

InterOil Corporation Management Discussion and Analysis

For the Quarter ended June 30, 2010 (Unaudited)
August 16, 2010



TABLE OF CONTENTS

FORWARD-LOOKING STATEMENTS	2
OIL AND GAS DISCLOSURES.....	3
INTRODUCTION	4
BUSINESS STRATEGY.....	4
OPERATIONAL HIGHLIGHTS.....	5
SELECTED FINANCIAL INFORMATION AND HIGHLIGHTS.....	7
QUARTER AND SIX MONTH PERIOD IN REVIEW	12
LIQUIDITY AND CAPITAL RESOURCES.....	20
RISK FACTORS	28
CRITICAL ACCOUNTING ESTIMATES.....	28
NEW ACCOUNTING STANDARDS.....	28
NON-GAAP MEASURES AND RECONCILIATION	30
PUBLIC SECURITIES FILINGS.....	32
DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING	32
GLOSSARY OF TERMS.....	32

The following Management Discussion and Analysis (“MD&A”) should be read in conjunction with our audited annual consolidated financial statements and accompanying notes for the year ended December 31, 2009 and our unaudited interim financial statements and accompanying notes for the quarter and six months ended June 30, 2010. The MD&A was prepared by management and provides a review of our performance in the quarter and six months ended June 30, 2010, and of our financial condition and future prospects.

Our financial statements and the financial information contained in this MD&A have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and are presented in United States dollars (“USD”) unless otherwise specified. References to “we,” “us,” “our,” “Company,” and “InterOil” refer to InterOil Corporation and/or InterOil Corporation and its subsidiaries as the context requires. Information presented in this MD&A is as at June 30, 2010 and for the quarter and six months ended June 30, 2010, unless otherwise specified.

FORWARD-LOOKING STATEMENTS

This MD&A contains “forward-looking statements” as defined in U.S. federal and Canadian securities laws. Such statements are generally identifiable by the terminology used such as “may,” “plans,” “believes,” “expects,” “anticipates,” “intends,” “estimates,” “forecasts,” “budgets,” “targets” or other similar wording suggesting future outcomes or statements regarding an outlook. We have based these forward-looking statements on our current expectations and projections about future events. All statements, other than statements of historical fact, included in or incorporated by reference in this MD&A are forward-looking statements. Forward-looking statements may include, without limitation; plans for our exploration (including drilling plans) and other business activities and results therefrom; the construction of a proposed LNG plant and a proposed condensate stripping facility in Papua New Guinea; the development of such LNG plant and condensate stripping facility; the ability to secure investors in the LNG Project; the commercialization and monetization of any resources; whether sufficient resources will be established; the likelihood of successful exploration for gas and gas condensate; cash flows from operations; sources of capital; operating costs; business strategy; contingent liabilities; environmental matters; and plans and objectives for future operations; the timing, maturity and amount of future capital and other expenditures.

Many risks and uncertainties may affect the matters addressed in these forward-looking statements, including but not limited to:

- *our ability to finance the development of an LNG and a condensate stripping facility;*
- *the uncertainty in our ability to continue to attract capital;*
- *the uncertainty associated with the regulated prices at which our products may be sold;*
- *the inherent uncertainty of oil and gas exploration activities;*
- *potential effects from oil and gas price declines;*
- *the availability of crude feedstock at economic rates;*
- *our ability to timely construct and commission our LNG and condensate stripping facility;*
- *the implementation of a new ERP system could cause a financial statement error not to be detected;*
- *difficulties with the recruitment and retention of qualified personnel;*
- *losses from our hedging activities;*
- *fluctuations in currency exchange rates;*
- *the uncertainty of success in pending lawsuits and other proceedings;*
- *political, legal and economic risks in Papua New Guinea;*
- *our ability to meet maturing indebtedness;*
- *stock price volatility;*
- *landowner claims and disruption;*
- *compliance with and changes in foreign governmental laws and regulations, including environmental laws;*
- *the inability of our refinery to operate at full capacity;*
- *the impact of competition;*
- *the margins for our products;*
- *inherent limitations in all control systems, and misstatements due to errors that may occur and not be detected;*
- *exposure to certain uninsured risks stemming from our operations;*
- *contractual default;*
- *interest rate risk;*
- *weather conditions and unforeseen operating hazards;*
- *the impact of legislation regulating emissions of greenhouse gases on current and potential markets for our products;*
- *the impact of our current debt on our ability to obtain further financing;*
- *the adverse effects from importation of competing products contrary to our legal rights; and*
- *law enforcement difficulties.*

Forward-looking statements and information are based on our current beliefs as well as assumptions made by, and information currently available to, us concerning anticipated financial conditions and performance, business

prospects, strategies, regulatory developments, the ability to attract joint venture partners, future hydrocarbon commodity prices, the ability to obtain equipment in a timely manner to carry out development activities, the ability to market products successfully to current and new customers, the effects from increasing competition, the ability to obtain financing on acceptable terms, and the ability to develop reserves and production through development and exploration activities. Although we consider these assumptions to be reasonable based on information currently available to us, they may prove to be incorrect.

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements will eventuate. In light of the significant uncertainties inherent in our forward-looking statements, the inclusion of such information should not be regarded as a representation by us or any other person that our objectives and plans will be achieved. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described under the heading "Risk Factors" in our 2009 Annual Information Form.

Furthermore, the forward-looking information contained in this MD&A is made as of the date hereof, unless otherwise specified and, except as required by applicable law, we will not update publicly or revise any of this forward-looking information. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

OIL AND GAS DISCLOSURES

We are required to comply with Canadian Securities Administrators' National Instrument 51-101 Standards for Disclosure of Oil and Gas Activities ("NI 51-101"), which prescribes disclosure of oil and gas reserves and resources. GLJ Petroleum Consultants Ltd., an independent qualified reserve evaluator based in Calgary, Canada, has evaluated our resources data as at December 31, 2009 in accordance with NI 51-101, which evaluation is summarized in our 2009 Annual Information Form available at www.sedar.com. We do not have any reserves, including proved reserves, as defined under NI 51-101 or as per the guidelines set by the United States Securities and Exchange Commission ("SEC") under ASC Topic 932, as at June 30, 2010.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, possible and probable reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We include in this MD&A information that the SEC's guidelines generally prohibit U.S registrants from including in filings with the SEC. Investors are urged to consider closely the disclosure in the Company's Form 40-F dated March 1, 2010, available at www.sec.gov.

All calculations converting natural gas to crude oil equivalent have been made using a ratio of six mcf of natural gas to one barrel of crude equivalent. Barrels of oil equivalent may be misleading, particularly if used in isolation. A barrel of oil equivalent conversion ratio of six mcf of natural gas to one barrel of crude oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

INTRODUCTION

We are developing a vertically integrated energy company in Papua New Guinea and the surrounding region. Our operations are organized into four major segments:

Segments	Operations
Upstream	Exploration and Production – Explores for and appraises potential hydrocarbon structures in Papua New Guinea with a view to commercializing our discoveries. Such discoveries to date have been made in the Elk and Antelope fields and our current commercialization efforts involve the development of a proposed condensate stripping facility and development of gas production facilities for liquefied natural gas.
Midstream	Refining – Produces refined petroleum products at Napa Napa in Port Moresby, Papua New Guinea for the domestic market and for export. Liquefaction – Developing proposed onshore and/or offshore floating liquefied natural gas processing facilities in Papua New Guinea.
Downstream	Wholesale and Retail Distribution – Markets and distributes refined petroleum products domestically in Papua New Guinea on a wholesale and retail basis.
Corporate	Corporate – Provides support to the other business segments by engaging in business development and improvement activities and providing general and administrative services and management, undertakes financing and treasury activities, and is responsible for government and investor relations. General and administrative and integrated costs are recovered from business segments on an equitable basis. Our corporate segment results also include consolidation adjustments.

BUSINESS STRATEGY

Our business strategy is to develop a vertically integrated energy company in Papua New Guinea and surrounding regions, focusing on niche market opportunities with the goal of providing financial rewards for our shareholders, while being environmentally responsible, providing a quality working environment and contributing positively to the communities in which InterOil operates. A significant element of that strategy is to establish and produce gas and condensate reserves and develop liquefaction and condensate stripping facilities in Papua New Guinea. The produced LNG would be exported overseas, whilst we plan to use the condensate as feedstock for our refinery.

InterOil plans to achieve this strategy by:

- Developing our position as a prudent and responsible business operator
- Enhancing the refining and distribution business
- Maximizing the value of our exploration assets
- Monetizing our discovered resources through condensate and liquefied natural gas facilities and businesses

Further details of our business strategy can be found under the heading “*Business Strategy*” in our 2009 Annual Information Form available at www.sedar.com.

OPERATIONAL HIGHLIGHTS

Summary of operational highlights

A summary of the key operational matters and events for the quarter ended June 30, 2010, for each of the segments is as follows:

Upstream

- The definition phase (“Pre-FEED”) for the proposed Condensate Stripping Project (“CSP”) has been completed, and on April 15, 2010 we entered into a preliminary works joint venture and preliminary works financing agreement with Mitsui & Co. Ltd. (“Mitsui & Co”), to commence Front-End Engineering and Design (“FEED”) work on the CSP. Subsequent to the quarter ended June 30, 2010, on August 4, 2010, the definitive Joint Venture Operating Agreement (“JVOA”) for the proposed CSP was finalized and signed with Mitsui & Co.
- During the quarter we continued with drilling and logging of the Antelope 2 horizontal well, and performed two separate tests. The deeper of the tests confirmed an increasing condensate-to-natural gas ratio (“CGR”) of 20.4 barrels per million cubic feet of natural gas, 27% higher than observed at the top of the reservoir. The horizontal well also demonstrated dolomitization and higher porosity deeper in the reservoir than previously modeled. The well was designed to determine the CGR towards the lower section of the hydrocarbon interval of the reservoir. This ratio will assist us in the resource assessment of the reservoir and the final design of the proposed CSP.
- During the quarter, the processing and interpretation of the development seismic over the Antelope structure acquired in the prior quarter was completed. This work consisted of 100 km of 2D acquisition to further define the Antelope structure, and to select the location of the development wells on the field. Seismic interpretation and reservoir geophysical studies are continuing.
- We also conducted a joint seismic program with LNG Energy for a 27 km line which has been acquired in an area of mutual interest. Subsequent to quarter end, the processing of this data was completed. Furthermore, seismic acquisition of 20 km on the Wolverine prospect and another 20 km on the Bwata field was initiated during the second quarter and has been subsequently completed. The seismic program is designed to appraise the Bwata field and also prioritize our exploration inventory in time for deployment of our second drilling rig.
- The newly acquired drilling rig was shipped from New Zealand, and is currently at our facilities in Napa Napa where preparations for jungle operations are being completed.
- Subsequent to quarter ended June 30, 2010, on July 19, 2010, we bought back a total of 0.4% of IPI interests held under the 2005 Amended and Restated Indirect Participation Agreement. In exchange for these interests, we issued 208,281 common shares. Our current interest in the exploration licenses after this transaction is 74.5614%, assuming that all remaining indirect participation interest investors take up their working interest rights in such licenses and excluding the interests that the Independent State of Papua New Guinea is able to take up under relevant legislation.

