

Arapahoe Energy Corporation

Consolidated Financial Statements
December 31, 2004 and 2003

April 26, 2005

Auditors' Report

To the Shareholders of Arapahoe Energy Corporation

We have audited the consolidated balance sheets of **Arapahoe Energy Corporation** as at December 31, 2004 and 2003 and the consolidated statements of loss and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

ARAPAHOE ENERGY CORPORATION

Consolidated Balance Sheet

as at December 31

	2004 \$	2003 \$
Assets		
Current assets		
Cash	12,035	-
Accounts receivable and accruals	51,055	-
Receivable from issue of common shares	-	3,767
Due from related parties (note 8)	6,357	-
Prepaid expenses	10,939	-
	<hr/> 80,386	<hr/> 3,767
Property, plant and equipment (note 4)	2,185,559	-
	<hr/> 2,265,945	<hr/> 3,767
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	574,924	-
Due to related parties (note 8)	86,130	-
	<hr/> 661,054	<hr/> -
Asset retirement obligation (note 5)	14,224	-
	<hr/> 675,278	<hr/> -
Shareholders' Equity		
Capital stock (note 6)	1,472,189	3,767
Deficit	(240,780)	-
Contributed surplus	359,258	-
	<hr/> 1,590,667	<hr/> 3,767
	<hr/> 2,265,945	<hr/> 3,767
Going concern (note 2)		

Approved by the Board of Directors

ARAPAHOE ENERGY CORPORATION
Consolidated Statement of Loss and Deficit
For the year ended December 31

	2004	2003
	\$	\$
Revenue		
Oil and gas	106,368	-
Royalties	(13,136)	-
	<u>93,232</u>	-
Expenses		
Operating costs	15,261	-
Depletion, depreciation and accretion	35,015	-
Stock based compensation (note 6)	359,258	-
General and administrative	526,006	-
Reverse takeover transaction costs (note 1)	5,124	-
	<u>940,664</u>	-
Loss for the period before taxes	(847,432)	-
Future income tax recovery (note 7)	<u>620,834</u>	-
Loss for the period	(226,598)	-
Deficit – Beginning of period	-	-
Reverse takeover transaction costs (note 1)	(14,182)	-
Deficit – End of period	<u>(240,780)</u>	-
Basic and diluted loss per share	<u>(.02)</u>	-

ARAPAHOE ENERGY CORPORATION

Consolidated Statement of Cash Flows

For the year ended December 31

	2004	2003
	\$	\$
Cash provided by (used in)		
Operating activities		
Loss for the period	(226,598)	-
Items not affecting cash		
Depletion, depreciation and accretion	35,015	-
Stock-based compensation	359,258	-
Future tax recovery	(620,834)	-
	<hr/>	
Cash flow used in operations	(453,159)	-
Change in non-cash working capital items	325,090	(3,767)
	<hr/>	
	(128,069)	(3,767)
Financing activities		
Issuance of capital stock	2,269,728	3,767
Change in non-cash working capital	48,371	-
	<hr/>	
	2,318,099	3,767
Investing activities		
Acquisition of other petroleum and natural gas properties	(2,163,809)	-
Reverse takeover costs – cash portion	(14,186)	-
	<hr/>	
	(2,177,995)	-
Increase in cash	12,035	-
Cash – Beginning of period	<hr/>	<hr/>
	-	-
Cash – End of period	<hr/>	<hr/>
	12,035	-

FORMATION OF THE BUSINESS

Crazy Horse Energy Inc. (“Crazy Horse” or the “Company”) was incorporated under the Business Corporations Act (Alberta) on April 23, 2001 as 930639 Alberta Ltd. The Company’s name was changed to Crazy Horse Energy Inc. on September 17, 2003. The Company had no previous operations.

Pursuant to a Plan of Arrangement (the “Arrangement”) on February 6, 2004, the Company entered into a reverse takeover of Arapahoe Energy Corporation (“Old Arapahoe”), a public company that traded on the TSX Venture Exchange under the symbol “APR”. The Company continues to operate under Arapahoe Energy Corporation (“New Arapahoe”). New Arapahoe, a public company, trades on the TSX Venture Exchange under the symbol “AAO”. Upon completion of the Arrangement, the shareholders of the Old Arapahoe held approximately 13% of the common shares of the Company.

The Company’s intended primary business activity remains unchanged from the Old Arapahoe. The Company is engaged in the exploration, development and production of oil and natural gas in Canada.

1. BASIS OF PRESENTATION

Under the Arrangement, Old Arapahoe transferred all its assets and liabilities to the Company. Old Arapahoe shareholders exchanged all of their shares for shares in the Company on a basis of one common share for every three Old Arapahoe shares held.

The application of reverse takeover accounting, that does not constitute a business combination, was accounted for in accordance with EIC10 and results in the following:

- a) The financial statements are prepared as a reverse takeover transaction that is not a business combination. As a result of the transaction, control of Old Arapahoe passed to the shareholders of the Company and as such the Company is deemed to be the acquirer and the continuity entity.
- b) The consolidated financial statements are issued under the name of new Arapahoe Energy Corporation as a continuation of the Company.
- c) All net assets have been included at their historical carrying value. The operations of Old Arapahoe are included from February 6, 2004.
- d) Transaction costs, to the extent of cash in Old Arapahoe as at February 6, 2004, have been charged to deficit as reverse takeover transaction costs.
- e) The deemed consideration of the net identifiable assets acquired and liabilities assumed is measured at the net book value of the Old Arapahoe Corporation and the purchase deficiency attributed to the reverse takeover are as follows:

ARAPAHOE ENERGY CORPORATION
Notes to Consolidated Financial Statements

Book Value	
Current Assets	\$ 91,386
Property, Plant and Equipment	37,068
Current Liabilities	(362,320)
Asset Retirement Obligation	<u>(5,948)</u>
	(239,814)
Fair Value	<u>(228,843)</u>
Deficiency of fair value over book value attributed to property	<u>\$ 10,971</u>

2. GOING CONCERN

The Company reported a loss of \$226,598 and cash used in operations of \$453,159 for the period ended December 31, 2004. The Company had working capital deficit of \$580,668 at December 31, 2004. The Company's ability to continue as a going concern is dependent upon the Company's ability to raise capital and the success of the drilling and exploration program.

These financial statements have been prepared on a going concern basis, which contemplates the realization of assets and the payment of liabilities in the ordinary course of business. Should the Company be unable to continue as a going concern, it may be unable to realize the carrying value of its assets and to meet its liabilities as they become due.

The accompanying financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts and classification of liabilities that might be necessary should the Company be unable to continue in existence.

3. SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

These Consolidated Financial Statements have been prepared for the Company, pursuant to the Arrangement (as detailed in note 1). They are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

Measurement uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and equipment and the provision for asset retirement obligation costs are based on estimates. In addition, the ceiling test calculation is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

ARAPAHOE ENERGY CORPORATION
Notes to Consolidated Financial Statements

Joint interests

A portion of the Company's exploration, development and production activities is conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, demand deposits and investments in highly liquid money market instruments, which are convertible to known amounts of cash in less than three months.

Financial instruments

The fair market value of cash and cash equivalents, receivables, other current assets, payables and bank debt approximate their carrying value. From time to time, the Company may use derivative financial instruments to manage exposure to fluctuations in commodity prices and foreign currency exchange rates. All transactions of this nature entered into by the Company are related to an underlying financial position or to future petroleum and natural gas production. The Company does not use derivative financial instruments for speculative trading purposes.

Property, plant and equipment

The Company follows the full cost method of accounting whereby all costs relating to the exploration and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition, geological and geophysical, drilling of productive and non-productive wells, production equipment and facilities, carrying costs directly related to unproved properties and costs related to acquisition of petroleum and natural gas assets directly or by means of a business combination. These capitalized costs along with estimated future capital expenditures to be incurred in order to develop proved reserves, are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves as evaluated by independent engineers. For the purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs.

Gains or losses on the disposition of properties are not recognized unless the proceeds on disposition result in a change of 20 percent or more in the depletion rate.

Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25 percent.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, an estimate is made of the ultimate recoverable amount from undiscounted future net cash flows based on proved reserves, which are determined by using forecasted future prices, plus unproved properties. If the carrying amount exceeds the ultimate recoverable amount, an impairment loss is recognized in net earnings. The impairment loss is limited to the amount by which the carrying amount exceeds: (i) the sum of the fair value of proved and probable reserves; and (ii) the costs of unproved properties that have been subject to a separate impairment test and contained no probable reserves.

Asset retirement obligations

Estimated future costs relating to retirement obligations associated with oil and gas well sites and facilities are recognized as a liability, at fair value. The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. The liability is adjusted at each reporting period to reflect the passage of time, with the accretion charged to earnings. Actual costs incurred upon settlement of the obligations are charged against the liability.

Future income taxes

The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Flow-through shares

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share issues are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as a future income tax liability at the time of renunciation and a reduction in share capital.

Revenue recognition

Revenue from the sale of oil and natural gas is recorded when title passes to an external party.

Stock-based compensation

The Company has a stock-based compensation plan. Effective January 1, 2004, the Company adopted the fair-value method to record compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant and a provision for the costs is provided for as contributed surplus over the term of the option agreement. The consideration received by the Company on the exercise of share options is recorded as an increase to share capital together with corresponding amounts previously recognized in contributed surplus. Forfeitures are accounted for as they occur which could result in recoveries of the compensation expense.

Per share amounts

Basic per share amounts are calculated using the weighted average number of shares outstanding during the period. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in that period.

Diluted per share amounts are calculated using the treasury stock method, which assumes that any proceeds obtained on exercise of share options or other dilutive instruments would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

ARAPAHOE ENERGY CORPORATION
Notes to Consolidated Financial Statements

For the year ended December 31, 2004 the weighted average number of shares was 9,334,490. Diluted earnings per share and cash flow per share reflect the exercise of options as if issued at the later of the date of grant or the beginning of the period. The diluted weighted average number of shares for the year ended December 31, 2004 is 9,334,490.

Consolidation

These consolidated financial statements include the accounts of the Company and its wholly owned subsidiary, Torrence Resources Inc. ("Torrence").

Related party transactions

Related party transactions are conducted in the normal course of operations and are measured at fair market value.

4. PROPERTY, PLANT AND EQUIPMENT

	Cost \$	Accumulated Depreciation Depletion	Dec 31, 2004 Net Book Value	Dec 31, 2003 Net Book Value
P&NG Properties	2,212,612	31,603	2,181,009	-
Office assets	6,500	1,950	4,550	-
TOTAL	2,219,112	33,553	2,185,559	-

At December 31, 2004, the depletion calculation excluded unproved properties of \$2,185,876. The Company has not capitalized any general and administrative expenses for the year ended December 31, 2004.

The prices used in the ceiling test evaluation of the Corporation's natural gas, crude oil and natural gas liquids reserves at December 31, 2004 were:

	2005	2006	2007	2008	2009	% increase to 2015
Natural Gas (\$/mcf)	6.55	6.30	5.80	5.55	5.63	0.935%
Crude Oil (\$/Bbl)	50.22	49.00	47.72	45.15	43.87	0.911%
Natural Gas Liquids (\$/Bbl)	38.52	37.58	37.63	36.60	34.63	0.957%

ARAPAHOE ENERGY CORPORATION
Notes to Consolidated Financial Statements

5. ASSET RETIREMENT OBLIGATION

The future asset retirement obligations were estimated by management based on the Corporation's working interest in its wells, estimated costs to remediate, reclaim and abandon the wells and estimated timing of the costs to be incurred in future periods. The Corporation has estimated the net present value of its total asset retirement obligation to be \$14,224 at December 31, 2004 based on a total future liability of \$38,775. These costs are expected to be incurred over the next three to fifteen years. The Corporation's risk free interest rate of 8.5% and an inflation rate of 1.8% were used to calculate the net present value of asset retirement obligation.

The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

At December 31	2004	2003
Asset retirement obligation, beginning of period	-	-
Liabilities incurred and acquired	12,755	-
Accretion expense	1,469	-
Asset retirement obligation, end of period	14,224	-

ARAPAHOE ENERGY CORPORATION
Notes to Consolidated Financial Statements

6. SHARE CAPITAL

a) Authorized

Unlimited number of common voting shares of no par value

Unlimited number of preferred shares of no par value

b) Issued and outstanding

	Number of Shares #	Amount \$
Issued as at December 31, 2003		
Arapahoe share capital prior to acquisition	3,958,691	10,918,692
Elimination of Arapahoe share capital	(3,958,691)	(10,918,692)
Shares issued to shareholders of Old Arapahoe – based on exchange ratio	1,319,563	-
Crazy Horse share capital	3,766,667	3,767
Elimination of Crazy Horse share capital	(3,766,667)	-
Shares issued to shareholders of Crazy Horse	3,766,667	(228,843)
Debt settlement	80,619	48,371
Private placement	450,000	247,500
Common Share issued as part of offering units	839,373	461,655
Flow Through share issued as part of offering units	3,357,492	1,846,621
Share issue costs	-	(286,048)
Tax effect	-	(620,834)
Balance – December 31, 2004	9,813,714	1,472,189

c) Stock Option Plan

The Company has a stock option plan, under which the Company may grant options to its employees, directors and consultants for up to 10% of the total shares of common stock issued and outstanding at time of option grant. The number of options and the exercise price thereof is set by the Board of Directors at the time of grant, provided that the exercise price shall not be less than the market price of the common shares on the stock exchange on which such shares are then traded. The options granted may be exercisable for a period and may vest at such times as the Board of Directors may determine at the time of grant.

