

# EASTCOAST Energy

Natural gas solutions in East Africa



EastCoast Energy Corporation  
2006 Q3 Interim Report

Q3

## Financial and Operating Highlights

	Three months ended			Nine months ended		
	30 Sep 2006	30 Jun 2006	Change	30 Sep 2006	30 Sept 2005	Change
<i>Financial (US\$'000 except where otherwise stated)</i>						
Total revenue	<b>3,835</b>	3,198	20%	<b>9,106</b>	3,018	202%
Profit before taxation	<b>1,309</b>	1,080	21%	<b>2,655</b>	89	2,882%
Operating Netback (US\$/mcf)	<b>2.88</b>	2.71	6%	<b>2.58</b>	1.99	30%
Working capital	<b>3,298</b>	2,448	35%	<b>3,298</b>	3,559	(7%)
Shareholders' equity	<b>18,676</b>	17,715	5%	<b>18,676</b>	16,096	16%
Profit/(loss) per share – basic and diluted (US\$)	<b>0.03</b>	0.03	–	<b>0.06</b>	–	–
Net cash flows						
from operating activities	<b>2,513</b>	807	211%	<b>4,233</b>	816	419%
Net cash flow from operating activities per share – basic (US\$)	<b>0.11</b>	0.03	267%	<b>0.18</b>	0.04	350%
<b>OUTSTANDING SHARES ('000)</b>						
Class A shares	<b>1,751</b>	1,751	–	<b>1,751</b>	1,751	–
Class B shares	<b>21,658</b>	21,648	–	<b>21,658</b>	21,513	1%
Options	<b>2,042</b>	1,852	10%	<b>2,042</b>	1,987	3%
<b>OPERATING</b>						
Additional Gas sold						
– industrial (mmscf)	<b>491</b>	347	41%	<b>1,068</b>	477	124%
Additional Gas sold						
– power (mmscf)	<b>744</b>	739	1%	<b>2,165</b>	906	139%
Average price per mcf						
– industrial (US\$)	<b>8.63</b>	8.69	(1%)	<b>8.27</b>	6.58	26%
Average price per mcf						
– power (US\$)	<b>1.69</b>	2.13	(21%)	<b>1.87</b>	1.24	59%

This report contains certain forward-looking statements based on current expectations, but which involve risks and uncertainties. Actual results may differ materially. See page 21 for additional information on the risks and uncertainties. All financial information is reported in U.S. dollars, unless noted otherwise.

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## Quarter Highlights

- Earned profit before tax of US\$1.3 million with net cash flow from operating activities of US\$2.5 million.
- Increased EastCoast's Q3 sales of Additional Gas to Dar es Salaam industrial customers to an average over the quarter of 5.3 mmscf/d (Q2 2006: 3.8 mmscf/d), at an average price of US\$8.63/mcf (Q2 2006: US\$8.69/mcf).
- Maintained Additional Gas sales to the power sector at 8.1 mmscf/d (Q2 2006: 8.1 mmscf/d) at an average price of US\$1.69/mcf (Q2 2006: US\$2.13/mcf).
- Commenced the installation of a new pressure reduction station and pipeline connections to the emergency power plants namely the 40 MW Aggreko units and a 20 MW General Electric unit at a cost of US\$0.9 million. 20 MWs of the Aggreko units were installed and operational by the end of October 2006.
- Signed a short term agreement in early November 2006 for the supply of gas to these Aggreko units. It is forecast that this will be superseded by a two year fully termed agreement that will be signed by Q1 2007.
- Announced the intention to raise Cdn\$ 21.5 million before expenses by means of a 1 for 7 rights issue. The rights documentation was submitted to the shareholders on 14 November 2006.
- Continued to plan the drilling of a new development well on the Songo Songo field during Q1 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.
- 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. It is unlikely that this well will be drilled before 2008 given current rig constraints.
- Continued the negotiation of a master agreement with TANESCO, for the supply of gas to an expected 245 MWs of new permanent generation and 19.5% of the gas requirements of the Ubungo Power Plant currently being supplied by EastCoast under an Interim Agreement. These are forecast to be signed in Q1 2007.
- Commenced transportation tariff negotiations with Songas Limited ("Songas") that will enable the installation of a third and fourth train on Songo Songo Island at a cost of US\$26 million (payable by Songas). This is expected to increase capacity of the gas processing plant to 140 mmscf/d by Q4 2007.
- As operator of the gas processing plant, worked closely with the plant owners, Songas, on increasing the capacity of the existing infrastructure system before the third and fourth train are installed. As a consequence of this, Songas has appointed Bureau Veritas to recertify the capacity of the existing trains during Q4 2007.

## Glossary

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

## President & CEO's Letter to Shareholders

In Tanzania demand for natural gas continues to accelerate to meet urgent domestic power needs and the requirements of a steadily increasing industrial market. Tanzania is facing a severe energy crisis as a result of a significant multi-year shortfall in the country's hydro power generating capacity.

In the short term, EastCoast is working to increase natural gas deliverability from the Songo Songo field. Over the next year the Company intends to drill a new Songo Songo development well and to undertake remedial work on an offshore well to boost overall Songo Songo deliverability from 140 mmscf/d to 215 mmscf/d. Over the longer term, EastCoast is adding an exploration dimension to the Company.

To identify and assess low-risk, high-potential exploration opportunities, EastCoast has added two senior executives with extensive international oil and gas exploration and development experience. James Smith who was previously Exploration Vice President at PanOcean Energy Corporation has been named as a Director and Graham Goffey, who was previously the UK and International Exploration Manager at Paladin plc, has joined as EastCoast's Exploration and Business Development Manager.

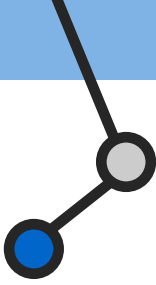
The Company's initial exploration focus will be within Tanzania. EastCoast's long-term presence and established reputation as the operator of the Songo Songo gas field and processing plant, provides a strong base for the Company to negotiate farm-in or joint venture projects with other Tanzania license holders. With the Government of Tanzania's expressed desire to develop the country's oil and gas reserves there are excellent opportunities for EastCoast. Over the longer term, the Company intends to expand its reserve base through the identification of additional new opportunities, primarily in Africa.

To fund this expanded scope of work, EastCoast has announced its intention to raise Cdn\$21.5 million from a rights offering. The offering documents were submitted to the Shareholders on 14 November 2006.