Midstream – Refining

- Total refinery throughput for the quarter ended June 30, 2010 was 23,120 barrels per operating day, as compared with 21,574 barrels per operating day for the same period of 2009. During the quarter ended June 30, 2010 and 2009, the refinery was shut down for 2 days and 31 days, respectively.
- Capacity utilization for the quarter, based on 36,500 barrels per day operating capacity, was 63% as compared to 39% in the same quarter of 2009.
- The refinery operating days were maximized to stockpile products in anticipation of an extended maintenance shutdown in the end of third quarter of 2010.
- The Catalytic Reformer Unit was shut down for the entire quarter for repairs and maintenance. A restart of this unit is planned for midway through the third quarter. This shutdown resulted in us having to import unleaded gasoline to satisfy domestic demand, and consequently resulted in reduced margins on gasoline sales during the quarter.

Midstream – Liquefaction

- We have continued the programme to sell a portion of our interests in our Elk and Antelope fields, and in our proposed Midstream Liquefaction plant to underpin the commercialization of our gas resources.
- Subsequent to the quarter ended June 30, 2010, on August 4, 2010, an option deed was also executed with Mitsui to acquire interests of up to a 5% in the Elk and Antelope fields, and in our proposed Midstream Liquefaction plant on equal terms, yet to be determined, to those agreed with a future industry partner.

Downstream

- Total Downstream sales volumes for the second quarter 2010 were 145.6 million liters compared with 140.8 million liters for the same quarter in 2009.
- During the quarter ended June 30, 2010, we finalized the renewal agreement with Ok Tedi Mining Limited for our supply contract for a two year term with estimated volume in excess of 100.0 million liters per annum. The previous supply agreement expired in December 2009, and was being rolled over on a month to month basis since that time pending formal renewal.

Corporate

- During 2009, we reviewed and selected an Enterprise Resource Planning (“ERP”) system for implementation group-wide. The implementation process for Microsoft Dynamics AX is ongoing and we have migrated all streams except for Downstream operations on to the new system during the quarter. Downstream is expected to be migrated to the new system during the first quarter of 2011.
- Subsequent to the quarter ended June 30, 2010, on August 11, 2010, we entered into a short term secured credit facility of \$25.0 million with Clarion Finanz AG (“Clarion”). The amount is available in two installments of \$12.5 million each on August 11, 2010 and August 30, 2010. The facility will mature on January 31, 2011 and carries an interest rate of 10% per annum.

SELECTED FINANCIAL INFORMATION AND HIGHLIGHTS

Consolidated Results for the Quarter and Six Months Ended June 30, 2010 compared with the Quarter and Six Months Ended June 30, 2009

Consolidated – Operating results (\$ thousands, except per share data)	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Sales and operating revenues	223,768	147,571	401,219	308,411
Interest revenue	34	89	76	165
Other non-allocated revenue	1,547	836	2,873	1,582
Total revenue	225,349	148,496	404,168	310,158
Cost of sales and operating expenses	(191,432)	(126,006)	(350,032)	(262,418)
Office and administration and other expenses	(11,603)	(10,629)	(22,933)	(19,627)
Derivative gain/(loss)	265	(346)	(681)	931
Exploration costs	(2,308)	(31)	(2,314)	(247)
Gain on sale of oil and gas properties assets	-	1,087	-	1,087
Foreign Exchange gain/(loss)	(5,383)	5,284	(8,461)	(1,106)
Earnings before interest, taxes, depreciation and amortization ("EBITDA" - non-GAAP measure) ⁽¹⁾	14,888	17,855	19,747	28,778
Depreciation and amortization	(3,623)	(3,774)	(7,008)	(7,154)
Interest expense	(1,640)	(3,077)	(2,926)	(7,118)
Profit before income taxes and non-controlling interest	9,625	11,004	9,813	14,506
Income tax benefit/(expense)	(1,793)	(1,564)	(5,124)	(2,420)
Non-controlling interest	(2)	(2)	(2)	(4)
Net profit	7,830	9,438	4,687	12,082
Net profit per share (dollars) (basic)	0.18	0.25	0.11	0.32
Net profit per share (dollars) (diluted)	0.17	0.24	0.10	0.32
Total assets	678,398	662,411	678,398	662,411
Total liabilities	224,280	277,256	224,280	277,256
Total long-term liabilities	91,898	131,946	91,898	131,946
Gross margin ⁽²⁾	32,336	21,565	51,187	45,993
Cash flows provided by/(used in) operating activities ⁽³⁾	(29,583)	60,140	(25,543)	78,726

Notes:

- (1) Earnings before interest, taxes, depreciation and amortization, or EBITDA, is a non-GAAP measure and is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".
- (2) Gross Margin is a non-GAAP measure and is "sales and operating revenues" less "cost of sales and operating expenses" and is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".
- (3) Refer to "Liquidity and Capital Resources – Summary of Cash Flows" for detailed cash flow analysis.

Analysis of Financial Condition Comparing Quarters and Six Months Ended June 30, 2010 and 2009

During the six months ended June 30, 2010, we maintained our debt-to-capital ratio at 10% (13% in June 2009) which is in well within our targeted gearing levels of 50% or less. The optimum gearing levels are overseen by the Board of Directors based on recommendations by Management. Such recommendations are based on operating cash flows, future cash needs for development, capital market conditions, economic conditions, and will be reassessed as situations change.

As at June 30, 2010, our total assets amounted to \$678.4 million, compared with \$662.4 million as at June 30, 2009. The increase of \$16.0 million or 2.4% was primarily due to increases in our oil and gas properties of \$60.4 million associated with the appraisal and development of the Elk and Antelope fields, and \$13.1 million increase to the future income tax benefit in relation to recognition of benefits associated with past tax losses of the refining operation that are expected to be recouped in future periods. These increases have been partly offset by decreases in cash and cash equivalents of \$64.7 million.

As at June 30, 2010 our total liabilities amounted to \$224.3 million, compared with \$277.3 million as at June 30, 2009, a decrease of \$53.0 million or 19.1%. The decrease was primarily due to a reduction in the IPI liability by \$31.3 million arising from the waiver of conversion rights (of indirect participation interests into InterOil Corporation shares) during 2009 by certain IPI investors and our buy back of 4.8364% of IPI interests.

Our current ratio (being current assets/current liabilities), which measures the ability to meet short term obligations, was 1.60 as at June 30, 2010 (1.85 as at June 30, 2009). The quick ratio (or acid test ratio, being [(current assets less inventories)/current liabilities] which is a more conservative measure of our ability to meet short term obligations, was 0.98 as at June 30, 2010 (1.06 as at June 30, 2009). These are in line with our target of maintaining ratios at or above 1.50 and 1.0 respectively.

Subsequent to the quarter ended June 30, 2010, on August 4, 2010, the JVOA for the proposed CSP was finalized. The capital cost for the CSP is currently estimated at \$550.0 million, with approximately \$32.0 million of this to be expended for front end engineering design. A final investment decision is targeted by March 31, 2011. Mitsui & Co. will be responsible for arranging or providing financing for the capital costs of the plant in the event a positive final investment decision is made.

Subsequent to the quarter ended June 30, 2010, on August 11, 2010, we entered into a short term secured facility of \$25.0 million with Clarion. The amount is available in two installments of \$12.5 million each on August 11, 2010 and August 30, 2010. The facility will mature on January 31, 2011 with an interest rate of 10% per annum. The first installment has been drawn down as at August 16, 2010. We believe Clarion owns more than 5% of our outstanding common shares and holds certain direct and indirect participation interests in our exploration leases, including the Elk and Antelope fields.

Analysis of Consolidated Financial Results Comparing Quarter and Six Months Ended June 30, 2010 and 2009

The net profit for the quarter ended June 30, 2010 was \$7.8 million compared with a profit of \$9.4 million for the same quarter of 2009, a reduction of \$1.6 million. The reduction in net profit was mainly on account of higher PGK foreign exchange losses, and expensing of the seismic acquisition over the Bwata field and the Wolverine prospect. These were partly offset by higher gross margins achieved in our operations due to improved refining crack spreads, lower volatility in crude prices and the positive effect of product price movements as applied to the inventory sold during the period.

The operating segments of Corporate, Midstream - Refining and Downstream collectively derived a net profit for the second quarter of \$16.1 million, while the development segments of Upstream and Midstream Liquefaction had a net loss of \$8.3 million, for an aggregate net profit of \$7.8 million.

Sales and operating revenue increased by \$76.2 million from \$147.6 million in the quarter ended June 30, 2009 to \$223.8 million in the quarter ended June 30, 2010 primarily due to a higher price environment, and approximately 3.4% increase in domestic sales volumes.

The net profit for the six months ended June 30, 2010 was \$4.7 million compared with a profit of \$12.1 million for the same period of 2009, a reduction of \$7.4 million. The reduction in net profit was mainly on account of higher PGK foreign exchange losses, higher consulting costs attributable to the asset sales process currently underway to sell down interests in the LNG Project and in the Elk and Antelope fields, and expensing of the seismic acquisition over the Bwata field and the Wolverine prospect. These were partly offset by higher gross margins achieved in our operations due to improved refining crack spreads, lower volatility in crude prices, and lower

interest expenses associated with the 8% debentures issued in May 2008 that were fully converted into shares by June 2009.

The operating segments of Corporate, Midstream - Refining and Downstream collectively derived a net profit for the six months ended June 30, 2010 of \$20.1 million, while the development segments of Upstream and Midstream Liquefaction had a net loss of \$15.4 million, for an aggregate net profit of \$4.7 million.

Sales and operating revenue increased by \$92.8 million from \$308.4 million in the six months ended June 30, 2009 to \$401.2 million in the six months ended June 30, 2010 primarily due to a higher price environment, and approximately 5.4% increase in domestic sales volumes.

