EastCoast Energy

Natural gas solutions in East Africa

EastCoast Energy Corporation
2006 Q2 Interim Report

Financial and Operating Highlights

	Three months ended			Six months ended		
	30 Jun 2006	31 Mar 2006	Change	**30 Jun 2006**	30 Jun 2005	Change
Financial (US$'000 *except where otherwise stated*)						
Total revenue	**3,198**	2,073	54%	**5,271**	862	511%
Profit/(loss) before taxation	**1,080**	266	306%	**1,346**	(793)	270%
Netback (IS$/*mcf*)	**2.71**	2.05	32%	**2.41**	3.58	(33%)
Working capital	**2,448**	2,118	16%	**2,448**	2,789	(12%)
Shareholders' equity	**17,715**	16,928	5%	**17,715**	15,240	16%
Profit/(loss) per share – basic and diluted (US$)	**0.03**	–	100%	**0.03**	(0.03)	200%
Cash flow per share – basic and diluted (US$)	**0.03**	0.04	(25%)	**0.07**	0.01	600%
OUTSTANDING SHARES ('000)						
Class A shares	**1,751**	1,751	–	**1,751**	1,751	–
Class B shares	**21,648**	21,613	–	**21,648**	21,513	(1%)
Options	**1,852**	1,887	(2%)	**1,852**	1,987	(7%)
OPERATING						
Additional Gas sold – industrial (*mmscf*)	**347**	230	51%	**577**	217	166%
Additional Gas sold – power (*mmscf*)	**739**	682	8%	**1,421**	–	100%
Average price per mcf – industrial (US$)	**8.69**	7.63	14%	**8.27**	5.76	44%
Average price per mcf – power (US$)	**2.13**	1.79	19%	**1.97**	–	100%

This report contains certain forward-looking statements based on current expectations, but which involve risks and uncertainties. Actual results may differ materially. See page 20 for additional information on the risks and uncertainties. All financial information is reported in U.S. dollars, unless noted otherwise.

Quarter Highlights

- Earned profit before tax of US$1.1 million with net cash flow from operating activities of US$0.8 million.
- Increased EastCoast's Q2 sales of Additional Gas to Dar es Salaam industrial customers to an average over the quarter of 3.8 mmscf/d (Q1 2006: 2.6 mmscf/d), at an average price of US$8.69/mcf (Q1 2006: US$7.63/mcf). In June 2006 industrial gas sales averaged 4.4 mmscf/d.
- Increased power plant Additional Gas sales to 8.1 mmscf/d (Q1 2006: 7.6 mmscf/d) at an average price of US$2.13/mcf (Q1 2006: US$1.79/mcf).
- Planned for the drilling of a new development well on the Songo Songo field during the first half of 2007 and for a well intervention on the SS9 offshore well. The programme is intended to increase the field's deliverability from 140 mmscf/d to approximately 215 mmscf/d.
- Continued the negotiation of a master agreement with TANESCO, for the supply of gas to an expected 245 MWs of new generation and 19.5% of the gas requirements of the Ubungo Power Plant currently being supplied by EastCoast under an Interim Agreement.
- Assessed options for the drilling of an exploration well approximately two kilometers west of the existing Songo Songo field at the same reservoir interval. The Company is searching for a jack-up drill rig, but is also assessing the feasibility of drilling a deviated well from Songo Songo Island.
- Worked closely with Songas Limited ("Songas") on plans to increase the capacity of the Songo Songo gas processing plant to 130 mmscf/d by the end of 2007. It is currently anticipated that a third and potentially a fourth gas processing train, financed by Songas, will be added in 2007.
- Completed construction of a 3.6 kilometer spur line to Serengeti Breweries Limited and East Coast Oils and Fats Limited. These two customers are expected to commence purchase of gas in Q3 2006 at a rate of 0.5 mmscf/d.

Glossary

Mcf . . . . Thousands of standard cubic feet
Mmscf . . . . Millions of standard cubic feet
Bcf . . . . Billions of standard cubic feet
Tcf . . . . Trillions of standard cubic feet
Mmscf/d . . . . Millions of standard cubic feet per day
Mmbtu . . . . Millions of British termal units
1P . . . . Proven reserves
2P . . . . Proven and probable reserves
GIIP . . . . Gas initially in place
Kwh . . . . Kilowatt hour
MW . . . . Megawatt
US$ . . . . U.S. dollars
Cdn$ . . . . Canadian dollars

President & CEO's Letter to Shareholders

It has been two years since EastCoast Energy began delivery of natural gas to utility and industrial customers in Tanzania. Over that time we have seen a rapid growth in demand for natural gas that has exceeded all our projections.

The majority of the increase in demand is emanating from the electric utility, TANESCO. TANESCO plans to have 245 MWs of new gas fired generation installed by the end of 2007. To this end, it has already contracted 40 MWs of temporary generation to be operational by the end of 2006 and 100 MWs of permanent generation that will be operational during Q3 2007.

Supply of Additional Gas to the industrial markets in the Dar es Salaam area has also developed quickly. By the end of August 2006, EastCoast will be supplying approximately 5.0 mmscf/d to 13 different industrial customers. Additional contracts are under discussion for a further 1.0 mmscf/d of new industrial gas sales.

The net result of these rapidly expanding Tanzanian natural gas markets is that the majority of the current natural gas in the Songo Songo field are forecast to be contracted by the end of 2007. To meet expanded demand for gas, EastCoast is pursuing two strategies. The first is to ensure that there is sufficient field deliverability and infrastructure capacity to meet the contracts currently under negotiation. The second is to establish new reserves by selective exploration drilling on our existing acreage and elsewhere in Tanzania.

Our physical presence and established operatorship of the Songo Songo field and gas processing plant enables the Company to negotiate with strength with other licence holders in Tanzania. There is a strong push by the Government of Tanzania to encourage the development of the country's potential oil and gas reserves and there are excellent opportunities for the Company to expand its operations in a proven but underexploited hydrocarbon province.

The Company is also evaluating a number of opportunities outside of Tanzania. To properly evaluate these opportunities, the Company has appointed Graham Goffey to manage our business development activities and our exploration initiatives and geological work on the Songo Songo field. Graham was a member of the successful management team of Paladin plc whose oil and gas assets were recently sold to Talisman Energy Inc.

Power sector demand

The long rains in the last few months have failed to provide sustainable relief to TANESCO in respect of its 561 MWs of hydro generation facilities. Significant load shedding is forecast to return in Q4 2006 as reservoir levels are depleted. To meet this shortfall, TANESCO has contracted Aggreko plc to supply 40 MWs of temporary generation consuming up to 12 mmscf/d. These units are due to be in service by the end of Q4 2006 in Dar es Salaam.

More efficient permanent generating units are expected to be operational during the second half of 2007 and will displace the temporary generation. TANESCO has contracted Wärtsilä to supply engines with a capacity of 100 MWs. These are due to be operational by Q3 2007 and will consume up to 19 mmscf/d. In addition, TANESCO is still intending to install 45 MWs at Tegeta in Dar es Salaam financed by a Dutch grant in Q3 2007 and to convert the 100 MW IPTL power plant to gas during 2007.

By the end of 2007, the Company could be selling up to 61 mmscf/d (or 43 mmscf/d at a 70% load factor) of Additional Gas to the power sector.

Infrastructure

As operator of the wells and gas processing plant on Songo Songo Island, EastCoast has been working closely with Songas Limited, to assess the best way to increase the capacity of the gas processing plant on Songo Songo Island to approximately 130 mmscf/d by the end of 2007.

Latest indications from the Ministry of Energy and Minerals are that Songas Limited will be requested to finance and develop the infrastructure to increase capacity. At a minimum, this is expected to include the construction of a third and potentially a fourth gas processing train. EastCoast has commenced negotiations with Songas Limited to contract this additional capacity at an agreed tariff.