### **Power developments**

EastCoast continues to supply 19.5% of the gas consumption of the six turbines at the Ubungo Power Plant that is owned and operated by Songas Limited. Sales averaged 8.1 mmscf/d in Q3 (Q2: 8.1 mmscf/d). However in September 2006, two units were down for repair and this impacted the price achieved. As a result, the average price for the quarter was reduced to an average of US\$1.69/mcf (Q2: US\$2.13/mcf).

Within Tanzania, the Government is accelerating the introduction of emergency power units and it is forecast that by the end of Q4 2006, the Company will be selling 19 mmscf/d to the power sector. The 40 MW Aggreko power plant that was due to be on stream by the end of 2006 is now partially operational and consuming approximately 9.5 mmscf/d from Songo Songo. A 20 MW General Electric unit is in the process of being assembled and should be operational by Q1 2007. This will consume approximately 6 mmscf/d. Both these emergency power plants are expected to be in operation for two years and then be superseded by new permanent generators that TANESCO, the electricity utility, is in the process of procuring.



## president & ceo's letter to shareholders

In addition, TANESCO has contracted Wartsila to supply 100 MW of permanent and efficient units that are forecast to be operational during Q3 2007. It is also finalizing negotiations with Wartsila and a Dutch multilateral to install 45 MWs of generation by the end of 2007. To convert the 100 MW International Power of Tanzania Limited ("IPTL") facility to gas, the electricity utility is continuing discussions with the equity and debt holders. While of the timing for the completion of these negotiations is uncertain, it is forecast that some of the IPTL units may be converted by the end of 2007.

To finalize the commercial terms for the supply of gas to these emergency power units, EastCoast is in the process of negotiating two-year fully termed agreements. The gas that has already been consumed by the Aggreko units is covered by an interim letter agreement and TANESCO paid US\$0.6 million for this gas in November at a price of US\$2.13/mcf. It is anticipated that fully termed agreements for the 60 MWs will be signed by Q1 2007.

The longer term agreements for the existing supply of gas to the 42 MW sixth turbine at the Ubungu power plant and to the permanent 100 MW Wartsila plant are also being progressed. The contracts and the pricing are subject to the approval of the newly established Tanzania regulator, the Electricity, Water, and Utilities Authority ("EWURA"). The Company is in the process of filing an application with EWURA to provide an appropriate natural gas pricing methodology in Tanzania.

### Industrial markets

Supply of Additional Gas to the industrial markets in the Dar es Salaam area continued to develop over the quarter. Industrial sales volumes increased 41% over Q2 to an average of 5.3 mmscf/d as a consequence of the seasonal increase in demand and the commencement of sales to East Coast Oils and Fats Limited. It is anticipated that sales to the industrial sector will be reduced in Q4 to approximately 3.5-4.0 mmscf/d, primarily as a result of a seasonal downturn and the uncertainty in electricity supply that will impact industrial production until the emergency power generation is fully operational.

Contracts are currently under discussion to supply 1.0 mmscf/d of new industrial sales and a number of EastCoast's customers are considering expanding their existing facilities. The Company will connect the new customers during the latter half of 2007 with an 8-kilometer extension to the north of Dar es Salaam at an estimated cost of US\$2.2 million. To meet the expanding industrial demand and ensure security of supply for our existing customers, 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\$2.2 million. This work is scheduled to begin in Q1 2007.

### Infrastructure

The current configuration of the gas processing plant on Songo Songo Island is limited to 70 mmscf/d. The peak demand of the gas sales by 31 December 2006, including Protected Gas, is forecast to be 80 mmscf/d. To address this challenge, EastCoast is working with Songas Limited ("Songas") to determine if the gas processing plants can be re-certified to meet the immediate peak demand requirements. This process will be complete in December 2006.



In anticipation of significantly increased Songo Songo deliverability and demand later in 2007, the Company is negotiating a transportation tariff with Songas to provide for the installation of a third and fourth train and ancillary equipment on Songo Songo Island at an approximate cost to Songas of US\$26 million. This infrastructure addition would be expected to increase capacity to 140 mmscf/d by Q4 2007. With additional compression, the main pipeline capacity can be increased beyond the current limit of 105-110 mmscf/d.

#### **Drilling programme**

To increase production capacity from the existing Songo Songo field, EastCoast plans to drill a Songo Songo development well in Q1 2007 and to undertake remedial work on the offshore well, SS9.

The new development well, SS10, is planned as a 1-kilometer deviated well from Songo Songo Island and will cost the Company approximately US\$8.0 - US\$10 million. The Company is in discussion with two drilling contractors who have land rigs in Tanzania that are capable of drilling the well. Long lead time items such as casing are being ordered. It is anticipated that SS10 will have initial production of approximately 50 mmscf/d.

The remedial work on SS9 is scheduled to be completed during January 2007. The total cost of this work is estimated at US\$1.0 – US\$2.0 million, and is expected to increase SS9 deliverability to 45 mmscf/d of production, an increase of approximately 25 mmscf/d.

In total, the new well and the workover of the existing well should have the effect of increasing the deliverability of the Songo Songo field from approximately 140 mmscf/d to 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.

As soon as an appropriate rig can be brought to Tanzania it is also the Company's intention to drill an exploration well into the Songo Songo West prospect where there is a forecast 600 bcf of GIIP if commercial gas is discovered. The rig will be either a land rig capable of drilling a 4-kilometer long deviated well from Songo Songo Island or a shallow water jack up rig.

#### **Outlook**

EastCoast is taking the next steps to move from a gas field operator and marketer of Additional Gas to a significant explorer, developer and producer of oil and gas. The opportunities are here in East Africa and elsewhere and we are committed to take our Company to the next level.

We appreciate the confidence of our shareholders and the skill and dedication of our employees. EastCoast will continue to work to the long-term benefit of all our stakeholders and the people of the areas in which we operate.



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 SEPTEMBER 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 27 NOVEMBER 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 FUNDS FLOW. FUNDS 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 OPERATING 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](http://www.sedar.com).

### Disclosure Controls and Procedures

Based on the requirements of Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual Financial and Interim Filings, the Chief Executive Officer and Chief Financial Officer of the Company evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Multilateral Instrument 52-109) as of 30 September 2006. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures were effective as at 30 September 2006 to provide reasonable assurance that material information relating to the Company, including its consolidated subsidiaries, would be made known to them by others within those entities.