Variance Analysis of results between the quarters and six months ended June 30, 2010 and 2009

A complete discussion of each business segment's results can be found under the section 'Quarter and Six Month Period in Review'. The following analysis outlines the key variances, the net of which are the primary explanations for the changes in the results between the quarters and six months ended June 30, 2010 and 2009.

	Quarterly Variance (\$ millions)	Six Months Variance (\$ millions)	
	(\$1.6)	(\$7.4)	Net profit/(loss) variance for the comparative periods primarily due to:
➤	\$10.8	\$5.2	Increase in gross margins due to improved refining spreads, lower volatility in crude prices, lower number of shutdown days, and improved margins associated with product price inventory gains compared with same periods of 2009.
➤	(\$1.0)	(\$3.3)	Higher office and administration and other expenses, mainly resulting from higher salaries and wages expenses on translation to AUD which strengthened against USD as compared to the prior year periods. The increase is also due to higher stock compensation expense and higher consulting costs in relation to the asset sales process currently underway.
➤	(\$2.3)	(\$2.2)	Higher exploration costs during current periods on account of the seismic acquisition over the Bwata field and the Wolverine prospect which were expensed as incurred under the successful efforts method of accounting.
➤	(\$10.1)	(\$7.4)	Increase in foreign exchange loss due to movements of PGK against the USD, and lower PGK rates being achieved from banks on conversion of the PGK sales revenue into USD for repayment of our crude purchase working capital facility. The rates achieved fluctuate significantly based on the extent to which other PNG participants are looking to convert their foreign currencies. We are unable to undertake PGK currency hedging due to the relatively small size of the PGK foreign exchange market.
➤	\$1.4	\$4.2	Lower interest expense primarily due to the mandatory conversion in June 2009 of the remaining portion of the \$95.0 million 8% convertible debentures.
➤	(\$0.2)	(\$2.7)	Increase in income tax expense due to higher profit made by the Downstream segment, and under-provision of deferred tax expense in prior year taken up during the current six month period.

Analysis of Consolidated Cash Flows Comparing Quarters and Six Months Ended June 30, 2010 and 2009

As at June 30, 2010, we had cash, cash equivalents and cash restricted of \$57.2 million (June 2009 – \$117.7 million), of which \$25.6 million (June 2009 - \$21.4 million) was restricted. Of the total cash restricted, \$19.2 million (June 2009 - \$14.5 million) was restricted pursuant to the BNP Paribas working capital facility utilization requirements, and \$6.1 million (June 2009 – \$6.5 million) was restricted as a cash deposit on the Overseas Petroleum Investment Corporation (“OPIC”) secured loan.

Our cash outflows from operations for the quarter ended June 30, 2010 were \$29.6 million compared with inflows of \$60.1 million for the quarter ended June 30, 2009, a decrease in net cash inflows of \$89.7 million. This decrease is mainly due to a \$93.9 million change in operating working capital associated with timing of payments and product purchases. Our cash outflows from operations for the six months ended June 30, 2010 were \$25.5 million compared with inflows of \$78.7 million for the six months ended June 30, 2009, a decrease in net cash inflows of \$104.3 million. This decrease is mainly due to \$88.8 million change in operating working capital associated with timing of payments and product purchases, and \$15.2 million of cash received on the close out of long term hedges during the prior year six month period.

Cash outflows for investing activities for the quarter ended June 30, 2010 were \$14.9 million compared with \$36.6 million for the quarter ended June 30, 2009. For the six month period ended June 30, 2010 cash outflows were \$29.8 million compared with \$43.9 million for the same period of 2009. These outflows mainly relate to the net cash expenditure on exploration activities net of IPI cash calls, offset by the movement in the restricted cash balance governed by the BNP Paribas working capital facility and OPIC secured loan and timing of development stream (Upstream and Liquefaction) payments which are classified under investing activities. These outflows have been partly offset by the receipt of the final installment of \$13.9 million during first quarter of 2010 relating to the sale of a 2.5% direct working interest in the Elk and Antelope fields to Pacific LNG in September 2009.

Cash inflows from financing activities for the quarter ended June 30, 2010 amounted to \$35.0 million, as compared with \$30.2 million during the quarter ended June 30, 2009. For the six month period ended June 30, 2010 cash inflows were \$40.6 million compared with \$12.6 million for the same period in 2009. The financing activities section in the cash flow statement includes the capital and debt raisings by us, receipts of cash contributions from Mitsui & Co. and Petromin PNG Holdings Limited (“Petromin”) for Upstream development projects, as well as the movement in the working capital facility balance with BNP Paribas. The cash inflows/outflows due to the working capital facility drawdown/repayments are due to the timing of cash flows and use of working capital.

Summary of Consolidated Quarterly Financial Results for Past Eight Quarters

The following is a table containing the consolidated results for the eight quarters ended June 30, 2010 by business segment, and on a consolidated basis.

Quarters ended (\$ thousands except per share data)	2010		2009				2008	
	Jun-30	Mar-31	Dec-31	Sep-30	Jun-30	Mar-31	Dec-31	Sep-30
Upstream	1,349	998	1,027	1,011	660	611	487	698
Midstream – Refining	194,016	152,093	173,438	141,295	114,347	145,523	194,617	216,750
Midstream – Liquefaction	0	0	0	1	2	4	23	35
Downstream	119,300	109,687	118,270	107,712	85,472	78,572	128,540	172,528
Corporate	11,321	12,093	10,539	10,087	8,640	7,753	9,591	8,415
Consolidation entries	(100,637)	(96,052)	(93,971)	(86,509)	(60,625)	(70,801)	(114,691)	(134,695)
Sales and operating revenues	225,349	178,819	209,303	173,597	148,496	161,662	218,567	263,731
Upstream	(3,498)	(1,964)	574	(29,097)	(669)	(469)	(2,483)	231
Midstream – Refining	16,962	4,402	8,492	8,199	14,134	14,747	(13,976)	17,516
Midstream – Liquefaction	(3)	(563)	(1,200)	(2,119)	(1,379)	(2,361)	(2,501)	(1,570)
Downstream	7,060	4,492	4,391	6,542	4,150	3,241	(7,244)	610
Corporate	1,751	4,402	1,765	1,980	1,897	3,051	226	764
Consolidation entries	(7,384)	(5,910)	(4,884)	(4,092)	(278)	(7,285)	(2,865)	(737)
EBITDA ⁽¹⁾	14,888	4,859	9,138	(18,587)	17,855	10,924	(28,843)	16,814
Upstream	(7,943)	(6,182)	(3,626)	(31,392)	(2,382)	(2,133)	(4,003)	(1,039)
Midstream – Refining	12,056	(74)	18,070	3,762	9,624	10,350	(19,490)	12,660
Midstream – Liquefaction	(360)	(911)	(1,591)	(2,481)	(1,765)	(2,552)	(2,597)	(1,677)
Downstream	3,719	671	2,371	3,440	1,742	964	(5,901)	(886)
Corporate	1,796	3,544	3,036	1,602	(677)	349	(2,275)	(1,759)
Consolidation entries	(1,438)	(191)	1,047	(237)	2,894	(4,332)	37	1,928
Net profit/(loss)	7,830	(3,143)	19,307	(25,306)	9,436	2,646	(34,229)	9,227
Net profit/(loss) per share (dollars)								
Per Share – Basic	0.18	(0.07)	0.45	(0.60)	0.25	0.07	(0.96)	0.26
Per Share – Diluted	0.17	(0.07)	0.43	(0.60)	0.24	0.07	(0.96)	0.22

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled “Non-GAAP Measures and Reconciliation”.

QUARTER AND SIX MONTH PERIOD IN REVIEW

The following section provides a review of the quarter and six months ended June 30, 2010 for each of our business segments.

UPSTREAM – QUARTER AND SIX MONTH PERIOD IN REVIEW

Upstream – Operating results (\$ thousands)	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Other non-allocated revenue	1,349	660	2,347	1,271
Total revenue	1,349	660	2,347	1,271
Office and administration and other expenses	(2,367)	(1,358)	(4,818)	(2,572)
Exploration costs	(2,308)	(31)	(2,314)	(247)
Gain on sale of oil and gas properties	-	1,087	-	1,087
Foreign Exchange gain/(loss)	(172)	(1,028)	(676)	(678)
EBITDA ⁽¹⁾	(3,498)	(670)	(5,461)	(1,139)
Depreciation and amortization	(78)	(150)	(217)	(262)
Interest expense	(4,367)	(1,562)	(8,447)	(3,115)
Loss before income taxes and non-controlling interest	(7,943)	(2,382)	(14,125)	(4,516)
Income tax expense	-	-	-	-
Net (loss)/profit	(7,943)	(2,382)	(14,125)	(4,516)

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

Analysis of Upstream Financial Results Comparing Quarter and Six Months Ended June 30, 2010 and 2009

The following analysis outlines the key movements, the net of which primarily explains the difference in the results between the quarters and six months ended June 30, 2010 and 2009.

	Quarterly Variance (\$ millions)	Six Month Variance (\$ millions)	
	(\$5.6)	(\$9.6)	Net profit/(loss) variance for the comparative periods primarily due to:
➤	(\$2.3)	(\$2.2)	Higher exploration costs during current periods for seismic acquisition over the Bwata field and the Wolverine prospect which are expensed as incurred under the successful efforts method of accounting.
➤	(\$1.0)	(\$2.2)	Increase in office and administration and other expenses due primarily to higher drilling rig and equipment maintenance expenses, and higher consulting costs in relation to the asset sales process currently underway.
➤	(\$2.8)	(\$5.3)	Higher interest expense due to an increase in inter-company loan balances.

