

CONSOLIDATED INCOME STATEMENT (Unaudited)

<i>(thousands of US dollars except per share amounts)</i>	Note	Three months ended		Six months ended	
		30 Jun 2006	31 Mar 2006	30 Jun 2006	30 Jun 2005
Revenue		3,198	2,073	5,271	862
Cost of sales					
Production and distribution expenses		(197)	(165)	(362)	(86)
Depletion expense		(382)	(324)	(706)	(66)
Gross profit		2,619	1,584	4,203	710
Other income		14	16	30	24
Administrative expenses		(1,562)	(1,293)	(2,855)	(1,481)
Foreign exchange gain/(losses)		9	(41)	(32)	(46)
Profit/(loss) before taxation		1,080	266	1,346	(793)
Taxation	1	(420)	(183)	(603)	-
Profit/(loss) after taxation		660	83	743	(793)
Profit/(loss) per share					
Basic and diluted (US\$)		0.03	-	0.03	(0.03)

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEET (Unaudited)

<i>(thousands of US dollars)</i>	Note	As at 30 June 2006	As at 31 March 2006	As at 31 December 2005
ASSETS				
Current assets				
Cash and cash equivalents		2,829	3,454	3,198
Trade and other receivables		4,076	2,044	2,862
		6,905	5,498	6,060
Natural gas properties and other equipment	2	16,161	15,537	15,037
		23,066	21,035	21,097
LIABILITIES				
Current liabilities				
Trade and other payables		4,457	3,380	3,849
Non current liabilities				
Deferred tax	1	743	619	506
Deferred additional profits tax		151	108	80
SHAREHOLDERS' EQUITY				
Capital stock	3	16,355	16,324	16,237
Capital reserve		956	860	764
Accumulated profit/(loss)		404	(256)	(339)
		17,715	16,928	16,662
		23,066	21,035	21,097

Contingent liabilities (Note 4)

Contractual obligations and committed capital investment (Note 5)

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS (Unaudited)

<i>(thousands of US dollars)</i>	Three months ended		Six months ended	
	30 Jun 2006	31 Mar 2006	30 Jun 2006	30 Jun 2005
CASH FLOWS FROM OPERATING ACTIVITIES				
Profit/(loss) after taxation	660	83	743	(793)
Adjustments for:				
Depletion and depreciation	410	351	761	110
Stock-based compensation	96	96	192	142
Deferred taxation	123	113	236	-
Deferred additional profits tax	44	28	72	-
Funds from operations before working capital changes	1,333	671	2,004	(541)
(Increase)/decrease in trade and other receivables	(2,032)	818	(1,214)	(217)
Increase/(decrease) in trade and other payables	1,506	(576)	930	980
Net cash flows from operating activities	807	913	1,720	222
CASH FLOWS USED IN INVESTING ACTIVITIES				
Acquisition of natural gas properties and other equipment	(1,034)	(851)	(1,885)	(2,261)
Increase/(decrease) in trade and other payables	(429)	107	(322)	-
Net cash used in investing activities	(1,463)	(744)	(2,207)	(2,261)
CASH FLOWS FROM FINANCING ACTIVITIES				
Net proceeds from rights issue	-	-	-	4,365
Proceeds from exercise of options	31	87	118	10
Net cash flow from financing activities	31	87	118	4,375
Increase/(decrease) in cash and cash equivalents	(625)	256	(369)	2,336
Cash and cash equivalents at the beginning of the period	3,454	3,198	3,198	2,040
Cash and cash equivalents at the end of the period	2,829	3,454	2,829	4,376

See accompanying notes to the interim consolidated financial statements.

STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY (Unaudited)

<i>(thousands of US dollars)</i>	Capital stock	Capital reserve	Accumulated Profit/(Loss)	Total
Note	3			
Balance as at 31 December 2004	11,862	381	(727)	11,516
Rights issue net of share issue costs	4,365	-	-	4,365
Options exercised	10	-	-	10
Profit for the year	-	-	388	388
Stock-based compensation	-	383	-	383
Balance as at 31 December 2005	16,237	764	(339)	16,662
Options exercised	118	-	-	118
Profit for the period	-	-	743	743
Stock based compensation	-	192	-	192
Balance as at 30 June 2006	16,355	956	404	17,715

See accompanying notes to the interim consolidated financial statements.

Notes to the Consolidated Financial Statements (Unaudited)

Basis of preparation

The interim consolidated financial statements are measured and presented in US dollars as the main operating cash flows are linked to this currency through the commodity price.

The same accounting policies and methods of computation have been followed as the consolidated financial statements at 31 December 2005. The interim consolidated financial statements for the three months ended 30 June 2006 should be read in conjunction with the audited financial statements and related notes for the year ended 31 December 2005.

Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the period. Actual results could differ from these estimates.

