TransGlobe Energy Corporation
2006 ANNUAL REPORT

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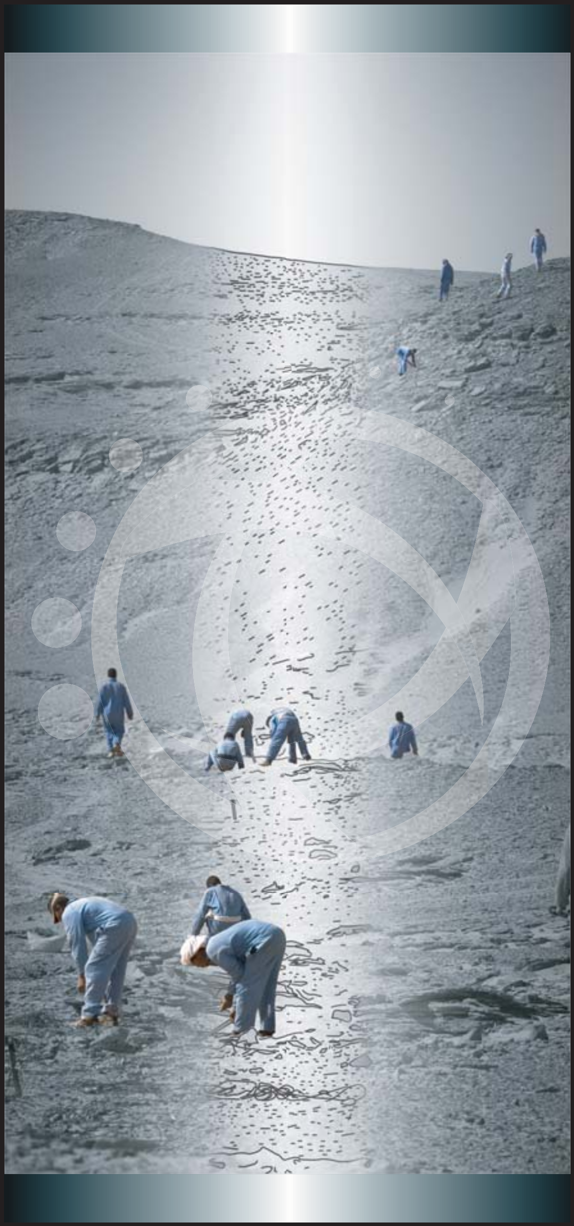


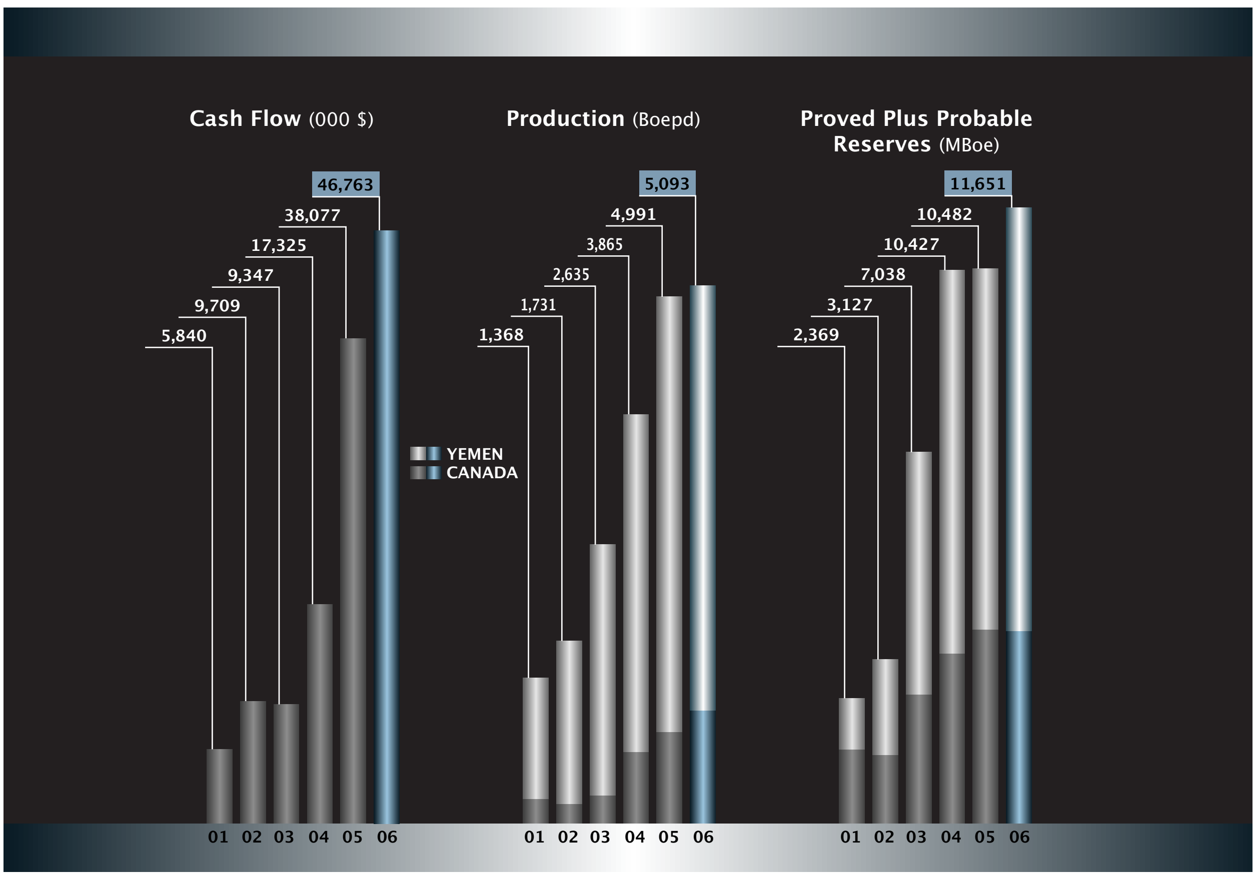
Annual Meeting

TransGlobe Energy Corporation will hold its Annual Meeting on Wednesday, May 9, 2007 at 3:00 p.m. The meeting will be held in the Viking Room at the Calgary Petroleum Club located at 319 - 5th Avenue S.W., Calgary, Alberta, Canada.

This annual report may include certain statements that may be deemed to be "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. All statements in this annual report, other than statements of historical facts, that address future production, reserve potential, exploration drilling, exploitation activities and events or developments that the Company expects, are forward-looking statements. Although TransGlobe believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Factors that could cause actual results to differ materially from those in forward-looking statements include, but are not limited to, oil and gas prices, well production performance, exploitation and exploration successes, continued availability of capital and financing, and general economic, market or business conditions.

HIGHLIGHTS

- **Record Company Cash Flow of $46.8 million for 2006, increasing 23% from 2005.**
- **Record Company Total Revenue of $109 million for 2006, increasing 21% from 2005.**
- **Record Company Net Income of $26.2 million for 2006, increasing 32% from 2005.**
- **Reserves increased to a record 11,651 MBoe, growing over 39% in the last four years on a compound average rate.**
- **TransGlobe successfully executed its 2006 spending program through cash and cash flow from operations.**
- **Operational highlights:**
  - **41 wells drilled.**
  - **Two new pools discovered at Block 32, Yemen, one brought on production.**
  - **Two new pools discovered at Block S-1, Yemen, one brought on production.**
  - **Two new exploration blocks awarded in Yemen.**
  - **Started drilling first exploration well in Egypt.**
  - **Drilled first exploration well on Block 72, Yemen.**



Throughout the text of TransGlobe's annual report and consolidated financial statements, all dollar values are expressed in United States dollars unless otherwise stated.

Disclosure provided herein in respect of Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Message To The Shareholders

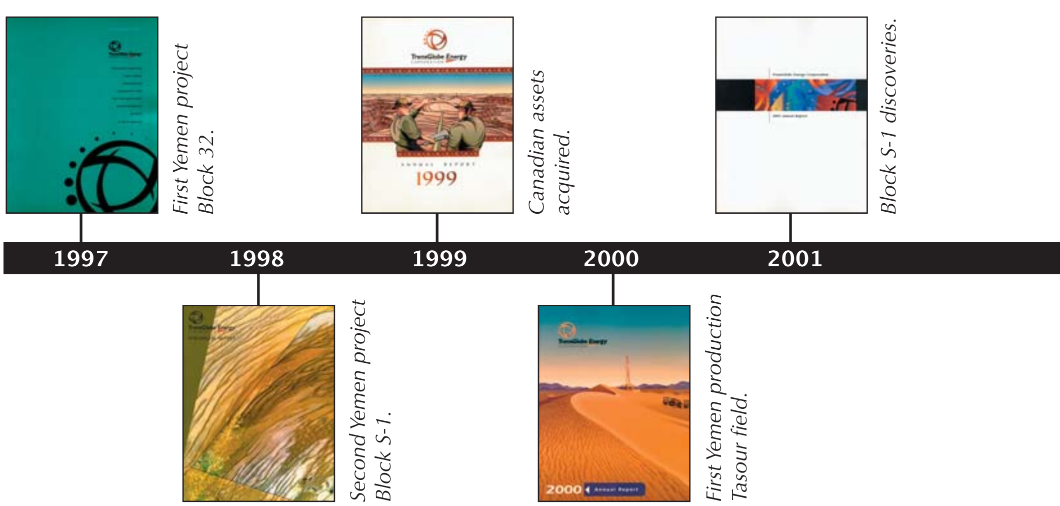
2007 marks the tenth anniversary of TransGlobe's entry into international exploration and my tenth year leading the Company. So it is appropriate to contemplate where we are as a company, how we got here compared to 1997, and where we are going.

I can see three areas of achievement in 2006 that greatly represent and affect the present circumstances. The first of these is land holdings. TransGlobe's land holdings are unparalleled throughout the industry for its market capitalization. In 2006, two new blocks were added in Yemen raising our holdings to over one million acres on five blocks. TransGlobe is now one of the largest land holders in Yemen, in areas of high exploration potential. The Nuqra Block in Egypt is over five million acres and in Canada our undeveloped mineral rights cover more than 46,000 acres. Exploration land is a primary asset from which all our growth emanates. A clear example of this are the recent developments in the Canadian coal bed methane ("CBM") play in the Horseshoe Canyon and Mannville coals. TransGlobe has benefited from other operators' research and development work on this emerging play and has recently assessed the Company's contingent resource in the Horseshoe Canyon and Mannville CBM at over 160 Bcf. Bid prices for CBM mineral rights continue to increase. Based on mineral rights sales values during 2005/2006 in lands surrounding our CBM play, the Company's mineral rights value alone increased to $25 million. Our Yemen lands are another example. The Company has lands covering every play concept in Yemen, which provides us with a variety of drilling targets and several different horizons to explore for.

The second achievement of 2006 is becoming an international operator in Egypt. The Company's financial capabilities, technical abilities and operational experience have grown, allowing us to take on the role of operator in an international venture. The ability to operate greatly expands future investment possibilities. Several experienced professionals were hired to achieve this end and they have brought not only skill but also new ideas and energy.

The third achievement of 2006 is exploration success. There were new discoveries at Godah, Osaylan, Wadi Bayhan and an intriguing light oil test in a deep Tasour well. Two of these discoveries, Godah and Osaylan, have already commenced production. We have recognised a conservative amount of reserves on Godah and Osaylan. I believe our reserve statements do not reflect the total potential of these discoveries. When Tasour was first discovered we booked 6 million barrels of gross recoverable reserves. It has produced 30 million barrels, and the estimated reserves still stand at 6 million barrels gross. We hope Godah and Osaylan will also prove to be larger than our current estimates.

To prove the ultimate potential of these new discoveries the 2007 drilling program will concentrate on appraisal and development drilling. On Block 32, ten to twenty development wells could be required if Godah proves to be as large as our mapping suggests. The Tasour #23 light oil test is intriguing as our first discovery in the deeper horizons and requires testing and appraisal drilling. The Osaylan discovery will require additional development wells also. Osaylan and Wadi Bayhan have provided positive insight into the prospectivity of the newly acquired Block 75 which will lead to future exploration drilling.



Robert A. Halpin
Chairman of the Board and Director

In Canada, for the first time, we are disclosing contingent resources in the Mannville CBM, 139 Bcf, an emerging play. We are watching the actions of the surrounding operators with interest. In 2006 this play was declared commercial for the first time by one operator. To date exploitation of the Mannville has been capital intensive. We may drill one Mannville horizontal well this year to test the play concept.

2006 speaks to the emergent capabilities of TransGlobe. So how did we get here? In 1997, the Company had no high potential exploration projects; no further development drilling locations; was undercapitalized with poor access to capital; and had no staff with oil and gas experience. A new business strategy was formulated to grow the Company in a stepwise method. Start with small interests initially, working towards larger interests, and building towards operatorship. Domestic production would provide a stable base to strengthen the balance sheet. The success of that strategy is evident in the record \$46.8 million cash flow from operations, a \$55 million undrawn credit line, 6.8 million acres of high potential lands, and our first international operatorship.

Where to next? TransGlobe's capabilities have clearly outgrown the simple strategy set out in 1997. To date the Company has grown by the drill bit, a successful but time intensive strategy. We have many more opportunities now that could dramatically change the Company, including mergers and acquisitions.

One frustration of 2006 was construction delays which postponed production increases throughout the year. The reserve increases are there, but production increases have lagged. This industry-wide problem was mentioned in 2005 as well. Increased staff levels have not been able to ameliorate the equipment delivery delays, lengthening licensing and government approval time lines. This problem is ongoing and will affect Godah and Osaylan development. We are vigilant to every action that can lead to timely asset development.

We enter 2007 as a larger entity with increased lands, enlarged facilities, new oil and gas fields under development, strengthened operational capabilities and a pristine balance sheet. We have come a long way from 1997 and yet the journey has just begun. We have vast horizons of opportunity and multiple paths to reach journey's end.

Ross G. Clarkson
President, CEO and Director

March 7, 2007

2002

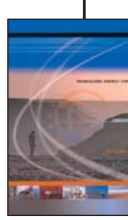
Tasour extension and
An Nagyah discovery.

2003

Block S-1 declared
Commercial.

2004

Block S-1 production start,
Block 72 acquired.



2005

Added Egypt project,
operated and Block 72.

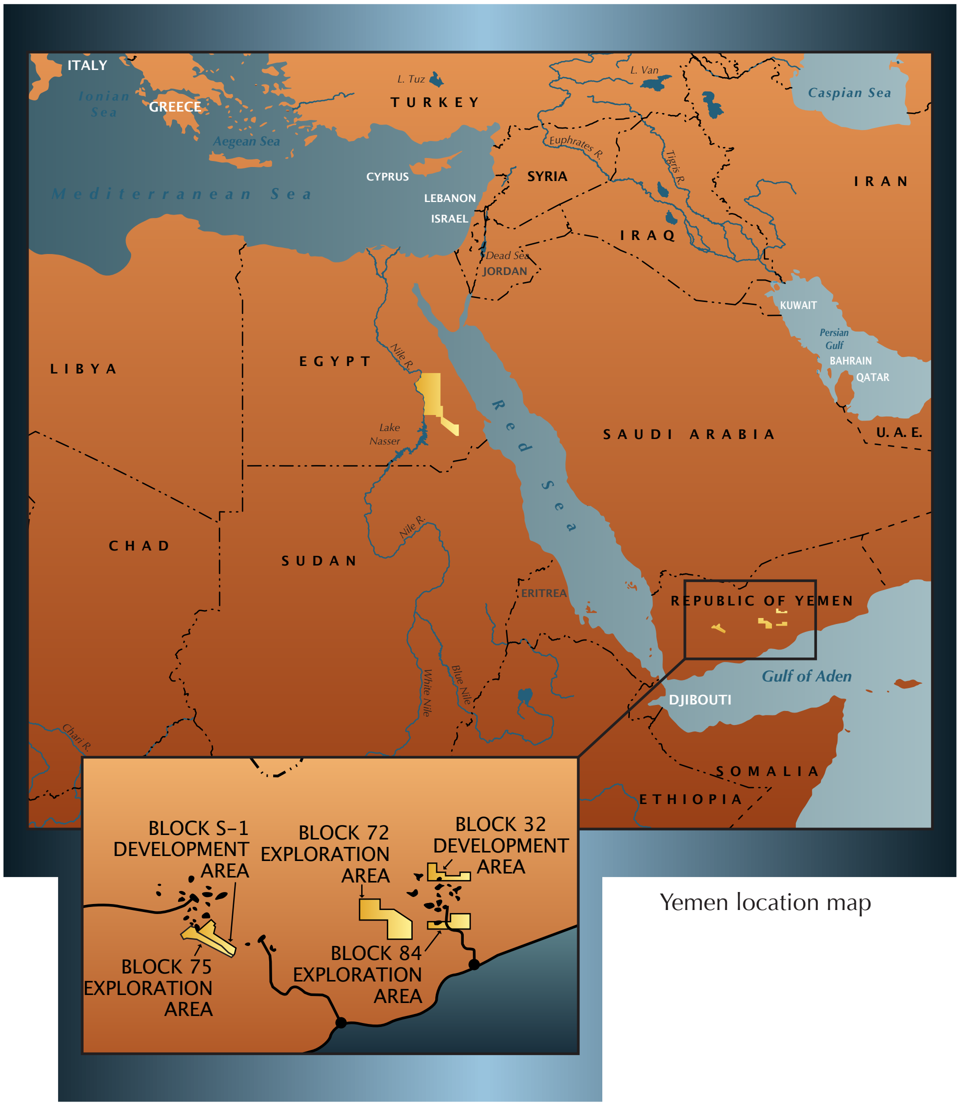
2006

Block 84,
Block 75, fifth Yemen project.

Ross G. Clarkson
President, CEO and Director

2006 Annual Report

Operations Review



Yemen location map

INTERNATIONAL ACTIVITY

TransGlobe's first International property was acquired in the Republic of Yemen ("Yemen") in January 1997, through a farmout and joint venture agreement on Block 32. During the past 10 years, TransGlobe has consistently grown its international portfolio in the Middle East North African region ("MENA") to an impressive 6.8 million acres (3.1 million net acres) in Yemen and the Arab Republic of Egypt ("Egypt").

Through TransGlobe's wholly owned subsidiaries, TG Holdings Yemen Inc. and TransGlobe Petroleum Egypt Inc., the Company has interests in six production sharing agreements (five in Yemen and one in Egypt).

With the expanded number of exploration and development blocks in Yemen, the blocks have been grouped into East and West Yemen.

In Eastern Yemen, the Company has interests in three Blocks located in the prolific Masila Basin which are operated by DNO ASA (an independent Norwegian oil company). The Masila basin was originally discovered and developed by Nexen (formerly Canadian Occidental) and has ultimate reserves in excess of 1 billion barrels of oil discovered to date. Current producers in the Masila basin are Nexen, Total, DNO, Dove and Calvalley.

In Western Yemen, the Company has interests in two Blocks located in the prolific Marib Basin which are operated by Occidental Petroleum ("OXY"). The Marib basin was originally discovered and developed by Hunt Oil and has ultimate reserves in excess of 900 million barrels of oil and 16 trillion cubic feet of natural gas discovered to date. Current producers in the Marib basin are Safer, Hunt, OXY and OMV.

