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PACIFIC RUBIALES ENERGY CORP.
MANAGEMENT DISCUSSION AND ANALYSIS

May 18, 2011
Form 51-102 F1
For the three month period ended March 31, 2011

1. Preface

This Management Discussion and Analysis ("MD&A") contains forward-looking information and is based on the current expectations, estimates, projections and assumptions of Pacific Rubiales Energy Corp-. This information is subject to a number of risks and uncertainties, many of which are beyond the Company's control. Users of this information are cautioned that actual results may differ materially. For information on material risk factors and assumptions underlying our forward-looking information, see page 37.

This MD&A is management's assessment and analysis of the results and financial condition of the Company, and should be read in conjunction with the accompanying consolidated financial statements for the first quarter of 2011, and the 2010 audited annual consolidated financial statements of the Company and related notes. The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standard Board ("IASB") unless otherwise noted. Note 24 to the interim condensed consolidated financial statements contains a detailed description of the Company's first annual reporting under IFRS. All comparative percentages are between the quarters ended March 31, 2011 and March 31, 2010, unless otherwise stated. The following financial measures: (i) EBITDA; (ii) funds flow from operations; and (iii) income from operations, as referred to in this MD&A, are not prescribed by IFRS and are outlined under "Additional Financial Measures" on page 37. All references to net barrels or net production reflect only the Company's share of production after deducting royalties and the operating partner's working interest. A glossary of oil and gas terms is provided on page 40.

In order to provide the shareholders of the Company with full disclosure relating to potential future capital expenditures, we have provided cost estimates for projects that, in some cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For further discussion of the significant capital expenditures, see "Capital Expenditures" on page 25.

References to "we", "our", "us", "Pacific Rubiales" or "the Company" mean Pacific Rubiales Energy Corp., its subsidiaries, partnerships and joint venture investments, unless the context otherwise requires. The table and charts in this document form an integral part of this MD&A. Pacific Rubiales, a Canadian-based company and producer of natural gas and heavy crude oil, owns 100 percent of Meta Petroleum Corp., a Colombian oil branch which operates the Rubiales/ Piriri and Quifa oil fields in the Llanos Basin in association with Ecopetrol, S.A. ("Ecopetrol"); and Pacific Stratus Energy Colombia Corp. ("Pacific Stratus"), which operates the wholly-owned La Creciente gas field in the northern part of Colombia and other light and medium oil fields. The Company, through an intensive exploration activity and a large exploration portfolio, is focused on identifying opportunities primarily within the eastern Llanos Basin of Colombia, as well as in other areas in Colombia, Guatemala and northern Peru. Pacific Rubiales has a current gross production of approximately 225,000 boe/d, with working interests in 35 blocks in Colombia, 2 blocks in Guatemala and 3 blocks in Peru.

Additional information relating to the Company filed with Canadian securities regulatory authorities, including the Company's quarterly and annual reports and the Annual Information Form, are available on SEDAR at www.sedar.com and at www.pacificrubiales.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

2. Executive Summary

Financial and Operating Summary

During the first quarter of 2011, the Company continued the trend of outstanding production growth and exploratory success, leveraging its technical know-how and operational expertise. The results for this period underline the strength of the Company's operational activity and its capacity to increase production, as well as management's commitment to deliver robust financial results. Management is focused on achieving challenging operational goals, while pursuing an ambitious exploration and production ("E&P") investment program, under the umbrella of the Company's paramount strategic focus: Growth.

Revenue increased 54% to $583.5 million compared to $379.4 million in the same period in 2010. The increase resulted from higher production, optimization of marketing activities and higher combined crude and gas prices. Revenues in the first quarter of 2011 were impacted by the timing of the revenue recognition of 732,934 bbl of crude oil production exported in the first week of April 2011.

EBITDA for the first quarter of 2011 totaled $363 million, representing a significant increase of 56% as compared to EBITDA for the previous year's first quarter of $232 million. First quarter 2011 EBITDA represents a 62% margin in comparison to total revenues for the period.

Net earnings, before non-cash items, amounted to $134.2 million, or $0.50 per common share, compared to $98.9 million in the previous year. Net earnings after non-cash items of $203.8 million, was a net loss of $69.6 million for the period. The non-cash items include unrealized mark-to-market losses on derivatives of $92.6 million, the equity tax in Colombia of $68.5 million fully recognized in this quarter, share-based compensation of $46.7 million, and foreign exchange gain of $4 million.

Average gross production in the first quarter of 2011 reached 196,272 boe/d, 51% higher than in the same period of 2010, and is the result of the production yield from more than 61 new development wells, mainly in the Rubiales and Quifa fields. The operated production in the first quarter of 2011 was negatively impacted by land transportation logistics, caused by heavy rains that generated a country-wide state of emergency, and delays in the OCENSA expansion from 450,000 bbl/d to 560,000 bbl/d. Once the transportation problems were solved, the Company's production reached 225,000 boe/d of gross operated production as of May 12, 2011, which continues to make the Company the fastest growing oil and gas company in Colombia, as well as the country's second largest operator.

Crude oil operating netback during the first quarter of 2011 was $56.20/bbl, higher by 22% in comparison to the same period in 2010, due to higher realized prices and lower differentials with respect to WTI. Natural gas operating netback was $30.71/boe, higher by 44% in comparison to the same period of 2010.

Capital expenditures in the first quarter totaled $175.7 million (2010 - $80.8 million), of which $75.5 million was invested in the expansion and construction of production infrastructure; $41.5 million went into exploration activities including seismic, aerogravimetry, aeromagnetometry and drilling; $56.1 million was invested in production drilling activities; and $2.6 million was invested in other projects.

On March 10, 2011, the Company's Board of Directors approved a cash dividend in the aggregate amount of $25 million, or $0.093 per common share. The dividend was paid on March 30, 2011 to shareholders of record as of March 16, 2011.

On March 6, 2011, the Company announced that it had filed with the Toronto Stock Exchange (the "TSX") a Notice of Intention to commence a normal course issuer bid to purchase for cancellation up to a maximum of 11,598,513, or 4.3%, of the total issued and outstanding common shares in the capital of the Company as of March 31, 2011. The Company has not purchased any common shares to date pursuant to the normal course issuer bid.

On March 31, 2011, the Company announced the acquisition of 49.9999% of the interests held by Maurel et Prom in the Sabanero, Muisca, SSJN-9, CPO-17 and COR-15 blocks, which are all located on-shore in Colombia. The Sale and Purchase Agreement was executed on April 28, 2011, subject to legal and regulatory approvals of the ANH and certain contractual approvals with the partners in Colombia. The Company will pay to Maurel et Prom cash consideration to a maximum of $66 million as a reimbursement for past exploration costs in the blocks incurred as at March 31, 2011. In addition, the Company will assume: i) a fully carried obligation of up to $120 million in three years for exploration activities in the SSJN-9, CPO-17 and Muisca Blocks, ii) a fully carried obligation on the exploration activities in the Sabanero and COR-15 blocks with a reimbursement out of the free cash flow.

On April 27, 2010, the Company closed the syndication of the unsecured revolving credit facility in the amount of $250 million (the “Revolving Credit Facility”). On April 13, 2011, the Company closed an amendment to the Revolving Credit Facility. As a result of the demand generated amongst the lending syndicate, the amount of the Revolving Credit Facility was increased from the $250 million initially committed by the lenders to $350 million, and the Company extended the term of the Revolving Credit Facility to April, 2013 and reduced the applicable commitment fees and the applicable margin. As at March 31, 2011, no borrowing has been made under the Revolving Credit Facility. The Company believes it has adequate resources to fund its capital plan for 2011, with the Company’s cash flows from operations and current debt facilities. With respect to the Company’s broader integration strategy (see “Strategy” section on page 7), the Company will pay for the expansion plan with its own cash flow. However, if additional resources are required, possible sources of funds available to the Company to finance additional capital expenditures and operations include the Revolving Credit Facility, existing working capital and incurring new debt, and the issuance of additional common shares, if necessary.

On April 13, 2011, the Company and Ecopetrol announced an agreement to carry out a pilot project of the Synchronized Thermal Additional Recovery (“STAR”) technology, provided by the Company, in the Quifa field in the Llanos Orientales in Colombia. The two companies, after a period of studies and tests in the research laboratories at the University of Calgary, have reached the conclusion that the implementation of in-situ combustion based technologies, such as STAR, is one of the best options to increase the recovery factor in the heavy oil fields of Colombia. Both companies have agreed start a pilot project as soon as possible under field conditions at the Quifa field, under the terms, conditions and obligations established in the existing Quifa Association Contract between the two companies.

On May 5, 2011 Moody's Investors Service assigned to the Company a first-time Corporate Family Rating of Ba3 with a positive outlook.

A summary of the financial results for the three months ended March 31, 2011 follows:

	Three Months Ended March 31	
(in thousands of US$ except per share amounts or as noted)	2011	2010
Oil and gas sales [(1)]	583,549	379,431
EBITDA [(2)]	362,527	231,966
EBITDA Margin (EBITDA/Revenues)	62%	61%
Per share - basic ($) [(4)]	1.35	0.97
Net earnings before non-cash items [(3)]	134,221	98,929
Per share - basic ($) [(4)]	0.50	0.41
Net earnings (loss) [(3)]	(69,593)	76,127
Per share - basic ($) [(4)]	(0.26)	0.32
- diluted ($)	(0.26)	0.30
Cash Flow from Operations	319,803	257,599
Per share - basic ($) [(4)]	1.19	1.07

(1) See additional details explained in the ”Commercial Activity” Section on page 14.
(2) See “Additional Financial Measures” on page 37.
(3) The first quarter of 2011 net earnings was impacted by a number of non-cash items totaling $203.8 million which generated a net loss of $69.6 million for the period. The adjusting non-cash items are mainly related to unrealized mark-to-market losses on derivatives of $92.6 million, the equity tax in Colombia of $68.5 million fully recognized in this quarter, stock-based compensation effect of $46.7 million, and foreign exchange gain of $4 million (with the exception of the equity tax in Colombia, these non-cash items may or may not materialize in future periods). See “Additional Financial Measures” page 37.
(4) The basic weighted average number of common shares outstanding for the first quarter ended March 31, 2011 and 2010 was 267,946,959 (fully diluted – 267,946,959) and 240,126,671 (fully diluted – 251,582,984), respectively.

Operating Summary

The Company produces and sells crude oil and natural gas. It also purchases crude oil from third parties as diluents and for trading purposes. The following sets out the netback for the first quarter of 2011 as well as a comparison of the combined total for the first quarter of 2010:

Operating Netback Crude Oil and Gas

	Three months ended March 31,			
	2011 Oil	**2011 Gas**	**2011 Combined**	**2010 Combined**
Average net production (after royalties and field consumption) [1]	**68,991**	**10,658**	**79,648**	**52,227**
Average daily production sold (boe/day) [1]	**71,953**	**10,794**	**82,747**	**65,702**
Operating netback ($/boe) [2]				
Crude oil and natural gas sales price	85.58	30.21	78.36	64.17
Cost of production [3]	6.10	1.48	5.50	3.74
Transportation (trucking and pipeline)	12.44	0.52	10.88	5.96
Diluent cost [4]	15.38	-	13.37	12.83
Other costs [5]	(2.36)	1.58	(1.84)	0.01
Overlift/Underlift [6]	(2.18)	(4.08)	(2.43)	(0.82)
Operating netback ($/boe)	**56.20**	**30.71**	**52.88**	**42.45**

(1) See additional comments on page 14 – "Reconciliation of Volumes Produced Vs. Volumes Sold".

(2) Combined operating netback data based on weighted average daily production sold which includes diluents necessary for the upgrading of the Rubiales blend.

(3) Cost of production mainly includes lifting costs and other production costs such as personnel, energy, security, insurance and others.

(4) Net blending cost is estimated at $3.9 per bbl of Rubiales crude, considering an average diluents purchase price delivered at the Rubiales field of $92.83 per bbl (Light Crude Oil (38°API) and Natural Gasoline (79°API), plus pipeline fees from the Rubiales field to Coveñas of $7.76 per bbl, less the average Rubiales Blend (Castilla) sale price of $84.38 per bbl, times the Rubiales average blending ratio of around 24%.

(5) Other costs mainly correspond to royalties on gas production, external road maintenance at the Rubiales field, inventory fluctuation, and the net effect of the currency hedges of operating expenses incurred in Colombian pesos during the period. The negative cost for oil of $1.84 per bbl was mainly attributable to the realized hedge gain recognized against operating expenses during this period. See additional comments on page 27 – Risk Management Contracts.

(6) Corresponds to the net effect of the overlift position for the period amounting to $18.1 million, which generated a reduction in the combined production costs of $2.43 per boe as explained in the section "Corporate Development Highlights – Financial Position – Operating Costs" on page 21.

Exploration

During the first quarter of 2011, the Company focused its exploration campaign in the Rubiales, Quifa, CPE-6, La Creciente, Abanico and Buganviles Blocks, for a total drilling campaign of twenty (20) wells in these areas. In the Rubiales-Piriri Block, five appraisal wells were drilled in the eastern and southern buffer zone. The Rub-243, 446, 447 and 448 were drilled in the southern buffer zone, outside the commercial area, while the Rub- 363 well was drilled in the eastern buffer zone. In the Quifa Block, seven (7) appraisal wells were drilled in the Quifa southwest area, while one (1) appraisal and three (3) stratigraphic wells were drilled in the northern part of the block. The Quifa-036, Quifa-048, Quifa-049ST and Quifa-053 appraisal wells were drilled in the northeastern and southwestern part of the "H" prospect, while the Quifa-DW1, Quifa-077 and 078 wells were drilled in the southern border of the prospect "J". In the northern part of Quifa, the Jaspe-2 appraisal well and the Jaspe-3 stratigraphic well were drilled in prospect "A", the Zircon-1 stratigraphic well was drilled in the prospect "Q", and the Ambar-3 stratigraphic well (started during the last quarter of 2010) was drilled in prospect "F". In the CPE-6 Block, the Guairuro-5 stratigraphic well was drilled in the northeastern part of the Guairuro prospect. In the La Creciente Block, the Company finished drilling the Apamate-1X exploratory well. In the Abanico Block, the Company started drilling the Gecko-1 exploratory well, and in the Buganviles Block, the Company continued drilling the Tuqueque-1X exploratory well. Additionally, the Company finished the acquisition of 649.5 km of 2D seismic in the SSJN-3 and Peru Block 138 and 130 km^2 of 3D seismic in the Arrendajo Block.

The exploration program during the first quarter of 2011 resulted in fourteen (14) exploratory successes: 1) the Rub-243, Rub-446, Rub-448 and Rub-363 appraisal wells drilled in the southern buffer zone outside the commercial area, which showed 23, 16, 16 and 10 feet of net pay in the basal sandstones, respectively; 2) the Quifa-036, 048, 049ST, 053 and DW-1, located in the prospects “H” and “J”, with 13, 14, 11, 13 and 15 feet of net pay, respectively; 3) The Jaspe-3 stratigraphic well, located in prospect “A” in the Quifa Block, which showed 29 feet of net pay in the Carbonera Basal sandstones; 4) the Guairuro-5 stratigraphic well, located in the CPE-6 block, which showed presence of hydrocarbons in the Carbonera basal sand unit with 14 feet of net pay; 5) the Apamate-1X exploratory well, located in the La Creciente Block, with 53 feet of net pay of gas; and 6) the Tuqueque-1X exploratory well located in the Buganviles Block, with 31 feet of net pay in Monserrate Formation and 9 feet in El Cobre Formation. Total net exploration expenditure for the first quarter of 2011 was $41.53 million.

For more details please see “Discussion of First Quarter Results – Exploration” on page 8.