Statement of Compliance

These interim consolidated financial statements of EastCoast Energy Corporation (“EastCoast” or the “Company”) including comparatives, have been prepared in accordance with IAS 34 of the International Financial Reporting Standards (“IFRS”) and interpretations issued by the Standing Interpretations Committee of the IASB.

These principles may differ in certain respects from those in Canada. These differences are summarised in note 6.

1 Tax

As at 30 June 2006, there were temporary differences between the carrying value of the assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Accordingly a deferred tax liability has been recognised for the quarter ended 30 June 2006.

Tax rate reconciliation: Figures in US\$'000

	Three months ended		Six months ended
	30 Jun 2006	31 Mar 2006	30 Jun 2006
Profit before taxation	1,080	266	1,346
Provision for income tax calculated at the statutory rate of 30%	324	80	404
Add/(deduct) the tax effect of non-deductible income tax items:			
Other income	(4)	(5)	(9)
Administrative and operating expenses	36	53	89
Stock based compensation	29	29	58
Other	35	26	61
	420	183	603
The tax charge may be analysed as follows:			
Current tax	297	70	367
Deferred tax	123	113	236
	420	183	603

The deferred income tax liability is based on the following timing differences:

	30 Jun 2006	31 Mar 2006	31 Dec 2005
Differences between tax base and carrying value of natural gas properties	681	575	474
Other timing differences	62	44	32
	743	619	506

2 Natural gas properties and other equipment

Figures in US\$'000	Natural gas properties	Leasehold improve ments	Computer equipment	Vehicles	Fixtures & fittings	Total
Costs						
As at 1 January 2006	15,693	156	59	38	37	15,983
Additions – Q1	819	-	4	27	1	851
Additions – Q2	1,031	-	-	-	3	1,034
As at 30 June 2006	17,543	156	63	65	41	17,868
Depletion/Depreciation						
As at 1 January 2006	853	49	19	13	12	946
Charge for the period – Q1	324	13	5	5	4	351
Charge for the period – Q2	383	13	5	6	3	410
As at 30 June 2006	1,560	75	29	24	19	1,707
Net Book Values						
At 30 June 2006	15,983	81	34	41	22	16,161
At 31 March 2006	15,335	94	39	47	22	15,537
At 31 December 2005	14,840	107	40	25	25	15,037

Included in the natural gas properties as at 30 June 2006 is US\$0.5 million representing the costs of acquiring and processing 328 kilometers of seismic on the Nyuni 'A' area subject to the farm-in terms with a subsidiary of Aminex plc. This asset will not be depleted until it is determined whether or not proved reserves are attributable to the properties, or impairment occurs.

In determining the depletion charge, it is estimated by the independent reserve engineers that future development costs of US\$69.6 million will be required to bring the total proved reserves to production.

3 Capital Stock

Thousands of shares or US\$	Authorised	Issued	Valuation
Class A shares			
As at 31 December 2005 and 30 June 2006	50,000	1,751	983
Class B shares			
As at 31 December 2005	50,000	21,513	15,254
Options exercised	-	135	118
As at 30 June 2006	50,000	21,648	15,372
Total Class A and B shares as at 30 June 2006	100,000	23,399	16,355

In Q2 2006, 35,000 (Q1 2006: 100,000) options were exercised at a price of Cdn\$1 per option. A total of 1,852,400 options remain outstanding. These options have a term of 10 years and an exercise price of Cdn\$1.

4 Contingent Liabilities

The Company received two letters in the period ended 31 March 2006 from the Tanzania Revenue Authority (“TRA”) demanding US\$433,000 for unremitted import duties on the gas distribution pipeline and other related equipment and US\$373,000 for uninvoiced and unremitted Value Added Tax. The Company has objected to the demands and claims exemptions under the terms of the Songo Songo PSA and Customs Tariff Act. As such, no accrual has been made in these financial statements.

5 Contractual Obligations and Committed Capital Investment

Under the terms of the PSA, in the event that there is a shortfall in Protected Gas as a consequence of the sale of Additional Gas, the Company is liable to pay the difference between the price of Protected Gas (US\$0.55/mmbtu) and the price of an alternative feedstock multiplied by the volumes of Protected Gas up to a maximum of the volume of Additional Gas sold. Songas has the right to request reasonable security on all Additional Gas sales. No security has been requested for the industrial gas sales to date but Songas has this right and may require security for larger volumes.

Songas has confirmed that, subject to certain conditions, security will not be required for the supply of Additional Gas to the Ubungu Power Plant, for the supply of up to 15 mmscf/d for a period of five years for additional power generation and up to 10 mmscf/d for the industrial sector. The Company is in discussion with Songas to develop a mechanism that only triggers the need for security or additional investment in the field, if the field deliverability falls below certain agreed parameters as a proportion of demand.

