" are the total acres in which Expedition has or had an interest.

(2) "Net Acres" is the aggregate of the total acres in which Expedition has or had an interest multiplied by Expedition's working interest percentage held therein.

There are no costs or work commitments associated with Expedition's non-producing properties except for annual lease rental payments.

Forward Contracts

Expedition may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. Expedition currently has no hedges in place.

Additional Information Concerning Abandonment and Reclamation Costs

Expedition estimates the costs associated with well abandonment and reclamation based on its previous experience, current regulations, costs, technology and industry standards area by area. Expedition expects to incur abandonment and reclamation costs on 30 gross wells (18.554 net wells). Expedition's share of the expected total abandonment and reclamation costs for wells with assigned reserves, non-producing and service wells and facilities, net of salvage value are summarized, without discount and using a discount rate of 10%, in the following table:

	Constant Pricing (M$)		Forecast Pricing (M$)			
Category	**Proved NPV 0%**	**Proved NPV 10%**	**Proved 0%**	**Proved 10%**	**Proved Plus Probable 0%**	**Proved Plus Probable NPV 10%**
Wells with reserves assigned(1)	386	152	491	179	588	142
Wells with no reserves assigned and Facilities(2)	18	8	18	8	18	8
Total abandonment and reclamation cost provision	404	160	509	187	606	150
Portion forecast to be paid during the next three years	70	63	72	64	41	37

Notes:

(1) Abandonment and reclamation costs were estimated by GLJ and included in the GLJ Report for all wells assigned reserves.

(2) Expedition has estimated the timing and the costs associated with the abandonment and reclamation for wells with no reserves assigned and for facilities. This represents the total abandonment and reclamation costs that were not deducted in computing future net revenue.

Tax Horizon

At the end of 2005, Expedition had estimated income tax deductions of approximately $12.0 million available to reduce future taxable income. Unless sufficient income tax deductions are generated by future business operations, Expedition could incur current income taxes in 2006 and 2007.

Costs Incurred

The following table summarizes Expedition's property acquisition costs, exploration costs and development costs incurred during the financial year ended December 31, 2005.

Property Acquisitions and Capital Expenditures	
Nature of Cost	**Amount ($M)**
Property Acquisition Costs	0
Proved	0
Unproved	0
Exploration Costs	3,875,255
Development Costs	6,295,023
Total	10,170,278

Exploration and Development Activities

The following table summaries the results of exploration and development activities during the financial year ended December 31, 2005.

Number of Wells	Gross	Net
Development		
Gas	3	2.0
Oil	3	1.425
Coal Bed Methane	4	4.0
Unsuccessful	0	0
Exploratory		
Gas	2	1.476
Oil	1	0.2
Coal Bed Methane	0	0
Unsuccessful	1	.55
Total	14	9.651

Expedition's initial plans for 2006 include a $10.0 million capital expenditure program, funded from cash flow from operating activities, bank debt and the issuance of new equity.

Production Estimates

The following table discloses the estimated average daily production before the deduction of royalties of Expedition for 2006 by product type associated with the first year of the future net revenue estimates reported in the GLJ Report effective December 31, 2005, based on constant prices and costs.

Corporation	Light and Medium Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined Oil Equivalent (BOE/d)
Proved					
Developed producing	7	100	1550	31	396
Developed non-producing	0	0	376	6	69
Undeveloped	0	0	0	0	0
Total Proved	7	100	1926	37	464
Probable	0	2	135	1	26
Total proved plus probable	7	102	2061	38	490

The following tables disclose the estimated average daily production before deduction of royalties for 2006 for Expedition's Ferrier, AB, Kerrobert, SK, and Nevis, AB properties, each being in excess of 20% of the total estimated production set forth in the immediately preceding table.

Ferrier, AB Property	Light and Medium Crude Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined (BOE/d)
Proved					
Developed producing	0	0	432	27	99
Developed non-producing	0	0	40	3	9
Undeveloped	0	0	0	0	0
Total Proved	0	0	472	30	108
Probable	0	0	11	1	3
Total proved plus probable	0	0	483	30	111

Kerrobert, SK Property	Light and Medium Crude Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined (BOE/d)
Proved					
Developed producing	0	100	0	0	100
Developed non-producing	0	0	0	0	0
Undeveloped	0	0	0	0	0
Total Proved	0	100	0	0	100
Probable	0	2	0	0	2
Total proved plus probable	0	102	0	0	102

Nevis, AB Property	Light and Medium Crude Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined (BOE/d)
Proved					
Developed producing	0	0	782	0	130
Developed non-producing	0	0	0	0	0
Undeveloped	0	0	0	0	0
Total Proved	0	0	782	0	130
Probable	0	0	16	0	3
Total proved plus probable	0	0	798	0	133

Production History

The following table summarizes Expedition's average daily production before deduction of royalties, for the periods indicated.