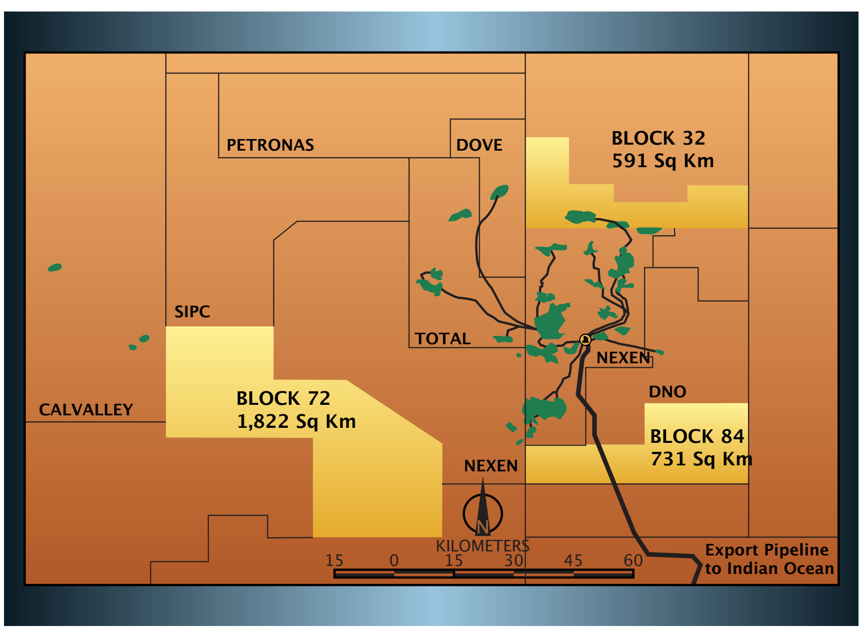
The following table summarizes the Company's current international land holdings:

International (Yemen and Egypt)
Summary of Production Sharing Agreements ("PSA")

Country		**Yemen (East)**		**Yemen (West)**		**Egypt**
Block	32	72	84	S-1	75	Nuqra #1
Basin	Masila	Masila	Masila	Marib	Marib	Nuqra
Year acquired	1997	2004/2005	2006/2007*	1998	2007*	2004
Status	Development	Exploration	Exploration	Development	Exploration	Exploration
Operator	DNO	DNO	DNO	OXY	OXY	TransGlobe
TransGlobe WI (%)	13.81087%	33%	33%	25%	25%	50%**
Block Area (Km^2)	519	1,822	731	1,152	1,050	22,500
Block Area (acres)	146,070	450,234	183,000	284,700	262,500	5,500,000
Expiry date	Nov. 2020	Jan. 2008	N/A*	Oct. 2023	N/A*	July 2009
Extensions:						
Exploration	N/A	2nd Phase 36 months	1st Phase 42 months 2nd Phase 30 months	N/A	1st Phase 36 months 2nd Phase 36 months	2nd Extension 36 months
Development	5 yr	20 yr + 5 yr	20 yr + 5 yr	5 yr	20 yr + 5 yr	20 yr + 5 yr

** PSA's awaiting final government approval and ratification. First exploration term commences on the ratification date.*
*** TransGlobe pays 60% of costs to first oil production. TransGlobe recovers carried costs from partner's share of production.*

YEMEN EAST– Masila Basin



■ OIL FIELD — OIL PIPELINE

BLOCK 32, Republic of Yemen

Highlights

- Two new pools discovered (Godah #1 and Tasour #23ST).
- Successful appraisal drilling (Tasour #21, #22ST, Godah #2, #3, and #4).
- Godah field on production Q4.
- Acquired 275 km^2 of 3-D Seismic (Godah/East and Tasour NW).

2006 Activities and Results

During 2006, the Block 32 joint venture group drilled eight wells (two exploration, three appraisal and three development) resulting in: two new discoveries at Godah #1 and Tasour #23ST; preliminary appraisal of the Godah field (Godah #2, #3 and #4) and increased reserves and production performance at Tasour (#21, #22 and #24).

The Qishn sandstone Godah pool was discovered in February 2006. Subsequently, the focus in 2006 was the appraisal and development of the Godah pool. After Godah #1 three appraisal wells were drilled resulting in two oil producers (Godah #2 and #3) and one water injection well (Godah #4). This defined the gas/oil and oil/water contacts of the Godah pool which facilitates reserve definition.

A new 275 km^2 3-D seismic program was acquired over the Godah field, the eastern portion of Block 32 and the area northwest of Tasour. The new 3-D seismic will be utilized to select the planned 2007 appraisal and development drilling locations on the Godah structure.

The Tasour #23ST exploration well was drilled to a total depth of 3,139 meters and suspended as a potential upper Naifa oil well. Approximately 200 barrels of 27 API oil and 457 barrels of drilling fluids were recovered from a 10.5 meter perforated interval in the upper Naifa carbonate. The production test was terminated early due to mechanical issues. Well stimulation and horizontal drilling have led to the successful exploitation of the upper Naifa carbonates on other adjacent blocks in Yemen. Therefore the initial result on Tasour #23ST is very encouraging. To evaluate the new discovery the Operator is preparing to stimulate the zone with acid, and place the well on a long term production test. It is expected that the production test will commence during the second quarter of 2007, with oil trucked to the Tasour facility for treatment and export. With successful development wells at Tasour #21 and #22ST, the mature Tasour field has continued to exceed our expectations for both production and reserves. However, Tasour is a mature field and we expect the field production to decline.

2006 Drilling Results

Well	Well Type	Status	Initial Production Test (Bopd - gross)	Formation
Tasour #21	Development	Oil producer	785	Qishn S-1A
Tasour #22ST	Development	Oil producer	6,440	Qishn S-1A
Tasour #23ST	Exploration	Shut in Oil	200 bbls	Naifa
Tasour #24	Development	Water Injector	-	Qishn S-1A
Godah #1	Exploration	Shut in Oil	1,839	Qishn S-1A
Godah #2	Appraisal	Oil producer	1,160	Qishn S-1A
Godah #3	Appraisal	Oil producer	1,511	Qishn S-1A
Godah #4	Appraisal	Cased, Water Injector	-	Qishn S-1A

Production

Block 32 production averaged 10,345 Bopd (1,429 Bopd to TransGlobe) during 2006, which exceeded our original 2006 guidance of approximately 8,000 Bopd (1,100 Bopd to TransGlobe) by 29%. The successful development drilling program (Tasour #21 and #22ST) and continued excellent reservoir performance were the primary reasons for the 2006 production results. The Tasour field accounted for 97% of the 2006 average production from Block 32. Facility expansion at the Tasour Central Production Facility ("CPF") was ongoing and finalized in early 2007 increasing capacity from 120,000 to 200,000 barrels of fluid per day.

A new, initial production facility was constructed at Godah during 2006. Godah #2 and #3 were placed on production (October 27 and November 5, respectively). Godah contributed an average 1,219 Bopd (168 Bopd to TransGlobe) during the fourth quarter of 2006, or 307 Bopd (42 Bopd to TransGlobe) on an annualized basis. Together, the Godah #2 and #3 wells produced approximately 1,500 barrels of oil per day (207 Bopd to TransGlobe) in January/February 2007.

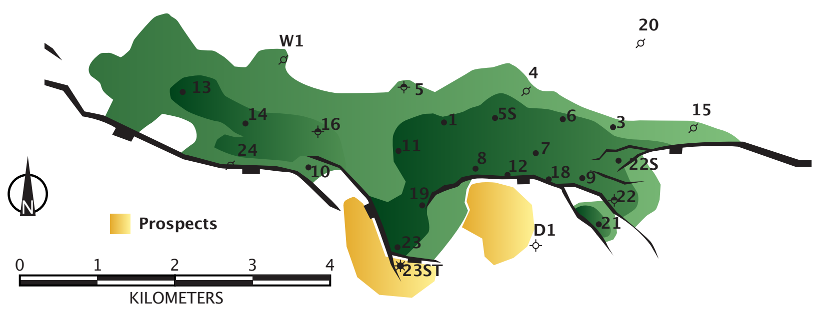
The initial Godah production facility is pipeline connected to the Block 32 oil sales export line which passes through the Godah Field. Produced water was initially trucked to the Tasour CPF for treatment and disposal. A 23 km pipeline connecting the Godah production facility to the Tasour CPF was completed in December 2006. The new pipeline became operational in January 2007 and Godah production is now processed at the Tasour CPF. Trucking of produced water has been discontinued. It is expected that the Godah field will be fully developed over the next two years.

2006 Production by Quarter (Bopd)

	Q-1	Q-2	Q-3	Q-4
Gross field production rate	9,427	8,522	10,673	12,718
TransGlobe working interest	1,302	1,177	1,474	1,756
TransGlobe net (after royalties and other)	982	675	766	973
TransGlobe net (after royalties, other and tax)	874	508	532	708

Under the terms of the Block 32 PSA, royalties and taxes are paid out of the government's share of production sharing oil.

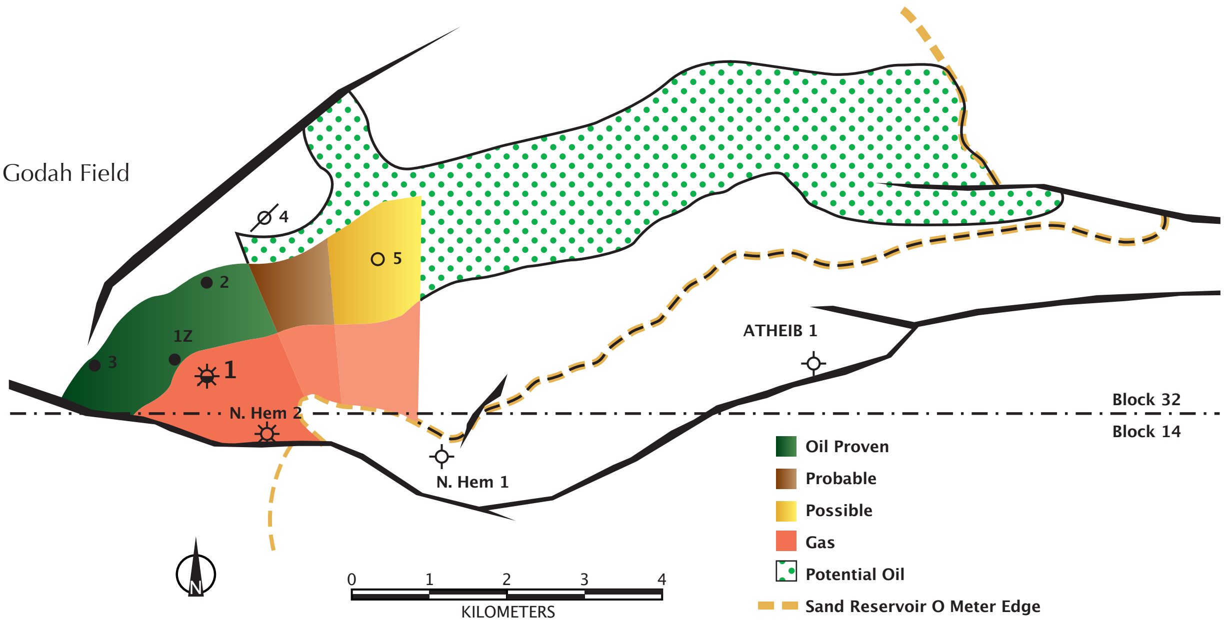
Tasour Field



2007 Outlook

The Block 32 joint venture group has approved an aggressive capital budget for 2007, which includes appraisal/ development drilling at Godah (four to six wells), extended production testing at Tasour #23ST, new exploration drilling (two wells) and production facilities expansion for processing the increasing Godah production.

The Godah field could extend a significant distance to the east as indicated on the map below. The extension is dependant upon sand deposition. The next well, Godah #5, is planned to begin testing the eastern extension of the Godah pool. Godah #5 is located approximately two kilometers east of the Godah #2 oil well. If successful, it is expected that an additional appraisal well approximately one kilometer east of Godah #5 will be drilled, and the step-out process repeated until the eastern limit of the field has been defined. There are three to four development locations currently defined in the Godah pool. Each successful appraisal/step-out well (e.g. Godah #5) will set up two to three follow-up development locations. The approved 2007 budget has four to six wells allocated to the Godah appraisal/development program. It is anticipated that the Godah #5 appraisal well will commence drilling by late March/early April 2007.



BLOCK 72, REPUBLIC OF YEMEN

Highlights

- Processed and mapped 255 km of new 2-D seismic (acquired December 2005).
- Drilled the first exploration well, Nasim #1 in Q-1 2007 (D&A).

2006 Activities and Results

The 255 km new 2-D seismic and approximately 500 km of reprocessed, older 2-D seismic was interpreted and mapped resulting in several prospects and leads on the north-western side of the Block.

2007 Outlook

The first exploration well, Nasim #1, was drilled to a depth of 2,305 meters and subsequently plugged and abandoned in the first quarter of 2007. The Nasim #1 well tested Qishn and Naifa prospects defined by 2-D seismic. Nasim #1 was the first of a two-well commitment in the first exploration period on Block 72. A 250 km^2 3-D seismic program is planned for the fourth quarter of 2007 to reduce exploration risk on future exploration wells. A second commitment well is scheduled to commence during the fourth quarter of 2007 or early 2008.

BLOCK 84, REPUBLIC OF YEMEN

Highlights

- Awarded Block 84 in the Third International Bid Round.

2006 Activities and Results

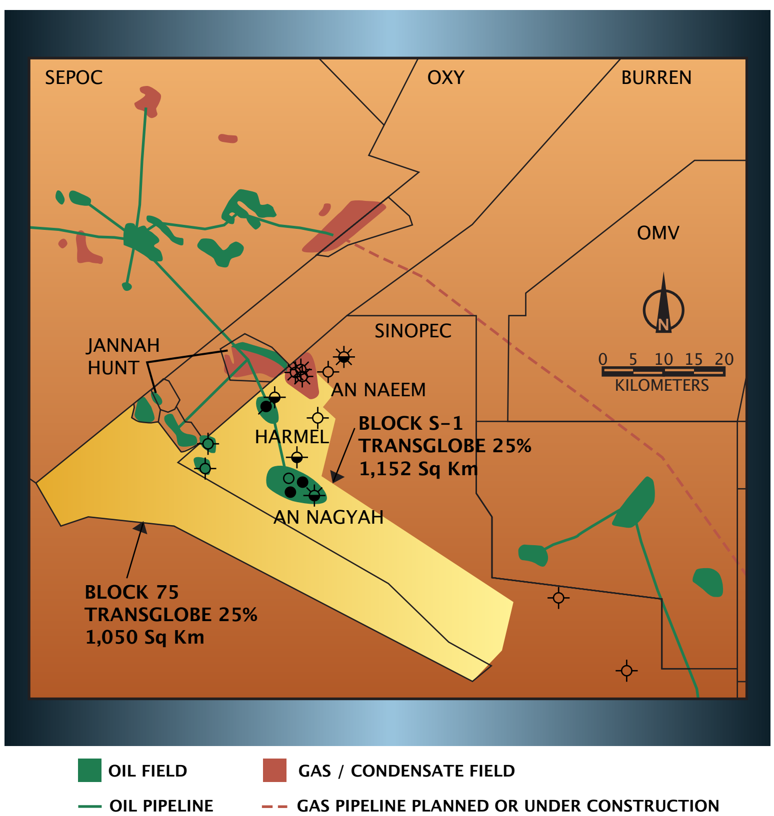
During the fourth quarter of 2006, the Ministry of Oil and Minerals ("MOM") selected the joint venture group comprised of DNO ASA (operator at 34%), TG Holdings Yemen Inc. (33%) and Ansan Wikfs (Hadramaut) Limited (33%) as the successful bidder for Block 84 in the Third International Bid Round for Exploration and Production of Hydrocarbons. TG Holdings Yemen Inc is a wholly owned subsidiary of TransGlobe Energy Corporation. The award is subject to government approval and ratification of a PSA.

Block 84 encompasses 731 km^2 (approximately 183,000 acres) and is located in the Masila Basin adjacent to the Canadian Nexen Masila Block where more than one billion barrels of oil have been discovered. The Block 84 joint venture group plans to carry out a 3-D seismic acquisition program and the drilling of four exploration wells during the first exploration period of 42 months.

2007 Outlook

A 300 km^2 3-D seismic program is planned for late 2007/early 2008 with exploration drilling to commence in late 2008. The timing of the 3-D seismic acquisition program is contingent upon receiving final approval and ratification of the Block 84 PSA.

YEMEN WEST– Marib Basin



BLOCK S-1, REPUBLIC OF YEMEN

Highlights

- New operator, January 2006 (Occidental acquired Vintage).
- Two new discoveries (Osaylan and Wadi Bayhan).
- Horizontal development drilling at An Nagyah.
- Increased reserves at An Nagyah due to drilling and performance
- New reserves at Osaylan and a portion of An Naeem.

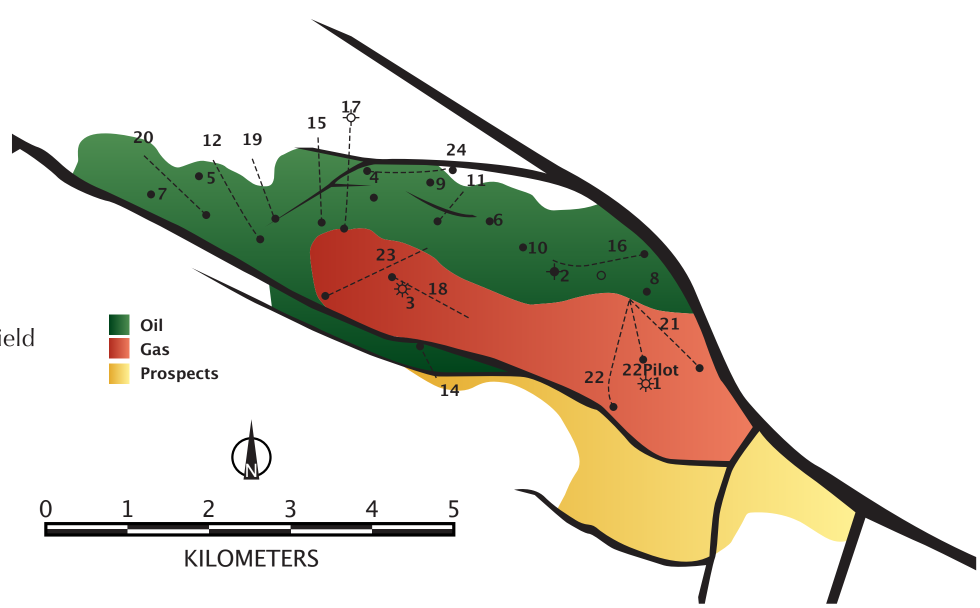
2006 Activities and Results

During 2006, the Block S-1 joint venture group drilled 7 wells (3 exploration, 2 appraisal and 2 development) resulting in: two new discoveries (Osaylan #2 and Wadi Bayhan #2), two oil wells (An Nagyah #19 and #20), one water injection well (An Nagyah #22), one suspended well (An Nagyah #21) and one dry hole (Al Qurain). A 610 square kilometer 3-D seismic program was designed and approved by the joint venture group in early 2006. Field work was scheduled to commence in the third quarter with planned completion date of mid 2007. The program was subsequently suspended and the seismic contractor was released due to a local labor dispute. The seismic acquisition is now planned to recommence in association with a 3-D seismic acquisition program on Block 75.

2006 Drilling Results

Well	Well Type	Status	Initial Production Test (Bopd - gross)	Formation
An Nagyah #19	Hz Development	Oil producer	3,226	Lam A
An Nagyah #20	Hz Development	Oil producer	2,992	Lam A
An Nagyah #21	Hz Appraisal	Suspended	-	Lam B
An Nagyah #22	Hz Appraisal	Water Injector	-	Lam B
Wadi Bayhan #2	Exploration	Shut in Gaswell	3.5 Mmcfd	Lam A
Osaylan #2	Exploration	Oil producer	1,307	Alif/Lam A
Al Qurain #1	Exploration	D & A	-	Alif/Lam

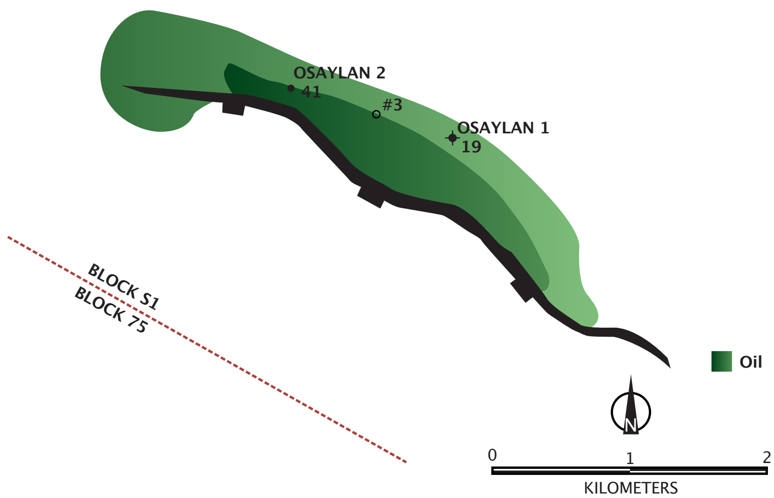
An Nagyah Field



Production

Production from Block S-1 averaged 10,369 Bopd (2,592 Bopd to TransGlobe) during 2006, representing the first full year of production with the 10 inch sales pipeline operational. Production was increased to approximately 12,000 Bopd in the second quarter with the addition of new producers (An Nagyah #19 and #20) and facility modifications. In mid 2006 the An Nagyah field production was choked back to the 10,000 Bopd level in response to an increase in water production in several horizontal wells located in the western portion of the field. This increase in water production has been attributed in part to localized pressure draw-down in the western portion of the field. The choked back wells have responded favorably, with water cut stabilizing. To improve production rates and field recoveries the joint venture group has approved a project to utilize natural gas from the An Naeem pool to maintain reservoir pressure and enhance recovery in the An Nagyah pool. The proposed project (subject to Ministry approval), includes the extraction of stabilized condensate from both the An Naeem gas and the An Nagyah solution gas currently being injected. It is expected that condensate extracted from the injection gas will be mixed with oil production for export and sale in late 2007/early 2008.