ARAPAHOE ENERGY CORPORATION
Notes to Consolidated Financial Statements

Agent's Option

The Agent's Option entitles the Agent to acquire 125,906 units of the Issuer at a price of \$2.75 each until February 6, 2005 under the private placement offering, which closed on February 6th, 2004. Each of the units consists of five Common Shares and five one-half common share purchase warrants. Each whole share purchase warrant entitles the holder thereof to purchase one Common Share at a price of \$0.80 each until February 6, 2005. In the

event the Common Shares trade for 20 consecutive trading days at a price of not less than \$1.20 each, the Issuer may accelerate the exercise period of the share purchase warrants to not less than 30 days by providing the share purchase warrant holders with written notice of such reduction in the exercise period. Subsequent to year-end, all of these options expired without exercise.

A summary of the status of the Company's stock option plan as at December 31, 2004 and changes during the period ended on that date:

	Year ended December 31, 2004 # Shares	Year ended December 31, 2004 Weighted average exercise price \$
Outstanding – beginning of period	-	-
Granted	929,014	.58
Expired during period	(56,666)	.58
Outstanding – end of period	872,348	.58

The following table summarizes information about stock options outstanding at December 31, 2004:

Exercise price	Options outstanding	Options outstanding	Options exercisable		Options exercisable
	# Outstanding Dec 31, 2004	Weighted average remaining contractual life in years	Weighted average exercise price at Dec 31, 2004	Number exercisable	Weighted average exercise price
\$0.55 - \$0.75	872,348	4.04	\$0.58	872,348	\$0.58
	872,348			872,348	

Compensation cost of \$359,258 has been recognized for stock options granted. The fair value

ARAPAHOE ENERGY CORPORATION
Notes to Consolidated Financial Statements

for options granted to employees and directors was estimated at the date of grant using a Black-Scholes Option Pricing Model with the following assumptions:

Volatility factor of expected market price	140%
Weighted average risk-free interest rate	3.10%
Weighted average expected life in years	3
Weighted average expected annual dividends per share	Nil

d) Warrants

- (i) Old Arapahoe issued warrants in connection with a private placement, which closed on September 18, 2003. Each whole warrant entitles the holder to purchase one common share of the corporation at an exercise price of \$0.60 for a period of one year from the date of issuance. TSX Venture Exchange has approved the extension of the expiry date of 333,333 warrants from September 17, 2004 to March 17, 2005. All of these warrants expired subsequent to year end.
- (ii) The Company issued warrants in connection with a private placement, which closed on February 6, 2004. Each whole warrant entitles the holder to purchase one common share of the corporation at an exercise price of \$0.80 for a period of one year from the date of issuance. All of these warrants expired subsequent to year end.
- (iii) The Corporation as a result of another private placement which also closed on February 6, 2004 issued warrants. Each whole warrant entitles the holder to purchase one common share of the corporation at an exercise price of \$0.70 for a period of one year from the date of issuance. All of these warrants expired subsequent to year end.

Warrants issued	Number of Shares	Weighted average exercise price \$
Pursuant to (i)	333,334	0.60
Pursuant to (ii)	2,098,433	0.80
Agent warrants pursuant to private placement	314,764	0.80
Pursuant to (iii)	450,000	0.70
Outstanding Dec 31, 2004	3,196,531	0.77
Warrants exercisable	3,196,531	0.77

ARAPAHOE ENERGY CORPORATION
Notes to Consolidated Financial Statements

7. INCOME TAX

	2004
Loss before income taxes	(847,432)
Combined federal and provincial income tax rate	38.87%
Crown charges	3,829
Stock based compensation costs	139,644
Resource allowance	(31,696)
Benefit of losses not previously recognized	(403,214)
Future income taxes recovery	(620,834)

The components of the net future income tax asset as at December 31, 2004 were as follows:

	2004	2003
Future income tax assets:		
Asset retirement obligation	4,782	-
Share issue costs	96,169	-
Non-capital losses carried forward	811,701	-
	912,653	-
Future income tax liabilities:		
Property, plant and equipment	580,079	-
Net future income asset before valuation allowance	332,574	-
Valuation allowance	(332,574)	-
Net future income tax asset	-	-

The Company's non-capital losses expire between 2005 and 2011. Given the uncertainty of realization, no future tax asset has been recognized in these financial statements. The Company's tax pools associated with its property, plant and equipment expenditures consist of approximately \$70,000 Canadian Oil and Gas Property Expenditures (COGPE), \$13,000 of Canadian Development Expenditures (CDE), \$373,000 of Canadian Exploration Expenditures (CEE) and \$4,000 of Undepreciated Capital Costs (UCC).

8. RELATED PARTY TRANSACTIONS

The amount due from and payable to related parties as at December 31, 2004 consists primarily of the following:

- a) The Company has accrued \$6,130 payable to an officer and \$80,000 payable to two directors for services provided to the corporation. Payment for the services provided by all parties will be withheld until such time as and when the Company has revenues to sustain the same.
- b) A loan to a director for \$6,357, from a prior period is recorded in accounts receivable. The loan is non-interest bearing and has no fixed repayment terms.
- c) On October 20, 2003, the Company entered into an arms-length farm-out agreement (the "Farm-Out Agreement") with Extreme Energy Corporation ("Extreme") as a part of the Plan of Arrangement (note 1), whereby the Company acquired the right to farm-in to certain oil and gas properties owned by Extreme by drilling and completing up to four wells on the properties. After the reverse takeover of Old Arapahoe Energy Corporation on February 6, 2004, the Company and Extreme are related whereby a director of the Company is an officer of Extreme. On December 22, 2004 Extreme was sold to C1 Energy Ltd. at which time the Directors and Officers resigned. As at December 31, 2004 Extreme is no longer considered to be a related part to Arapahoe Energy Corporation.
- d) General administration charges of \$4,500 per month are paid to a Company related by virtue of a common director and an officer. As stated in note 8(c) this party is not considered to be related to Arapahoe as of December 22, 2004.

9. SUBSEQUENT EVENTS

On March 16, 2005, Arapahoe entered into a Farmout Agreement with Tsuu T'ina Energy Corporation pursuant to which it has acquired a 100% working interest in certain petroleum and natural gas rights underlying approximately 21,000 acres (the "Sarcee Farmout Lands") located on the Tsuu T'ina First Nation west of Calgary, Alberta. The Corporation is obliged to drill at least two wells per year on the Sarcee Farmout Lands. Quest Capital Corp. ("Quest") provided the Corporation with a loan in the principal amount \$2,495,820 (the "Loan"), which was used by the Corporation to acquire the Sarcee Farmout Lands and for working capital purposes. Interest accrues on the amount outstanding under the Loan at the amount of 12% per annum, calculated and compounded monthly, not in advance, and is payable to Quest on the last business day of every month commencing March 31, 2005. The outstanding balance of the Loan, including any accrued interest, is due September 30, 2005. The Corporation issued 1,181,000 Common Shares to Quest as additional consideration for the advance of the Loan. In support of its obligation to repay the Loan, the Corporation provided Quest with a security interest in all of its assets, including its interest in the Sarcee Farmout Lands.

