

**APPENDED TO AND MADE A PART OF
FORM 51-101F1 OF
COSTA RESOURCES LTD.**

**Form 51-101F1
STATEMENT OF RESERVES DATA AND
OTHER OIL AND GAS INFORMATION
FOR KELSO ENERGY INC.**

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 Kelso Energy Inc. (the "Company") was prepared by McDaniel & Associates Consultants Ltd. ("McDaniel"), the Company's independent reserve evaluator, dated May 2, 2006 effective as of December 31, 2005.

All properties evaluated in this report are located in British Columbia and Alberta, Canada.

The Company had a June 30 year end and filed Form 51-101F1 with an effective date of June 30, 2005. The Company was acquired by COSTA Resources Ltd. ("Resources") by way of a reverse takeover effective March 1, 2006. Resources has a December 31 year end and is the acquirer for accounting purposes. Consequently the weighted average historical prices realized by the Company (Part 3), and the Reconciliation of Changes in Reserves and Future Net Revenue (Part 4), Costs Incurred in 2005 (Part 6.6), Exploration and Development Activities (Part 6.7) and Production History (Part 6.9) contained herein deal with the six months ended December 31, 2005.

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. A boe may be misleading, particularly if used in isolation.

PART 2 RESERVES AND FUTURE NET REVENUE DATA

Notes to 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	-	-	7.2	6.3	287	201	3.3	2.3
Developed Non-Producing	-	-	-	-	94	66	0.8	0.6
Undeveloped	-	-	-	-	-	-	-	-
TOTAL PROVED	-	-	7.2	6.3	381	267	4.1	2.9
PROBABLE	-	-	4.9	4.2	235	165	2.2	1.5
TOTAL PROVED PLUS PROBABLE	-	-	12.1	10.5	616	432	6.2	4.4

**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%	5%	10%	15%	0%	5%	10%	15%
	M\$	M\$	M\$	M\$	M\$	M\$	M\$	M\$
PROVED								
Developed Producing	1,596	1,436	1,309	1,207	1,596	1,436	1,309	1,207
Developed Non-Producing	378	362	347	332	378	362	347	332
Undeveloped	-	-	-	-	-	-	-	-
TOTAL PROVED	1,974	1,798	1,656	1,539	1,974	1,798	1,656	1,539
PROBABLE	1,468	1,208	1,023	884	1,468	1,208	1,023	884
TOTAL PROVED PLUS PROBABLE	3,442	3,007	2,679	2,423	3,442	3,007	2,679	2,423

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	4,253	1,144	852	150	141	1,974	-	1,974
Total Proved Plus Probable	6,872	1,860	1,315	150	138	3,442	-	3,442

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 Taxes (Discounted at 10% per year) \$M
Total Proved	Heavy Oil (including solution gas and other by-products)	46
	Natural Gas (including by-products but not solution gas)	1,601
	Alberta Royalty Tax Credit	9
Proved Plus Probable	Heavy Oil (including solution gas and other by-products)	116
	Natural Gas (including by-products but not solution gas)	2,534
	Alberta Royalty Tax Credit	29

**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	-	-	8.6	7.5	287	201	3.3	2.3
Developed Non-Producing	-	-	-	-	94	66	0.8	0.6
Undeveloped	-	-	-	-	-	-	-	-
TOTAL PROVED	-	-	8.6	7.5	381	268	4.1	2.9
PROBABLE	-	-	5.2	4.4	239	169	2.2	1.5
TOTAL PROVED PLUS PROBABLE	-	-	13.8	11.9	620	436	6.2	4.4

**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	1,320	1,236	1,164	1,102	1,320	1,236	1,164	1,102
Developed Non-Producing	321	313	304	295	321	313	304	295
Undeveloped	-	-	-	-	-	-	-	-
TOTAL PROVED	1,640	1,549	1,468	1,397	1,640	1,549	1,468	1,397
PROBABLE	1,107	953	835	742	1,107	953	835	742
TOTAL PROVED PLUS PROBABLE	2,747	2,502	2,303	2,139	2,747	2,502	2,303	2,139

Notes: [1] Includes ARTC

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

FORECAST 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	3,973	1,041	982	158	164	1,640		1,640
Total Proved Plus Probable	6,207	1,623	1,546	158	165	2,747		2,747

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	Heavy Oil (including solution gas and other by-products)	100
	Natural Gas (including by-products but not solution gas)	1,359
	Alberta Royalty Tax Credit	10
Proved Plus Probable	Heavy Oil (including solution gas and other by-products)	193
	Natural Gas (including by-products but not solution gas)	2,081
	Alberta Royalty Tax Credit	29

PART 3 PRICING ASSUMPTIONS

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

OIL AND LIQUIDS							
Year	WTI Cushing Oklahoma (\$US/Bbl)	Bow River At Hardisty (\$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]	36.71 [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] Hardisty heavy crude price from Shell, Imperial, PetroCanada, EnCana, 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)	Hardisty Heavy Oil Price (\$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	45.70	46.10	48.80	51.40	10.40	2.5	0.85
2007	55.40	45.30	43.00	47.00	48.90	9.35	2.5	0.85
2008	52.50	44.00	39.50	44.50	45.80	8.30	2.5	0.85
2009	49.50	42.60	35.90	41.90	42.60	7.20	2.5	0.85
2010	46.90	40.30	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

The weighted average historical prices realized by the Company for the six months ended December 31, 2005 were \$6.20/mcf for natural gas and \$70.62/bbl for light crude oil. The time interval of this comment is clarified in Part 1 of this form.