Production

The increase in gross operated production of the Company during the first quarter of 2011 was a significant achievement, averaging 196,272 boe/d (79,648 boe/d net after royalties and field consumption), or 51% greater than the production reported during the first quarter of 2010. This growth in operated production is mostly the result of the increase in production capacity at the Rubiales and Quifa heavy oil fields, in tandem with the construction of new facilities at both fields to process crude oil.

Production continues to grow and as of May 12, 2011 the Company had reached its highest historical level of 225,000 boe/d of gross operated production, which continues to make the Company the fastest growing oil and gas company in Colombia, as well as the country’s second largest operator.

During the first quarter of 2011, the Company drilled 42 producing wells at the Rubiales field and 19 producing wells at the Quifa field. This, together with the completion of the Central Processing Facility at Quifa ("CPF Quifa") as well as the CPF-2 at the Rubiales field, will allow the Company to accomplish its targeted gross production of 265,000 boe/d by the end of 2011, which will be fully realized once the expansion of OCENSA pipeline is completed.

For more details please see “Discussion of First Quarter Results – Production” on page 11.

Commercial Activity

During the first quarter of 2011, the average of the WTI Nymex was $94.60/bbl in comparison to $78.88/bbl in the same period of 2010. The average oil sales price realized for the first quarter of 2011 was $85.22 per bbl, higher by 19% than the $71.66 per bbl realized in the same period of 2010.

During the first quarter of 2011, the Company exported 5.6 million bbl in eight cargoes of Castilla, four cargoes of 110,000 bbl of Rubiales 12.5°API and eleven small parcels averaging 25,000 bbl each, of Rubiales 12.5°API sold through other exporters (HOCOL, PETROBRAS), representing a total volume of 6.3 million bbl of crude oil at an average sales price of $85.22/bbl, generating gross revenues of approximately $540 million. Total volume exported during the first quarter of 2011 represents an increase of 40% in comparison to the same period of 2010 (4.5 million bbl). During the first quarter of 2011 the Company sold 140,000 bbl of Rubiales crude to the Colombian domestic market at an average sales price of $89.48/bbl. In addition, sales of natueral gas produced at the La Creciente, Abanico, Cerrito and Guaduas fields to the domestic market averaged 62 mmscf/d at an average price of $5.31/mmbtu, in comparison with 59.5 mmscf/d at an average price of $4.95/mmbtu for the same period of 2010.

For more details please see “Discussion of First Quarter Results – Commercial Activity” on page 14.

Status of Projects

<u>STAR Project in Quifa</u>

In March 2011, Pacific Rubiales and Ecopetrol agreed to continue with the STAR Project in the Quifa field as a prior step for expanding the technology in the future. The project will make full utilization of all production facilities and infrastructure already bought for the Rubiales field and carry out the main specialized studies and lab tests under a fast track strategy. The pilot test will be carried out under the existing terms and conditions of the Ecopetrol Association Contract at Quifa.

The pilot area has already been selected and after finishing a geological and reservoir model, four (4) synchronizing – producers and one (1) injector well will be drilled initially and after a period of 4-5 months, two more wells may be drilled as part of the STAR synchronization process.

To date, almost all production and injection facilities needed for the Quifa pilot test are already on site. The preparation of the platforms for production and well facilities had already been designed and built. The installation of the entire infrastructure will commence during the second quarter of 2011, as well as the drilling of the 5 wells, which will start as soon as the environmental permit is obtained.

The Company continues its commitment to the implementation of this technology, not only because it creates significant value to the Company, its partners, investors and the country by increasing reserves, but also because it is believed that once in place, STAR will have a powerful impact on the recovery factors for the entire Llanos region.

Llanomulsion Project

In January 2009, the Company initiated the development of a special transport emulsion formula (oil in water), that eliminates the need for diluents as part of the efforts to minimize transportation costs in the ODL pipeline while maximizing line capacity. The patented formula, called Llanomulsion, increases pipeline capacity by reducing fluid viscosity to one-third of the original viscosity of the diluted crude. Tests in the main pumping units of the ODL pipeline were performed, using a batch of 3,500 bbl of emulsion. The next step in this development is a complete industrial test (a batch of 40,000 bbl of emulsion) in the ODL pipeline. Facilities for this industrial test have been completed in the CPF-1 in the Rubiales field, whereas implementation of dehydration facilities in the Cusiana Station is at the design stage. Ecopetrol has developed an emulsion formula that was tested in the main pumping units of the ODL pipeline with excellent results and it will be also tested in the pipeline. The industrial test of both formulations will take place when the ODL and OCENSA pipelines provide an appropriate operational window in the second half of 2011.

Oleoducto de Los Llanos Pipeline

As of the end of the first quarter of 2011, the planned 340,000 bbl/d expansion project was 75% completed. This project includes construction of two booster stations along the line, increasing storage capacity at the Rubiales Pumping Station and construction of a pipeline branch to Cusiana Station. In December 2010, the pipeline branch to Cusiana was fully commissioned and started operations successfully. The expected completion date for the first booster station is July 2011, whereas the second one is expected to be completed by November 2011.

On May 4, 2011 a pumping record of 246,588 bbl was achieved. This record was the result of new impellers installed in the main pumping units of the pipeline, the use of a drag reducing agent and the improved capacity of the OCENSA pipeline, which is connected to the ODL.

Petroeléctrica de los Llanos – Power Transmission Line Project

In 2010, the Company incorporated a new affiliate, Petroeléctrica de los Llanos, S.A. (“PEL”), which will be responsible for the design, construction and operation of a new power transmission line of 230 Kilovolts that will connect the Rubiales field to Colombia´s national grid. The new transmission line will originate at the Chivor Substation and will have an extension of 260 km to the Rubiales field. The line includes two substations to supply power to the booster stations of the ODL, as well as a main substation for the Rubiales and Quifa fields. During the first quarter of 2011, purchasing of long lead items took place and, as of the date of this report, more than 55% of the right of ways have been negotiated. Environmental licensing is underway. Construction will start in the second half of 2011, once environmental permits are granted.

Oleoducto Bicentenario – Bicentennial Pipeline

The Company obtained a 32.88% equity interest in Oleoducto Bicentenario de Colombia ("OBC") in November 2010. OBC is a special purpose vehicle promoted by Ecopetrol, which has a 55.97% interest together with its affiliates, with the participation of other oil producers operating in Colombia, who control the remaining 11.15% interest. OBC will be responsible for the financing, design, construction and eventual operation of Colombia's newest oil pipeline transportation system, which will run from Araguaney, in the Casanare Department of central Colombia, to the Coveñas Export Terminal in the Caribbean. The new pipeline will add 450,000 bbl/d to the capacity of the existing pipeline systems connecting the Los Llanos Basin to the export markets, which are projected to reach full capacity as the increase in planned production from Colombian producers materializes in the mid-term. The project will be developed in six phases. The Company has committed its participation to Phases 0 and 1 of the project for an initial capacity of 120,000 bbl/d, and the financial commitment estimated at $1.03 billion, excluding financing costs, of which $340 million represents the Company´s share.

Please see "Project Status" on page 16 for more details.

3. Company Overview

Profile

Pacific Rubiales, a Canadian-based company and producer of natural gas and heavy crude oil, owns 100 percent of Meta Petroleum Corp., a Colombian oil branch which operates the Rubiales/ Piriri and Quifa oil fields in the Llanos Basin in association with Ecopetrol; and Pacific Stratus Energy Colombia Corp., which operates the wholly-owned La Creciente gas field in the northern part of Colombia and other light and medium oil fields. The Company, through intensive exploration activity and a large exploration portfolio, is focused on identifying opportunities primarily within the eastern Llanos Basin of Colombia, as well as in other areas in Colombia, Guatemala and northern Peru. Pacific Rubiales has a current net production of approximately 225,000 boe/d, including the natural gas and light and medium oil fields, with working interests in 35 blocks in Colombia, 2 blocks in Guatemala and 3 blocks in Peru.

Vision

The Company's vision is to be the premier independent E&P company in the Latin American region, noted for its technical excellence, operational capabilities and its outstanding ability to discover, develop and market new hydrocarbon reserves.

Strategy

The Company has an enviable strategic position with the right combination of production assets and exploration areas. The Company expects significant cash flows and profit from operations generated by production growth that will be utilized to support the Company's ambitious exploration and production activities. The Company's goal of increasing its reserve base and growing its production will be achieved through continuous exploration activities in low to mid risk areas, where our knowledge and talents can provide a significant advantage and by the continuous use of the appropriate technology in order to increase and optimize the recovery rates in our existing resource base.

On November 8, 2010, the Company announced a broadening of its comprehensive growth strategy which includes three major components:

i. Continuing growth through exploration, development and production of new and existing reserves.

ii. Securing market access by participating in key oil and gas transportation and infrastructure projects.
    - The Company will have a significant participation in the OBC with Ecopetrol and other oil companies operating in Colombia.
    - The Company also anticipates maintaining its stake in Pacific Infrastructure Inc. ("PII"; formerly known as Lando Industrial Park, S.A.), a company developing a new crude oil and products terminal and also a port in Cartagena, as well as a new pipeline that will link Coveñas with Cartagena.

iii. Integrating downstream assets.
    - The Company will start making inroads on developing the bunker market within Colombia and the supply of finished products to wholesale markets.

The cornerstone of the Company's strategy is the technical excellence of its people, coupled with the experience and the know-how of management to deliver its vision. Our management team is primed to take full advantage of present and future opportunities in exploration and production in the Latin American region.

4. Discussion of 2011 First Quarter Results

Exploration

During the first quarter of 2011, the Company continued its exploration drilling campaign for a total of 20 wells drilled during this period. The exploration campaign was focused in the Rubiales-Piriri, Quifa, CPE-6, La Creciente, Abanico and Buganviles Blocks. In the Rubiales- Piriri Block, the Rub-243, 446, 447 and 448 were drilled in the southern buffer zone outside the commercial area, while the Rub-363 well was drilled in the eastern buffer zone. In the Quifa southwest area, the Quifa-036, Quifa-048, Quifa-049ST and Quifa-053 appraisal wells were drilled in the northeastern and southwestern part of the “H” prospect, while the Quifa-DW1, Quifa-077 and 078 wells were drilled in the southern border of the prospect “J”. In Quifa North, the Company drilled the Jaspe-2 appraisal well and the Jaspe-3 stratigraphic well in prospect “A”, the Zircon-1 stratigraphic well in prospect “Q”, and also finished the drilling of the Ambar-3 stratigraphic well in prospect “F”. In the CPE-6 Block, the Guairuro-5 stratigraphic well was drilled in the northeastern part of the Guairuro prospect. In La Creciente Block the Company finished the drilling of the Apamate-1X exploratory well, located in the La Creciente A-south prospect. In the Abanico Block, the Gecko-1X exploratory well was drilled in the southern part of the Block; and in the Buganviles Block, the Company continued drilling the Tuqueque-1X exploratory well.

<u>Rubiales-Piriri Block</u>

As part of the appraisal campaign in the block, the Company drilled a total of 5 appraisal wells in the so-called buffer zone of the Rubiales-Piriri contract: The Rub-243, Rub-446, Rub447 and Rub-448 wells were drilled in the southernmost buffer-part of the Rubiales contract area, while the Rub-363 well was drilled to the east of the field, in the eastern buffer-part of the Pirirí Contract. Four wells were successful and the Rub-447 well resulted dry. The four wells exhibited net pays varying from 10 to 40 feet and porosities from 30% to 33%. The Company is preparing all required documentation to support the corresponding reserves certification and the commerciality application for an estimated area of up to 16,700 acres in the buffer zone.

<u>Quifa Block</u>

Quifa southwest

As a continuation of its exploration/delineation campaign in prospects "E", "H" and "J" in the Quifa SW commercial area, the Company drilled seven (7) wells: (i) the Quifa-36, Quifa-48, Quifa-49ST and Quifa-53 appraisal wells in prospect "H" and (ii) the Quifa-DW1, Quifa-77 and Quifa-78 appraisal wells in prospect "J". Six of these wells not only successfully appraised and extended the Quifa SW reservoir (prospects “E” and “H”), but also extended these oil accumulations south and southeast into prospect “J” supporting the corresponding reserves certification made by Petrotech as of January 31 and published on March 10, 2011. The Quifa-78 well was the only well which was deemed a non-economic producer, in spite of having 8 feet of net pay.

Quifa north

In this part of the block, the Company continued its exploration/delineation campaign in prospects "A", "F" and "Q", and drilled four wells: (i) the Jaspe-2 appraisal well and the Jaspe-3 stratigraphic well in prospect "A"; (ii) the Zircon-1 stratigraphic well in prospect “Q”; and (iii) finished drilling the Ambar-3 stratigraphic well in prospect "F". The Jaspe-3 well confirmed the extension of the “A” prospect to the northeast. The Ambar-3 and Jaspe-2 wells found 3 and 2 feet of net pay respectively, and were declared non-economic, while Zircon-1 did not find oil-bearing sandstones.

<u>CPE-6 Block</u>

During the first quarter of 2011, the Company drilled one stratigraphic well, the Guairuro-5. The well was drilled in the northeastern part of the Guairuro prospect and showed a hydrocarbon column of up to 14 feet of net pay. This well is the fifth stratigraphic well drilled in the block, as part of the exploratory commitment for the TEA Contract. At the end of this period, the Company was preparing the location and mobilizing the equipment required to drill the Guairuro-6 well which will fulfill the TEA Contract commitments.

<u>La Creciente Block</u>

During the first quarter of 2011, the Company finished drilling the Apamate-1X exploratory well, located south of La Creciente “A” and La Creciente “D” gas fields. The well showed 53 feet of net pay in the gas-bearing sands of the Ciénaga de Oro Formation. During the initial test the well achieved a gas production of 24 MMscfd. This finding at the well confirmed the stratigraphic nature of the prospect. The post-drill maps associated with the gas sandstones show an acreage that goes from 1,124 acres as a minimum to a maximum upside of around 5,266 acres. The Company is now preparing the well for an extended test and planning an appraisal drilling campaign of two appraisal wells 500 feet down dip of the Apamate-1X well to delineate the prospect.

Abanico Block

In the Abanico Block, the Company started drilling the Gecko-1X exploratory well, which targeted the Cretaceous Caballos Formation at an approximate depth of 6,500 feet. Final depth for the well is expected to be reached during the second quarter of 2011.

Buganviles Block

In the Buganviles Block, the Company continued drilling the Tuqueque-1X exploratory well which targeted the Cretaceous Caballos Formation. After a tie-in between a vertical seismic profile in the well, and the available 2D seismic data, the estimated final depth of the objective was estimated at approximately 9,500 feet, so the Company is in the process of redefining the directional plan to continue drilling the well to reach the objective.

Topoyaco Block

During the first quarter 2011, in the Topoyaco-2 exploratory well a production test was carried out with an electro submersible pump (ESP), obtaining production rates between 45 and 65 bbl/d of 9.8^{o} API, and an average water cut of 60%. The well is currently suspended and the Company has already submitted the relevant documents to the ANH, requesting the approval of an evaluation area around this discovery. The Company is also readying the drilling of another exploratory well to evaluate the “D” prospect in this block.

Peru

Exploration activities continue in the country with the acquisition of 537 km of a 2D seismic program in the Block 138. The Company expects to finish the seismic acquisition during the second quarter of 2011, and then proceed with processing and interpretation.

Guatemala

During the first quarter of 2011 the Company continued the definition of the exploratory program for the “N-10-96" and "O-10-96" blocks. The exploratory activities for 2011 in Guatemala will include: seismic reprocessing of 300 km of 2D seismic; acquisition and processing of additional 300 km of 2D seismic; 6,800 km of aero-magnetic and aero-gravimetric data; 6,600 km^2 of remote perception surveys; a surface geology campaign (including samples analysis); and the beginning of an integrated geological interpretation to define exploratory prospect locations to be drilled in 2012.

Exploration Milestones

During the first quarter of 2011, the results of the exploratory campaign included the drilling of 20 exploratory wells, and the acquisition of 649.5 km of 2D seismic and 130 km^2 of 3D seismic.