MIDSTREAM REFINING – QUARTER AND SIX MONTH PERIOD IN REVIEW

Midstream Refining – Operating results (\$ thousands)	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
External sales	104,674	62,311	172,748	144,790
Inter-segment revenue	89,327	51,961	173,239	114,983
Interest and other revenue	15	75	122	97
Total segment revenue	194,016	114,347	346,109	259,870
Cost of sales and operating expenses	(170,756)	(103,383)	(312,168)	(224,821)
Office and administration and other expenses	(2,468)	(2,581)	(5,552)	(4,873)
Derivative gain/(loss)	483	(346)	(463)	931
Foreign Exchange gain/(loss)	(4,314)	6,096	(6,562)	(2,226)
EBITDA ⁽¹⁾	16,961	14,133	21,364	28,881
Depreciation and amortization	(2,888)	(2,800)	(5,460)	(5,412)
Interest expense	(1,651)	(1,709)	(3,383)	(3,495)
Profit before income taxes and non-controlling interest	12,422	9,624	12,521	19,974
Income tax expense	(366)	-	(539)	-
Net profit	12,056	9,624	11,982	19,974
Gross Margin ⁽²⁾	23,245	10,889	33,819	34,952

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

(2) Gross Margin is a non-GAAP measure and is external sales and inter-segment revenue less cost of sales and operating expenses and is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

Midstream Refining Operating Review

Key Refining Metrics	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Throughput (barrels per day) ⁽¹⁾	23,120	21,574	24,557	22,161
Capacity utilization (based on 36,500 barrels per day operating capacity)	63%	39%	58%	46%
Cost of production per barrel ⁽²⁾	\$3.60	\$4.16	\$2.77	\$3.27
Working capital financing cost per barrel of production ⁽²⁾	\$0.42	\$0.31	\$0.43	\$0.33
Distillates as percentage of production	47%	56%	50%	57%

(1) Throughput per day has been calculated excluding shut down days. During the quarter ended June 30, 2010 and 2009, the refinery was shut down for 2 days and 31 days, respectively.

(2) Our cost of production per barrel and working capital financing cost per barrel have been calculated based on a notional throughput. Our actual throughput has been adjusted to include the throughput that would have been necessary to produce the equivalent amount of diesel that we imported during the quarter.

During the quarter ended June 30, 2010, the Customs Services Commission of Papua New Guinea ("Commission") undertook an historical review of our petroleum product imports into Papua New Guinea. Certain administrative and procedural matters concerning Papua New Guinean goods and services tax and excise are being reviewed and discussed with the Commission. We are of the view that no quantifiable liability exists and, accordingly, we have not made any provision in our accounts in relation to matter.

Analysis of Midstream - Refining Financial Results Comparing the Quarters and Six Months Ended June 30, 2010 and 2009

The following analysis outlines the key movements, the net of which primarily explains the variance in the results between the quarters and six months ended June 30, 2010 and 2009.

	Quarterly Variance (\$ millions)	Six Months Variance (\$ millions)	
	\$2.4	(\$8.0)	Net profit/(loss) variance for the comparative periods primarily due to:
➤	\$12.4	(\$1.1)	Change in Gross Margin was due to the following contributing factors: <ul style="list-style-type: none"> + Lower volatility in crude prices + Improved refining crack spreads + Improved Naphtha premiums + Less shutdown days in the second quarter - Lack of availability of preferred crude feedstock compared to prior year periods - Hedge gains realized on close out of long term hedges in early 2009, compared with little or no hedging in current periods.
➤	(\$10.4)	(\$4.3)	Increase in foreign exchange losses due to movements of PGK against the USD, and PGK lower rates being achieved from banks on conversion of the PGK sales revenue into USD for repayment of working capital facility. The rates achieved fluctuate significantly based on the extent to which other PNG participants are looking to convert their foreign currencies. We are unable to do any currency hedging due to the relatively small size of the PGK foreign exchange market.
➤	\$0.8	(\$1.4)	Movement in gains/(losses) from derivative contracts undertaken as part of our risk management strategy that were not accounted for as hedges.

MIDSTREAM LIQUEFACTION – QUARTER AND SIX MONTH PERIOD IN REVIEW

Midstream Liquefaction – Operating results (\$ thousands)	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Interest and other revenue	-	2	-	7
Total segment revenue	0	2	-	7
Office and administration and other expenses	(48)	(1,432)	(579)	(3,805)
Foreign Exchange gain/(loss)	45	51	13	58
EBITDA ⁽¹⁾	(3)	(1,379)	(566)	(3,740)
Depreciation and amortization	(6)	(20)	(12)	(40)
Interest expense	(351)	(334)	(693)	(493)
Loss before income taxes and non-controlling interest	(360)	(1,733)	(1,271)	(4,273)
Income tax expense	-	(32)	-	(44)
Net loss	(360)	(1,765)	(1,271)	(4,317)

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

Analysis of Midstream Liquefaction Financial Results Comparing the Quarters and Six Months Ended June 30, 2010 and 2009

This segment results include the proportionate consolidation of our interest in the joint venture development of a proposed midstream gas liquefaction plant. The development is being progressed through PNG LNG Inc. (we hold 52.5% economic and 86.66% shareholding interest through a wholly owned subsidiary InterOil LNG Holdings) and its subsidiaries.

All costs incurred, subsequent to the execution of the shareholders' agreement on July 31, 2007, and through the pre-acquisition and feasibility stage have been expensed as incurred, unless they were directly identified with the property, plant and equipment of the LNG Project. Since the execution of the LNG Project Agreement by a subsidiary of PNG LNG Inc with the Independent State of Papua New Guinea in December 2009, all project related direct costs have been capitalized other than overheads and other costs that are incurred in the normal course of running the business, which costs are expensed.

The following analysis outlines the key movements, the net of which primarily explains the variance in the results between the quarters and six months ended June 30, 2010 and 2009.

	Quarterly Variance (\$ millions)	Six Month Variance (\$ millions)	
	\$1.4	\$3.0	Net profit/(loss) variance for the comparative periods primarily due to:
➤	\$1.4	\$3.2	Reduction in office, administration and other expenses due to capitalization of direct expenses relating to the LNG Project during the current periods, and reduced consulting expenses incurred as the Project Agreement was executed in December 2009. The prior period balances also included loss on proportionate consolidation of PNG LNG Inc. subsequent to the acquisition of Merrill Lynch's interest in early 2009.

DOWNSTREAM QUARTER AND SIX MONTH PERIOD IN REVIEW

Downstream – Operating results (\$ thousands)	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
External sales	119,094	85,260	228,470	163,622
Inter-segment revenue	-	30	60	68
Interest and other revenue	206	182	457	354
Total segment revenue	119,300	85,472	228,987	164,044
Cost of sales and operating expenses	(108,534)	(77,450)	(209,408)	(151,081)
Office and administration and other expenses	(3,294)	(3,554)	(7,316)	(6,236)
Foreign Exchange gain/(loss)	(412)	(318)	(710)	664
EBITDA ⁽¹⁾	7,060	4,150	11,553	7,391
Depreciation and amortization	(651)	(662)	(1,311)	(1,313)
Interest expense	(1,167)	(1,013)	(1,967)	(2,154)
Profit before income taxes and non-controlling interest	5,242	2,475	8,275	3,924
Income tax expense	(1,524)	(733)	(3,885)	(1,218)
Net profit	3,718	1,742	4,390	2,706
Gross Margin ⁽²⁾	10,560	7,840	19,122	12,609

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

(2) Gross Margin is a non-GAAP measure and is "external sales" and "inter-segment revenue" less "cost of sales and operating expenses" and is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

Downstream Operating Review

Key Downstream Metrics	Quarter ended June 30,		Six Months ended June 30,	
	2010	2009	2010	2009
Sales volumes (millions of liters)	145.6	140.8	289.6	274.8

In June 2009, the Papua New Guinea Independent Consumer and Competition Commission ("ICCC") commenced a review into the pricing arrangements for petroleum products in PNG. The last such review was undertaken during 2004 and was due to expire on December 31, 2009. The purpose of the review is to consider the extent to which the existing regulation of price setting arrangements at both wholesale and retail levels should continue, or be revised for the next five year period. We have provided detailed submissions to the ICCC. After numerous deferrals commencing in late 2009, the ICCC have most recently advised that its final report will be issued in early September 2010. It is possible that the ICCC may determine to increase regulation of pricing and reduce the margins able to be obtained by our distribution business. Such a decision, if made, may negatively affect our downstream business and require a review of its operations.

Analysis of Downstream Financial Results Comparing the Quarters and Six Months Ended June 30, 2010 and 2009

The following analysis outlines the key movements, the net of which primarily explains the variance in the results between the quarters and six months ended June 30, 2010 and 2009.

	Quarterly Variance (\$ millions)	Six Month Variance (\$ millions)	
	\$2.0	\$1.7	Net profit/(loss) variance for the comparative periods primarily due to:
➤	\$2.7	\$6.5	Increase in gross margin due to 3.4% and 5.4% increases in volumes for the quarter and six months respectively, and increase in and the positive effect of product price movements as applied to the inventory sold during the period. During the same periods of the prior year the prices of the major products were in a declining trend leading to lower margins on inventories sold.
➤	(\$0.8)	(\$2.7)	Increase in income tax expense due to higher profit, and under-provision of deferred tax expense in the prior year taken during first quarter of 2010.
➤	\$0.2	(\$1.1)	Increase in office and administration and other expenses mainly relating to higher staff salary costs on translation of PGK balances to USD, and higher lease and utility costs of office premises in PNG.
➤	(\$0.1)	(\$1.4)	Foreign exchange movements during the periods due to the currency fluctuations between PGK and the USD.

CORPORATE – QUARTER AND SIX MONTH PERIOD IN REVIEW

Corporate – Operating results (\$ thousands)	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Inter-segment revenue	5,394	5,491	11,789	10,310
Interest revenue	5,927	3,149	11,625	6,083
Total revenue	11,321	8,640	23,414	16,393
Office and administration and other expenses	(8,822)	(7,226)	(16,517)	(12,521)
Derivative Loss	(218)	-	(218)	-
Foreign Exchange gain/(loss)	(530)	483	(527)	1,077
Gain on LNG shareholder agreement	-	-	-	-
EBITDA ⁽¹⁾	1,751	1,897	6,152	4,949
Depreciation and amortization	(32)	(174)	(73)	(192)
Interest expense	(20)	(1,600)	(40)	(3,925)
Profit/(loss) before income taxes and non-controlling interest	1,699	123	6,039	832
Income tax expense	97	(800)	(700)	(1,159)
Net profit/(loss)	1,796	(677)	5,339	(327)

(1) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

Analysis of Corporate Financial Results Comparing the Quarters Ended March 31, 2010 and 2009

The following analysis outlines the key movements, the net of which primarily explains the variance in the results between the quarters and six months ended June 30, 2010 and 2009.

Quarterly Variance (\$ millions)	Six Month Variance (\$ millions)	
\$2.5	\$5.7	Net profit/(loss) variance for the comparative periods primarily due to:
➤ \$5.1	\$9.4	Reduced interest expenses (net of recharged intercompany interest revenue from other segments) due to mandatory conversion in June 2009 on the remaining portion of the \$95.0 million debentures issued in May 2008, and higher interest charges to other streams on increased loan balances.
➤ (\$1.7)	(\$2.5)	Increase in net office and administration and other expenses after recharges to other streams (included in inter-segment revenue). Higher office and administration and other expenses, mainly resulting from higher salaries and wages expenses on translation to AUD which strengthened against USD as compared to the prior year periods.
➤ (\$1.0)	(\$1.6)	Decrease in foreign exchange gains due to the currency fluctuations between AUD and the USD.
➤ \$0.9	\$0.5	Reduction in income tax expense during the period primarily due to the movement related to future income tax benefit balances.