PART 4 RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

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

	Heavy Oil and Natural Gas Liquids [2]			Natural Gas		
	Net Proved (Mbbbl)	Net Probable (Mbbbl)	Net Proved plus Probable (Mbbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved plus Probable (MMcf)
June 30, 2005 [1]	8.1	5.7	13.8	235	254	489
PLUS						
Extensions	-	-	-	280	-	280
Improved Recovery	8.2	-	8.2	-	-	-
Technical Revisions	(1.0)	0.2	(0.8)	(188)	(85)	(273)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
LESS						
Dispositions	-	-	-	-	-	-
Production	(4.9)	-	(4.9)	(59)	-	(59)
December 31, 2005 [3]	10.4	5.9	16.3	268	169	436

Notes: [1] GLJ reserve evaluation at the Company's year-end, June 30, 2005.

[2] Reported as Light and Medium Oil in the Company's reserve evaluation dated June 30, 2005.

[3] McDaniel reserve evaluation dated December 31, 2005.

**RECONCILIATION OF CHANGES IN NET PRESENT VALUE OF FUTURE NET REVENUE
TOTAL PROVED RESERVES
FORECASTED PRICES AND COSTS DISCOUNTED AT 10% [1]**

Period and Factor	Before Tax [3] (M\$)	After Tax [3] (\$M)
Estimated Future Net Revenue at June 30, 2005 [2]	1,253	1,253
Oil and Gas Sales Net of Production Costs and Royalties	(569)	(569)
Net Change in Prices, Production Costs and royalties Related to Future Production	0	0
Changes in Previously Estimated Development Costs Incurred During the Period	125	125
Changes in Estimated Future Development Costs	0	0
Extensions and Improved Recovery	1,091	1,091
Changes due to Discoveries	0	0
Acquisition of Reserves	0	0
Disposition of Reserves	0	0
Net Change Resulting from Revisions in Quantity Estimates	(432)	(432)
Accretion of Discount	0	0
Net Change in Income Taxes	0	0
All other Changes	0	0
Estimated Future Net Present Value at December 31, 2005	1,468	1,468

Notes: [1] Reconciliation not performed on Constant Prices and Costs as data is not available

[2] The Company's year-end was June 30.

[3] Includes ARTC

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 Undeveloped Reserves

5.1.1 Proved Non-Producing Reserves

At December 31, 2005, proved non-producing reserves were assigned to 2 drilled, tested, and shut in wells. One of these wells is located in the Legal, Alberta area and tested marginal gas rates subsequent to the effective date of the reserve evaluation. The well has therefore not been tied in. The other well is located in the Boundary Lake field in northeast B.C., and at the time of the effective date of this reserve report was waiting on regulatory approval to begin production. This approval was received and the well began production in April, 2006.

5.1.2 Proved Undeveloped Reserves

The Company has no proved undeveloped reserves.

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 Corporations 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	-	-	-	-
2007	150	150	158	158
2008	-	-	-	-
Remaining Years	-	-	-	-
TOTAL UNDISCOUNTED	150	150	158	158
Total 10% Discounted	130	130	137	137

PART 6 OTHER OIL AND GAS INFORMATION

6.1 Oil and Gas Properties and Wells

		WELL COUNT SUMMARY							
		As at September 26, 2006							
		OIL WELLS				NATURAL GAS WELLS			
		Producing		Shut In		Producing		Shut In	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net
ALBERTA WELLS									
	Hollow	-	-	-	-	-	-	6	3.0
	Veteran	2	1.50	1	.50	-	-	-	-
B. C. WELLS									
	Aitken Creek	-	-	-	-	-	-	1	0.13
	Boundary Lake	-	-	-	-	3	1.00	-	-
	Stoddart	-	-	-	-	-	-	1	.34
TOTAL		2	1.50	1	0.50	3	1.00	8	3.47

Hollow: In the Hollow, Alberta area, the Company holds a 50% working interest in 8 sections of land with multi-zone potential in formations which can be penetrated with well depths of 1,100 m or less. At December 31, 2005, the Company had one producing well, 4 shut in wells, and one abandoned well, with only one of the 4 shut in wells assigned reserves. As at September 26, 2006, the producing well had watered out (February, 2006) and all the standing wells were tested and yielded marginal gas rates so they were not tied in. In addition, the Company participated in the drilling of 2 more wells in this area in May and June of 2006. One well flowed marginal gas rates and will not be tied in while the other is more promising but is awaiting an economic evaluation before expending the capital required to tie the well in.