- In the Rubiales-Piriri Block, the Rub-243, Rub-446, Rub-447 and Rub-448 wells extended the Rubiales field to southernmost buffer-part of the Rubiales contract area, while the Rub-363, Rub-404 and Rub-534 wells extended the field to the eastern buffer-part of the Pirirí Contract.

- In the Quifa southwest area of the Quifa Block, the Quifa-36, Quifa-45, Quifa-48, Quifa-49 and Quifa-53 appraisal wells in prospect "H" confirmed the extension of the reservoir to the northeast and the southwest, and the Quifa-DW1 and Quifa-77 appraisal wells extended the Quifa SW reservoir to the south and southeast into prospect “J”.

- In the northern part of the Quifa Block**,** the Jaspe-2 appraisal well and the Jaspe-3 stratigraphic well were drilled in prospect “A”. This last well confirmed the extension of the “A” prospect to the northeast. The Jaspe-2 appraisal well only showed 2 feet of net pay. The Zircon-1 stratigraphic well was drilled in prospect “Q” but the well did not show any prospective interval. The Company also finished drilling the Ambar-3 stratigraphic well in prospect “F” which showed 3 feet of net pay.

- In the CPE-6 Block, the Guairuro-5 stratigraphic well was drilled in the northeastern part of the block. The Guairuro-5 confirmed the presence of hydrocarbons in the well with 14 feet of net pay in the basal sand unit of the C-7 interval.

- In the La Creciente Block, the Company finished drilling the Apamate-1X exploratory well. The well showed 53 feet of net pay and resulted in a new gas discovery for the Block. Initial production tests showed an average of 24 MMscfd of gas with a well head flowing pressure of 3730 psig.

- In the Arrendajo and SSJN-3 Blocks, the Company finished the acquisition of 130 km^2 of 3D seismic and 112.5 km of 2D seismic, respectively.

- In the Peru Block 138, the Company continues with the acquisition of 537 km of a 2D seismic program

- The exploration activity for the rest of 2011 includes: 1) the continuation of the drilling campaign in Colombia with 40 additional wells, which include drilling activity in the recently acquired Maurel et Prom blocks and appraisal wells in the buffer zone of the Rubiales-Piriri Block and Quifa southwest; 2) the acquisition of 2,811 km of 2D seismic in five blocks in Colombia and in Block 135 in Peru; and 3) the acquisition of 1,486 km^2 of 3D seismic in three blocks in Colombia and in the two exploratory blocks in Guatemala.

Further detailed information with respect to the Company's exploration update in Colombia, Peru and Guatemala was announced on February 3, and May 12, 2011, respectively.

Exploration Capital Expenditures

Net capital expenditures during the first quarter of 2011 totaled $41.5 million in exploration activities, as follows:

		Q1 2011	
		In thousands of US$	
Block	**Working Interest**	**Gross**	**Net**
Colombia - Llanos Basin			
CPE6	50%	9,446	4,605
CPO1 (1)	50%	100	0
CPO12	40%	192	140
CPO14	63%	13	6
Quifa (2)	70%	7,634	5,340
CPE1	100%	60	60
Arauca	100%	2,518	2,518
Colombia - Lower Magdalena			
Guama	100%	280	280
La Creciente	100%	9,700	9,700
CR1	60%	2	1
SSJN-3	100%	1,866	1,866
Colombia - Putumayo Basin			
Topoyaco	50%	3,190	1,595
Terecay	100%	24	24
Upper & Middle Magdalena Basin			
Abanico	80%	5,591	2,796
Buganviles	35%	4,307	1,457
Dindal - Rio Seco	100%	1,046	1,046
Colombia - Others			
Other exploration projects		5,652	4,269
Peru Marañon &Ucayali Basin			
Lote 138	55%	10,591	5,825
Total		**62,211**	**41,527**

(1) A farm-out agreement was signed with Petroamerica Oil Corp. on March 2010, and based on this agreement the partner is assuming a full carried obligation on the exploratory activities for an amount of up to $8.6 million. As of March 31, 2011 a total of $6.9 million had been reimbursed by the partner.

(2) Corresponds to the exploration/delineation campaign for the wells drilled at Quifa north, (i) the Jaspe-2 appraisal well; (ii) the Jaspe-3 stratigraphic well, (iii) the Zircon-1 stratigraphic well and (iv) Ambar-3 stratigraphic well.

The Company's exploration program for 2011 is budgeted at $340 million and includes exploration across 26 blocks, in which 20 exploratory wells, as well as 36 appraisal wells and 3 stratigraphic wells will be drilled. In addition, 539 km of 2D seismic and 440 km^2 of 3D seismic is planned during the year. The exploration activity for the next months of 2011 includes the drilling of the planned wells and the Company is evaluating additional exploration activities.

Production

Average Daily Oil and Gas Production – Net Volumes before and after Royalties

Total operated production during the first quarter of 2011 averaged 196,272 boe/d (79,648 boe/d net after royalties and field consumption) for an increase of 66,586 boe/d (27,421 boe/d net after royalties and field consumptions) over the same period in 2010. This represents a 51% growth in operated production, which came about mainly through increased production at the Rubiales, Quifa and La Creciente fields. The operated production in the first quarter of 2011 was negatively impacted by problems in land transportation, caused by the delays in the OCENSA upgrade and heavy rains that caused a country-wide state of emergency. The following sets out the first quarter 2011 average production at all of the Company's producing fields:

Producing Fields	Gross production before royalties Q1 2011 boe/d	Q1 2010 boe/d	Share before royalties Q1 2011 boe/d	Q1 2010 boe/d	Share after royalties and field consumption Q1 2011 boe/d	Q1 2010 boe/d
Rubiales / Piriri [1]	146,003	111,912	60,935	48,896	48,748	39,117
Quifa	33,690	1,797	20,098	1,078	18,461	1,013
La Creciente	10,575	9,964	10,409	9,900	10,406	9,898
Puli [2]	86	66	41	31	32	25
Dindal / Rio Seco [3]	1,026	730	710	661	588	529
Moriche	297	13	125	5	118	4
Quinchas	57	30	52	17	49	16
Abanico [4]	2,463	3,147	684	1,066	652	1,139
Buganviles [5]	34	4	24	2	22	2
Rio Ceibas [2]	1,813	1,943	491	530	393	424
Guasimo	10	-	10	-	9	-
Cerrito[6]	218	80	170	60	170	60
Total	**196,272**	**129,686**	**93,748**	**62,246**	**79,648**	**52,227**

(1) Net of internal consumption at the field.
(2) Corresponds to the Company´s share in non-operated fields.
(3) Gas sales started in November 2010 for a nearby Compressed Vehicular Gas plant which is reflected in the above figures. Remaining gas is currently being injected and used for power generation. The Company is evaluating additional economic uses for this hydrocarbon.
(4) Ecopetrol accepted the commerciality of the northern extension of the Abanico field. The Company started sales of CO2-free gas, produced by the northernmost wells in the field; and purchased a CO2 treatment plant that it plans to install during Q2, 2011. It is expected that gas sales will increase to 1MMcfd when the installation is complete.
(5) The Samarkanda field, in the Chipalo Association Contract, has been temporarily shut-in while the Company evaluates technical alternatives for its reactivation.
(6) In October 2008, the Company executed a memorandum of understanding (the "Cerrito MOU") with Alange under which the Company agreed to assign to Alange its interest in the Cerrito Contract for $ 7.5 million. The Cerrito MOU is subject to all necessary approvals before Ecopetrol. Until such approvals are obtained Alange must bear the costs of the Cerrito operation by the Company and its entitled to its profits.

Despite the transport problems experienced which significantly reduced the production average in January 2011, the operated production increased during the first quarter of 2011 mainly attributable to the drilling of 42 producing wells at the Rubiales field and 19 producing wells at the Quifa field. The completion of the CPF-Quifa allowed the Quifa field's production to reach 35,000 bbl/d by the end of March 2011, and increase the new target capacity to 45,000 bbl/d by the end of 2011; also, the completion of CPF2 at the Rubiales field raised production capacity to 170,000 bbl/d and increased the year-end target to 183,000 bbl/d, which will be fully realized as the expansion of the OCENSA pipeline is completed.

La Creciente natural gas field increased its production by 5%, while improving the safety of its operations. After replacement of subsurface safety valves, and construction of additional control and treatment systems, the La Creciente 1 and 2 wells now account for over 60% of the field's production. The field's production is now only limited by constraints in the natural gas transport network downstream of the field.

New Facilities Construction

During the first quarter of 2011, the following new facilities were constructed and brought into operation, which contributed to the increase in production levels:

Rubiales field

- New FWKO Tank at CPF-2 in order to handle an incremental volume of 502,000 bbl/d of fluid
- New oil dehydration train at CPF-2 in order to handle an incremental volume of 21,300 bbl/d of oil
- New SKIM Tank at CPF-2 in order to handle an incremental volume of 500,000 bbl/d of fluid
- New water treatment facilities at CPF-2 in order to handle an incremental volume of 300,000 bbl/d of water

- New SKIM Tank at CPF-1 in order to handle an incremental volume of 500,000 bbl/d of fluid
- 13.3 km of new roads
- 26.5 km of flow lines
- 8 new electrical power sub-stations
- 18,3 km of new field electric network
- 110,000 bbl/d additional water injection capacity

Quifa field:

- New water treatment facilities in order to handle an incremental volume of 200,000 bbl/d of water
- 4.9 km of new roads
- 9.8 km of flow lines between 10" and 24"

Historical Production Milestone

Production continued its growth trend, and as of May 15, 2011 the Company's gross operated production exceeded the historical milestone of 225,000 boe/d, which is the result of the continuous growth in production of heavy oil in the Rubiales/Piriri and Quifa blocks, supported by the operation of the ODL pipeline and Company's downstream transportation strategy. This volume also incorporates the development of the Company's light and medium oil blocks, as well as the natural gas volume produced (at a conversion rate of 5,700 standard cubic feet per barrel) from the La Creciente block and other smaller fields.

Supply and Sales Balance

The following is the Company´s reconciliation of boe produced vs. boe sold for the period ended on March 31, 2011:

Inventory Movements	**Total boe Net**	**Aver. day Net**
Ending inventory as of December 2010	1,204,058	13,378
		-
Transactions in Q1 2011		-
Net oil and gas production	7,168,340	79,648
Settlement of overlift position from December 2010 (1)	(291,825)	(3,243)
Purchases of diluents	1,268,567	14,095
Total sales	(7,447,199)	(82,747)
Overlift position as of March 31, 2011 (2)	75,376	838
Volumetric compensation	(54,892)	(610)
Ending inventory as of March 2011 (3)	**1,922,425**	

(1) This volume corresponds to the settlement of the overlift position for crude oil as of December 31, 2010, which resulted in a lower volume of sales during the period it was settled.
(2) This volume corresponds to an overlift position of 75,376 boe of crude oil and gas as of March 31, 2011, which will be settled during future periods.
(3) Corresponding to permanent inventory in the pipeline systems and storage facilities at the field, and Coveñas Terminal.

Reconciliation of Volumes Sold vs. Volumes Produced

First Quarter 2011

Production and sales reconciliation for first quarter of 2011:

	Volumes Produced	Volumes Sold	Difference (higher volume sold)	
	Oil and Gas (boe)	**Oil and Gas (boe)**	**Oil and Gas (boe)**	
Total 2011 (1Q)	7,168,340	7,447,199	278,859	
Avg. per day	79,648	82,747	3,099	(a)

(a) The main reason for the higher volumes sold in the first quarter of 2011 in comparison to the volumes produced is due to:

Production after royalties Q1 2011	79,648
Production sold Q1 2011	82,747
Difference	**3,099**
Explanation of the difference	
Begining inventory	13,378
Purchases of diluent	14,095
Overlift settlement from Q4 2010	(3,243)
Volumetric compensation	(610)
Overlift position at the end Q1 2011	838
Ending Inventory	(21,359)
Reconciliation of the difference	**3,099**

Commercial Activity

First Quarter 2011 Market Overview

- The first quarter of 2011 was subject to considerable levels of intraday volatility. The demand from China during the last part of the quarter reached 9.2 million bbl, with an average of 9.26 million bbl for the first quarter, up 1 million from the same period in 2010. In particular, Mexico´s crude oil output for the first quarter averaged 2.57 million bbl/d, down 1% from a year earlier and Venezuela's output was in the order of 2.2 million bbl/d, according to the IEA.
- In January, crude prices were driven by speculation of higher demand, which was affected by cold temperatures in USA and Europe.
- In February, anti-government protests in Tunisia and Egypt led to the removal of their governments. This created anxiety about the closing of the Suez Canal and the oil terminal of Sidi Kerir (3.3 million bbl/d). The riots spread through the Middle Eastern region and later hit Libya, in which a civil war erupted.
- Geopolitical tensions in Libya shutdown an estimated 1-1.2 million bbl/d from its total production of 1.6 million bbl/d, pushing oil prices higher and at the same time, helping the WTI – Dated Brent differential average $10.82/bbl during the first quarter of 2011.
- At the same time other countries in the Middle East, such as Saudi Arabia, Bahrain, Yemen, and Syria, suffered from geopolitical tensions, creating more speculation about future crude disruptions in the Middle Eastern region.
- In mid-March an earthquake of magnitude 9.9 struck Japan and caused great damage to its energy sector. About 1.3 million bbl/d of Japan's total refining capacity of 4.5 million bbl/d was closed throughout the month and an estimate of 9.7GW of nuclear capacity was closed. Japan will likely need to increase liquid natural gas imports in order to meet its energy needs.
- All these events pushed the WTI Price from $90/bbl to over $100/bbl, and Dated Brent from $97/bbl to over $110/bbl.

Crude Oil and Gas Prices

In the first quarter of 2011, WTI NYMEX reached an average of $94.60/bbl compared to the $78.88/bbl average in the first quarter of 2010, a 20% increase. The following describes the average realized crude oil and gas prices during the first quarter of 2011 and the first quarter of 2010

- During the first quarter of 2011 the Company sold through other exporters eleven small parcels of Vasconia blend crude oil mainly to the US and South America. The average realized oil price for these sales was $96.35/bbl, higher by 35% than the $71.61/bbl realized in 2010.

- The average realized oil price for Castilla blend crude oil during the first quarter of 2011 was $84.38/bbl, higher by 20% than the $70.34/bbl realized in 2010. The average differential vs. WTI NYMEX improved $1.43/bbl during the first quarter of 2011. In this period the Company exported eight cargos of Castilla blend crude oil, four delivered to the US Gulf Coast, one to the Caribbean, one to Europe and two to Asia.

- In the same period, we sold four small cargoes of 12.5°API crude oil trucked from the Rubiales field to the Atlantic Oil Terminal in Barranquilla, at an average price of $89/bbl, taking advantage of the strength of the fuel oil prices. These four cargoes were delivered to the US Gulf Coast.

- Guajira Maximum Regulated Price increased 6.2% as of Feb 1, going from $4/MBTU to $4.26/MBTU. The Maximum Regulated Price is escalated every 6 months based on previous half-year variation of the US Gulf Coast fuel oil 1.0% Sulfur LP Spot Price, Platts.

- The combined realized oil and gas price for the Company for the first quarter of 2011 was $78.36 per boe, higher by 22% than the $64.17 per boe realized in the same period of 2010.