Osaylan Field



The Osaylan #2 well was placed on production on January 23, 2007 at an initial rate of 750 to 800 Bopd utilizing a newly constructed well test facility. Production from the Osaylan #2 well is trucked to the Halewah truck terminal, which was constructed for early production from the An Nagyah field.

The operator is evaluating a cycling scheme to produce additional condensate from the An Naeem pool in conjunction with the neighboring Block 20. If the cycling project is recommended and approved, it is expected that production could commence in late 2009.

2006 Production by Quarter (Bopd)

	Q-1	Q-2	Q-3	Q-4
Gross field production rate	11,000	10,636	10,048	9,806
TransGlobe working interest	2,750	2,659	2,512	2,452
TransGlobe net (after royalties and other)	1,631	1,467	1,735	1,634
TransGlobe net (after royalties, other and tax)	1,423	1,266	1,546	1,428

Under the terms of the Block S-1 PSA, royalties and taxes are paid out of the government's share of production sharing oil.

2007 Outlook

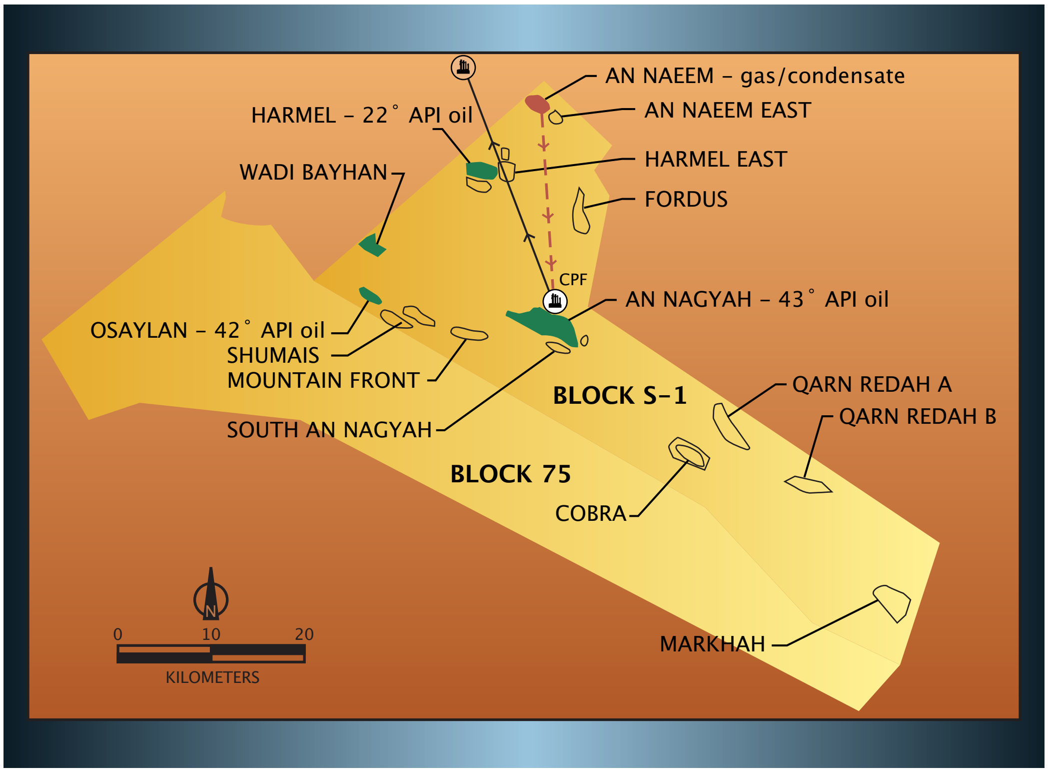
The Block S-1 joint venture group has approved a capital budget for 2007 which includes horizontal development wells (Lam A and Lam B) at An Nagyah, appraisal drilling (Osaylan), exploration drilling, 3-D seismic acquisition, facility expansions at An Nagyah and a project to connect An Naeem gas to An Nagyah for pressure maintenance and condensate production.

The An Nagyah #23 well commenced drilling on December 25, 2006 and was drilled to a total depth of 2,327 meters. An Nagyah #23 was completed as a Lam B producing oil well in January 2007, after flowing at a stabilized rate of 651 barrels of light (43 degree API) oil per day and 337 thousand cubic feet of gas per day at a flowing pressure of 220 psi on a 30/64 inch choke. The well was completed in a 916 meter horizontal section in the Lam B sandstone reservoir. The well is on production through a pipeline connected to the An Nagyah facilities.

Subsequent to An Nagyah #23, Osaylan #1, which encountered oil shows in the Lam formation (October 25, 2002 Press Release), was re-entered and tested. The test was suspended early due to low inflow rates of 42 API oil and drilling/ completion fluid. The low inflow rates were attributed to formation damage associated with the drilling of Osaylan #1 in 2002. The operator is evaluating stimulation/testing options which would be conducted using a work-over rig, during the second or third quarter of 2007.

In March 2007 a Lam A horizontal development well is drilling at An Nagyah #24.

Block S-1 Prospects



CPF – Central Production Facility — Oil Pipeline – – Gas pipeline under construction

BLOCK 75, REPUBLIC OF YEMEN

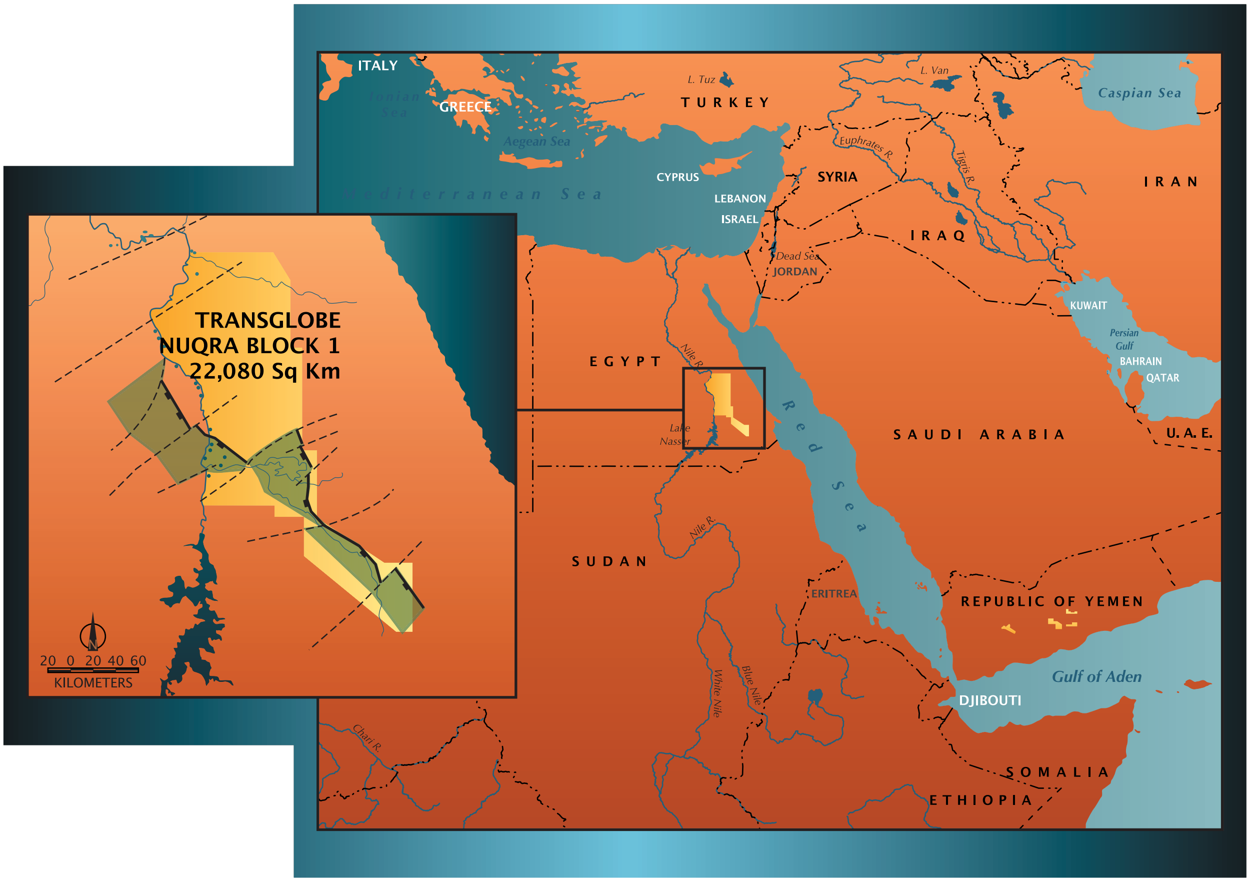
2007 Outlook

Subsequent to year end, TG Holdings Yemen Inc., a wholly owned subsidiary of TransGlobe Energy Corporation, agreed to participate at a 25% working interest with OXY in Block 75. OXY is the operator of Block 75 with a 75% working interest. Block 75 was awarded to OXY in the Second International Bid Round for Exploration and Production of Hydrocarbons. The PSA was initialled on January 28, 2007 and is now in the process of final government approval and ratification by parliament.

Block 75 encompasses 1,050 km^2 (approximately 262,500 acres) and is located in the Marib Basin adjacent to Block S-1 where OXY and TransGlobe are engaged in exploration and production operations. The Block 75 joint venture group plans to carry out a 3-D seismic acquisition program and the drilling of one exploration well during the First Exploration Period of 36 months.

A 3-D seismic acquisition program is planned for late 2007 (in conjunction with a 3-D seismic program on Block S-1) with drilling to commence in 2008. The timing of the 3-D seismic acquisition program is contingent upon receiving final approval and ratification of the Block 75 PSA.

ARAB REPUBLIC OF EGYPT



NUQRA BLOCK 1

Highlights

- Acquired 834 km of new 2-D seismic.
- Processed, interpreted and mapped prospects.
- Entered first three year extension to the exploration period, July 18 2006.
- Selected and approved three well exploration program (two firm, one contingent).
- Designed drilling programs, ordered long lead items (casing, wellheads).
- Established Aswan office and constructed logistics/operations base in Upper Egypt.
- Fulfilled the $6.0 million farm-in commitment, Q3-2006.

2006 Activities

The Company moved the Nuqra project ahead to the drilling stage during 2006 by completing seismic, identifying locations and carrying out extensive drilling preparation work. A three well exploration program consisting of two firm wells (Set #1 and Narmer #1) and one contingent well (West Narmer #1) was approved by the joint venture partners and the Government.

The Company acquired 834 km of new 2-D seismic during the first quarter of 2006 to infill and supplement the 3,400 kilometers of reprocessed older 2-D seismic data. The seismic data was processed, interpreted and mapped during the second quarter resulting in a number of prospects and leads, primarily in the Nuqra sub basin of the Block.

The Company elected to proceed with the first three year extension to the exploration period, effective July 18, 2006. The extension requires a mandatory relinquishment of 25% of the Block and completion of a two well drilling program, with a minimum expenditure of $4.0 million over a period of three years. The area relinquished was considered non-prospective by the Company. The total area of the Nuqra Block 1 concession is approximately 5.5 million acres following the relinquishment. TransGlobe fulfilled the original $6 million farm-in commitment in 2006 and will pay 60% of future program expenditures until first production.

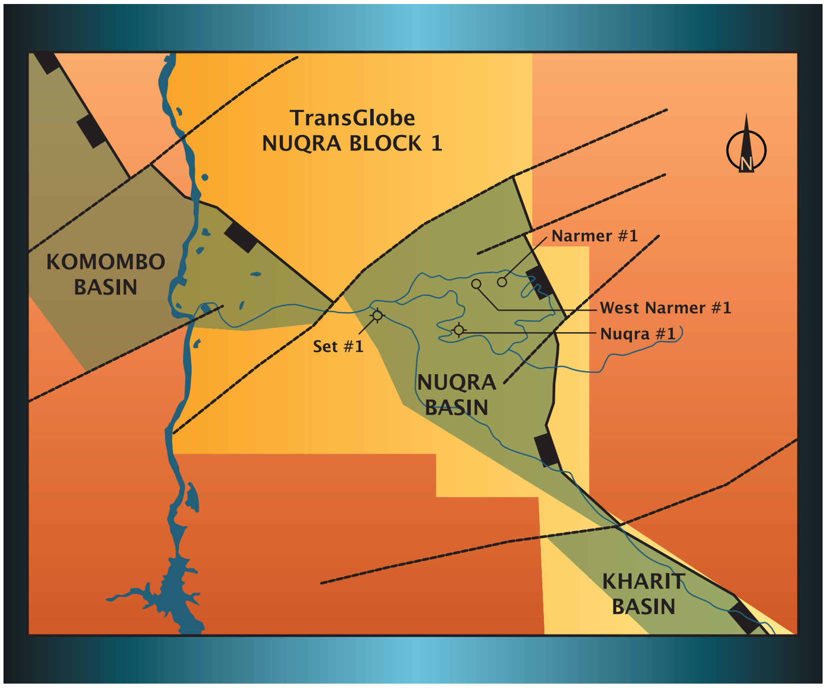
An operations team was assembled in Cairo in early 2006 to prepare for the upcoming drilling program. A regional office in Aswan was opened mid year and a logistics/operations base on the Block was constructed in the third quarter of 2006. The required services and contracts were finalized and approved and the long lead items such as casing and wellheads were imported and transported to the logistics base.

2007 Outlook

In early February the ECDC rig #2 was trucked approximately 1,100 kilometers from the Nile delta to the Set #1 location in Upper Egypt. Drilling commenced February 18, 2007 on the first exploration well Set #1, targeting a 30 million barrel gross unrisked prospect. The Set #1 well was drilled to a total depth of 1,372 meters and was plugged and abandoned after failing to encounter any hydrocarbons. Set #1 was the first exploration well drilled in Upper Egypt, since 1995.

Following Set #1 the drilling rig was moved during March 2007 to the second exploration commitment well at Narmer #1, located approximately 30 kilometers east of Set #1. The Narmer #1 well is targeting an unrisked gross10 million barrel Jurassic prospect at approximately 2,400 meters. Contingent upon the results of Narmer #1, a third well at West Narmer #1 is planned.

The two well exploration program will fulfill the work commitments of the first three-year exploration extension period approved July 18, 2006. Upon expiry of the first three-year extension on July 17, 2009 there is an option to proceed with a second three-year extension and work program. The second exploration extension requires a mandatory relinquishment of 25% of the original Block and completion of a two-well drilling program. Exploitation of any discovered commercial fields will continue under a development lease for a further 20 years.



SUMMARY OF INTERNATIONAL PSA TERMS

All of the Company's international Blocks are production sharing contracts between the host government and the Contractor (Joint venture partners). The government and the Contractors take their share of production based on the terms and conditions of the respective contracts. The Contractors' share of all taxes and royalties are paid out of the Governments' share of production.

The PSA's provide for the Government to receive a percentage gross royalty on the gross production. The remaining oil production, after deducting the gross royalty, is split between cost sharing oil and production sharing oil. Cost sharing oil is up to a maximum percentage as defined in the specific PSA. Cost Oil is assigned to recover approved operating and capital costs spent on the specific project. Each PSA is ring fenced for cost recovery and production sharing purposes. The remaining production sharing oil (total production, less gross royalty, less cost oil) is shared between the Government and the Contractor as defined in the specific PSA's.

The following tables summarizes the Company's international PSA terms for the first 25,000 Bopd for each Block. All the PSA's have different terms for production levels above 25,000 Bopd, which are unique to each PSA. The Government's share of production increases and the Contractor's share of production decreases as the production volumes go to the next production tranche (25,000 to 50,000 Bopd; 50,000 Bopd to 100,000 Bopd; 100,000 +Bopd).

PSA Terms - Yemen and Egypt (Oil Production: 0 to 25,000 Bopd)

Country		**Yemen (East)**		**Yemen (West)**		**Egypt**
Block	32* (original)	72	84	S-1	75	Nuqra #1
First Production Tranche	0-25,000 Bopd	0-25,000 Bopd	0-25,000 Bopd	0-12,500 Bopd/ (12,500-25,000)**	0-25,000 Bopd	0-25,000 Bopd
Gross Royalty %	3%/(10%)	3%	6.50%	3%/(4%)	3%	10%
Max. Cost Oil %	60%/(25%)	50%	35%	50%	50%	40%
Depreciation per Quarter						
Operating	100%	100%	100%	100%	100%	100%
Capital	12.5%	12.5%	8.333%	12.5%	12.5%	6.25%
Production Sharing Oil:						
Contractor	33.25%/(23%)	32.40%	23.98%	28.875%/(24.75%)	34.20%	30.00%
MOM	65%/(77%)	64.00%	71.00%	65%/(70%)	64.00%	70.00%
Yemen Oil Co.	1.75%/(0%)	3.60%	5.08%	6.125%/(5.25%)	1.80%	-

** Block 32 terms will revert to original PSA terms if production exceeds 25,000 Bopd or Proved reserves exceed 30 million barrels. Reserves are audited every two years by an independent evaluator. At November 2006, Proved reserves were less than 5 million barrels. The next reserve audit is November 2008.*
*** Block S-1 terms for second tranche of production from 12,500 to 25,000 Bopd.*

CANADA

Highlights

- 2006 production averaged 1,072 Boepd, up 24% from 2005.
- Drilled 26 wells (20.8 net) during 2006 - 19 gas, 5 oil and 2 dry.
- Pipeline connected 20 wells - 15 gas and 5 oil.
- Installed compression/dehydration facilities at Nevis and Twining.
- Acquired 16,100 net acres.

2006 Activities and Results

In western Canada, the first half of 2006 was a very challenging operating environment for the Company due to increased demand for services, equipment and personnel. In addition to the significant pressure on the cost structure, it was a very challenging year to gain access to third party operated facilities, pipelines, compressors and gas plants due to overall pressure on the industry. By mid year, larger companies reduced their natural gas/CBM projects in response to lower natural prices and high gas storage numbers in North America. The Company completed its 2006 drilling program in the fourth quarter at a much improved cost structure. Considerable gains have been made in the past three months to tie-in production which was stranded for up to two years waiting on third party approvals for transportation and processing.

During 2006, the Company drilled 26 wells (20.8 net wells) resulting in 19 gas, 5 oil and 2 dry. Approximately 53% of the 2006 program (14 wells) targeted proved undeveloped reserves which had been assigned to the Wabamun formation in Nevis (2 oil and 1 gas) and the Horseshoe Canyon Coal Bed formation in Nevis (10 gas wells) and Morningside (one gas well).

The majority of the Company's acreage is located in central Alberta, which is the focus of extensive Horseshoe Canyon CBM development and, more recently, the focus of Mannville CBM development utilizing horizontal wells. TransGlobe commissioned an independent third party evaluation of the Company's CBM properties to evaluate the resource potential of the undeveloped Horseshoe Canyon CBM and the emerging Mannville CBM play. The findings of the report are summarized in the Contingent Resources section.

The Company acquired 16,100 net acres of exploration land in 2006, bringing the Company's total net undeveloped land to 46,100 acres at year end.

2006 Drilling Results

	Oil		Gas		Dry		Total	
Area	Gross	(Net)	Gross	(Net)	Gross	(Net)	Gross	(Net)
Nevis	3	2.3	13*	11.8	1	1.0	17	15.1
Morningside	1	1.0	2**	1.2	-	-	3	2.2
Thorsby	1	0.5	1	0.5	1	0.5	3	1.5
Other	-	-	3	2.0	-	-	3	2.0
Total	5	3.8	19	15.5	2	1.5	26	20.8

** Includes 10 (9.1 net) CBM wells*
*** Includes 1 (0.4 net) CBM wells*

2006 Wells	Q-1	Q-2	Q-3	Q-4	Total
Total drilled	7	9	-	10	26
Successfully drilled	6	8	-	10	24
Pipeline connected (including 2005 wells)	2	1	3	14	20

Production

Canadian production increased 24% to 1,072 Boepd (69% natural gas) in 2006 from an average of 867 Boepd in 2005. Production averaged 1,267 Boepd during the fourth quarter of 2006, with an average December rate of 1,414 Boepd. Approximately 450 Boepd of Nevis gas production was shut-in from mid September to mid October in response to very low spot gas prices, which strengthened in late October. Canadian production reached approximately 1,600 Boepd during the final week of December with the addition of the Nevis CBM gas wells.