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Notes to Consolidated Financial Statements

On March 17, 2005, Arapahoe entered into an engagement letter with Dominick & Dominick Securities Inc. for the private placement of 11,111,111 Common Shares of the Corporation, to be issued as “flow-through shares” within the meaning of the *Income Tax Act*, at the price of \$0.45 per share (\$5,000,000) and 5,000,000 Common Shares of the Corporation at the price of \$0.40 per share (\$2,000,000) for aggregate gross proceeds of \$7,000,000. The Corporation agreed to pay to the Agent at the Closing Time a fee in cash, equal to 7% of the gross proceeds from the sale of the Offered Securities, as well as Broker’s Warrants to purchase that number of Common Shares equal to 10% of the total number of Flow-Through Shares and Common Shares sold in the Offering which Broker Warrants are exercisable for a period of 12 months from the closing time at an exercise price of \$0.40 per share. The closing of this financing is expected to occur over the period from April 22, 2005 through May 15, 2005 and is subject to receipt of normal course regulatory approvals. The proceeds of the private placement will be used for further drilling, exploration and development on the Tsuu T’ina First Nation Lands as well as general and administrative purposes.

Arapahoe has closed on a portion of this financing pursuant to the engagement letter with Dominick & Dominick Securities Inc. On April 22, 2005 Arapahoe issued 1,263,100 common shares at \$0.40 and 7,512,113 flow-through shares at \$0.45 resulting in a total of \$3,885,691 raised. On April 28, 2005 Arapahoe issued 986,900 common shares at \$0.40 and 100,000 flow-through shares at \$0.45 resulting in a total of \$439,760 raised. Additional funds are expected to close in by May 10, 2005.

ARAPAHOE ENERGY CORPORATION

Statement of Reserves Data and Other Oil and Gas Information

Effective December 31, 2004

Prepared on April 27, 2005

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ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	Mmcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
Mmbbls	million barrels	Mmcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMBTU	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
BOPD	barrels of oil per day	GJ	gigajoule
NGLs	natural gas liquids		
STB	standard tank barrels		
Other			
API	American Petroleum Institute		
^o API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid Petroleum with a specified gravity of 28 ^o API or higher is generally referred to as light crude oil.		
ARTC	Alberta Royalty Tax Credit		
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.		
BOE/d	barrel of oil equivalent per day		
m3	cubic meters		
MBOE	1,000 barrels of oil equivalent		
McfGE	1,000 cubic feet of gas equivalent on the basis of 6 McfGEs to 1 bbl of crude oil. McfGEs may be misleading, particularly if used in isolation. A McfGE conversion ratio of 6 McfGEs to 1 bbl based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.		
McfGE/d	1,000 cubic feet equivalent per day		
MMcfGE	1,000 McfGE		
\$000s	thousands of dollars		
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade		

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

“Reserves” are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, 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 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.

“Developed Producing” reserves are those reserves that are expected to be recovered from completion intervals open at the time of 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 (e.g., 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 sub-divide 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.

“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 + probable reserves.

The following terms, used in the preparation of the Chapman Petroleum Reports (as defined herein) and this document, have the following meanings:

“associated gas” means the gas cap overlying a crude oil accumulation in a reservoir.

“constant prices and costs” means prices and costs used in an estimate that are:

- (a) the Corporation’s prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies;

- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for and extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

“Corporation” or **“Arapahoe”** means Arapahoe Energy Corporation.

“crude oil” and **“oil”** means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulfur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

“development costs” means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (a) gain access to a prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
- (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;
- (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
- (d) provide improved recovery systems.

“development well” means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

“exploration costs” means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as “prospecting costs”) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are;

- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
- (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;
- (c) dryhole contributions and bottom hole contributions;
- (d) costs of drilling and equipping exploratory wells; and
- (e) costs of drilling exploratory type stratigraphic test wells.

“exploratory well” means a well that is not a development well, a service well or a stratigraphic test well.

“field” means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to denote localized geological features, in contrast to broader terms such as “basin”, “trend”, “province”, “play” or “area of interest”.

“future prices and costs” means future prices and costs that are:

- (a) generally accepted as being a reasonable outlook on the future;
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

“future income tax expense” means future income tax expenses estimated (generally, year-by-year):

- (a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
- (b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;
- (c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and
- (d) applying to the future pre-tax cash flows relating to the reporting issuer’s oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

“future net revenue” means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

“gross” means:

- (a) in relation to the Corporation’s interest in production or reserves, its “company gross reserves”, which are its working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;
- (b) in relation to wells, the total number of wells in which the Corporation has an interest; and
- (c) in relation to properties, the total area of properties in which the Corporation has an interest.

“natural gas” means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

“natural gas liquids” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

“net” means

- (a) in relation to the Corporation’s interest in production or reserves its working interest (operating non-operating) share after deduction of royalty obligations, plus the its royalty interests in production or reserves;
- (b) in relation to the Corporation’s interest in wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and
- (c) in relation to the Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

“non-associated gas” means an accumulation of natural gas in a reservoir where there is no crude oil.

“operating costs” or **“production costs”** means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“production” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

“property” includes:

- (a) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
- (b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
- (c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

“property acquisition costs” means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

- (a) costs of lease bonuses and options to purchase or lease a property;
- (b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;
- (c) brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

“proved property” means a property or part of a property to which reserves have been specifically attributed.

“reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“service well” means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

“solution gas” means natural gas dissolved in crude oil.

“stratigraphic test well” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) “exploratory type” if not drilled into a proved property; or (b) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”.

“support equipment and facilities” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division or field offices.

“unproved property” means a property or part of a property to which no reserves have been specifically attributed.

“well abandonment costs” means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, Chapman Petroleum Engineering Ltd. (“Chapman”) prepared three reports (“the Chapman Reports”) dated April 1, 2004, November 1, 2004 and January 1, 2005. Each of these reports evaluated oil, natural gas liquids and natural gas reserves in various areas as at December 31, 2004. The tables below are a summary of the oil, natural gas liquids and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Chapman Reports based on constant and forecast price and cost assumptions. The tables summarize the data contained in the Chapman Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. **The net present value of future net revenue attributable to the Corporation’s reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Chapman. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation’s reserves estimated by Chapman 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 of the Corporation’s oil, natural gas liquids 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 Chapman Reports are based on certain factual data supplied by the Corporation and Chapman’s opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation’s petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to Chapman and accepted without any further investigation. Chapman accepted this data as presented and neither title searches nor field inspections were conducted.