Average benchmark crude oil and natural gas prices for the first quarter ended March 31 of 2011 were as follows:

Average Crude Oil Reference Prices	**2011 1Q ($/bbl)**	**2010 1Q ($/bbl)**	**°API**
Domestic Market	$89.48	$68.26	12,5
WTI NYMEX (Weighted Average of PRE Cargoes)	$92.11	$78.45	38
Vasconia (Weighted Average Parcels PRE) (1)	$96.35	$ 71.61	24
Castilla (Weighted Average Cargoes PRE) (2)	$84.38	$70.34	19
Rubiales Export. 12.5 (Weighted Average of 2 PRE Cargoes) (3)	$89.00	N/A	12,5
Combined Realized International Oil Sales Price	**$85.22**	**$71.66**	**N/A**
PRE Natural Gas Sales ($/mmbtu)	$5.31	$4.95	N/A
Combined Realized Oil and Gas Sales Price	**$78.36**	**$64.17**	**N/A**
WTI NYMEX ($/Bbl)	$94.60	$78.88	
Henry Hub average Natural Gas Price ($/MMBTU)	$4.20	$5.30	

(1) Weighted average price of eleven parcels of Vasconia crude oil exported during the first quarter 2011.
(2) Weighted average price of eight Castilla crude oil cargoes exported during the first quarter of 2011
(3) Weighted average price of four Rubiales (12.5°API) small cargoes exported during the first quarter of 2011.

Crude Oil Sales to International and Local Markets

In the first quarter of 2011, the Company exported twelve cargoes and eleven small parcels of crude oil, 89% Castilla blend crude (5.614 million bbl), 4% Vasconia blend crude (275,000 bbl), and 7% Rubiales (443,000 bbl), representing a total volume of 6.332 million bbl.

The Company also maintained its flexible commercial strategy by selling 140,000 bbl of Rubiales 12.5°API in the Colombian domestic market.

For purposes of securing diluents for Rubiales crude oil, the Company increased local purchases of light crude oils (11,267 bbl/d average) in the eastern Llanos.

The following are the milestones achieved on product transported during the first quarter of 2011:

- The Company transported 82,700 bbl/d through the different pipelines and trucking systems; 72% of this volume was transported via pipeline at maximum capacity utilization and 28% by trucks. Pipeline use represents a saving of $15.1/bbl in transportation costs for the Company when compared to truck transportation.
- The Company loaded 3,055 trucks of diluents and 7,323 trucks of produced crude oil, all without traffic accident or environmental damage.
- The Guaduas Facility handled and transported 19,189 bbl/d of crude oil from the Company and third parties, generating an operational profit of $2.63/bbl for the Company, totaling $4.5 million for the period.

Natural Gas Sales to Local Markets

During the first quarter of 2011, the volume of natural gas sales increased to 62 MMscf/d, from a volume of 59.45 MMscf/d for the same period in 2010 (a 4% increase). These sales were mainly from La Creciente field, at an average price of $5.31 MMbtu (equivalent to $ 5.1835/MMscf), representing a premium of 25% over the weighted domestic regulated price of $ 4.1646/MMbtu, and 24% over the Henry Hub natural gas prices in the US Gulf Cost during the same period.

Natural gas from La Creciente field was sold mainly (95%) to power generators located in Cartagena and Barranquilla and the remaining 5% was sold to industries connected to the trunk gas pipeline.

5. Project Status

STAR Project in Quifa

In March 2011 Pacific Rubiales and Ecopetrol agreed to continue with the STAR project in the Quifa field as a preliminary step to expanding the technology in the future. The project will make full utilization of all production facilities and infrastructure already acquired for the Rubiales field and carry out the main specialized studies and lab tests under a fast track strategy. A pilot test will be carried out under the existing terms and conditions of the Ecopetrol Association Contract in Quifa.

The pilot area has already been selected; it will have a five pattern spot in 25 acres, located within approximately 225 m of the Quifa 38 Cluster. After finishing a geological and reservoir model, four synchronizing – producers and one injector well will be drilled and after a period of 4-5 months, two more wells may be drilled as part of the STAR synchronization process.

Preliminary simulations have been done using the updated geological and reservoir model and kinetic reactions equations available for the Rubiales field. Preliminary results have indicated the successful feasibility of carrying out the pilot test in Quifa and high recovery factors are expected.

At the date of this report, almost all production and injection facilities needed for Quifa pilot test are already on site, with the exception of the SCADA system and the steam generation plant, both of which are expected at site shortly. The main infrastructure involved in the Quifa pilot test consists of:

- Air compressor system
- Production facilities including casing manifolds, gas separator and main production valves
- Strafford plant for handling acid fluids

- Automation system
- Water pumps system
- Fire control system
- Main pipelines for well drilling and special cement, among others

The preparation of the platforms for production and well facilities have already been designed and built. The installation of the entire infrastructure will start in a few days and is expected to finish in 2.5 - 3 months. The drilling of the five wells will start as soon as the environmental permit is granted, which is expected within 3 weeks.

At the time of this report, the Company is involved in the design of the completion and artificial lift equipment needed for the producer and injector wells. Purchase orders are under way. In addition, the design of the specialized lab and field special tests such as Nitrogen and seismic survey, are in progress; they will be needed for the synchronization model, which is also in progress. The STAR project pilot test is expected to begin in August 2011.

The Company continues its commitment to the implementation of this technology, not only because it creates significant value to the Company, its partners, shareholders and the country, but also because it is believed that once in operation, STAR will have a dramatic impact on the entire Llanos region.

Llanomulsion Project

In January 2009, the Company started the development of a special transport emulsion formula (oil in water), which could eliminate the need for diluents. The patented formula, called Llanomulsion, increases pipeline capacity by reducing fluid viscosity to one-third of the original viscosity of the diluted crude.

During 2010, tests for Llanomulsion formulation and for a new surfactant developed by Ecopetrol´s research and development affiliate Instituto Colombiano del Petróleo were performed at the Rubiales field pilot plant. Both formulations were also tested at the main pumping units of ODL with excellent results. The next phase of this project includes pumping 40,000 bbl of Llanomulsion from the Rubiales field to the Cusiana Station, through the ODL pipeline. This phase involves the construction of additional facilities at CPF1, at the ODL Rubiales Pumping Station, and at the OCENSA Cusiana Station. The 40,000 bbl of Llanomulsión will be produced at CPF1, sent to a 50,000 bbl storage tank at the Rubiales Pumping Station, and then pumped in a separate batch to Cusiana, where the emulsion will be dehydrated and the crude oil treated for commercialization. The industrial test is intended to be performed when an operational window for ODL and OCENSA is available in the second half of 2011. In the meantime, design parameters for breaking the emulsion will be developed and tested in the pilot plant.

Implementation of this technology is expected to have a significant impact on the transportation costs for the Rubiales and Quifa fields, and could represent a breakthrough for the development of the Llanos Basin.

Oleoducto de Los Llanos Pipeline

The Company has a 35% interest in the ODL pipeline with the balance of 65% owned by Ecopetrol. The ODL pipeline was completed on schedule at a total cost of $558 million. Since October 1, 2009, a total of 72,414,741 bbl of diluted crude have been transported from the Rubiales field to the Monterrey Station.

In November 2009, the ODL board of directors approved an expansion of the pipeline from 170,000 bbl/d to 340,000 bbl/d. The project includes construction of a pipeline branch to Cusiana Station already in operation, construction of two booster stations and increase storage capacity at the Rubiales Pumping Station. As of March 31, 2011 the expansion was 75% completed. During the first quarter of 2011 the pipeline system pumped a total of 16,126,372 bbl and from this volume, 5,412,156 bbl corresponded to the Company’s crude oil.

On May 4, 2011 a pumping record of 246,588 bbls was achieved. This record was the result of new impellers installed in the main pumping units of the pipeline, the use of a drag reducing agent and the improved capacity of the OCENSA pipeline, which is connected to ODL.

During 2010, the Company decided to pursue a feasibility study for a heated oil line in the ODL pipeline for the purpose of reducing dilution costs. This project, if completed, should increase operating capacity and reduce dependence on truck transportation of diluents.

Petroeléctrica de los Llanos ("PEL") – Power Transmission Line Project

The Company incorporated PEL, a wholly-owned subsidiary, in 2010, which is responsible for constructing and operating a new power transmission line of 230 kilovolts to connect the Rubiales field with the country´s electrical grid. The new transmission line will originate at the Chivor Substation and will extend 260 km to the Rubiales field. The line includes two substations to supply power to the booster stations of the ODL pipeline, as well as a main substation for the Rubiales and Quifa fields. The new power line will be able to supply up to 220 MVA that will be used in oil production and transportation activities. Total capital expenditures for this project have been estimated at $135 million of which up to 70% is expected to be project financed.

During the third quarter of 2010, the construction of this power line was approved by the Unidad de Planificación Minero Energética", which is the governmental entity in charge of planning and approving construction of new power transmission lines in the country. During the same quarter, the Engineering, Procurement & Construction contract ("EPC") was awarded. Construction will start as soon as the environmental license is approved.

As of the date of this report, acquisition of rights of way reached 55%. During the first quarter of 2011, the Environment Ministry performed site visits and the EPC contractor awarded purchase orders for aluminum conductors and towers. Also during the first quarter of 2011, the Company's finance group started negotiations with local financial institutions interested in funding this project.

Oleoducto Bicentenario – Bicentennial Pipeline

The Company obtained a 32.88% equity interest in OBC in November 2010. The OBC is a special purpose vehicle promoted by Ecopetrol, which has a 55.97% interest together with its affiliates, with the participation of other oil producers operating in Colombia, who control the remaining 11.15% interest. OBC will be responsible for the financing, design, construction and eventual operation of Colombia's newest oil pipeline transportation system, which will run from Araguaney, in the Casanare Department of central Colombia, to the Coveñas Export Terminal in the Caribbean.

The new pipelines will add 450,000 bbl/d to the capacity of the existing pipeline systems connecting the Los Llanos Basin to the export markets, which are projected to reach full capacity as the increase in planned production from Colombian producers materializes in the mid-term.

For the Company, the participation in this project is a perfect strategic fit, time and volume-wise, as it moves towards reaching the goal of having a gross production of 500,000 bbl/d in the mid-term.

It is estimated that the first two phases of this project will require an aggregate investment of $1.03 billion, excluding financing costs, of which $340 million represents the Company´s share. The partners intend to finance the OBC pipeline project through project financing, with a debt/equity ratio of 70/30. This financing will be structured to maximize the use of export credit agencies and multilateral financing, as well as to access the Colombian capital markets.

The Company will have representation on the board of OBC and will play an active role in the financing and construction of the project. It is expected that the Company's equity contributions in the initial phases of the OBC will be funded through internally generated cash flow.

During the first quarter of 2011, 84% of the required pipe for phase 1 of the project (pipeline Araguaney – Banadia), arrived to Colombian ports. In addition, acquisition of rights of way reached 70% as of March 31, 2011 and the EPC contractor started mobilization of construction equipment. Construction will start as soon as the environmental license is approved.

6. Reserves

Proved and Probable Oil and Gas Reserves

The total proved and probable oil equivalent reserves of the Company as of March 31, 2011, discounting production for the first quarter of 2011, is 357.39 million bbl gross (before royalties) or 309.83 million bbl net to the Company. Oil equivalent is expressed in thousands of barrels (Mbbl). Gas volumes are expressed in billion cubic feet (Bcfg) and, when expressed in oil equivalent, were converted using 5,700 cubic feet of gas equivalent to one (1) bbl. Each of the 2010 Reserves Reports were prepared in accordance with NI 51-101 and published on the Company's website on March 11, 2011.

7. Discussion of Quarterly Results

Financial Position

<u>Assets</u>

Total assets were $4.1 billion as of March 31, 2011 compared to $4.0 billion as of December 31, 2010. The $4.1 billion in assets consisted primarily of $2.7 billion in oil and gas properties and equipment (December 31, 2010 - $2.6 billion), $604 million in cash and cash equivalents (December 31, 2010 - $603 million), $306 million in accounts receivable (December 31, 2010 - $293 million), $281 million in investments and other assets, primarily ODL (December 31, 2010- $250 million), and $209 million in other assets (December 31, 2010 - $155 million). Total assets increased primarily due to an increase in cash and accounts receivable, as a result of increased cash flows from operations.

<u>EBITDA</u>

EBITDA during the three months ended March 2011 totaled $363 million, which represents a significant increase of 56% compared to the first quarter 2010 EBITDA of $232 million, mainly generated from international sales (85%); EBITDA from gas and domestic sales contributed 13% and 2%, respectively. First quarter 2011 EBITDA represents a 62% margin in comparison to total revenues for the period (March 31, 2010 – 61% margin).

<u>Debt</u>

On April 13, 2011 the Company closed the amendment to its existing unsecured revolving credit facility (the “Revolving Credit Facility”), which was increased from $250 million, initially committed by the lenders in April 2010 to $350 million. The amendment was limited to the same lenders under the Revolving Credit Facility and, in addition to increasing the amount of the facility, the Company extended the term to April, 2013 and reduced the applicable commitment fees and the applicable margin. To date, the Company has not drawn down any funds from this credit facility and the Company does not expect to require any proceeds to fund its 2011 capital expenditure budget. Funds will be utilized as needed to take advantage of opportunities in the Colombia E&P sector that may become available and to fulfill the Company's business strategy. The applicable margin and commitment fees will continue to be determined in accordance with the rating assigned to the Company's senior debt securities by Standard & Poor's Ratings Group and Fitch Inc. Based on the Company's current rating and expected usage, the commitment fee will be reduced from 100 bps to 75 bps and the applicable margin from 325 bps to 250 bps over LIBOR. Subject to customary acceleration events set forth in the credit agreement relating to the Revolving Credit Facility, or unless terminated earlier by the Company without penalty, repayment of outstanding principal on the Revolving Credit Facility will be made in full on April 26, 2013.

As of March 31, 2011, the Company has issued standby and letters of credit for operational and exploration commitments for a total of $184 million (March 31, 2010 – $143.8 million). Most of these bank guarantees are related to light oil purchases and exploration commitments.

On May 5, 2011 Moody's Investors Service assigned a first-time Corporate Family Rating of Ba3 to Pacific Rubiales. The outlook is positive. The Ba3 rating for the Company reflects the scale of its oil-focused reserves and production, a favorable leverage position, the Company’s track record in overcoming infrastructure constraints and achieving production growth in the past three years, and a technically capable and seasoned management team. In addition to this, the positive outlook considers the expectation that the Company’s growth pattern will continue as it develops its prospects while also working towards a long-term solution to replace its core Rubiales and Piriri production before those concessions expire in 2016

On November 3, 2010, Standard & Poor's Ratings Services raised its corporate credit rating on Pacific Rubiales to 'BB-' from 'B+'. The outlook is stable. They also raised the rating of Senior Unsecured Notes to 'BB-'. This upgrade is based on the Company's improved financial performance because of a strong growth in its production, adequate liquidity and its ability to generate sufficient operating cash flow to finance most of its required investments.

The Company has senior unsecured notes (the “Senior Unsecured Notes”) outstanding, with an aggregate principal amount of $450 million and maturity dates of November 10, 2014 (33.3%), November 10, 2015 (33.3%), and November 10, 2016 (33.4%). The Senior Unsecured Notes carry an interest rate of 8.75%, payable on May 10th and November 10th of each year; payment began on May 10, 2010. The Senior Unsecured Notes may be redeemed in whole (but not in part) at any time at the discretion of the Company with a redemption price equal to the greater of: (1) 100% of the principal amount of the Senior Unsecured Notes to be redeemed; and (2) the sum of the present values of the remaining scheduled payments of principal and interest discounted to the date of redemption on a semi-annual basis at the applicable treasury rate plus 75 basis points, in each case plus accrued and unpaid interest on the outstanding principal amount. The Senior Unsecured Notes are senior unsecured and will rank equal in right of payment with all of the Company's existing and future senior indebtedness. The Senior Unsecured Notes are listed on the Official List of the Luxembourg Stock Exchange and are traded on the Euro MTF.

Securities

During the three months ended March 31, 2011, no convertible unsecured subordinated debentures were converted into common shares of the Company.