During January and February 2007 production averaged 1,300 Boepd. Production was lower due to production restrictions on the new CBM wells and the loss of approximately 160 Boepd from a new gas producer in Morningside, which watered out. The Nevis CBM wells were selectively shut-in during January/February to conduct mandatory pressure segregation build up tests, which were completed. It is expected that the Nevis CBM program will contribute an additional 300+ Boepd when additional compression is installed and facility de-bottlenecking is completed in the second quarter of 2007.

2006 Canadian Production by Quarter (Boepd)

	Q-1	Q-2	Q-3	Q-4
TransGlobe working interest	975	1,079	966	1,267
TransGlobe net (after royalties)	798	910	808	1,016

2007 Outlook

During 2007 the Company will focus its Canadian efforts towards higher impact opportunities and towards optimizing our production. In addition to the Nevis area facility work which will add 300 Boepd in the 2nd Quarter, there are also plans to tie in another 10 to 15 existing wells over the balance of the year. In 2007 the Company has drilled 3 wells to date, resulting in gas wells at Nevis, Morningside and Thorsby (CBM).

TransGlobe recently released the best estimate of contingent resources for CBM underlying the Company's Canadian lands. Central Alberta is the focus area for CBM development where several thousand wells have been drilled by other operators for Horseshoe Canyon gas. The Horseshoe Canyon formation coals are unique in that they frequently produce dry gas immediately and do not require dewatering. TransGlobe has drilled 20 Horseshoe Canyon gas wells in the Nevis and Morningside areas and recently completed another gas well in the Thorsby area. This is a proven resource play.

The Mannville coals are a recent development for CBM development. Some operators are drilling long reach horizontal wells in the Nevis area which appear to be producing dry gas. TransGlobe is monitoring this developing play closely. The Company has a large contingent resource underlying its lands in the Mannville coals. In 2007 the Company is working on a plan to drill one horizontal Mannville coal well to test this play.

This year the Canadian budget has been scaled back somewhat to accommodate the increased spending overseas. The Canadian budget of approximately $15 million is weighted 65% to development projects. The Company plans to drill 10 to 12 wells in Canada during 2007.

CONSOLIDATED PRODUCTION

The following table is a summary of working interest production, **before royalty**, by country, for the years ended 2006 and 2005:

	2006			2005		
	Oil & Liquids Bopd	**Gas Mcfpd**	**Total Boepd**	Oil & Liquids Bopd	Gas Mcfpd	Total Boepd
Yemen	**4,021**	**-**	**4,021**	4,124	-	4,124
Canada	**331**	**4,449**	**1,072**	220	3,880	867
Total	**4,352**	**4,449**	**5,093**	4,344	3,880	4,991

RESERVES AND ESTIMATED FUTURE NET REVENUES

In 2005 and 2006, DeGolyer and MacNaughton Canada Limited ("DeGolyer") of Calgary, Alberta, independent petroleum engineering consultants based in Calgary and part of the DeGolyer and MacNaughton Worldwide Petroleum Consulting group headquartered in Dallas, Texas, were retained by the Company's Reserve Committee, to independently evaluate 100% of TransGlobe's reserves as at December 31, 2005 and December 31, 2006.

Total Proved reserves for the Company increased 19% from 7,828 MBoe ("MBoe" thousand barrels of oil equivalent at 6:1) at December 31, 2005 to 9,340 MBoe at December 31, 2006 replacing 181% of the 1,859 MBoe produced during 2006. The major increases in proved reserves were primarily attributable to the An Nagyah field (Block S-1) and new discoveries at Osaylan (Block S-1), Godah (Block 32) in Yemen, and drilling in Canada. The An Nagyah increases were primarily associated with the performance of the Lam oil pool and recovery of condensate from An Nagyah solution gas. The proved reserves assigned at the Osaylan and Godah discoveries were limited to the existing well bores. It is expected that both discoveries will be delineated during 2007 and 2008 which should result in recognition of additional reserves. In Canada, new reserve additions associated with the 2006 drilling program at Nevis and Morningside were offset by production and by downward revisions. The majority of the 2006 Canadian drilling program (14 of 26 wells) was focused on the conversion of Proved undeveloped to Proved developed.

Total Proved plus Probable reserves for the Company increased by 11% from 10,482 MBoe at December 31, 2005 to 11,651 MBoe at December 31, 2006 replacing 163% of 2006 production. Increases in Proved plus Probable reserves in Yemen were primarily associated with the An Nagyah pool and new discoveries at Osaylan and Godah. Canadian Proved plus Probable reserves remained unchanged, as increases were offset by production and by downward revisions.

The Company's Reserves Committee, comprised of independent directors, has reviewed and recommended acceptance of the 2006 year end reserve evaluations prepared by DeGolyer.

The 2005 and 2006 year end reserves were prepared by the Company's independent reserve evaluators in accordance with the Canadian National Instrument (NI) 51-101 policy introduced in 2003.

Disclosure provided herein in respect of Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The recovery and reserve estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than, or less than, the estimates provided herein. Note that columns may not add due to rounding.

All reserves (gross and net) presented are based on Forecast Pricing.

Reserves

	2006								2005	
	Light & Medium Crude Oil		**Natural Gas**		**Natural Gas Liquids**		**Total 2006 Boe**		Total 2005 Boe	
Company By Category	**Gross* (MBbls)**	**Net** (MBbls)**	**Gross* (MMcf)**	**Net** (MMcf)**	**Gross* (MBbls)**	**Net** (MBbls)**	**Gross* (Mboe)**	**Net** (Mboe)**	Gross* (Mboe)	Net** (Mboe)
Proved										
Producing	**4,699**	**2,697**	**6,493**	**5,249**	**176**	**128**	**5,957**	**3,699**	4,283	2,758
Non-producing	**454**	**251**	**3,288**	**2,737**	**49**	**33**	**1,051**	**740**	1,326	879
Undeveloped	**2,293**	**1,289**	**224**	**190**	**2**	**1**	**2,332**	**1,322**	2,219	1,316
Total Proved	**7,445**	**4,238**	**10,005**	**8,176**	**227**	**161**	**9,340**	**5,762**	7,828	4,953
Proved plus Probable	**8,552**	**4,876**	**16,095**	**13,029**	**416**	**291**	**11,651**	**7,339**	10,482	6,608

** Gross reserves are the Company's working interest share before the deduction of royalties.*
*** Net reserves are the Company's working interest share after the deduction of royalties. Net reserves in Yemen include our share of future cost recovery and production sharing oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, a portion of the reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices.*

Reserves

	2006						2005	
	Oil & Liquids		**Gas**		**Total Boe**		Total Boe	
Company By Area	**Gross (MBbls)**	**Net (MBbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mboe)**	**Net (Mboe)**	Gross (Mboe)	Net (Mboe)
Proved								
Yemen	**7,048**	**3,887**	**-**	**-**	**7,048**	**3,887**	5,342	2,927
Canada	**624**	**512**	**10,005**	**8,176**	**2,292**	**1,874**	2,486	2,026
Total Proved	**7,673**	**4,399**	**10,005**	**8,176**	**9,340**	**5,762**	7,828	4,953
Proved plus Probable								
Yemen	**7,999**	**4,387**	**-**	**-**	**7,999**	**4,387**	6,814	3,636
Canada	**970**	**781**	**16,095**	**13,029**	**3,652**	**2,952**	3,668	2,972
Total Proved plus Probable	**8,969**	**5,168**	**16,095**	**13,029**	**11,651**	**7,339**	10,482	6,608

Proved Reserves Reconciliation

	Yemen Oil	**Canada Oil & Liquids**	**Canada Natural Gas**	**Total Boe**
	Gross (MBbls)	**Gross (MBbls)**	**Gross (MMcf)**	**Gross (Mboe)**
Reserves at December 31, 2005	5,342	621	11,189	7,828
Extensions/Discoveries	1,243	239	4,215	2,184
Technical revisions	2,424	(92)	(3,152)	1,807
Acquisitions	-	-	78	13
Divestitures	-	-	-	-
Economic factors	(493)	(23)	(701)	(633)
Production	(1,468)	(121)	(1,624)	(1,859)
Reserves at December 31, 2006	**7,048**	**624**	**10,005**	**9,340**

Proved Plus Probable Reserves Reconciliation

	Yemen Oil	Canada Oil & Liquids	Canada Natural Gas	Total Boe
	Gross (MBbls)	**Gross (MBbls)**	**Gross (MMcf)**	**Gross (Mboe)**
Reserves at December 31, 2005	6,814	839	16,975	10,482
Extensions/Discoveries	1,659	335	5,917	2,980
Technical revisions	1,554	(62)	(4,689)	710
Acquisitions	-	-	129	22
Divestitures	-	-	-	-
Economic factors	(560)	(21)	(613)	(683)
Production	(1,468)	(121)	(1,624)	(1,859)
Reserves at December 31, 2006	**7,999**	**970**	**16,095**	**11,651**

Estimated Future Net Revenues

All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Company's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.

The estimated future net revenues presented below are calculated using the average price received December 31 of the respective reporting periods. The prices were held constant for the life of the reserves.

Present Value of Future Net Revenues, Before Income Tax*
Constant Pricing

	December 31, 2006 Discounted at					December 31, 2005 Discounted at				
($MM)	**Undis-counted**	**5%**	**10%**	**15%**	**20%**	Undis-counted	5%	10%	15%	20%
Proved										
Yemen *	**94.3**	**80.4**	**69.8**	**61.5**	**54.9**	78.5	71.0	64.6	59.0	54.1
Canada **	**48.8**	**42.3**	**37.2**	**33.1**	**29.7**	69.9	59.6	51.6	45.2	40.0
Total Proved	**143.1**	**122.7**	**107.0**	**94.6**	**84.6**	148.4	130.6	116.1	104.2	94.0
Proved plus Probable										
Yemen *	**105.5**	**89.1**	**76.7**	**67.1**	**59.5**	108.0	96.0	86.0	77.5	70.2
Canada **	**76.3**	**62.6**	**52.7**	**45.3**	**39.5**	106.2	87.5	73.7	63.1	54.8
Total Proved plus Probable	**181.8**	**151.7**	**129.4**	**112.4**	**99.0**	214.1	183.5	159.7	140.6	125.0

** Yemen future net revenues presented are after Yemen income tax.*
*** Canadian values converted at the December 31, 2006 and December 31, 2005 exchange rates of 1.1654 and 1.1630 $US/$C respectively.*

The estimated future net revenues presented below are calculated using the independent engineering evaluator's price forecast.

Present Value of Future Net Revenues, Before Income Tax*
Independent Evaluator's Price Forecast

	December 31, 2006 Discounted at					December 31, 2005 Discounted at				
($MM)	**Undis-counted**	**5%**	**10%**	**15%**	**20%**	Undis-counted	5%	10%	15%	20%
Proved										
Yemen *	**94.2**	**81.1**	**71.0**	**63.0**	**56.5**	75.6	68.7	62.8	57.6	53.0
Canada **	**63.6**	**55.3**	**48.7**	**43.4**	**39.0**	70.4	61.3	54.1	48.2	43.4
Total Proved	**157.8**	**136.4**	**119.7**	**106.3**	**95.5**	146.0	130.0	116.8	105.8	96.4
Proved plus Probable										
Yemen *	**106.5**	**90.6**	**78.5**	**69.1**	**61.5**	96.6	86.6	78.1	70.8	64.6
Canada **	**100.8**	**82.5**	**69.5**	**59.8**	**52.3**	104.0	87.7	75.4	65.9	58.3
Total Proved plus Probable	**207.3**	**173.1**	**148.0**	**128.8**	**113.8**	200.6	174.3	153.5	136.7	122.9

** Yemen future net revenues presented are after Yemen income tax.*
*** Canadian values converted at the December 31, 2006 and December 31, 2005 exchange rates of 1.1654 and 1.1630 $US/$C respectively.*

The following table summarizes the **constant pricing** used to estimate future net revenues.

	December 31, 2006		December 31, 2005	
	Oil US$/Bbl	**Natural Gas US$/Mcf**	Oil US$/Bbl	Natural Gas US$/Mcf
Yemen *	**59.76**	**-**	56.42	-
Canada **	**54.26**	**5.58**	52.49	8.08

** Yemen prices are based on prices received for production from Block 32 and Block S-1.*
*** Canadian prices are based on prices received for Canadian production converted at the December 31, 2006 and December 31, 2005 exchange rates of 1.1654 and 1.1630 $US/$C respectively.*

The following table summarizes the **independent evaluator's price forecast** used to estimate future net revenues.

	WTI Oil Reference US$/Bbl		AECO Spot Gas Reference US$/Mcf	
Year	**2006**	2005	**2006***	2005*
2007	**65.00**	56.38	**6.28**	8.29
2008	**65.52**	52.53	**6.79**	7.33
2009	**64.27**	51.69	**6.62**	6.76
2010	**61.73**	52.72	**6.42**	6.12
2011	**59.07**	53.78	**6.59**	5.92
2012	**59.11**	54.86	**6.67**	6.03
Forecasted	**2%/yr**	2%/yr	**1.9% to 17 then 2%**	1.8% to 17 then 2%

** Canadian values converted at the December 31, 2006 and December 31, 2005 exchange rates of 1.1654 and 1.1630 $US/$C respectively.*

CONTINGENT RESOURCES

DeGolyer MacNaughton Canada Limited ("DeGolyer") was retained by TransGlobe to complete an independent estimate of CBM resource potential on Company owned lands in Canada, effective December 31 2006.

The contingent resources were evaluated using probabilistic analysis of certain parameters related to the **quantity of petroleum present and recoverable in discovered accumulations**. The discovered accumulations may be developed in the future depending on economic and market conditions, additional well data, or seismic information.

Working interest Share of Contingent Resources*
Potentially Recoverable from known Accumulations
Central Alberta, Canada

Formation	Low Estimate	Median Estimate	High Estimate	Best Estimate
Horseshoe Canyon				20.7 Bcf
Mannville				139.1 Bcf
Total	105.7 Bcf	154.0 Bcf	224.3 Bcf	160.8 Bcf

** The definitions of contingent resources applied are in agreement with the petroleum resources definitions approved in February 2000 by the Society of Petroleum Engineers, the World Petroleum Congresses and the American Association of Petroleum geologists. Because of the uncertainty of commerciality, the contingent resources estimated cannot be classified as reserves. The contingent resource estimates in the report are provided as a means of comparison to other contingent resources and do not provide a means of direct comparison to the reserves.*

The estimates of potentially recoverable petroleum resources in the report are expressed using the terms low estimate, median estimate, best estimate, and high estimate to reflect the range of uncertainty.

- *The "low estimate" reported is the P90 quantity derived from the probabilistic analysis. This means that there is at least a 90 percent probability that, assuming the accumulation is discovered and developed, the quantities actually recovered will equal or exceed the low estimate.*

- *The "median estimates" reported is the P50 quantity derived from the probabilistic analysis. This means that there is at least a 50 percent probability that, assuming the accumulation is discovered and developed, the quantities actually recovered will equal or exceed the low estimate.*

- *The "high estimates" reported is the P10 quantity derived from the probabilistic analysis. This means that there is at least a 10 percent probability that, assuming the accumulation is discovered and developed, the quantities actually recovered will equal or exceed the low estimate.*

- *The "best estimate" is the expected value, an outcome of the probabilistic analysis.*

The contingent resource estimated in the report, is defined as that quantity of gas estimated on a given date to be potentially recoverable from known accumulations but is not currently economic. There is no certainty that it will be economically viable or technically feasible to produce any portion of the resource.

These resources are categorized by DeGolyer as contingent resources which are defined in the COGE Handbook. This definition states that contingent resources are not currently economic or lack a market. TransGlobe believes that there is a market for these resources however, the economics of the resources have not been determined at this time.

Management's Discussion and Analysis

March 20, 2007

The following discussion and analysis is management's opinion of TransGlobe's historical financial and operating results and should be read in conjunction with the message to the shareholders, the operations review, the audited consolidated financial statements of the Company for the years ended December 31, 2006 and 2005, together with the notes related thereto. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada in the currency of the United States (except where indicated as being another currency). The effect of significant differences between Canadian and United States accounting principles is disclosed in Note 16 of the consolidated financial statements. Additional information relating to the Company, including the Company's Annual Information Form, is on SEDAR at www.sedar.com.

Forward Looking Statements

This Management's Discussion and Analysis (MD&A) may include certain statements that may be deemed to be "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. All statements in this annual report, other than statements of historical facts, that address future production, reserve potential, exploration drilling, exploitation activities and events or developments that the Company expects, are forward-looking statements. Although TransGlobe believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Factors that could cause actual results to differ materially from those in forward-looking statements include, but are not limited to, oil and gas prices, well production performance, exploitation and exploration successes, continued availability of capital and financing, and general economic, market or business conditions.

Non-GAAP Measures

This document contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than "cash flow from operation activities" as determined in accordance with Generally Accepted Accounting Principles (GAAP). Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. We consider this a key measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment. Cash flow from operations may not be comparable to similar measures used by other companies.

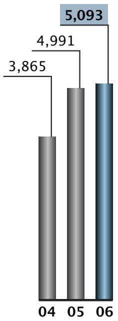
Net operating income is a non-GAAP measure that represents revenue net of royalties and operating expenses. Management believes that net operating income is a useful supplemental measure to analyse operating performance and provide an indication of the results generated by the Company's principal business activities prior to the consideration of other income and expenses. Net operating income may not be comparable to similar measures used by other companies.

Use of Boe Equivalents

The calculations of barrels of oil equivalent ("Boe") are based on a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

OVERVIEW

Production
(Boepd)

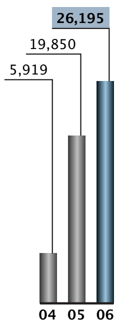


TransGlobe is an independent, public company whose activities are concentrated in three main geographic segments: Republic of Yemen, Canada and Arab Republic of Egypt. Yemen includes the Company's exploration, development and production of crude oil. Canada includes the Company's exploration, development and production of natural gas, natural gas liquids and crude oil. Egypt includes the Company's exploration for natural gas, natural gas liquids and crude oil.

Selected Annual Information

($000's, except per share, price and volume amounts and % change)	**2006**	**% Change**	2005	% Change	2004
Average production volumes (Boepd)*	**5,093**	**2**	4,991	29	3,865
Average sales volumes (Boepd)*	**5,077**	**2**	4,959	31	3,796
Average price ($/Boe)	**58.92**	**18**	49.92	40	35.63
Oil and gas sales	**109,190**	**21**	90,350	83	49,495
Oil and gas sales, net of royalties and other	**70,097**	**19**	58,911	86	31,630
Cash flow from operations**	**46,763**	**23**	38,077	120	17,325
Cash flow from operations per share					
- Basic	**0.80**		0.66		0.32
- Diluted	**0.77**		0.63		0.31
Net income	**26,195**	**32**	19,850	235	5,919
Net income per share					
- Basic	**0.45**		0.34		0.11
- Diluted	**0.43**		0.33		0.10
Total assets	**116,473**	**35**	86,286	43	60,522

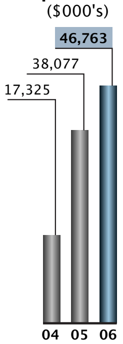
Net Income
($000's)



** The differences in production and sales volumes result from inventory changes.*
*** Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital.*

Cash flow from operations increased by 23% in 2006 compared to 2005 mainly as a result of a 2% increase in sales volumes attributed to the pipeline completion and development drilling on Block S-1, Yemen, new wells in Canada and a 18% increase in commodity prices, which were offset in part by increases in royalties, operating costs and taxes associated with the increased volumes and prices, as displayed below:

Cash Flow From
Operations
($000's)



	$000's	$ Per Share Diluted	% Variance
2005 Cash flow from operations**	38,077	0.63	
Volume variance	2,197	0.04	6
Price variance	16,643	0.27	44
Royalties	(7,654)	(0.13)	(20)
Expenses:			
Operating	(854)	(0.01)	(2)
Cash general and administrative	(797)	(0.01)	(2)
Current income taxes	(1,247)	(0.02)	(3)
Realized foreign exchange gain (loss)	54	-	-
Settlement of asset retirement obligations	99	-	-
Other	245	-	-
Change in weighted average number of diluted shares outstanding	-	-	-
2006 Cash flow from operations**	46,763	0.77	23

*** Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital.*

Net income for 2006 increased 32% mainly as a result of the above increases in cash flow from operations.

Management Strategy and Business Environment

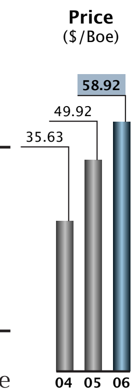
In 2007, the capital budget is focused on growing reserves and production in Yemen and in Canada. Also, a portion of the 2007 capital budget will be spent drilling two exploration wells on Nuqra Block 1 in Egypt.