Songo Songo field development

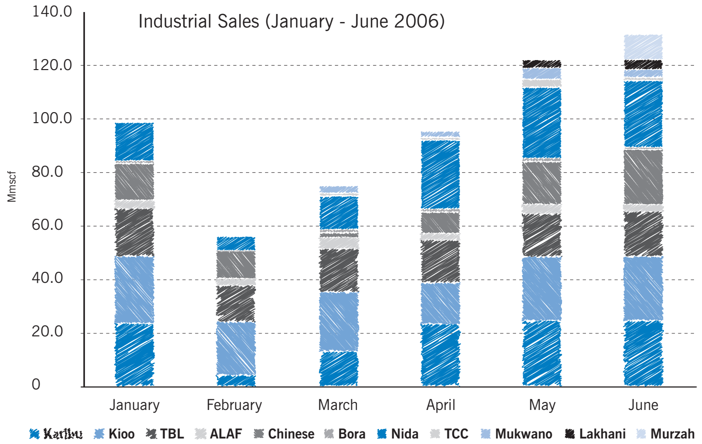
To increase production capacity from the existing Songo Songo field, EastCoast plans to drill a Songo Songo development well within the next 12 months. The Company will also service SS9 using a "fishing tool". This work programme is expected to increase the field deliverability from 140 mmscf/d to approximately 215 mmscf/d. This increase in deliverability will ensure security of supply in the event of the failure of any single Songo Songo well at the higher planned rates.

The new development well is planned as a 1 kilometer deviated well from Songo Songo Island, reducing the drilling and tie-in costs to approximately US$8 million. When drilling the new development well the Company intends to also test a further structure in the Eocene formation which previously flowed gas, but not under test conditions.

Exploration progress

Currently, EastCoast is assessing the best method of drilling the Songo Songo West prospect, approximately 2 kilometers west of the existing Songo Songo field. The original plan was to use a shallow water jack up rig to drill a target in the north of the prospect. However intense worldwide demand for offshore rigs is making the sourcing of such a rig challenging. The Company is now considering the drilling of a 4-kilometer deviated well into the southern part of the prospect and is assessing the engineering and geological feasibility of this option. The Songo Songo West prospect is a high potential target. If gas is discovered, it could contain GIIP of 600 bcf, compared with current certified 2P Additional Gas recoverable reserves of 320 bcf in the Songo Songo field.

During the quarter, the Company completed the evaluation of the seismic on the Nyuni A licence acreage ("Area A") pursuant to the terms of the Nyuni farm-in agreement between EastCoast and a subsidiary of Aminex plc. TPDC has indicated that it will not be possible to split out Area A from the remainder of the Nyuni Production Sharing Agreement ("Nyuni PSA"). Accordingly, the Company is negotiating with Aminex plc to transfer the work undertaken on Area A into an equivalent interest in the Nyuni PSA.



Utility and industrial sales of Additional Gas

During Q2, industrial sales volumes increased 51% over Q1 to an average of 3.8 mmscf/d. In June average production totaled 4.4 mmscf/d. Industrial sales are expected to increase to an average of 4.8 mmscf/d in Q3 as a result of seasonal increases in demand and the commencement of sales to Serengeti Breweries Limited and East Coast Oils and Fats Limited. The construction of a 3.6 kilometer spur line connecting these customers was completed during Q2 and gas sales to these two customers are expected to commence in Q3 2006 at a rate of approximately 0.5 mmscf/d.

Additional contracts are currently under discussion for a further 1.0 mmscf/d of industrial sales and a number of our customers are considering expanding their existing facilities. To meet this demand and ensure security of supply, the Company plans to expand the capacity of the existing distribution system by installing an additional pressure reduction station and 8 kilometers of distribution pipeline at a cost of approximately US$2.5 million. This work is scheduled to begin in Q4 2006. A tender process is currently underway.

In addition to its industrial sales, EastCoast continues to supply 19.5% of the gas consumption of the six turbines at the Ubungo Power Plant. The availability of these units improved during Q2 and the volume of Additional Gas sold by EastCoast increased 8% over Q1 to an average of 8.1 mmscf/d. The price also increased from US$1.79/mcf to US$2.13/mcf.

Outlook

EastCoast is fortunate to be well established in East Africa at a time when there is rapid growth in demand for natural gas. The Company is also in a strong financial position with working capital of US$2.4 million at June 30, 2006. Over the second half of 2006, the Company is projecting increased industrial and power sector gas sales. Internally generated cash flow combined with funds raised through a mixture of equity and debt will enable EastCoast to go forward confident that it has the resources to take advantage of the exciting opportunities that are available. A surge in new oil and gas exploration activities, both onshore and offshore East Africa, is gaining momentum and your Company is well placed to access these opportunities

I want to thank our staff for their skill, dedication and hard work which has enabled EastCoast to operate the Songo Songo gas plant and field for the last two years without any significant downtime. This important milestone clearly establishes our operating credentials and our reliability.

We value the ongoing confidence of our shareholders and are confident we can continue to add long term value to the benefit of all. This is an exciting time and EastCoast has great potential for sustained growth.

Peter R. Clutterbuck
President & CEO

Management's Discussion & Analysis

Management's Discussion & Analysis

THIS MDA OF FINANCIAL CONDITIONS AND RESULTS OF OPERATIONS SHOULD BE READ IN CONJUNCTION WITH THE COMPANY'S UNAUDITED FINANCIAL STATEMENTS FOR THE THREE MONTHS ENDED 30 JUNE 2006 AND THE AUDITED FINANCIAL STATEMENTS AND THE RELATED NOTES FOR THE YEAR ENDED 31 DECEMBER 2005. THIS MDA IS BASED ON THE INFORMATION AVAILABLE ON 25 AUGUST 2006. IT CONTAINS CERTAIN FORWARD-LOOKING STATEMENTS 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 THE COMPANY 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 GAS OPERATIONS. THEREFORE, EASTCOAST'S ACTUAL RESULTS, PERFORMANCE OR ACHIEVEMENT COULD DIFFER MATERIALLY FROM THOSE EXPRESSED, 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.

THE COMPANY EVALUATES ITS PERFORMANCE BASED ON EARNINGS AND CASH FLOWS. CASH FLOW FROM OPERATING ACTIVITIES IS A NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) TERM THAT REPRESENTS EARNINGS BEFORE DEPLETION, DEPRECIATION AND STOCK-BASED COMPENSATION. IT IS A KEY MEASURE AS IT DEMONSTRATES COMPANY'S ABILITY TO GENERATE CASH NECESSARY TO ACHIEVE GROWTH THROUGH CAPITAL INVESTMENTS. EASTCOAST ALSO ASSESSES ITS PERFORMANCE UTILIZING OPERATING NETBACKS. OPERATING NETBACKS REPRESENT THE PROFIT MARGIN ASSOCIATED WITH THE PRODUCTION AND SALE OF ADDITIONAL GAS AND IS CALCULATED AS REVENUES LESS RINGMAIN TARIFF, GOVERNMENT PARASTATAL'S REVENUE SHARE, OPERATING AND DISTRIBUTION COSTS. THESE NON-GAAP MEASURES ARE NOT STANDARDISED AND THEREFORE MAY NOT BE COMPARABLE TO SIMILAR MEASUREMENTS OF OTHER ENTITIES.

ADDITIONAL INFORMATION REGARDING EASTCOAST ENERGY CORPORATION IS AVAILABLE UNDER THE COMPANY'S PROFILE ON SEDAR AT www.sedar.com.

Background

EastCoast Energy Corporation's ("EastCoast" or the "Company") principal asset is its interest in a Production Sharing Agreement ("PSA") with the Tanzania Petroleum Development Corporation ("TPDC") in Tanzania. This PSA covers the production and marketing of certain gas from the Songo Songo gas field.

The gas in the Songo Songo field is divided between Protected Gas and Additional Gas. The Protected Gas is owned by TPDC and is sold under a 20-year gas agreement to Songas Limited ("Songas"). Songas is the owner of the infrastructure that enables the gas to be delivered to Dar es Salaam, namely a gas processing plant on Songo Songo Island, 232 kilometers of pipeline to Dar es Salaam and a 16 kilometer spur to the Wazo Hill cement plant.