CONSOLIDATION ADJUSTMENTS – QUARTER AND SIX MONTH PERIOD IN REVIEW

Consolidation adjustments – Operating results (\$ thousands)	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Inter-segment revenue ⁽¹⁾	(94,721)	(57,483)	(185,086)	(125,363)
Interest revenue ⁽⁵⁾	(5,916)	(3,142)	(11,603)	(6,064)
Total revenue	(100,637)	(60,625)	(196,689)	(131,427)
Cost of sales and operating expenses ⁽¹⁾	87,860	54,827	171,546	113,484
Office and administration and other expenses ⁽²⁾	5,394	5,522	11,848	10,379
EBITDA ⁽³⁾	(7,383)	(276)	(13,295)	(7,564)
Depreciation and amortization ⁽⁴⁾	32	32	65	65
Interest expense ⁽⁵⁾	5,916	3,142	11,604	6,065
Profit/(loss) before income taxes and non-controlling interest	(1,435)	2,898	(1,626)	(1,434)
Non-controlling interest	(2)	(2)	(2)	(4)
Net profit/(loss)	(1,437)	2,896	(1,628)	(1,438)
Gross Margin ⁽⁶⁾	(6,861)	(2,656)	(13,540)	(11,879)

(1) Represents the elimination upon consolidation of our refinery sales to other segments and other minor inter-company product sales.

(2) Includes the elimination of inter-segment administration service fees.

(3) EBITDA is a non-GAAP measure and is reconciled to GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

(4) Represents the amortization of a portion of costs capitalized to assets on consolidation.

(5) Includes the elimination of interest accrued between segments.

(6) Gross Margin is a non-GAAP measure and is "inter-segment revenue elimination" less "cost of sales and operating expenses" and represents elimination upon consolidation of our refinery sales to other segments. This measure is reconciled to Canadian GAAP in the section to this document entitled "Non-GAAP Measures and Reconciliation".

Analysis of Consolidation Adjustments Comparing the Quarters and Six Months Ended June 30, 2010 and 2009

The following table outlines the key movements, the net of which primarily explains the variance in the results for between the quarters and six months ended June 30, 2010 and 2009.

Quarterly Variance (\$ millions)	Six Month Variance (\$ millions)	
(\$4.3)	(\$0.2)	Net profit/(loss) variance for the comparative periods primarily due to:
➤ (\$4.2)	(\$1.7)	Decrease in net income due to changes in intra-group profit eliminated on consolidation between Midstream – Refining and Downstream segments in the prior periods relating to the Midstream – Refining segment's profit component of inventory on hand in the Downstream segment at period ends.
➤ (\$0.1)	\$1.5	Movement in elimination entries related to inter-segment administration service fees.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Debt Facilities

Summarized below are the debt facilities available to us and the balances outstanding as at June 30, 2010.

Organization	Facility	Balance outstanding June 30, 2010	Maturity date
OPIC secured loan	\$49,000,000	\$49,000,000	December 2015
BNP Paribas working capital facility	\$190,000,000	\$50,633,368 ⁽¹⁾	December 2010
Westpac working capital facility	\$28,800,000	\$6,999,314	October 2011
BSP working capital facility	\$18,000,000	\$0	October 2010
Mitsui unsecured loan	\$1,118,500 ⁽²⁾	\$1,118,500	Not Applicable

(1) Excludes letters of credit totaling \$52.9 million.

(2) Facility is to fund our share of the CSP costs as they are incurred pursuant to the JVOA.

(3) On August 11, 2010, the Company closed on a \$25 million secured term loan with Clarion Finanz AG.

OPIC Secured Loan (Midstream)

On September 12, 2001, we entered into a loan agreement with OPIC for provision of \$85.0 million project financing facility for the development of our refinery in PNG. The loan is primarily secured by the assets of the refinery, and supported by a parent guarantee from InterOil Corporation. The interest rate on the loan is equal to the agreed U.S. Government treasury cost applicable to each promissory note outstanding plus 3%, and is payable quarterly in arrears. Principal repayments of \$4.5 million each are due on June 30 and December 31 of each year until December 31, 2015. At June 30, 2010, an amount of \$6.1 million was held as deposit on secured loan to secure our December 31, 2010 principal and interest payments.

BNP Paribas Working Capital Facility (Midstream)

This working capital facility is used to finance purchases of crude feedstock for our refinery. In accordance with the agreement with BNP Paribas, the total facility is split into two components, Facility 1 and Facility 2. Facility 1 is for \$130.0 million and can be used for the issuance of documentary letters of credit and or standby letters of credit, short term advances, advances on merchandise, freight loans, receivables financing and a sublimit of Euro 18.0 million or USD equivalent for hedging transactions via BNP Paribas Commodity Indexed Transaction Group or other acceptable counter parties. Facility 2 amounts to \$60.0 million and can be used for partly cash-secured short term advances and for discounting of any monetary receivables acceptable to BNP Paribas. The facility is secured by sales contracts, purchase contracts, certain cash accounts associated with the refinery, all crude and refined products of the refinery and trade receivables.

The facility is renewable annually. During the quarter ended December 31, 2009, the facility was renewed to December 31, 2010.

As of June 30, 2010, \$86.5 million remained available for use under the facility. The facility bears interest at LIBOR plus 3.5% on the short term advances. The weighted average interest rate under the working capital facility was 2.61% for the six months ended June 30, 2010 (compared to 4.39% for the same period of 2009), after including the reduction in interest due to the deposit amounts (restricted cash) maintained as security which reduces the interest being charged on the facility utilization.

Bank South Pacific and Westpac Working Capital Facility (Downstream)

On October 24, 2008, we secured a PGK 150.0 million (approximately \$54.0 million) combined revolving working capital facility for our Downstream wholesale and retail petroleum products distribution business in Papua New Guinea from Bank of South Pacific Limited and Westpac Bank PNG Limited. The facility limit as at June 30, 2010 was PGK 130.0 million (approximately \$46.8 million).

The Westpac facility limit is PGK 80.0 million (approximately \$28.8 million) and the BSP facility limit was initially PGK 70.0 million (approximately \$25.2 million). The Westpac facility is for an initial term of three years and is due for renewal in October 2011. The BSP facility is renewable annually and was renewed in October 2009 at a limit of Papua New Guinea Kina 50.0 million (approximately \$18.0 million). As at June 30, 2010, PGK 19.4 million (approximately \$7.0 million) of this combined facility had been utilized. The weighted average interest rate under the Westpac facility was 9.50% for the six months to June 30, 2010. The weighted average interest rate under the BSP facility was 9.20% for the six months to June 30, 2010.

Mitsui Unsecured Loan (Upstream)

On April 15, 2010, we entered into a preliminary works joint venture and preliminary works financing agreement with Mitsui relating to a proposed CSP for the Elk and Antelope fields. The proposed joint venture is to be entered into with equal shares held by Mitsui and InterOil. Mitsui will be responsible for arranging or providing financing for the capital costs of the plant. Subsequent to the quarter ended June 30, 2010, on August 4, 2010, the JVOA for the CSP was finalized and signed.

The portion of funding that relates to Mitsui's share of the project as at June 30, 2010, amounting to \$2.1 million is held in current liabilities as the agreement requires repayment if a FID is not reached by the end of March 2011. The portion of funding that relates to InterOil's share of the project (amounting to \$1.1 million), funded by Mitsui, is classed as an unsecured loan and interest is accrued daily based on LIBOR plus a margin of 6%.

While cash flows from operations are expected to be sufficient to cover our operating commitments, should there be a major deterioration in refining or downstream margins, our operations may not generate sufficient cash flows to cover all of the interest and principal payments under our debt facilities noted above. Also, our exploration and development activities require funding beyond our operational cash flows. As a result, we may be required to raise additional capital and/or refinance these facilities in the future. We can provide no assurances that we will be able to obtain such additional capital or that our lenders will agree to refinance these debt facilities, or, if available, that the terms of any such capital raising or refinancing will be acceptable to us.

Other Sources of Capital

Upstream

Currently our share of expenditures on exploration wells, appraisal wells and extended well programs are funded from capital raising activities, operational cash flows and asset sales.

On October 30, 2008, Petromin, a government entity mandated to invest in resource projects on behalf of the Independent State of Papua New Guinea ("the State"), entered into an agreement to take a 20.5% direct interest in the Elk and Antelope fields once the State's right to such an interest crystallized under relevant legislation. If certain conditions in the agreement are met, Petromin has agreed to fund 20.5% of the costs of developing the Elk and Antelope fields. The State's right to invest arises under legislation and is exercisable upon issuance of the Petroleum Development License ("PDL"), which has not yet occurred. The agreement contains certain provisions applicable in the event that the PDL is not issued within a certain timeframe. On grant of a PDL, Petromin has agreed to pay us 20.5% of all other sunk costs incurred by InterOil prior to entering into the agreement. Until the PDL is granted, any payment made by Petromin is to be separately held in a liability account in accordance with the provisions of the agreement. Once the PDL is granted, the conveyance of this interest to the State is able to occur, and we are obliged to distribute the proceeds received from Petromin between the existing interest holders (currently InterOil, IPI holders and Pacific LNG Operations Limited) on a pro-rata basis based on the interest surrendered by each to the State. The State may also elect to participate in

a further 2.0% working interest on behalf of the landowners of the licensed areas. As at June 30, 2010, \$13.4 million had been received from Petromin.

Cash calls are made to IPI investors, Pacific LNG Operations Ltd (for its 2.5% direct interest acquired during 2009) and Petromin for their share of amounts spent on appraisal wells and extended well programs pursuant to the relevant agreements in place with them.

In addition, as noted under summary of debt facilities section above, we entered into a preliminary works joint venture and preliminary works financing agreement with Mitsui & Co. relating to our proposed CSP for the Elk and Antelope fields. As at June 30, 2010, \$2.1 million has been received from Mitsui for their proportion of cash calls and sunk costs in relation to the venture. Mitsui has also provided a loan to us for \$1.1 million of our costs in relation the project.