The Company's financial results are significantly influenced by the oil industry business environment. Risks include, but are not limited to:

- Exploratory success.
- Crude oil and natural gas prices.
- The price differential and demand related to various crude oil qualities.
- Cost to find, develop, produce and deliver crude oil and natural gas.
- Availability of equipment and labour to conduct field activities.
- Availability of pipeline capacity.
- Foreign exchange and credit.
- Operational, safety and environmental.

Commodity Price and Foreign Exchange Benchmarks

	2006	**% Change**	2005	% Change	2004
Dated Brent average oil price ($ per barrel)	**64.88**	**19**	54.57	41	38.58
WTI average oil price ($ per barrel)	**66.09**	**17**	56.46	36	41.42
Edmonton Par average oil price (C$ per barrel)	**73.30**	**6**	69.29	31	52.91
AECO average gas price (C$ per MMBtu)	**6.51**	**(25)**	8.73	33	6.54
U.S./Canadian Dollar Year End Exchange Rate	**1.1654**	**-**	1.1630	(3)	1.2020
U.S./Canadian Dollar Average Exchange Rate	**1.1343**	**(6)**	1.2114	(7)	1.3013



World crude oil prices continued to increase significantly in 2006. Oil prices continued to be volatile during 2006 since global demand for oil remained very strong and outpaced supply increases. Also, supply uncertainties continued due to geopolitical concerns mainly in the Middle East, West Africa and South America.

In 2006, TransGlobe sold approximately:

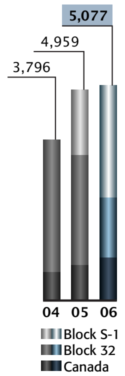
- 96% of its crude oil at dated Brent minus the selling price differentials.
- the remaining 4% at the Edmonton Par price less quality differentials.

In 2005, natural gas prices increased with concern over North America's ability to grow gas supply despite high drilling levels. A warm summer across North America and a cold December in the U.S. Northeast increased demand for power and two successive hurricanes damaged gas supply infrastructure in the U.S. Gulf Coast. Combined with high oil prices these factors caused the AECO gas price to average C$8.73/MMBtu in 2005, a 33% increase from 2004. In 2006 the weather in North America was extremely mild which reduced demand for natural gas. As a result, the 2006 average AECO natural gas price moderated to approximately C$6.51 per MMBtu.

In 2006, TransGlobe sold all of its natural gas at AECO Index based pricing.

OPERATING RESULTS

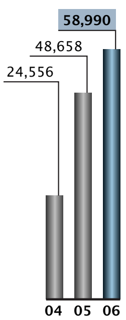
Sales Volumes
(Boepd)



Daily Volumes, Working Interest Before Royalties and Other

		2006	2005	% Change
Yemen - Oil sales	Bopd	**4,046**	4,092	(1)
Canada - Oil and liquids sales	Bopd	**331**	220	50
- Gas sales	Mcfpd	**4,204**	3,880	8
Canada	Boepd	**1,031**	867	19
Total Company - daily sales volumes	Boepd	**5,077**	4,959	2

Net Operating Income Consolidated
($000's)



Consolidated Net Operating Results

	Consolidated			
	2006		2005	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Oil and gas sales	**109,190**	**58.92**	90,350	49.92
Royalties and other	**39,093**	**21.09**	31,439	17.37
Operating expenses	**11,107**	**5.99**	10,253	5.67
Net operating income*	**58,990**	**31.84**	48,658	26.88

** Net operating income amounts do not reflect Yemen income tax expense which is paid through oil allocations with MOM in Yemen (2006 - $9,129,000, $4.93/Boe, 2005 - $7,882,000, $4.36/Boe).*

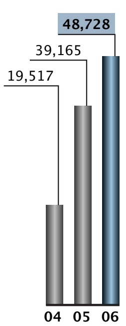
Segmented Net Operating Results

In 2006 the Company had producing operations in two geographic areas, segmented as Yemen and Canada. Also, the Company had operations in a third geographic segment, Egypt. MD&A will follow under each of these segments.

Republic of Yemen

Yemen operating results are generated from two non-operated Blocks: Block 32 (13.81087% working interest) and Block S-1 (25% working interest).

Net Operating Income Yemen
($000's)



	2006		2005	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Oil sales	**93,189**	**63.10**	76,300	51.09
Royalties and other	**36,353**	**24.62**	28,916	19.36
Operating expenses	**8,108**	**5.49**	8,219	5.50
Net operating income*	**48,728**	**32.99**	39,165	26.23

** Net operating income amounts do not reflect Yemen income tax expense which is paid through oil allocations with MOM in Yemen (2006 - $9,129,000, $6.18/Boe, 2005 - $7,882,000, $5.28/Boe).*

Net operating income in Yemen increased 24% in 2006 primarily as a result of the following:

- Oil sales increased 22% mainly as a result of the following:
    1. Oil prices increased by 24%.
    2. Sales volumes decreased 1% in 2006 primarily as a result of:
        - Block 32 sales volumes decreased by 26% from 1,926 Bopd in 2005 to 1,429 Bopd in 2006, due to natural declines in the Tasour field.
        - Block S-1 sales volumes increased 21% from 2,166 Bopd in 2005 to 2,617 Bopd in 2006.

Daily Volumes, Working Interest Before Royalties	**12 Months Ended December 31, 2006**	12 Months Ended December 31, 2005	
	Bopd	Bopd	% Change
Block S-1 - production	**2,592**	2,198	18
- inventory change	**25**	(32)	-
Block S-1 - sales	**2,617**	2,166	21
Block 32 - sales	**1,429**	1,926	(26)
Total sales	**4,046**	4,092	(1)

- Royalty costs increased 26%. Royalties as a percentage of revenue (royalty rate) increased to 39% in 2006 compared to 38% in 2005. Royalty rates fluctuate in Yemen due to changes in the amount of cost sharing oil, whereby the Block 32 and Block S-1 PSA's allow for the recovery of operating and capital costs through a reduction in MOM take of oil production as discussed below:

  - Block 32:
    - Operating costs are recovered in the quarter expended.
    - The capital costs are amortized over two years with 50% recovered in the quarter expended and the remaining 50% recovered in the first quarter of the following calendar year. As a result, the Company will receive a larger share of production in the first quarter of each year as 50% of the previous year's historical costs are recovered.
    - In 2006, the Company's royalty rate was 41% compared to 42% in 2005.
    - In 2007, the Company's royalty rate is expected to average between 27% and 29% in the first quarter and increase to between 34% to 39% for the balance of the year depending upon production volumes, oil prices, operating costs and eligible capital expenditures.

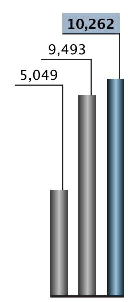
  - Block S-1:
    - Operating costs are recovered in the quarter expended.
    - New capital costs are amortized over eight quarters with one eighth (12.5%) recovered each quarter.
    - For the first three quarters 2005, the Company's royalty rate was 30%. At the end of the third quarter, the Company had recovered its historical exploration cost pools which resulted in an increased royalty rate of 46% for the fourth quarter. In 2006, the Company's royalty rate was 38%.
    - In 2007, the Company's royalty rate is expected to average between 38% and 43% depending upon production volumes, oil prices, operating costs and eligible capital expenditures.

- Operating expenses on a Boe basis were consistent at $5.49 in 2006 compared to $5.50 in 2005.
  1. Block 32 operating expenses decreased to $5.18 per barrel in 2006 compared to $5.80 per barrel in 2005 primarily due to decreased diesel costs. A diesel topping plant was constructed in 2005 to manufacture diesel from produced crude oil which reduced diesel costs significantly on a go forward basis. The plant became operational in December 2005.
  2. Block S-1 operating costs increased to $5.66 per barrel in 2006 compared to $5.17 per barrel in 2005.

Canada

	2006		2005	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Oil sales	**3,178**	**58.45**	1,886	52.04
Gas sales ($ per Mcf)	**9,478**	**6.18**	10,292	7.27
NGL sales	**3,266**	**49.24**	1,785	40.46
Other sales	**79**	**-**	87	-
	16,001	**42.51**	14,050	44.41
Royalties and other	**2,740**	**7.28**	2,523	7.97
Operating expenses	**2,999**	**7.97**	2,034	6.43
Net operating income	**10,262**	**27.26**	9,493	30.01

Net Operating Income Canada
($000's)



Net operating income in Canada increased 8% in 2006 primarily as a result of the following:

- Sales increased 14% mainly due to:
  1. Sales volumes increased 19% as a direct result of successful drilling.
  2. Offset by a commodity price decrease of 4% on a Boe basis.
- Royalty costs decreased 9% on a Boe basis. Royalties as a percentage of revenue were consistent at 17% in 2006 compared to 18% in 2005. During the third quarter of 2006, the Alberta government announced it is discontinuing the Alberta Royalty Tax Credit program effective January 1, 2007. As a result, the Company's royalties will be increased by C$500,000 in 2007.
- Operating costs increased 24% on a Boe basis mainly as a result of five well workovers and overall general cost increases for all services resulting from a very active oil and gas industry in Canada.

UNREALIZED GAIN ON COMMODITY CONTRACTS

In September 2005, the Company entered into a crude oil costless collar for 15,000 barrels per month from January 1, 2006 to December 31, 2006. The transaction consisted of the purchase of a $50.00 per barrel dated Brent put (floor) and a $77.93 per barrel dated Brent call (ceiling). Through to the expiration of the contract, no realized gains or losses occurred.

GENERAL AND ADMINISTRATIVE EXPENSES

	2006		2005	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
G&A (gross)	**5,914**	**3.19**	4,754	2.63
Stock based compensation	**1,168**	**0.63**	723	0.40
Capitalized G&A	**(1,999)**	**(1.08)**	(1,675)	(0.93)
Overhead recoveries	**(409)**	**(0.22)**	(258)	(0.14)
G&A (net)	**4,674**	**2.52**	3,544	1.96

General and administrative expenses ("G&A") increased 32% in 2006 (29% increase on a Boe basis) compared to 2005 as a result of the following:

- Personnel and office overhead costs increased due to additional staff in both the Calgary and Cairo offices.
- Public company costs increased mainly due to the Company preparing for the new Sarbanes Oxley compliance requirements.
- Capitalized general and administrative expenses increased mainly as a result of expansion in the Eqypt operations and overhead recoveries increased due to the increased capital activity in Canada.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSE (DD&A)

	2006		2005	
(000's, except per Boe amounts)	**$**	**$/Boe**	$	$/Boe
Republic of Yemen	**11,623**	**7.87**	13,172	8.82
Canada	**7,281**	**19.34**	3,812	12.05
Arab Republic of Egypt	**37**	**-**	6	-
	18,941	**10.22**	16,990	9.39

In Yemen, DD&A on a Boe basis decreased 11% in 2006 compared to 2005 primarily as a result of decreased finding and development costs in Yemen.

In Yemen (Block 72, Block 75 and Block 84) and Egypt (Nuqra Block 1) major development costs of $2,638,000 and $7,683,000 respectively, were excluded from costs subject to depletion and depreciation.

In Canada, DD&A on a Boe basis increased 60% in 2006 compared to 2005 primarily as a result of increased finding and development costs in Canada.

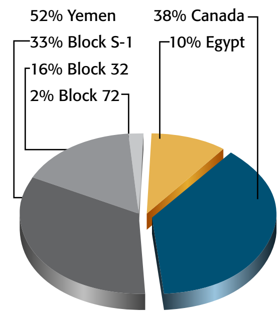
INCOME TAXES

($000's)	**2006**	2005
Current income tax	**9,129**	7,882
Future income tax	**263**	471
	9,392	8,353

Current income tax expense in 2006 of $9,129,000 (2005 - $7,882,000) represents income taxes incurred and paid under the laws of Yemen pursuant to the PSA's on Block 32 and Block S-1. The increase in Yemen is primarily the result of increased revenue in Yemen. The income tax expense in Yemen as a percent of Yemen revenue was 10% in 2006 and 2005. No income tax was paid in Canada in 2006 or in 2005. At December 31, 2006, the Company has C$53 million in Canadian tax pools. It is estimated that C$24 million of these pools will be available to deduct against 2007 taxable Canadian income.

The future income expense was $263,000 in 2006 (2005 - $471,000) which relates to a non-cash expense for taxes to be incurred in the future as Canadian tax pools reverse.

2006
Capital Expenditures



CAPITAL EXPENDITURES/DISPOSITIONS

Capital Expenditures

	2006						2005
($000's)	Land and Acquisition	Geological and Geophysical	Drilling and Completions	Facilities and Pipelines	Other	**Total**	Total
Republic of Yemen							
Block S-1	-	1,050	10,054	5,732	305	**17,141**	12,487
Block 32	-	791	5,943	1,430	114	**8,278**	3,999
Block 72	-	419	365	-	110	**894**	1,453
Block 75	250	-	-	-	-	**250**	-
Block 84	-	-	-	-	15	**15**	-
Other	-	-	-	-	7	**7**	-
	250	2,260	16,362	7,162	551	**26,585**	17,939
Canada	2,081	312	10,916	5,649	647	**19,605**	13,189
Arab Republic of Egypt	-	3,053	1,241	-	1,071	**5,365**	1,526
	2,331	5,625	28,519	12,811	2,269	**51,555**	32,654

On Block S-1 in Yemen, the Company drilled six wells (An Nagyah #19, #20, #21, #22, Wadi Bayhan #2 and Osaylan #2), continued working on CPF construction and expansion and began shooting a 3-D seismic acquisition (which was postponed). On Block 32, the Company drilled eight wells (Godah #1, #2, #3, #4, Tasour #21, #22, #23 and #24), began work on the Godah tie-in and began seismic acquisition. On Block 72, the Company continued to define drilling leads through seismic acquisition and processing and began access construction and the rig move for the first exploration well.

In Canada, the Company drilled 26 wells (20.8 net) mainly in the Nevis, Morningside and Thorsby areas. Also, the Company carried out completion and testing work on 27 wells, tied-in 18 wells and added compression equipment, mainly in the Nevis area.

In Egypt, the Company completed the field seismic acquisition on Nuqra Block 1 on April 5, 2006. The processing of seismic was completed in July. Interpretation and mapping of the seismic were completed and drilling locations selected. Drilling preparation began by starting access construction and purchasing drilling materials.

FINDING AND DEVELOPMENT COSTS

Proved

($000's, except volumes and $/Boe amounts)	**2006**	2005	2004
Total capital expenditure	**51,555**	32,654	26,367
Net change from previous year's future capital	**(1,154)**	8,418	8,796
	50,401	41,072	35,163
Reserve additions and revisions (MBoe)	**3,371**	2,987	4,332
Average cost per Boe	**14.95**	13.75	8.12
Three year average cost per Boe	**11.85**	9.57	7.42

Proved Plus Probable

($000's, except volumes and $/Boe amounts)	**2006**	2005	2004
Total capital expenditure	**51,555**	32,654	26,367
Net change from previous year's future capital	**3,943**	9,449	597
	55,498	42,103	26,964
Reserve additions and revisions (MBoe)	**3,025**	1,879	4,804
Average cost per Boe	**18.35**	22.41	5.61
Three year average cost per Boe	**12.83**	8.19	5.37

The finding and development costs shown above have been calculated in accordance with Canadian National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

RECYCLE RATIO

Proved

	Three Year Average	**2006**	2005	2004
Netback ($/Boe)	**$ 20.22**	**$ 25.23**	$ 21.04	$ 12.46
Proved finding and development costs ($/Boe)	**$ 11.85**	**$ 14.95**	$ 13.75	$ 8.12
Recycle ratio	**1.71**	**1.69**	1.53	1.53

Proved Plus Probable

	Three Year Average	**2006**	2005	2004
Netback ($/Boe)	**$ 20.22**	**$ 25.23**	$ 21.04	$ 12.46
Proved plus Probable finding and development costs ($/Boe)	**$ 12.83**	**$ 18.35**	$ 22.41	$ 5.61
Recycle ratio	**1.58**	**1.38**	0.94	2.22

The 2006 proved recycle ratio increased to 1.69 compared to 1.53 in 2005 mainly as a result of an increase in commodity prices. The 2006 proved plus probable recycle ratio increased to 1.38 compared to 0.94 in 2005 mainly as a result of increased commodity prices and lower proved plus probable finding and development costs. The decrease in the 2005 proved plus probable recycle ratio to 0.94 compared to 2004 of 2.22 mainly relates to a higher finding and development cost.

The recycle ratio measures the efficiency of TransGlobe's capital program by comparing the cost of finding and developing proved reserves with the netback from production. The ratio is calculated by dividing the netback by the proved finding and development cost on a Boe basis. Netback is defined as net sales less operating, general and administrative (excluding non-cash items), foreign exchange (gain) loss, interest and current income tax expense per Boe of production.

($000's, except volumes and per Boe amounts)	**2006**	2005	2004
Net income	**26,195**	19,850	5,919
Adjustments for non-cash items:			
Depletion, depreciation and accretion	**18,941**	16,990	10,346
Stock-based compensation	**1,168**	723	1,310
Future income taxes	**263**	471	(285)
Amortization of deferred financing costs	**179**	291	35
Unrealized loss (gain) on commodity contracts	**83**	(83)	-
Settlement of asset retirement obligations	**(66)**	(165)	-
Netback	**46,763**	38,077	17,325
Sales volumes	**1,853,252**	1,809,779	1,389,920
Netback per Boe	**$ 25.23**	$ 21.04	$ 12.46

OUTSTANDING SHARE DATA

Common Shares issued and outstanding as at March 7, 2007 are 59,542,439.

SELECTED QUARTERLY INFORMATION

	2006				2005			
($000's, except per share, price and volume amounts)	**Q-4**	**Q-3**	**Q-2**	**Q-1**	Q-4	Q-3	Q-2	Q-1
Average production volumes (Boepd)*	**5,475**	**4,952**	**4,915**	**5,026**	5,132	5,285	4,658	4,887
Average sales volumes (Boepd)*	**5,313**	**4,952**	**5,522**	**4,515**	4,935	5,533	4,375	4,985
Average price ($/Boe)	**55.30**	**61.88**	**62.17**	**55.93**	54.58	56.57	44.99	42.04
Oil and gas sales	**27,032**	**28,190**	**31,238**	**22,730**	24,781	28,796	17,911	18,863
Oil and gas sales, net of royalties and other	**17,647**	**18,542**	**18,600**	**15,308**	14,442	19,147	11,778	13,544
Cash flow from operations**	**10,448**	**12,662**	**12,356**	**11,297**	8,603	13,142	7,263	9,070
Cash flow from operations per share								
- Basic	**0.18**	**0.22**	**0.21**	**0.19**	0.15	0.23	0.13	0.16
- Diluted	**0.17**	**0.21**	**0.20**	**0.19**	0.14	0.22	0.12	0.15
Net income	**4,726**	**7,366**	**7,246**	**6,857**	4,331	7,539	3,474	4,507
Net income per share								
- Basic	**0.08**	**0.13**	**0.12**	**0.12**	0.07	0.13	0.06	0.08
- Diluted	**0.08**	**0.12**	**0.12**	**0.11**	0.07	0.13	0.06	0.08

** The differences in production and sales volumes result from inventory changes.*
*** Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital.*

In the first quarter of each calendar year the Company's royalty and income tax rate decreases at Block 32, Yemen due to the addition of the recovery of 50% of the capital costs from the prior year as well as 50% of the capital costs from the first quarter. This results in an increase to cash flow from operations and net income in the first quarter of each year. The second through fourth quarters recover 50% of the capital costs incurred with the balance recovered in the first quarter of the following year.

Oil and gas sales decreased 8% in Q1-2006 compared to Q4-2005; however, cash flow from operations and net income increased 31% to $11,297,000 and 58% to $6,857,000, respectively, in the same period mainly as a result of royalty and income tax costs decreasing at Block 32, Yemen in Q1-2006 due to the recovery of 50% of the 2005 capital costs from oil production as part of the Block 32 PSA, as discussed above. This was partially offset by an inventory build-up at Block S-1 since a portion of the March 2006 lifting was deferred to April 1, 2006.

Fourth Quarter 2006

Cash flow from operations decreased in Q4-2006 by $2,214,000 (17%) compared to Q3-2006 mainly as a result of the following:

- An 11% decrease in average commodity prices.
- Increased operating costs in Yemen due to technical charges from the partner for Block S-1.
- This is partially offset by an 7% increase in sales volumes.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and proved reserves, to acquire strategic oil and gas assets and to repay debt. TransGlobe's capital programs are funded principally by cash provided from operating activities.

