

Form 51-101F1

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

PART 1 DATES

The effective date of this Form 51-101F1 is December 31, 2005 and is dated September 26, 2006.

A reserve and economic evaluation of oil and gas properties owned by COSTA Resources Ltd. ("the Company") was prepared by McDaniel & Associates Consultants Ltd. ("McDaniel"), the Company's independent reserve evaluator, dated February 2, 2006 and is effective as of December 31, 2005.

This Form 51-101F1 for the Company contains as an appendix, the Form 51-101F1 of Kelso Energy Inc., a company whose name was subsequently changed to COSTA Energy Inc. McDaniel also prepared the reserve and economic evaluation of the oil and gas properties owned by Kelso Energy Inc. in a report dated May 2, 2006, which is also effective as of December 31, 2005.

All properties evaluated in this report are located within the provinces of British Columbia and Alberta, Canada.

For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent ("boe") using six thousand cubic feet ("mcf") to one barrel of oil. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boe's may be misleading, particularly if used in isolation.

PART 2 RESERVES AND FUTURE NET REVENUE DATA

Notes to the Following Reserve Data Tables

1. Columns may not add due to rounding.
2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the McDaniel report are based on the definitions and guidelines contained in the National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGEH").
3. Abbreviations and conversions are shown on Attachment 1.

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005**

CONSTANT PRICES AND COSTS

Reserves Category	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl
PROVED								
Developed Producing	10.8	10.6	0	0	474	397	2.2	1.6
Developed Non-Producing	0	0	0	0	193	160	0	0
Undeveloped	0	0	0	0	300	242	0	0
TOTAL PROVED	10.8	10.6	0	0	967	799	2.2	1.6
PROBABLE	6.2	6.1	0	0	202	167	1.3	0.9
TOTAL PROVED PLUS PROBABLE	17.0	16.7	0	0	1,168	967	3.5	2.5

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005**

CONSTANT PRICES AND COSTS

Reserve Category	NET PRESENT VALUE OF FUTURE NET REVENUE [1]							
	Before Income Taxes Discounted at (% per Year)				After Income Taxes Discounted at (% per Year)			
	0% M\$	5% M\$	10% M\$	15% M\$	0% M\$	5% M\$	10% M\$	15% M\$
PROVED								
Developed Producing	3,393	3,038	2,744	2,500	3,019	2,736	2,496	2,294
Developed Non-Producing	1,324	1,152	1,019	913	893	785	702	636
Undeveloped	1,404	1,111	885	709	923	710	545	415
TOTAL PROVED	6,121	5,301	4,648	4,122	4,835	4,231	3,743	3,346
PROBABLE	1,626	1,229	953	758	1,102	834	646	513
TOTAL PROVED PLUS PROBABLE	7,747	6,530	5,601	4,880	5,937	5,065	4,389	3,859

Notes: [1] Includes ARTC

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2005**

CONSTANT PRICES AND COSTS

Reserve Category	Revenue [1]	Royalties [2]	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenues Before Income Tax [3]	Income Taxes	Future Net Revenues After Income Tax
	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$
Total Proved	10,251	1,626	1,615	754	291	6,121	1,286	4,835
Total Proved Plus Probable	12,672	1,987	2,080	754	291	7,747	1,810	5,937

Notes: [1] Includes non-producing income
[2] Includes Net Profits Interest paid.
[3] Includes ARTC

**FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2005**

CONSTANT PRICES AND COSTS

Reserve Category	Production Group	Before Income Tax Discounted at 10% per Year \$M
Total Proved	Light and Medium Oil (including solution gas and other by-products)	359
	Natural Gas (including by-products but not solution gas)	4169
	Alberta Royalty Tax Credit	121
Proved Plus Probable	Light and Medium Oil (including solution gas and other by-products)	531
	Natural Gas (including by-products but not solution gas)	4.930
	Alberta Royalty Tax Credit	140

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005**

FORECAST PRICES AND COSTS

Reserves Category	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl
PROVED								
Developed Producing	10.8	10.6	0	0	474	397	2.2	1.6
Developed Non-Producing	0	0	0	0	193	160	0	0
Undeveloped	0	0	0	0	300	242	0	0
TOTAL PROVED	10.8	10.6	0	0	967	799	2.2	1.6
PROBABLE	6.2	6.1	0	0	202	167	1.3	0.9
TOTAL PROVED PLUS PROBABLE	17.0	16.7	0	0	1,168	967	3.5	2.5