Summary of Cash Flows

(\$ thousands)	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Net cash inflows/(outflows) from:				
Operations	(29,583)	60,140	(25,543)	78,726
Investing	(14,963)	(36,611)	(29,844)	(43,934)
Financing	34,983	30,178	40,603	12,588
Net cash movement	(9,563)	53,707	(14,784)	47,380
Opening cash	41,228	42,644	46,449	48,971
Closing cash	31,665	96,351	31,665	96,351

Analysis of Cash Flows Provided By/(Used In) Operating Activities Comparing the Quarters and Six Months Ended June 30, 2010 and 2009

The following table outlines the key variances in the cash flows from operating activities between quarters and six months ended June 30, 2010 and 2009:

Quarter variance	Six months variance	
(\$ millions)	(\$ millions)	
(\$89.7)	(\$104.3)	Variance for the comparative periods primarily due to:
➤ \$4.2	(\$15.5)	Decrease/(Increase) in cash used by operations prior to changes in operating working capital due to reduced margins from operations and the timing difference between the recognition and settlement of derivatives.
➤ (\$93.9)	(\$88.8)	Increase in cash used by operations due to the timing of receipts, payments and inventory purchases.

Analysis of Cash Flows Provided By/(Used In) Investing Activities Comparing the Quarters and Six Months Ended June 30, 2010 and 2009

The following table outlines the key variances in the cash flows from investing activities between quarters and six months ended June 30, 2010 and 2009:

	Quarter variance (\$ millions)	Six months variance (\$ millions)	
	\$21.6	\$14.1	Variance for the comparative periods primarily due to:
➤	(\$12.1)	(\$17.8)	Higher cash outflows for the quarter and six months to June 30, 2010 on exploration expenditures compared to the prior year period. The outflows related primarily to the Antelope 2 horizontal drilling, development seismic program on the Antelope structure, seismic on the Bwata field and the Wolverine prospect, and the Antelope Condensate Stripping project.
➤	(\$2.6)	\$9.6	Lower/(higher) cash calls and related inflows from IPI investor's.
➤	\$2.8	(\$0.6)	Lower/(higher) expenditure on acquisition of plant and equipment. Current period expenditure is mainly associated with capitalized LNG Project costs, tank upgrades and additional camp facilities at the refinery.
➤	-	\$13.9	Receipt in the first quarter of 2010 for the final installment of \$13.9 million relating to the sale of 2.5% direct working interest in the Elk and Antelope fields to Pacific LNG Operations Ltd. in September 2009.
➤	\$13.0	(\$1.2)	Higher/(lower) cash inflows due to movement in our secured cash restricted balances in line with the usage of the BNP working capital facility.
➤	\$20.5	\$10.2	Increase in cash used in our Upstream development segment for working capital requirements. This working capital relates to movements in accounts payable and accruals in our Upstream operations.

Analysis of Cash Flows Provided By/(Used In) Financing Activities Comparing the Quarters and Six Months Ended June 30, 2010 and 2009

Following table outlines the key variances in the cash flows from financing activities between quarters and six months ended June 30, 2010 and 2009:

	Quarter variance (\$ millions)	Six months variance (\$ millions)	
	\$4.8	\$28.0	Variance for the comparative periods primarily due to:
➤	\$71.8	\$97.8	Higher utilization of the BNP Paribas working capital facility
➤	\$0.9	\$0.9	Net proceeds from PNG LNG cash call made to Pacific LNG Operations Ltd for its share of costs incurred by PNG LNG and its subsidiaries in the quarter ended June 30, 2010.
➤	(\$72.1)	(\$68.9)	Lower net proceeds from the issuance of common shares in the six months ending June 30, 2010 compared to the prior year. During the quarter ended June 30, 2009 we completed a \$74.0 million registered stock offering to certain institutional investors.
➤	\$3.2	\$3.2	Funding from Mitsui relating to the CSP.

Capital Expenditures

Upstream Capital Expenditures

Gross capital expenditures for exploration in Papua New Guinea for the quarter ended June 30, 2010 were \$32.1 million compared with \$20.1 million during the same period of 2009. Total expenditures for the six month period to June 30, 2010 were \$61.5 million compared to \$43.7 million during the same period of 2009.

The following table outlines the key expenditures in the quarter and six months ended June 30, 2010:

	Quarter	Six Months	
	(\$ millions)	(\$ millions)	
	\$32.1	\$61.5	Expenditures in the quarter and six months ended June 30, 2010 due to:
➤	\$19.2	\$39.6	Drilling costs on the Antelope-2 well.
➤	-	\$4.3	Conducting development seismic program on the Antelope structure.
➤	\$2.3	\$2.3	Conducting seismic in relation to Bwata field and the Wolverine prospect.
➤	\$3.4	\$5.7	Costs for early works on Antelope condensate stripping project.
➤	\$0.9	\$2.0	Site preparation costs for the Antelope-3 appraisal well.
➤	\$6.3	\$7.6	Other expenditure, including purchase of rig and other fixed assets, and drilling consumable purchases.

IPI investors and Pacific LNG Operations (2.5% direct interest in Elk and Antelope fields) are required to fund 25.8386% as at June 30, 2010 of the Elk and Antelope extended well program costs to maintain their interest in that well program. This is the net interest to be funded by third parties after the completion of IPI buyback of 4.8364% by us and the sale of 2.5% interest to Pacific LNG Operations Limited in September 2009 pursuant to the option agreement of 2007. The amounts capitalized in our books, or expensed as incurred, in relation to the extended well program are the net amounts after adjusting for these interests.

Petromin will fund 20.5% of ongoing costs for developing the fields. Petromin contributed \$2.0 million in the quarter ended June 30, 2010 and \$3.0 million in the six months ended June 30, 2010. All funds received are being treated as a deposit until a PDL is granted.

The preliminary funding agreement entered into with Mitsui provides for funding by Mitsui of all the costs relating to the CSP. 50% of the funding is for Mitsui's share of the project and the other 50% is funding by Mitsui of our share of the project. Mitsui has contributed \$3.2 million during the quarter and six months ended June 30, 2010.

Midstream Capital Expenditures

Capital expenditures totaled \$1.5 million in our Midstream refinery segment for the six months ended June 30, 2010 mainly associated with tank upgrades and additional camp facilities. Following the signing of the LNG Project Agreement with the State in December 2009, \$0.7 million of costs incurred during the six months in relation to the Midstream Liquefaction segment have been capitalized.

Downstream Capital Expenditures

Capital expenditures for the Downstream segment totaled \$2.9 million for the six months ended June 30, 2010. These expenditures mainly related to a number of upgrade projects across various terminals and depots, and purchase of motor vehicles.

Corporate Capital Expenditures

Capital expenditures for the Corporate segment totaled \$1.5 million for the six months ended June 30, 2010. These expenditures mainly related to project costs in relation to the ERP implementation.

Capital Requirements

The oil and gas exploration and development, refining and liquefaction industries are capital intensive and our business plans necessarily involve raising additional capital. The availability and cost of such capital is highly dependent on market conditions at the time we raise such capital. No assurance can be given that we will be successful in obtaining new sources of capital on terms that are acceptable to us, particularly given continuing market conditions.

Upstream

We are required under our \$125.0 million Amended and Restated Indirect Participation Agreement (“IPI Agreement”) of 2005 to drill eight exploration wells. We have drilled four wells to date. As at June 30, 2010, we are committed to spend a further \$83.0 million as a condition of renewal of our petroleum prospecting and retention licenses up to 2014. Of this \$83.0 million commitment, as at June 30, 2010, management estimates that \$46.4 million would be used to drill the final four wells and satisfy the commitments in relation to the Amended and Restated IPI Agreement of February 2005.

We will need to raise additional funds in order for us to complete the programs and meet our exploration commitments. Therefore, we must extend or secure sufficient funding through renewed borrowings, equity raising and or asset sales to enable the availability of sufficient cash to meet these obligations over time and complete these long term plans. No assurances can be given that we will be successful in obtaining new sources of capital on terms acceptable to us, particularly given the current market conditions.

We will also be required to obtain substantial amounts of financing for the development of Elk and Antelope fields, condensate stripping plant and delivery of gas to the LNG Project and it would take a number of years to complete these projects. In the event that the commercial viability of these projects is established, we plan to use a combination of debt, equity and the partial sale of capitalized properties to raise adequate capital. The Pre-FEED analysis for the CSP was completed and on April 15, 2010 we signed a preliminary works joint venture and preliminary works financing agreement with Mitsui & Co Ltd for the condensate stripping venture for the Elk and Antelope fields. We are also progressing the asset sell down process.

The availability and cost of various sources of financing is highly dependent on market conditions at the time and we can provide no assurances that we will be able to obtain such financing or conduct such sales on terms that are acceptable.

Midstream - Refining

Refinery is planned to be on an extended maintenance shutdown in the end of third quarter of 2010. We believe that we will have sufficient funds from our operating cash flows to pay our estimated capital expenditures associated with our Midstream – Refining segment in 2010. We also believe cash flows from operations will be sufficient to cover the costs of operating our refinery and the financing charges incurred under our crude import facility. Should there be a major deterioration in refining margins, our refinery may not generate sufficient cash flows to cover all of the interest and principal payments under our secured loan agreements. As a result, we may be required to raise additional capital and/or refinance these facilities in the future. No assurances can be given that we will be able to do so on acceptable terms.

Midstream - Liquefaction

We and our current joint venture partner in the LNG Project - Pacific LNG Operations Limited, are currently in the process of inviting bids from industry majors and other interested parties to participate in the LNG Project as a joint venture partner in association with the direct sell down process previously referred to.

Completion of any liquefaction facility will require substantial amounts of financing and construction will take a number of years to complete. As a joint venture partner in the LNG Project, if the project proceeds, we would be required to fund our share of the development costs. No assurances can be given that we will be able to source sufficient gas, successfully construct such a facility, or as to the timing of such construction. The availability and cost of capital is highly dependent on market conditions and our circumstances at the time we raise such capital.

Downstream

We believe on the basis of current market conditions and the status of our business that our cash flows from operations will be sufficient to meet our estimated capital expenditures for our wholesale and retail distribution business segment for 2010.