### 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 drilling of new development wells.

- (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 construction of a third and a fourth gas processing 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 mmscf/d	Cumulative sales of Additional Gas bcf	TPDC's share of Profit Gas %	Company's share of Profit Gas %
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

## Q3 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:

(US\$'000 except production and per mcf data)	Three months ended			Nine months ended	
	30 Sept 2006	30 Jun 2006	30 Sept 2005	30 Sept 2006	30 Sept 2005
Gross sales volume (mcf):					
Industrial sector	491	347	261	1,068	477
Power sector	744	739	905	2,165	906
<b>Total volumes</b>	<b>1,235</b>	1,086	1,166	<b>3,233</b>	1,383
Average sales price (US\$/mcf):					
Industrial sector	8.63	8.69	7.26	8.27	6.58
Power sector	1.69	2.13	1.24	1.87	1.24
<b>Weighted average price</b>	<b>4.45</b>	4.23	2.58	<b>4.04</b>	3.08
Gross sales revenue	5,490	4,590	3,013	13,056	4,261
Gross tariff for processing plant and pipeline infrastructure	857	727	480	2,055	667
<b>Gross revenue after tariff</b>	<b>4,633</b>	3,863	2,533	<b>11,001</b>	3,594
<i>Analysed as to:</i>					
Company Cost Gas	3,474	2,898	1,898	8,250	2,694
Company Profit Gas	289	241	161	687	227
<b>Company operating revenue</b> (see Note 1)	<b>3,763</b>	3,139	2,059	<b>8,937</b>	2,921
TPDC Profit Gas	870	724	474	2,064	673
	<b>4,633</b>	3,863	2,533	<b>11,001</b>	3,594
<b>Production and distribution expenses</b>					
Ring main distribution pipeline	95	91	55	256	113
Share of well maintenance	59	50	19	154	26
Other field and operating costs	57	56	16	163	36
Production and distribution expenses	211	197	90	573	175
Depletion	435	382	376	1,141	443

Note 1 The Company's total revenues for the quarter amounted to US\$3,835,000 after adjusting the Company's operating revenue of US\$3,763,000 by:

- i) US\$124,000 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\$52,000 for the deferred effect of Additional Profit Tax. This tax is deducted from revenue as a royalty.

Revenue per the income statements may be reconciled to the operating revenue as follows:

(US\$'000)	Three months ended			Nine months ended	
	30 Sept 2006	30 Jun 2006	30 Sept 2005	30 Sept 2006	30 Sept 2005
Industrial sector	<b>4,235</b>	3,016	1,893	<b>9,006</b>	1,120
Power sector	<b>1,255</b>	1,574	1,120	<b>4,050</b>	3,141
<b>Gross sales revenue</b>	<b>5,490</b>	4,590	3,013	<b>13,056</b>	4,261
Processing and transportation tariff	<b>(857)</b>	(727)	(480)	<b>(2,055)</b>	(667)
TPDC share of revenue	<b>(870)</b>	(724)	(474)	<b>(2,064)</b>	(673)
Operating revenue	<b>3,763</b>	3,139	2,059	<b>8,937</b>	2,921
Additional Profits Tax	<b>(52)</b>	(44)	-	<b>(125)</b>	-
Gross-up for income tax	<b>124</b>	103	97	<b>294</b>	97
<b>Revenue</b>	<b>3,835</b>	3,198	2,156	<b>9,106</b>	3,018

## Volumes

### Industrial

Industrial sales volumes increased by 41% during Q3 from 347 mmscf to 491 mmscf as demand by the textile customers peaked to take account of low cotton prices during the harvest season. In addition, gas sales commenced to two factories owned by Murzah Oil Mills at a rate of 0.2 mmscf/d. Industrial sales averaged 5.3 mmscf/d (Q2 2006: 3.8 mmscf/d) and peaked in August at 5.7 mmscf/d. Gas consumption by the textile customers is expected to decline in Q4 2006 and Q1 2007 as a result of higher cotton prices and the impact of the electricity interruptions that will impact their production runs.

### Power

Despite breakdown of transformers for UGT5 and UGT6 in Q3, the Additional gas sales to the Ubungo Power Plant recorded an increase of 1% to 744 mmscf (Q2 2006: 739 mmscf). Consumption averaged 8.1 mmscf/d (Q2 2006: 8.1 mmscf/d) during the quarter.

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 is in the process of being extended until all parties are ready to sign the long term contract forecast for Q1 2007.

## 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\$8.63/mcf (Q2 2006: US\$8.69/mcf) during Q3. The slight decline in the price is attributed to falling oil prices in the world market.

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 September 2006 was US\$ 8.49/mcf to US\$8.74/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 a minimum of US\$0.67/mmbtu (US\$0.62/mcf) to the maximum of US\$2.32/mmbtu (US\$2.13/mcf). In August, UGT6 suffered mechanical problems but was repaired in late September. UGT5 also developed mechanical problems in September and was temporarily closed during the month. In accordance with the terms of the Interim Agreement with Songas, the minimum gas price of US\$0.67/mmbtu (US\$0.62/mcf) was applicable in September.

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.

The Company is currently preparing an application to a newly established regulatory authority, Electricity Water and Utilities Authority ("EWURA"), for the supply of gas to the power sector. This application covers the proposed pricing structure for the supply of gas to this sector.

It is expected that the long term contracts for the existing and new power contracts will be signed by 31 March 2007 when EWURA is forecast to have finalized their review of the pricing mechanisms.

The prices to the power sector are forecast to average US\$2.13-US\$2.30/mcf during 2007 rising annually in accordance with a pre-agreed formula.

## **Tariff**

Under the terms of the project agreements, the tariff paid for transporting the gas is calculated as 17.5% of the price of gas at the Songas main pipeline in Dar es Salaam ("Songas Outlet Price") for the first 65 mmscf/d of pipeline capacity.

In calculating the Songas Outlet Price for the industrial customers, an amount of US\$1.26/mcf (Q2 2006: US\$1.28/mcf) ("Ringmain Tariff") has been deducted from the achieved sales price of US\$8.63/mcf (Q2 2006: US\$8.69/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.

It is envisaged that Songas will finance the construction of a third and a fourth gas processing 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 the expansion of the pipeline and the gas processing plant is yet to be agreed and will be subject to approval by EWURA. However, the Company has assumed it will be no more than approximately 17.5% of the Songas Outlet Price.