Songas utilises the Protected Gas (maximum 45.1 mmscf/d) as feedstock for its gas turbine electricity generators at Ubungo, for onward sale to the Wazo Hill cement plant and for electrification of some villages along the pipeline route. EastCoast receives no revenue for the Protected Gas delivered to Songas and operates the field and gas processing plant on a 'no gain no loss' basis.

EastCoast has the right to produce and market all gas in the Songo Songo field in excess of the Protected Gas requirements ("Additional Gas").

Principal terms of the PSA and related agreements

The principal terms of the Songo Songo PSA and related agreements are as follows:

Obligations and restrictions

(a) The Company has the right to conduct petroleum operations, market and sell all Additional Gas produced and share the net revenue with TPDC for a term of 25 years expiring in October 2026.

(b) The PSA covers the two licences in which the Songo Songo field is located ("Discovery Blocks").

The Proven Section is essentially the area covered by the Songo Songo field within the Discovery Blocks.

(c) No sales of Additional Gas may be made from the Discovery Blocks if in EastCoast's reasonable judgement such sales would jeopardise the supply of Protected Gas. Any Additional Gas contracts entered into prior to 31 July 2009 are subject to interruption. Songas has the right to request that the Company and TPDC obtain security reasonably acceptable to Songas prior to making any sales of Additional Gas from the Discovery Block to secure the Company's and TPDC's obligations in respect of Insufficiency (see (e) below).

Songas has written to EastCoast confirming that, subject to certain conditions, security will not be required for the supply of Additional Gas to the Ubungo 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 deliverability falls below certain agreed parameters as a proportion of foreseen demand.

(d) By 31 July 2009, the Government of Tanzania ("GoT") can request EastCoast to sell 100 bcf of Additional Gas for the generation of electricity over a period of 20 years from the start of its commercial use, subject to a maximum of 6 bcf per annum or 20 mmscf/d ("Reserved Gas"). In the event that the GoT does not nominate by 31 July 2009 or consumption of the Reserved Gas has not commenced within three years of the nomination date, then the reservation shall terminate. Where Reserved Gas is utilised, TPDC and the Company will receive a price that is no greater than 75% of the market price of the lowest cost alternative fuel delivered at the facility to receive Reserved Gas or the price of the lowest cost alternative fuel at Ubungo.

(e) "Insufficiency" occurs if there is insufficient gas from the Discovery Blocks to supply the Protected Gas requirements or is so expensive to develop that its cost exceeds the market price of alternative fuels at Ubungo.

Where there have been third party sales of Additional Gas by EastCoast and TPDC from the Discovery Blocks prior to the occurrence of the Insufficiency, then EastCoast and TPDC shall be jointly liable for the Insufficiency and shall satisfy its related liability by either replacing the Indemnified Volume (as defined in (f) below) at the Protected Gas price with natural gas from other sources; or by paying money damages equal to the difference between: (a) the market price for a quantity of alternative fuel that is appropriate for the five gas turbine electricity generators at Ubungo ("Complex") without significant modification together with the costs of any modification; and (b) the sum of the price for such volume of Protected Gas (at US$0.55/mmbtu) and the amount of transportation revenues previously credited by Songas to the electricity utility, TANESCO, for the gas volumes.

(f) The "Indemnified Volume" means the lesser of the total volume of Additional Gas sales supplied from the Discovery Blocks prior to an Insufficiency and the Insufficiency Volume. "Insufficiency Volume" means the volume of natural gas determined by multiplying the average of the annual Protected Gas volumes for the three years prior to the Insufficiency (where the fifth turbine has been installed, but has not been operational for three years an imputed amount of annual gas consumption for the fifth turbine is incorporated) by 110% and multiplied by the number of remaining years (initial term of 20 years) of the power purchase agreement entered into between Songas and TANESCO in relation to the five gas turbine electricity generators at Ubungo from the date of the Insufficiency.

Access and development of infrastructure

(g) The Company is able to utilise the Songas infrastructure including the gas processing plant and main pipeline to Dar es Salaam. The pipeline and gas processing plant is open access and can be utilised by any third party who wishes to process or transport gas.

Songas is not required to incur capital costs with respect to additional processing and transportation facilities unless the construction and operation of the facilities are, in the reasonable opinion of Songas, financially viable. If Songas is unable to finance such facilities, Songas shall permit the seller of the gas to construct the facilities at its expense, provided that, the facilities are designed, engineered and constructed in accordance with good pipeline and oilfield practices.

It is envisaged that Songas will finance the expansion of the gas processing plant and the construction of a third and potentially a fourth train to enable there to be sufficient infrastructure capacity to meet the peak gas demand including the 245 MWs of new generation that TANESCO intends to install in Dar es Salaam during 2006/2007.

Revenue sharing terms and taxation

(h) 75% of the gross revenues less pipeline tariffs and direct sales taxes in any year ("Net Revenues") can be used to recover past costs incurred. Costs recovered out of Net Revenues are termed Cost Gas.

The Company pays and recovers all costs of exploring, developing and operating the Additional Gas with two exceptions: (i) TPDC may recover reasonable market and market research costs as defined under the PSA; and (ii) TPDC has the right to elect to participate in the drilling of at least one well for Additional Gas in the Contract Area for which there is a development program as detailed in the Additional Gas plans as submitted to the Ministry of Energy and Minerals ("Additional Gas Plan") subject to TPDC being able to elect to participate in a development program only once and TPDC having to pay a proportion of the costs of such development program by committing to pay between 5% and 20% of the total costs ("Specified Proportion"). If TPDC does not notify the Company within 90 days of notice from the Company that the Ministry of Energy and Minerals has approved the Additional Gas Plan, then TPDC is deemed not to have elected. If TPDC elects to participate, then it will be entitled to a rateable proportion of the Cost Gas and their profit share increases by the Specified Proportion for that development program.

The Company forecasts that TPDC may elect to participate in the forthcoming drilling of new wells and the related infrastructure development.

(i) The price payable to Songas for the general processing and transportation of the gas is 17.5% of the price of gas delivered to a third party less any direct taxes payable by the customer that are included in the gas price less any tariffs paid for non-Songas owned distribution facilities ("Songas Outlet Price").

In September 2001, the GoT made a formal request to the World Bank for funds to increase the diameter of the onshore pipeline from 12 inches to 16 inches at a projected incremental cost of US$3.5 million. The World Bank agreed to finance this increase and accordingly the pipeline capacity was increased from circa 65 mmscf/d to in excess of 105 mmscf/d. The tariff that is payable to GoT for this incremental capacity has yet to be agreed, but the Company has assumed it will be 17.5% of the Songas Outlet Price.

It is envisaged that Songas will finance the expansion of the gas processing plant and the construction of a third and potentially a fourth train to enable there to be sufficient infrastructure capacity to meet the peak gas demand including the 245 MWs of new generation that TANESCO intends to install in Dar es Salaam during 2006/2007. The tariff associated with this development is yet to be agreed.

(j) The cost of maintaining the wells and flowlines is split between the Protected Gas and Additional Gas users in proportion to the volume of their respective sales. The cost of operating the gas processing plant and the pipeline to Dar es Salaam is covered through the payment of the pipeline tariff.

(k) Profits on sales from the Proven Section ("Profit Gas") are shared between TPDC and the Company, the proportion of which is dependent on the average daily volumes of Additional Gas sold or cumulative production.

The Company receives a higher share of the Net Revenues after cost recovery, the higher the cumulative production or the average daily sales, whichever is higher. The profit share is a minimum of 25% and a maximum of 55%.

Average daily sales of Additional Gas	Cumulative sales of Additional Gas	TPDC's share of Profit Gas	Company's share of Profit Gas
mmscf/d	bcf	%	%
0 - 20	0 - 125	75	25
>20 <=30	>125<=250	70	30
>30 <=40	>250<=375	65	35
>40 <=50	>375<=500	60	40
>50	>500	45	55

For Additional Gas produced outside of the Proven Section, the Company's profit share is 55%.