Contractual Obligations and Commitments

The following table contains information on payments required to meet contracted obligations due for each of the next five years and thereafter. It should be read in conjunction with our financial statements for the quarter ended June 30, 2010 and the notes thereto:

Contractual obligations (\$ thousands)	Payments Due by Period						
	Total	Less than 1 year	1 - 2 years	2 - 3 years	3 - 4 years	4 - 5 years	More than 5 years
Secured and Unsecured loans ⁽³⁾	50,119	10,119	9,000	9,000	9,000	9,000	4,000
Indirect participation interest ⁽¹⁾	1,384	540	844	-	-	-	-
PNG LNG Inc. Joint Venture (proportionate share of commitments)	23	23	-	-	-	-	-
Petroleum prospecting and retention licenses ⁽²⁾	83,000	4,500	9,500	20,000	14,850	34,150	-
Total	134,526	15,182	19,344	29,000	23,850	43,150	4,000

(1) These amounts represent the estimated cost of completing our commitment to drill exploration wells under our indirect participation interest agreement entered into in July 2003 (Indirect Participation Interest - PNGDV). See Note 19 to our financial statements for the quarter and six months ended June 30, 2010.

(2) The amount pertaining to the petroleum prospecting and retention licenses represents the amount we have committed as a condition on renewal of these licenses. Of this \$83.0 million commitment, as at June 30, 2010, management estimates that \$46.4 million would satisfy the commitments in relation to the IPI investors.

(3) This excludes the contractual interest payments on the principal amount. The effective interest rate on this loan for the quarter ended June 30, 2010 was 6.80%. The annual effective interest rate will be applied to the outstanding balance for the contractual interest payment calculation.

Off Balance Sheet Arrangements

Neither during the quarter, nor as at June 30, 2010, did we have any off balance sheet arrangements or any relationships with unconsolidated entities or financial partnerships.

Transactions with Related Parties

Petroleum Independent and Exploration Corporation, a company owned by Mr. Mulacek, our Chairman and Chief Executive Officer, earned management fees of \$75,000 during the six months ended June 30, 2010 (June 2009 - \$75,000). This management fee relates to Petroleum Independent and Exploration Corporation acting as the General Manager of one of our subsidiaries, S.P. InterOil LDC, in compliance with OPIC loan requirements.

Breckland Limited, a company controlled by Mr. Roger Grundy, one of our directors, provides technical and advisory services to us on normal commercial terms. Amounts paid or payable to Breckland for technical services during the six months ended June 30, 2010 amounted to \$22,550 (June 2009 - \$nil).

Share Capital

Our authorized share capital consists of an unlimited number of common shares and unlimited number of preferred shares, of which 1,035,554 series A preferred shares are authorized. As of June 30, 2010, we had 43,756,354 common shares (46,303,850 common shares on a fully diluted basis) and no preferred shares outstanding. The dilutive instruments outstanding as at June 30, 2010 included employee stock options and restricted stock in respect of 2,068,683 common shares, IPI conversion rights to 473,813 common shares, and 5,000 common shares able to be issued to Petroleum Independent and Exploration Corporation in exchange for the 5,000 shares it holds in our subsidiary, S.P. InterOil LDC.

Derivative Instruments

Our revenues are derived from the sale of refined products. Prices for refined products and crude feedstocks can be volatile and sometimes experience large fluctuations over short periods of time as a result of relatively small changes in supplies, weather conditions, economic conditions and government actions. Due to the nature of our business, there is always a time difference between the purchase of a crude feedstock and its arrival at the refinery and the supply of finished products to the various markets.

Generally, we purchase crude feedstock two months in advance, whereas the supply/export of finished products will take place after the crude feedstock is discharged and processed. Due to the fluctuation in prices during this period, we use various derivative instruments as a tool to reduce the risks of changes in the relative prices of our crude feedstocks and refined products. These derivatives, which we use to manage our price risk, effectively enable us to lock-in the refinery margin such that we are protected in the event that the difference between our sale price of the refined products and the acquisition price of our crude feedstocks contracts is reduced. Conversely, when we have locked-in the refinery margin and if the difference between our sales price of the refined products and our acquisition price of crude feedstocks expands or increases, then the benefits would be limited to the locked-in margin

The derivative instrument which we generally use is the over-the-counter (OTC) swap. The swap transactions are concluded between counterparties in the derivatives swaps market, unlike futures which are transacted on the International Petroleum Exchange ("IPE") and Nymex Exchanges. We believe these hedge counterparties to be credit worthy. It is common place among refiners and trading companies in the Asia Pacific market to use derivatives swaps as a tool to hedge their price exposures and margins. Due to the wide usage of derivatives tools in the Asia Pacific region, the swaps market generally provides sufficient liquidity for the hedging and risk management activities. The derivatives swap instrument covers commodities or products such as jet and kerosene, diesel, naphtha, and also bench-mark crudes such as Tapis and Dubai. Using these tools, we actively engage in hedging activities to lock in margins. Occasionally, there is insufficient liquidity in the crude swaps market and we then use other derivative instruments such as Brent futures on the IPE to hedge our crude costs.

At June 30, 2010, we had a net receivable of \$483,000 (June 2009 – \$nil) relating to commodity hedge contracts for which hedge accounting was not applied. The gain on hedges for which final pricing will be determined in future periods was \$nil (June 2009 - \$7.8 million and was included in comprehensive income).

No gain was recognized from the effective portion of priced out hedge accounted contracts for the six months ended June 30, 2010 (June 2009 –\$9.4 million), and no gain was recognized on the non-hedge accounted derivative contracts and the ineffective portion of hedge accounted contracts for the six months ended June 30, 2010 (June 2009 –\$0.3 million).

In addition to the commodity derivative contracts, we have also entered into foreign exchange derivative contracts to manage our foreign exchange risk in relation to Australian Dollars ("AUD"). As at June 30, 2010 we had a net payable of \$0.1 million relating to our foreign currency derivatives. A loss of \$0.2 million was recognized on these contracts for the six months ended June 30, 2010.

For a detailed description of our current derivative contracts as of June 30, 2010, see Note 7 to our financial statements for the quarter and six months ended June 30, 2010.

RISK FACTORS

Our business operations and financial position are subject to a range of risks. A summary of the key risks that may impact upon the matters addressed in this document have been included under section “Legal Notice – Risk Factors and Forward Looking Statements” above. Detailed risk factors can be found under the heading “Risk Factors” in our 2009 Annual Information Form available at www.sedar.com. Other than as set forth below, there have not been any changes to our risk factors.

The implementation of a new enterprise resource planning system could cause a financial statement error not to be detected:

We are in the process of implementing a new ERP system to replace our current system. This new system will result in changes to our internal controls over financial reporting, including disclosure controls and procedures. The possibility exists that the migration to new ERP system could adversely affect the effectiveness of our internal controls over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. For a discussion of those accounting policies, please refer to our Management’s Discussion and Analysis for the year ended December 31, 2009, in conjunction with Note 2 of the notes to our consolidated financial statements for the year ended December 31, 2009, available at www.sedar.com which summarizes our significant accounting policies.

NEW ACCOUNTING STANDARDS

For a discussion of the new accounting standards to be used by us in 2010, please refer to our Management’s Discussion and Analysis for the year ended December 31, 2009 available at www.sedar.com.

Based on the detailed review conducted by the Company of the new CICA sections, or revisions to current sections, that are effective for the year beginning January 1, 2010, no items have been identified as having any material impact on the Company’s financial statements.

Changeover to International Financial Reporting Standards (“IFRS”)

The Accounting Standards Board (“AcSB”) announced its intention to adopt International Financial Reporting Standards (“IFRS”) as Canadian GAAP, effective January 1, 2011. In anticipation of the change, the AcSB is revising certain Canadian accounting standards to conform to IFRS in advance of the 2011 implementation date. The required change to IFRS is mandatory for all Canadian publicly accountable entities, which includes those with public debt.

The SEC currently allows foreign private issuers using IFRS as their primary GAAP to not provide reconciliation to U.S. GAAP in their financial statements.

We will adopt IFRS as per the guidelines issued by AcSB and report under IFRS effective January 1, 2011 with comparative IFRS numbers for 2010.

We have an IFRS Steering Committee working under the oversight of the Audit Committee monitoring the IFRS transition plan. Based on the work performed on evaluating key differences between Canadian GAAP and IFRS as applicable to us, no major differences have yet been noted that would have any significant effect on transition to IFRS. As a result of this assessment, we do not expect that there will be a significant impact on us in relation to our systems and internal controls.

We will continue to monitor the revisions being made by AcSB to the Canadian accounting standards to conform to IFRS in advance of the 2011 implementation date. Any revisions that will result in a change in the accounting policy of InterOil, on adoption of IFRS effective January 1, 2011, will be disclosed as policy changes in the financial statements.

The areas in which we anticipate revisions to accounting standards prior to the IFRS adoption date of January 1, 2011 that may affect InterOil's accounting policies are:

- Oil and Gas industry specific accounting under IFRS or Canadian GAAP is currently not as comprehensive as the guidance provided under U.S. GAAP accounting for industry specific oil and gas transactions. International Accounting Standards Board ("IASB") has commenced a project to publish guidelines on accounting for oil and gas transactions, which may be different from the current guidelines under U.S. GAAP.
- Section 3055 - Joint Venture Interests under Canadian GAAP differs from similar guidance under IAS 31 as IAS 31 permits the use of either the proportionate consolidation method or the equity method to account for joint ventures. IASB has commenced a project to remove the option for accounting for interests in jointly controlled entities using the proportionate consolidation method. InterOil currently uses proportionate consolidation for accounting for the LNG joint venture under Canadian GAAP, and equity accounting for the same under U.S. GAAP.
- Other areas that are being monitored include property plant and equipment measurement and impairment, measurement and recognition of provisions, enterprises in development stage, and the optional exemptions available under IFRS 1 which provides a mandatory framework for first time adopters which supersedes the transitional provisions of individual standards.

We have reviewed current guidance under IFRS 1 – 'First-time Adoption of International Financial Reporting Standards' in relation to the transitional provisions on 'Exceptions to the retrospective application to other IFRSs' and 'Exemptions from other IFRSs', and noted no major differences that would have any significant effect on transition to IFRS based on optional elections that we are proposing to make under this standard.