## **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\$227,000 (Q2 2006: US\$350,000) and US\$59,000 (Q2 2006: US\$50,000) 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:

(Amounts in US\$/mcf)	Three months ended			Nine months ended	
	30 Sept 2006	30 Jun 2006	30 Sept 2005	30 Sept 2006	30 Sept 2005
Gas price – industrial	<b>8.63</b>	8.69	7.26	<b>8.27</b>	6.58
Gas price – power	<b>1.69</b>	2.13	1.24	<b>1.87</b>	1.24
<b>Average price for gas</b>	<b>4.45</b>	<b>4.23</b>	<b>2.58</b>	<b>4.04</b>	<b>3.08</b>
Tariff (after allowance for the Ringmain Tariff)	<b>(0.69)</b>	(0.67)	(0.41)	<b>(0.64)</b>	(0.48)
TPDC Profit Gas	<b>(0.70)</b>	(0.67)	(0.41)	<b>(0.64)</b>	(0.49)
<b>Net selling price</b>	<b>3.06</b>	<b>2.89</b>	<b>1.76</b>	<b>2.76</b>	<b>2.11</b>
Well maintenance and other operating costs	<b>(0.09)</b>	(0.09)	(0.03)	<b>(0.09)</b>	(0.04)
Ringmain distribution pipeline costs	<b>(0.09)</b>	(0.09)	(0.05)	<b>(0.09)</b>	(0.08)
<b>Netback</b>	<b>2.88</b>	<b>2.71</b>	<b>1.68</b>	<b>2.58</b>	<b>1.99</b>

Operating netbacks were higher in Q3 2006 against Q2 2006 as a result of an increase in the average price of industrial and power sales as the volumes of industrial sales as a proportion of total sales were higher in Q3. The netbacks will start to fall from Q4 as the sales to the power sector increase.

The operating 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:

(Figures in US\$'000)	Three months ended			Nine months ended	
	30 Sept 2006	30 Jun 2006	30 Sept 2005	30 Sept 2006	30 Sept 2005
Employee costs	<b>648</b>	533	272	<b>1,514</b>	647
Stock based compensation	<b>142</b>	96	71	<b>334</b>	214
Travel & accommodation	<b>135</b>	78	33	<b>285</b>	124
Communications	<b>11</b>	25	14	<b>57</b>	52
Office	<b>119</b>	99	113	<b>327</b>	283
Consultants	<b>260</b>	252	162	<b>741</b>	369
Insurance	<b>36</b>	36	57	<b>107</b>	144
Auditing & taxation	<b>43</b>	18	13	<b>112</b>	46
Depreciation	<b>27</b>	27	23	<b>81</b>	66
Marketing costs including legal fees	<b>289</b>	231	71	<b>705</b>	238
Reporting, regulatory and corporate finance	<b>124</b>	141	39	<b>383</b>	135
Directors' fees	<b>12</b>	26	17	<b>55</b>	47
<b>Total administrative expenses</b>	<b>1,846</b>	1,562	885	<b>4,701</b>	2,365

G&A averaged approximately US\$0.61 million per month (including the stock-based compensation and depreciation) during the period (Q2 2006: US\$0.52 million). The cost per gross mcf sold increased during the quarter to US\$1.49/mcf (Q2 2006: US\$1.44/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.

In Q3, higher costs were experienced in negotiating the power contracts with Songas and TANESCO. These are likely to increase in Q4 and Q1 2007, but will decrease substantially once the power contracts are signed and the EWURA process is completed.

The Company uses the Black-Scholes option pricing model in determining the fair value of options. The Options that were issued on 1 September 2004 became fully vested at 1 September 2006. Therefore the monthly charge to the income statement of US\$32,000 ceased at this time. On 1 September 2006, the Company issued 200,000 options to a newly recruited employee. These will vest in three equal annual installments starting on 1 September 2007. The Company will make a monthly charge to the income statement of US\$22,000 in respect of these options.

### **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\$375,000 (Q2 2006: US\$297,000) is payable as income tax for the quarter ended 30 September 2006 (cumulative to 30 September 2006: US\$743,000) 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 September 2006, the Company was yet to receive clarification of this issue.

As at 30 September 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\$867,000. 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 September 2006, the effective APT rate was calculated to be 18%. Accordingly, US\$52,000 has been deducted from revenue for the quarter.

As at 30 September 2006, there were un-recovered costs of US\$12.2 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 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 gross 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\$0.35/mcf in Q3 (Q2 2006: US\$0.36/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 September 2006, the Company had US\$12.2 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.

### Funds Flow

Funds from operations before working capital changes was US\$1.6 million in Q3 2006 (Q2 2006: US\$1.3 million).

(Figures in US\$'000)	Three months ended			Nine months ended	
	30 Sept 2006	30 Jun 2006	30 Sept 2005	30 Sept 2006	30 Sept 2005
Profit/(loss) after taxation	809	660	785	1,552	(8)
Adjustment for non cash items	780	673	470	2,041	722
<b>Funds from operations before working capital changes</b>	<b>1,589</b>	1,333	1,255	<b>3,593</b>	714
Working capital adjustments	924	(526)	(661)	640	102
<b>Net cash flows from operating activities</b>	<b>2,513</b>	807	594	<b>4,233</b>	816
Net cash flows used in investing activities	(772)	(1,463)	(485)	(2,979)	(2,746)
Net cash flows from financing activities	10	31	–	128	4,375
<b>Net increase/(decrease) in cash and cash equivalent</b>	<b>1,751</b>	(625)	109	<b>1,382</b>	2,445

The increased profitability and a reduction in the capital expenditure in Q3 led to a US\$1.8 million increase in cash and cash equivalent during Q3 2006. The increase of US\$2.4 million in the nine months ended 30 September 2005 was due to the net receipt of US\$4.4 million from a rights issue.

### Capital Expenditures

Gross capital expenditures amounted to US\$0.7 million in Q3 2006 (Q2 2006: US\$1.0 million). The capital expenditure may be analysed as follows:

(Figures in US\$'000)	Three months ended			Nine months ended	
	30 Sept 2006	30 Jun 2006	30 Sept 2005	30 Sept 2006	30 Sept 2005
Geological and geophysical	473	726	148	1,712	757
Pipelines and infrastructure	234	305	110	845	1,220
Power development	42	–	224	42	755
Other equipment	–	3	3	35	14
	<b>749</b>	1,034	485	<b>2,634</b>	2,746

During Q3, the Company continued with the preparation to drill a development well to increase gas deliverability and ensure security of supply in case of failure of any other single well. The Company spent US\$0.3 million during the quarter on drilling management and long lead items.