On March 10, 2011, the Company's Board of Directors approved a cash dividend in the aggregate of $25 million, or $0.093 per common share. The dividend was paid on March 30, 2011 to shareholders of record as of March 16, 2011; the ex-dividend date was March 14, 2011. Under the indenture dated August 28, 2008 that governs the debentures (the "Indenture"), the dividend payment on March 16, 2011 triggered an adjustment to the conversion rate applicable to the debentures. However, in accordance with the provisions of the Indenture, since the adjustment to the conversion rate resulting from the dividend payment was less than 1%, the adjustment was not to be made at the time, but instead will be carried over to the time of any subsequent adjustment.

On January 12, 2010, the Company announced that greater than 66 2/3% of its publicly-traded warrants outstanding as of December 14, 2009 had been exercised pursuant to the early exercise transaction. As a result of reaching the 66 2/3% threshold, each warrant that had not been so exercised during the 30-day early exercise period was deemed automatically exchanged by the warrantholder, without any further action or payment of additional consideration on the part of the warrantholder (including payment of the exercise price thereof), for consideration payable by the Company of C$0.75 (the "Exchange Payment") plus a fraction of a common share (collectively, the "Exchange Shares") equal to: (A) the volume weighted average trading price of the common shares on the TSX for the five trading days immediately prior to the early exercise expiry date (the "Market Price") minus (B) the current exercise price, divided by (C) the Market Price. Warrants that were held by U.S. warrantholders were not subject to the automatic exchange. In total, 27,295,661 warrants were exchanged for C$170 million in cash and 27,106,081 common shares in the capital of the Company.

Revenues

	Q1	
	2011	2010
Net crude oil and gas sales	583,549	379,431
$ per boe oil and gas	78.36	64.17

Revenue during the first quarter of 2011 totaled $583.5 million (22010 - $379.4 million), an increase of 54% in comparison to the same period of 2010. Net sales continued to grow mainly due to the 51% increase in production and construction of facilities at the Rubiales, Quifa and La Creciente fields coupled with better realized oil and gas prices throughout the first quarter of 2011 as explained in the table below. Revenues in the first quarter of 2011 were impacted by the timing of revenue recognition of 732,934 bbl crude oil produced in the quarter but exported in the first week of April 2011.

Summarized below is an analysis of the revenue increase due to the change in volume and price for the first quarter of 2011 in comparison to the same period of 2010.

	Q1			
	2011	**2010**	**Difference**	**% Change**
Total of boe sold (Mboe)	7,447	5,913	1,534	26%
Avg. Combined Price - Oil & gas and trading ($/bbl)	78.36	64.17	14.19	22%
Total Revenue (000$)	583,549	379,431	204,118	54%

Reasons for the difference (000$):		
Increase due to volume	98,434	48%
Increase due to price	105,684	52%
	204,118	

Operating Costs

	Q1 2011	Q1 2010
Oil and Gas Operating Costs	207,841	133,283
Overlift (Underlift)	(18,064)	(4,865)
$ per boe Crude Oil and Gas	27.91	22.54
$ per boe Over/Underlift	(2.43)	(0.82)

Notes:

(1) *Overlift or underlift corresponds to any resulting short term imbalance between cumulative production entitlement and cumulative sales attributable to each participant at the reporting date. Lifting or off take arrangements for oil and gas produced in jointly owned operations are frequently such that it is not practicable for each participant to receive or sell its precise share of the overall production during the period. Overlift represents an obligation to transfer future economic benefit (by foregoing the right to receive equivalent future production), and therefore constitutes a liability. Underlift represents a right to future economic benefit (through entitlement to receive equivalent future production) which constitutes an account receivable.*

(2) *The overlift recognized as of the end of March 31, 2011 of $18.1 million is the net balance between the overlift position reflected as of the fourth quarter of 2010 of $23.9 million (280,424 boe), settled in the first quarter of 2011, and the actual overlift as of the end of March 2011 of $6.2 million (75,376 boe). The overlift balance of $18.1 million was valued at the realized price of blend crude oil, and recorded as a liability and a reduction in the operating costs at March31, 2011. This overlift and its related financial impact will be reversed once the volume is settled in the second quarter of 2011.*

Operating costs for oil and gas during the first quarter of 2011 were $207.8 million (2010 - $133.3 million); the increase over the previous period of 2010 is primarily due to the increase in oil production at the Rubiales and Quifa fields. Production costs per boe for the first quarter of 2011 totaled $27.91, which represents an increase of 24% in comparison to the same period of 2010, mainly explained by the increase in the production in the first quarter of 2011 and a $0.5 million positive effect recognized during the first quarter of 2011 resulting from foreign currency risk management contracts recorded against operating expenses. The $27.91 per boe consists of production cost of $5.50, transportation cost of $10.88, dilution cost of $13.37 and other recovery costs of $(1.84).

Depletion, Depreciation and Amortization

	Q1 2011	Q1 2010
Depletion, depreciation and amortization	149,060	85,760
$ per boe	20.02	14.50

The increase in depletion, depreciation and amortization over the previous year was primarily due to increased production and increase in oil and gas property costs incurred subject to depletion. Included in the costs subject to depletion is $0.84 billion (2010 - $0.21 billion) of future development costs that are estimated to be required to bring proved undeveloped reserves to development.

General and Administrative

	Q1 2011	Q1 2010
General and administrative costs	31,245	19,047
$ per boe	4.20	3.22

General and administrative expenses for the first quarter ended March 31, 2011 were $31.2 million (2010 - $19.0 million), and the increase is mainly attributable to increased salaries and benefits as additional personnel were hired during 2010 and first quarter of 2011 to support the increased operations, oil production, and the drilling campaign at other exploratory blocks in 2010. In addition, part of the increase was due to a 5% appreciation of the Colombian peso against the US dollar when compared to the same period of 2010. The majority of the general and administrative costs are incurred in Colombian pesos and therefore subject to fluctuation when converted to the US dollar, after taking into account currency hedging arrangements. The number of direct and indirect employees in the first quarter of 2011 increased 73% to a total of 1,465 compared to 846 in the same period in 2010.

During the first quarter of 2011, general and administrative expenses on a per boe basis reflected an increase of $0.98/boe (30%) in comparison to the same period in 2010 due to the increased production.

Share-Based Compensation

	Q1	
	2011	2010
Share-based compensation	46,687	40,822
$ per boe	6.27	6.90

Share-based compensation was $46.7 million as a result of the granting of 4,331,500 (2010 - 6,296,500) fully vested options in the first quarter of 2011 compared to $40.8 million in the previous year. The increase is due to an increase in the fair value per option granted. All stock options outstanding as of March 31, 2011 are completely vested and exercisable and the fair values are calculated using the Black-Scholes option pricing model.

Equity Tax Expense

	Q1	
	2011	2010
Equity tax expense	68,446	522
$ per boe	9.19	0.09

On December 29, 2010 the Colombian Congress passed the law which imposes a surcharge on the existing equity tax levied on Colombian companies. This surcharge increased the equity tax rate for the Company from 4.8% to 6% and is applied on the net taxable equity as of January 1, 2011. The Company's total equity tax payable for the years 2011 to 2014 is $83.4 million, to be paid in eight equal installments.

In contrast to previous equity tax legislation, the newly calculated equity tax is payable even in the event that the Company ceases to have taxable equity in subsequent years. As such, the Company has recognized the equity tax payable on the consolidated statement of financial position with a corresponding expense in the current quarter. The amount recognized is calculated by discounting the eight future equity tax payments by the Company's weighted cost of capital at 10.8%.

Foreign Exchange

	Q1	
	2011	2010
Foreign exchange (loss) gain	3,953	13,525
$ per boe	0.53	2.29

Foreign exchange gains primarily resulted from the translation of monetary assets or liabilities which are denominated in Colombian pesos and Canadian dollars to US dollars. Since the Company's functional currency is the Canadian dollar, any US dollar denominated cash balance and debts would be subject to fluctuations in the exchange rate. For the first quarter 2011 and 2010, the Canadian dollar appreciated against the US dollar, resulting in a foreign exchange gain upon the revaluation of the $450 million senior notes.

Finance Cost

	Q1	
	2011	2010
Interest expense	23,149	13,876
$ per boe	3.11	2.35

Interest expense includes interest on bank loans, convertible debentures, notes, finance leases and fees on letters of credit. For the three months ended March 31, 2011, interest expense totaled $23.1 million (March 31, 2010 - $13.9 million). The higher interest expense over the same quarter of 2010 is mainly due to interest incurred on promissory notes and commitment fees paid on the unused Revolving Credit Facility. No new long-term debt was incurred in the first quarter of 2011.

Income Tax Expense

	Q1	
	2011	2010
Current income tax	77,657	57,076
Future income tax	(28,283)	(26,746)
Total	49,374	30,330

The tax rate in Canada is 28.25% and in Colombia 33% of taxable income. The Colombian Congress passed a tax reform on December 29, 2010 eliminating the 30% special tax benefit starting January 2011. However, the new law allows certain tax payers which had submitted a tax stabilization contract prior to November 1, 2010 to maintain this benefit for another three years once it has been approved by the applicable governmental authority. The Company is in the process of having its stabilization contracts reviewed and the Company expects to have a positive outcome before the end of 2011.

Income tax expense increased during the three month period ended March 31, 2011, which is in line with increased revenues and operating income. The effective tax rate is greater than the statutory rate of 33% primarily due to the non-deductible costs for tax purposes such as share-based compensation costs, equity tax and loss on risk management contracts.

Current income tax represents the estimated cash income taxes payable for the period. Current income tax increased to $77.5 million from $57 million during the same period of 2010, which was primarily due to increased operating income and reduced by the special deduction for investment in assets eligible for the special tax benefit.

Net Earnings (Loss)

	Q1	
	2011	2010
Net earnings (loss)	(69,593)	76,127
$ per boe	(9.34)	12.87

Net loss for the three months ended March 31, 2011 totaled $69.6 million (2010 gain - $76.1 million). The Company´s first quarter 2011 financial results were impacted by a number of non-cash items totaling $203.8 million. These non-cash items are mainly related to unrealized mark-to-market losses on derivatives of $92.6 million, the equity tax in Colombia of $68.4 million fully recognized in this quarter, share-based compensation of $46.7 million, and foreign exchange gain of $4 million, which are discussed in detail later in this document. With exception of the equity tax, the rest of the non-cash items may or may not materialize in the future. Excluding these items, the Company earned $134.2 million, or $0.50 per diluted common share as shown below:

	Q1	
	2011	2010
Net earnings (loss)	(69,593)	76,128
Other non - cash items		
Foreign exchange gain	(3,953)	(13,525)
Loss (gain) on risk management contracts	92,634	(5,017)
Share-based compensation	46,687	40,822
Equity tax	68,446	522
Net earnings (loss) - (excluding non-cash items)	134,221	98,930
Per share - basic ($)	0.50	0.41

Cash Flow from Operations

	Q1	
	2011	2010
Cash flow from operations	319,803	257,599
$ per share, diluted	1.19	1.02

The Company continued to generate positive cash flow from operations as a result of the increase in production together with the increase in the combined realized oil and gas price. The funds flow from operations during the quarter ended March 31, 2011 totaled $266.7 million. This increase is primarily attributable to the 25% increase in the combined net back in the first quarter of 2011 as compared to the same period in 2010 ($52.88 per boe in the first quarter of 2011 versus $42.45 per boe in the same period of 2010), as well as the significant increase in production. The increase in net back is due to higher realized prices from $64.17 per boe in 2010 to $78.36 per boe in 2011.

Cash flow from operations for the first quarter of 2011 increased by $62.2 million over the same period of 2010. As mentioned above, this increase is primarily attributable to the increase in net back due to improved realized prices and the significant increase in production.

Liquidity and Capital Resources

Liquidity

Funds provided by operating activities for the quarter ended March 31, 2011 totaled $320 million (2010 – $258 million), The increase in cash flow in 2011 was the result of the increase in production and higher combined crude oil and gas sale prices. The Company has been generating cash flows from operations from the sale of crude oil and natural gas and continues to plan for increased future production.

As of March 31, 2011 the Company had working capital of $247.5 million, mainly composed of $604 million of cash and cash equivalents, $306 million of account receivables, $92 million of inventory, $2 million of income tax receivable, $1.5 million of prepaid expenses, $584 million of accounts payable and accrued liabilities, $168 million of income tax payable, and $6 million of current portion of capital lease obligations.

On April 27, 2010, the Company closed the syndication of the Revolving Credit Facility. On April 13, 2011, the Company closed an amendment to the Revolving Credit Facility. As a result of the demand generated amongst the lending syndicate, the amount of the Revolving Credit Facility was increased from the $250 million initially committed by the lenders to $350 million, and the Company extended the term of the Revolving Credit Facility to April, 2013 and reduced the applicable commitment fees and the applicable margin.

As at March 31, 2011, no borrowing has been made under the Revolving Credit Facility. The Company believes it has adequate resources to fund its capital plan for 2011, with the Company's cash flows from operations and current debt facilities. With respect to the Company's broader integration strategy (see "Strategy" section on page 7), the Company will pay for the expansion plan with its own cash flow. However, if additional resources are required, there are possible sources of funds available to the Company to finance additional capital expenditures and operations including the Revolving Credit Facility, existing working capital and incurring new debt, and the issuance of additional common shares, if necessary.

8. Capital Expenditures

Capital expenditures during the quarter ended March 31, 2011 totaled $175.7 million (2010 - $80.8 million), of which $75.5 million was invested in the expansion and construction of production infrastructure; $41.5 million went into exploration activities including seismic, aerogravimetry, aeromagnetometry and drilling; $56.1 million were invested in production drilling activities; and $2.6 million were invested in other projects as follows:

	Net Capital Expenditures (Thousands of $) Q1	
	2011	**2010**
Production facilities	75,535	36,633
Exploration drilling including seismic acq.	41,526	13,418
Development drilling	56,058	30,753
Other projects (STAR, Llanomulsion, Gas export)	2,563	nil
Total Capital Expenditures	**175,682**	**80,804**

Capital Expenditure Plan for 2011

On January 10, 2011, the Company announced its fully funded capital expenditure budget for 2011 that includes a $1.12 billion capital expenditure program. With this investment program, the Company will significantly increase its gross operated production from the average 2010 production of 144,307 boe/d to 265,000 boe/d at the end of 2011. The Company's capital expenditure strategy entails two main long-term initiatives: (i) growth based upon discovering, developing and producing new and existing reserves; and (ii) securing market access by participating in key oil and gas transportation and port infrastructure projects. For 2011, the Company has budgeted $340 million for exploration activities as it enters into a more intensive phase in more than 26 of its blocks in Colombia, and begins operations in Peru and Guatemala. The Company plans to invest $438 million in production facilities, mainly at the Quifa and Rubiales fields, as it ramps up production in the Quifa field and continues to expand the fluid handling capacities in the Rubiales field. The expansion of production capacity in all of the fields calls for an investment of $139 million in development drilling. Finally, the Company has earmarked $204 million for projects such as STAR, IT investment and its investment in transportation and port projects. The $1.12 billion capital expenditure program is an increase of $359 million over actual capital expenditures in 2010.

The Company’s broader integration strategy (see “Strategy” section on page 7), requires a minimal investment, with the exception of the exploration and production capital expenditures (discussed immediately above) and the OBC project. The latter will have its own financing through a special purpose vehicle project financing structure.