Where TPDC elects to participate in a development program, their profit share increases by the Specified Proportion (for that development program).

The Company is liable to income tax. Where income tax is payable, there is a corresponding deduction in the amount of the Profit Gas payable to TPDC.

(l) Additional Profits Tax is payable where the Company has recovered its costs plus a specified return out of Cost Gas revenues and Profit Gas revenues. As a result: (i) no Additional Profits Tax is payable until the Company recovers all its costs out of Additional Gas revenues plus 25% plus the percentage change in the United States Industrial Goods Producer Price Index ("PPI") annual return; and (ii) the maximum Additional Profits Tax rate is 55% of the Company's profit share when costs have been recovered with a 35% plus PPI return. The PSA is, therefore, structured to encourage the Company to develop the market and the gas fields in the knowledge that the profit share can increase with larger daily gas sales and that the costs will be recovered with a 25% plus PPI annual return before Additional Profits Tax becomes payable. Additional Profits Tax can have a significant negative impact on the project economics if only limited capital expenditure is incurred.

Operatorship

(m) The Company is appointed to develop, produce and process Protected Gas and operate and maintain the gas production facilities and processing plant, including the staffing, procurement, capital improvements, contract maintenance, maintain books and records, prepare reports, maintain permits, handle waste, liaise with GoT and take all necessary safe, health and environmental precautions all in accordance with good oilfield practices. In return, the Company is paid or reimbursed by Songas so that the Company neither benefits nor suffers a loss as a result of its performance.

(n) In the event of loss arising from Songas' failure to perform and the loss is not fully compensated by Songas, EastCoast, CDC or insurance coverage, then EastCoast is liable to a performance and operation guarantee of US$2,500,000 when (i) the loss is caused by the gross negligence or wilful misconduct of the Company, its subsidiaries or employees, and (ii) Songas has insufficient funds to cure the loss and operate the project.

Consolidation

The companies that are being consolidated are:

Company	Incorporated
EastCoast Energy Corporation	British Virgin Islands
PAE PanAfrican Energy Corporation	Mauritius
PanAfrican Energy Tanzania Limited	Jersey

Q2 Results

Revenue and Operating Costs

Under the terms of the PSA with TPDC, EastCoast is responsible for invoicing, collecting and allocating the revenue from Additional Gas sales.

EastCoast is able to recover all costs incurred on the exploration, development and administration of the project out of 75% of the Net Revenues. Any costs not recovered in any period are carried forward to be recovered out of future revenues. Revenue less cost recovery is allocated 75% to TPDC and 25% to EastCoast.

EastCoast had recoverable costs throughout the period and accordingly was allocated 81.25% of the Net Revenues as follows:

	Three months ended			Six months ended	
(US$'000 *except production and per mcf data*)	**30 Jun 2006**	31 Mar 2006	30 Jun 2005	**30 Jun 2006**	30 Jun 2005
Gross sales volume *(mcf)*:					
Industrial sector	**347**	230	120	**577**	217
Power sector	**739**	682	–	**1,421**	–
Total volumes	**1,086**	912	120	**1,998**	217
Average sales price (US$/*mcf*):					
Industrial sector	**8.69**	7.63	6.19	**8.27**	5.76
Power sector	**2.13**	1.79	–	**1.97**	–
Average weighted price	**4.23**	3.26	6.19	**3.79**	5.76
Gross sales revenue	**4,590**	2,975	741	**7,566**	1,248
Gross tariff for processing plant and pipeline infrastructure	**727**	471	111	**1,198**	187
Gross revenue after tariff	**3,863**	2,504	630	**6,368**	1,061
Analysed as to:					
Company Cost Gas	**2,898**	1,877	473	**4,776**	796
Company Profit Gas	**241**	157	39	**398**	66
Company operating revenue *(see Note 1)*	**3,139**	2,034	512	**5,174**	862
TPDC Profit Gas	**724**	470	118	**1,194**	199
	3,863	2,504	630	**6,368**	1,061
Production and distribution expenses					
Ring main distribution pipeline	**91**	70	35	**161**	60
Share of well maintenance	**50**	45	4	**95**	16
Other field and operating costs	**56**	50	11	**106**	10
Production and distribution expenses	**197**	165	50	**362**	86
Depletion	**382**	324	37	**706**	66

Note 1 *The Company's total revenues for the quarter amounted to* US$3,198,000 *after adjusting the Company's operating revenue of* US$3,139,000 *by:*

i) US$103,000 *for income tax. The Company is liable for income tax in Tanzania, but the income tax is recoverable out of TPDC's Profit Gas when the tax is payable. To account for this, revenues are grossed up for the income tax and the tax is shown separately;*

ii) US$44,000 *for the deferred effect of Additional Profit Tax. This tax is deducted from revenue as a royalty.*

Volumes

Industrial

Sales volumes increased by 51% during Q2 from 230 mmscf to 347 mmscf as a result of a seasonal pick up in demand by the textile customers and the commencement of gas sales to Mukwano Industries Tanzania Limited, Lakhani Industries Limited and Murzah Oil Mills Limited at a rate of 0.5 mmscf/d. Industrial sales averaged 3.8 mmscf/d (Q1 2006: 2.6 mmscf/d) and peaked in June at 4.4 mmscf/d.

Power

An Interim Agreement with Songas Limited for the sale of Additional Gas to Ubungo Power Plant was signed on 1 October 2005. In accordance with the terms of the Interim Agreement, 19.5% of the gas volumes supplied to the six turbines at Ubungo Power Plant is considered Additional Gas. The Interim Agreement has been extended to 31 August 2006 to allow for time to negotiate a longer term agreement within the context of increasing demand by the power sector for a number of different projects and the need to revise some of the original project agreements. It is likely that this Interim Agreement will be further extended to 31 December 2006 when a longer term contract should be signed.

The Additional gas sales to the Ubungo Power Plant increased by 8% to 739 mmscf (Q1 2006: 682 mmscf) after gas consumption at the plant resumed to normal level towards the end of March following replacement of faulty transformers for UGT 5 and UGT 6. Consumption averaged 8.1 mmscf/d (Q1 2006: 7.6 mmscf/d) during the quarter.

Pricing

Industrial

The price of gas for the industrial sector is at a discount to the price of Heavy Fuel Oil ("HFO") in Dar es Salaam. This resulted in average gas prices of US$8.69/mcf (Q1 2006: US$7.63/mcf) during Q2.

The gas price achieved for the industrial sector will fluctuate with world oil prices and the discount agreed with the customers. The monthly range of Additional Gas price sold to industrial customers in Dar es Salaam during the three months ended 30 June 2006 was US$ 8.28/mcf to US$8.96/mcf.

Power

The Interim Agreement for the sale of Additional Gas to the Ubungo Power Plant provided for different gas prices, depending on the average availability of the six turbines, from the minimum of US$0.67/mmbtu (US$0.62/mcf) to the maximum of US$2.32/mmbtu (US$2.13/mcf). In Q1 2006, the average price fell to US$1.79/mcf following the break down of transformers for UGT 5 and UGT 6. As a result of the repair of these transformers in late March and normalization of gas consumption, the Company realised a price of US$2.13/mcf during Q2.

Consumers currently pay approximately 7.5 cents/kwh for their electricity. This tariff is the lowest in East Africa and significantly lower than the current prices in western economies. This will limit the price that gas can be sold to the power sector. Accordingly, Gas prices to the power sector are forecast to average US$2.13-US$2.30/mcf rising annually in accordance with a pre-agreed formula.

Tariff

The tariff is calculated as 17.5% of the price of gas at the Songas main pipeline in Dar es Salaam ("Songas Outlet Price"). In calculating the Songas Outlet Price for the industrial customers, an amount of US$1.28/mcf (Q1 2006: US$1.24/mcf) ("Ringmain Tariff") has been deducted from the achieved sales price of US$8.69/mcf (Q1 2006: US$7.63/mcf) to reflect the gas price that would be achievable at the Songas main pipeline. The Ringmain tariff represents the amount that would be required to compensate a third party distributor of the gas for constructing the connections from the Songas main pipeline to the industrial customers. No deduction has been made for sales to the power sector since the gas is not transported through the Company's own infrastructure.