Veteran: In Veteran, Alberta, Kelso has 3 gross (2 net) oil wells producing from the Dina formation. The current engineering evaluator (McDaniel) classified this production as heavy oil, whereas Kelso's previous engineering evaluator (GLJ), designated production from these lands as medium gravity crude. Kelso is currently reviewing options for additional Dina drilling to further exploit its Veteran acreage and to lower its operating costs.

Aitken Creek: Kelso holds a 12.5% working interest in 9 sections of land in the Aitken Creek area of British Columbia. In 2004, the Company drilled one well on this property that encountered encouraging gas indications. At this time, the Corporation has no further plans for this area.

Boundary Lake: Kelso holds a one-third interest in 2 sections of land and 3 producing gas wells in the Boundary Lake field of north east British Columbia. The Company has no further development plans for this area.

Stoddart: Kelso holds a 34% working interest in one suspended gas well in the Stoddart field in north east British Columbia. This well has no reserves assigned to it, and the Company has no further plans for this area.

6.2 Properties with No Attributed Reserves

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

	UNDEVELOPED ACRES	
	Gross	Net
Alberta	5,345	2,374
British Columbia	2,520	654
TOTAL	7,865	3,388

6.3 Forward Contracts

Kelso is not currently party to any forward sales contracts.

6.4 Additional Information Concerning Abandonment and Reclamation Costs

Costs are estimated utilizing the Alberta Energy and Utilities Board's abandonment and reclamation ("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 expected to incur undiscounted Abandonment costs of \$165,000 (\$91,000 discounted at 10%) on 5.47 net wells. All amounts were deducted as Abandonment costs by McDaniel in estimating the future net revenue. Over the next three years, Kelso expects to pay an undiscounted \$16,000 (\$13,000 discounted at 10%) on well Abandonment expenditures.

6.5 Tax Horizon

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 several years.

6.6 Costs Incurred in 2005

The following table summarizes the capital expenditures related to the Company's activities for the six months ended December 31, 2005 [1]:

	Exploration (\$M)	Development (\$M)	Total (\$M)
Land	-	330	330
Seismic	637	-	637
Drilling	25	1,151	1,176
Facilities	157	150	307
Corporate Acquisitions	-	-	-
TOTAL	819	1,631	2,450

Note: [1] The time interval for this table is clarified in Part 1 of this form.

6.7 Exploration and Development Activities

The following table sets out the gross and net exploratory and developments wells in which the corporation participated during the six months ended December 31, 2005 [1]:

	Six months ended December, 2005	
	Gross	Net
Natural gas	5	2.17
Crude oil	-	-
Service wells	-	-
Dry and abandoned	-	-
Total	5	2.17

Note: [1] The time interval for this table is clarified in Part 1 of this form.

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)
Boundary Lake Total Proved	-	301	4	54
Veteran Total Proved	16	-	-	16
Other Total Proved	-	21	-	4
Boundary Lake Probable	-	27	-	5
Veteran Probable	3	-	-	3
Other Probable	-	19	-	3
PROVED PLUS PROBABLE	18	368	4	84

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)
Boundary Lake Total Proved	-	301	4	54
Veteran Total Proved	17	-	-	17
Other Total Proved	-	21	-	4
Boundary Lake Probable	-	27	-	5
Veteran Probable	3	-	-	3
Other Probable	-	19	-	3
PROVED PLUS PROBABLE	20	368	4	85

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 Corporation for the two quarters from the most recently completed financial year of the Corporation.

	Fourth Quarter 2005	Third Quarter 2005
Average daily production		
Light and Medium Crude Oil (Bbls/d)	20	28
Gas (Mcf/d)	354	288
NGLs (Bbls/d)	3	2
Combined (BOE/d)	82	78
Average Net Prices Received		
Light and Medium Crude Oil (\$/Bbl)	54.87	63.9
Gas (\$/Mcf)	11.69	9.28
NGLs (\$/Bbl)	67.77	62.74
Combined (\$/BOE)	66.29	58.81
Royalties		
Light and Medium Crude Oil (\$/Bbl)	4.67	9.92
Gas (\$/Mcf)	3.26	1.31
NGLs (\$/Bbl)	31.62	10.41
Combined (\$/BOE)	16.28	8.68
Production Expenses		
Light and Medium Crude Oil (\$/Bbl)	37.92	19.62
Gas (\$/Mcf)	1.04	0.92
Combined (\$/BOE)	13.82	10.39
Netback Received		
Light and Medium Crude Oil (\$/Bbl)	12.28	34.36
Gas (\$/Mcf)	7.39	7.05
NGLs (\$/Bbl)	36.15	52.33
Combined (\$/BOE)	36.19	39.74

ATTACHMENT 1

Abbreviations

Crude Oil and Natural Gas Liquids

bbls	barrels
bbls/d	barrels per day
mbbl	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