9. Commitments and Contingencies

As part of the Company’s normal course of business, the Company entered into arrangements that will impact the Company’s future operations and liquidity. The principal commitments of the Company are ship or pay arrangements on crude oil and gas transportation, asset retirement obligations, debt repayments, service contracts with suppliers in relation with the exploration and operation of oil properties and engineering and construction contracts, among others. Commitments as of March 31, 2011 are summarized in the following table:

	2011	2012	2013	2014	2015	Subsequent to 2017	Total	
Operating leases	$ 196	$ 578	$ 6,173	$ 5,509	$ 5,509	$ 30,074	$ 48,039	(a)
Transportation and processing commitments	35,235	46,980	46,980	46,980	41,580	83,160	300,915	(b)
Minimum work commitments	120,380	100,350	42,428	30,778	-	-	293,936	(c)
OBC Investment	242,676	-	-	-	-	-	242,676	(d)
Maurel et Prom - SPA	73,000	20,000	20,000	10,000	-	-	123,000	(e)
EPC Contract (transmission line)	100,885	-	-	-	-	-	100,885	(f)
Total	$ 572,372	$ 167,908	$ 115,581	$ 93,267	$ 47,089	$ 113,234	$ 1,109,451	

The Company has various commitments in place in the ordinary course of business between 2011 and subsequent to 2016:

a) Operating leases of $48 million mainly related to the 10-year lease of Bogota offices signed in January 2011 and lease of the Canadian office.

b) Ship or pay contracts totaling $300.9 million as follows: $280.7 million signed with ODL for the transportation of crude oil from the Rubiales field to Colombia's oil transportation system, and $20.2 million signed with Promigas for gas transportation from the La Creciente field to connect the Cartagena gas pipeline to deliver the product to customers´ facilities.

c) Minimum capital investments agreed in E&E contracts that include acquisition and processing of seismic data and drilling exploration wells in Colombia, Peru and Guatemala.

d) The $242.6 million represents the future commitment to pay in 2011 on the acquisition of a 32.9% interest in OBC for a total investment of $1.03 billion ($340 million being the Company's share). The investment in OBC is accounted for using the equity method.

e) On March 31, 2011, the company announced the acquisition of 49.999% of the interests held by Maurel et Prom in the Sabanero, Muisca, SSJN-9, CPO-17 and COR-15 blocks. Based on the SPA Rubiales will pay to Maurel et Prom cash consideration to a maximum of $66 million as a reimbursement for past exploration costs in the blocks incurred as at March 31, 2011. In addition, the Company will assume: i) a full carried obligation of up to $120 million in three years for exploration activities in the SSJB-9, CPO-17, and Muisca blocks and ii) a full carried obligation in the Sabanero and COR-15 blocks with a reimbursement out of future free cash flow.

f) Arrangement to build a new transmission line with an extension of 260 km and 520 towers from Chivor hydroelectric station to the Rubiales field. The construction will start in the second half of 2011, once environmental permits are granted.

Disclosure about the Company's significant commitments can be found in note 13 to the consolidated financial statements. The Company has no off-balance sheet arrangements.

10. Risk Management Contracts

The Company had the following commodity price risk management contracts outstanding as at March 31, 2011:

Type of Instrument	Term	Volume (bbl)	Floor/ceiling or strike price ($/bbl)	Benchmark	Fair value
Zero cost collars	April 2011 to December 2012	13,421,400	70-80 / 98-120	WTI	(131,695)
Call option	November 2011 to January 2012	1,680,000	114.10 -118.80	WTI	(11,991)
Put option	April to July 2011	1,532,500	40-70	WTI	(1,538)
	Total				**$ (145,224)**
	Short-term				(123,354)
	Long-term				(21,870)
	Total				**$ (145,224)**

The fair market value of hedge commodities, like for many oil producers, was impacted by several factors during the first quarter of 2011, including political unrest in countries of the Middle East and Africa, as well as the earthquake and resulting tsunami in Japan, which significantly increased oil price.

For the quarter ended March 31, 2011 the Company recorded a loss of $92.6 million (2010 - $5.0 million gain) on commodity price risk management contracts in net income. Included in these amounts were $91.6 million of unrealized loss (2010– $6.8 million gain) representing the change in the fair value of the contracts, and $1.0 million of realized loss (2010 - $1.6 million loss).

If the forward WTI crude oil price at March 31, 2011 had been $1/boe higher or lower, the unrealized loss on these contracts would change by approximately $9.7 million (2010 – $1.5 million) and would be reflected in the statement of income of the Company.

Foreign currency exchange risk

The Company is exposed to foreign currency fluctuations in Colombian pesos (COP) and Canadian dollars relative to US dollars.

To reduce its foreign currency exposure associated with operating expense incurred in COP, the Company may enter into currency risk management contracts such as foreign exchange forwards, options, and costless collars. The Company has the following currency risk management contracts outstanding as at March 31, 2011, which qualify for cash flow hedge accounting:

Instrument	Term	Notional amount ($)	Floor-ceiling (COP/$)	Fair value ($)
Currency collars	April to December 2011	$ 405,000	1860 - 1930	$ 6,253

The effective portion of the change in the fair value of the above currency hedges is recognized in other comprehensive income as unrealized gains or losses on cash flow hedges. The effective portion is reclassified to operating expenses in net income in the same period as the hedged operating expenses are incurred. During the quarter ended March 31, 2011, $7.1 million (2010 - $8.0 million) of unrealized gains were recorded in other comprehensive income, and $0.5 million was subsequently recorded against operating cost when the gains became realized. The Company excludes changes in fair value due to the time value of options and records these amounts along with hedge ineffectiveness in foreign exchange gains or losses in the period that they arise. During the quarter ended March 31, 2011, $1.9 million of ineffectiveness was recorded as foreign exchange loss (2010 - $0.5 million).

11. Selected Quarterly Information

(In thousands of $ except per share amounts or as noted)	2011	2010				2009 (5)		
	Q1	Q4	Q3	Q2	Q1	Q4 (Restated (4))	Q3	Q2
Financials:								
Net sales	583,549	516,730	408,535	356,848	379,431	211,650	156,557	160,994
Net earnings (loss) for the period	(69,593)	82,993	86,535	19,382	76,127	3,218	(63,107)	(118,540)
Earnings (loss) per share								
- basic	$ (0.26)	$ 0.31	$ 0.33	$ 0.07	$ 0.32	$ 0.02	$ (0.29)	$ (0.56)
- diluted	$ (0.26)	$ 0.29	$ 0.31	$ 0.07	$ 0.30	$ 0.02	$ (0.29)	$ (0.56)

(1) Calculated based on cash flow from operations before changes in non-cash operating working capital.
(2) Combined operating netback data is based on weighted average daily production sold.
(3) Operating netback data based on weighted average daily production sold.
(4) The Company has restated its 2009 consolidated financial statements to correct an error that resulted in an overstatement of accounts payable and accrued liabilities as of December 31, 2009. This occurred in the fourth quarter of 2009 as a result of the amalgamation of several operating subsidiaries of the Company and an enterprise resource planning system conversion.
(5) 2009 comparative figures prepared in accordance with Canadian GAAP.

During the first quarter of 2011, net sales of $583.5 million were higher by $110.5 million over the prior quarter of 2010, due to the increase in production and better realized crude oil and gas prices. Net earnings decreased by $145.7 million due to non-cash items totaling $203.8 million, which are mainly related to unrealized mark-to-market losses on derivatives of $92.6 million, the equity tax in Colombia $68.4 million fully recognized in this quarter, share-based compensation effect of $46.7 million, and foreign exchange effect of $4 million.

12. Outstanding Share Data

Issued and Fully Paid Common Shares

As at March 31, 2011, 268,124,603 common shares were issued and outstanding.

The Company does not have shares subject to escrow restrictions or pooling agreements.

On March 6, 2011, the Company announced that it had filed a Notice of Intention, subject to acceptance by the TSX, to purchase for cancellation up to a maximum of 11,598,513, or 4.3%, of the total common shares issued and outstanding of the Company as of March 31, 2011, through the facilities of the TSX and La Bolsa de Valores de Colombia (the Colombian Stock Exchange) (the "BVC"). There were a total of 268,124,603 common shares issued and outstanding as of March 31, 2011. The Company will determine the actual number of common shares that may be purchased and the timing of any such purchases, subject to compliance with applicable TSX rules. Daily purchases will be limited to 442,322 common shares, other than block purchase exceptions. The Company commenced the bid on April 8, 2011, and it is proposed to remain open until the earlier of April 7, 2012 or the date on which the Company has purchased the maximum number of common shares permitted under the bid. No common share purchases have been executed to date, pursuant to any issuer bid.

Stock Options and Warrants

As at March 31, 2011, 611,682 warrants to acquire an equal number of common shares were outstanding and exercisable) and 25,079,879 stock options were outstanding, of which all were exercisable.

13. New Accounting Pronouncements

First Time Adoption of IFRS

The Company's interim condensed consolidated financial statements as at and for the three month period ended March 31, 2011 have been prepared in accordance with International Financial Reporting Standard 1 *First-time adoption of IFRS* ("IFRS 1") and International Accounting Standard 34 *Interim Financial Reporting* ("IAS 34") as issued by the International Accounting Standards Board. They are the Company's first interim condensed consolidated financial statements prepared in accordance with IFRS using the accounting policies the Company expects to adopt in its annual financial statements for the year ending December 31, 2011. Previously the Company prepared its financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). The transition to IFRS resulted in changes to the Company's previous accounting policies as applied and disclosed in the consolidated financial statements for the year ended December 31, 2010, prepared in accordance with Canadian GAAP. A summary of the significant changes to the Company's accounting policies is disclosed in Note 24 of the interim condensed consolidated financial statements along with the impact of the changeover to IFRS on the comparative periods.

IFRS 1 Exemptions

The general principle to be applied on first-time adoption of IFRS is that standards in force at the first annual reporting date (December 31, 2011) should be applied as at the date of transition to IFRS (January 1, 2010) and throughout all periods presented in the first IFRS financial statements. IFRS 1 contains a number of exemptions that companies are permitted to apply. The Company has elected to apply the following exemptions:

a) To apply IFRS 3 *Business Combinations* prospectively and not restate business combinations that occurred prior to January 1, 2010.
b) To not apply IFRS 2 *Share-Based Payments* to equity awards that vested before January 1, 2010
c) To deem cumulative currency translation differences for all foreign operations to be zero as at January 1, 2010.
d) To deem the cost of oil and gas properties and exploration and evaluation assets equal to its Canadian GAAP historical property, plant and equipment net book value as at January 1, 2010.

Reconciliations from Canadian GAAP to IFRS

In preparing the interim condensed consolidated financial statements, the Company has adjusted amounts reported previously in its consolidated financial statements prepared under Canadian GAAP. An explanation of how the transition from Canadian GAAP to IFRS has impacted the Company's consolidated statement of financial position, consolidated statement of income and shareholders' equity is included in the following reconciliations and notes.

Reconciliation of Consolidated Statement of Financial Position as at January 1, 2010

	Jan. 1, 2010 Cdn GAAP	O&G assets (1)	Transmeta (2)	ARO (3)	Deferred income tax (4)	Land acquisition (5)	Equity investments (6)	Functional currency (7)	Jan. 1, 2010 IFRS
Current assets	656,296	-	(13,925)	-	(2,693)	(3,926)	-	-	635,752
Non-current assets	2,162,814	-	(3,495)	-	100,732	3,536	28,123	(124)	2,291,586
Total assets	**$ 2,819,110**	**$ -**	**$ (17,420)**	**$ -**	**$ 98,039**	**$ (390)**	**$ 28,123**	**$ (124)**	**$ 2,927,338**
Current liabilities	250,938	-	(7,990)	-	(846)	126	-	-	242,228
Non-current liabilities	1,039,414	-	108	253	22,091	-	-	-	1,061,866
Total liabilities	**1,290,352**	**-**	**(7,882)**	**253**	**21,245**	**126**	**-**	**-**	**1,304,094**
Shareholders' equity	1,528,758	-	(9,538)	(253)	76,794	(516)	28,123	(124)	1,623,244
Total liabilities and shareholders' equity	**$ 2,819,110**	**$ -**	**$ (17,420)**	**$ (253)**	**$ 98,039**	**$ (390)**	**$ 28,123**	**$ (124)**	**$ 2,927,338**

Reconciliation of Consolidated Statement of Financial Position as at March 31, 2010

	Mar. 31, 2010 Cdn GAAP	O&G assets (1)	Transmeta (2)	ARO (3)	Deferred income tax (4)	Land acquisition (5)	Equity investments (6)	Functional currency (7)	Mar. 31, 2010 IFRS
Current assets	$ 827,902	$ (834)	$ (470)	$ -	$ (2,459)	$ (4,405)	$ -	$ -	$ 819,734
Non-current assets	2,365,851	(15,438)	(3,617)	(1,209)	107,145	3,536	30,920	404	2,487,592
Total assets	**$ 3,193,753**	**$ (16,272)**	**$ (4,087)**	**$ (1,209)**	**$ 104,686**	**$ (869)**	**$ 30,920**	**$ 404**	**$ 3,307,326**
Current liabilities	331,988	-	2,539	-	-	(109)	-	-	334,418
Non-current liabilities	1,069,522	-	108	(982)	(12,618)	-	-	-	1,056,030
Total liabilities	**1,401,510**	**-**	**2,647**	**(982)**	**(12,618)**	**(109)**	**-**	**-**	**1,390,448**
Shareholders' equity	1,792,243	(16,272)	(6,734)	(227)	117,304	(760)	30,920	404	1,916,878
Total liabilities and shareholders' equity	**$ 3,193,753**	**$ (16,272)**	**$ (4,087)**	**$ (1,209)**	**$ 104,686**	**$ (869)**	**$ 30,920**	**$ 404**	**$ 3,307,326**

Reconciliation of Consolidated Statement of Financial Position as at December 31, 2010

	Dec. 31, 2010 Cdn GAAP	O&G assets (1)	Transmeta (2)	ARO (3)	Deferred income tax (4)	Land acquisition (5)	Equity investments (6)	Functional currency (7)	Dec. 31, 2010 IFRS
Current assets	984,393	690	(9,366)	-	(2,669)	(5,324)	-	-	967,724
Non-current assets	2,870,693	(81,951)	(11,093)	2,644	166,142	4,431	34,798	741	2,986,405
Total assets	**$ 3,855,086**	**$ (81,261)**	**$ (20,459)**	**$ 2,644**	**$ 163,473**	**$ (893)**	**$ 34,798**	**$ 741**	**$ 3,954,129**
Current liabilities	801,712	-	(14,273)	-	(3,396)	(111)	-	-	783,932
Non-current liabilities	1,018,302	-	114	2,177	4,779	-	-	-	1,025,372
Total liabilities	**1,820,014**	**-**	**(14,159)**	**2,177**	**1,383**	**(111)**	**-**	**-**	**1,809,304**
Shareholders' equity	2,035,072	(81,261)	(6,300)	467	162,090	(782)	34,798	741	2,144,825
Total liabilities and shareholders' equity	**$ 3,855,086**	**$ (81,261)**	**$ (20,459)**	**$ 2,644**	**$ 163,473**	**$ (893)**	**$ 34,798**	**$ 741**	**$ 3,954,129**

Reconciliation of Consolidated Statement of Income for the three months ended March 31, 2010