Production and distribution expenses

The cost of maintaining the ring main distribution pipeline and pressure reduction station (security, insurance and personnel) is forecast to be approximately US$0.3 million per annum in its current form.

The well maintenance costs are allocated between Protected and Additional Gas based on the proportion of their respective sales during the year. The total costs for the maintenance for the period was US$350,000 (Q1 2006: US$225,000) and US$50,000 (Q1 2006: US$45,000) was allocated for the Additional Gas.

Other operating costs include an apportionment of the annual PSA licence costs and some costs associated with the evaluation of the reserves.

Operating Netbacks

The netback per mcf before general and administrative costs, overheads, tax and Additional Profits Tax may be analysed as follows:

	Three months ended			Six months ended	
(Amounts in US$/mcf)	30 Jun 2006	31 Mar 2006	30 Jun 2005	30 Jun 2006	30 Jun 2005
Gas price – industrial	**8.69**	7.63	6.19	**8.27**	5.76
Gas price – power	**2.13**	1.79	–	**1.97**	–
Average price for gas	**4.23**	3.26	6.19	**3.79**	5.76
Tariff (after allowance for the Ringmain Tariff)	**(0.67)**	(0.52)	(0.93)	**(0.60)**	(0.86)
TPDC Profit Gas	**(0.67)**	(0.51)	(0.99)	**(0.60)**	(0.92)
Net selling price	**2.89**	2.23	4.27	**2.59**	3.98
Well maintenance and other operating costs	**(0.09)**	(0.10)	(0.12)	**(0.09)**	(0.12)
Ringmain distribution pipeline costs	**(0.09)**	(0.08)	(0.29)	**(0.09)**	(0.28)
Netback	**2.71**	2.05	3.86	**2.41**	3.58

Netbacks were higher in Q2 2006 against Q1 2006 as a result of the increase in industrial and power prices. The netbacks for Q2 and Q1 2006 are lower against Q2 2005 due to the sale of a higher volume of power sales at lower prices than industrial sales. The Company commenced sales to the power sector in Q3 2005.

The netbacks are currently benefiting from the recovery of 75% of the Net Revenues as Cost Gas.

Administrative Expenses

The administrative expenses ("G&A") may be analysed as follows:

	Three months ended			Six months ended	
(*Figures in* US$'000)	30 Jun 2006	31 Mar 2006	30 Jun 2005	30 Jun 2006	30 Jun 2005
Employee costs	**533**	333	188	**866**	376
Stock based compensation	**96**	96	71	**192**	142
Travel & accommodation	**78**	72	35	**150**	90
Communications	**25**	21	21	**46**	39
Office	**99**	110	86	**209**	170
Consultants	**252**	228	66	**480**	207
Insurance	**36**	36	45	**72**	87
Auditing & taxation	**18**	51	15	**69**	34
Depreciation	**27**	27	19	**54**	44
Marketing costs including legal fees	**231**	184	48	**415**	96
Reporting, regulatory and corporate finance	**141**	118	87	**259**	167
Directors' fees	**26**	17	15	**43**	29
Total administrative expenses	**1,562**	1,293	696	**2,855**	1,481

G&A averaged approximately US$0.52 million per month (including the stock-based compensation and depreciation) during the period (Q1 2006: US$0.43 million). The cost per gross mcf sold increased during the quarter to US$1.44/mcf (Q1 2006: US$1.42/mcf).

The Company has implemented a bonus scheme that incorporates some stock appreciation rights for staff that are still employed by the Company as at 31 December 2007. The fair value of these stock appreciation rights are calculated using the Black-Scholes option pricing model and have a maximum pay out of Cdn$1.2 million. Employee costs increased by US$150,000 during Q2 for these stock appreciation rights.

In Q2, higher costs were experienced in negotiating the power contracts with Songas and TANESCO. These are likely to increase in Q3 and Q4, but will decrease substantially once the power contracts are signed.

The Company uses the Black-Scholes option pricing model in determining the fair value of options. The monthly charge is US$32,000 and this monthly amount will continue to be charged to the income statement until all options have vested in September 2006.

Taxes

Under the terms of the PSA, the Company is liable to Tanzanian income tax. However, this is recovered from TPDC by deducting an amount from TPDC's profit share. On receipt of any Profit Gas under the PSA, the Company's revenue will be grossed up for associated income tax.

The Company and TPDC are seeking clarification from the Commissioner of Taxes as to how it intends to treat the capitalised costs for tax purposes as there appears to be some conflict between the language of the PSA and the Tanzanian Income Tax Act 2004. The principal difference is whether the capitalised costs will be written off (PSA language) or capitalised over a few years (per the Income Tax Act 2004). US$297,000 (Q1 2006: US$70,000) is payable as income tax for the quarter ended 30 June 2006 (cumulative to 30 June 2006: US$384,000) in the event that the Commissioner of Taxes follows the Income Taxes Act 2004. No tax will be payable if it is determined that there should be an acceleration in the write off of the capitalised costs. As at 30 June 2006, the Company was yet to get a clarification and, as such, US$59,000 was paid as income tax for the year ended 31 December 2005. The amount was fully recovered out of TPDC's Q2 Profit Gas paid in July 2006 in accordance with the terms of the PSA.

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 under the Income Tax Act 2004. Applying the 30% Tanzanian tax rate, the Company has recognised a deferred tax liability of US$743,000. This tax has no impact on cash flow until it becomes a current income tax at which point the tax is paid to the Commissioner of Taxes and recovered from TPDC.

Additional Profits Tax

Under the terms of the PSA, in the event that all costs have been recovered with an annual return of 25% plus the percentage change in the United States Industrial Goods Producer Price Index, an Additional Profits Tax ("APT") is payable.

The Company provides for APT by forecasting the total APT payable as a proportion of the forecast Profit Gas over the term of PSA licence. As at 30 June 2006, the effective APT rate was calculated to be 18%. Accordingly, US$44,000 has been deducted from revenue for the quarter.

As at 30 June 2006, there were un-recovered costs of US$12.6 million. Management does not anticipate that any APT will be payable in 2006 as the forecast revenues will not be -sufficient to cover the un-recovered costs brought forward as inflated by 25% plus the percentage change in the United States Industrial Goods Producer Price Index and the forecast expenditures for the year. The actual APT that will be paid is dependent on the achieved value of the Additional Gas sales and the quantum and timing of the operating costs and capital expenditure programme.

The APT can have a significant negative impact on the Songo Songo project economics as measured by the net present value of the cash flow streams. Higher revenue in the initial years leads to a rapid payback of the project costs and consequently accelerates the payment of the APT that can account for up to 55% of the Company's profit share. Therefore, the terms of the PSA rewards the Company for taking higher risks by incurring capital expenditure in advance of revenue generation.

Depletion and Depreciation

The Natural Gas Properties are depleted using the unit of production method based on the production for the period as a percentage of the total future production from the Songo Songo proven reserves. As at 31 December 2005, the proven reserves as evaluated by the independent reservoir engineers, McDaniel & Associates Consultants Ltd. ("McDaniel") were 240.6 bcf (2004: 171.2 bcf) on a life of licence basis. This leads to a depletion charge of US$0.36/mcf in Q2 and Q1 2006 (Q2 2005: US$0.30/mcf).

Non-Natural Gas Properties are depreciated as follows:

Leasehold improvements	Over remaining life of the lease
Computer equipment	3 years
Vehicles	3 years
Fixtures and fittings	3 years

Recoverable Costs

As at 30 June 2006, the Company had US$12.6 million of costs that are recoverable out of 75% of the future Net Revenues.