The following table illustrates TransGlobe's sources and uses of cash during the years ended December 31, 2006 and 2005:

Sources and Uses of Cash

($000's)	**2006**	2005
Cash sourced		
Cash flow from operations*	**46,763**	38,077
Issue of common shares	**297**	1,218
	47,060	39,295
Cash used		
Exploration and development expenditures	**51,555**	32,654
Other	**545**	155
	52,100	32,809
Net cash	**(5,040)**	6,486
Increase in non-cash working capital	**1,655**	747
Change in cash and cash equivalents	**(3,385)**	7,233
Cash and cash equivalents - beginning of year	**12,221**	4,988
Cash and cash equivalents - end of year	**8,836**	12,221

** Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital.*

Funding for the Company's capital expenditures in 2006 was provided mainly by cash flow from operations and working capital.

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2006 the Company had working capital of $4,361,000 (2005 - $9,471,000), zero debt and an unutilized loan facility of $55,000,000. Accounts receivable increased due primarily to higher revenue receivables as a result of volume increases in Yemen and Canada, oil price increases in Yemen offset by gas price decreases in Canada. This was offset by increased accounts payable due primarily to higher operating costs in Yemen and increased drilling activity at year end in Yemen.

The Company expects to fund its approved 2007 exploration and development program of $51 million through the use of working capital, cash flow and debt if necessary. The use of our credit facilities or equity financing during 2007 may also be utilized to accelerate existing projects or to finance new opportunities. Fluctuations in commodity prices, product demand, foreign exchange rates, interest rates and various other risks may impact capital resources.

COMMITMENTS AND CONTINGENCIES

As part of its normal business, the Company entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. The principal commitments of the Company are as follows:

($000's)	2007	2008	2009	2010	2011
Office and equipment leases	284	386	409	402	101

Upon the determination that proved recoverable reserves are 40 million barrels or greater for Block S-1, Yemen, the Company will be required to pay a finders' fee to third parties in the amount of $281,000.

Pursuant to the Nuqra Concession Agreement in the Arab Republic of Egypt, the Company and its partners have entered into the first three year extension period which requires the completion of a two well drilling program with a minimum expenditure of $4.0 million over a period of three years. As part of this extension, the Company issued a $4.0 million letter of credit (expiring March 4, 2010) to guarantee the Company's performance under the extension period. This letter of credit was reduced to $1,225,699 during 2006 and is secured by a guarantee granted by Export Development Canada.

Pursuant to the PSA for Block 72, Yemen, the Contractor (Joint Venture Partners) has a minimum financial commitment of $4 million ($1.32 million to TransGlobe) during the first exploration period of 30 months (expiring January 12, 2008) for exploration work consisting of seismic acquisition (completed) and two exploration wells (planned completion in Q4-2007).

Pursuant to the bid awarded for Block 75, Yemen, the Contractor (Joint Venture Partners) has a minimum financial commitment of $7 million ($1.75 million to TransGlobe) for the signature bonus and first exploration period work program consisting of seismic acquisition and one exploration well. The first 36 month exploration period will commence when the PSA has been approved and ratified by the government of Yemen, anticipated to occur during 2007.

Pursuant to the bid awarded for Block 84, Yemen, the Contractor (Joint Venture Partners) has a minimum financial commitment of $20.1 million ($6.63 million to TransGlobe) for the signature bonus and first exploration period work program consisting of seismic acquisition and four exploration wells. The first 42 month exploration period will commence when the PSA has been approved and ratified by the government of Yemen, anticipated to occur in 2007.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with generally accepted accounting principles requires that management make appropriate decisions with respect to the selection of accounting policies and in formulating estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses. The following is included in MD&A to aid the reader in assessing the critical accounting policies and practices of the Company. The information will also aid in assessing the likelihood of materially different results being reported depending on management's assumptions and changes in prevailing conditions which affect the application of these policies and practices. Significant accounting policies are disclosed in Note 1 of the Consolidated Financial Statements.

Oil and Gas Reserves

TransGlobe's proved and probable oil and gas reserves are 100% evaluated and reported on by independent reserve evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Full Cost Accounting for Oil and Gas Activities

Depletion and Depreciation Expense

TransGlobe follows the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs are depleted, depreciated and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion, depreciation and amortization. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20% or greater.

Unproved Properties

Certain costs related to unproved properties and major development projects are excluded from costs subject to depletion and depreciation until the earliest of a portion of the property becomes capable of production, development activity ceases or impairment occurs. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of reserves; and
ii) the costs of unproved properties that have been subject to a separate impairment test.

Income Tax Accounting

The Company has recorded a future income tax asset in 2006 and 2005. This future income tax asset is an estimate of the expected benefit that will be realized by the use of deductible temporary differences in excess of carrying value of the Company's Canadian property and equipment against future estimated taxable income. These estimates may change substantially as additional information from future production and other economic conditions such as oil and gas prices and costs become available.

The determination of the Company's income tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at year-end exchange rates and revenues and expenses are translated using average annual exchange rates. Translation gains and losses relating to the self-sustaining operations are included as a separate component of shareholders' equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Income and Retained Earnings.

Derivative Financial Instruments

Derivative financial instruments are used by the Company to manage its exposure to market risks relating to commodity prices. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded at fair values where instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net income. Realized gains or losses from financial derivatives related to commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimation of the fair value of certain derivative financial instruments requires considerable judgement. The estimation of the fair value of commodity price instruments requires sophisticated financial models that incorporate forward price and volatility data. The estimated fair value of all derivative instruments is based on quoted market prices and/or third party market indications and forecasts.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of the fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion in the Consolidated Statement of Income. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs which will not be incurred for several years. Actual payment to settle the obligations may differ from estimated amounts.

NEW ACCOUNTING STANDARDS

Financial Instruments, Comprehensive Income and Hedges

The AcSB has issued new accounting standards for financial instruments standards that comprehensively address when an entity should recognize a financial instrument on its balance sheet, or how it should measure the financial instrument once recognized. The new standards comprise three handbook sections:

CICA Section 3855, *Financial Instruments - Recognition and Measurement,* establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. It also specifies how financial instrument gains and losses are to be presented.

CICA Section 3865, *Hedges,* provides optional alternative treatments to Section 3855 for entities which choose to designate qualifying transactions as hedges for accounting purposes. It will replace Accounting Guideline AcG-13, *Hedging Relationships*, and build on Section 1650, *Foreign Currency Translation*, by specifying how hedge accounting is applied and what disclosures are necessary when it is applied.

CICA Section 1530, *Comprehensive Income,* introduces a new requirement to temporarily present certain gains and losses as part of a new earnings measurement called comprehensive income.

All three standards are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. The Company is currently assessing the impact of these new standards on the Consolidated Financial Statements.

Financial Instruments Disclosures

The ASB issued CICA 3862, *Financial Instruments Disclosures,* to enhance the disclosure requirements in CICA 3861, *Financial Instruments and Disclosures*. The main features of this section are to establish requirements for an entity to disclose the significance of financial instruments for its financial position and performance, revised from those of Section 3861. These requirements are less detailed than those of Section 3861 in certain areas and more so in others. There are also requirements for disclosures about fair value, revised but not substantially different from those of Section 3861. Lastly, there are requirements for an entity to disclose qualitative and quantitative information about exposure to risks arising from financial instruments, revised from, and more extensive than, those of Section 3861. The new requirements are effective for annual and interim periods beginning on or after October 1, 2007, or may be adopted earlier in place of Section 3861. As the Company is adopting Financial Instruments Standards 3855, 3865 and 1530 at January 1, 2007, Section 3862 will also be adopted at this time.

Financial Instruments Presentation

The ASB issued CICA 3863, *Financial Instruments Presentation,* which carries forward, unchanged from Section 3861, standards for presentation of financial instruments and non-financial derivatives. The new requirements are effective for annual and interim periods beginning on or after October 1, 2007, or may be adopted earlier in place on Section 3861. As the Company is adopting Financial Instruments Standards 3855, 3865, and 1530 at January 1, 2007, Section 3863 will also be adopted at this time.

Capital Disclosures

The Accounting Standards Board (AcSB) issued Canadian Institute of Chartered Accountants (CICA) Section 1535, *Capital Disclosures*. The main features of this section are to establish requirements for an entity to disclose qualitative information about its objectives, policies and processes for managing capital, quantitative data about what it regards as capital, and whether it has complied with any externally imposed capital requirements and, if not, the consequences of such non-compliance. The new requirements are effective for annual and interim periods beginning on or after October 1, 2007, and, upon adoption, are not expected to materially impact the Consolidated Financial Statements.

Variable Interest Entities

The EIC issued EIC 163, *determining the variability to be considered in applying AcG-15 (Variable Interest Entities)*. The EIC provides guidance on those arrangements where application of either the cash flow method or the fair value method does not result in a clear determination as to whether those arrangements are variable interests or creators of variability. The Committee reached a consensus that variability to be considered should be based on the design of the entity as determined through analyzing the nature of the risks in the entity and the purpose for which the entity was created, as well as the variability (created by the risks) the entity is designed to create and pass along to its interest holders. The EIC is applicable to the first interim period or annual fiscal period beginning after January 1, 2007, and, upon adoption, is not expected to materially impact the Consolidated Financial Statements.

Equity

The ASB issued CICA 3251, *Equity,* which replaces CICA 3250, *Surplus*. This section establishes standards for the presentation of equity and changes in equity during the reporting period. The main feature of this section is a requirement for an entity to present separately each of the changes in equity during the period, including comprehensive income, as well as components of equity at the end of the period. The new requirements are effective for annual and interim periods beginning on or after October 1, 2007. This standard will have an effect on the Company's Financial Statements due to adoption of the new financial instruments standards on January 1, 2007.

RISKS

The Company is exposed to a variety of business risks and uncertainties in the international petroleum industry including commodity prices, exploration success, production risk, foreign exchange, interest rates, government regulation including the Kyoto Protocol, changes of laws affecting foreign ownership, political risk of operating in foreign jurisdictions, taxes, environmental preservation and safety concerns.

Many of these risks are not within the control of management, but the Company has adopted several strategies to reduce and minimize the effects of these factors:

- The Company applies rigorous geological, geophysical and engineering analysis to each prospect.
- The Company utilizes its in-house expertise for all international ventures or employs and contracts professionals to handle each aspect of the Company's business.
- The Company maintains a conservative approach to debt financing and currently has no long-term debt.
- The Company maintains insurance according to customary industry practice, but cannot fully insure against all risks.
- The Company conducts its operations to ensure compliance with government regulations and guidelines, including the Kyoto Protocol. At this time, it is not possible to predict either the nature of the Kyoto Protocol requirements or impact on the Company.
- The Company retains independent reserve evaluators to determine year-end Company reserves and estimated future net revenues.
- The Company manages commodity prices by entering physical fixed price sales contracts and other commodity price instruments when deemed appropriate.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2006, an evaluation was carried out under the supervision, and with the participation, of the Company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that as of the end of the fiscal year, the design and operation of these disclosure controls and procedures were effective to ensure that information required to be disclosed by the Company in its annual filings is recorded, processed, summarized and reported within the specified time periods.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed such internal control over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles (GAAP), including a reconciliation to U.S. GAAP.

Because of its inherent limitations, the Company's internal control over financial reporting may not prevent or detect all possible misstatements or frauds. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

To evaluate the effectiveness of the Company's internal control over financial reporting, Management has used the Internal Control - Integrated Framework, which is a suitable, recognized control framework established by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management has assessed the effectiveness of the Company's internal control over financial reporting for fiscal year ended December 31, 2006 and concluded that such internal control over financial reporting is effective.

OUTLOOK

2007 Production Outlook

A number of projects are underway in Yemen and in Canada that are anticipated to increase oil and gas production during 2007. The majority of these projects will be completed during the first two quarters of 2007 and therefore will not have an impact on production until the second half of the year. Therefore a "Baseline" forecast is currently estimated using only the existing production and planned development in Canada. The Baseline forecast will be updated quarterly or when the facilities and development projects are completed.

Baseline Production Forecast

		2007	2006	Change (*)
Barrels of oil equivalent per day	Boepd	**5,300-5,400**	5,093	5%

(*) % growth based on mid point of guidance

2007 Cash Flow From Operations Outlook

The 2007 Cash Flow From Operations Outlook was developed using the above Baseline Production Forecast, a dated Brent oil price of $55.00/Bbl and a gas price of C$7.50/Mcf. The prices used for the Outlook are 15% lower for oil and 6% higher for gas than the actual realized prices during 2006. The lower forecasted oil price has resulted in a decrease in the estimated 2007 Cash Flow From Operations. In addition, the Block S-1 Production Sharing Agreement has reached payout on the exploration expenditures and is quickly paying out the development expenditures which will result in a lower cost oil allocation during 2007, reducing 2007 Cash Flow From Operations.

2007 Cash Flow From Operations Outlook

($000's)	2007(**)	2006	Change (*)
Cash flow from operations	**39,000-41,000**	46,763	(14)%

(*) % growth based on mid point of guidance
(**) Based on a dated Brent oil price of $55.00/Bbl and a gas price of C$7.50/Mcf, from existing fields in Yemen and planned development in Canada.

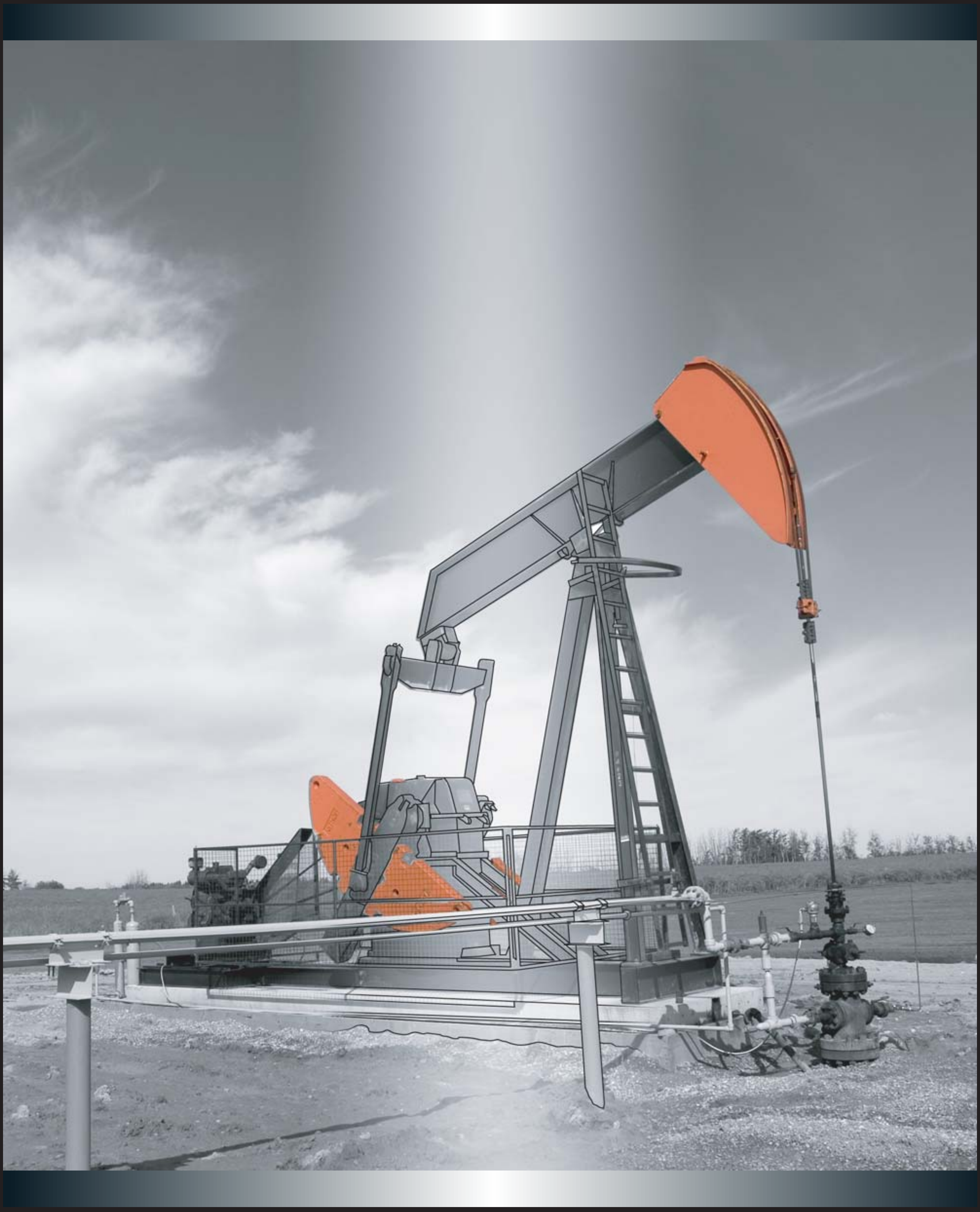
Variations in production and commodity prices during 2007 could significantly change this Outlook. An estimate of the price sensitivity on the Baseline Production Forecast is shown below. During January and February 2007 the dated Brent oil price averaged $55.55 per barrel and the gas price averaged approximately C$7.50 per Mcf.

Sensitivity ($000's)	**2007 Cash Flow from Operations Increase/Decrease**
$1.00 per barrel change in dated Brent	**537**
C$1.00 per Mcf change in AECO	**1,633**

2007 Capital Budget

($000's)		2007
Canada		**15,400**
Yemen	- Block S1	**12,600**
	- Block 32	**5,900**
	- Block 72	**4,600**
	- Block 75	**1,000**
	- Block 84	**2,000**
Egypt		**4,700**
Total		**46,200**

TransGlobe plans to continue increasing crude oil production in Yemen and natural gas production in Canada to deliver near term growth. Potential production growth could come from Block 72, in Yemen, in the medium term. In the long term, production growth could come from Blocks 75 and 84 in Yemen and Nuqra Block 1 in Egypt. For the near term growth, the Company expects to drill 12 wells in Yemen during 2007 of which six wells will be development wells and six wells will be exploration wells. In Canada, the Company plans on drilling 10 to 12 wells during 2007 which are mainly development wells. The Company plans on drilling two exploratory wells in Egypt in 2007. The Company attaches a significantly higher risk to the exploratory wells. The 2007 capital budget of $46.2 million is expected to be funded from cash flow, working capital and debt as required. The use of our credit facilities or equity financing during 2007 may be utilized in the future to accelerate existing projects or to finance new opportunities.



TransGlobe Energy Corporation

Management's Report

The consolidated financial statements of TransGlobe Energy Corporation were prepared by management within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles. Management is responsible for ensuring that the financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

The consolidated financial statements have been prepared by management in accordance with the accounting policies as described in the notes to the consolidated financial statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgements made by management.

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records properly maintained to facilitate the preparation of consolidated financial statements for reporting purposes.

Deloitte & Touche LLP, an independent firm of Chartered Accountants appointed by the shareholders, have conducted an examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements. The Audit Committee, consisting of three independent directors, has met with representatives of Deloitte & Touche LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Board of Directors has approved the consolidated financial statements.