The Company also commenced the installation of a second Pressure Reduction Station (“PRS”) to ensure supply of gas to the 40 MW Aggreko power plant that became operational in Q4 2006.

### Working Capital

Working capital as at 30 September 2006 was US\$3.3 million (30 June 2006: US\$2.4 million) and may be analysed as follows:

(Figures in US\$'000)	30 Sept 2006	30 Jun 2006	31 Dec 2005
Cash and cash equivalents	4,580	2,829	3,198
Trade and other receivables	3,653	4,076	2,862
	<b>8,233</b>	6,905	6,060
Trade and other payables	4,935	4,457	3,849
<b>Working capital</b>	<b>3,298</b>	2,448	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 September 2006, US\$886,000 (30 June 2006: US\$800,000) 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 September 2006, US\$317,000 (30 June 2006: US\$175,000) 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 September 2006 the Company owed Songas US\$563,000 (30 June 2006: US\$816,000) for the tariff.

Also included in cash and cash equivalents was US\$130,000 advanced by East Coast Oils & Fats Limited and Murzah Oil Mills Limited 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 end of the month in which the gas was consumed. As at 30 September 2006, US\$2.3 million (including VAT) was due 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\$0.7 million due from Songas for the supply of Additional Gas to the Ubungu Power Plant. The contract with Songas accounted for 23% of the Company's operating revenue during the period (Q2 2006: 34%). 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. The Company subsequently collected all amounts due from Songas for the sales to 30 September 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 30 September 2006 and may be analysed as follows:

No of shares ('000)	30 Sept 2006	30 Jun 2006	31 Dec 2005
<b>SHARES OUTSTANDING</b>			
Class A shares	1,751	1,751	1,751
Class B shares	21,658	21,648	21,513
	<b>23,409</b>	23,399	23,264
<b>CONVERTIBLE SECURITIES:</b>			
Options	2,042	1,852	1,987
Fully diluted Class A and Class B shares	<b>25,451</b>	25,251	25,251

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

No of shares ('000)	30 Sept 2006	30 Jun 2006	31 Mar 2006
<b>WEIGHTED AVERAGE</b>			
Class A and Class B shares	23,475	23,375	23,325
Options	1,662	1,453	1,358
Weighted average diluted Class A and Class B shares	<b>25,137</b>	24,828	24,683

On 11 September 2006, the Company announced the intention of raising gross proceeds of Cdn\$21.5 million by way of a 1 for 7 rights issue. The rights documentation was submitted to the shareholders on 14 November 2006. Under the terms of this rights offer:

- each holder of a Class B Subordinated Voting share ("Class B Share") will receive one right for each Class B Share held and that seven rights will entitle the holder to subscribe for one Class B Share at a price of Cdn\$6.43.
- each holder of a Class A Common share ("Class A Share") will receive one right for each Class A Share held and that seven rights will entitle the holder to subscribe for one Class B Share at a price of Cdn\$6.43.

The subscription price of Cdn\$6.43 represents a 15% discount to the closing price of the Class B Shares on 8 September, 2006. Under the terms of the rights issue, the Company will issue a maximum of approximately 3,345,540 Class B Shares. As at 27 November 2006, 21,657,588 Class B Shares were outstanding.

### 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. 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. These options vested equally over two years and were fully vested on 1 September 2006.

On 1 September 2006, 200,000 options were issued to a newly recruited employee at a price of Cdn\$6.80 per option. These options have a term of 5 years and vest in three equal annual installments starting on 1 September 2007. The fair value of these options were estimated at the grant date using the Black-Scholes option pricing model with the following assumptions: risk free rate of 2.6% dividend yield of 0%, expected life of 5 years and volatility of 80%.

In Q3 2006, 10,000 (Q2 2006: 35,000) options were exercised at a price of Cdn\$1 per option. A total of 2,042,400 options remain outstanding.

### 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 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 foreseen demand. These negotiations form part of the overall negotiations for the supply of gas to the power sector and it is forecast that they will not be concluded before 31 March 2007.

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 2005, the Company acquired in excess of 300 kilometers of seismic in Area A. Under the terms of the agreement, the Company had until 30 September 2006 to elect whether or not to participate in the drilling of a well on Area A. TPDC has indicated that it may not be possible to split out Area A from the remainder of the Nyuni PSA and 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 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 and a 20 MW General Electric unit. The total cost of this installation is estimated at US\$0.9 million and will be incurred in Q4.

In November 2006, the Company committed to perform remedial work on the offshore well SS9. The cost of this work is estimated at US\$1.0 – US\$2.0 million.

In November 2006, the Company committed to purchasing an estimated US\$4.0 million of long lead drilling items for two wells, including all the casing.

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

#### **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**

As part of the raising of Cdn\$21.5 million through the rights issue, the Company has entered into an underwriting agreement with a company that is controlled by the non executive chairman, WD Lyons. Under the terms of the agreement, EastCoast Energy agreed to pay the company US\$0.3 million to underwrite the rights issue in full.