Carrying Value of Assets

Capitalised costs are periodically assessed to determine whether it is likely that such costs will be recovered in the future. To the extent that these capitalised costs are unlikely to be recovered in the future, they will be written off and charged to earnings.

Cash Flow

Pre tax cash flows from operations was US$0.8 million in the period to 30 June 2006. The components of the Company's cash flow were as follows:

	Three months ended			Six months ended	
(*Figures in* US$'000)	**30 Jun 2006**	31 Mar 2006	30 Jun 2005	**30 Jun 2006**	30 Jun 2005
Profit/(loss) after taxation	**660**	83	(275)	**743**	(793)
Adjustment for non cash items	**673**	588	127	**1,261**	252
Cash flows from operations	**1,333**	**671**	**(148)**	**2,004**	**(541)**
Working capital adjustments	**(526)**	242	910	**(284)**	763
Net cash flows from operating activities	**807**	**913**	**762**	**1,720**	**222**
Cash flows used in investing activities	**(1,463)**	(744)	(1,958)	**(2,207)**	(2,261)
Net cash flows from financing activities	**31**	87	–	118	4,375
Net increase/(decrease) in cash and cash equivalent	**(625)**	**256**	**(1,196)**	**(369)**	**2,336**

There was a significant increase in the net cash and cash equivalent in the first half of 2005 due to the net receipt of US$4.4 million from the rights issue.

Capital Expenditures

Gross capital expenditures amounted to US$1.0 million in Q2 2006 (Q1 2006: US$0.8 million). The capital expenditure may be analysed as follows:

	Three months ended			Six months ended	
(*Figures in* US$'000)	**30 Jun 2006**	31 Mar 2006	30 Jun 2005	**30 Jun 2006**	30 Jun 2005
Geological and geophysical	**726**	514	520	**1,240**	608
Pipelines and infrastructure	**305**	305	902	**610**	1,112
Power development	**–**	–	531	**–**	531
Other equipment	**3**	32	5	**35**	10
	1,034	**851**	**1,958**	**1,885**	**2,261**

During the period, the Company continued with the preparation to drill a development well in the Discovery Block to increase gas deliverability and ensure security of supply in case of failure of any other single well. The Company spent US$814,000 during the quarter on drilling management and long lead items. The Company received US$211,000 from Silver Queen Maritime Limited in respect of a pro-rata repayment of the mobilization costs for the seismic vessel that conducted seismic work in Q4 2005. This has been netted off against the the geological and geophysical costs in Q2. The gross capital expenditure during the quarter is, therefore, US$1,245,000.

During Q2 2006, the Company completed the construction of 3.6 kilometer spur to East Coast Oils & Fats Limited and Serengeti Breweries Limited. These customers are expected to start consumption in Q3 2006 at a rate of 0.5 mmscf/d.

Working Capital

Working capital as at 30 June 2006 was US$2.4 million (31 March 2006: US$2.1 million) and may be analysed as follows:

(*Figures in* US$'000)	30 Jun 2006	31 Mar 2006	31 Dec 2005
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**
Trade and other payables	4,457	3,380	3,849
Working capital	**2,448**	**2,118**	**2,211**

Under the terms of the PSA and other Songo Songo agreements:

- The profit share owed to TPDC is payable within 30 days of each quarter end. Accordingly, the Company benefits from holding the cash receipts for this period of time and the quarter end cash balance is likely to increase as sales increase. As at 30 June 2006, US$800,000 (31 March 2006: US$464,000) was owed to TPDC.
- Songas advances funds to cover all anticipated expenditure on the gas processing plant and wells in the following month. As at 30 June 2006, US$175,000 (31 March 2006: US$294,000) of cash had been advanced by Songas to cover these operating expenses.
- The tariff for the use of the gas processing plant and pipeline infrastructure is payable to Songas within 30 days of each month end or after the Company has received its revenue from the sale of gas to the Ubungo Power Plant. As at 30 June 2006 the Company owed Songas US$816,000 (31 March 2006: US$259,000) for the tariff.

Also included in cash and cash equivalents was US$110,000 advanced by Lakhani and Murzah as a deposit for their connection. This amount will be repaid to the companies after they have consumed in excess of US$200,000 and US$100,000 of Additional Gas respectively. This amount is included in trade and other payables.

The majority of the cash is held in US and Cdn dollars in Mauritius and in Tanzanian Shillings in Tanzania bank accounts. There are no restrictions in Tanzania for converting Tanzania Shillings into US dollars. Any surplus cash is held in a fixed rate interest earning deposit account.

Under the contract terms with the industrial customers, the Additional Gas payments must be received within 30 days of the month end. As at 30 June 2006, US$1.9 million was due for the month of May and June (including VAT) from the industrial customers. The majority of this has been subsequently received from the industrial customers. Trade and other receivables also include an amount of US$1.6 million due from Songas for the supply of Additional Gas to the Ubungo Power Plant. The contract with Songas accounted for 34% of the Company's operating revenue during the period (Q1 2006: 40%). Songas' financial security is heavily reliant on the payment of capacity and energy charges by the electricity utility, TANESCO. TANESCO is currently experiencing financial difficulties principally caused by low rains and the consequential loss of the hydro electricity generation. As a result, TANESCO is dependent on the Government of Tanzania for day to day funding. Whilst payment for June sales remains outstanding, the Company subsequently collected all amounts due from Songas for the sales to 31 May 2006. The level of receivables will be closely monitored to minimise any potential default by any of the Company's customers.

Management forecasts that the Company will be able to meet its 2006 capital expenditure programme through the use of existing funds, self - generated cash flows and the raising of equity. In addition, the Company has no bank borrowings and there is scope for utilising debt funding once the contracts for the supply of gas to the power sector are in place.

Outstanding Share Capital

There were 23.4 million shares outstanding at 31 March 2006 and may be analysed as follows:

No of shares ('000)	30 Jun 2006	31 Mar 2006	31 Dec 2005
SHARES OUTSTANDING			
Class A shares	**1,751**	1,751	1,751
Class B shares	**21,648**	21,613	21,513
	23,399	23,364	23,264
CONVERTIBLE SECURITIES:			
Options	**1,852**	1,887	1,987
Fully diluted Class A and Class B shares	**25,251**	**25,251**	**25,251**

The weighted average shares for the quarter ended 30 June 2006 may be analysed as follows:

No of shares ('000)	30 Jun 2006	31 Mar 2006
WEIGHTED AVERAGE		
Class A and Class B shares	**23,375**	23,325
Options	**1,453**	1,358
Weighted average diluted Class A and Class B shares	**24,828**	**24,683**

Stock Based Compensation

The stock option plan provides for the granting of stock options to directors, officers, employees and consultants. Stock options granted have a maximum term of ten years to expiry and vest equally over a two year period commencing 1 September 2004. The exercise price of each stock option is determined as the closing market price of the common shares on the day prior to the day of grant. Each stock option granted permits the holder to purchase one common share at the stated exercise price. In accordance with IFRS2, the Company records a charge to the profit and loss account using the Black & Scholes fair valuation option pricing model. The valuation is dependent on a number of estimates, including the risk free interest rate, the level of stock volatility, together with an estimate of the level of forfeiture.

2,000,000 options were issued to certain Directors and Officers on 1 September 2004 at a price of Cdn$1 per option. During Q2 2006, 35,000 options were exercised. A total of 1,852,400 options remain outstanding as at 30 June 2006.

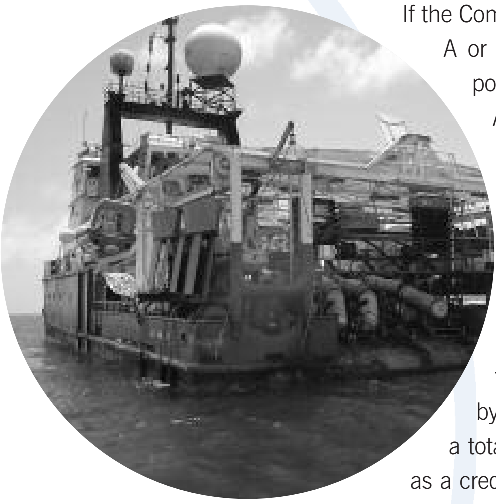
Contractual Obligations and Committed Capital Investment

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, then 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.