	2005				
Product	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Oil and NGLs (Bbl/d)	74.3	113.1	70.1	59.4	53.8
Natural gas (Mcf/d)	961	1339	1427	671	381
Total (BOE/d)	234.5	336.3	309.9	171.2	117.4

Netback History

The following table sets forth information respecting average net product prices received, royalties paid, production expenses and operating netbacks received by the Corporation in respect of the Corporation's production of crude oil and natural gas for the periods indicated.

Category	2005				
	Year	Q4	Q3	Q2	Q1
Selling prices					
Heavy Oil	31.09	26.84	43.07	28.39	27.90
Light Oil & NGLs ($/Bbl)	62.61	64.74	65.12	53.95	50.07
Natural gas ($/Mcf)	9.53	11.81	9.17	7.14	6.96
Royalties					
Heavy Oil	7.72	6.26	13.47	6.37	5.31
Light Oil & NGLs ($/Bbl)	5.46	3.81	6.05	6.13	12.47
Natural gas ($/Mcf)	.37	(0.41)	.92	.24	1.30
Transportation and selling expenses					
Heavy Oil	0.84	0.78	1.13	0.00	1.64
Light Oil & NGLs ($/Bbl)	0.43	0.14	0.34	0.89	1.98
Natural gas ($/Mcf)	0.27	0.67	0.03	0.06	0.15
Production expenses[(1)]					
Heavy Oil	8.12	5.69	3.24	7.98	17.56
Light Oil & NGLs ($/Bbl)	8.50	1.13	13.35	39.30	14.64
Natural gas ($/Mcf)	1.69	2.44	1.01	1.95	1.12
Operating netbacks					
Heavy Oil	14.41	14.11	25.23	14.04	3.39
Light Oil & NGLs ($/Bbl)	48.22	59.66	45.38	7.63	20.98
Natural gas ($/Mcf)	7.20	9.11	7.21	4.83	4.39

Note:

(1) Production expenses include petroleum and surface lease rentals, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems.

Production Volume by Field

The following table discloses for each important field, and in total, Expedition's production volumes for the financial year ended December 31, 2005 for each product type.

Field	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Ferrier, Alberta	0	0	163	10.2	37.4	15.9
Highvale, Alberta	0	0	85	0.1	14.2	6.1
Huxley, Alberta	1.9	0	65	1.5	14.1	6.0
Medicine Hat, Alberta	0	0	83	0	13.8	5.9
Nevis, Alberta	0	0	491	0	81.9	34.9
Three Hills Creek, Alberta	0.1	0	73	1.3	13.6	5.8
Other, Alberta	2.8	0	2	0.2	3.3	1.4
Saskatchewan	0	56.2	0	0	56.2	24.0
Total	4.8	56.2	962	13.3	234.5	100.0

APPENDIX A
DEFINITIONS USED FOR RESERVE CATEGORIES

Reserves estimates have been prepared by GLJ Petroleum Consultants Ltd. ("GLJ") in accordance with standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. The following reserves definitions are set out by the Canadian Securities Administrators in National Instrument 51-101 (NI51-101; in Part 2 of Appendix 1 to Companion Policy 51-101CP) with reference to the COGE Handbook.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from know accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology;
- specified economic conditions[1], which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

Proved Reserves

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

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

Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

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[1] For the purposes of NI 51-101, the key economic assumptions will be the prices and costs used in the estimate, namely:
(a) constant prices and costs as at the last day of a reporting issuer's financial year; or
(b) forecast prices and costs.

Developed 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 (e.g., 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

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 know with reasonable certainty.

Developed Non-Producing Reserves

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

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, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

> A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.
>
> Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of the COGE Handbook.

Incorporation of these guidelines means that total corporate proved reserves reflect a conservative estimated and proved plus probable reserves reflect a current “best estimate” of the oil and gas quantities which will be recovered.