Summary of Oil and Natural Gas Reserves
January 1, 2005
(as of December 31, 2004)
Constant Prices and Costs

Reserves Category	Company Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas [1]		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	MSTB	MSTB	MSTB	MSTB	MMscf	MMscf	Mbbl	Mbbl
PROVED								
Developed Producing	2	2	0	0	9	7	0	0
Undeveloped	0	0	0	0	1,260	850	23	16
TOTAL PROVED	2	2	0	0	1,269	857	23	16
TOTAL PROBABLE	1	1	0	0	8,740	5,949	157	117
TOTAL PROVED PLUS PROBABLE	3	3	0	0	10,009	6,806	180	133
Reference: Item 2.1 (1) Form 51-101F1								
Columns may not add precisely due to accumulative rounding of values throughout the report.								
Notes: [1] Includes associated and non-associated and solution gas where applicable								
[2] Reserves shown as "0" reflect a value of less than 0.5 (MSTB/MMscf/Mbbl)								

Summary of Net Present Values
January 1, 2005
(as at December 31, 2004)
Constant Prices and Costs

Reserves Category	Net Present Values of Future Net Revenue [1]			
	Before Income Tax		After Income Tax [2]	
	Undiscounted	Discounted @ 10%/yr.	Undiscounted	Discounted @ 10%/yr.
	M\$	M\$	M\$	M\$
PROVED				
Developed Producing	109	80	109	80
Undeveloped	4,472	3,003	4,472	3,003
TOTAL PROVED	4,581	3,083	4,581	3,083
PROBABLE	40,393	22,817	40,393	22,817
TOTAL PROVED PLUS PROBABLE	44,974	25,900	44,974	25,900
Reference: Item 2.1 (2) Form 51-101F1				
Columns may not add precisely due to accumulative rounding of values throughout the report.				
Notes: [1] Includes ARTC				
[2] The company outstanding tax pool exceed the company Net Present Values of Future Net Revenue				

Total Future Net Revenue (Undiscounted)
January 1, 2005
(as at December 31, 2004)
Constant Prices and Costs

Reserve Category	Revenue M\$	Royalties M\$	Operating Costs M\$	Development Costs M\$	Well Abandonment Costs M\$	Future Net Revenues BIT [1] M\$	Income Taxes M\$	Future Net Revenues AIT M\$
Total Proved	10,694	3,451	895	1,750	21	4,581	0	4,581
Total Proved plus Probable	80,363	25,815	6,397	3,125	58	44,974	0	44,974

Reference: Item 2.1 (3)(b) NI 51-101F1
Notes: [1] Includes ARTC
[2] The company outstanding tax pool exceed the company Net Present Values of Future Net Revenue

Total Future Net Revenue (Undiscounted)
January 1, 2005
(as of December 31, 2004)
Constant Prices and Costs

Reserve Category	Production Group	Future Net Revenue Before Income Taxes [1] Discounted at 10%/yr. \$M
Total Proved	Light and Medium Oil (including solution gas and other by-products)	80
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	3,003
Proved Plus Probable	Light and Medium Oil (including solution gas and other by-products)	105
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	25,795

Reference: Item 2.1 (3)(c) NI 51-101F1
Notes: [1] Includes ARTC

**Oil and Gas Reserves and Net Present Values
by Production Group
January 1, 2005
(as of December 31, 2004)
Constant Prices and Costs**

Reserve Group by Category	Reserves						Net Present Value (BIT) [2] 10% M\$	Unit Values @ 10%/yr. \$/STB
	Oil		Gas[1]		NGL			
	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl		
Light and Medium Oil								
Proved								
Developed Producing	2	2	8	6	0	0	80	37.30
Total Proved	2	2	8	6	0	0	80	37.30
Probable	1	1	4	3	0	0	25	24.46
Proved Plus Probable	3	3	12	9	0	0	105	33.22
Assoc & Non-Assoc Gas								
								\$/Mscf
Proved								
Developed Producing	0	0	1	0	0	0	0	.53
Undeveloped	0	0	1,260	850	23	16	3,003	3.53
Total Proved	0	0	1,261	850	23	16	3,003	3.53
Probable	0	0	8,736	3,783	187	117	22,792	6.02
Proved Plus Probable	0	0	9,997	4,633	211	133	25,795	5.57
Reference: Item 2.1 (3)(c) NI 51-101F1								
Notes: [1] Includes solution gas.								
[2] Includes ARTC								
[3] Net Present Values shown as "0" reflect a value of less than \$500								
[4] Reserves shown as "0" reflect a value of less than 0.5(MSTB/MMscf/Mbbl)								

Summary of Oil and Natural Gas Reserves
January 1, 2005
(as of December 31, 2004)
Forecast Prices and Costs

Reserves Category	Company Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas [1]		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	MSTB	MSTB	MSTB	MSTB	MMscf	MMscf	Mbbl	Mbbl
PROVED								
Developed Producing	2	2	0	0	9	6	0	0
Developed Non-Producing								
Undeveloped	0	0	0	0	1,260	822	23	15
TOTAL PROVED	2	2	0	0	1,269	828	23	15
TOTAL PROBABLE	1	1	0	0	8,740	6,076	188	120
TOTAL PROVED PLUS PROBABLE	3	3	0	0	10,009	6,905	211	135
Reference: Item 2.1 (1) Form 51-101F1								
Columns may not add precisely due to accumulative rounding of values throughout the report.								
Notes: [1] Includes associated and non-associated gas.								
[2] Reserves shown as "0" reflect a value of less than 0.5 (MSTB/MMscf/Mbbl)								

Summary of Net Present Values
January 1, 2005
(as at December 31, 2004)
Forecast Prices and Costs

Reserve Category	Net Present Values of Future Net Revenue [1]				
	Before Income tax				
	0%/yr M\$	5%/yr M\$	10%/yr M\$	15%/yr M\$	20%/yr M\$
PROVED					
Developed Producing	96	83	73	65	59
Undeveloped	3,266	2,637	2,174	1,822	1,549
TOTAL PROVED	3,362	2,720	2,247	1,887	1,608
PROBABLE	32,214	23,233	18,196	14,993	12,777
TOTAL PROVED PLUS PROBABLE	35,576	25,953	20,443	16,880	14,385

Reserve Category	Net Present Values of Future Net Revenue [1]				
	After Income tax				
	0%/yr M\$	5%/yr M\$	10%/yr M\$	15%/yr M\$	20%/yr M\$
PROVED					
Developed Producing	96	83	73	65	59
Undeveloped	3,266	2,637	2,174	1,822	1,549
TOTAL PROVED	3,362	2,720	2,247	1,887	1,608
PROBABLE	32,214	23,233	18,196	14,993	12,777
TOTAL PROVED PLUS PROBABLE	35,576	25,953	20,443	16,880	14,385

Total Future Net Revenue (Undiscounted) January 1, 2005 (as of December 31, 2004) Forecast Prices and Costs								
Reserve Category	Revenue M\$	Royalties M\$	Operating Costs M\$	Development Costs M\$	Well Abandonment Costs M\$	Future Net Revenues BIT [1] M\$	Income Taxes M\$	Future Net Revenues AIT M\$
Total Proved	8,827	2,714	955	1,776	24	3,362	0	3,362
Proved Plus Probable	66,443	20,503	7,128	3,172	71	35,576	0	35,576

Reference: Item 2.2 (3)(b) NI 51-101F1

Columns may not add precisely due to accumulative rounding of values throughout the report.