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

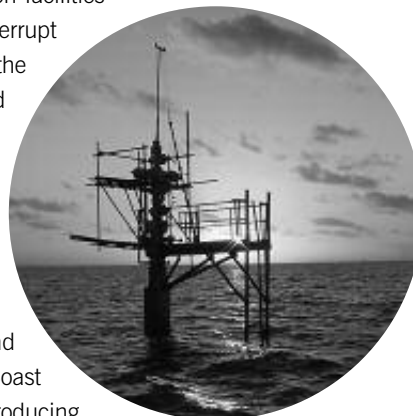
## Summary Quarterly Results

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

	2006				2005			2004	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
<b>FINANCIAL</b> (US\$'000 except where otherwise stated)									
Revenue	<b>3,835</b>	3,198	2,073	2,741	2,156	512	350	391	50
Profit/(loss) after taxation	<b>809</b>	660	83	396	785	(275)	(518)	(643)	(34)
Operating netback (US\$/mcf)	<b>2.88</b>	2.71	2.05	2.27	1.68	3.86	3.24	3.00	3.51
Working capital	<b>3,298</b>	2,448	2,118	2,211	3,559	2,789	4,895	1,216	2,289
Shareholders' equity	<b>18,676</b>	17,715	16,928	16,662	16,096	15,240	15,444	11,516	11,857
Profit/(loss) per share – basic and diluted (US\$)	<b>0.03</b>	0.03	–	0.02	0.03	(0.01)	(0.02)	(0.03)	(0.04)
<b>CAPITAL EXPENDITURE</b>									
Geological and geophysical	<b>473</b>	726	514	2,001	148	520	88	137	10
Pipeline and infrastructure	<b>234</b>	305	305	868	110	902	210	479	1
Power development	<b>42</b>	–	–	34	224	531	–	–	–
Other equipment & business development	–	3	32	(1)	3	5	5	150	148
<b>OPERATING</b>									
Additional Gas sold)									
– industrial (mmscf)	<b>491</b>	347	230	299	261	120	97	107	14
Additional Gas sold									
– power (mmscf)	<b>744</b>	739	682	766	905	–	–	–	–
Average price per mcf									
– industrial (US\$)	<b>8.63</b>	8.69	7.63	7.86	7.26	6.19	5.23	5.31	5.41
Average price per mcf									
– power (US\$)	<b>1.69</b>	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

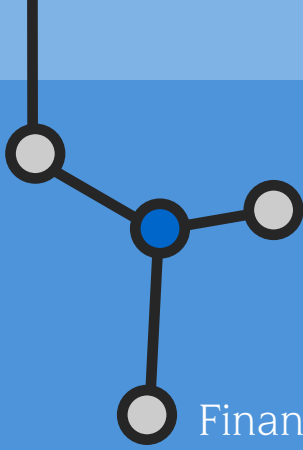
EastCoast intends to acquire natural gas infrastructure and possibly additional oil and gas properties. Although EastCoast performs a review of the acquired properties that it believes is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review 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 key 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. 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			Nine months ended	
		30 Sept 2006	30 Jun 2006	30 Sept 2005	30 Sept 2006	30 Sept 2005
Revenue		<b>3,835</b>	3,198	2,156	<b>9,106</b>	3,018
<b>Cost of sales</b>						
Production and distribution expenses		<b>(211)</b>	(197)	(90)	<b>(573)</b>	(175)
Depletion expense		<b>(435)</b>	(382)	(376)	<b>(1,141)</b>	(443)
<b>Gross profit</b>		<b>3,189</b>	2,619	1,690	<b>7,392</b>	2,400
Other income		<b>17</b>	14	77	<b>47</b>	54
Administrative expenses		<b>(1,846)</b>	(1,562)	(885)	<b>(4,701)</b>	(2,365)
Foreign exchange gain/(losses)		<b>(51)</b>	9	–	<b>(83)</b>	–
<b>Profit before taxation</b>		<b>1,309</b>	1,080	882	<b>2,655</b>	89
Taxation	1	<b>(500)</b>	(420)	(97)	<b>(1,103)</b>	(97)
<b>Profit/(loss) after taxation</b>		<b>809</b>	660	785	<b>1,552</b>	(8)
<b>Profit per share</b>						
Basic and diluted (US\$)		<b>0.03</b>	0.03	0.03	<b>0.06</b>	–

See accompanying notes to the interim consolidated financial statements.

## Consolidated Balance Sheet (unaudited)

<i>(thousands of US dollars)</i>	Note	As at 30 Sept 2006	As at 30 June 2006	As at 31 December 2005
<b>ASSETS</b>				
<b>Current assets</b>				
Cash and cash equivalents		<b>4,580</b>	2,829	3,198
Trade and other receivables		<b>3,653</b>	4,076	2,862
		<b>8,233</b>	6,905	6,060
Natural gas properties and other equipment	2	<b>16,448</b>	16,161	15,037
		<b>24,681</b>	23,066	21,097
<b>LIABILITIES</b>				
<b>Current liabilities</b>				
Trade and other payables		<b>4,935</b>	4,457	3,849
<b>Non current liabilities</b>				
Deferred tax	1	<b>867</b>	743	506
Deferred additional profits tax		<b>203</b>	151	80
<b>SHAREHOLDERS' EQUITY</b>				
Capital stock	3	<b>16,365</b>	16,355	16,237
Capital reserve		<b>1,098</b>	956	764
Accumulated profit/(loss)		<b>1,213</b>	404	(339)
		<b>18,676</b>	17,715	16,662
		<b>24,681</b>	23,066	21,097

*Contingent liabilities (Note 4)*

*Contractual obligations and committed capital investment (Note 5)*

*Post balance sheet events (Note 8)*

*See accompanying notes to the interim consolidated financial statements.*

## Consolidated Statement of Cash Flows (unaudited)

(thousands of US dollars)	Three months ended			Nine months ended	
	30 Sept 2006	31 Jun 2006	30 Sept 2005	30 Sept 2006	30 Sept 2005
<b>CASH FLOWS FROM OPERATING ACTIVITIES</b>					
<b>Profit/(loss) after taxation</b>	<b>809</b>	660	785	<b>1,552</b>	(8)
Adjustments for:					
Depletion and depreciation	<b>462</b>	410	399	<b>1,223</b>	509
Stock-based compensation	<b>142</b>	96	71	<b>334</b>	213
Deferred taxation	<b>124</b>	123	–	<b>361</b>	–
Additional profits tax	<b>52</b>	44	–	<b>123</b>	–
Funds from operations before working capital changes	<b>1,589</b>	1,333	1,255	<b>3,593</b>	714
(Increase)/decrease in trade and other receivables	<b>423</b>	(2,032)	(1,959)	<b>(791)</b>	(2,176)
Increase in trade and other payables	<b>501</b>	1,506	1,298	<b>1,431</b>	2,278
<b>Net cash flows from operating activities</b>	<b>2,513</b>	807	594	<b>4,233</b>	816
<b>CASH FLOWS USED IN INVESTING ACTIVITIES</b>					
Acquisition of natural gas properties and other equipment	<b>(749)</b>	(1,034)	(485)	<b>(2,634)</b>	(2,746)
(Decrease) in trade and other payables	<b>(23)</b>	(429)	–	<b>(345)</b>	–
<b>Net cash flows used in investing activities</b>	<b>(772)</b>	(1,463)	(485)	<b>(2,979)</b>	(2,746)
<b>CASH FLOWS FROM FINANCING ACTIVITIES</b>					
Net proceeds from rights issue	–	–	–	–	4,365
Proceeds from exercise of options	<b>10</b>	31	–	<b>128</b>	10
<b>Net cash flows from financing activities</b>	<b>10</b>	31	–	<b>128</b>	4,375
<b>Increase/(decrease) in cash and cash equivalents</b>	<b>1,751</b>	(625)	109	<b>1,382</b>	2,445
<b>Cash and cash equivalents at the beginning of the period</b>	<b>2,829</b>	3,454	4,376	<b>3,198</b>	2,040
<b>Cash and cash equivalents at the end of the period</b>	<b>4,580</b>	2,829	4,485	<b>4,580</b>	4,485

See accompanying notes to the interim consolidated financial statements.