Ross G. Clarkson
President &
Chief Executive Officer

David C. Ferguson
Vice President, Finance &
Chief Financial Officer

March 20, 2007

Report of Independent Registered Chartered Accountants

To the Shareholders of **TransGlobe Energy Corporation:**

We have audited the consolidated balance sheets of TransGlobe Energy Corporation as at December 31, 2006 and 2005 and the consolidated statements of income and retained earnings (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly we express no such opinion.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Alberta, Canada
February 23, 2007

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have material effect on the comparability of the Company's financial statements, such as the changes described in Note 2 of the consolidated financial statements. Our report to the Shareholders, dated February 23, 2007, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Alberta, Canada
February 23, 2007

Consolidated Statements of Income and Retained Earnings (Deficit)

(Expressed in thousands of U.S. Dollars)

	Year Ended December 31, 2006	Year Ended December 31, 2005
REVENUE		
Oil and gas sales, net of royalties and other	**$ 70,097**	$ 58,911
Unrealized gain (loss) on commodity contracts (Note 14)	**(83)**	83
Other income	**283**	46
	70,297	59,040
EXPENSES		
Operating	**11,107**	10,253
General and administrative	**4,674**	3,544
Foreign exchange (gain) loss	**(12)**	42
Interest	**-**	8
Depletion, depreciation and accretion	**18,941**	16,990
	34,710	30,837
Income before income taxes	**35,587**	28,203
INCOME TAXES (Note 9)		
Current	**9,129**	7,882
Future	**263**	471
	9,392	8,353
NET INCOME	**26,195**	19,850
Retained earnings (deficit), beginning of year	**19,165**	(685)
RETAINED EARNINGS, END OF YEAR	**$ 45,360**	$ 19,165
Net income per share (Note 11)		
Basic	**$ 0.45**	$ 0.34
Diluted	**$ 0.43**	$ 0.33

Consolidated Balance Sheets

(Expressed in thousands of U.S. Dollars)

	December 31, 2006	December 31, 2005
ASSETS		
Current		
Cash and cash equivalents	**$ 8,836**	$ 12,221
Accounts receivable	**7,742**	7,414
Product inventory	**508**	436
Prepaid expenses	**782**	463
Unrealized commodity contracts (Note 14)	**-**	83
	17,868	20,617
Property and equipment		
Republic of Yemen (Note 3)	**46,124**	30,898
Canada (Note 4)	**42,645**	30,261
Arab Republic of Egypt (Note 5)	**7,839**	2,512
	96,608	63,671
Future income tax asset (Note 9)	**1,626**	1,886
Deferred financing costs (Note 6)	**371**	112
	$ 116,473	$ 86,286
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**$ 13,507**	$ 11,146
Asset retirement obligations (Note 7)	**2,171**	1,503
	15,678	12,649
Commitments and contingencies (Note 13)		
SHAREHOLDERS' EQUITY		
Share capital (Note 8)	**49,360**	48,922
Contributed surplus (Note 8d)	**2,863**	1,908
Cumulative translation adjustment	**3,212**	3,642
Retained earnings	**45,360**	19,165
	100,795	73,637
	$ 116,473	$ 86,286

APPROVED ON BEHALF OF THE BOARD

Ross G. Clarkson, Director

Fred J. Dyment, Director

Consolidated Statements of Cash Flows

(Expressed in thousands of U.S. Dollars)

	Year Ended December 31, 2006	Year Ended December 31, 2005
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net income	**$ 26,195**	$ 19,850
Adjustments for:		
Depletion, depreciation and accretion	**18,941**	16,990
Amortization of deferred financing costs	**179**	291
Future income taxes	**263**	471
Stock-based compensation (Note 8d)	**1,168**	723
Unrealized (gain) loss on commodity contracts	**83**	(83)
Settlement of asset retirement obligations	**(66)**	(165)
Changes in non-cash working capital (Note 10)	**620**	1,280
	47,383	39,357
FINANCING		
Issue of common shares for cash	**297**	1,218
Deferred financing costs	**(438)**	(17)
Changes in non-cash working capital (Note 10)	**-**	(24)
	(141)	1,177
INVESTING		
Exploration and development expenditures		
Republic of Yemen	**(26,585)**	(17,939)
Canada	**(19,605)**	(13,189)
Arab Republic of Egypt	**(5,365)**	(1,526)
Changes in non-cash working capital (Note 10)	**1,035**	(509)
	(50,520)	(33,163)
Effect of exchange rate changes on cash and cash equivalents	**(107)**	(138)
NET INCREASE IN CASH AND CASH EQUIVALENTS	**(3,385)**	7,233
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	12,221	4,988
CASH AND CASH EQUIVALENTS, END OF YEAR (Note 10)	**$ 8,836**	$ 12,221

Notes to the Consolidated Financial Statements

Years Ended December 31, 2006 and December 31, 2005
(Expressed in U.S. Dollars, unless otherwise stated)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Consolidated Financial Statements include the accounts of TransGlobe Energy Corporation and subsidiaries ("TransGlobe" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles (information prepared in accordance with generally accepted accounting principles in the United States is included in Note 16). In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

Nature of Business and Principles of Consolidation

The Company is engaged primarily in oil and gas exploration, development and production and the acquisition of properties. Such activities are concentrated in three geographic areas:

* Block 32, Block S-1, Block 72, Block 75 and Block 84 within the Republic of Yemen.
* the Western Canadian Sedimentary Basin within Canada.
* Nuqra Block 1 within the Arab Republic of Egypt.

Joint Ventures

Investments in unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Currency Translation

The accounts of the self-sustaining Canadian operations are translated using the current rate method, whereby assets and liabilities are translated at year end exchange rates, while revenues and expenses are translated using average annual rates. Translation gains and losses relating to the self-sustaining Canadian operations are included as a separate component of shareholders' equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statements of Income and Retained Earnings (Deficit).

Measurement Uncertainty

Timely preparation of the financial statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depletion, depreciation and amortization, asset retirement costs and obligations, future income taxes, and amounts used for ceiling test and impairment calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

Revenue Recognition

Revenues associated with the sales of the Company's crude oil, natural gas and natural gas liquids owned by the Company are recognized when title passes from the Company to its customer. Crude oil and natural gas produced and sold by the Company below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue.

International operations conducted pursuant to production sharing agreements (PSA's) are reflected in the Consolidated Financial Statements based on the Company's working interest in such operations. Under the PSA's, the Company and other non-governmental partners pay all operating and capital costs for exploring and developing the concessions. Each PSA establishes specific terms for the Company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after Cost Recovery Oil and is shared between the joint venture partners and the government of each country, varying with the level of production. Profit Oil that is attributable to the government includes an amount in respect of all income taxes payable by the Company under the laws of the respective country. Revenue represents the Company's share and is recorded net of royalty payments to government and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty payments. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations.

Income Taxes

The Company records income taxes using the liability method. Under this method, future income tax assets and liabilities are measured using the substantively enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

Flow Through Shares

The Company has financed a portion of its prior years' exploration and development activities in Canada through the issue of flow through shares. Under the terms of these share issues, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits, share capital is reduced and a future income tax liability is recorded for the income tax amount related to the renounced deductions.

Per Share Amounts

Basic net income per share is calculated using the weighted average number of shares outstanding during the year. Diluted net income per share is calculated by giving effect to the potential dilution that would occur if stock options were exercised. Diluted net income per share is calculated using the treasury stock method. The treasury stock method assumes that the proceeds received from the exercise of "in-the-money" stock options are used to repurchase common shares at the average market price.

Cash and Cash Equivalents

Cash includes actual cash held and short-term investments such as treasury bills with original maturity of less than 90 days.

Inventories

Product inventories are valued at the lower of average cost and net realizable value on a first-in, first-out basis.

Property and Equipment

The Company follows the full cost method of accounting for oil and gas operations whereby all costs associated with the exploration for and development of oil and gas reserves are capitalized on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, production equipment and overhead charges directly related to acquisition, exploration and development activities.

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

Depletion, Depreciation, Amortization and Impairment (DD&A)

Capitalized costs within each country are depleted and depreciated on the unit-of-production method based on the estimated gross proved reserves and determined by independent reserve evaluators. Oil and gas reserves and production are converted into equivalent units of 6,000 cubic feet of natural gas to one barrel of oil. Depletion and depreciation is calculated using the capitalized costs, including estimated asset retirement costs, plus the estimated future costs to be incurred in developing proved reserves, net of estimated salvage value.

Costs of acquiring and evaluating unproved properties and major development projects are initially excluded from the depletion and depreciation calculation until it is determined whether or not proved reserves can be assigned to such properties. Costs of unproved properties and major development projects are transferred to depletable costs based on the percentage of reserves assigned to each project over the expected total reserves when the project was initiated. These costs are assessed periodically to ascertain whether impairment has occurred.

Proceeds from the sale of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion and depreciation by more than 20 percent in a particular country, in which case a gain or loss on disposal is recorded.

An impairment loss is recognized in net income if the carrying amount of a country (cost centre) is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment is the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved plus probable reserves; and
ii. the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Furniture and fixtures are depreciated at declining balance rates of 20 to 30 percent.

Amortization of Deferred Financing Costs

Deferred financing costs are charged to expense on a straight-line basis over the term of the related loan facility.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when the liability is incurred. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Asset retirement costs for natural gas and crude oil assets are amortized using the unit-of-production method.

Amortization of asset retirement costs are included in depletion, depreciation and accretion on the Consolidated Statements of Income and Retained Earnings (Deficit). Increases in the asset retirement obligation resulting from the passage of time are recorded as depletion, depreciation and accretion in the Consolidated Statements of Income and Retained Earnings (Deficit). Actual expenditures incurred are charged against the accumulated obligation.

Stock-based Compensation

The Company records compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors using the fair value method. Fair values are determined using the lattice-based binomial option pricing model in 2006, and the Black-Scholes option pricing model in 2005 and prior years. Compensation costs are recognized over the vesting period.

Derivative Financial Instruments

Derivative financial instruments are used by the Company to manage its exposure to market risks relating to commodity prices. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded at fair values where instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net income. Realized gains or losses from financial derivatives related to commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimated fair value of all derivative instruments is based on quoted market prices and/or third party market indications and forecasts.

2. CHANGES IN ACCOUNTING POLICIES

Non-monetary transactions
Effective January 1, 2006, the Canadian Institute of Chartered Accountants (CICA) Section 3831 "Non-Monetary Transactions" was adopted by the Company which replaced Section 3830 of the same name. The Standard, which harmonizes Canadian generally accepted accounting principles with the United States Financial Accounting Standards Board (FASB) Statement 153 Exchanges of Non-Monetary Assets, requires that all non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business. A transaction is determined to have commercial substance if it causes an identifiable and measurable change in the economic circumstances, or expected cash flows, of the entity. The guidance was effective for all non-monetary transactions initiated in periods beginning on or after January 1, 2006. The adoption of Section 3831 had no effect on the Company's Consolidated Financial Statements.

Implicit variable interests
Effective January 1, 2006, Emerging Issues Committee (EIC) Abstract 157 "Implicit Variable Interests" was adopted by the Company. The Abstract harmonizes Canadian generally accepted accounting principles with the United States FASB Staff Position (FSP) FIN 46(R)-5 Implicit Variable Interests. Implicit variable interests are implied financial interests in an entity and act the same as an explicit variable interest except they involve the absorbing and or receiving of variability indirectly from the entity rather than directly. The adoption of EIC Abstract 157 had no effect on the Company's Consolidated Financial Statements.

Conditional asset retirement obligations
Effective April 1, 2006, EIC Abstract 159 "Accounting for Conditional Asset Retirement Obligations" was adopted by the Company. The Abstract, which is harmonized with the equivalent United States FASB Interpretation 47 (Accounting for Conditional Asset Retirement Obligations), clarifies the accounting for conditional asset retirement obligations where the timing or method of settlement are conditional on a future event that may or may not be within the control of the entity. Although these uncertainties affect the fair value of the liability, they do not relieve an entity from the requirement to record a liability, if it can be reasonably determined. The adoption of EIC Abstract 159 had no effect on the Company's Consolidated Financial Statements.

Stock-based compensation for employees eligible to retire before the vesting date
In the fourth quarter of 2006, the Company retroactively adopted EIC Abstract 162, "Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date". The Abstract provides that if an employee is eligible to retire on the grant date of a stock-based award, related compensation expense is recognized in full at that date as there is no ongoing service requirement to earn the award. In addition, if an employee becomes eligible to retire during the vesting period, related compensation expense is recognized over the period from the grant date to the retirement eligibility date on a graded vesting basis. The Abstract is effective for interim and annual periods ending on or after December 31, 2006 and is to be adopted on a retroactive basis. This EIC had no effect on the Company's Consolidated Financial Statements for the twelve months ended December 31, 2006 and 2005.

3. PROPERTY AND EQUIPMENT – REPUBLIC OF YEMEN

(000's)		**2006**		2005
Oil and gas properties				
- Block S-1	**$**	**54,410**	$	37,269
- Block 32		**34,060**		25,790
- Block 72		**2,373**		1,479
- Block 75		**250**		-
- Block 84		**15**		-
- Other		**96**		90
Accumulated depletion and depreciation		**(45,080)**		(33,730)
	$	**46,124**	$	30,898

The Company has working interests in five blocks in Yemen: Block 32, Block S-1, Block 72, Block 75 and Block 84. The Block 32 (13.81087%) Production Sharing Agreement ("PSA") continues to 2020, with provision for a five year extension. The Block S-1 (25%) PSA continues to 2023, with provision for a five year extension. The Contractor (Joint Venture Partners) is in the first exploration period of the Block 72 (33%) PSA which ends in January 2008, at which time the Contractor can elect to proceed to the second exploration period. The Block 84 (33%) and Block 75 (25%) PSA's are in the ratification process with the Republic of Yemen.

During the year the Company capitalized overhead costs relating to exploration and development activities of $419,000 (2005 - $351,000). Unproven property costs in the amount of $2,638,000 in 2006 ($1,479,000 in 2005) were excluded in the costs subject to depletion and depreciation representing the costs incurred at Block 72, Block 75 and Block 84.

4. PROPERTY AND EQUIPMENT – CANADA

(000's)		**2006**		2005
Oil and gas properties	**$**	**57,624**	$	38,144
Furniture and fixtures		**1,004**		867
Accumulated depletion and depreciation		**(15,983)**		(8,750)
	$	**42,645**	$	30,261

During the year the Company capitalized overhead costs relating to exploration and development activities of $524,000 (2005 - $317,000).

5. PROPERTY AND EQUIPMENT – ARAB REPUBLIC OF EGYPT

(000's)		**2006**		2005
Oil and gas properties	**$**	**7,683**	$	2,457
Furniture and fixtures		**199**		61
Accumulated depreciation		**(43)**		(6)
	$	**7,839**	$	2,512

The Contractor is in the first three year extension period of the Concession Agreement which expires in July 2009. One additional extension period of three years is available to the Contractor at its option.

The Company capitalized general and administrative costs relating to TransGlobe Petroleum Egypt Inc. of $1,056,000 (2005 - $1,007,000). The remaining costs related to drilling preparation and geological and geophysical activity. Unproven property costs associated with Nuqra Block 1 in the amount of $7,683,000 in 2006 (2005 - $2,457,000) were excluded from costs subject to depletion and depreciation.

6. LONG-TERM DEBT

The Company has a $55 million credit agreement, with the initial borrowing base established at $25 million, which expires July 18, 2009. The credit agreement bears interest at the Eurodollar Rate plus three percent and is secured by a first floating charge debenture over all assets of the Company, a general assignment of book debts and certain covenants, among other things. At December 31, 2006 $Nil (2005 - $Nil) was drawn on these loan facilities.

During the year the Company spent $438,000 to secure the credit agreement, of which $67,000 was amortized to the income statement and the remaining $371,000 was deferred and will be amortized to income over the term of the loan facility.

7. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties:

(000's)	**2006**	2005
Asset retirement obligations, beginning of year	**$ 1,503**	$ 902
Liabilities incurred	**632**	638
Liabilities settled	**(66)**	(165)
Accretion	**124**	75
Foreign exchange (gain) loss	**(22)**	53
Asset retirement obligations, end of year	**$ 2,171**	$ 1,503

At December 31, 2006, the estimated total undiscounted amount required to settle the asset retirement obligations was $2,957,000 (2005 - $2,171,000). These obligations will be settled at the end of the useful lives of the underlying assets, which currently extend up to 9 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of 6.5%.

8. SHARE CAPITAL

a) Authorized

The Company is authorized to issue an unlimited number of common shares with no par value.

b) Issued

(000's)	Number of shares	**Amount**
Balance, December 31, 2004	57,176	$ 47,296
Stock options exercised (c)	1,297	1,218
Transfer from contributed surplus related to stock options exercised (d)	-	408
Balance, December 31, 2005	**58,473**	**48,922**
Stock options exercised (c)	**410**	**297**
Transfer from contributed surplus related to stock options exercised (d)	**-**	**141**
Balance, December 31, 2006	**58,883**	**$ 49,360**

c) Stock Options

The Company adopted a stock option plan in May 2004 (the "Plan"). The maximum number of common shares to be issued upon the exercise of options granted under the Plan is 5,888,300 common shares. All incentive stock options granted under the Plan have a per-share exercise price not less than the trading market value of the common shares at the date of grant. Stock options granted prior to February 1, 2005 vest as to 50% of the options, six months after the grant date, and as to the remaining 50%, one year from the grant date. Effective February 1, 2005, all new grants of stock options vest one-third on each of the first, second and third anniversaries of the grant date.

The following tables summarize information about the stock options outstanding and exercisable at December 31, 2006:

	2006		2005	
(000's except per share amounts)	**Number of Options**	**Weighted-Average Exercise Price**	Number of Options	Weighted-Average Exercise Price
Options outstanding at beginning of year	**3,361**	**$2.76**	3,462	$1.15
Granted	**297**	**$4.60**	1,196	$5.31
Exercised	**(410)**	**$0.63**	(1,297)	$0.83
Cancelled	**(138)**	**$4.85**	-	-
Options outstanding at end of year	**3,110**	**$3.12**	3,361	$2.76
Options exercisable at end of year	**2,143**	**$2.20**	2,165	$1.35

	Options Outstanding			Options Exercisable		
Exercise Price	Number Out-standing at Dec. 31 2006 (000's)	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price	Number Exercisable at Dec. 31, 2006 (000's)	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price
C$0.50-C$0.63	800	0.3	C$0.50	800	0.3	C$0.50
C$3.26-C$4.50	955	2.2	C$3.33	955	2.2	C$3.33
C$6.03-C$7.74	1,109	3.8	C$6.23	370	3.8	C$6.23
US$5.17	54	3.9	US$5.17	18	3.9	US$5.17
C$5.07-C$5.49	192	4.8	C$3.92	-	-	-
	3,110	2.5	US$3.12	2,143	1.8	US$2.20

d) Stock-based Compensation

Compensation expense of $1,168,000 has been recorded in general and administrative expenses in the Consolidated Statements of Income and Retained Earnings (Deficit) in 2006 (2005- $723,000). The fair value of all common stock options granted is estimated on the date of grant using the lattice-based binomial option pricing model in 2006, and the Black-Scholes option-pricing model prior to 2006. The weighted average fair value of options granted during the year and the assumptions used in their determination are as noted below:

	2006	2005
Weighted average fair market value per option (C$)	**$ 2.23**	3.38
Risk free interest rate (%)	**4.09**	3.86
Expected lives (years)	**5.00**	4.00
Expected volatility (%)	**48.79**	68.19
Dividend per share	**0.00**	0.00
Early exercise (Year 1/Year 2/Year 3/Year 4/Year 5)	**0%/10%/20%/30%/40%**	N/A

During the year, employees exercised 410,000 stock options. In accordance with Canadian generally accepted accounting principles, the fair value related to these options was $141,000 at time of grant and has been transferred from contributed surplus to common shares.

(000's)	2006	2005
Contributed surplus, beginning of year	**$ 1,908**	$ 1,593
Stock-based compensation expense	**1,096**	723
Transfer of stock-based compensation expense to common shares related to stock options exercised	**(141)**	(408)
Contributed surplus, end of year	**$ 2,863**	$ 1,908

9. INCOME TAXES

The Company's future Canadian income tax assets are as follows:

(000's)	2006	2005
Temporary differences related to:		
Oil and gas properties	**$ 1,292**	$ 1,555
Non-capital losses carried forward	**214**	118
Share issue expenses	**120**	213
	$ 1,626	$ 1,886

The Company has deductible temporary differences of C$818,000 related to non-capital losses carried forward, C$460,000 related to share issuance expenses and C$4,941,000 related to income tax pools in excess of the carrying value of the Company's Canadian property and equipment. The Company also has $12,764,000 of income tax losses in the United States of America. The Canadian losses carried forward expire in 2009 and the United States of America losses carried forward expire between 2008 and 2020.

Current income taxes in the amount of $9,129,000 (2005 - $7,882,000) represents income taxes incurred and paid under the laws of the Republic of Yemen pursuant to the PSA on Block 32 and Block S-1.

The provision for income taxes has been computed as follows:

(000's)	2006	2005
Computed Canadian expected income tax expense at 34.5% (2005 - 37.62%)	**$ 12,276**	$ 10,660
Non-deductible Crown charges (net of Alberta Royalty Tax Credit)	**196**	407
Resource allowance	**(239)**	(522)
Non-deductible stock-based compensation expense	**403**	272
Different tax rates in the Republic of Yemen	**(3,523)**	(1,751)
Future income tax assets not previously recognized	**-**	(594)
Other differences	**279**	(119)
	$ 9,392	$ 8,353

10. SUPPLEMENTAL CASH FLOW INFORMATION

(000's)	**2006**	2005
Operating activities		
Decrease (increase) in current assets		
Accounts receivable	**$ (556)**	$ (591)
Prepaid expenses	**61**	(189)
Product inventory	**(60)**	17
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	**1,175**	2,043
	$ 620	$ 1,280
Investing activities		
Decrease (increase) in current assets		
Accounts receivable	**$ 228**	$ (795)
Prepaid expenses	**(379)**	-
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	**1,186**	286
	$ 1,035	$ (509)
Financing activities		
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	**$ -**	$ (24)
	$ -	$ (24)
Interest paid	**$ -**	$ 8
Taxes paid	**$ 9,129**	$ 7,882
Cash on hand and balances with banks	**$ 8,836**	$ 5,193
Short-term investments	**-**	7,028
Total cash and cash equivalents	**$ 8,836**	$ 12,221

11. NET INCOME PER SHARE

In calculating the net income per share basic and diluted, the following weighted average shares were used:

(000's)	**2006**	2005
Weighted average number of shares outstanding	**58,663**	57,903
Shares issuable pursuant to stock options	**2,662**	3,251
Shares to be purchased from proceeds of stock options under treasury stock method	**(763)**	(824)
Weighted average number of diluted shares outstanding	**60,562**	60,330

The treasury stock method assumes that the proceeds received from the exercise of "in-the-money" stock options are used to repurchase common shares at the average market price. In calculating the weighted average number of diluted common shares outstanding for the year ended December 31, 2006, the Company excluded 1,109,000 options (2005 - 63,000) because their exercise price was greater than the annual average common share market price in this period.