NON-GAAP MEASURES AND RECONCILIATION

Gross Margin is a non-GAAP measure and is “sales and operating revenues” less “cost of sales and operating expenses”. The following table reconciles sales and operating revenues, a GAAP measure, to Gross Margin:

Consolidated – Operating results (\$ thousands)	Quarter ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Midstream – Refining	194,001	114,272	345,987	259,773
Downstream	119,094	85,290	228,530	163,690
Corporate	5,394	5,491	11,789	10,310
Consolidation Entries	(94,721)	(57,482)	(185,087)	(125,362)
Sales and operating revenues	223,768	147,571	401,219	308,411
Midstream – Refining	(170,756)	(103,383)	(312,168)	(224,821)
Downstream	(108,534)	(77,450)	(209,408)	(151,081)
Corporate ⁽¹⁾	-	-	-	-
Consolidation Entries	87,859	54,827	171,544	113,484
Cost of sales and operating expenses	(191,432)	(126,007)	(350,032)	(262,418)
Midstream – Refining	23,245	10,889	33,819	34,952
Downstream	10,560	7,840	19,122	12,609
Corporate ⁽¹⁾	5,394	5,491	11,789	10,310
Consolidation Entries	(6,862)	(2,655)	(13,543)	(11,878)
Gross Margin	32,336	21,564	51,187	45,993

(1) Corporate expenses are classified below the gross margin line and mainly relates to ‘Office and admin and other expenses’ and ‘Interest expense’.

EBITDA represents our net income/(loss) plus total interest expense (excluding amortization of debt issuance costs), income tax expense, depreciation and amortization expense. EBITDA is used by us to analyze operating performance. EBITDA does not have a standardized meaning prescribed by United States or Canadian generally accepted accounting principles and, therefore, may not be comparable with the calculation of similar measures for other companies. The items excluded from EBITDA are significant in assessing our operating results. Therefore, EBITDA should not be considered in isolation or as an alternative to net earnings, operating profit, net cash provided from operating activities and other measures of financial performance prepared in accordance with GAAP. Further, EBITDA is not a measure of cash flow under GAAP and should not be considered as such. For reconciliation of EBITDA to the net income (loss) under GAAP, refer to the following table.

The following table reconciles net income (loss), a GAAP measure, to EBITDA, a non-GAAP measure for each of the last eight quarters.

Quarters ended (\$ thousands)	2010		2009				2008	
	Jun-30	Mar-31	Dec-31	Sep-30	Jun-30	Mar-31	Dec-31	Sep-30
Upstream	(3,498)	(1,964)	574	(29,097)	(669)	(469)	(2,483)	231
Midstream – Refining	16,962	4,402	8,492	8,199	14,134	14,747	(13,976)	17,516
Midstream – Liquefaction	(3)	(563)	(1,200)	(2,119)	(1,379)	(2,361)	(2,501)	(1,570)
Downstream	7,060	4,492	4,391	6,542	4,150	3,241	(7,244)	610
Corporate	1,751	4,402	1,765	1,980	1,897	3,051	226	764
Consolidation Entries	(7,384)	(5,910)	(4,884)	(4,092)	(278)	(7,285)	(2,866)	(737)
Earnings before interest, taxes, depreciation and amortization	14,888	4,859	9,138	(18,587)	17,855	10,924	(28,844)	16,814
Subtract:								
Upstream	(4,367)	(4,080)	(4,056)	(2,164)	(1,563)	(1,552)	(1,345)	(1,137)
Midstream – Refining	(1,651)	(1,731)	(1,973)	(1,682)	(1,709)	(1,786)	(2,771)	(2,113)
Midstream – Liquefaction	(351)	(342)	(379)	(348)	(333)	(158)	(65)	(63)
Downstream	(1,167)	(800)	(930)	(1,045)	(1,013)	(1,142)	(2,232)	(885)
Corporate	(20)	(20)	(27)	-	(1,600)	(2,325)	(2,320)	(2,484)
Consolidation Entries	5,916	5,687	5,905	3,823	3,141	2,923	2,866	2,636
Interest expense	(1,640)	(1,286)	(1,460)	(1,416)	(3,077)	(4,040)	(5,867)	(4,046)
Upstream	-	-	-	-	-	-	-	-
Midstream – Refining	(366)	(173)	14,316	-	-	-	0	-
Midstream – Liquefaction	0	0	(8)	(3)	(32)	(12)	(12)	(25)
Downstream	(1,524)	(2,361)	(411)	(1,398)	(733)	(485)	4,297	82
Corporate	97	(797)	1,340	(339)	(800)	(359)	(163)	(21)
Consolidation Entries	(2)	0	(3)	(1)	(2)	(2)	4	(3)
Income taxes and non- controlling interest	(1,795)	(3,331)	15,234	(1,741)	(1,567)	(858)	4,126	33
Upstream	(78)	(138)	(144)	(132)	(150)	(112)	(175)	(134)
Midstream – Refining	(2,888)	(2,572)	(2,765)	(2,755)	(2,801)	(2,611)	(2,742)	(2,742)
Midstream – Liquefaction	(6)	(6)	(7)	(10)	(20)	(20)	(19)	(19)
Downstream	(651)	(660)	(679)	(658)	(662)	(651)	(722)	(693)
Corporate	(32)	(41)	(43)	(40)	(174)	(18)	(19)	(18)
Consolidation Entries	32	32	33	33	32	32	33	33
Depreciation and amortisation	(3,623)	(3,385)	(3,605)	(3,562)	(3,775)	(3,380)	(3,644)	(3,573)
Upstream	(7,943)	(6,182)	(3,626)	(31,392)	(2,382)	(2,134)	(4,003)	(1,039)
Midstream – Refining	12,056	(74)	18,071	3,762	9,624	10,349	(19,490)	12,660
Midstream – Liquefaction	(360)	(911)	(1,593)	(2,481)	(1,764)	(2,551)	(2,596)	(1,677)
Downstream	3,718	671	2,371	3,440	1,742	964	(5,900)	(886)
Corporate	1,796	3,544	3,034	1,601	(677)	350	(2,276)	(1,759)
Consolidation Entries	(1,437)	(191)	1,050	(236)	2,893	(4,332)	38	1,929
Net profit/(loss) per segment	7,830	(3,143)	19,307	(25,306)	9,436	2,646	(34,227)	9,228

PUBLIC SECURITIES FILINGS

You may access additional information about us, including our Annual Information Form for the year ended December 31, 2009, in documents filed with the Canadian Securities Administrators at www.sedar.com, and in documents, including our Form 40-F, filed with the U.S. Securities and Exchange Commission at www.sec.gov. Additional information is also available on our website www.interoil.com.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's certifying officers have designed disclosure controls and procedures, as such term is defined in National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings ("National Instrument 52-109"), or caused them to be designed under their supervision, to provide reasonable assurance that all material information required to be disclosed the Company in its interim filings is processed, summarized and reported within the time periods specified in applicable Canadian securities legislation.

The Company's certifying officers are responsible for establishing and maintaining internal control over financing reporting ("ICFR"), as such term is defined in National Instrument 52-109. The control framework the Company's officers used to design the Company's ICFR is the framework established by the Committee of Sponsoring Organizations (COSO) entitled – Internals Controls – Integrated Framework.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its ICFR as at December 31, 2009 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2009, the Company's ICFR provides reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

The Company is in the process of implementing its new enterprise resource planning system (the "ERP System") in line with its growth objective. The ERP system implementation required installation of new hardware and software into our Information Technology environment and the way we record, process and report financial transactions. Effective June 1, 2010 we migrated to the new ERP system for companies in our Corporate, Midstream and Upstream segments, with a plan to migrate the operating company of our downstream segment during Quarter 1, 2011.

Management has reviewed the internal controls over financial reporting affected by the implementation and made appropriate changes to internal controls as part of the implementation. Other procedures including the testing of redundant controls and selected testing of new controls ensures the financial statements were materially accurate for the one month ended June 30, 2010.

For further details on our disclosure controls and procedures, please refer to our Management's Discussion and Analysis for the year ended December 31, 2009 available at www.sedar.com.

GLOSSARY OF TERMS

Barrel, Bbl Unit volume measurement used for petroleum and its products, equivalent to 42 U.S. gallons.

BNP Paribas BNP Paribas Capital (Singapore) Limited.

Condensate A component of natural gas which is a liquid at surface conditions.

Crude Oil A mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

CSP The proposed Condensate Stripping Project being progressed in joint venture with Mitsui & Co.

EBITDA Earnings before interest, taxes, depreciation and amortization. EBITDA represents net income/(loss) plus total interest expense (excluding amortization of debt issuance costs), income tax expense, depreciation and amortization expense. EBITDA is used to analyze operating performance.

Feedstock Raw material used in a processing plant.

GAAP Generally accepted accounting principles.

Gas A mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

ICCC Independent Consumer and Competition Commission. The statutory competition authority in Papua New Guinea.

IPP Import Parity Price. For each refined product produced and sold locally in Papua New Guinea, IPP is calculated by adding the costs that would typically be incurred to import such product to the average posted price for such product in Singapore as reported by Platts. The costs that are added to the reported Platts price include freight costs, insurance costs, landing charges, losses incurred in the transportation of refined products, demurrage and taxes.

IPI Indirect Participation Interest. These interests are held by various investors pursuant to participation interest agreements entered into in 2003, 2004 and 2005 and identified more fully in our Annual Information Form.

Joint Venture Company or **PNG LNG** means PNG LNG, Inc., a joint venture company established in 2007, and now owned by InterOil LNG Holdings Inc., an affiliate of InterOil, and Pacific LNG Operations Ltd. to construct the proposed LNG plant.

JVOA Joint Venture Operating Agreement.

LIBOR Daily reference rate based on the interest rates at which banks borrow unsecured funds from banks in the London wholesale money market.

LNG Liquefied natural gas. Natural gas converted to a liquid state by pressure and severe cooling, and then returned to a gaseous state to be used as fuel. LNG is moved in tankers, not via pipelines. LNG, which is predominantly artificially liquefied methane, is not to be confused with NGLs, natural gas liquids, which are heavier fractions that occur naturally as liquids

LNG Project The potential development by us of a liquefied natural gas processing facility in Papua New Guinea described as our Midstream Liquefaction business segment and being undertaken as a joint venture with Pacific LNG Operations Ltd through a joint venture company PNG LNG Inc.

LSWR Low Sulphur Waxy Residue.

Naphtha That portion of the distillate obtained in the refinement of petroleum which is an intermediate between the lighter gasoline and the heavier benzene, has a specific gravity of about 0.7, and is used as a solvent for varnishes, illuminant, and other similar products.

Natural gas A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

PDL Petroleum Development License. The right granted by the State to develop a field for commercial production.

PGK the Kina, Currency of Papua New Guinea.

PPL Petroleum Prospecting License. The tenement given by the State to explore for oil and gas.

PRL Petroleum Retention License. The tenement given by the Independent State of Papua New Guinea to allow the licensee holder to evaluate the commercial and technical options for the potential development of an oil and/or gas field.

State or **PNG** means the Independent State of Papua New Guinea.

USD United States Dollars.