## Statement of Changes in Shareholders' Equity (Unaudited)

<i>(thousands of US dollars)</i>	Capital stock	Capital reserve	Accumulated Profit/(Loss)	Total
Note	3			
Balance as at 31 December 2004	11,862	381	(727)	<b>11,516</b>
Rights issue net of share issue costs	4,365	–	–	<b>4,365</b>
Options exercised	10	–	–	<b>10</b>
Profit for the year	–	–	388	<b>388</b>
Stock-based compensation	–	383	–	<b>383</b>
Balance as at 31 December 2005	16,237	764	(339)	<b>16,662</b>
Options exercised	128	–	–	<b>128</b>
Profit for the period	–	–	1,552	<b>1,552</b>
Stock based compensation	–	334	–	<b>334</b>
<b>Balance as at 30 September 2006</b>	<b>16,365</b>	<b>1,098</b>	<b>1,213</b>	<b>18,676</b>

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 and nine months ended 30 September 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 7.

## 1 TAX

As at 30 September 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 September 2006.

### Tax rate reconciliation:

Figures in US\$'000	Three months ended		Nine months ended
	30 Sept 2006	30 Jun 2006	30 Sept 2006
Profit before taxation	<b>1,309</b>	1,080	<b>2,655</b>
Provision for income tax calculated at the statutory rate of 30%	<b>393</b>	324	<b>796</b>
Add/(deduct) the tax effect of non-deductible income tax items:			
Other income	<b>(3)</b>	(4)	<b>(12)</b>
Administrative and operating expenses	<b>31</b>	36	<b>120</b>
Stock based compensation	<b>43</b>	29	<b>101</b>
Permanent differences	<b>36</b>	35	<b>98</b>
	<b>500</b>	420	<b>1,103</b>
The tax charge may be analysed as follows:			
Current tax	<b>375</b>	297	<b>743</b>
Deferred tax	<b>125</b>	123	<b>360</b>
	<b>500</b>	420	<b>1,103</b>

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

	30 Sept 2006	30 Jun 2006	30 Sept 2005
Differences between tax base and carrying value of natural gas properties	<b>784</b>	681	474
Other timing differences	<b>83</b>	62	32
	<b>867</b>	743	506

## 2 NATURAL GAS PROPERTIES AND OTHER EQUIPMENT

US\$000	Natural gas properties	Leasehold improvements	Computer equipment	Vehicles	Fixtures & fittings	Total
<b>COSTS</b>						
As at 1 January 2006	15,693	156	59	38	37	<b>15,983</b>
Additions – Q1	819	–	4	27	1	<b>851</b>
Additions – Q2	1,031	–	–	–	3	<b>1,034</b>
Additions – Q3	749	–	–	–	–	<b>749</b>
As at 30 September 2006	18,292	156	63	65	41	<b>18,617</b>
<b>DEPLETION/DEPRECIATION</b>						
As at 1 January 2006	853	49	19	13	12	<b>946</b>
Charge for the period – Q1	324	13	5	5	4	<b>351</b>
Charge for the period – Q2	383	13	5	6	3	<b>410</b>
Charge for the period – Q3	435	13	5	5	4	<b>462</b>
<b>As at 30 September 2006</b>	<b>1,995</b>	<b>88</b>	<b>34</b>	<b>29</b>	<b>23</b>	<b>2,169</b>
<b>NET BOOK VALUES</b>						
<b>At 30 September 2006</b>	<b>16,297</b>	<b>68</b>	<b>29</b>	<b>36</b>	<b>18</b>	<b>16,448</b>
At 31 December 2005	14,840	107	40	25	25	<b>15,037</b>

Included in the natural gas properties as at 30 September 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 was estimated by the independent reserve engineers as at 31 December 2005, 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
<b>CLASS A SHARES</b>			
As at 31 December 2005 and 30 September 2006	<b>50,000</b>	<b>1,751</b>	<b>983</b>
<b>CLASS B SHARES</b>			
As at 31 December 2005	50,000	21,513	15,254
Options exercised	–	145	128
As at 30 September 2006	<b>50,000</b>	<b>21,658</b>	<b>15,382</b>
Total Class A and B shares as at 30 June 2006	<b>100,000</b>	<b>23,409</b>	<b>16,365</b>

On 1 September 2006, 200,000 options were issued to an employee at a price of Cdn\$6.80 per option. These options have a term of 5 years and vest in three equal annual installments starting on 1 September 2007. The fair value of these options of Cdn\$4.46 per option was estimated at the grant date using the Black-Scholes option pricing model with the following assumptions: risk free rate of 2.6% dividend yield of 0%, expected life of 5 years and volatility of 80%.

In Q3 2006, 10,000 (Q2 2006: 35,000) options were exercised at a price of Cdn\$1 per option. A total of 2,042,400 options remain outstanding.

Thousands of options	Options	Price (Cdn\$)
Outstanding as at 1 January 2006	1,987,400	1.00
Granted	200,000	6.80
Exercised	(145,000)	1.00
Outstanding as at 30 September 2006	<b>2,042,400</b>	<b>1.00 - 6.80</b>

### 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.

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. These negotiations form part of the overall negotiations for the supply of gas to the power sector and it is forecast that they will not be concluded before 31 March 2007.

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 2005, the Company acquired in excess of 300

kilometers of seismic in Area A. Under the terms of the agreement, the Company had until 30 September 2006 to elect whether or not to participate in the drilling of a well on Area A. TPDC has indicated that it may not be possible to split out Area A from the remainder of the Nyuni PSA and 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 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 and a 20 MW General Electric unit. The total cost of this installation is estimated at US\$0.9 million and will be incurred in Q4.