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005**

FORECAST PRICES AND COSTS

Reserve Category	NET PRESENT VALUE OF FUTURE NET REVENUE [1]							
	Before Income Taxes Discounted at (% per Year)				After Income Taxes Discounted at (% per Year)			
	0% M\$	5% M\$	10% M\$	15% M\$	0% M\$	5% M\$	10% M\$	15% M\$
PROVED								
Developed Producing	2,600	2,426	2,259	2,108	2,461	2,312	2,164	2,029
Developed Non-Producing	1,056	947	858	785	711	647	595	552
Undeveloped	889	707	561	443	571	435	325	236
TOTAL PROVED	4,546	4,080	3,678	3,336	3,743	3,394	3,084	2,816
PROBABLE	1,048	824	658	535	717	567	453	368
TOTAL PROVED PLUS PROBABLE	5,593	4,903	4,335	3,871	4,460	3,961	3,536	3,184

Notes: [1] Includes ARTC

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2005**

FORECAST PRICES AND COSTS

Reserve Category	Revenue [1] M\$	Royalties [2] M\$	Operating Costs M\$	Development Costs M\$	Well Abandonment Costs M\$	Future Net Revenues Before Income Tax [3] M\$	Income Taxes M\$	Future Net Revenues After Income Tax M\$
Total Proved	8,752	1,378	1,804	772	385	4,546	803	3,743
Total Proved Plus Probable	10,637	1,652	2,375	772	401	5,593	1,134	4,460

Notes: [1] Includes non-producing income.
 [2] Includes Net Profits Interest paid.
 [3] Includes ARTC.

**FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2005**

FORECAST PRICES AND COSTS

Reserve Category	Production Group	Before Income Tax Discounted at 10% per Year \$M
Total Proved	Light and Medium Oil (including solution gas and other by-products)	273
	Natural Gas (including by-products but not solution gas)	3,299
	Alberta Royalty Tax Credit	107
Proved Plus Probable	Light and Medium Oil (including solution gas and other by-products)	381
	Natural Gas (including by-products but not solution gas)	3,833
	Alberta Royalty Tax Credit	122

PART 3 PRICING ASSUMPTIONS

**SUMMARY OF PRICING ASSUMPTIONS
CONSTANT PRICES AND COSTS**

OIL AND LIQUIDS							
Year	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40° API (\$C/Bbl)	Edmonton Propane (\$C/Bbl)	Edmonton Butane (\$C/Bbl)	Edmonton NGL Mix (\$C/Bbl)	Alberta AECO Spot Price (\$C/MMBtu)	US/Cdn Exchange Rate (\$US/\$C)
2006	61.04 [1]	68.46 [2]	49.75 [3]	56.50 [3]	56.30 [3]	9.80 [4]	0.85

Notes: [1] WTI from December 30, 2005 NYMEX close
 [2] Edmonton Par Price from Shell, Imperial, PetroCanada, EnCanan, and Suncor pricing, December 30, 2005
 [3] Propane, Butane, and NGL Mix Prices based on historical price differentials and adjustments.
 [4] Estimated from AECO December 31, 2005 price of \$9.47/GJ

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS [1]
FORECAST PRICES AND COSTS**

OIL AND LIQUIDS								
Year	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40° API (\$C/Bbl)	Edmonton Propane (\$C/Bbl)	Edmonton Butane (\$C/Bbl)	Edmonton NGL Mix (\$C/Bbl) [2]	Alberta Average Plant Gate (\$C/MMBtu)	Inflation (%)	US/Cdn Exchange Rate (\$US/\$C)
2006	57.50	66.60	46.10	48.80	51.40	10.40	2.5	0.85
2007	55.40	64.20	43.00	47.00	48.90	9.35	2.5	0.85
2008	52.50	60.70	39.50	44.50	45.80	8.30	2.5	0.85
2009	49.50	57.20	35.90	41.90	42.60	7.20	2.5	0.85
2010	46.90	54.10	33.70	39.60	40.20	6.70	2.5	0.85
Thereafter				Various Inflation Rates				

Notes: [1] Forecast by McDaniel as at January 1, 2006
 [2] Edmonton NGL Mix is based on 45% propane, 35% butane, and 20% natural gasolines

Weighted average historical prices realized by the Company for the year ended December 31, 2005 were \$11.10 per GJ for natural gas and \$58.13 per Bbl for light crude oil.