12. SEGMENTED INFORMATION

In 2006 the Company had oil and natural gas production in two geographic segments, the Republic of Yemen and Canada, and has operations in a third geographic segment, the Arab Republic of Egypt. The property and equipment in each geographic segment are disclosed in Notes 3, 4 and 5.

The results of operations for the year ended December 31, 2006 are comprised of the following:

(000's)	Republic of Yemen	Canada	Arab Republic of Egypt	Total
Revenue				
Oil and gas sales, net of royalties and other	**$ 56,836**	**$ 13,261**	**$ -**	**$ 70,097**
Expenses				
Operating	**8,108**	**2,999**	**-**	**11,107**
Depletion, depreciation and accretion	**11,623**	**7,281**	**37**	**18,941**
Income taxes	**9,129**	**263**	**-**	**9,392**
Segmented operations	**$ 27,976**	**$ 2,718**	**$ (37)**	**30,657**
Foreign exchange gain				**12**
Other income				**283**
				30,952
General and administrative				**4,674**
Unrealized loss on commodity contracts				**83**
Net income				**$ 26,195**

The results of operations for the year ended December 31, 2005 are comprised of the following:

(000's)	Republic of Yemen	Canada	Arab Republic of Egypt	Total
Revenue				
Oil and gas sales, net of royalties and other	$ 47,384	$ 11,527	$ -	$ 58,911
Expenses				
Operating	8,219	2,034	-	10,253
Depletion, depreciation and accretion	13,172	3,812	6	16,990
Income taxes	7,882	471	-	8,353
Segmented operations	$ 18,111	$ 5,210	$ (6)	23,315
Unrealized gain on commodity contracts				83
Other income				46
				23,444
General and administrative				3,544
Foreign exchange loss				42
Interest				8
Net income				$ 19,850

13. COMMITMENTS AND CONTINGENCIES

The Company is committed to office and equipment leases over the next five years as follows:

2007	284,000
2008	386,000
2009	409,000
2010	402,000
2011	101,000

Upon the determination that proved recoverable reserves are 40 million barrels or greater for Block S-1, Yemen, the Company will be required to pay a finders' fee to third parties in the amount of $281,000.

Pursuant to the Nuqra Concession Agreement in the Arab Republic of Egypt, the Company and its partners have entered into the first three year extension period which requires the completion of a two well drilling program with a minimum expenditure of $4.0 million over a period of three years. As part of this extension, the Company made the mandatory relinquishment of 25% of the Block and issued a $4.0 million letter of credit (expiring March 4, 2010) to guarantee the Company's performance under the extension period. This letter of credit was reduced to $1,225,699 during 2006 and is secured by a guarantee granted by Export Development Canada.

Pursuant to the PSA for Block 72, Yemen, the Contractor (Joint Venture Partners) has a minimum financial commitment of $4 million ($1.32 million to TransGlobe) during the first exploration period of 30 months (expiring January 12, 2008) for exploration work consisting of seismic acquisition (completed) and two exploration wells.

Pursuant to the bid awarded for Block 75, Yemen, the Contractor (Joint Venture Partners) has a minimum financial commitment of $7 million ($1.75 million to TransGlobe) for the signature bonus and first exploration period work program consisting of seismic acquisition and one exploration well. The first 36 month exploration period will commence when the PSA has been approved and ratified by the government of Yemen, anticipated to occur during 2007.

Pursuant to the bid awarded for Block 84, Yemen, the Contractor (Joint Venture Partners) has a minimum financial commitment of $20.1 million ($6.63 million to TransGlobe) for the signature bonus and first exploration period work program consisting of seismic acquisition and four exploration wells. The first 42 month exploration period will commence when the PSA has been approved and ratified by the government of Yemen, anticipated to occur during 2007.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Carrying Values and Estimated Fair Values of Financial Assets and Liabilities
Carrying values of financial instruments, which include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate their fair value due to the short-term nature of these amounts.

Credit Risk
The majority of the accounts receivable are in respect of oil and gas operations. The Company generally extends unsecured credit to these customers and therefore the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit. The Company has not experienced any material credit loss in the collection of accounts receivable to date.

In the Republic of Yemen, the Company sold all of its 2006 Block 32 production to one purchaser and all of its 2006 Block S-1 production to two purchasers. In Canada, the Company sold primarily all of its 2006 gas production to one purchaser and primarily all of its 2006 oil production to another single purchaser.

Commodity Price Risk Management
The Company has commodity price risk associated with its sale of crude oil and natural gas.

The Company has entered into various financial derivative contracts and physical contracts to manage fluctuations in commodity prices in the normal course of operations.

In March 2005, the Company entered into a physical contract to sell 2,000 gigajoules ("GJ") per day of natural gas in Canada from April 1 to April 30, 2005 and from June 1 to October 31, 2005 for C$6.95/GJ.

In September 2005, the Company entered into a crude oil costless collar for 15,000 barrels per month from January 1, 2006 to December 31, 2006. The transaction consisted of the purchase of a $50.00 per barrel dated Brent put (floor) and a $77.93 per barrel dated Brent call (ceiling).

The estimated fair value of unrealized commodity contracts is reported on the Consolidated Balance Sheet with any change in the unrealized positions recorded to income. The fair values of these transactions are based on an approximation of the amounts that would have been paid to or received from counter parties to settle the transactions outstanding as at the Consolidated Balance Sheet date with reference to forward prices and market values provided by independent sources. The actual amounts realized may differ from these estimates.

15. SUBSEQUENT EVENT

Subsequent to December 31, 2006, the Company entered into a physical contract to sell 2,500 GJ per day of natural gas in Canada from April 1, 2007 to October 31, 2007 for C$6.97/GJ.

16. DIFFERENCES BETWEEN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN CANADA AND THE UNITED STATES OF AMERICA

The Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP or Cdn. GAAP) which differ in certain material respects from those principles that the Company would have followed had its Consolidated Financial Statements been prepared in accordance with United States of America generally accepted accounting principles (U.S. GAAP) as described below:

Consolidated Statements of Income and Retained Earnings (Deficit)

Had the Company followed U.S. GAAP, the statement of income would have been reported as follows:

(000's, except per share amounts)	**2006**	2005
Net income for the year under Canadian GAAP	**$ 26,195**	$ 19,850
Adjustments, before income taxes:		
Stock-based compensation (b)	**-**	723
Net income for the year under U.S. GAAP	**26,195**	20,573
Retained earnings (deficit), beginning of year - U.S. GAAP	**19,370**	(1,203)
Retained earnings, end of year - U.S. GAAP	**$ 45,565**	$ 19,370
Net income per share under U.S. GAAP		
- Basic	**$ 0.45**	$ 0.36
- Diluted	**$ 0.43**	$ 0.34

Statement of Other Comprehensive Income

(000's)	**2006**	2005
Net income - U.S. GAAP	**$ 26,195**	$ 20,573
Currency translation adjustment (d)	**(430)**	1,067
Other comprehensive income	**$25,765**	$ 21,640

Consolidated Balance Sheets

Had the Company followed U.S. GAAP, asset and liability sections of the balance sheet would not have changed from Canadian GAAP to U.S. GAAP, however the shareholders' equity would have been reported as follows:

	2006		2005	
	Cdn. GAAP	**U.S. GAAP**	Cdn. GAAP	U.S. GAAP
Share capital (b, c, e)	**$ 49,360**	**$ 51,063**	$ 48,922	$ 50,625
Contributed surplus (b)	**2,863**	**955**	1,908	-
Cumulative translation adjustment (d)	**3,212**	**-**	3,642	-
Accumulated other comprehensive income (d)	**-**	**3,212**	-	3,642
Retained earnings (b, c, e)	**45,360**	**45,565**	19,165	19,370
	$ 100,795	**$ 100,795**	$ 73,637	$ 73,637

The reconciling items between share capital and retained earnings for Canadian and U.S. GAAP are $833,000 related to escrowed shares, and $1,278,000 related to flow through shares. The reconciling items between contributed surplus and deficit for Canadian and U.S. GAAP are $283,000 for the adoption of stock-based compensation under Canadian GAAP and $2,033,000 for the 2005 and 2004 stock-based compensation expense under Canadian GAAP, which was not expensed in 2005 under U.S. GAAP APB Opinion No. 25 as interpreted by FASB Interpretation No. 44. The reconciling item between share capital and contributed surplus is $408,000 for the transfer of compensation expense related to options exercised in 2005 and prior.

a) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respect. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10%, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production costs and applicable taxes. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecasted pricing to determine whether impairment exists. However, in Canada, the impaired amount is measured using the fair value of reserves.

There are no impairment charges under Canadian GAAP or U.S. GAAP as at December 31, 2006. Under U.S. GAAP, the unamortized cost of the Company's Canadian oil and gas properties exceeded the full cost ceiling limitation by $3,060,000, net of taxes. The natural gas price for December 31, 2006 referenced an AECO price of C$6.50 per GJ adjusted for appropriate price differentials. As permitted by full cost accounting rules under U.S. GAAP, improvements in AECO spot natural gas prices subsequent to December 31, 2006 eliminated the necessity to record a writedown. Because of the volatility of oil and natural gas prices, no assurance can be given that the Company will not experience a writedown in future periods.

b) Stock-based Compensation

The Company has a stock-based compensation plan as more fully described in Note 8. Under Canadian GAAP, compensation costs have been recognized in the financial statements for stock options granted to employees and directors since January 1, 2002. For U.S. GAAP, the Company has adopted SFAS No. 123R effective January 1, 2006. As permitted by SFAS No. 123R, the Company has applied this change using modified prospective application for new awards granted after January 1, 2006 and for the compensation cost of awards that were not vested at December 31, 2005. In 2005 and prior periods, the Company used the intrinsic value method of accounting for stock options granted to employees and directors whereby no costs were recognized in the financial statements, per APB Opinion No. 25 as interpreted by FASB Interpretation No. 44.

The effect of applying APB Opinion No. 25 in 2005 and prior years to the Company's U.S. GAAP financial statements resulted in a decrease to stock-based compensation in 2005 by $723,000 (2004 - $1,310,000) and a corresponding decrease to the contributed surplus account. Also, the deficit would decrease by $283,000 in 2004 with a corresponding decrease to the contributed surplus account relating to the 2004 adoption entry for Canadian GAAP that is not required for U.S. GAAP. Also, the share capital would decrease by $408,000 for options exercised since the compensation expense was transferred into common shares for Canadian GAAP, this is not required for U.S. GAAP.

Had compensation expense been determined in 2005 based on fair value at the grant dates for the stock option grants consistent with the method under SFAS No. 123, the pro forma effect on the Company's net income under U.S. GAAP would be as follows:

(000's, except per share amounts)		2005
Compensation costs		$ 723
Net Income (U.S. GAAP)		
As reported		$ 20,573
Pro form		$ 19,850
Net Income per share (U.S. GAAP)		
As reported	- Basic	$ 0.36
	- Diluted	$ 0.34
Pro forma	- Basic	$ 0.34
	- Diluted	$ 0.33

c) Future Income Taxes

The Company records the renouncement of tax deductions related to flow through shares by reducing share capital and recording a future tax liability in the amount of the estimated cost of the tax deductions flowed to the shareholders. U.S. GAAP requires that the share capital on flow through shares be stated at the quoted market value of the shares at the date of issuance. In addition, the temporary difference that arises as a result of the renouncement of the deductions, less any proceeds received in excess of the quoted market value of the shares is recognized in the determination of income tax expense for the period. The effect of applying this provision to the Company's financial statements would result in an increase in income tax expense and future tax liability by $Nil in 2006, $Nil in 2005, $Nil in 2004, $876,000 in 2003, $67,000 in 2002 and $335,000 in 2000 representing the tax effect of the flow through shares and a corresponding increase to share capital and decrease to future tax liability by $Nil in 2006, $Nil in 2005, $Nil in 2004, $876,000 in 2003, $67,000 in 2002 and $335,000 in 2000 to record the recognition of the benefit of tax losses available to the Company equal to the liability arising from renouncing tax pools to the subscribers.

Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates. The effect of this change between Canadian and U.S. GAAP would result in an increase in future income tax expense and future tax liability of $215,000 in 2006, $168,000 in 2005, $231,000 in 2004 and $435,000 in 2003 representing the higher enacted tax rates over the substantively enacted tax rates and a corresponding reduction in future income tax expense and future tax liability of $215,000 in 2006, $168,000 in 2005, $231,000 in 2004 and $435,000 in 2003 to record an additional valuation allowance against the increased tax asset.

d) Foreign Currency Translation Adjustments and Other Comprehensive Income

U.S. GAAP requires gains or losses arising from the translation of self-sustaining operations to be included in other comprehensive income. Canadian GAAP requires these amounts to be recorded in a separate component of Shareholders' Equity. Other comprehensive income arose from the translation adjustment resulting from the translation of Canadian currency financial statements into U.S. dollars under FAS 52, *Foreign Currency Translation*. At December 31, 2006, accumulated other comprehensive income related to these items was a gain of $3,212,000 (2005 - $3,642,000).

e) Escrowed Shares

For U.S. GAAP purposes, escrowed shares would be considered a separate compensatory arrangement between the Company and the holder of the shares. Accordingly, the fair market value of shares at the time the shares are released from escrow will be recognized as a charge to income in that year with a corresponding increase in share capital. The difference in share capital between Canadian GAAP and U.S. GAAP represents the effect of applying this provision in 1995 when 188,000 escrow shares were released resulting in an increase in share capital of $833,000 with the offset to deficit.

f) Derivative Instruments and Hedging

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards ("SFAS") 133 effective January 1, 2001. SFAS 133 requires all derivatives to be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings unless specific hedge accounting criteria are met. To eliminate future GAAP reconciling items the Company has not designated any of its financial instruments, for the year ended December 31, 2006, as hedges for U.S. GAAP purposes under SFAS 133.

g) Recent Accounting Pronouncements

The Fair Value Option for Financial Assets and Financial Liabilities
The FASB issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. The Statement permits entities to choose to measure many financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. This Statement is expected to expand the use of fair value measurement, which is consistent with the Board's long-term measurement objectives for accounting for financial instruments.

The Statement is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. The Company is currently assessing the impact of these new requirements on the Consolidated Financial Statements.

Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans
The FASB issued SFAS 158, *Employers' Accounting for Defined Benefit Pension Plans and Other Postretirement Plans*, which amends SFAS 87, SFAS 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, SFAS 106, and SFAS 132R, *Employers' Disclosures about Pensions and Other Postretirement Benefits*. The Statement improves financial reporting by requiring an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity or changes in unrestricted net assets of a not-for-profit organization. The Statement also improves financial reporting by requiring an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions.

The Statement requires the initial recognition of the funded status of a defined benefit postretirement plan and the required disclosures as of the end of the fiscal year ending after December 15, 2006. This statement had no effect on the Consolidated Financial Statements upon adoption.

Fair Value Measurements
The FASB issued SFAS 157, *Fair Value Measurements,* which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, the Board having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, this Statement does not require any new fair value measurements. However, for some entities, the application of this Statement will change current practice.

The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company is currently assessing the impact of these new requirements on the Consolidated Financial Statements.

Accounting for Certain Hybrid Financial Instruments

The FASB issued SFAS 155, *Accounting for Certain Hybrid Financial Instruments*, which amends SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, and SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. The Statement resolves issues addressed in Statement 133 Implementation Issue No. D1, Application of Statement 133 to Beneficial Interests in Securitized Financial Assets. This Statement:

a. Permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation

b. Clarifies which interest-only strips and principal-only strips are not subject to the requirements of Statement 133

c. Establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation

d. Clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives

e. Amends Statement 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument.

The Statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. The Company is currently assessing the impact of these new requirements on the Consolidated Financial Statements.

Accounting for Uncertainty in Income Taxes

The FASB issued Interpretation 48, *Accounting For Uncertainty in Income Taxes*, which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS 109, *Accounting for Income Taxes*. The Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. Tax positions that previously failed to meet the more-likely-than-not recognition threshold should be recognized in the first subsequent financial reporting period in which that threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not recognition threshold should be derecognized in the first subsequent financial reporting period in which that threshold is no longer met.

The Interpretation is effective for fiscal years beginning after December 15, 2006. The Company is currently assessing the impact of these new requirements on the Consolidated Financial Statements.

Taxes Collected from Customers

The EITF issues EITF Abstract 06-3, *How Taxes Collected from Customers and Remitted to Government Authorities Should be Presented in the Income Statement*. The abstract provides accounting guidance on how taxes ranging from sales taxes that are applied to a broad class of transactions involving a wide range of goods and services to excise taxes that are applied only to specific types of transactions or items should be presented in the income statement.

The consensuses in the Issue should be applied to financial reports for interim and annual reporting periods beginning after December 15, 2006. The Company does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of this Abstract.

CORPORATE INFORMATION

OFFICERS AND DIRECTORS

Robert A. Halpin[1,2,3]
Director, Chairman of the Board

Ross G. Clarkson
Director, President & CEO

Lloyd W. Herrick
Director, Vice President & COO

Erwin L. Noyes[2,3,4]
Director

Geoffrey C. Chase[1,2,4]
Director

Fred J. Dyment[1,3,4]
Director

David C. Ferguson
Vice President, Finance, CFO & Secretary

Edward Bell
Vice President, Exploration

1 Audit Committee
2 Reserves Committee
3 Compensation Committee
4 Governance and Nominating Committee

STOCK EXCHANGE LISTINGS

TSX:	TGL
AMEX:	TGA

TRANSFER AGENT & REGISTRAR

Computershare Trust Company of Canada
Calgary, Toronto, Vancouver

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

BANKER

Standard Bank Plc
London, England

AUDITOR

Deloitte & Touche LLP
Calgary, Alberta

EVALUATION ENGINEERS

DeGolyer and MacNaughton Canada Limited
Calgary, Alberta

EXECUTIVE OFFICES

TransGlobe Energy Corporation
#2500, 605 - 5th Avenue S.W.
Calgary, Alberta, Canada, T2P 3H5

Telephone:	(403) 264-9888
Facsimile:	(403) 264-9898
Website:	www.trans-globe.com
E-mail:	trglobe@trans-globe.com

ABBREVIATIONS

Words

AMEX	American Stock Exchange
C	Canadian
CBM	Coal bed methane
CPF	Central Production Facility
Egypt	The Arab Republic of Egypt
GAAP	Generally Accepted Accounting Principles
G&A	General and Administrative
MD&A	Managements' Discussion and Analysis
MOM	Ministry of Oil and Minerals, Republic of Yemen
NGL	natural gas liquids
PSA	Production Sharing Agreement
Q	quarter
the Company	TransGlobe Energy Corporation and/or its wholly owned subsidiaries
TransGlobe	TransGlobe Energy Corporation and/or its wholly owned subsidiaries
TSX	Toronto Stock Exchange
U.S.	United States
WTI	West Texas Intermediate
Yemen	The Republic of Yemen
YOC	Yemen Oil Company
yr	year

Metrics

Bbl	barrel
Bopd	barrels of oil per day
MBbls	thousand barrels
MMBbls	million barrels
Mcf	thousand cubic feet
Mcfpd	thousand cubic feet per day
MMcf	million cubic feet
MMcfpd	million cubic feet per day
Bcf	billion cubic feet
MMBtu	million British thermal units
GJ	gigajoule
Boe	barrel of oil equivalent*
Boepd	barrel of oil equivalent per day*
MBoe	thousand barrels of oil equivalent*
Km	kilometer
$MM	million dollars

Well Symbols

○	drilling location
●	oil well
☼	gas well
⌖	abandoned well
	injection well

* A Boe conversion ratio of 6 Mcf = 1 Bbl has been used. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf to 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

TransGlobe Energy Corporation

#2500, 605 - 5TH AVENUE S.W., CALGARY, ALBERTA, CANADA,T2P 3H5