Notes: [1] Includes ARTC

[2] The company outstanding tax pool exceed the company Net Present Values of Future Net Revenue

Future Net Revenue - By Production Group
January 1, 2005
(as of December 31, 2004)
Forecast Prices and Costs

Reserve Category	Production Group	Future Net Revenue Before Income Taxes [1] Discounted at 10%/yr. \$M
Total Proved	Light and Medium Oil (including solution gas and other by-products)	73
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	2,174
Proved Plus Probable	Light and Medium Oil (including solution gas and other by-products)	95
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	20,348

Reference: Item 2.2 (3)(c) NI 51-101F1

Notes: [1] Includes ARTC

**Oil and Gas Reserves and Net Present Values
by Production Group
January 1, 2005
(as of December 31, 2004)**

Forecast Prices and Costs

Reserve Group by Category	Reserves						Net Present Value (BIT)[2] 10% M\$	Unit Values @ 10%/yr. \$/STB
	Oil		Gas [1]		NGL			
	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbbl	Net Mbbbl		
Light and Medium Oil								
Proved								
Developed Producing	2	2	8	6	0	0	73	33.66
Total Proved	2	2	8	6	0	0	73	33.66
Probable	1	1	4	3	0	0	22	21.93
Proved Plus Probable	3	3	12	9	0	0	95	29.93
Assoc & Non-Assoc Gas								
								\$/Mscf
Proved								
Developed Producing	0	0	1	0	0	0	0	.83
Undeveloped	0	0	1,260	822	23	15	2,174	2.64
Total Proved	0	0	1,261	822	23	15	2,174	2.64
Probable	0	0	8,736	6,073	187	120	18,174	2.99
Proved Plus Probable	0	0	9,997	6,895	211	135	20,348	2.95

Reference: Item 2.2 (3)(c) NI 51-101F1

Columns may not add precisely due to accumulative rounding of values throughout the report.

Notes: [1] Includes solution gas

[2] Includes ARTC

[3] Net Present Values shown as "0" reflect a value of less than \$500

[4] Reserves shown as "0" reflect a value of less than 0.5 (MSSTB/MMscf/Mbbbl)

Pricing Assumptions – Constant / Forecast Prices and Costs (Oil)

CHAPMAN PETROLEUM ENGINEERING LTD.								
CRUDE OIL								
CONSTANT PRICES & PRICE FORECASTS								
JANUARY 1, 2005								
Date	WTI [1] \$US/STB	Alberta Par Price [2] \$CDN/STB	Alberta Heavy [3] \$CDN/STB	Sask. Light [4] \$CDN/STB	Sask. Heavy [5] \$CDN/STB	B.C. Light [6] \$CDN/STB	ART Credits [7] Rate %	Max M\$
HISTORICAL PRICES								
1994	17.16	22.27	18.19	20.76	19.16	21.12	n/a	n/a
1995	18.41	25.11	19.76	22.77	20.57	23.85	n/a	n/a
1996	21.98	29.39	25.09	28.41	26.07	27.99	n/a	n/a
1997	20.59	27.90	21.15	26.52	23.73	26.32	n/a	n/a
1998	14.46	20.39	14.68	19.31	17.01	19.38	n/a	n/a
1999	19.21	27.88	23.71	27.23	25.65	27.42	n/a	n/a
2000	30.39	44.90	34.51	43.37	40.12	n/a	n/a	n/a
2001	25.98	39.66	25.41	35.57	31.84	n/a	n/a	n/a
2002	26.09	40.63	32.20	37.67	34.57	n/a	n/a	n/a
2003	30.84	43.57	32.65	40.13	37.64	n/a	n/a	n/a
2004	41.48	52.89	37.52	48.96	45.74	n/a	n/a	n/a
CONSTANT PRICES								
December 31, 2004	43.45	50.65	25.97	39.11	34.50	49.38	25.00	500
CURRENT YEAR FORECAST								
2005	42.00	50.22	35.15	46.64	43.59	48.96	25.00	500
FUTURE FORECAST								
2006	40.00	49.00	34.30	45.51	42.53	47.78	25.00	500
2007	38.00	47.72	33.40	44.32	41.42	46.53	25.00	500
2008	36.00	45.15	31.61	41.94	39.19	44.03	25.00	500
2009	35.00	43.87	30.71	40.75	38.08	42.78	25.00	500
2010	35.53	44.54	31.18	41.37	38.66	43.42	25.00	500
2011	36.06	45.23	31.66	42.01	39.26	44.07	25.00	500
2012	36.60	45.92	32.15	42.65	39.86	44.72	25.00	500
2013	37.15	46.63	32.64	43.31	40.47	45.40	25.00	500
2014	37.70	47.34	33.14	43.97	41.09	46.08	25.00	500
2015	38.27	48.06	33.65	44.64	41.72	46.77	25.00	500
2016	38.84	48.80	34.16	45.33	42.36	47.47	25.00	500
2017	39.43	49.55	34.68	46.02	43.01	48.17	25.00	500
2018	40.02	50.31	35.21	46.72	43.66	48.91	25.00	500
2019	40.62	51.08	35.75	47.44	44.33	49.64	25.00	500
2020	41.23	51.86	36.30	48.16	45.01	50.39	25.00	500
Constant thereafter								
Notes:	[1] West Texas Intermediate quality (D2/S2) crude landed in Cushing, Oklahoma. [2] Equivalent price for Light Sweet Crude (D2/S2) landed in Edmonton, Alberta after exchange of .820 \$US/\$CDN(2005), 0.80\$US/\$CDN(2006) and 0.78\$US/\$CDN thereafter and transportation differential of \$1.00 CDN/STB. [3] Bow River at Hardisty, Alberta (905 kg/m3, 2.1% sulphur). [4] Light Sour Blend at Cromer, Saskatchewan (850 kg/m3, 1..2% sulphur). [5] Midale at Cromer, Saskatchewan (880 kg/m3, 2.0% sulphur). [6] B.C. Light at Taylor, British Columbia (825 kg/m3, 0.5% sulphur). [7] ARTC rate ranges from www.revenue.gov.ab.ca/publications/tax_rebates/rates_surveys_tnotes/rtc.html . [8] December 30, 2004 is the last trading day of 2004 [9] Capital expenditures and operating costs are escalated at 1.5% per year until 2020.							