	Mar. 31, 2010 Cdn GAAP	O&G assets (24.1)	Transmeta (24.2)	ARO (24.3)	Deferred income tax (24.4)	Land acquisition (24.5)	Equity investments (24.6)	Functional currency (24.7)	Mar. 31, 2010 IFRS
Oil and gas sales	$ 380,523	$ -	$ (1,092)	$ -	$ -	$ -	$ -	$ -	$ 379,431
Cost of operations									
Production and operating costs	131,366	402	(422)	-	(2,928)	-	-	-	128,418
Depletion, depreciation and amortization	64,285	15,912	-	-	5,563	-	-	-	85,760
	195,651	16,314	(422)	-	2,635	-	-	-	214,178
Earnings before undernoted	184,872	(16,314)	(670)	-	(2,635)	-	-	-	165,253
Expenses									
General and administrative expenses	19,808	(5)	(674)	(26)	(56)	-	-	-	19,047
Shared-based compensation	40,822	-	-	-	-	-	-	-	40,822
	60,630	(5)	(674)	(26)	(56)	-	-	-	59,869
Earnings from operations	124,242	(16,309)	4	26	(2,579)	-	-	-	105,384
Finance costs	(13,916)	40	-	-	-	-	-	-	(13,876)
Profit (loss) from equity-investments	-	-	-	-	-	-	(1,184)	-	(1,184)
Equity tax	(522)							-	(522)
Foreign exchange	(31,750)	-	3,064	-	24,095	(244)	-	18,360	13,525
Gain (loss) on risk management	5,017	-	-	-	-	-	-	-	5,017
Other expenses	(1,621)	(1)	(265)	-	-	-	-	-	(1,887)
Net earnings before income tax	81,450	(16,270)	2,803	26	21,516	(244)	(1,184)	18,360	106,457
Income tax expense	(49,324)	-	-	-	18,994	-	-	-	(30,330)
Net earnings for the period	**$ 32,126**	**$ (16,270)**	**$ 2,803**	**$ 26**	**$ 40,510**	**$ (244)**	**$ (1,184)**	**$ 18,360**	**$ 76,127**
Other comprehensive income									
Foreign currency translation (nil tax effect)	4,819		-	-	-	-	3,752	(17,832)	(9,261)
Unrealized gain on cash flow hedges (nil tax effect)	8,036		-	-	-	-	-	-	8,036
	12,855	-	-	-	-	-	3,752	(17,832)	(1,225)
Comprehensive income for the period	44,981	(16,270)	2,803	26	40,510	(244)	2,568	528	74,902

Reconciliation of Consolidated Statement of Income for the year ended December 31, 2010

	Dec. 31, 2010 Cdn GAAP	O&G assets (24.1)	Transmeta (24.2)	ARO (24.3)	Deferred income tax (24.4)	Land acquisition (24.5)	Equity investments (24.6)	Functional currency (24.7)	Dec. 31, 2010 IFRS
Oil and gas sales	$ 1,661,544	$ -	$ -	$ -	$ -	$ -	$ -		$ 1,661,544
Cost of operations									
Production and operating costs	626,772	(1,435)	5,035	-	-	-	-		630,372
Depletion, depreciation and amortization	298,567	83,083	-	-	12,658	-	-		394,308
	925,339	81,648	5,035	-	12,658	-	-	-	1,024,680
Earnings before undernoted	736,205	(81,648)	(5,035)	-	(12,658)	-	-	-	636,864
Expenses									
General and administrative expenses	111,919	1,253	(3,699)	(380)	104	-	-		109,197
Shared-based compensation	73,327	-	-	-	-	-	-		73,327
	185,246	1,253	(3,699)	(380)	104	-	-	-	182,524
Earnings from operations	550,959	(82,901)	(1,336)	380	(12,762)	-	-	-	454,340
Finance costs	(76,447)	(1,112)	176	-	-	-	-		(77,383)
Profit (loss) from equity-investments	(1,634)	-	-	-	-	-	9,404		7,770
Foreign exchange	(11,092)	-	2,937	340	11,278	(266)	-	30,654	33,851
Gain (loss) on risk management	(40,230)	-	-	-	-	-	-		(40,230)
Other expenses	(951)	2,753	1,375	-	(155)	-	(304)		2,718
Net earnings before income tax	420,605	(81,260)	3,152	720	(1,639)	(266)	9,100	30,654	381,066
Income tax expense	(202,999)	-	133	-	86,887	-	-		(115,979)
Net earnings for the period	**$ 217,606**	**$ (81,260)**	**$ 3,285**	**$ 720**	**$ 85,248**	**$ (266)**	**$ 9,100**	**$ 30,654**	**$ 265,087**
Other comprehensive income									
Foreign currency translation (nil tax effect)	11,577						(2,425)	(29,789)	(20,637)
Unrealized gain on cash flow hedges (nil tax effect)	21,721								21,721
Realized gain on cash flow hedges transferred to profit (nil tax effect)	(21,721)								(21,721)
	11,577	-	-	-	-	-	(2,425)	(29,789)	(20,637)
Comprehensive income for the period	229,183	(81,260)	3,285	720	85,248	(266)	6,675	865	244,450

Notes for reconciliations from Canadian GAAP to IFRS

1. Oil and gas properties and exploration and evaluation assets

The Company has elected to apply the exemption under IFRS 1 to deem the cost of oil and gas properties and exploration and evaluation assets as at January 1, 2010 equal to the net book value of property, plant and equipment recorded under Canadian GAAP.

Under Canadian GAAP, depreciation, depletion and amortization of oil and gas properties is determined on a unit-of-production basis with Colombia being considered one cost centre. Under IAS 16 *Property, Plant and Equipment*, depletion, depreciation and amortization is calculated at the level of the cash generating unit, which the Company has determined to be the major producing fields.

Depreciation charged against certain administrative assets related to oil producing fields is now included under cost of operations rather than general and administrative expenses.

2. Consolidation of Transmeta

Under Canadian GAAP, the Company consolidated Transportadora Del Meta S.A. (“Transmeta”) as a variable interest entity. Under SIC 12 requirements, consolidation of special purpose entities is determined based on control. The Company has concluded it does not control Transmeta as of January 1, 2010 and therefore consolidation has been reversed.

3. Asset retirement obligation

As the Company elected to use the full cost as deemed cost exemption as described above, the asset retirement obligation has been re-measured as at January 1, 2010 using the guidance in IAS 37. In re-measuring the asset retirement obligation, expected future cash outflows were estimated and discounted to January 1, 2010 using the risk free rate of 4%.

4. Deferred income tax

a) Under Canadian GAAP the Company recognized a deferred income tax arising from the bonus depreciation "superdeduction" related to qualifying new investments in Colombia. This type of benefit is not within the scope of IAS 20 and is therefore not treated as part of the tax base. Instead, the deduction is recognized as a reduction to income tax expense in the current period.

b) Under Canadian GAAP, deferred income tax assets were classified between current and non-current, based on the classification of the underlying assets and liabilities that gave rise to the differences. IAS 12 requires that deferred taxation amounts be classified as non-current assets only.

c) Deferred income tax assets and liabilities have been adjusted for the changes to net book values of oil and gas properties arising as a result of the adjustments for first time adoption of IFRS as discussed in 1 above. Under Canadian GAAP, deferred tax was not recognized for temporary differences resulting from differences between the functional currency and the currency in which the Company's taxes are denominated, being the Colombian peso. Under IFRS, such temporary tax differences are recognized as part of the deferred tax expense or recovery in the consolidated statement of income.

d) Under IFRS, temporary difference is calculated on the difference between the accounting base and the tax base of the convertible debenture. The tax effect calculated on the equity component of the convertible debenture is recorded as a deferred tax liability with a corresponding adjustment to the equity component at the time of issue. The tax effect on the subsequent change in the temporary difference related to the debt component of the convertible debenture is recognized as deferred tax expense or recovery in the consolidated statement of income.

5. Land acquisition

Certain advances made for the acquisition of land that were included in accounts receivable under Canadian GAAP have been reclassified to oil and gas properties, as the title of the land has been transferred to a trust that is considered to be a special purpose entity subject to consolidation pursuant to the requirements of SIC 12.

6. Equity-accounted investments

The Company determined that the effect of the changeover to IFRS on the financial statements of the Company's equity-accounted investments as at January 1, 2010 was an increase to the carrying amount of the investments by $28.1 million with a corresponding adjustment to retained earnings. The carrying amounts of property, plant and equipment of ODL and PII were adjusted for IFRS requirements, including the effect of the accounting for the superdeduction related to qualifying investments in Colombia.

7. Functional currency

The Company's functional currency under Canadian GAAP was the U.S. dollar. Under IFRS, the Company has determined that its functional currency is the Canadian dollar. The Company's presentation currency continues to be the U.S. dollar. The effect of this change is primarily related to the translation of the Company's cash and debts on the consolidated statement of financial position and the resulting foreign exchange gains and losses on the consolidated statement of income. Unrealized gains and losses resulting from the translation to the U.S. dollar presentation currency have been included in other comprehensive income

8. Reconciliation of the statement of cash flows from Canadian GAAP to IFRS

The transition from Canadian GAAP to IFRS did not materially change the underlying cash flows of the Company with the exception that the Company no longer consolidates the operating results of Transmeta as described in 2 above. As a result of the reversal of consolidation of Transmeta, the Company's net cash provided by operating activities was reduced by $2.2 million for the three months ended March 31, 2010.

Standards issued but not yet effective

Standards issued but not yet effective up to the date of issuance of the Company's financial statements are listed below. This listing is of standards and interpretations issued, which the Company reasonably expects to be applicable at a future date. The Company intends to adopt those standards when they become effective.

IFRS 7 *Financial Instruments: Disclosures*

In October 2010, the IASB amended IFRS 7 to enhance the disclosure about transfers of financial assets. This improvement is to assist users in understanding the possible effects of any risks that remain in an entity after the asset has been transferred. In addition, if disproportionate amounts are transferred near year end, additional disclosures would be required. The effective date of the amendment is July 1, 2011. The Company has determined that the adoption of this amendment will not have a material impact on the consolidated financial statements.

IAS 12 *Income Taxes*

In December 2010, the IASB amended IAS 12 for the recovery of underlying assets and the impact on deferred taxes. The amendments provide a solution to the problem of assessing whether recovery would be through use or through sale when the asset is measured at fair value under IAS 40 *Investment Property*, by adding the presumption that the recovery would normally be through sale. The amendment also incorporates the remaining guidance in SIC-21 *Income Taxes – Recovery of Revalued Non-depreciable Assets*, as SIC-21 has been withdrawn. The effective date of amendment is January 1, 2012. The Company is in the process of reviewing the amendment to determine the possible impact on the consolidated financial statements.

IFRS 9 *Financial Instruments: Classification and Measurement*

In November 2009, the IASB issued IFRS 9, which covers classification and measurement as the first part of its project to replace IAS 39. In October 2010, the Board also incorporated new accounting requirements for liabilities. The standard introduces new requirements for measurement and eliminates the current classification of loans and receivables, available-for-sale and held-to-maturity, currently in IAS 39. There are new requirements for the accounting of financial liabilities as well as carryover of requirements from IAS 39. The Company does not anticipate early adoption and will adopt the standard on the effective date of January 1, 2013. The Company has not determined the impact of the new standard on the consolidated financial statements.

IFRS 10 *Consolidated Financial Statements*

IFRS 10 *Consolidated Financial Statements* will replace portions of IAS 27 *Consolidated and Separate Financial Statements and interpretation* SIC-12 *Consolidation – Special Purpose Entities*. The key features of IFRS 10 include consolidation using a single control model, definition of control, considerations on power, and continuous reassessment. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Company has not determined the impact of the new standard on the consolidated financial statements.

IFRS 11 *Joint Arrangements*

IFRS 11 *Joint Arrangements* will apply to interests in joint arrangements where there is joint control. IFRS 11 would require joint arrangements to be classified as either joint operations or joint ventures. The structure of the joint arrangement would no longer be the most significant factor when classifying the joint arrangement as either a joint operation or a joint venture. In addition, the option to account for joint ventures (previously called jointly controlled entities) using proportionate consolidation would be removed, equity accounting would be required. Venturers would transition the accounting for joint ventures from the proportionate consolidation method to the equity method by aggregating the carrying values of the proportionately consolidated assets and liabilities into a single line item.
These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Company has not determined the impact of the new standard on the consolidated financial statements.

IFRS 12 ***Disclosure of Involvement with Other Entities***

The IASB has issued IFRS 12 *Disclosure of Involvement with Other Entities*, which includes disclosure requirements about subsidiaries, joint ventures, and associates, as well as unconsolidated structured entities and replaces existing disclosure requirements. This standard is effective for annual periods beginning on or after January 1, 2013. Entities will be permitted to apply any of the disclosure requirements in IFRS 12 before the effective date. The Company has not determined the impact of the new standard on the consolidated financial statements.

IFRS 13 ***Fair Value Measurement***

IFRS 13 will generally converge the IFRS and US GAAP requirements for how to measure fair value and the related disclosures. IFRS 13 establishes a single source of guidance for fair value measurements, when fair value is required or permitted by IFRS. The key features of IFRS 13 include: a single framework for measuring fair value while requiring enhanced disclosures when fair value is applied, fair value would be defined as the 'exit price', and concepts of 'highest and best use' and 'valuation premise' would be relevant only for non-financial assets and liabilities. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Company has not determined the impact of the new standard on the consolidated financial statements.

IAS 27 ***Separate Financial Statements***

As a result of the issue of the new consolidation suite of standards, IAS 27 *Separate Financial Statements* has been reissued as the consolidation guidance will now be included in IFRS 10. IAS 27 will now only prescribe the accounting and disclosure requirements for investments in subsidiaries, joint ventures and associates when an entity prepares separate financial statements. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Company does not believe IAS 27 will have a material impact on the Company's consolidated financial statements.

IAS 28 ***Investments in Associates and Joint Ventures***

As a consequence of the issue of IFRS 10, IFRS 11 and IFRS 12, IAS 28 has been amended and will provide the accounting guidance for investments in associates and to set out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. The amended IAS 28 will be applied by all entities that are investors with joint control of, or significant influence over, an investee. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Company has not determined the impact of the new standard on the consolidated financial statements.

14. Related-Party Transactions

a) In June 2007, the Company entered into a 5-year lease agreement with Blue Pacific for administrative office space in one of its Bogota, Colombia locations. Monthly rent expense of $57 is payable to Blue Pacific under this agreement. Three directors and officers of the Company control, or provide investment advice to the holders of, 67.2% of the shares of Blue Pacific. The Company also has accounts receivable of $1.3 million from Blue Pacific related to certain administrative costs paid by the Company on behalf of Blue Pacific. In addition, the Company paid $554 (2010 - $500) to Blue Pacific during the three months ended March 31, 2011 for air transportation services received.

b) As at March 31, 2011, the Company had trade accounts receivable of $0.9 million (2010 - $1.7 million) from Proelectrica, in which the Company has a 17.7% indirect interest and which is 31.49% owned by Blue Pacific. The Company's and Blue Pacific's indirect interests are held through Ronter. Revenue from Proelectrica in the normal course of the Company's business was $3.9 million for the three months ended March 31, 2011 (2010 - $7.4 million).

c) During the three months ended March 31, 2011, the Company paid $10.9 million (2010 - $11.9 million) to Transmeta in crude oil transportation costs. The Company had accounts receivable of $4 million (2010 - $4.1 million) from Transmeta as at March 31, 2011. Transmeta is controlled by a director of the Company. Prior to the Company's transition to IFRS, the financial results of Transmeta were consolidated by the Company as Transmeta was a variable interest entity and the Company was its primary beneficiary. Under IFRS, the Company no longer consolidates Transmeta.

d) During the period ended March 31, 2011, the Company received $537 (2010 - $1.8 million) from companies related by way of a number of directors in common, for reimbursement of general and administrative support expenses for the office premises in Canada. As at March 31, 2011, the Company has accounts receivable of $350 (2010 - $215) from the above companies, which has since been fully repaid.

e) Loans receivable in the aggregate amount of $497 (2010 – $322) are due from three management directors and three officers of the Company as at March 31, 2011. The loans are non-interest bearing and payable in equal monthly payments over 48 months. The loans were issued by the Company to these individuals in connection with costs incurred by these individual as a result of their relocation.

f) The Company has entered into aircraft transportation agreements with Petroleum Aviation Services S.A.S., a company controlled by a director of the Company. During the three months ended March 31, 2011, the Company paid $1.4 million (2010 - $1.9 million) in fees as set out under the agreements.

g) The Company received $.03 million from ODL during the three months ended March 31, 2011 (2010 – nil) with respect to certain administrative services and rental equipment and machinery. The Company has accounts receivable of $1.9 million from ODL with respect to reimbursement of power supply costs as at March 31, 2011 (2010 – $3.1 million).