In November 2006, the Company committed to perform remedial work on the offshore well SS9. The cost of this work is estimated at US\$1.0 – US\$2.0 million.

In November 2006, the Company committed to purchasing an estimated US\$4.0 million of long lead drilling items for two wells, including all the casing.

## 6 RELATED PARTY TRANSACTIONS

As part of the raising of gross proceeds of Cdn\$21.5 million through the rights issue, the Company has entered into an underwriting agreement with a company that is controlled by the non executive chairman, WD Lyons. Under the terms of the agreement, EastCoast agreed to pay the company US\$0.3 million to underwrite the rights issue in full.

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

## 7 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 a predecessor company pursuant to a scheme of arrangement. Under Canadian GAAP, a deferred tax liability has to be recognised for the taxable temporary differences arising from the initial recognition of an asset or liability under any scenario. IFRS does not permit the setting up of a deferred tax liability for all taxable temporary differences arising from the initial recognition of an asset or liability except in a business combination.

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

The following are the differences in accounting principles:

Figures in US\$'000	30 September 2006		30 June 2006		30 September 2005	
	IAS	CDN	IAS	CDN	IAS	CDN
Current assets	<b>8,233</b>	<b>8,233</b>	6,905	6,905	7,102	7,102
Natural gas properties and other equipment	<b>16,448</b>	<b>18,224</b>	16,161	17,937	12,537	14,352
	<b>24,681</b>	<b>26,457</b>	<b>23,066</b>	<b>24,842</b>	<b>19,639</b>	<b>21,454</b>
Current liabilities	<b>4,935</b>	<b>4,935</b>	4,457	4,357	3,543	3,543
Non-current liabilities	<b>1,070</b>	<b>2,641</b>	894	2,654	–	1,799
Capital stock	<b>16,365</b>	<b>16,365</b>	16,355	16,355	16,237	16,237
Reserves	<b>2,311</b>	<b>2,516</b>	1,360	1,476	(141)	(125)
	<b>24,681</b>	<b>26,457</b>	<b>23,066</b>	<b>24,842</b>	<b>19,639</b>	<b>21,454</b>

Figures in US\$'000	Quarter ended 30 September 2006		Quarter ended 30 June 2006		Year ended 30 September 2005	
	IAS	CDN	IAS	CDN	IAS	CDN
Profit before taxation	<b>1,309</b>	<b>1,295</b>	<b>1,080</b>	<b>1,180</b>	<b>882</b>	<b>882</b>

## 8 POST BALANCE SHEET EVENTS

On 11 September 2006, the Company announced the intention of raising gross proceeds of Cdn\$21.5 million by way of a 1 for 7 rights issue. The rights documentation was submitted to the shareholders on 14 November 2006. Under the terms of this rights offer:

- each holder of a Class B Subordinated Voting share ("Class B Share") will receive one right for each Class B Share held and that seven rights will entitle the holder to subscribe for one Class B Share at a price of Cdn\$6.43.
- each holder of a Class A Common share ("Class A Share") will receive one right for each Class A Share held and that seven rights will entitle the holder to subscribe for one Class B Share at a price of Cdn\$6.43.

The subscription price of Cdn\$6.43 represents a 15% discount to the closing price of the Class B Shares on 8 September, 2006. Under the terms of the rights issue, the Company will issue a maximum of approximately 3,345,540 Class B Shares.

## Forward Looking Statements

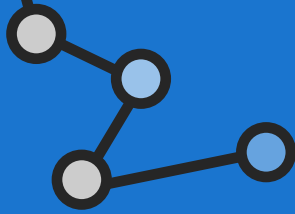
THIS DISCLOSURE CONTAINS CERTAIN FORWARD-LOOKING ESTIMATES THAT INVOLVE SUBSTANTIAL KNOWN AND UNKNOWN RISKS AND UNCERTAINTIES, CERTAIN OF WHICH ARE BEYOND EASTCOAST'S CONTROL, INCLUDING THE IMPACT OF GENERAL ECONOMIC CONDITIONS IN THE AREAS IN WHICH EASTCOAST OPERATES, CIVIL UNREST, INDUSTRY CONDITIONS, CHANGES IN LAWS AND REGULATIONS INCLUDING THE ADOPTION OF NEW ENVIRONMENTAL LAWS AND REGULATIONS AND CHANGES IN HOW THEY ARE INTERPRETED AND ENFORCED, INCREASED COMPETITION, THE LACK OF AVAILABILITY OF QUALIFIED PERSONNEL OR MANAGEMENT, FLUCTUATIONS IN COMMODITY PRICES, FOREIGN EXCHANGE OR INTEREST RATES, STOCK MARKET VOLATILITY AND OBTAINING REQUIRED APPROVALS OF REGULATORY AUTHORITIES. IN ADDITION THERE ARE RISKS AND UNCERTAINTIES ASSOCIATED WITH OIL AND GAS OPERATIONS, THEREFORE EASTCOAST'S ACTUAL RESULTS, PERFORMANCE OR ACHIEVEMENT COULD DIFFER MATERIALLY FROM THOSE EXPRESSED IN, OR IMPLIED BY, THESE FORWARD-LOOKING ESTIMATES AND, ACCORDINGLY, NO ASSURANCES CAN BE GIVEN THAT ANY OF THE EVENTS ANTICIPATED BY THE FORWARD-LOOKING ESTIMATES WILL TRANSPIRE OR OCCUR, OR IF ANY OF THEM DO SO, WHAT BENEFITS, INCLUDING THE AMOUNTS OF PROCEEDS, THAT EASTCOAST WILL DERIVE THEREFROM.

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## Corporate Information

### BOARD OF DIRECTORS

W. David Lyons	Peter R. Clutterbuck	Nigel A. Friend	John Patterson	David Ross
Non-Executive Chairman	President & Chief Executive Officer	Chief Financial Officer London	Non-Executive Director Nanoose Bay Canada	Non-Executive Director Calgary Canada
St. Helier Jersey	Haslemere United Kingdom	United Kingdom		

### OFFICERS

Pierre Raillard	David W. Ross
Vice President Operations	Company Secretary

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& Palmer LLP  
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### TRANSFER AGENT

CIBC Mellon Trust Company  
Toronto, Montreal  
and Calgary,  
Canada



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