PART 4 RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

**RECONCILIATION OF COMPANY NET RESERVES
FORECAST PRICES AND COSTS**

	Light and Medium Crude Oil			Natural Gas		
	Net Proved (MBbl)	Net Probable (MBbl)	Net Proved plus Probable (MBbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved plus Probable (MMcf)
December 31, 2004 [1]	0.0	0.0	0.0	0	0	0
PLUS						
Extensions						
Improved Recovery						
Technical Revisions						
Discoveries						
Acquisitions	12.2	7.0	19.2	799	167	967
Economic Factors						
LESS						
Dispositions						
Production						
December 31, 2005	12.2	7.0	19.2	799	167	967

Notes: [1] The Company was incorporated on November 22, 2004 and did not have reserves at December 31, 2004.

**RECONCILIATION OF CHANGES IN NET PRESENT VALUE OF FUTURE NET REVENUE
TOTAL PROVED RESERVES
CONSTANT PRICES AND COSTS DISCOUNTED AT 10%**

Period and Factor	Before Tax (M\$)	After Tax (\$M)
Estimated Future Net Revenue at December 31, 2004 [1]	0	0
Oil and Gas Sales Net of Production Costs and Royalties	(279)	(279)
Net Change in Prices, Production Costs and Royalties Related to Future Production	0	0
Changes in Previously Estimated Development Costs Incurred During the Period	0	0
Changes in Estimated Future Development Costs	0	0
Extensions and Improved Recovery	0	0
Changes due to Discoveries	0	0
Acquisition of Reserves	4,927	4,022
Disposition of Reserves	0	0
Net Change Resulting from Revisions in Quantity Estimates	0	0
Accretion of Discount	0	0
Net Change in Income Taxes	0	0
All other Changes	0	0
Estimated Future Net Revenue at December 31, 2005	4648	3,743

Notes: [1] The Company was incorporated on November 22, 2004 and did not have reserves at December 31, 2004.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 Undeveloped Reserves

5.1.1 Proved Non-Producing Reserves

Proved non-producing gas reserves are assigned to 3 drilled and tested wells in the Alderson, Alberta area. At December 31, 2005, these wells were shut in pending the construction of pipelines. The wells began production in early 2006.

5.1.2 Proved Undeveloped Reserves

Proved undeveloped gas reserves are assigned to 3 undrilled locations in the Alderson, Alberta area. These reserves have a high degree of certainty for recovery because the proposed locations are situated between existing producing wells. At December 31, 2005, the drilling, completion, and tie-in of these undrilled wells were pending the construction of extra plant capacity by the major operator in the area. As this plant upgrade is unlikely to remove the production restrictions from the area, these wells are now planned to be drilled in late 2006 or early 2007 to mitigate production declines at an estimated capital expenditure of \$772,000 net to the Company.

5.1.3 Probable Reserves

Probable reserves are assigned to statistically feasible improved recoveries from the Company's current and future producing reserves. In accordance with the definitions set out in NI51-101, it is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the reported proved plus probable reserves. Because these reserves additions are the result of improved recoveries from existing wells, no capital is required or planned by the company for the future recovery of these reserves.

5.2 Significant Factors or Uncertainties

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company as discussed in Section 9 of COGEH.