Pricing Assumptions – Constant / Forecast Prices and Costs (Gas)

CHAPMAN PETROLEUM ENGINEERING LTD.										
NATURAL GAS & BY-PRODUCTS										
CONSTANT PRICES & PRICE FORECASTS										
JANUARY 1, 2005										
	GRP [1]		AECO Spot	Sask.	B.C.			Pentanes	NGL	
Date	\$/MMBTU	\$/GJ	Gas [NIT] \$/MMBTU	Gas [2] \$/MMBTU	Gas [3] \$/MMBTU	Propane [4] \$/BBL	Butane [4] \$/BBL	Plus [4] \$/BBL	Mix [5] \$/BBL	
HISTORICAL PRICES										
1994	1.82	1.73	1.78	1.88	1.81	12.72	13.44	21.67	15.62	
1995	1.31	1.24	1.08	1.35	1.29	14.38	13.97	24.11	17.18	
1996	1.63	1.55	1.33	1.52	1.50	22.95	17.19	30.05	23.35	
1997	1.97	1.87	1.67	1.84	1.80	17.73	19.07	30.90	22.08	
1998	1.94	1.84	1.94	2.05	1.94	11.13	12.06	21.86	14.63	
1999	2.48	2.35	2.82	2.83	2.51	15.93	18.01	27.73	20.09	
2000	4.50	4.27	5.56	4.85	4.00	31.38	35.01	46.35	36.96	
2001	5.78	5.48	5.44	5.48	6.12	31.27	30.27	44.98	35.08	
2002	3.86	3.66	4.13	4.17	3.85	19.14	25.11	40.72	27.41	
2003	6.45	6.11	7.03	6.47	6.45	28.85	32.15	44.23	34.46	
2004	6.25	5.92	6.60	6.50	6.25	31.95	38.40	54.06	40.52	
CONSTANT PRICES										
December 31, 2004 [6]	5.92	5.61	6.22	6.17	5.92	29.41	37.36	50.56	38.14	
CURRENT YEAR FORECAST										
2005	6.25	5.92	6.55	6.50	6.25	30.21	36.58	51.53	38.52	
FUTURE FORECAST										
2006	6.00	5.69	6.30	6.25	6.00	29.48	35.69	50.28	37.58	
2007	5.50	5.21	5.80	5.75	5.50	28.71	34.76	48.96	37.63	
2008	5.25	4.98	5.55	5.50	5.25	27.16	32.89	46.33	36.60	
2009	5.33	5.05	5.63	5.58	5.33	26.39	31.96	45.02	34.63	
2010	5.41	5.13	5.71	5.66	5.41	26.80	32.45	45.71	33.65	
2011	5.49	5.20	5.74	5.49	27.21	32.94	46.41	34.69	27.34	
2012	5.57	5.28	5.87	5.82	5.57	27.63	33.45	47.12	35.22	
2013	5.66	5.36	5.96	5.91	5.66	28.05	33.96	47.84	35.76	
2014	5.74	5.44	6.04	5.99	5.74	28.48	34.48	48.58	36.31	
2015	5.83	5.52	6.13	6.08	5.83	28.92	35.01	49.32	36.87	
2016	5.91	5.61	6.21	6.16	5.91	29.36	35.55	50.07	37.43	
2017	6.00	5.69	6.30	6.25	6.00	29.81	36.09	50.84	38.00	
2018	6.09	5.78	6.39	6.34	6.09	30.26	36.64	51.62	38.58	
2019	6.18	5.86	6.48	6.43	6.18	30.73	37.20	52.41	39.17	
2020	6.28	5.95	6.58	6.53	6.28	31.20	37.77	53.21	39.77	
Constant thereafter										
Notes:	[1] Gas Reference Price (GRP) represents the average of all system and direct (spot and firm) sales. [2] Price paid at field delivery point. [3] Price paid by CanWest net of raw gas gathering and processing charges but before deduction of field gathering and compression charges. [4] Reference point is FOB Edmonton for fractionated product. [5] Natural Gas Liquids blended mix price assuming typical liquid composition of 40% propane, 30% butane and 30% pentanes plus. [6] December 30, 2004 is the last trading day of 2004 [7] Capital expenditures and operating costs are escalated at 1.5% per year until 2020.									

RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

The following table sets forth a reconciliation of Arapahoe's total proved, probable and total proved plus probable reserves as at December 31, 2004 against such reserves as at December 31, 2003 based on forecast price and cost assumptions.

	Light and Medium Oil			Natural Gas Liquids		
	Total Proved Reserves	Probable Reserves	Total Proved Plus Probable	Total Proved Reserves	Probable Reserves	Total Proved Plus Probable
	Bbls	Bbls	Bbls	Bbls	Bbls	Bbls
December 31, 2003	2,300	800	3,100	-	-	-
Acquisitions	-	-	-	16	117	133
Technical Revisions	300	200	500			
Dispositions	-	-	-			
Production	(400)	-	(400)			
December 31, 2004	<u>2,200</u>	<u>1,000</u>	<u>3,200</u>	<u>16</u>	<u>117</u>	<u>133</u>

	Associated and Non-Associated Gas		
	Total Proved Reserves	Probable Reserves	Total Proved Plus Probable
	MMcf	MMcf	MMcf
December 31, 2003	2	2	4
Extensions	-	-	-
Acquisitions	868	6,026	6,894
Technical Revisions	1	(2)	(1)
Dispositions	-	-	-
Production	(2)	-	(2)
December 31, 2004	<u>869</u>	<u>6,026</u>	<u>6,895</u>

Future Net Revenue Reconciliation

The following table sets for the a reconciliation of the estimate of the net present value of future revenue attributable to Arapahoe's reserves as evaluated in the Chapman Reports as at December 31, 2004 against the estimate of such amounts s at December 31, 2003, calculated before tax using a discount rate of 10% and constant price and cost assumptions.

PROVED RESERVES

CONSTANT PRICES AND COSTS

	2004 (M\$)
Estimated Future Net Revenue at Beginning of Year (Dec 31, 2003)	74
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(20)
Net Change in Production Costs for Future Production	8
Net Change in sales price for Future Production	20
Net Change in royalties for Future Production	-
Change in development costs incurred	-
Changes in Estimated Future Development Costs	(1,642)
Extensions and Improved Recovery	-
Discoveries	-
Acquisitions of Reserves	4,631
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	7
Accretion of discount	5
Net Change in Income Taxes	-
Other (may include value of production in disposed and acquired properties, changes in timing of future production)	-
Estimated Future Net Revenue at End of Year (December 31, 2004)	3,083

UNDEVELOPED RESERVES

The following discussion generally describes the basis on which Arapahoe 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 Arapahoe 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 requires 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 cost change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. Arapahoe's reserves are evaluated by Chapman Petroleum Engineering Ltd., an independent engineering firm.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, 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. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performances. Such revisions can be either positive or negative.