All related party transactions are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

15. Internal Controls over Financial Reporting ("ICFR")

The Company´s internal audit department provides support to the Board of Directors, Audit Committee, and Management, and contributes to the continuous improvement strategies of the organization. The Chief Audit Executive (CAE) reports to the Audit Committee. The role of the Internal Audit department is to provide guidance and expertise in areas including, but not limited to, corporate governance, risk management, fraud policies and prevention, and information technology systems, in addition to the overall internal control. The internal audit process provides reasonable assurance over the:

- Evaluation of design and operating effectiveness of internal controls over financial reporting and disclosure controls and procedures as promulgated by National Instrument 52-109 "NI 52-109" as issued by the Canadian Securities Administrator "CSA"
- Effectiveness and efficiency of operations,
- Reliability of internal and external reporting, and
- Compliance with applicable laws and regulations.

During 2011, Internal Audit will continue focusing its activities on identifying, evaluating, and addressing critical and material risks for the organization. Following are some of the most significant risks reviewed, as well as, the actions addressed by management to mitigate them:

- Regulatory compliance: Some of the areas posing the greatest complexity include maintaining effectiveness of corporate process compliance controls in light of reporting, governance programs, the Corruption of Foreign Public Officials Act ("CFPOA"), anti-money laundering, and data security.

- Credit and liquidity strains: The audit review was focused on hedging capabilities and strategies, improving the automated environment to gain greater control of processing, and centralized cash pooling to improve cash management to capture synergies.

- Potential increased fraud risk: Audit reviews performed to reduce this risk included employee fraud awareness training to help maintaining fraud-resistance, fraud risk assessment within key areas and used the results to prioritized fraud detection efforts toward key current fraud risks, and review of segregation of duties controls and other fraud controls.

- Data security and privacy protection: The audit review was focused on the implementation of tools to protect the access to the network and the implementation of application securities, the use of tools to continuous auditing and monitoring, and the strengthening of control IT environment according with the standards.

The internal audit activities for the first quarter of 2011 included the following:

- During this quarter, the Internal Audit group reviewed the key differences identified by management between IFRS and Canadian GAAP to determine the impact of such differences on internal controls over financial reporting for the purposes of NI 52-109. Based on the review performed, additional controls were identified in the areas of Property, Plant and Equipment, Financial Statement Close and Reporting, and Entity Level Controls. Based on the review performed, the impact of IFRS on ICFR is not considered to be a material change to the control environment for the Company.

    - Evaluation of the design effectiveness of internal controls over financial reporting for the new controls that have been design as a result of the transition to IFRS
    - Evaluation of operating effectiveness of the ICFR for 10 processes considered to be high risk.

- Evaluation of the effectiveness of internal controls, encompassed within the requirements of "NI 52-109" issued by the CSA, over the design and operating effectiveness of the ICFR. During this quarter an evaluation of the design effectiveness of internal controls for the 21 new controls that have been designed as a result of the transition to IFRS was performed. Evaluation of operating effectiveness of the ICFR for 239 controls over 10 processes considered with high impact to IFRS transition was performed.

  From this evaluation the Company concludes that there are no material weaknesses or significant deficiencies in the design and effectiveness of the controls evaluated. The identified opportunities to improve the ICFR are in the following main areas:
  - Warehouse materials management
  - Tax reporting
  - Compliance with the Company´s procedures in the payment process
  - Compliance with the Company´s security standards to access SAP

- Four audit reports were completed by the internal audit team during the quarter. These audit reports included the control evaluation in operational effectiveness to the following business processes: Maintenance of equipment and facilities, Oil inventory and Oil & Gas measurement and reporting, CAPEX accounting, and Transport contracting. The results were reported to management and the Audit Committee, and action plans agreed with business process owners are in implementation.

- The Governance, Risk and Compliance solution was implemented. This solution will streamline governance programs, improve accountability and communication, ensuring adoption of corporate governance principles and best practices, and providing a systematic framework for documenting and assessing risks, defining controls, managing audits, identifying issues and implementing recommendations and remediation plans, and it provides an integrated approach to meet cross-industry mandates and regulations.
- As part of the risk management activities, a Corporate Risk Assessment was conducted with the participation of the Company´s senior management, in an effort to refresh and further assess the critical risks impacting the organization. The risk assessment process focused on assessing and prioritizing risks based on both impact and inherent like hood. 25 key risks were assessed and risk champions assigned to implement risk management plans. Also, a Fraud Risk Assessment through the organization was evaluated and its results presented to the Audit Committee; management is implementing plans to mitigate the fraud risks identified. Internal audit provides coaching and coordinates Risk Management activities.

Regulatory Policies

Certification of Disclosures Filings

In accordance with NI 52-109, the Company issues, on a quarterly and annual basis, a Certification of Filings ("Certification"). The Certification requires certifying officers to state that they are responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and ICFR.

The Certification requires certifying officers to state that they designed DC&P, or caused it to be designed under their supervision, to provide reasonable assurance that: (i) material information related to the Company is made known to the certifying officers by others; (ii) information required to be disclosed by the Company in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian securities legislation. In addition, the Certification requires certifying officers to state that they have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes.

16. Outlook

The Company will continue working on increasing its production and transportation capacity. Expansion of current facilities and the drilling of new production wells will allow the Company to increase its gross production to 265,000 boe/d, equivalent to a range between 100,000 and 105,000 boe/d net after royalties and field consumption, by the end of 2011. The Company will continue pursuing its strategy of production growth from its producing assets, but also accelerating the addition of new reserves from its exploration assets.

The Company's exploration activities will continue in 2011 and will include exploration in more than 26 blocks. In total, 20 exploratory wells, 36 appraisal wells and 3 stratigraphic wells will be drilled in 2011. This aggressive drilling campaign also includes the final acquisition of 539 km of 2D seismic and 440 km^2 of 3D seismic during 2011 in Colombia and further exploratory development of two blocks in Peru and one in Guatemala.

The STAR project is expected to begin in August 2011 and the Company continues its commitment to the implementation of this technology, not only because it creates significant value to the Company, its partners, shareholders and the country, by extending the production life of the Rubiales field, but also because it is believed that once in operation, STAR will have a dramatic impact on the entire Llanos region.

In addition, the broadening of the Company's growth strategy, including the Company's downstream integration and participation in infrastructure projects, is anticipated to complement the continued growth of the Company and provide it with secure and stable access to profitable markets. The Company will also concentrate on increasing its gas sales from the La Creciente field, and in order to achieve this, the Company is currently negotiating with gas transporters the commercial terms for an expansion of the infrastructure in the area.

17. Additional Financial Measures

This report contains the following financial terms that are not considered measures under IFRS: operating netback, net operating income from operations, funds flow from operations, and EBITDA.

A) *Reconciliation of cash flow from operating activities to funds flow from operations:*

The following table shows the reconciliation of funds flow from operations to cash flow from operating activities for the first quarter 2011 as compared with the first quarter of 2010:

	Q1	
	2011	2010
Cash flow from operating activities	319,803	257,599
Changes in non-cash working capital	53,096	108,212
Funds flow from operations (non-GAAP)	266,707	149,387

B) Reconciliation of Net Earnings (Loss) to EBITDA:

	Q1	
	2011	2010
Net earnings (loss)	(69,593)	76,127
Adjustments to net earnings (loss)		
Income taxes expense	49,374	30,330
Foreign exchange gain	(3,953)	(13,525)
Finance cost	23,149	13,876
Loss (gain) on risk management contracts	92,634	(5,017)
Loss from equity investment	3,388	1,184
Other expense	3,335	1,887
Share-based compensation	46,687	40,822
Equity tax	68,446	522
Depletion, depreciation and amortization	149,060	85,760
EBITDA	362,527	231,966

C) Earnings from operations:

Earnings from operations includes revenues less oil and gas operating costs, depletion, depreciation and amortization and G&A expenses, and excludes effect of the underlift, share-based compensation and other income and expenses.

	Q1	
	2011	2010
Revenues	$ 583,549	$ 379,431
Less		
Operating cost	(189,777)	(128,418)
Depletion, depreciation and amortization	(149,060)	(85,760)
General and administration	(31,245)	(19,047)
Earnings from operations	$ 213,467	$ 146,206

D) Net Earnings before Non-cash Items:

	Q1	
	2011	2010
Net earnings (loss)	$ (69,593)	$ 76,127
Less non-cash items		
Loss (gain) on risk management contracts	92,634	(5,017)
Share-based compensation	46,687	40,822
Equity tax	68,446	522
Foreign exchange gain	(3,953)	(13,525)
Total non-cash items	$ 203,814	$ 22,802
Net earnings before non-cash items	$ 134,221	$ 98,929

18. Legal Notice – Forward-Looking Information and Statements

Certain statements in this MD&A constitute forward-looking statements. Often, but not always, forward-looking statements use words or phrases such as: "expects", "does not expect" or "is expected", "anticipates" or "does not anticipate", "plans" or "planned", "estimates" or "estimated", "projects" or "projected", "forecasts" or "forecasted", "believes", "intends", "likely", "possible", "probable", "scheduled", "positioned", "goal", "objective" or state that certain actions, events or results "may", "could", "would", "might" or "will" be taken, occur or be achieved. Such forward-looking statements, including but not limited to statements with respect to anticipated levels of production, the estimated costs and timing of the Company's planned work programs and reserves determination involve known and unknown risks, uncertainties and other factors which may cause the actual levels of production, costs and results to be materially different from estimated levels of production, costs or results expressed or implied by such forward-looking statements. The Company believes the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. Factors that could cause actual results to differ materially from those anticipated in these forward-looking statements are described under the caption “Risks and Uncertainties”. Although the Company has attempted to take into account important factors that could cause actual costs or operating results to differ materially, there may be other unforeseen factors to cause costs to the Company's program and results may not to be as anticipated, estimated or intended.

Statements concerning oil and gas reserve estimates may also be deemed to constitute forward-looking statements to the extent they involve estimates of the oil and gas that will be encountered if the property is developed. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Estimated values of future net revenue disclosed do not represent fair market value.

19. Risks and Uncertainties

The business and operations of the Company will be subject to a number of risks. The Company considers the risks set out below to be the most significant to potential investors in the Company, but does not include all of the risks associated with an investment in securities of the Company:

- fluctuating oil and gas prices;
- cash flows and additional funding requirements;
- global financial conditions;
- exploration and development;
- operating hazards and risks;
- reserve estimates;
- transportation costs;
- disruptions in production;
- political risk;
- environmental factors;
- title matters;
- dependence on management;
- changes in legislation;
- repatriation of earnings;
- enforcement of civil liabilities;
- competition; and
- payment of dividends.

If any of these risks materialize into actual events or circumstances or other possible additional risks and uncertainties of which the Company is currently unaware or which it considers not to be material in relation to the Company’s business, actually occur, the Company’s assets, liabilities, financial condition, results of operations (including future results of operations), business and business prospects, are likely to be materially and adversely affected. In such circumstances, the price of the Company’s securities could decline and investors may lose all or part of their investment. For more information, please see the Company’s Annual Information Form which is available at www.sedar.com.

20. Glossary

1P	Proven reserves (also known as P90).
2D seismic	Shows a single cross-section through the earth along a relatively straight line.
2P	Proven reserves + Probable reserves.
3D seismic	3D seismic is shot similar to 2D, except that the “shotpoints” are much closer together and are laid out on a grid, instead of in a straight line. The geophones that receive the reflected sound waves are also laid out in a grid.
3P	Proven reserves + Probable reserves + Possible reserves.
Appraisal well	Exploration well drilled near a well already in production as part of an appraisal campaign, which is carried out to determine the physical extent and likely production rate of a field.
bbl/d	Barrels per day
Bcf	Billion cubic feet
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
Btu	British thermal units
Bwpd	Barrels of water per day
Core sampling	At depths of interest, the drill bit is replaced by a hollow one that will extract a cylinder of several meters of rock. Confirms rock type, fluid content, dip, porosity and permeability.
Density	Also known as the oil’s gravity – measured in ÅãAPI and indicative of what products the crude can be refined into. The higher the gravity, the lighter the oil.
Development well	A production well drilled to begin production after a reservoir has been discovered and defined. Usually takes place over the area with the largest pay thickness in the reservoir.
Diluent	The addition of diluents enables the fluid to meet pipeline specifications in order for it to be efficiently transported. Typical diluents in this application are naphtha or light oil used with very heavy oil or bitumen.
Dip	The slant of a reservoir.
Discovery well	An exploration well that has encountered hydrocarbons.
MMbbl	million barrels
Mmboe	Million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Mmscf/d	Million standard cubic feet per day
Mw	Megawatts
Netbacks	Total of revenues from oil/gas, less all costs associated with getting oil/gas to market. These costs can include importing, transportation, production and refining costs and royalty fees.
Net reservoir thickness/net pay or oil zone	Reservoir vertical extent – thickness measured in feet of the productive portion of a reservoir.
NGL	natural gas liquids
Permeability	Measured in millidarcies (mD), measures how connected the pores are within the rock, indicating how easily oil will flow through it.
Porosity	Percentage of void space versus solid rock, which is the space where oil is potentially trapped.
Possible reserves	Estimates with a probability of 10%-49% under present technical and economical conditions. Also known as P3 when referred to as an individual component.
Primary recovery	Extraction of oil using methods and mechanisms of natural lift or artificial lift.
Probable reserves	Estimates with a probability of 50%-89% under present technical and economical conditions. Also known as P2 when referred to as an individual component.
Proven reserves	Estimates with a probability of 90% or greater under present technical and economical conditions. Also known as P1 when referred to as an individual component.
Recovery factor	Maximum percentage of oil in place which is technically recoverable.
Reservoir rock	A porous and permeable rock for hydrocarbons to accumulate in.

Dry hole	A well that is drilled does not encounter hydrocarbons.
ESP	Electro-Submersible Pump
Farm-out agreements	The “farmor” agrees to assign acreage to a second company (the “farmee”) in return for the second company performing specified drilling and testing obligations, with the farmor also reserving an interest in the acreage assigned and in the production from the wells drilled by the second company.
Geophysics	See Gravity survey – Magnetic survey – Seismic survey.
Gravity survey	A study of the earth’s gravity, which varies with changes in density of subsurface rock.
Gross pay	Average thickness of the entire reservoir.
Heavy crude	Oil with a low gravity density (generally <25Åã API).
km	kilometers
Light crude	Oil with a high gravity density (generally >30Åã API).
Magnetic survey	A study of the earth’s magnetism. Most oil is contained in nonmagnetic sedimentary rocks (igneous & metamorphic rocks are magnetic and contain no oil).
Mbbl	thousand barrels
Mboe	thousand barrels of oil equivalent
Mcf/d	thousand cubic feet per day
Mcf	thousand cubic feet
MD	Measured depth
Secondary recovery	Involves “push” mechanisms that attempt to maintain or increase reservoir pressure when primary recovery production rates fall. Water flooding is the most commonly used method.
Seismic survey	Works on the principle of the time it takes for reflected sound waves to travel through rock of varying densities. 2D or 3D seismic surveys create virtual images of what a reservoir looks like.
Service contracts	Flat fee paid by mineral rights owner to E&P company to carry out the E&P. Only paid if production takes place.
Source rock	Rich in dead, organic material (kerogen) buried deep enough for heat and pressure to change it into hydrocarbons.
Spudding	Initial stage of drilling.
Stratigraphic traps	Stratigraphic traps form when other beds seal a reservoir bed or when the permeability changes within the reservoir bed itself. Examples of stratigraphic traps are a) unconformity traps, b) pinchout traps, and c) lens traps.
Structural traps	Structural traps form because of a deformation in the rock layer that contains the hydrocarbons. Examples of structural traps are a) anticlinal traps, b) fault traps, and c) salt dome.
Tcf	trillion cubic feet
TD	True depth
TVDSS	True vertical depth below sea level
Viscosity	Inside the reservoir, viscosity is measured in poise (P); outside the reservoir, measured in centistoke (cS). Viscosity indicates how easily oil will flow.
WTI	West Texas Intermediate index