5.3 Future Development Costs

The development cost deduction in the estimation of the future net revenue attributable to the Company's reserves is summarized as follows:

Year	CONSTANT PRICES AND COSTS		FORECAST PRICES AND COSTS	
	Proved Reserves (\$M)	Proved plus Probable Reserves (\$M)	Proved Reserves (\$M)	Proved plus Probable Reserves (\$M)
2006	753.6	753.6	772.4	772.4
2007	-	-	-	-
2008	-	-	-	-
Remaining Years	-	-	-	-
TOTAL UNDISCOUNTED	753.6	753.6	772.4	772.4
Total 10% Discounted	718.3	718.3	736.3	736.3

PART 6 OTHER OIL AND GAS INFORMATION

6.1 Oil and Gas Properties and Wells

**WELL COUNT SUMMARY
as at September 26, 2006**

AREA	OIL WELLS				NATURAL GAS WELLS				SERVICE WELLS			
	Producing		Shut In		Producing		Shut In		Active		Shut In	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alderson	-	-	-	-	19	7.83	-	-	-	-	-	-
Enchant	-	-	-	-	-	-	5	4.94	-	-	-	-
Long Coulee	-	-	-	-	-	-	2	1.31	-	-	-	-
Pembina	6	2.48	-	-	-	-	-	-	3	1.24	-	-
Schuler	-	-	-	-	8	4.00	1	0.50	-	-	-	-
TOTAL	6	2.48	-	-	27	11.83	8	6.75	3	1.24	-	-

Alderson: The Company holds working interests ranging from 28.875% to 100% in 5½ sections of land in Township 12 and 13, Range 8W4M near Redcliff, Alberta, and operates 15 shallow gas wells on this property. Production from these wells is limited because it is tied into a facility owned and operated by Imperial Oil Ltd. Recently, the Company discovered that it is unlikely that any future plant design upgrades will benefit the company with increased throughput at Imperial's plant. However, the Company has allocated approximately \$750,000 for development in this area to mitigate future production declines from this field.

Pembina: The Company operates 6 producing oil wells, two water injection wells, one source water well, and an oil battery facility located on a half section of land just south west of Drayton Valley in Township 47 Range 9W5M of the Pembina field. The Company holds 41.25% working interest in this operation, which produces light, sweet crude from the Cardium formation. The Company is currently evaluating the potential to re-stimulate the existing oil zones to improve production and ultimate recovery. In addition, the Company will evaluate the potential that may exist in the shallow gas zones on its lands.

Schuler: The Company holds a 50% working interest in 9 sections of land in Township 15 Range 1W4M near the town of Schuler, Alberta. The Company operates 8 producing shallow gas wells and the associated gas gathering system which is tied into a facility operated by Direct Energy Limited. The property contains one shut in gas well but no reserves are assigned to this well. The Company has no plans for future development in this area.

Enchant: The Company holds a 100% working interest in 3 sections of land, just to the east of the town of Enchant in Township 14, Range 18W4M. At December 31, 2005, the Company had drilled and was evaluating 3 shallow gas wells. During 2006, the Company drilled and tested 2 more wells. All 5 of these wells flowed marginal quantities of gas, or were determined to contain uneconomic quantities of reserves. As a result, the Company has no development plans for this area, but may abandon these wells at a cost of approximately \$60,000 net to the Company.

6.2 Properties with No Attributed Reserves

The following table sets out the Company's undeveloped land holdings as at December 31, 2005:

	UNDEVELOPED ACRES	
	Gross	Net
Alberta	1,127	495
Saskatchewan	1,079	337
TOTAL	2,206	832

6.3 Forward Contracts

The Company is not currently party to any forward sales contracts.

6.4 Additional Information Concerning Abandonment and Reclamation Costs

The Company performs an annual review of its forecast abandonment and site reclamation ("Abandonment") costs. These costs are estimated utilizing the Alberta Energy and Utilities Board's Abandonment and liability calculation spreadsheet as a basis, but the Company's review is further augmented with adjustments on an individual well and facility basis. The review considers the following factors in assessing liability: well depth, nature of the production stream, the nature, location and condition of the surface lease, age of the well and/or facility, number of zones to be abandoned, and presence of salvageable equipment such as tanks, tubing, and rods. The Abandonment cost determined is net of salvage.

At December 31, 2005, the Company had a working interest in 44 gross (22.0 net) wells and estimates its undiscounted and unescalated well Abandonment obligation to be \$291,000 (\$114,000 discounted at 10%). All amounts were deducted as Abandonment costs by McDaniel in estimating the future net revenue. At September 28, 2006, the Company expects to incur an undiscounted and unescalated \$58,000 (\$55,000 discounted at 10%) as a result of well Abandonment expenditures during the next 3 years.