FUTURE DEVELOPMENT COSTS

The table below sets out the 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 process and costs only).

	Constant Prices and Costs	Forecast Prices and Costs	
	Proved Reserves	Proved Reserves	Proved Plus Probable Reserves
	(M\$)	(M\$)	(M\$)
2005	1,750	1,776	3,172
2006	0	0	0
2007	0	0	0
2008	0	0	0
Remaining Years	0	0	0
Total Undiscounted	1,750	1,776	3,172
Total Discounted at 10% per year	1,642	1,667	2,960

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

OIL AND GAS PROPERTIES

A summary description of Arapahoe's major producing and exploration properties is set out below. References to gross volumes refer to total production. References to net volumes refer to Arapahoe's working interest share before the deduction of royalties payable to others.

Arapahoe currently owns a 14.7485 percent working interest in one producing oil well and one suspended oil well in the Drumheller area of Southern Alberta. Arapahoe also owns a 2.2% interest in a well located in the Zama area of Northern Alberta. Production from both interests are subject to Alberta crown royalties.

In addition to the producing properties listed above, Arapahoe owns an interest in various minor non producing properties in Western Canada. As these properties are either shut-in or are not productive, no value has been assigned to them and they have not been included in the Chapman Reports (defined below).

OIL AND GAS WELLS

The following table summarizes the Corporation's interest as at December 31, 2004 in wells that are producing and non-producing.

Producing Properties				
<u>Area</u>	<u>Gas Wells</u>		<u>Oil Wells</u>	
	<u>Gross⁽¹⁾</u>	<u>Net⁽²⁾</u>	<u>Gross⁽¹⁾</u>	<u>Net⁽²⁾</u>
Drumheller, Alberta	-	-	2	0.4384
Zama, Alberta	1	0.022	-	-
TOTAL	1	0.022	2	0.4384

Non-Producing Properties				
<u>Area</u>	<u>Gas Wells</u>		<u>Oil Wells</u>	
	<u>Gross⁽¹⁾</u>	<u>Net⁽²⁾</u>	<u>Gross⁽¹⁾</u>	<u>Net⁽²⁾</u>
Drumheller, Alberta	-	-	2	0.6969
Pembina, Alberta	-	-	1	0.0611
Retlaw, Alberta	-	-	2	0.3395
Morinville, Alberta	1	0.185	-	-
TOTAL	1	0.185	5	1.0975

Notes

- 1 "Gross Wells" means the total number of wells in which Arapahoe has an interest.
- 2 "Net Wells" means the total number of wells in which Arapahoe has an interest multiplied by their percentage working interest in such wells and assuming that all interests convertible to working interests have been covered.

DRILLING ACTIVITY

The following table summarizes Arapahoe's drilling results for the year ended December 31, 2004.

	2004	
	Gross	Net
Oil	0	0
Natural		
Gas	1	.3
Dry & Abandoned	0	0
Total	0	0

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

Arapahoe estimates well abandonment costs stereotypically area by area. Such costs are included in the Chapman Reports as deductions in arriving at future net revenue. The expected total abandonment costs included in the Chapman Reports for 0.47 net wells under the proved reserve category is \$21,000 undiscounted (\$8,465 discounted at 10%), of which a total of \$814 is estimated to be incurred by 2006. This estimate includes expected reclamation costs for surface leases and salvage value recovery. Expected future abandonment costs related to facilities are expected to match the salvage value recovery.

TAX HORIZON

Arapahoe was not required to pay income taxes during the year ended December 31, 2004. Based on a strategy of re-investing fully all internally generated cash flow in an exploration and development program and based on the commodity prices used in the Chapman Reports, Arapahoe estimates that it will not be required to pay income taxes for the period evaluated under this report.

COSTS INCURRED

The following table summarized Arapahoe's property acquisition costs, exploration costs and development costs for the year ended December 31, 2004.

	Property Acquisition Costs		Exploration Costs	Development Costs
	Proven Properties	Unproven Properties		
Total (\$)	19,319	2,193,293	0	0

PRODUCTION ESTIMATES

The following table disclosed for each product type the total volume of production estimated by Chapman for 2005 in the estimates of future net revenue from proved reserves disclosed above under the heading “Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue”.

	Oil	Natural Gas	Natural gas Liquids	BOE	%
	Bbls	MMcf	Bbls		
Drumheller	364	1	23	387	98%
Zama	-	-	8	8	2%
Others	-	-	-	-	0%
Estimated Total Production	364	1	31	395	100%

PRODUCTION HISTORY

The following table discloses, on a quarterly basis for the year ended December 31, 2004, Arapahoe’s share of average daily production volume, prior to royalties, and the prices received, royalties paid, production costs incurred and netbacks on a per unit of volume basis for each production type.

Average Daily Production Volume

	Three Months Ended				
	March 31,2004	June,30 2004	September 30,2004	December 31,2004	Total
Oil (Bbl/d)	4	3	4	3	4
Natural Gas (Mcf/d)	25	18	18	19	20
NGL (Bbl/d)	0	0	0	0	0
Total (BOE/d)	9	7	8	7	8

Prices Receive, Royalties Paid, Production Costs and Netback – Light and Medium Crude Oil / Natural Gas and NGLs

	Three Months Ended				
	March 31,2004	June,30 2004	September 30,2004	December 31,2004	Total
Prices Received					
Oil (\$ per Bbl)	34.39	31.86	32.08	31.95	32.58
Gas (\$ per Mcf)	6.30	6.41	6.94	6.59	6.69
NGL (\$ per Bbl)	25.33	31.90	34.14	30.87	32.99
Royalties Paid					
Oil (\$ per Bbl)	3.36	2.86	3.49	3.46	3.46
Gas (\$ per Mcf)	1.43	1.43	1.43	1.43	1.70
NGL (\$ per Bbl)	2.36	2.67	2.56	2.76	3.10
Production Costs per BOE	8.56	5.35	4.27	13.54	7.83
Netback	20.80	26.37	36.32	22.52	26.57

Production Volume by Field

The following table discloses for each important field, and in total, Arapahoe's production volumes for the financial year ended December 31, 2004 for each product type.

	Oil (Bbls)	Natural Gas (Mcf)	NGL (Bbl)	BOE	%
Drumheller, Alberta	1,307	6,577	195	2,598	95%
Zama, Alberta		862	2	146	5%
Others				-	0%
Total	1,307	7,439	197	2,743	100%