Songas has communicated to EastCoast confirming that, subject to certain conditions, security will not be required for the supply of Additional Gas to the Ubungo 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 foreseen 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.

Management expects to fund its committed capital investments in 2006 from operating cash flows, debt and the raising of equity.

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 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.

Operating Leases

The Company has entered into a five year rental agreement that expires on 30 November 2007 for the use of the offices in Dar es Salaam at a cost of approximately US$102,000 per annum.

Related Party Transactions

There have been no transactions undertaken with related parties during the quarter ended 30 June 2006.

Summary Quarterly Results

The following is a summary of the results for the Company for the most recently completed quarters:

	2006		2005				2004	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
FINANCIAL (US$'000 *except where otherwise stated*)								
Revenue	**3,198**	2,073	2,741	2,156	512	350	391	50
Profit/(loss) after taxation	**660**	83	396	785	(275)	(518)	(643)	(34)
Netback (US$/*mcf*)	**2.71**	2.05	2.27	1.68	3.86	3.24	3.00	3.51
Working capital	**2,448**	2,118	2,211	3,559	2,789	4,895	1,216	2,289
Shareholders' equity	**17,715**	16,928	16,662	16,096	15,240	15,444	11,516	11,857
Profit/(loss) per share – basic (US$)	**0.03**	–	0.02	0.03	(0.01)	(0.02)	(0.03)	(0.03)
Profit/(loss) per share – diluted (US$)	**0.03**	–	0.02	0.03	(0.01)	(0.02)	(0.03)	(0.04)
CAPITAL EXPENDITURE								
Geological and geophysical	**726**	514	2,001	148	520	88	137	10
Pipeline and infrastructure	**305**	305	868	110	902	210	479	1
Power development	**–**	–	34	224	531	–	–	–
Other equipment & business development	**3**	32	(1)	3	5	5	150	148
OPERATING								
Additional Gas sold – industrial (*mmscf*)	**347.0**	229.8	299.3	260.7	119.7	96.9	107.1	13.5
Additional Gas sold – power (*mmscf*)	**739.0**	682.2	766.1	905.4	–	–	–	–
Average price per mcf – industrial (US$)	**8.69**	7.63	7.86	7.26	6.19	5.23	5.31	5.41
Average price per mcf – power (US$)	**2.13**	1.79	2.15	1.24	–	–	–	–

Operating Hazards and Uninsured Risks

The business of EastCoast is subject to all of the operating risks normally associated with the exploration for, and the production, storage, transportation and marketing of oil and gas. These risks include blowouts, explosions, fire, gaseous leaks, migration of harmful substances and oil spills, any of which could cause personal injury, result in damage to, or destruction of, oil and gas wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, all of EastCoast's operations will be subject to the risks normally incident to drilling of natural gas wells and the operation and development of gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks. Drilling conducted by EastCoast overseas will involve increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. The impact that any of these risks may have upon EastCoast is increased due to the fact that EastCoast currently only has one producing property. EastCoast will maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavourable event not fully covered by insurance could have a material adverse effect on EastCoast's financial condition, results of operations and cash flows. Furthermore, EastCoast cannot predict whether insurance will continue to be available at a reasonable cost or at all.

Foreign Operations

All of EastCoast's operations and related assets are located in countries which may be considered to be politically and/or economically unstable. Exploration or development activities in such countries may require protracted negotiations with host governments, national oil companies and third parties and are frequently subject to economic and political considerations, such as, the risks of war, actions by terrorist or insurgent groups, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favour or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, if a dispute arises with foreign operations, EastCoast may be subject to the exclusive jurisdiction of foreign courts.

In the foreign countries in which EastCoast will conduct business, currently limited to Tanzania, the state generally retains ownership of the minerals and consequently retains control of (and in many cases, participates in) the exploration and production of hydrocarbon reserves. Accordingly, these operations may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges.

All of EastCoast's development properties and all of its proved natural gas reserves are located offshore on the Songo Songo Island in Tanzania, and, consequently, EastCoast's assets will be subject to regulation and control by the government of Tanzania and certain of its national and parastatal organizations. EastCoast and its predecessors have operated in Tanzania for a number of years and believe that it has good relations with the current Tanzanian government. However, there can be no assurance that present or future administrations or governmental regulations in Tanzania will not materially adversely affect the operations or future cash flows of EastCoast.

Additional Financing

Depending on future exploration, development, and marketing plans, EastCoast may require additional financing. The ability of EastCoast to arrange such financing in the future will depend in part upon the prevailing capital market conditions as well as the business performance of EastCoast. There can be no assurance that EastCoast will be successful in its efforts to arrange additional financing on terms satisfactory to EastCoast. If additional financing is raised by the issuance of shares from treasury of EastCoast, control of EastCoast may change and shareholders may suffer additional dilution.

From time to time EastCoast may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may temporarily increase EastCoast's debt levels above industry standards.

Industry Conditions

The oil and gas industry is intensely competitive and EastCoast competes with other companies which possess greater technical and financial resources. Many of these competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum, natural gas products and other products on an international basis. Oil and gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and invasion of water into producing formations. Currently, EastCoast's Songo Songo natural gas property is operated by EastCoast. There is a risk that in the future either the operatorship could change and the property operated by third parties or operations may be subject to control by national oil companies, Songas, or parastatal organisations and, as a result, EastCoast may have limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties.

The marketability and price of natural gas which may be acquired, discovered or marketed by EastCoast will be affected by numerous factors beyond its control. There is currently no developed natural gas market in Tanzania and no infrastructure with which to serve potential new markets beyond that being constructed by EastCoast and Songas. The ability of EastCoast to market any natural gas from current or future reserves may depend upon its ability to develop natural gas markets in Tanzania and the surrounding region, obtain access to the necessary infrastructure to deliver sales gas volumes, including acquiring capacity on pipelines which deliver natural gas to commercial markets. EastCoast is also subject to market fluctuations in the prices of oil and natural gas, uncertainties related to the delivery and proximity of its reserves to pipelines and processing facilities and extensive government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business. EastCoast is also subject to a variety of waste disposal, pollution control and similar environmental laws.

The oil and natural gas industry is subject to varying environmental regulations in each of the jurisdictions in which EastCoast may operate. Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently and oil and natural gas and can impact on the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures.

Additional Gas

EastCoast has the right, under the terms of the PSA, to market volumes of Additional Gas subject to satisfying the requirements to deliver Protected Gas to Songas.

There is a risk that Songas could interfere in EastCoast's ability to produce, transport and sell volumes of Additional Gas if EastCoast's obligations to Songas under the Gas Agreement are not met. In particular, Songas has the right to request reasonable security on all Additional Gas sales.

Under the terms of the contracts with Kioo Limited, Tanzania Breweries Limited 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.

Replacement of Reserves

EastCoast's natural gas reserves and production and, therefore, its cash flows and earnings are highly dependent upon EastCoast developing and increasing its current reserve base and discovering or acquiring additional reserves. Without the addition of reserves through exploration, acquisition or development activities, EastCoast's reserves and production will decline over time as reserves are depleted. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, EastCoast's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. There can be no assurance that EastCoast will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs.

Asset Concentration

EastCoast's natural gas reserves are limited to one property, the Songo Songo field, and the production potential from this field is limited to five wells. There has been limited production from the five wells in the Songo Songo field to date. There is no assurance that EastCoast will have sufficient deliverability through the existing wells to provide additional natural gas sales volumes, and that there may be significant capital expenditures associated with any remedial work or new drilling required to achieve deliverability. In addition, any difficulties relating to the operation or performance of the field would have a material adverse effect on EastCoast.