On 21 September 2005, the Company signed an agreement with a subsidiary of Aminex plc to farm-in to 382 square kilometers (“Area A”) of the Nyuni Production Sharing Agreement (“Nyuni PSA”) that lies adjacent to the Songo Songo field. During October, the Company fulfilled the initial terms of the farm-in agreement by acquiring in excess of 300 kilometers of seismic in Area A. Under the terms of the agreement, the Company has until 30 September 2006 to elect whether or not to participate in the drilling of a well on Area A. If the Company elects to drill, it will pay either 42% to earn a 35% interest in Area A or 64% to earn a 50% interest. TPDC has indicated that it may not be possible to split out Area A from the remainder of the Nyuni PSA. Accordingly, the Company is in discussion with Aminex plc with respect to transferring the work undertaken on Area A into an equitable interest in the Nyuni PSA.

Under the terms of the contracts with Kioo Ltd., Tanzania Breweries Ltd. and Karibu Textile Mills Ltd., the Company is liable to pay penalties in the event that there is a shortfall in the Additional Gas supply in excess of 5% of the contracted quantity. The penalties equate to the difference between the price of gas and an alternative feedstock multiplied by the notional daily quantities. The maximum penalty for shortfall gas is a total of US\$1.1 million for these three contracts and the remedy is payable as a credit against future monthly invoices.

The Board has approved the purchasing of an estimated US\$4.0 million of long lead drilling items for two wells, including all the casing.

The Company has signed a contract for the installation of additional pressure reduction equipment to ensure gas can be supplied to the 40 MWs of temporary leased generation that is being installed by Aggreko plc.

6 Reconciliation of IFRS to Accounting Principles Generally Accepted in Canada

These interim consolidated financial statements have been prepared in accordance with the IFRS basis of accounting, which differ in some respects from those in Canada.

This reconciliation has been restated for the recognition of a difference between IFRS and Canadian Generally Accepted Accounting Principles ("GAAP").

On 31 August 2004, the Company was spun off from PanOcean Energy Corporation pursuant to a scheme of arrangement. Under Canadian GAAP, a deferred tax liability has to be recognised for the taxable temporary differences arising from the initial recognition of an asset or liability under any scenario. IFRS does not permit the setting up of a deferred tax liability for all taxable temporary differences arising from the initial recognition of an asset or liability except in a business combination.

The Company has implemented a bonus scheme that incorporates stock appreciation rights ("rights") that have a maximum pay out of Cdn\$1.2 million as at 31 December 2007. Under IFRS, the fair value of the rights are calculated using a Black-Scholes option pricing model. Under Canadian GAAP, the fair value is calculated using the intrinsic value method whereby the rights are valued at the market price less the rights price at each reporting period. Under both IFRS and Canadian GAAP, the fair value is expensed over the service period of the rights.

The following are the differences in accounting principles:

Figures in US\$'000	30 June 2006		31 March 2006		31 December 2005	
	IAS	CDN	IAS	CDN	IAS	CDN
Current assets	6,905	6,905	5,498	5,498	6,060	6,060
Natural gas properties and other equipment	16,161	17,937	15,537	17,313	15,037	16,852
	23,066	24,842	21,035	22,811	21,097	22,912
Current liabilities	4,457	4,357	3,380	3,380	3,849	3,849
Non-current liabilities	894	2,654	727	2,487	586	2,385
Capital stock	16,355	16,355	16,324	16,324	16,237	16,237
Reserves	1,360	1,476	604	620	425	441
	23,066	24,842	21,035	22,811	21,097	22,912

Figures in US\$'000	Quarter ended 30 June 2006		Quarter ended 31 March 2006		Year ended 31 December 2005	
	IAS	CDN	IAS	CDN	IAS	CDN
Profit before taxation	1,080	1,180	266	266	953	953

There are no other material differences in accounting principles as they pertain to the accompanying consolidated financial statements.

EastCoast Energy Corporation Limited is a TSXV listed company focused on the exploration and production of Tanzanian natural gas and the sale of “Additional Gas” to markets in East Africa. The Company began trading on the TSXV on 31 August 2004 under the trading symbols ECE.B and ECE.A. The company is headquartered in Tortola, British Virgin Islands and maintains its operations offices in Dar es Salaam, Tanzania.

Forward Looking Statements

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond EastCoast's control, including the impact of general economic conditions in the areas in which EastCoast operates, civil unrest, industry conditions, changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced, increased competition, the lack of availability of qualified personnel or management, fluctuations in commodity prices, foreign exchange or interest rates, stock market volatility and obtaining required approvals of regulatory authorities. In addition there are risks and uncertainties associated with oil and gas operations, therefore EastCoast's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking estimates will transpire or occur, or if any of them do so, what benefits, including the amounts of proceeds, that EastCoast will derive therefrom.

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