6.5 Tax Horizon

The Company had current taxes of \$98,845 attributable to 2005 based on its acquisition of three private companies during the year. Although its current tax horizon depends on product prices, production levels, and the nature, magnitude, and timing of capital expenditures, the Company believes that no cash income tax will be payable for one to two years.

6.6 Costs Incurred in 2005

The following table summarizes the capital expenditures related to the Company's activities for the year ended December 31, 2005:

	Exploration (\$M)	Development (\$M)	Total (\$M)
Land	18	38	57
Seismic	174	-	174
Drilling	380	423	803
Facilities	59	73	59
Corporate Acquisitions	-	-	4,356
TOTAL	631	534	5,521

6.7 Exploration and Development Activities

The following table sets out the gross and net exploratory and developments wells in which the Company participated during the year ended December 31, 2005:

	Year ended December, 2005	
	Gross	Net
Natural gas	5	3.83
Crude oil	-	-
Service wells	-	-
Dry and abandoned	-	-
Total	5	3.83

6.8 Production Estimates

The following tables summarize the Company's estimate future average daily production volumes for 2006 for each product type. Production for properties which individually account for 20% or more of the Company's forecast production (total proved plus probable reserves, boe basis) in the first year of forecast has been identified separately in these tables.

ESTIMATED 2006 PRODUCTION BY PRODUCT TYPE CONSTANT PRICES AND COSTS

Property	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
Alderson Total Proved	-	470	-	78
Other Total Proved	8	25	2	13
Alderson Probable	-	11	-	2
Other Probable	-	-	-	-
PROVED PLUS PROBABLE	8	506	2	94

ESTIMATED 2006 PRODUCTION BY PRODUCT TYPE FORECAST PRICES AND COSTS

Property	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
Alderson Total Proved	-	470	-	78
Other Total Proved	8	25	2	13
Alderson Probable	-	11	-	2
Other Probable	-	-	-	-
PROVED PLUS PROBABLE	8	506	2	94

6.9 Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and the resulting netbacks received by the Company for the period indicated below:

	Fourth Quarter <u>2005 [1]</u>
Average daily production	
Light and Medium Crude Oil (Bbls/d)	7
Gas (Mcf/d)	342
NGLs (Bbls/d)	2
Combined (BOE/d)	66
Average Net Prices Received	
Light and Medium Crude Oil (\$/Bbl)	68.81
Gas (\$/Mcf)	11.39
NGLs (\$/Bbl)	14.57
Combined (\$/BOE)	66.89
Royalties	
Light and Medium Crude Oil (\$/Bbl)	3.84
Gas (\$/Mcf)	1.78
Combined (\$/BOE)	9.60
Production Expenses	
Light and Medium Crude Oil (\$/Bbl)	27.20
Gas (\$/Mcf)	1.17
Combined (\$/BOE)	9.10
Netback Received	
Light and Medium Crude Oil (\$/Bbl)	37.77
Gas (\$/Mcf)	8.44
NGLs (\$/Bbl)	14.57
Combined (\$/BOE)	48.19

NOTES: [1] The Company had no production or revenue prior to this period.

ATTACHMENT 1

Abbreviations

Crude Oil and Natural Gas Liquids

bbls	barrels
bbls/d	barrels per day
mdbl	thousand barrels
bopd	barrels of oil per day
NGL	natural gas liquids
mmbtu	million British thermal units
stb	stock tank barrel
mstb	thousand stock tank barrels

Natural Gas

mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
gj	gigajoule
MM	Million

Other

m	thousand
mm	million
m ³	cubic metres
\$000s	thousands of dollars
boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 bbl of crude oil for 6 mcf of natural gas, unless otherwise indicated
mboe	thousand barrels of oil equivalent
boe/d	barrel of oil equivalent per day
AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute (provides crude oil density measurement)
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
ARTC	Alberta Royalty Tax Credit
OPEC	Organization of Petroleum Exporting Countries
U.S.	United States of America
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. 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.

Conversion

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

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
mcf	cubic metres ("m ³ ")	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls oil	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471