Environmental and Other Regulations

Extensive national, state, and local environmental laws and regulations in foreign jurisdictions will affect nearly all of EastCoast's operations. These laws and regulations set various standards regulating certain aspects of health and environmental quality, provide for penalties and other liabilities for the violation of such standards and establish in certain circumstances obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. There can be no assurance that EastCoast will not incur substantial financial obligations in connection with environmental compliance. Significant liability could be imposed on EastCoast for damages, cleanup costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of property purchased by EastCoast or non-compliance with environmental laws or regulations. Such liability could have a material adverse effect on EastCoast. Moreover, EastCoast cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered or enforced. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by

EastCoast for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on EastCoast. As party to various licenses, EastCoast has an obligation to restore producing fields to a condition acceptable to the authorities at the end of their commercial lives.

While management believes that EastCoast is currently in compliance with environmental laws and regulations applicable to EastCoast's operations in Tanzania, no assurances can be given that EastCoast will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

EastCoast's petroleum and natural gas operations are subject to extensive governmental legislation and regulation and increased public awareness concerning environmental protection.

No provision has been recognised for future decommissioning costs which are anticipated to be immaterial as it is forecast that there will still be commercial gas reserves once EastCoast relinquishes the licence in 2026. EastCoast expects that the cost of complying with environmental legislation and regulations will increase in the future. Compliance with existing environmental legislation and regulations has not had a material effect on capital expenditures, earnings or competitive position of EastCoast to date. Although management believes that EastCoast's operations and facilities are in material compliance with such laws and regulations, future changes in these laws, regulations or interpretations thereof or the nature of its operations may require the Company to make significant additional capital expenditures to ensure compliance in the future.

Volatility of Oil and Gas Prices and Markets

EastCoast's financial condition, operating results and future growth will be dependent on the prevailing prices for its natural gas production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes to the demand for oil and natural gas, whether the result of uncertainty or a variety of additional factors beyond the control of EastCoast. Any substantial decline in the prices of oil and natural gas could have a material adverse effect on EastCoast and the level of its natural gas reserves. Additionally, the economics of producing from some wells may change as a result of lower prices, which could result in a suspension of production by EastCoast.

No assurance can be given that oil and natural gas prices will be sustained at levels which will enable EastCoast to operate profitably. From time to time EastCoast may avail itself of forward sales or other forms of hedging activities with a view to mitigating its exposure to the risk of price volatility.

The Songo Songo field is the first gas field to be developed in East Africa. The Company has therefore been able to negotiate industrial gas sales contracts with gas prices that are at a discount to the lowest cost alternative fuels in Dar es Salaam, namely HFO.

Recently, there has been increased activity in the exploration of oil and gas in Tanzania, with the result that one well has been drilled on an adjacent prospect to Songo Songo. There has been a commercial gas discovery in the south of Tanzania at Mnazi Bay and a number of Production Sharing Agreements are being negotiated for the drilling onshore and offshore Tanzania. These developments will be closely monitored by the Company, but could lead to increased competition for gas markets and lower gas prices in the future.

In addition, various factors, including the availability and capacity of oil and gas gathering systems and pipelines, the effect of foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect EastCoast's ability to market its gas production. Any significant decline in the price of oil or gas would adversely affect EastCoast's revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of EastCoast's gas properties and its planned level of capital expenditures.

Uncertainties in Estimating Reserves and Future Net Cash Flows

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and cash flows to be derived therefrom, including many factors beyond the control of EastCoast. The reserve and cash flow information contained herein represents estimates only. The reserves and estimated future net cash flow from EastCoast's properties have been independently evaluated by McDaniel & Associates Consultants Ltd. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, crude oil price differentials to benchmarks, future prices of oil and natural gas, operating costs, transportation costs, cost recovery provisions and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date of the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of EastCoast. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material.

Title to Properties

Although title reviews have been done and will continue to be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of EastCoast which could result in a reduction of the revenue received by EastCoast.

Acquisition Risks

EastCoast intends to acquire natural gas infrastructure and possibly additional oil and gas properties. Although EastCoast performs a review of the acquired properties that it believes is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, EastCoast will focus its due diligence efforts on the higher valued properties and will sample the remainder. However, even an in depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not be performed on every well, and structural or environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. EastCoast may be required to assume pre-closing liabilities, including environmental liabilities, and may acquire interests in properties on an “as is” basis. There can be no assurance that EastCoast's acquisitions will be successful.

Reliance on Key Personnel

EastCoast is highly dependent upon its executive officers and key personnel. The unexpected loss of the services of any of these individuals could have a detrimental effect on EastCoast. EastCoast does not maintain key life insurance on any of its employees.

Controlling Shareholder

W David Lyons, the Company’s non-executive Chairman, is the sole controlling shareholder of EastCoast and holds approximately 99.3% of the outstanding Class A shares and approximately 16.7% of the Class B shares before the exercise of his options. Consequently, Mr. Lyons holds approximately 22.9% of the equity and controls 67.9% of the total votes of EastCoast.

Financial Statements

Consolidated Income Statement (unaudited)

(thousands of US dollars except per share amounts)	Note	Three months ended 30 Jun 2006	Three months ended 31 Mar 2006	Six months ended 30 Jun 2006	Six months ended 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)

(thousands of US dollars)	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

See accompanying notes to the interim consolidated financial statements.

Contingent liabilities (Note 4)

Contractual obligations and committed capital investment (Note 5)

Consolidated Statement of Cash Flows (unaudited)

	Three months ended		Six months ended	
(thousands of US dollars)	**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)

(thousands of US dollars)	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 Interim 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:

	Three months ended		Six months ended
Figures in US$'000	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

US$000	Natural gas properties	Leasehold improvements	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 Ubungo 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.

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:

	30 June 2006		31 March 2006		31 December 2005	
Figures in US$'000	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.

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.

For further information please contact:

Nigel A. Friend, CFO
+255 (0)22 2138737
nfriend@eastcoast-energy.com

Peter R. Clutterbuck, CEO
+44 (0) 7768 120727.
prclutterbuck@eastcoast-energy.com

or visit the Company's web site at *www.eastcoast-energy.com*.

BOARD OF DIRECTORS

W. David Lyons
Non-Executive
Chairman
St. Helier
Jersey

Peter R. Clutterbuck
President & Chief
Executive Officer
Haslemere
United Kingdom

Nigel A. Friend
Chief Financial Officer
London
United Kingdom

John Patterson
Non-Executive Director
Nanoose Bay
Canada

Robert K. Spence
Non-Executive Director
Dar es Salaam
Tanzania

OFFICERS

Pierre Raillard
Vice President
Operations

David W. Ross
Company Secretary

OPERATING OFFICE

EastCoast Energy Corporation
Barclays House, 5th Floor
Ohio Street, P.O. Box 80139
Dar es Salaam
Tanzania
Tel: + 255 22 2138737
Fax: + 255 22 2138938

REGISTERED OFFICE

EastCoast Energy Corporation
P.O. Box 3152, Road Town
Tortola
British Virgin Islands

INVESTOR RELATIONS

Nigel A. Friend
Chief Financial Officer
Tel: + 255 22 2138737
nfriend@eastcoast-energy.com
www.eastcoast-energy.com

INTERNATIONAL SUBSIDIARIES

PanAfrican Energy
Tanzania Limited
Barclays House, 5th Floor
Ohio Street, P.O. Box 80139
Dar es Salaam
Tanzania
Tel: + 255 22 2138737
Fax: + 255 22 2138938

PAE PanAfrican
Energy Corporation
1st Floor
Cnr St George/Chazal Streets
Port Louis
Mauritius
Tel: + 230 207 8888
Fax: + 230 207 8833

ENGINEERING CONSULTANTS

McDaniel & Associates
Consultants Ltd.
Calgary
Canada

AUDITORS

KPMG LLP
Calgary
Canada

LAWYERS

Burnet, Duckworth
& Palmer LLP
Calgary
Canada

TRANSFER AGENT

CIBC Mellon Trust Company
Toronto, Montreal
and Calgary,
Canada

EastCoast Energy

www.eastcoast-energy.com